PUBLIC

Part 1 of 2

INFORMATION SHEET

PRESIDING: Commissioner Duffley, Presiding; Chair Mitchell, and Commissioners Brown-Bland, Clodfelter, Hughes, McKissick, Jr., and Kemerait

PLACE: Raleigh, NC

DATE: Friday, September 1, 2023

TIME: 12:07 p.m. to 1:21 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 toElectric Service in North Carolina and for Performance-BasedRegulation

VOLUME NUMBER: 15

APPEARANCES

See attached

WITNESSES

See attached

EXHIBITS

None attached

REPORTED BY: Lisa A. DeGroat	TRANSCRIPT PAGES: 93
TRANSCRIBED BY: Lisa A. DeGroat	PREFILED PAGES: 1227
DATE FILED: September 8, 2023	TOTAL PAGES: 1320

PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Friday, September 1, 2023

TIME: 12:07 p.m. - 1:21 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 15

Noteworthy Reporting Services, LLC

A P P E A R A N C E S:

FOR DUKE ENERGY CAROLINAS, LLC:

Jack E. Jirak, Esq., Deputy General Counsel
Duke Energy Corporation
410 South Wilmington Street, NCRH 20
Raleigh, North Carolina 27602

Jason A. Higginbotham, Esq.
Associate General Counsel
Duke Energy Corporation
525 South Tryon Street/ECA3
Charlotte, North Carolina 28202

James H. Jeffries, IV, Esq., Partner
McGuireWoods LLP
201 North Tryon Street, Suite 3000
Charlotte, North Carolina 28202

Andrea Kells, Esq.
Kristin M. Athens, Esq.
McGuireWoods LLP
501 Fayetteville Street, Suite 500
Raleigh, North Carolina 27601

A P P E A R A N C E S (Cont'd.):

Brandon F. Marzo, Esq., Partner
Melissa Oellerich Butler, Esq., Associate
Joshua Warren Combs, Esq., Associate
Troutman Pepper Hamilton Sanders LLP
600 Peachtree Street Northeast, Suite 3000
Atlanta, Georgia 30308

Kiran H. Mehta, Esq., Partner
Molly McIntosh Jagannathan, Esq., Partner
Melinda L. McGrath, Esq., Partner
Troutman Pepper Hamilton Sanders LLP
301 South College Street, Suite 3400
Charlotte, North Carolina 28202

FOR CAROLINA UTILITY CUSTOMERS ASSOCIATION:

Marcus W. Trathen, Esq.
Matthew Tynan, Esq.
Christopher B. Dodd, Esq.
Brooks Pierce McLendon Humphrey & Leonard, LLP
150 Fayetteville Street, Suite 1700
Raleigh, North Carolina 27601

A P P E A R A N C E S (Cont'd.):

FOR CAROLINA INDUSTRIAL GROUP FOR FAIR UTILITY RATES III:

Christina D. Cress, Esq., Partner
Douglas D.C. Conant, Esq., Associate
Bailey & Dixon, LLP
434 Fayetteville Street, Suite 2500
Raleigh, North Carolina 27601

Chris S. Edwards, Esq., Partner
Ward and Smith, P.A.
127 Racine Drive
Wilmington, North Carolina 28403

FOR NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:

Ethan Blumenthal, Esq., Regulatory Counsel
Cassie Gavin, Esq., Director of Policy
4800 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

A P P E A R A N C E S (Cont'd.):

HAYWOOD EMC, BLUE RIDGE EMC, PIEDMONT EMC, and
RUTHERFORD EMC:

Christina D. Cress, Esq., Partner
Bailey & Dixon, LLP
434 Fayetteville Street, Suite 2500
Raleigh, North Carolina 27601

Chris S. Edwards, Esq., Partner
Ward and Smith, P.A.
127 Racine Drive
Wilmington, North Carolina 28403

FOR NORTH CAROLINA LEAGUE OF MUNICIPALITIES:
Ben Snowden, Esq., Partner
Fox Rothschild LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

FOR THE COMMERCIAL GROUP:
Alan Jenkins, Esq.
Jenkins at Law, LLC
2950 Yellowtail Avenue
Marathon, Florida 33050

A P P E A R A N C E S (Cont'd.):

FOR THE SIERRA CLUB:

Catherine Cralle Jones, Esq.
Andrea Bonvecchio, Esq.
Law Offices of F. Bryan Brice, Jr.
130 South Salisbury Street
Raleigh, North Carolina 27601

FOR NORTH CAROLINA JUSTICE CENTER, NORTH CAROLINA HOUSING COALITION, NATURAL RESOURCES DEFENSE COUNCIL, SOUTHERN ALLIANCE FOR CLEAN ENERGY, AND VOTE SOLAR:

David L. Neal, Esq., Senior Attorney
Munashe Magarira, Esq., Staff Attorney
Thomas Gooding, Esq., Associate Attorney
Southern Environmental Law Center
601 West Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

FOR NC WARN:

Matthew D. Quinn, Esq., Partner
Lewis & Roberts, PLLC
Post Office Box 17529
Raleigh, North Carolina 27619

A P P E A R A N C E S (Cont'd.):

FOR THE KROGER CO. AND HARRIS TEETER, LLC:
Kurt J. Boehm, Esq.
Jody Kyler Cohn, Esq.
Boehm, Kurtz & Lowry
36 East 7th Street, Suite 1510
Cincinnati, Ohio 45202

Ben Royster, Esq.
Royster & Royster, PLLC
851 Marshall Street
Mount Airy, North Carolina 27030

FOR ANDALE, LLC:
Marcus W. Trathen, Esq.
Brooks Pierce McLendon Humphrey & Leonard, LLP
150 Fayetteville Street, Suite 1700
Raleigh, North Carolina 27601

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):

Tirrill Moore, Esq., Assistant Attorney General
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:

Lucy E. Edmondson, Esq., Chief Counsel
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

TABLE OF CONTENTS

EXAMINATIONS

E X H I B I T S

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: ___

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.

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

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

Email: JACK.JIRAK@DUKE-ENERGY.COM

SIGNATURE: ______________________

(Signature Required for distribution of CONFIDENTIAL information)

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.

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

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

Email: jason.higginbotham@duke-energy.com

SIGNATURE: [signature]

(Signature Required for distribution of CONFIDENTIAL information)

OFFICIAL COPY May 26 2023

OFFICIAL COPY Oct 04 2023

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: ___

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.

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: JJEFFRIES@MCGUIREWOODS.COM

SIGNATURE: ______

(Signature Required for distribution of CONFIDENTIAL information)

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: ___

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.

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: akells@mcguirewoods.com

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

(Signature Required for distribution of CONFIDENTIAL information)

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: ___

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.

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: kathens@mcguirewoods.com

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

(Signature Required for distribution of CONFIDENTIAL information)

OFFICIAL COPY

Oct 04 2023

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: ___

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.

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: brandon.marzo@troutman. com

SIGNATURE: [signature]

(Signature Required for distribution of CONFIDENTIAL information)

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:** ___

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.

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: melissa.butler2@duke-energy.com

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

(Signature Required for distribution of CONFIDENTIAL information)

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:** ___

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.

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: Josh.Combs@troutman.com

SIGNATURE: ______________________________

(Signature Required for distribution of CONFIDENTIAL information)

NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

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

ATTORNEY NAME and TITLE: Kiran H. Mehta, Partner

FIRM NAME: Troutman Pepper Hamilton Sanders LLP

ADDRESS: 301 S. College St., Suite 3400

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

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.

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: kiran.mehta@troutman.com

SIGNATURE: Kiran H. Mehta

(Signature Required for distribution of CONFIDENTIAL information)

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:** ___

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.

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: molly.jagannathan@troutman.com

SIGNATURE: Molly M. Jagannathan

(Signature Required for distribution of CONFIDENTIAL information)

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:** ___

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.

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.**

Email: Mindy.McGrath@troutman.com

SIGNATURE: M McGrath

(Signature Required for distribution of CONFIDENTIAL information)

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: ___

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 and 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.

To receive an electronic **CONFIDENTIAL** transcript, please complete the following:

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

Email: mtrathen@brookspierce.com

SIGNATURE: /s/ Marcus Trathen

(Required for distribution of CONFIDENTIAL transcript)

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: ___

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.

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: mtynan@brookspierce.com

SIGNATURE: Matthew B. Tynan

(Signature Required for distribution of CONFIDENTIAL information)

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:** ___

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.

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)

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:** ___

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.

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: ccress@bdixon.com

SIGNATURE: Christina D. Cress Digitally signed by Christina D. Cress Date: 2023.08.22 13:33:10 -04'00'

(Signature Required for distribution of CONFIDENTIAL information)

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: ___

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.

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

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

Email: ethan@energync.org

SIGNATURE: Ethan Blumenthal Digitally signed by Ethan Blumenthal Date: 2023.08.21 21:17:22 -04'00'

(Signature Required for distribution of CONFIDENTIAL information)

NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

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

ATTORNEY NAME and TITLE: Cassie Gavin, Director of Policy

FIRM NAME: NCSEA

ADDRESS: 4800 Six Forks Rd, Suite 300

CITY: Raleigh STATE: NC ZIP CODE: 27609

APPEARANCE ON BEHALF OF: NCSEA

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X

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.

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

☐ ✓ **Yes, I have signed the Confidentiality Agreement.**

Email: cassie@energync.org

SIGNATURE: /s/ by KJM: Cassie Gavin

(Signature Required for distribution of CONFIDENTIAL information)

NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

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

ATTORNEY NAME and TITLE: Ben Snowden, Partner

FIRM NAME: Fox Rothschild LLP

ADDRESS: 434 Fayetteville St., Suite 2800

CITY: Raleigh STATE: NC ZIP CODE: 27601

APPEARANCE ON BEHALF OF: North Carolina League of Municipalities

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: x__

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.

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: bsnowden@foxrothschild.com

SIGNATURE: BSnowden Digitally signed by BSnowden Date: 2023.04.27 16:52:04 -04'00'

(Signature Required for distribution of CONFIDENTIAL information)

NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

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

ATTORNEY NAME and TITLE:

Alan Jenkins

FIRM NAME: Jenkins at Law, LLC

ADDRESS: 2950 Yellowtail Ave

CITY: Marathon STATE: FL ZIP CODE: 33050

APPEARANCE ON BEHALF OF: The Commercial Group

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: x__

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.

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

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

Email: aj@jenkinsatlaw.com

SIGNATURE: ______________________________

(Signature Required for distribution of CONFIDENTIAL information)

NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

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

ATTORNEY NAME and TITLE: Catherine Cralle Jones

FIRM NAME: Law Offices of F. Bryan Brice, Jr.

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: ___

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.

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: cathy@attybryanbrice.com

SIGNATURE: Catherine Cralle Jones

(Signature Required for distribution of CONFIDENTIAL information)

NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP

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

ATTORNEY NAME and TITLE: Andrea C. Bonvecchio

FIRM NAME: Law Offices of F. Bryan Brice, Jr.

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: ___

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.

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: andrea@attybryanbrice.com

SIGNATURE: ____________

(Signature Required for distribution of CONFIDENTIAL information)

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

FIRM NAME: Southern Environmental Law Center

ADDRESS: 601 West Rosemary Street, Suite 220

CITY: Chapel Hill STATE: North Carolina ZIP CODE: 27516

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: ___

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.

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: dneal@selcnc.org

SIGNATURE: 2023.08.23 12:33:09 -04'00'

(Signature Required for distribution of CONFIDENTIAL information)

NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

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

ATTORNEY NAME and TITLE: Munaashe Magarira, Staff Attorney

FIRM NAME: Southern Environmental Law Center

ADDRESS: 601 W Rosemary Street, Suite 220

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: ___

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.

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: mmagarira@selcnc.org

SIGNATURE: Digitally signed by Munashe Magarira Date: 2023.08.22 09:28:18 -04'00'

(Signature Required for distribution of CONFIDENTIAL information)

NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

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

ATTORNEY NAME and TITLE: Thomas Gooding, Associate Attorney

FIRM NAME: Southern Environmental Law Center

ADDRESS: 601 W. Rosemary Street, Suite 220

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:** ___

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.

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: tgooding@selcnc.org

SIGNATURE: Thomas Gooding Digitally signed by Thomas Gooding Date: 2023.04.29 12:46:36 -04'00'

(Signature Required for distribution of CONFIDENTIAL information)

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

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.

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

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

Email: ____________________

SIGNATURE: ____________________

(Signature Required for distribution of CONFIDENTIAL information)

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: ___

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.

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: kboehm@bkllawfirm.com

SIGNATURE: KBd

(Signature Required for distribution of CONFIDENTIAL information)

NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

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

ATTORNEY NAME and TITLE: Jody Kyler Cohn, Esq.

FIRM NAME: Boehm, Kurtz & Lowry

ADDRESS: 36 East 7th Street, Suite 1510

CITY: Cincinnati STATE: Ohio ZIP CODE: 45202

APPEARANCE ON BEHALF OF: The Kroger Company

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X

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.

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

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

Email: ____________________

SIGNATURE: ____________________

(Signature Required for distribution of CONFIDENTIAL information)

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:** ___

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.

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

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

Email: ____________________

SIGNATURE: ____________________

(Signature Required for distribution of CONFIDENTIAL information)

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: Andale, LLC

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X

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 and 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.

To receive an electronic **CONFIDENTIAL** transcript, please complete the following:

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

Email: mtrathen@brookspierce.com

SIGNATURE: /s/ Marcus Trathen

(Required for distribution of CONFIDENTIAL transcript)

NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP

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

ATTORNEY NAME and TITLE: Tirrill Moore

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

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.

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: temoore@ncdoj.gov

SIGNATURE: [signature]

(Signature Required for distribution of CONFIDENTIAL information)

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

ADDRESS: 114 W. Edenton Steet

CITY: Raleigh **STATE:** NC **ZIP CODE:** 27603

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)

APPLICANT: ___ **COMPLAINANT:** ___ **INTERVENOR:** X__

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.

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: dmertz@ncdoj.gov

SIGNATURE: Derrick Mertz Digitally signed by Derrick Mertz Date: 2023.08.23 15:26:03 -04'00'

(Signature Required for distribution of CONFIDENTIAL information)

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

TO REQUEST A **CONFIDENTIAL** TRANSCRIPT, PLEASE PROVIDE YOUR EMAIL ADDRESS BELOW:

ACCOUNTING

CONSUMER SERVICES
COMMUNICATIONS
ENERGY

ECONOMICS
LEGAL lucy.edmondson@psncuc.nc.gov; robert.josey@psncuc.nc.gov; nadia.luhr@psncuc.nc.gov; thomas.felling@psncuc.nc.gov; zeke.creech@psncuc.nc.gov; william.freeman@psncuc.nc.gov; anne.keyworth@psncuc.nc.gov

TRANSPORTATION
WATER

Non-confidential transcripts are located on the Commission's website. To view and/or print, please access https://www.ncuc.net/.

COUNSEL/MEMBER(s) REQUESTING A **CONFIDENTIAL** TRANSCRIPT WHO HAS SIGNED A CONFIDENTIALITY AGREEMENT WILL NEED TO SIGN BELOW.

/s/ Lucy E. Edmondson
/s/ Robert B. Josey
/s/ Nadia L. Luhr
/s/ Thomas J. Felling
/s/ William E. H. Creech
/s/ William Freeman /s/ Anne M. Keyworth

/A

NERP Table of Metrics with Comparisons

This table shows the list of potential metrics propsoed during the NERP stakeholder process.
The shading represents the metrics also proposed by either DEC or the Public Staff in this proceeding.

	Peak Demand Reduction	Integration of utility-scale Renewable Energy (RE) & Storage	Integration of DERs (RE/storage/non-wires alternatives)	Low-Income Affordability	Carbon Emissions Reduction
Preferred	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) (programbased PIM)	Meeting interconnection review deadlines agreed on in queue reform (downside only)	3-year rolling average of net metered projects connected (MW and # of projects) (upside only)	% 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)	Tons of CO2 equivalents reduced beyond what is required by law or policy (with costeffectiveness test, upside only)
	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)	MW of RE interconnected over and above that required by law or policy (upside only)			
	MW reduced from the utility s NCUC-accepted IRP peak demand forecast (for summer and winter peak) (upside only) (outcome-based PIM)	% MWh generation represented by RE			
Alternative	Enrollment (% of load or # of customers) in TOU rates or other advanced rates (symmetrical, likely as ROE adjustment)	MW of utility-scale RE interconnected/yr	MW/MWh customer-sited storage in utility management programs	Total disconnections for nonpayment	Reduction in carbon intensity (tons carbon/MWh sold) (symmetrical)
	MW demand response enrolled with TOU or other advanced rates (upside only, likely as ROE adjustment)	MWh RE curtailment (symmetrical around a reasonable number)	# customers (and MW) participating in utility programs to promote customer-owned or customer-leased DER	Usage per customer vs. historic rolling average, per class	Carbon price used in IRP scenarios ($/ton, tracked metric only)
	% 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)	MWh of power from RE-charged utility-scale storage/yr (upside only)	# customers (and MW) participating in utility programs to provide grid services (including RE, storage, smart thermostat, etc.)	Average monthly bill	
	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)	% RE capacity (MW) (tracked metric only)	% of rooftop solar systems passing interconnection screens (upside only)	% customers past due on their accounts	
		Avg. number of days to interconnect utility-scale solar, below target(s) set forth in queue reform (upside only)		# customers on fixed-bill programs	

DEC proposed metrics
Public Staff proposed metrics

NERP Table of Metrics with Comparisons

This table shows the list of potential metrics propsoed during the NERP stakeholder process.
The shading represents the metrics also proposed by either DEC or the Public Staff in this proceeding.

	Electrification of Transportation	Equity in Contracting	Resilience	Reliability	Customer Service
Preferred	EV customers on TOU or managed charging (include home, workplace, fleets, and public charging) (upside only)	% 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)	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	SAIDI (performance year-over-year, excluding extreme event days, downside only, feeder-byfeeder)	Third-party customer satisfaction survey (e.g., JD Power score or Net Promoter score) (downside only)
	MWh or % of EV charging load at low-cost hours (upside 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)	Critical asset energy demand not served (cumulative kW)		
			Critical asset time to recovery (average hrs)		
Alternative	Utilization of utility-owned public charging stations (upside only)		Cumulative critical customer hours of outages (hrs)	CEMI4 (customers experiencing more than 4 outages of 1 minute or more per year)	
	Utility-owned charging in low-income areas (# or % chargers) (symmetrical)			SAIFI	
	Customers enrolled in programs to encourage private charger installation (upside only)			Miles of vegetation management (tracked metric 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				

DEC proposed metrics
Public Staff proposed metrics

Public Staff's Proposed PIMs				
PIM	**Measurement of Metric**	**Policy Goal Achievement**	**Benefit to Customer**	**Reward / Penalty**
TOU Enrollment	Number of incremenetal TOU customers	Cost Savings Operational Efficiency	Driving improved optimization of the grid	Reward Only: Max $1M
Utility Scale Interconnections	Incremental MW of Interconnections above Carbon Plan forecast	Operational Efficiency	Increased amount of Interconnected Generation	Reward Only: (0, $4M, $6M)

Company PIMs Supported By Public Staff				
PIM	**Measurement of Metric**	**Policy Goal Achievement**	**Benefit to Customer**	**Reward / Penalty**
Customer Reliability	SAIDI reductions	Reliability	Reduction in system outage duration	Penalty Only: Max $9M

/A

DOCKET NO. E-7, Sub 1276

CONFIDENTIAL MICHNA EXHIBIT 1

CONFIDENTIAL MICHNA EXHIBIT 2

CONFIDENTIAL MICHNA EXHIBIT 3

Marshall Units 1-4 Gas Co-firing Schedule

Milestone	Date
Risk Register & Independent Review Board Estimate completed	9/29/2017
TRC Review / CEO Approval	10/01/17
FHO/RRE Project Review Board Approval	10/6/2017
PNG files the Agreement with NCUC	12/15/17
Initiate Gate Approval / Phase I Funding Approval	12/28/17
NCDAQ PSD Construction Permit Filing	05/03/18
PNG receives NCUC approval and execute Agreement	04/10/18
TRC Review/Approval – Additional Funding	06/14/2019
Build Gate Approval / Phase II Funding Approval	07/22/2019
Conceptual Design Review Board (DRB)	10/5/18
IER & PRB Review	10/15/18
NCDAQ PSD Construction Permit Received	08/30/19
Construction Start	11/18/19
Units 3&4 Burner material on-site	02/02/20
Units 3 Outage	04/17/20
Units 4 Outage	07/06/20
Units 4 Outage Completion	08/14/20
PNG gas available on-site	09/25/20
Unit 3 Outage Rework Burners	9/14/20 - 10/9/20
Unit 3 Commission Window	10/10/20 - 11/17/20
Unit 3 Gas System & Common Equipment in-service	11/11/20
Unit 4 Commission Window	1/4/2021 - 1/20/2021
Units 4 Gas system in-service	01/14/2021
Units 1&2 Burner material on-site	04/14/21
Units 1 Outage Completion	10/24/21
Units 2 Outage Completion	11/14/21
Units 2 Gas system in service	11/30/21
Units 1 Gas system in service	12/15/21

DOCKET NO. E-7, Sub 1276

CONFIDENTIAL MICHNA EXHIBIT 5

CONFIDENTIAL MICHNA EXHIBIT 6

CONFIDENTIAL MICHNA EXHIBIT 7

CONFIDENTIAL MICHNA EXHIBIT 8

Walsh Exhibit 1	MYRP Project Name	Project Forecasted In-Service Date	Funding Project #	Documentation	Grand Total	Latest Update	Documentation
62	HCA Dust BC23 Conv Trans Repl	Dec-23	BC001465	None	$ 1,840,330.10	Original	None
63	Marshall - Replace Fuel Handling Trnsfr 2024	Nov-25	MS000745	None	$ 2,377,042.11	Other Significant Developments	None
64	HCA Transfer House Wash Down	Nov-23	MS000747	Funding Ap	$ 1,518,635.75	Overall Cost Estimate Change	Funding Approval
65	Marshall - Replace Fuel Handling Trnsfr 2025	Nov-26	MS000746	None	$ 2,625,605.02	Other Significant Developments	None
66	Marshall Aux Boiler	Feb-26	MSCM124	Evaluator	$ 12,169,850.47	Project > $10M	Evaluator
67	Marshall Coal Blending PLC Replacement	Dec-23	MS001315	Evaluator	$ 1,332,300.74	Overall Cost Estimate Change	Evaluator
68	OPTIM ST Valve RHSVIVTVGV U2	May-24	BC020371	None	$ 4,513,477.50	Overall Cost Estimate Change	None
69	HCA DustBC 6A6D Vibratory Fdrs	Dec-24	BCCM0023	None	$ 1,899,900.37	Overall Cost Estimate Change	None
70	Marshall Crusher Motor Chillers Alt Feed	Sep-23	MS000926	Evaluator +	$ 1,471,620.18	Overall Cost Estimate Change	Evaluator + Funding Approval
71	Marshall MS01 600V 1XS MCC Replacement	Oct-24	MS011378	Evaluator	$ 954,589.70	Overall Cost Estimate Change	Evaluator
72	Marshall MS1 600V 1XD MCC Replacement	Oct-25	MS011394	Evaluator	$ 994,168.70	Overall Cost Estimate Change	Evaluator
73	Marshall MS1 MSU Transf Cooler and Pump	Oct-24	MS010109	Evaluator	$ 1,106,134.51	Overall Cost Estimate Change	Evaluator
74	Marshall MS2 4kV Relay System replacement	Oct-25	MS020111	Evaluator	$ 960,041.60	Overall Cost Estimate Change	Evaluator
75	HCA DustBC 1 Head Chute Repl	Aug-25	BC000199	None	$ 1,513,087.52	Overall Cost Estimate Change	None
76	Belews Creek BC01 SCR Catalyst Replacement	May-25	BC010717	None	$ 3,181,663.63	Overall Cost Estimate Change	None
77	Marshall MS2 MSU Xfrmr Cooler and Pump	Nov-24	MS020064	Evaluator	$ 974,863.66	Other Significant Developments	Evaluator
78	Marshall MS3 FD Fan Bearing Oil System	Apr-24	MS030130	Evaluator	$ 790,478.18	Overall Cost Estimate Change	Evaluator
79	Cliffside CS06 Template Turbine MajorValve	May-26	CS060059	None	$ 472,846.20	Overall Cost Estimate Change	None
80	Belews Creek BC FGD Lighting Replacement	Sep-26	BC000951	Funding Ap	$ 2,212,120.55	Overall Cost Estimate Change	Funding Approval
81	OPTIM Exciter MJR U2HP	Jun-26	BC020271	Funding Ap	$ 2,209,702.33	Overall Cost Estimate Change	Funding Approval
82	HCA Dust BC 6C7C6D7D Transfer	Dec-26	BC020315	None	$ 2,793,125.67	Overall Cost Estimate Change	None
83	Marshall MS4 BCP Valve Replacement	Jun-26	MS040111	None	$ 2,081,792.77	Overall Cost Estimate Change	None
84	Marshall MS4 FD Fan Bearing Oil System	Apr-24	MS040117	Evaluator	$ 936,919.29	Overall Cost Estimate Change	Evaluator
85	Marshall MS4 ID fan motor LCI replacement	Jun-24	MS040139	Evaluator +	$ 2,498,280.28	Overall Cost Estimate Change	Evaluator + Funding Approval
86	Marshall MS4 replace ME in absorber tank	Dec-26	MS040168	Evaluator	$ 1,154,891.04	Overall Cost Estimate Change	Evaluator
87	OPTIM ST Valve CRV MS4	Jun-26	MS040203	None	$ 2,146,113.31	Overall Cost Estimate Change	None
88	Marshall Station - Replace #3 chiller and air handling unit (AHU).	Dec-23	MS001093	Evaluator	$ 948,385.21	Overall Cost Estimate Change	Evaluator
91	Marshall Station - Replace #4,#5 chiller and air handling units (AHU).	Dec-24	MS001094	Evaluator	$ 1,642,431.29	Overall Cost Estimate Change	Evaluator
92	Replace Filtered Water Riser - Marshall	Nov-23	MS000577	Evaluator	$ 2,008,267.69	Overall Cost Estimate Change	Evaluator
93	Replace Marshall Coal Crusher Transfer Feeder Belts and Chutes 2026	Sep-26	MS000480	None	$ 2,543,638.33	Overall Cost Estimate Change	None
98	Replace Marshall Unit 2 Air Preheater (APH) baskets	Dec-23	MS020175	Evaluator	$ 4,010,213.02	Overall Cost Estimate Change	Evaluator
148	Belews Creek Replace Valves 2-BU-200-1 and 2	Jun-26	BC020470	Evaluator	$ 1,354,332.15	Project Added	Evaluator
149	Belews Creek OPTIM HP Major Unit 2	May-26	BC020486	Evaluator	$ 1,266,685.51	Project Added	Evaluator
150	Belews Creek OPTIM ST Valve CV/GV 1-3-5-7 U2	May-26	BC020493	None	$ 3,823,214.73	Project Added	None
151	Cliffside CS06 Install Flyash Line Heat Ex	May-26	CS060229	Evaluator	$ 1,059,023.05	Project Added	Evaluator
152	Marshall U3B Booster Fan Rotor Replacement	May-26	MS030238	Evaluator	$ 1,203,073.87	Project Added	Evaluator
153	Cliffside Replace recycle pumps A, B, D, E	May-26	CS060271	Evaluator	$ 3,187,346.60	Project Added	Evaluator
154	Cliffside CS6 Replace Condensate Recovery	Apr-26	CS060123	Evaluator	$ 1,164,801.27	Project Added	Evaluator
155	Belews Creek Replace U1 Bentley Nevada equipment	Dec-25	BC010732	Evaluator	$ 2,982,565.68	Project Added	Evaluator
156	Marshall 600V 2XA MCC Replacements	Dec-25	MS021362	Evaluator	$ 1,223,576.38	Project Added	Evaluator
157	Cliffside U6 New ICE Shop	Oct-25	CS560217	Evaluator	$ 989,407.58	Project Added	Evaluator
158	Cliffside CS06 Air Comp Controls Upgrade	Oct-25	CS060281	Evaluator	$ 1,424,950.09	Project Added	Evaluator
159	Marshall MS1 600V 1XA MCC Replacement	Oct-25	MS011393	Evaluator	$ 1,281,317.87	Project Added	Evaluator
160	Belews Creek D10 Certified Rebuild 2025	Sep-25	BC001085	Evaluator	$ 1,611,145.75	Project Added	Evaluator
161	Marshall MS3 TUBE CLEANING REPLACEMENT	Aug-25	MS030276	Evaluator	$ 1,069,419.38	Project Added	Evaluator
162	Belews Creek OPTIM ST DFLP Major U1	May-25	BC010466	None	$ 5,381,959.82	Project Added	None
163	Belews Creek OPTIM Gen MJR U1HP	May-25	BC010558	None	$ 6,938,351.14	Project Added	None
164	Cliffside CS06 SCR Catalyst Replacement	May-25	CS060259	None	$ 1,254,768.87	Project Added	None
165	Belews Creek OPTIM ST Valve RHSVIVTVGV U1	May-25	BC010741	None	$ 4,394,327.63	Project Added	None
166	Belews Creek Replace Valves 1-BU-200-1 and 2	May-25	BC010722	Evaluator	$ 1,224,043.34	Project Added	Evaluator
167	Marshall U4A Booster Fan Rotor Replacement	May-25	MS040200	Evaluator	$ 1,230,643.26	Project Added	Evaluator
168	Belews Creek OPTIM Exciter MJR U1HP	May-25	BC010396	None	$ 1,401,232.25	Project Added	None
169	Cliffside CS06 add disch isolation for ARP	May-25	CS060272	Evaluator	$ 4,159,912.77	Project Added	Evaluator
170	Cliffside Replace SHRH bias dampers	Apr-25	CS060098	Evaluator	$ 2,249,943.55	Project Added	Evaluator
171	Belews Creek Replace Unit 2 Bentley Nevada equip	Dec-24	BC020481	Evaluator	$ 2,378,205.76	Project Added	Evaluator
172	Marshall Service Building Roof Replacement	Nov-24	MS001216	None	$ 1,114,777.03	Project Added	None
173	Cliffside CS06 B ID Fan Rotor Replacement	Nov-24	CS060168	Evaluator	$ 2,580,572.16	Project Added	Evaluator
174	Cliffside CS06 HPT Major & Inlet Pipe Rep	Nov-24	CS060243	Funding Ap	$ 2,669,168.18	Project Added	Funding Approval
175	Cliffside CS06 Baghouse Bag Replacements	Nov-24	CS060283	None	$ 2,721,397.64	Project Added	None
176	Marshall HCAD Tripper Room Transfer Chutes	Nov-24	MS001126	None	$ 1,314,685.69	Project Added	None
177	Belews Creek BC2 H2 Cooler Retube and Coating	Oct-24	BC020480	Evaluator	$ 1,476,491.64	Project Added	Evaluator
178	Marshall Replace Drinking Water Main Piping	Sep-24	MS001391	Funding Ap	$ 1,459,248.47	Project Added	Funding Approval
179	Belews Creek D10 Dozer Certified Rebuild	Sep-24	BC001084	Evaluator	$ 1,611,145.75	Project Added	Evaluator
180	Marshall MS4 BOILER BAFFLES	Aug-24	MS040234	Evaluator	$ 1,380,793.43	Project Added	Evaluator
181	Marshall 2024 MS3 SCR Catalyst Replacement	Jun-24	MS030277	Funding Ap	$ 1,653,560.20	Project Added	Funding Approval
182	Belews Creek BC02 SCR Catalyst Layer Replacement	Jun-24	BC020473	Funding Ap	$ 4,030,105.89	Project Added	Funding Approval
183	Marshall U3A Booster Fan Rotor Replacement	May-24	MS030237	Evaluator	$ 1,177,504.05	Project Added	Evaluator
184	Cliffside OPTIM 2024 ST VALVE SVCV CS6	Mar-24	CS061205	None	$ 1,033,616.98	Project Added	None
185	Marshall 1A Mill Motor Refurbishment	Oct-25	MS010429	None	$ 147,657.85	Project Added	None
186	Marshall 4A CCW Pump Rebuild/Replacement	May-25	MS040226	None	$ 474,271.33	Project Added	None
187	Marshall 4C CCW Pump Rebuild/Replacement	May-25	MS040228	None	$ 474,271.33	Project Added	None
188	Marshall 1A ID Fan Motor Refurbishment	Nov-24	MS010424	None	$ 168,323.90	Project Added	None
189	Marshall 1B ID Fan Motor Refurbishment	Nov-24	MS010426	None	$ 168,323.90	Project Added	None
190	Marshall 1HP MG Set Exciter Motor Refurbishment	Nov-24	MS010435	None	$ 156,023.55	Project Added	None
191	Marshall 1D Mill Motor Refurbishment	Nov-24	MS010431	None	$ 150,310.41	Project Added	None
192	Marshall 1E Mill Motor Refurbishment	Nov-24	MS010432	None	$ 150,307.12	Project Added	None
193	Marshall 1 4kV Relay System Obsolete	Nov-24	MS011321	Evaluator	$ 943,221.00	Project Added	Evaluator
194	Marshall 4B FD Fan Motor Refurbishment	Jun-24	MS040236	None	$ 170,170.08	Project Added	None
195	Marshall 4D Mill Motor Refurbishment	Jun-24	MS040235	None	$ 149,718.14	Project Added	None
196	Marshall 1A CCW Pump Rebuild/Replacement	May-24	MS010406	None	$ 443,080.02	Project Added	None
197	Marshall 2B CCW Pump Rebuild/Replacement	May-24	MS020189	None	$ 453,292.08	Project Added	None
198	Marshall 4B CCW Pump Rebuild/Replacement	May-24	MS040227	None	$ 474,271.33	Project Added	None
199	Cliffside Soot blower maintenance	Dec-23	CS560213	Funding Ap	$ 154,369.93	Project Added	Funding Approval
200	Marshall Soot blower maintenance	Dec-23	MS001194	Funding Ap	$ 155,884.34	Project Added	Funding Approval
201	Belews Creek Soot blower maintenance	Dec-24	BC001080	Funding Ap	$ 151,670.54	Project Added	Funding Approval
202	Marshall FGD A BALL MILL LIFTING BARS	Dec-24	MS010404	None	$ 437,500.00	Project Added	None
203	Marshall 1B Mill Motor Refurbishment	Nov-23	MS010430	Funding Ap	$ 147,000.07	Project Added	Funding Approval
204	Marshall 2A ID Fan Motor Refurbishment	Nov-23	MS020196	None	$ 166,714.61	Project Added	None
205	Marshall 2B ID Fan Motor Refurbishment	Nov-23	MS020197	None	$ 166,714.61	Project Added	None
206	Marshall 2HP MG Set Exciter Motor Refurbishment	Nov-23	MS020198	None	$ 156,295.43	Project Added	None

207	Marshall 3E Mill Motor Refurbishment	Oct-23	MS030279	Funding Ap	$ 149,493.61	Project Added	Funding Approval
208	Marshall 3F Mill Motor Refurbishment	Jul-23	MS030280	Funding Ap	$ 149,315.42	Project Added	Funding Approval
209	Marshall 2A CCW Pump Rebuild/Replacement	Nov-23	MS020187	None	$ 453,292.08	Project Added	None
210	Marshall 3C CCW Pump Rebuild/Replacement	May-25	MS030264	Funding Ap	$ 474,271.33	Project Added	Funding Approval
211	Marshall 3B CCW Pump Rebuild/Replacement	May-24	MS030268	None	$ 474,271.33	Project Added	None
212	Cliffside Soot blower maintenance	Dec-24	CS00XXXX		$ 149,999.93	Project Added	None
213	Marshall Soot blower maintenance	Dec-25	MS00XXXX		$ 150,000.34	Project Added	None
214	Cliffside Soot blower maintenance	Dec-25	CS00XXXX		$ 149,999.93	Project Added	None
215	Marshall HDP Motor Refurbishment	Dec-24	MS00XXXX		$ 200,000.00	Project Added	None
216	Marshall 4B BCP Capital Rebuild	Nov-25	MS00XXXX		$ 375,000.00	Project Added	None
217	Marshall 4A FD Fan Motor Refurbishment	May-24	MS00XXXX		$ 168,750.00	Project Added	None
218	Marshall Soot blower maintenance	Nov-24	MS00XXXX		$ 150,000.34	Project Added	None
219	Marshall 4A BCP Capital Rebuild	Jan-24	MS00XXXX		$ 375,000.00	Project Added	None
220	Belews Creek Soot blower maintenance	Dec-25	BC00XXXX		$ 150,000.00	Project Added	Evaluator + Funding Approval
221	DEC Winterization Capital Projects	Dec-25	FHGOXXXX		$ 6,000,000.00	Project Added	None
222	Belews Creek Breaker/Bus Mainteance	Dec-25	BC00XXXX		$ 150,000.00	Project Added	Evaluator + Funding Approval

Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 165

Docket No. E-7, Sub 1276

Date of Request: **June 7, 2023**
Date of Response: **June 19, 2023**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 165-2, was provided to me by the following individual(s): Trudy H. Morris, Generation and Regulatory Strategy Director, was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

Request:

2. Please provide a narrative detailing how the MYRP addition of $6M in Winterization Capital Projects will differentiate from the increase to pro forma NC-2160 of $5.9M for both "winterization O&M" and "reliability improvements," as referenced in Witness Walsh's supplemental testimony.

    a. Provide a detailed list of "Winterization O&M" and "reliability improvements," per plant along with a narrative of each expense/project.

Response:

The DEC $6M winterization capital project is for winterization work that qualifies for capital, and the $5.9M of the Winterization O&M is for winterization work that does not qualify for capital and will be an O&M expense. In general, O&M expense items would be repairs of existing assets (e.g. strip and replace heat trace cable and insulation on a short run of piping or tubing), where capital would be for unit of property replacement or addition of new assets (e.g. addition of an enclosure/building around cold weather sensitive equipment). See attached list of DEC winterization O&M expense items (previously supplied in response to PSDR 1-8 as workpaper in support of Walsh Supplemental Testimony).

Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 165

Docket No. E-7, Sub 1276

Date of Request: **June 7, 2023**
Date of Response: **June 15, 2023**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 165-3, was provided to me by the following individual(s): Trudy H. Morris, Generation and Regulatory Strategy Director, was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

North Carolina Public Staff
Data Request No. 165
DEC Docket No. E-7, Sub 1276
Item No. 165-3
Page 1 of 1

Request:

3. For known DEC winterization projects (both included in line item 221 and other "parking lot" projects), please provide a project ranking or prioritization of all known winterization capital projects for the coal units, by plant.

Response:

Currently planned DEC coal unit winterization projects for line item 221 are as follows in priority order. Note that these projects and their priority are subject to change as the detailed plans are refined.

- Belews Creek 1
- Belews Creek 2
- Cliffside 6
- Marshall 4
- Marshall 3
- Cliffside 5
- Marshall 2
- Marshall 1

No other winterization capital is included in parking lot projects.

Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 165

Docket No. E-7, Sub 1276

Date of Request: **June 7, 2023**
Date of Response: **June 15, 2023**

[ ] **CONFIDENTIAL**

[X] **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 165-4, was provided to me by the following individual(s): Trudy H. Morris, Generation and Regulatory Strategy Director, was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

North Carolina Public Staff
Data Request No. 165
DEC Docket No. E-7, Sub 1276
Item No. 165-4
Page 1 of 1

Request:

4. As listed in Witness Walsh's Supplemental Exhibit 1, the item "DEC Winterization Capital Projects" is given a forecasted plant in service date of Dec-25. Please provide a narrative detailing the timing of these projects' plant in-service date.

Response:

DEC coal unit winterization capital projects would be placed in service between Spring and Fall of 2025.

Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 165

Docket No. E-7, Sub 1276

Date of Request: **June 7, 2023**
Date of Response: **June 19, 2023**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 165-5, was provided to me by the following individual(s): Trudy H. Morris, Generation and Regulatory Strategy Director, was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

North Carolina Public Staff
Data Request No. 165
DEC Docket No. E-7, Sub 1276
Item No. 165-5
Page 1 of 4

Request:

5. For all projects expected to be included in the $6M "DEC Winterization Capital Projects" provided in line item 221 of Witness Walsh's Supplemental Exhibit 1, please provide or respond to the following for each of the known projects for the coal units:

   a. A description of the overall function of this project in relation to plant operations.

   b. The expected plant in-service date of this project

   c. A narrative that describes the scope of the overall project.

      i. Discuss how this project will mitigate or prevent future failures and/or minimize/prevent the unit from going into a forced or maintenance outage.
      ii. Identify each forced or maintenance outage by unit that occurred over the last five years (2018 – 2022) that each project (or group of projects) would have prevented had it been completed at the time of the outage.

   d. All supporting documentation for this project, as well as the benefit/cost evaluation.

   e. When were the components to be replaced or upgraded in this project work/scope installed?

   f. The work history on the components in question.

      i. When was it last replaced or repaired?

   g. What is the expected replacement cycle for these parts?

      i. Will the new parts/equipment be provided under any warranty? If so, how long, and describe the warranty provisions.

North Carolina Public Staff
Data Request No. 165
DEC Docket No. E-7, Sub 1276
Item No. 165-5
Page 2 of 4

h. Has the equipment to be replaced or upgraded ever failed to the point that it caused the plant to experience a forced or maintenance outage? If so, when?

i. Has the equipment to be replaced or upgraded ever caused the plant to have a unit derate? If so, when?

j. A description of the typical maintenance, preventative maintenance, and inspections on the equipment to be replaced.

   i. Provide any analysis used on the equipment to be replaced over its life, or at least the last five years, that would be used to determine adverse trending of equipment health, as well as benchmarks to determine a need for replacement.

k. Has the unit ever undergone forced emergency repairs for a similar failure? If so, how long did the outage last?

l. A description of why this project meets the standards for a capital project versus a typical operation and maintenance expense.

m. A description of how this project will or will not reduce ongoing operational and maintenance expenses.

   i. List the expected annual decrease in operational expenses resulting from this project.

n. A list of spare parts inventory for the equipment to be replaced.

o. Will 100% of the existing spare parts inventory assigned to the equipment in question be/remain usable for the new equipment/project?

   i. If not, please provide the monetary value of spare parts inventory equipment that will no longer be applicable to the new project and discuss how the Company removed the excess spare parts inventory costs in this general rate case.

Response:

a. These capital projects for DEC coal units would generally include the following items, but note that any one item may or may not be required for a specific site.
• Addition of real-time data monitoring systems to existing heat trace systems
• Addition of permanent windbreaks or enclosures in cold weather sensitive areas that have previously been seasonally protected with temporary structures
• Addition of permanent heating and insulation systems to weather sensitive material handling systems to avoid freezing
b. These capital projects are expected to go in service by December 2025.

c. i. For the purposes of describing winterization projects, "critical" would be defined as equipment, components, or systems that if frozen could cause a derate or unit shutdown.
• Real-time monitoring of heat trace systems for critical systems/equipment/components allows us to understand deficiencies or problems that may occur after one-time manual seasonal preparation PMs are completed and respond accordingly.
• Windbreaks and enclosures provide more robust wind protection and efficient space heating in critical areas for systems/equipment/components, avoiding freezing.
• Material handling heating and insulation systems in critical areas will avoid freezing and pluggage of systems that are either providing fuel, reagents, or evacuating byproducts.
c. ii. Based on our review of GADS data, there were no events noted for this period for DEC coal units. However, there is Duke Energy fleet experience from previous cold weather events that have identified these key areas and opportunities, that if addressed, would significantly reduce operational "emergencies" during future cold weather events, decreasing the likelihood of a reliability event. An example would include an outdoor uninsulated unheated steel transfer chute conveying moist limestone reagent to a flue gas scrubber, where the limestone freezes and accumulates in the chute, backing up and tripping the limestone conveyer system. If this frozen accumulation isn't quickly cleared from the chute, the limestone will freeze on the belts and require manual removal of the material (potentially up to 1 mile of belts). These emergent items can consume significant resources during extreme cold weather and distract the operations teams from other reliability threats.

d. These projects are in response to fleet and industry issues experienced during winter storm Elliott and target systems, equipment, and components that are susceptible to freezing during extreme cold weather scenarios. These are winter hardening projects, improving reliability during times where the grid margins are most challenged.
The tools and processes typically used for economic analyses do not apply to these projects due to the level of risk. The term "tail risk" could be used to characterize the

North Carolina Public Staff
Data Request No. 165
DEC Docket No. E-7, Sub 1276
Item No. 165-5
Page 4 of 4

evaluation of these projects. A tail risk is one in which the cost of a negative event (dollar, reputation, environmental, safety, etc.) is so high that very little risk is acceptable. This risk profile does not compare well with the economic analysis of most projects and can misrepresent the true risk. For this reason these projects are not evaluated and compared against projects that have moderate risk profiles.

e. Not applicable. Projects are new additions.

f. Not applicable. Projects are new additions.

g. Not applicable. Projects are new additions.

h. Not applicable. Projects are new additions.

i. Not applicable. Projects are new additions.

j. Not applicable. Projects are new additions.

k. Not applicable. Projects are new additions.

l. The projects add new systems/equipment/components. These projects meet the requirements set forth in Duke Energy's capitalization policy.

m. The winterization projects for cold weather reliability are not expected to have a material impact on ongoing O&M expenses.
i. There will be no decrease in operational expenses in the 2021 test year.

n. Not applicable. Projects are new additions.

o. Yes.

/A

Lawrence Exhibit 1 Index **Page(s)**

Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 8

Docket No. E-7, Sub 1276

Date of Request:	**January 30, 2023**
Date of Response:	**February 9, 2023**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 8-3, was provided to me by the following individual(s): Alisa Ewald, Developmental Assignment, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

North Carolina Public Staff
Data Request No. 8
DEC Docket No. E-7, Sub 1276
Item No. 8-3
Page 1 of 1

Request:

3. Please provide the OHMY-SA target by year, from 2015 through 2023.

Response:

OHMY-SA is a new metric that was just recently implemented so there was only a target for 2022 of 0.55 and the current target for 2023 of 0.55.

Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 8

Docket No. E-7, Sub 1276

Date of Request:	**January 30, 2023**
Date of Response:	**February 9, 2023**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 8-4, was provided to me by the following individual(s): Alisa Ewald, Developmental Assignment, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

North Carolina Public Staff
Data Request No. 8
DEC Docket No. E-7, Sub 1276
Item No. 8-4
Page 1 of 1

Request:

4. Please provide the actual OHMY-SA achieved by year from 2015 through 2022.

Response:

While Targets were not set for previous years, historical actual results were calculated for past years to develop targets.

2015 - 0.49
2016 - 0.71
2017 - 0.61
2018 - 0.58
2019 - 0.60
2020 - 0.60
2021 - 0.43
2022 - 0.60

Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 136

Docket No. E-7, Sub 1276

Date of Request: **May 23, 2023**
Date of Response: **July 5, 2023**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached supplemental response to NC Public Staff Data Request No. 136-2, was provided to me by the following individual(s): Jacqueline Walker, Lead Planning and Regulatory Support Specialist, was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

North Carolina Public Staff
Data Request No. 136
DEC Docket No. E-7, Sub 1276
Item No. 136-2
Page 1 of 2

Request:

2. Please provide the following related to electric vehicle supply equipment (EVSE):
    a. Funding project ID.
    b. Pilot program the project is associated with (if applicable).
    c. List of all locations where the Company has installed EVSE, broken down by type of equipment.
    d. Costs sought for recovery in this case related to EVSE.
    e. FERC account(s) in which the costs are booked.
    f. Amount booked to each FERC account.
    g. Whether the EVSE is a public or private installation.
    h. Number of bays/plugs at each location.
    i. Charging capability of each bay, in kW.
    j. Charging type at each location (e.g., Level 1, Level 2, DCFC, etc.).
    k. Explanation of how the Company determines customer cost to use the EVSE (for public locations).
    l. Amount of revenue the Company has received from each location.
    m. FERC account(s) the revenues are booked to.

Supplemental Response (7/5/2023):

For the Fleet charging project, please see below responses:

a.Funding project ID. EVFLTCHN
b.Pilot program the project is associated with (if applicable). N/A
c.List of all locations where the Company has installed EVSE, broken down by type of equipment. Please see PSDR 136-2 EVFLTCGN Charger Detail.xlsx
d.Costs sought for recovery in this case related to EVSE. $559,744
e.FERC account(s) in which the costs are booked. FERC 394-70
f.Amount booked to each FERC account. $559,744
g.Whether the EVSE is a public or private installation. Private
h.of bays/plugs at each location. Please see PSDR 136-2 EVFLTCGN Charger Detail.xlsx
i.Charging capability of each bay, in kW. Please see PSDR 136-2 EVFLTCGN Charger Detail.xlsx
j.Charging type at each location (e.g., Level 1, Level 2, DCFC, etc.). Level 2
k.Explanation of how the Company determines customer cost to use the EVSE (for public locations). N/A
l.Amount of revenue the Company has received from each location. N/A
m.FERC account(s) the revenues are booked to. N/A

North Carolina Public Staff
Data Request No. 136
DEC Docket No. E-7, Sub 1276
Item No. 136-2

Corrections were made to the files submitted in the original response to this question. For corrected files and response, please see PSDR 136-1.

Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 136

Docket No. E-7, Sub 1276

Date of Request: **May 23, 2023**
Date of Response: **June 2, 2023**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 136-4, was provided to me by the following individual(s): Jacqueline Walker, Lead Planning and Regulatory Support Specialist, was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

North Carolina Public Staff
Data Request No. 136
DEC Docket No. E-7, Sub 1276
Item No. 136-4
Page 1 of 1

Request:

4. Please provide the following related to passenger vehicle leases for which costs are included in this case:
   a. Make, model, trim, and year of vehicle leased.
   b. Number of each vehicle identified in 4(a).
   c. Final price of the vehicle used in the lease payment calculation.
   d. FERC account the lease payment is booked to.
   e. Lease term (number of months).
   f. Lease payment.
   g. Yearly mileage allowance.
   h. Agreed upon residual value.
   i. Formula used to calculate lease payment.

Response:

Not applicable. No costs for leases of passenger vehicles are included in this case.

Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 136

Docket No. E-7, Sub 1276

Date of Request: **May 23, 2023**
Date of Response: **June 9, 2023**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached supplemental response to NC Public Staff Data Request No. 136-4, was provided to me by the following individual(s): Jacqueline Walker, Lead Planning and Regulatory Support Specialist, was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

North Carolina Public Staff
Data Request No. 136
DEC Docket No. E-7, Sub 1276
Item No. 136-4
Page 1 of 1

Request:

4. Please provide the following related to passenger vehicle leases for which costs are included in this case:
    a. Make, model, trim, and year of vehicle leased.
    b. Number of each vehicle identified in 4(a).
    c. Final price of the vehicle used in the lease payment calculation.
    d. FERC account the lease payment is booked to.
    e. Lease term (number of months).
    f. Lease payment.
    g. Yearly mileage allowance.
    h. Agreed upon residual value.
    i. Formula used to calculate lease payment.

Supplemental Response (6/9/23):

Correction: Costs for passenger vehicle leases are included in this Rate Case.

a. Please see attachment "PSDR 136-4.xlsx"
b. Please see attachment "PSDR 136-4.xlsx"
c. Please see attachment "PSDR 136-4.xlsx"
d. 080329
e. Please see attachment "PSDR 136-4.xlsx"
f. Please see attachment "PSDR 136-4.xlsx"
g. Not applicable.
h. Please see attachment "PSDR 136-4.xlsx"
i. Purchase price x rent factor = monthly lease payment.

North Carolina Public Staff
Duke Energy Carolinas, LLC
Public Staff Data Request No. 136
Docket No. E-7, Sub 1276
Item No. 136-4
Page of Page

Asset Number	Year	Manufacturer	Model	Trim	Purchase Price	Lease Term	Lease Payment	Residual Value
26488	2022	MITSUBISHI	OUTLANDER	SEL	$36,663	60	$511	$10,999
26489	2022	MITSUBISHI	OUTLANDER	SEL	$36,663	60	$511	$10,999
26490	2022	MITSUBISHI	OUTLANDER	SEL	$36,663	60	$511	$10,999
28810	2022	MITSUBISHI	OUTLANDER	SEL	$36,663	60	$529	$10,999
28819	2022	MITSUBISHI	OUTLANDER	SEL	$35,871	60	$517	$10,761
28823	2022	MITSUBISHI	OUTLANDER	SEL	$36,593	60	$528	$10,978
33663	2018	MITSUBISHI	OUTLANDER	SEL	$34,000	60	$470	$10,200
33669	2020	MITSUBISHI	OUTLANDER	SEL	$32,470	60	$449	$9,741
33739	2020	MITSUBISHI	OUTLANDER	SEL	$32,470	60	$449	$9,741
33741	2020	MITSUBISHI	OUTLANDER	SEL	$32,470	60	$449	$9,741
33742	2020	MITSUBISHI	OUTLANDER	SEL	$32,470	60	$449	$9,741
33749	2020	MITSUBISHI	OUTLANDER	SEL	$32,470	60	$449	$9,741
33753	2020	MITSUBISHI	OUTLANDER	SEL	$32,470	60	$449	$9,741
33754	2020	MITSUBISHI	OUTLANDER	SEL	$32,470	60	$449	$9,741
33756	2020	MITSUBISHI	OUTLANDER	SEL	$32,470	60	$449	$9,741
33759	2020	MITSUBISHI	OUTLANDER	SEL	$32,470	60	$449	$9,741
35831	2021	FORD	ESCAPE HYB	S	$31,706	60	$429	$9,512
35832	2021	FORD	ESCAPE HYB	S	$31,706	60	$429	$9,512
35833	2021	FORD	ESCAPE HYB	S	$31,706	60	$429	$9,512
35861	2021	CHEVROLET	BOLT	LT	$28,086	60	$445	$8,426
36249	2021	MITSUBISHI	OUTLANDER	SEL	$34,416	60	$470	$10,325
36250	2021	MITSUBISHI	OUTLANDER	SEL	$34,416	60	$470	$10,325
36257	2021	MITSUBISHI	OUTLANDER	SEL	$34,346	60	$469	$10,304
36262	2022	MITSUBISHI	OUTLANDER	SEL	$36,663	60	$511	$10,999
36267	2021	MITSUBISHI	OUTLANDER	SEL	$34,416	60	$470	$10,325
36268	2021	MITSUBISHI	OUTLANDER	SEL	$34,416	60	$470	$10,325
37825	2022	MITSUBISHI	OUTLANDER	SEL	$35,593	60	$482	$10,678
37971	2020	Kia Corp	NIROEV	EX	$37,630	60	$519	$11,289
37973	2021	Kia Corp	NIROEV	EX	$38,886	60	$537	$11,666
37989	2022	MITSUBISHI	OUTLANDER	SEL	$36,616	60	$511	$10,985
38033	2022	MITSUBISHI	OUTLANDER	SEL	$37,053	60	$575	$11,116
38039	2022	MITSUBISHI	OUTLANDER	SEL	$34,871	60	$472	$10,461
39399	2022	MITSUBISHI	OUTLANDER	SEL	$36,629	60	$528	$10,989
39437	2022	MITSUBISHI	OUTLANDER	SEL	$36,593	60	$568	$10,978
39441	2022	MITSUBISHI	OUTLANDER	SEL	$36,728	60	$530	$11,018

Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 136

Docket No. E-7, Sub 1276

Date of Request: **May 23, 2023**
Date of Response: **July 3, 2023**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached second supplemental corrected response to NC Public Staff Data Request No. 136-4, was provided to me by the following individual(s): Jacqueline Walker, Lead Planning and Regulatory Support Specialist, was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

North Carolina Public Staff
Data Request No. 136
DEC Docket No. E-7, Sub 1276
Item No. 136-4
Page 1 of 1

Request:

4. Please provide the following related to passenger vehicle leases for which costs are included in this case:
   a. Make, model, trim, and year of vehicle leased.
   b. Number of each vehicle identified in 4(a).
   c. Final price of the vehicle used in the lease payment calculation.
   d. FERC account the lease payment is booked to.
   e. Lease term (number of months).
   f. Lease payment.
   g. Yearly mileage allowance.
   h. Agreed upon residual value.
   i. Formula used to calculate lease payment.

Second Supplemental Corrected Response (6/29/23):

Correction: The Passenger Vehicle leases are recorded to DEBS. The DEBS vehicles are used by DEC employees in the course of business and are charged to the appropriate project or cost center based on the what the vehicle is being used for. The transportation chargeback from DEBS would charge DEC's project or cost center based on the usage of the vehicle. This chargeback includes the cost of the lease, licensing, and other costs associated with the DEB's ownership of the vehicle. DEC cannot isolate just the cost of the lease as the lease is not uniquely identified in the transportation chargeback amount received from DEBS. The transportation charge back would be recorded to various FERC accounts on DEC's books, depending upon if the charge was recorded to capital or O&M. All vehicles included in PSDR 136-4.xlsx provided in the 1st Supplemental response are on DEBS books and not DEC's.

Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 137

Docket No. E-7, Sub 1276

Date of Request: **May 23, 2023**
Date of Response: **June 2, 2023**

[ ] **CONFIDENTIAL**

[X] **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 137-3, was provided to me by the following individual(s): Jacqueline Walker, Lead Planning and Regulatory Support Specialist, was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

North Carolina Public Staff
Data Request No. 137
DEC Docket No. E-7, Sub 1276
Item No. 137-3
Page 1 of 1

Request:

3. Please provide all analysis conducted by the Company comparing the total cost of ownership between a traditional ICE vehicle, a plug-in hybrid vehicle, and an electric vehicle, by type of vehicle (light duty, medium duty, heavy duty).
   a. Please explain if and how this analysis has shaped the Company's plans to electrify its fleet.

Response:

See tab "137-3" in attachment "DEC PSDR 137 Data Request.xlsx". Given the volatile vehicle market and supply chain constraints, anticipated EPA requirements for gasoline and diesel engines within the next few years, as well as expected legislative requirements for adoption of alternative fuel vehicles over traditional ICE vehicles through 2030, the cost of ownership calculation can only be utilized to capture current market conditions rather than future state conditions. Cost trends during this transition are unknown at this time; however, as volumes for assembly components and electric vehicles themselves increase, the expected cost per unit should trend in a more favorable direction from a purchase standpoint. This trend will become more well-known as production ramps up over the next few years.

North Carolina Public Staff
Duke Energy Carolinas, LLC
Public Staff Data Request No. 137
Docket No. E-7, Sub 1276
Item No. 137-1, 2 3
Page of Page

Total Cost of Ownership - Electrification of Light Duty Vehicles

- All purchase prices are estimates and exclude upfit costs.

- Calculations assume 40% reduction in fuel cost of PHEV vs conventional unit. Additional savings may be realized if charged more than once a day.

- Based on assumed electric range of 50 miles for pickup PHEV and ~60 mile daily driving for the majority of these units, the majority of daily fuel costs can be eliminated by moving to PHEV and plugging in once a day.
- Within Duke fleet, there has been no noteable decrease in maintenance cost of PHEV vs conventional assets. This is attributed to the higher cost of parts and repairs characteristic to lower volume, high technology PHEVs.

- Based on 2019 maintenance data, approximately 32% of regular maintenance could be eliminated by moving to fully electric vs conventional unit.
- Estimated cost of charging has not been included in this analysis for PHEV and EV alternatives

SUV	Purchase Price	Ownership	Fuel	Maintenance	Monthly TOC
Gasoline	$ 32,000.00	$ 426.67	$ 100.00	$ 105.00	$ 631.67
PHEV	$ 46,000.00	$ 613.33	$ 60.00	$ 105.00	$ 778.33
					$ (146.67)
SUV	**Purchase Price**	**Ownership**	**Fuel**	**Maintenance**	**Monthly TOC**
Gasoline	$ 32,000.00	$ 426.67	$ 100.00	$ 105.00	$ 631.67
Full EV	$ 45,000.00	$ 600.00	$ -	$ 71.40	$ 671.40
**Full EV expected 2024*					**$ (39.73)**
Pickup	**Purchase Price**	**Ownership**	**Fuel**	**Maintenance**	**Monthly TOC**
Gasoline	$ 36,000.00	$ 480.00	$ 200.00	$ 140.00	$ 820.00
PHEV	$ 75,000.00	$ 1,000.00	$ 120.00	$ 95.20	$ 1,215.20
**PHEV pickup unknown availability; assume 50 mile electric range*					**$ (395.20)**
Pickup	**Purchase Price**	**Ownership**	**Fuel**	**Maintenance**	**Monthly TOC**
Gasoline	$ 36,000.00	$ 480.00	$ 200.00	$ 140.00	$ 820.00
Full EV	$ 65,000.00	$ 866.67	$ -	$ 95.20	$ 961.87
					$ (141.87)

Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 137

Docket No. E-7, Sub 1276

Date of Request: **May 23, 2023**
Date of Response: **June 2, 2023**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 137-4, was provided to me by the following individual(s): Jacqueline Walker, Lead Planning and Regulatory Support Specialist, was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

North Carolina Public Staff
Data Request No. 137
DEC Docket No. E-7, Sub 1276
Item No. 137-4
Page 1 of 1

Request:

4. Please provide the supporting documentation and analysis, including a description of the analysis relied upon, used to develop the estimated costs of the Electrification Charging Infrastructure program.

Response:

The cost estimates provided are AACE Class 5 estimates and are, therefore, not informed by site specificity or vendor quotes for the project. The estimates were drawn from as found condition confidential quotes from vendors for other projects. An example quote for a recent Level 2 charger installation in late 2022 is provided in attachment "DEC PS DR 137-4 Example Install Estimate.pdf." In this example, there were six chargers installed equating to $10,000 per charger for the installation cost.

Level 2 chargers range from 4kW to 20kW; therefore, Level 2 chargers vary in cost based on charge capacity and features. The average cost equated to the "as found condition" amount utilized in the estimate (see attachments "DEC PS DR 137-4 Example Level 2 Invoice 1.pdf" and "DEC PS DR 137-4 Example Level 2 Invoice 2.pdf").

Level 3 DC Fast Chargers range from 24kW to 350kW; therefore, Level 3 chargers have a wide price range. Considering the mid-range 100kW – 150kW units, the average cost equated to the "as found condition" amount utilized in the estimate (see attachment "DEC PS DR 137-4 DCFC Pricing List.xlsx").

Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 137

Docket No. E-7, Sub 1276

Date of Request: **May 23, 2023**
Date of Response: **June 2, 2023**

[ ] **CONFIDENTIAL**

[X] **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 137-5, was provided to me by the following individual(s): Jacqueline Walker, Lead Planning and Regulatory Support Specialist, was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

North Carolina Public Staff
Data Request No. 137
DEC Docket No. E-7, Sub 1276
Item No. 137-5
Page 1 of 1

Request:

5. Please provide the supporting methodology and calculations used to determine the number of each type of charger the Company projects to install during the MYRP period. For example, if the Company indicates that it projects to install 50 L2 and 4 L3 chargers in MYRP year 1, the analysis should show exactly how the 50 L2 and 4 L3 chargers are the most appropriate combination for the number of EVs and plug-in hybrid vehicles the Company expects to have in its fleet.

Response:

The charger count was derived from expected vehicle replacements from 2023 through 2027. The charging infrastructure must be in place prior to vehicle delivery, therefore, the average between the two future years' vehicle replacements was used to estimate charger counts. For example, the average vehicle replacements between 2023 and 2024 were used to define the total charger count for 2024. The average vehicles replacements between 2025 and 2026 were used to define the total charger count for 2025. This continued through 2027 to define the 2026 charger counts.

Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 137

Docket No. E-7, Sub 1276

Date of Request: **May 23, 2023**
Date of Response: **June 2, 2023**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 137-6, was provided to me by the following individual(s): Jacqueline Walker, Lead Planning and Regulatory Support Specialist, was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

North Carolina Public Staff
Data Request No. 137
DEC Docket No. E-7, Sub 1276
Item No. 137-6
Page 1 of 1

Request:

6. Please provide the location where each charger required for the Fleet Electrification Program will be installed, and whether the charger is located at a DEC-owned or leased facility.

    a. If the charger is located at an employee's home, please provide the county where the employee's home is located and a justification for locating the charger at the employee's home.
    b. What will be the disposition of the charger in the event the employee is no longer employed by the Company?

Response:

The exact number of charging stations at each location is currently under review as part of the data analysis being performed for the project. The chargers will be installed at DEC-owned facilities.

The locations and policy around the home charging program is under development at this time and will be determined as the project progresses through the PMCoE process.
The policy around the home charging program is under development at this time and will be determined as the project progresses through the PMCoE process.

Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 137

Docket No. E-7, Sub 1276

Date of Request: **May 23, 2023**
Date of Response: **June 2, 2023**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 137-9, was provided to me by the following individual(s): Jacqueline Walker, Lead Planning and Regulatory Support Specialist, was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

North Carolina Public Staff
Data Request No. 137
DEC Docket No. E-7, Sub 1276
Item No. 137-9
Page 1 of 1

Request:

9. Who will pay for the electricity consumed at the employee's premise due to charging of a Company vehicle?
    a. Will the employee pay for the energy usage and be reimbursed by DEC?
    b. If DEC will pay or reimburse the employee, please provide the method that will be used to determine the amount. If this amount is based on energy consumption, please describe how the energy will be measured and disaggregated from typical residential usage.

Response:

9a. The home charging program and associated policies are currently under review by the project team. Final details will be determined as the project progresses through the Project Management Center of Excellence process.

9b. Policies and methods are currently under review. There are various options to determine electricity usage. These options will be piloted and tested to determine the final solution as part of project roll out.

Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 137

Docket No. E-7, Sub 1276

Date of Request: **May 23, 2023**
Date of Response: **June 2, 2023**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 137-10, was provided to me by the following individual(s): Jacqueline Walker, Lead Planning and Regulatory Support Specialist, was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

North Carolina Public Staff
Data Request No. 137
DEC Docket No. E-7, Sub 1276
Item No. 137-10
Page 1 of 1

Request:

10. Describe whether and how DEC intends to pay for upgrades to the grid, or to the employee's home, to facilitate the installation of the charging equipment.
    a. How will this factor in to whether an employee will receive the charger or EV?
    b. What will be the disposition of the grid upgrades in the event the employee is no longer employed by the Company?

Response:

The policies related to the home charging program are under development at this time and will be determined as the project progresses through the PMCOE process.

Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 137

Docket No. E-7, Sub 1276

Date of Request: **May 23, 2023**
Date of Response: **June 2, 2023**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 137-11, was provided to me by the following individual(s): Jacqueline Walker, Lead Planning and Regulatory Support Specialist, was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

North Carolina Public Staff
Data Request No. 137
DEC Docket No. E-7, Sub 1276
Item No. 137-11
Page 1 of 1

Request:

11. Will DEC retain ownership of any part of the charging equipment located at an employee's home?
    a. If not, describe why not.

Response:

The policies related to the home charging program are under development at this time and will be determined as the project progresses through the PMCOE process.

Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 137

Docket No. E-7, Sub 1276

Date of Request: **May 23, 2023**
Date of Response: **June 2, 2023**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 137-12, was provided to me by the following individual(s): Jacqueline Walker, Lead Planning and Regulatory Support Specialist, was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

North Carolina Public Staff
Data Request No. 137
DEC Docket No. E-7, Sub 1276
Item No. 137-12
Page 1 of 1

Request:

12. If any of the requested information will be decided at a later date through the PMCOE gating process, please provide an estimated timeframe of when this will occur.

Response:

The project is expected to move to the next stage of the gating process for 2024 installations in Q3 2023.

Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 187

Docket No. E-7, Sub 1276

Date of Request: **June 15, 2023**
Date of Response: **June 26, 2023**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 187-3, was provided to me by the following individual(s): Alisa Ewald, Developmental Assignment, was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

North Carolina Public Staff
Data Request No. 187
DEC Docket No. E-7, Sub 1276
Item No. 187-3
Page 1 of 1

Request:

3. Please provide the Company's expected installation cost for a wood, concrete, and steel pole, for each voltage class, for the standard height pole for that voltage class.
   a. Please specifically include labor, pole cost, other material costs, and other relevant categories.

Response:

DEC no longer installs wood for pole replacements, only steel. Concrete poles are not used for program pole replacements, only under special circumstances/requirements with specific projects. Based on this, no estimated installation cost exists for these materials. The average unit cost for 44kV wood pole replacement to steel is approximately $25k/pole based on 2021 and 2022 actuals. The average breakdown is below:
Labor and Allocations - $6.97k
Materials – $3.55k
Vehicles and Equipment - $1.37k
Contract/Contract Labor – $10.93k
Non-Labor Allocations - $2.56k
Total = $25.38k

**Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 187**

Docket No. E-7, Sub 1276

Date of Request: **June 15, 2023**
Date of Response: **June 26, 2023**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 187-9, was provided to me by the following individual(s): Alisa Ewald, Developmental Assignment, was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

North Carolina Public Staff
Data Request No. 187
DEC Docket No. E-7, Sub 1276
Item No. 187-9
Page 1 of 1

Request:

9. Has the Company been able to attribute any decrease (or any lack of increase) in O&M costs resulting from the transmission wood pole replacement program?
   a. If so, please provide the amount on a yearly basis.
      i. Please provide any and all supporting calculations, workpapers, and other documentation showing the amount attributable.
   b. If not, please explain why not.

Response:

No, because the wood to steel program only began in 2021 and only a small percentage of wood poles have been changed out under this program.

Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 187

Docket No. E-7, Sub 1276

Date of Request: **June 15, 2023**
Date of Response: **June 26, 2023**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 187-10, was provided to me by the following individual(s): Alisa Ewald, Developmental Assignment, was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

North Carolina Public Staff
Data Request No. 187
DEC Docket No. E-7, Sub 1276
Item No. 187-10
Page 1 of 1

Request:

10. Has the Company been able to attribute any decrease (or lack of increase) in any costs resulting from the transmission wood pole replacement program?
    a. If so, please provide the cost category.
        i. Please provide the amount on a yearly basis.
        ii. Please provide any and all supporting calculations, workpapers, and other documentation showing the amount attributable.
    b. If not, please explain why.

Response:

No, because the wood to steel program only began in 2021 and only a small percentage of wood poles have been changed out under this program.

Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 213

Docket No. E-7, Sub 1276

Date of Request: **June 27, 2023**
Date of Response: **July 7, 2023**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 213-1, was provided to me by the following individual(s): Jacqueline Walker, Lead Planning and Regulatory Support Specialist, was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

North Carolina Public Staff
Data Request No. 213
DEC Docket No. E-7, Sub 1276
Item No. 213-1

Request:

1. For each EV charger listed in response to PSDR 136-7, please provide the following:
    a. Charger type (L2, DCFC, etc.).
    b. Project ID under which the installation was completed.
    c. Total cost for installation of the chargers. If installation is under a larger project, the Public Staff is only requesting the costs related to the chargers themselves, and not the overall project.
    d. Date of installation.
    e. Total energy delivered from the charger since installation.
    f. Please confirm that the Company only has the 41 chargers at the 12 sites to support the charging of Company vehicles.

Response:

a. See PSDR 136-2 original and supplemental responses
b. See PSDR 136-2 original and supplemental responses
c. See PSDR 136-1&2 Supplemental Response with data through May 2023 and PSDR 49-1d
d. See DEC PSDR 136-10 response for Park & Plug (EV Pilot) installation dates and see attached "DEC PSDR 213-1.xlsx" for Company Fleet (ECI) installation dates
e. See PSDR 136-2 original and supplemental responses
f. confirmed, See PSDR 136-2 response for details.

North Carolina Public Staff
Duke Energy Carolinas, LLC
Public Staff Data Request No. 213
Docket No. E-7, Sub 1276
Item No. 213-1
Page of Page

PSDR 213-1

- Installations performed in DEC NC since 2020

EVFLTCHGN

Facility	Total Chargers Purchased	Total Installs	Install Date
Burlington Operations Center	4	4	10/31/2021
Durham Operations	6	6	11/30/2021
Fairfax Operations Center Parking Location	1	1	11/20/2020
Hickory Operations	2	2	11/20/2020
High Point Ops	2	2	7/31/2022
Moorseville Ops Ctr	6	6	12/31/2022
North Wilksboro Ops	2	2	1/28/2020
Reidsville Ops Ctr	2	2	7/31/2022
Rural Hall Ops Ctr	2	2	7/31/2022
Shelby Operations Center Parking Location	4	4	10/31/2022
Spindale Operations Center Parking Location	4	4	10/31/2022
Toddville Operations	6	6	10/31/2022

**Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 213**

Docket No. E-7, Sub 1276

Date of Request: **June 27, 2023**
Date of Response: **July 7, 2023**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 213-2, was provided to me by the following individual(s): Jacqueline Walker, Lead Planning and Regulatory Support Specialist, was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

North Carolina Public Staff
Data Request No. 213
DEC Docket No. E-7, Sub 1276
Item No. 213-2
Page 1 of 1

Request:

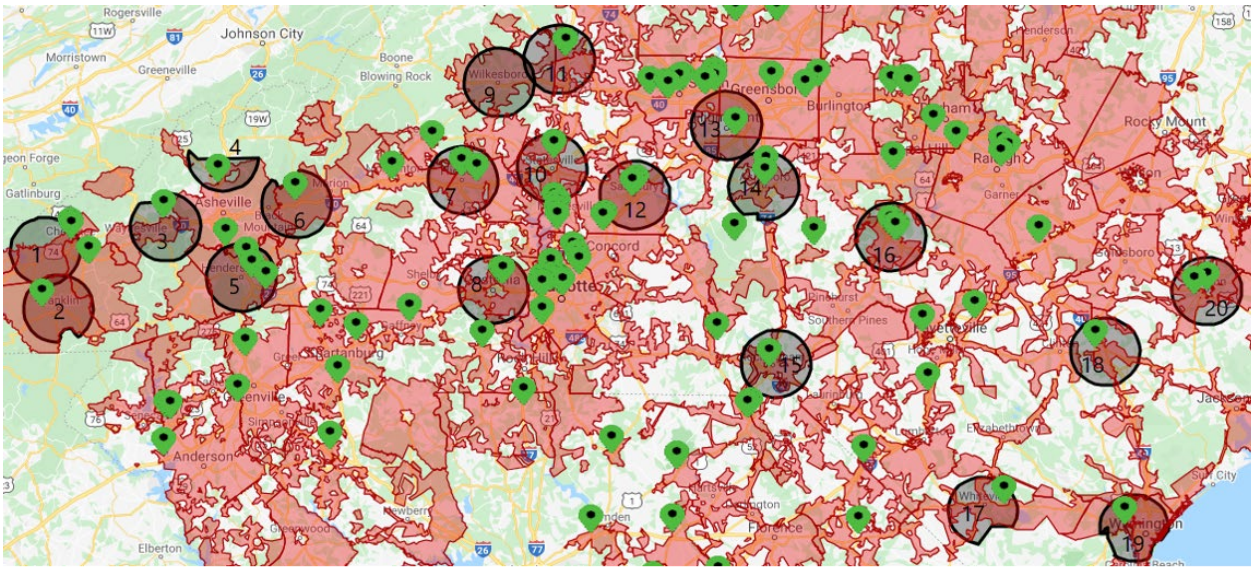
2. Please provide a detailed explanation, with supporting calculations, showing how the Company determined the locations to install the chargers, and the associated number of chargers.

Response:

In accordance with Docket E-2, Sub 1197 and Docket E-7, Sub 1195 the DEC DCFC site locations were determined using stakeholder engagement to select target locations along major highway corridors to eliminate range anxiety. The targeted locations are as shown in the attachment “DEC PSDR 213-2 ATTACHMENT.docx”. The number of chargers per site was discussed in the referenced Docket(s).

Charging infrastructure will be installed where the company currently domiciles vehicles at DEC-owned facilities. The exact number of charging stations at each location is currently under review as part of the data analysis being performed for the project. Please reference PSDR 137-5 Supplemental for detail on the analysis used to determine the total number of charging stations per MYRP year (also shared during a call with Public Staff on 6/9/23) and PSDR 137-6 for previously supplied information regarding number of chargers per location.

North Carolina Public Staff
Duke Energy Carolinas, LLC
Public Staff Data Request No. 213
Docket No. E-7, Sub 1276
Item No. 213-2
Page of Page

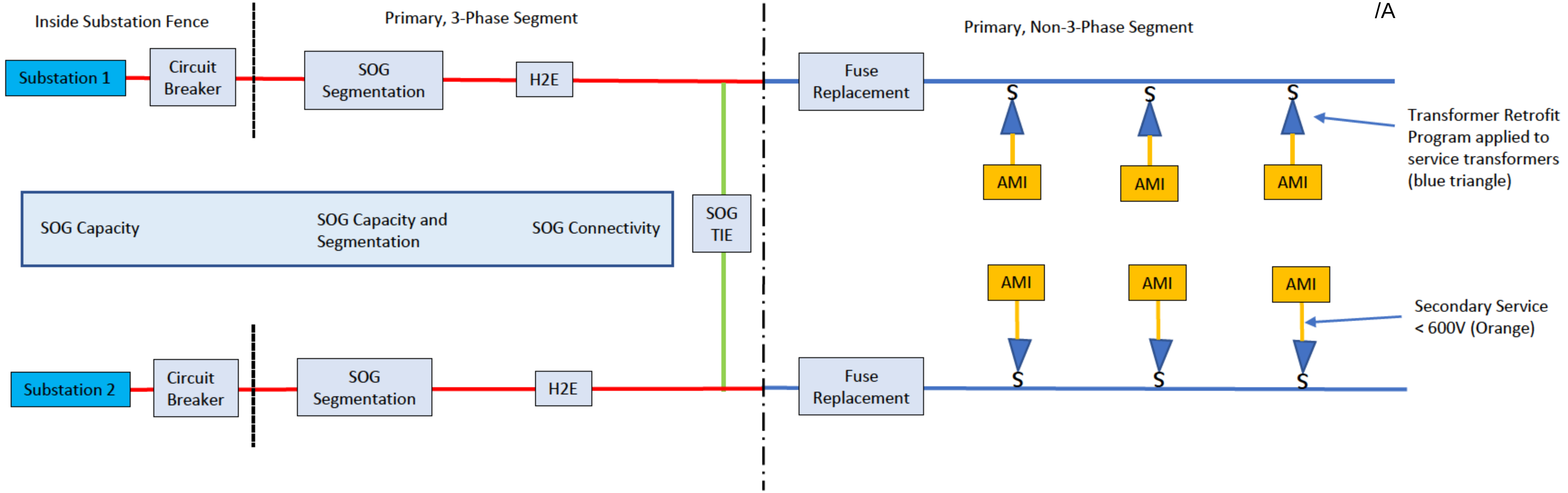


DOCKET NO. E-7, Sub 1276

LAWRENCE CONFIDENTIAL EXHIBIT 2

/A

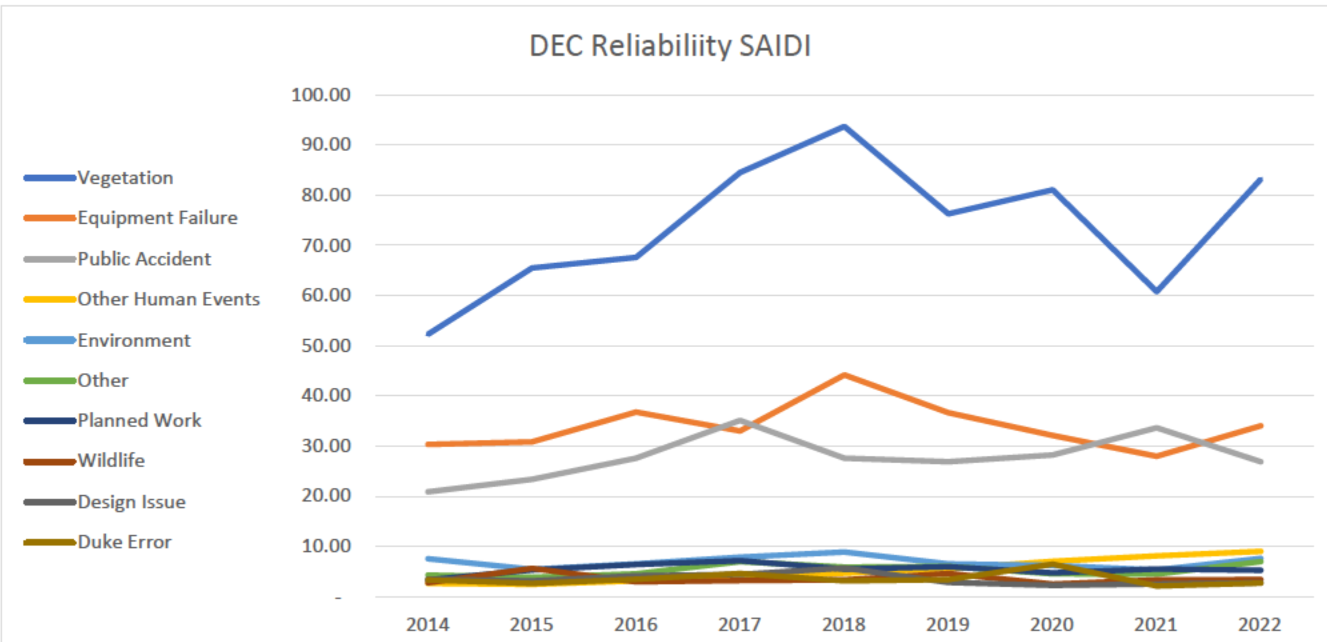
Distribution Circuit Illustration



Category	Primary, 3-Phase Segment	Primary, Non-3—Phase Segment
Electric Phases on Segment	3 electrical phases called primary feeders or backbone (Red, Green)	1 or 2 electrical phases tapped of off 3-phase segments. Called tap lines, or radial circuits (Blue)
Hazard Tree Assessment	All get Annual Level 1. SOP Segments get Level 2	SOP Segments get Level 1. All others in the on-cycle year only.
Leading Equipment Failures	Primary and secondary overhead and underground conductors	Primary and secondary overhead and underground conductors
TUG	Primary, 3-phase installed 2018-2022 – 8 miles. Installed in concrete duct bank. More costly.	Primary, non-3-phase installed 2018-2022 – 42 miles. Usually direct-buried. Less costly

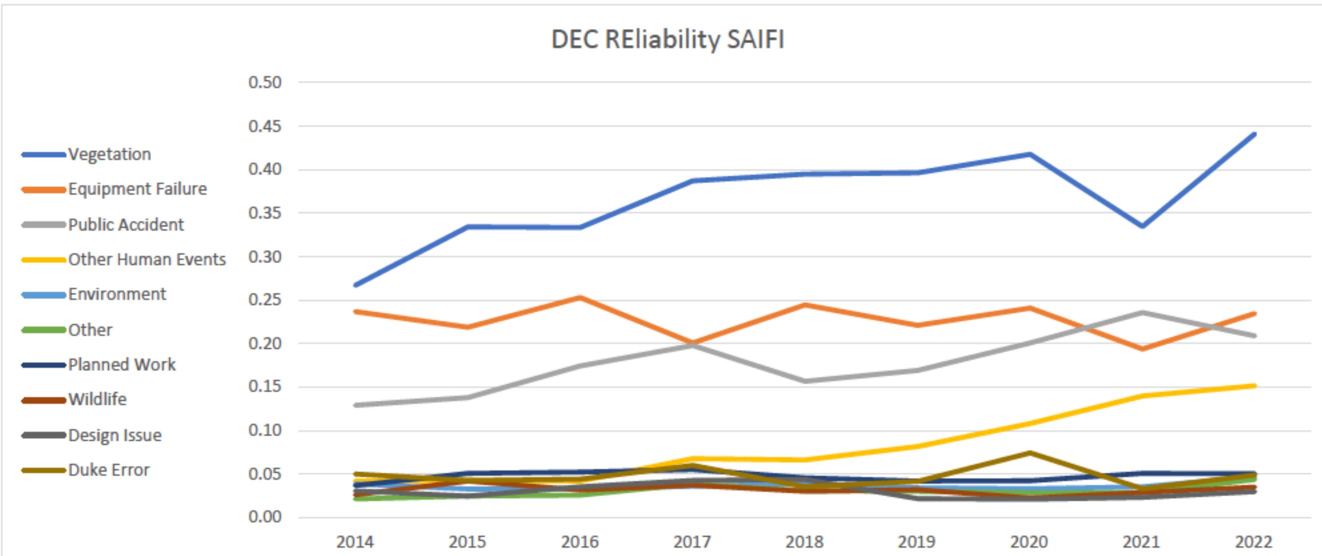
Reliability SAIDI

	2014	2015	2016	2017	2018	2019	2020	2021	2022
DEC NC	130.74	147.91	163.14	190.82	202.46	174.66	175.09	153.65	181.62
Vegetation	52.28	65.47	67.58	84.49	93.67	76.30	81.06	60.70	83.14
Equipment Failure	30.36	30.78	36.78	33.00	44.19	36.65	32.12	27.98	34.03
Public Accident	20.90	23.36	27.58	35.11	27.57	26.82	28.23	33.63	26.82
Other Human Events	2.62	2.42	3.11	4.03	4.67	5.56	7.01	8.13	9.01
Environment	7.53	5.40	6.53	7.85	8.90	6.53	6.14	5.33	7.60
Other	4.27	3.84	4.58	6.98	5.90	6.03	4.58	4.46	6.99
Planned Work	3.30	5.30	6.39	7.16	5.47	5.91	4.74	5.48	5.25
Wildlife	2.71	5.63	2.98	3.20	3.29	4.64	2.52	3.33	3.39
Design Issue	3.47	3.10	4.16	4.39	5.71	2.81	2.24	2.52	2.72
Duke Error	3.29	2.60	3.46	4.60	3.11	3.41	6.44	2.10	2.67



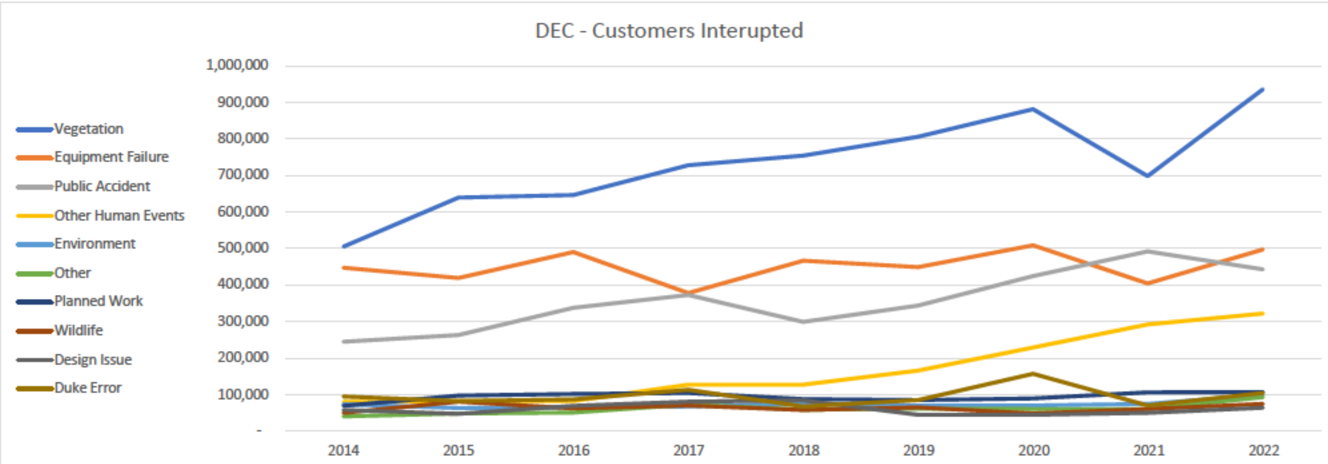
Reliability SAIFI

	2014	2015	2016	2017	2018	2019	2020	2021	2022
DEC NC	0.88	0.95	1.03	1.12	1.09	1.07	1.19	1.10	1.29
Vegetation	0.27	0.33	0.33	0.39	0.39	0.40	0.42	0.33	0.44
Equipment Failure	0.24	0.22	0.25	0.20	0.24	0.22	0.24	0.19	0.23
Public Accident	0.13	0.14	0.17	0.20	0.16	0.17	0.20	0.24	0.21
Other Human Events	0.04	0.04	0.04	0.07	0.07	0.08	0.11	0.14	0.15
Environment	0.04	0.03	0.03	0.04	0.04	0.03	0.03	0.04	0.05
Other	0.02	0.02	0.03	0.04	0.03	0.03	0.03	0.03	0.04
Planned Work	0.04	0.05	0.05	0.06	0.05	0.04	0.04	0.05	0.05
Wildlife	0.03	0.04	0.03	0.04	0.03	0.03	0.02	0.03	0.04
Design Issue	0.03	0.02	0.04	0.04	0.04	0.02	0.02	0.02	0.03
Duke Error	0.05	0.04	0.04	0.06	0.04	0.04	0.07	0.03	0.05



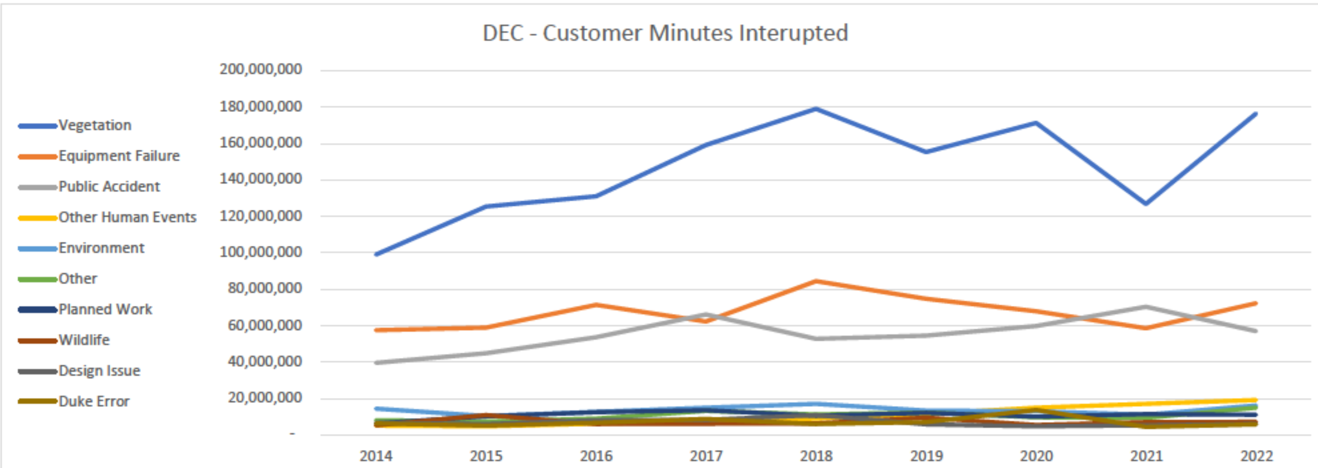
Customers Interupted (CI)

	2014	2015	2016	2017	2018	2019	2020	2021	2022
DEC NC	1,665,180	1,822,450	1,992,157	2,115,567	2,079,537	2,177,414	2,514,172	2,307,713	2,740,669
Vegetation	505,637	639,211	646,873	728,514	754,355	806,120	882,054	698,166	935,983
Equipment Failure	447,930	419,181	490,603	377,888	466,872	449,631	508,710	404,455	497,691
Public Accident	244,681	263,747	338,561	372,357	299,524	343,755	424,655	492,099	443,401
Other Human Events	80,053	82,042	81,908	127,802	127,168	165,978	229,148	292,288	321,727
Environment	73,473	62,984	64,622	67,805	74,897	70,186	70,018	74,300	99,511
Other	40,776	47,638	50,492	72,732	59,029	61,600	60,728	60,503	93,169
Planned Work	69,646	97,531	101,677	103,801	87,576	85,522	89,367	106,157	107,264
Wildlife	49,917	80,291	61,801	70,274	58,188	65,159	47,963	60,781	74,355
Design Issue	57,970	47,405	69,173	81,178	84,055	44,583	44,634	49,394	63,394
Duke Error	95,097	82,420	86,447	113,216	67,873	84,880	156,895	69,569	104,174



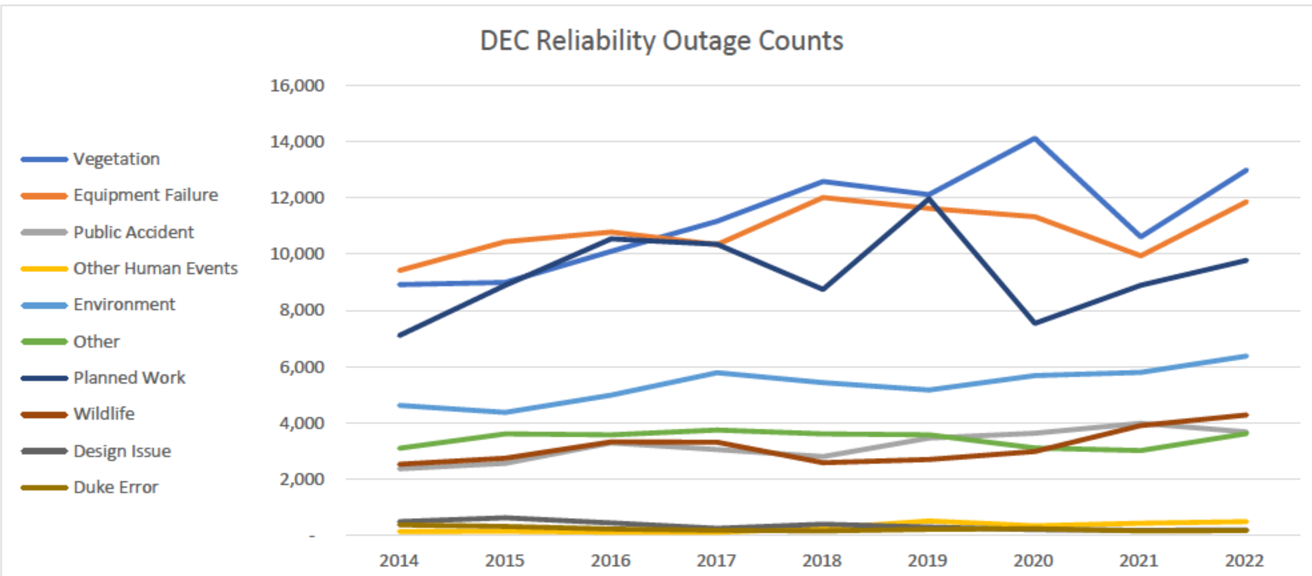
Customer Minutes Interupted (CMI)

	2014	2015	2016	2017	2018	2019	2020	2021	2022
DEC NC	247,675,550	283,166,221	316,584,796	359,349,170	387,016,784	355,540,177	370,098,175	321,091,995	385,678,457
Vegetation	99,050,924	125,337,852	131,138,735	159,115,007	179,053,372	155,312,014	171,354,736	126,851,549	176,550,758
Equipment Failure	57,514,191	58,932,382	71,367,509	62,149,098	84,481,327	74,613,629	67,887,048	58,465,621	72,272,392
Public Accident	39,594,532	44,726,498	53,524,344	66,120,294	52,697,329	54,592,234	59,676,579	70,271,378	56,958,599
Other Human Events	4,963,967	4,625,342	6,036,269	7,581,775	8,930,579	11,321,464	14,814,632	16,980,781	19,128,689
Environment	14,272,912	10,334,338	12,674,840	14,783,898	17,009,124	13,282,594	12,983,785	11,129,609	16,137,053
Other	8,095,483	7,354,019	8,883,039	13,139,880	11,269,111	12,266,736	9,686,270	9,328,792	14,851,064
Planned Work	6,253,187	10,149,401	12,396,267	13,491,054	10,447,615	12,039,249	10,013,598	11,453,953	11,148,922
Wildlife	5,127,541	10,786,885	5,774,106	6,032,841	6,281,640	9,451,887	5,324,580	6,965,467	7,192,410
Design Issue	6,568,801	5,935,477	8,065,752	8,274,341	10,910,953	5,723,100	4,737,254	5,265,924	5,778,867
Duke Error	6,234,013	4,984,027	6,723,936	8,660,983	5,935,732	6,937,270	13,619,693	4,378,919	5,659,705



Reliability Outage Count

	2014	2015	2016	2017	2018	2019	2020	2021	2022
DEC NC	39,125	42,761	47,448	48,328	48,634	51,682	49,200	46,961	53,505
Vegetation	8,917	8,998	10,093	11,162	12,571	12,105	14,111	10,604	12,978
Equipment Failure	9,418	10,444	10,780	10,327	12,007	11,617	11,320	9,932	11,860
Public Accident	2,374	2,568	3,298	3,059	2,810	3,472	3,637	3,992	3,687
Other Human Events	153	157	129	129	266	524	351	442	507
Environment	4,621	4,375	4,987	5,790	5,432	5,174	5,680	5,797	6,383
Other	3,108	3,616	3,587	3,749	3,623	3,582	3,110	3,022	3,631
Planned Work	7,102	8,881	10,540	10,340	8,744	11,956	7,531	8,891	9,778
Wildlife	2,540	2,752	3,333	3,320	2,598	2,712	2,996	3,917	4,288
Design Issue	503	640	461	256	405	309	210	191	207
Duke Error	389	330	240	196	178	231	254	173	186



Prepared by: Select the state first
Return to: Select the state first
Attn: Name
Address
City, State Zip

Parcel # Parcel Number

EASEMENT

State of North Carolina

County of County Name

THIS EASEMENT ("**Easement**") is made this _____ day of ___________________ 20_______, from NAME OF GRANTOR ("**Grantor**", whether one or more), to Entity, a North Carolina limited liability company ("**Grantee**").

Grantor, for and in consideration of the sum of One and 00/100 Dollar ($1.00) and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, does hereby grant unto Grantee a perpetual and non-exclusive easement, to construct, reconstruct, operate, patrol, maintain, repair, replace, relocate, add to, modify, and remove electric and communication lines including, but not limited to, all necessary supporting structures, and all other appurtenant apparatus and equipment for the transmission and distribution of electrical energy, and for technological purposes related to the operation of the electric facilities and for the communication purposes of Incumbent Local Exchange Carriers (collectively, "**Facilities**").

Grantor is the owner of that certain property described Select Property Description ("**Property**").

The Facilities may be both overhead and underground and located in, upon, over, along, under, through, and across a portion of the Property within an easement area described as follows:

A strip of land thirty feet (30') in uniform width for the overhead portion of said Facilities and a strip of land twenty feet (20') in uniform width for the underground portion of said Facilities, lying equidistant on both sides of a centerline, which centerline shall be established by the center of the Facilities as installed, along with an area ten feet (10') wide on all sides of the foundation of any Grantee enclosure/transformer, vault and/or manhole, (hereinafter referred to as the "**Easement Area**").

The rights granted herein include, but are not limited to, the following:

For Grantee's Internal Use:
Work Order #: Work Order #

1. Grantee shall have the right of ingress and egress over the Easement Area, Property, and any adjoining lands now owned or hereinafter acquired by Grantor (using lanes, driveways, and adjoining public roads where practical as determined by Grantee).
2. Grantee shall have the right to trim, cut down, and remove from the Easement Area, at any time or times and using safe and generally accepted arboricultural practices, trees, limbs, undergrowth, other vegetation, and obstructions.
3. Grantee shall have the right to trim, cut down, and remove from the Property, at any time or times and using safe and generally accepted arboricultural practices, dead, diseased, weak, dying, or leaning trees or limbs, which, in the opinion of Grantee, might fall upon the Easement Area or interfere with the safe and reliable operation of the Facilities.
4. Grantee shall have the right to install necessary guy wires and anchors extending beyond the boundaries of the Easement Area.
5. Grantee shall have the right to relocate the Facilities and Easement Area on the Property to conform to any future highway or street relocation, widening, or alterations.
6. Grantor shall not place, or permit the placement of, any structures, improvements, facilities, or obstructions, within or adjacent to the Easement Area, which may interfere with the exercise of the rights granted herein to Grantee. Grantee shall have the right to remove any such structure, improvement, facility, or obstruction at the expense of Grantor.
7. Excluding the removal of vegetation, structures, improvements, facilities, and obstructions as provided herein, Grantee shall promptly repair or cause to be repaired any physical damage to the surface area of the Easement Area and Property resulting from the exercise of the rights granted herein to Grantee. Such repair shall be to a condition which is reasonably close to the condition prior to the damage, and shall only be to the extent such damage was caused by Grantee or its contractors or employees.
8. [Select Clause]

9. All other rights and privileges reasonably necessary, in Grantee's sole discretion, for the safe, reliable, and efficient installation, operation, and maintenance of the Facilities.

The terms Grantor and Grantee shall include the respective heirs, successors, and assigns of Grantor and Grantee. The failure of Grantee to exercise or continue to exercise or enforce any of the rights herein granted shall not be construed as a waiver or abandonment of the right thereafter at any time, or from time to time, to exercise any and all such rights.

TO HAVE AND TO HOLD said rights, privilege, and easement unto Grantee, its successors, licensees, and assigns, forever. Grantor warrants and covenants that Grantor has the full right and authority to convey to Grantee this perpetual Easement, and that Grantee shall have quiet and peaceful possession, use and enjoyment of the same.

Select the State and Grantor Type to get the Signature Page

E-7 SUB 1276
GDS ADJUSTMENTS - DEC MYRP

Project Type	Project Name
Breakers	Cliffside TOIL Breaker Replacement
Breakers	Great Falls Switching Station TOIL Breaker Replacement
Breakers	Blue Ridge EC Del 14 TOIL Breaker Replacement
Breakers	Broad River EC Del 2 TOIL Breaker Replacement
Breakers	Burlington Main TOIL Breaker Replacement
Breakers	Crest Street Retail TOIL Breaker Replacement
Breakers	Duke University Station 1 TOIL Breaker Replacement
Breakers	Eastgate TOIL Breaker Replacement
Breakers	EnergyUnited EMC Del 32 TOIL Breaker Replacement
Breakers	Kivett Drive Retail TOIL Breaker Replacement
Breakers	Mt. Tabor TOIL Breaker Replacement
Breakers	Toast Retail TOIL Breaker Replacement
Capacity and Customer Planning	Eno Tie
Capacity and Customer Planning	North Greenville Tie Bus Junction Breaker (BJB) Replacement
Capacity and Customer Planning	Bethania and Shattalon Line Equipment Uprate
Capacity and Customer Planning	Shady Grove Tie
Capacity and Customer Planning	Page and Guilford 100 kV Line Rebuild
Capacity and Customer Planning	Stamey Tie
Capacity and Customer Planning	Boyds to Trinity Ridge
System Intelligence - Condition Based Monitoring	Carolina West - Condition Based Monitoring
System Intelligence - Condition Based Monitoring	Transformer Condition Based Monitoring
System Intelligence - Relay Upgrades	Albemarle Switching Station
System Intelligence - Relay Upgrades	Beech Street Retail
System Intelligence - Relay Upgrades	Campobello Tie
System Intelligence - Relay Upgrades	CNS Busline
System Intelligence - Relay Upgrades	Concord Main
System Intelligence - Relay Upgrades	Depot Street Retail
System Intelligence - Relay Upgrades	Dilworth
System Intelligence - Relay Upgrades	Draper Retail
System Intelligence - Relay Upgrades	Duke University Station 1 & 2

System Intelligence - Relay Upgrades	East Spencer
System Intelligence - Relay Upgrades	First Quality Tissue
System Intelligence - Relay Upgrades	Highland Retail
System Intelligence - Relay Upgrades	McAddenville Retail
System Intelligence - Relay Upgrades	North Kannapolis Retail
System Intelligence - Relay Upgrades	Robert Bosch
System Intelligence - Relay Upgrades	Seneca Place
System Intelligence - Relay Upgrades	Shuman Avenue
System Intelligence - Relay Upgrades	West Norwood Retail
Transmission Line Hardening & Resilience	Esto - Pickens 100 kV Rebuild
Transmission Line Hardening & Resilience	JP Stevens 44 kV to 100 kV Rebuild
Transmission Line Hardening & Resilience	Sawmill 1 & 2 44 kV to 100 kV Rebuild
Transmission Line Hardening & Resilience	Sigsbee A & B 44 kV to 100 kV Rebuild
Transmission Line Hardening & Resilience	Belfast 44 kV Line Rebuild
Transmission Line Hardening & Resilience	Rockford 44 kV Line Rebuild

Summary of Adjustments

Project Type
Breakers
Capacity and Customer Planning
System Intelligence - Condition Based Monitoring
System Intelligence - Relay Upgrades
Transmission Line Hardening & Resilience
Total Adjustments

/A

Roxie McCullar, CPA, CDP
8625 Farmington Cemetery Road
Pleasant Plains, IL

Roxie McCullar is a regulatory consultant, licensed Certified Public Accountant in the state of Illinois, and a Certified Depreciation Professional through the Society of Depreciation Professionals. She is a member of the American Institute of Certified Public Accountants, the Illinois CPA Society, and the Society of Depreciation Professionals. Ms. McCullar has received her Master of Arts degree in Accounting from the University of Illinois-Springfield as well as her Bachelor of Science degree in Mathematics from Illinois State University. Ms. McCullar has 25 years of experience as a regulatory consultant for William Dunkel and Associates. In that time, she has filed testimony in over 50 state regulatory proceedings on depreciation issues and cost allocation for universal service and has assisted Mr. Dunkel in numerous other proceedings.

Education

Master of Arts in Accounting from the University of Illinois-Springfield, Springfield, Illinois

12 hours of Business and Management classes at Benedictine University-Springfield College in Illinois, Springfield, Illinois

27 hours of Graduate Studies in Mathematics at Illinois State University, Normal, Illinois

Completed Depreciation Fundamentals training course offered by the Society of Depreciation Professionals

Relevant Coursework:

- Calculus
- Number Theory
- Linear Programming
- Finite Sampling
- Introduction to Micro Economics
- Principles of MIS
- Introduction to Managerial Accounting
- Intermediate Financial Accounting I
- Advanced Financial Accounting
- Accounting Information Systems
- Fraud Forensic Accounting
- Commercial Law
- Advanced Auditing
- Discrete Mathematics
- Mathematical Statistics
- Differential Equations
- Statistics for Business and Economics
- Introduction to Macro Economics
- Introduction to Financial Accounting
- Intermediate Managerial Accounting
- Intermediate Financial Accounting II
- Auditing Concepts/Responsibilities
- Federal Income Tax
- Accounting for Government & Non-Profit
- Advanced Utilities Regulation
- Advanced Corp & Partnership Taxation

Current Position: Consultant at William Dunkel and Associates

Participation in the proceedings below included some or all of the following:

Developing analyses, preparing data requests, analyzing issues, writing draft testimony, preparing data responses, preparing draft questions for cross examination, drafting briefs, and developing various quantitative models.

Previous Experience of Roxie McCullar

Year	State	Commission	Docket	Company	Description	On Behalf of
2023	North Carolina	North Carolina Utilities Commission	E-2, SUB 1300	Duke Energy Progress, LLC	Electric Depreciation Issues	Public Staff - North Carolina Utilities Commission
2023	Kansas	Kansas Corporation Commission	23-ATMG-359-RTS	Atmos Energy	Natural Gas Depreciation Issues	Kansas Corporation Commission Staff
2022	Alaska	Regulatory Commission of Alaska (RCA)	U-22-034	Chugach Electric Association, Inc.	Electric Depreciation Issues	Attorney General's Regulatory Affairs and Public Advocacy Section (RAPA)
2022	Kansas	Kansas Corporation Commission	22-COST-546-KSF	Columbus Communications Services, LLC	Non-Regulated Allocations, State Allocations, Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2022	Washington	Washington Utilities & Transportation Commission	UE-220066 & UG-220067	Puget Sound Energy	Electric & Natural Gas Depreciation Issues	Regulatory Staff - Washington Utilities & Transportation Commission Public
2022	North Carolina	North Carolina Utilities Commission	G-39, SUBS 46 and 47	Cardinal Pipeline Company, LLC	Natural Gas Depreciation Issues	Public Staff - North Carolina Utilities Commission
2022	Alaska	Regulatory Commission of Alaska (RCA)	U-21-070/U-21-071	Golden Heart Utilities and College Utilities Corporation	Water and Wastewater Depreciation Issues	Attorney General's Regulatory Affairs and Public Advocacy Section (RAPA)
2021	Kansas	Kansas Corporation Commission	22-CRKT-087-KSF	Craw-Kan Telephone Cooperative, Inc.	Non-Regulated Allocations, State Allocations, Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2021	North Carolina	North Carolina Utilities Commission	G-5, SUB 632	Public Service Company of North Carolina	Natural Gas Depreciation Issues	Public Staff - North Carolina Utilities Commission
2021	Kansas	Kansas Corporation Commission	21-BHCG-418-RTS	Black Hills Energy	Natural Gas Depreciation Issues	Kansas Corporation Commission Staff
2021	Florida	Florida Public Service Commission	20210015-EI	Florida Power & Light Company	Electric Depreciation Issues	Office of Public Counsel

Previous Experience of Roxie McCullar

Year	State	Commission	Docket	Company	Description	On Behalf of
2020	DC	District of Columbia Public Service Commission	FC1137	Washington Gas & Light	Natural Gas Depreciation Issues	District of Columbia Public Service Commission
2020	DC	District of Columbia Public Service Commission	FC1156	Potomac Electric Power Company	Electric Depreciation Issues	District of Columbia Public Service Commission
2020	North Carolina	North Carolina Utilities Commission	E-2, SUB 1219	Duke Energy Progress, LLC	Electric Depreciation Issues	Public Staff - North Carolina Utilities Commission
2020	Kansas	Kansas Corporation Commission	20-BLVT-218-KSF	Blue Valley Tele-Communications, Inc.	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2020	Utah	Public Service Commission of Utah	18-035-36	Rocket Mountain Power	Electric Depreciation Issues	Division of Public Utilities
2020	North Carolina	North Carolina Utilities Commission	E-7, SUB 1214	Duke Energy Carolinas, LLC	Electric Depreciation Issues	Public Staff - North Carolina Utilities Commission
2019	Kansas	Kansas Corporation Commission	20-UTAT-032-KSF	United Telephone Association	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2019	Kansas	Kansas Corporation Commission	19-ATMG-525-RTS	Atmos Energy	Natural Gas Depreciation Issues	Kansas Corporation Commission Staff
2019	Kansas	Kansas Corporation Commission	19-GNBT-505-KSF	Golden Belt Telephone Association	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2019	Arizona	Arizona Corporation Commission	E-01933A-19-0028	Tucson Electric Power Company	Electric Depreciation Issues	The Utilities Division Staff Arizona Corporation Commission
2019	North Carolina	North Carolina Utilities Commission	E-22, SUB 562	Dominion Energy North Carolina	Electric Depreciation Issues	Public Staff - North Carolina Utilities Commission
2019	Utah	Public Service Commission of Utah	19-057-03	Dominion Energy Utah	Natural Gas Depreciation Issues	Division of Public Utilities
2019	Kansas	Kansas Corporation Commission	19-EPDE-223-RTS	Empire District Electric Company	Electric Depreciation Issues	Kansas Corporation Commission Staff

Previous Experience of Roxie McCullar

Year	State	Commission	Docket	Company	Description	On Behalf of
2019	Arizona	Arizona Corporation Commission	T-03214A-17-0305	Citizens Telecommunications Company	Arizona Universal Service Fund	The Utilities Division Staff Arizona Corporation Commission
2018	Kansas	Kansas Corporation Commission	18-KGSG-560-RTS	Kansas Gas Service	Natural Gas Depreciation Issues	Kansas Corporation Commission Staff
2018	Kansas	Kansas Corporation Commission	18-KCPE-480-RTS	Kansas City Power & Light Company	Electric Depreciation Issues	Kansas Corporation Commission Staff
2018	Rhode Island	Rhode Island and Providence Plantations Public Utilities Commission	4800	SUEZ Water	Water Depreciation Issues	Division of Public Utilities and Carriers
2018	Rhode Island	Rhode Island and Providence Plantations Public Utilities Commission	4770	Narragansett Electric Company	Electric & Natural Gas Depreciation Issues	Division of Public Utilities and Carriers
2018	North Carolina	North Carolina Utilities Commission	E-7, SUB 1146	Duke Energy Carolinas, LLC	Electric Depreciation Issues	Public Staff - North Carolina Utilities Commission
2017	DC	District of Columbia Public Service Commission	FC1150	Potomac Electric Power Company	Electric Depreciation Issues	District of Columbia Public Service Commission
2017	Kansas	Kansas Corporation Commission	17-RNBT-555-KSF	Rainbow Telecommunications Association, Inc.	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2017	North Carolina	North Carolina Utilities Commission	E-2, SUB 1142	Duke Energy Progress, LLC	Electric Depreciation Issues	Public Staff - North Carolina Utilities Commission
2017	Washington	Washington Utilities & Transportation Commission	UE-170033 & UG-170034	Puget Sound Energy	Electric & Natural Gas Depreciation Issues	Washington State Office of the Attorney General, Public Counsel Unit
2017	Florida	Florida Public Service Commission	160186-EI & 160170-EI	Gulf Power Company	Electric Depreciation Issues	The Citizens of the State of Florida
2016	Kansas	Kansas Corporation Commission	16-KGSG-491-RTS	Kansas Gas Service	Natural Gas Depreciation Issues	Kansas Corporation Commission Staff

Previous Experience of Roxie McCullar

Year	State	Commission	Docket	Company	Description	On Behalf of
2016	DC	District of Columbia Public Service Commission	FC1139	Potomac Electric Power Company	Depreciation Issues	District of Columbia Public Service Commission
2016	Arizona	Arizona Corporation Commission	E-01933A-15-0239 & E-01933A-15-0322	Tucson Electric Power Company	Electric Depreciation Issues	The Utilities Division Staff Arizona Corporation Commission
2016	Georgia	Georgia Public Service Commission	40161	Georgia Power Company	Addressed Depreciation Issues	Georgia Public Service Commission Public Interest Advocacy Staff
2016	DC	District of Columbia Public Service Commission	FC1137	Washington Gas & Light	Depreciation Issues	District of Columbia Public Service Commission
2015	Kansas	Kansas Corporation Commission	16-ATMG-079-RTS	Atmos Energy	Natural Gas Depreciation Issues	Kansas Corporation Commission Staff
2015	Kansas	Kansas Corporation Commission	15-TWVT-213-AUD	Twin Valley Telephone, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2015	Kansas	Kansas Corporation Commission	15-KCPE-116-RTS	Kansas City Power & Light Company	Electric Depreciation Issues	Kansas Corporation Commission Staff
2015	Kansas	Kansas Corporation Commission	15-MRGT-097-AUD	Moundridge Telephone Company, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2014	Kansas	Kansas Corporation Commission	14-S&TT-525-KSF	S&T Telephone Cooperative Association, Inc.	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2014	Kansas	Kansas Corporation Commission	14-WTCT-142-KSF	Wamego Telecommunications Company, Inc.	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2013	Kansas	Kansas Corporation Commission	13-PLTT-678-KSF	Peoples Telecommunications, LLC	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2013	New Jersey	State of New Jersey Board of Public Utilities	BPU ER12121071	Atlantic City Electric Company	Electric Depreciation Issues	New Jersey Rate Counsel

Previous Experience of Roxie McCullar

Year	State	Commission	Docket	Company	Description	On Behalf of
2013	Kansas	Kansas Corporation Commission	13-JBNT-437-KSF	J.B.N. Telephone Company, Inc.	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2013	Kansas	Kansas Corporation Commission	13-ZENT-065-AUD	Zenda Telephone Company, Inc.	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2013	DC	District of Columbia Public Service Commission	FC1103	Potomac Electric Power Company	Depreciation Issues	District of Columbia Public Service Commission
2012	Kansas	Kansas Corporation Commission	12-LHPT-875-AUD	LaHarpe Telephone Company, Inc.	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2012	Kansas	Kansas Corporation Commission	12-GRHT-633-KSF	Gorham Telephone Company	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2012	Kansas	Kansas Corporation Commission	12-S&TT-234-KSF	S&T Telephone Cooperative Association, Inc.	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2011	DC	District of Columbia Public Service Commission	FC1093	Washington Gas & Light	Depreciation Issues	District of Columbia Public Service Commission
2011	Kansas	Kansas Corporation Commission	11-CNHT-659-KSF	Cunningham Telephone Company, Inc.	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2011	Kansas	Kansas Corporation Commission	11-PNRT-315-KSF	Pioneer Telephone Association	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2010	Kansas	Kansas Corporation Commission	10-HVDT-288-KSF	Haviland Telephone Company, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2009	Kansas	Kansas Corporation Commission	09-BLVT-913-KSF	Blue Valley Tele-Communications, Inc.	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2009	DC	District of Columbia Public Service Commission	FC1076	Potomac Electric Power Company	Depreciation Issues	District of Columbia Public Service Commission

Previous Experience of Roxie McCullar

Year	State	Commission	Docket	Company	Description	On Behalf of
2008	Kansas	Kansas Corporation Commission	09-MTLT-091-KSF	Mutual Telephone Company	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2007	Kansas	Kansas Corporation Commission	08-MRGT-221-KSF	Moundridge Telephone Company	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2007	Kansas	Kansas Corporation Commission	07-PLTT-1289-AUD	Peoples Telecommunications, LLC	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2007	Kansas	Kansas Corporation Commission	07-MDTT-195-AUD	Madison Telephone, LLC	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2007	Kansas	Kansas Corporation Commission	06-RNBT-1322-AUD	Rainbow Telecommunications Assn., Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2006	Kansas	Kansas Corporation Commission	06-WCTC-1020-AUD	Wamego Telecommunications Company, Inc.	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2006	Kansas	Kansas Corporation Commission	06-H&BT-1007-AUD	H&B Communications, Inc.	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2006	Kansas	Kansas Corporation Commission	06-ELKT-365-AUD	Elkhart Telephone Company, Inc.	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2005	Kansas	Kansas Corporation Commission	05-SCNT-1048-AUD	South Central Telephone Association, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2005	Utah	Public Service Commission of Utah	05-2302-01	Carbon/Emery Telecom, Inc.	Cost Study Issues & Depreciation Issues	Utah Committee of Consumer Services
2005	Kansas	Kansas Corporation Commission	05-TTHT-895-AUD	Totah Communications, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2005	Maine	Public Utilities Commission of the State of Maine	2005-155	Verizon	Depreciation Issues	Office of Public Advocate

Previous Experience of Roxie McCullar

Year	State	Commission	Docket	Company	Description	On Behalf of
2005	Kansas	Kansas Corporation Commission	05-TRCT-607-KSF	Tri-County Telephone Association	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2005	Kansas	Kansas Corporation Commission	05-CNHT-020-AUD	Cunningham Telephone Company, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2005	Kansas	Kansas Corporation Commission	05-KOKT-060-AUD	KanOkla Telephone Association, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2004	Kansas	Kansas Corporation Commission	04-UTAT-690-AUD	United Telephone Association, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2004	Kansas	Kansas Corporation Commission	04-CGTT-679-RTS	Council Grove Telephone Company	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2004	Kansas	Kansas Corporation Commission	04-GNBT-130-AUD	Golden Belt Telephone Association	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2004	Kansas	Kansas Corporation Commission	03-TWVT-1031-AUD	Twin Valley Telephone, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2003	Kansas	Kansas Corporation Commission	03-HVDT-664-RTS	Haviland Telephone Company	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2003	Kansas	Kansas Corporation Commission	03-WHST-503-AUD	Wheat State Telephone Company, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2003	Kansas	Kansas Corporation Commission	03-S&AT-160-AUD	S&A Telephone Company	Cost Study Issues	Kansas Corporation Commission Staff
2002	Kansas	Kansas Corporation Commission	02-JBNT-846-AUD	JBN Telephone Company	Cost Study Issues	Kansas Corporation Commission Staff
2002	Kansas	Kansas Corporation Commission	02-S&TT-390-AUD	S&T Telephone Cooperative Association, Inc.	Cost Study Issues	Kansas Corporation Commission Staff

Previous Experience of Roxie McCullar

Year	State	Commission	Docket	Company	Description	On Behalf of
2002	Kansas	Kansas Corporation Commission	02-BLVT-377-AUD	Blue Valley Telephone Company, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-PNRT-929-AUD	Pioneer Telephone Association, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-BSST-878-AUD	Bluestem Telephone Company	Cost Study Issues	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-SFLT-879-AUD	Sunflower Telephone Company, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-CRKT-713-AUD	Craw-Kan Telephone Cooperative, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-RNBT-608-KSF	Rainbow Telecommunications Association	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-SNKT-544-AUD	Southern Kansas Telephone Company, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-RRLT-518-KSF	Rural Telephone Service Company, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2000	Illinois	Illinois Commerce Commission	98-0252	Ameritech	Cost Study Issues	Government and Consumer Intervenors

Duke Energy Carolinas
Table 1: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2021

		Current Approved		DEC Proposed			Public Staff Proposed			
Functional Category	12/31/21 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from Current Approved	Accrual Rate	Accrual Amount	Difference from Current Approved	Difference from DEC Proposed
A	B	C	D	E	F	G	H	I	J	K
Steam Production Plant	8,463,138,018	3.87%	327,865,610	6.24%	527,976,439	200,110,829	4.97%	420,664,942	92,799,332	(107,311,497)
Nuclear Production Plant	9,130,612,833	2.13%	194,502,833	2.21%	202,087,899	7,585,066	2.21%	202,087,899	7,585,066	0
Hydraulic Production Plant	2,508,338,881	2.00%	50,119,329	2.31%	57,821,777	7,702,448	2.27%	56,902,965	6,783,636	(918,812)
Other Production Plant	3,393,027,734	3.19%	108,136,258	3.63%	123,027,119	14,890,861	3.39%	115,133,003	6,996,745	(7,894,116)
Transmission Plant	4,768,540,557	2.23%	106,292,693	2.43%	115,845,696	9,553,003	2.39%	113,854,381	7,561,688	(1,991,315)
Distribution Plant	14,397,276,812	2.19%	314,740,341	2.44%	351,764,448	37,024,107	2.44%	351,764,448	37,024,107	0
General Plant	1,361,576,220	5.47%	74,519,315	5.31%	72,301,569	(2,217,746)	5.31%	72,301,569	(2,217,746)	0
Rights of Way	200,607,727	0.98%	1,971,536	0.97%	1,944,823	(26,713)	0.97%	1,944,823	(26,713)	0
General Plant Reserve Amortization			(13,907,418)		(11,071,465)	2,835,953		(11,071,465)	2,835,953	0
Total Depreciable Plant	**44,223,118,782**	**2.63%**	**1,164,240,497**	**3.26%**	**1,441,698,305**	**277,457,808**	**2.99%**	**1,323,582,566**	**159,342,069**	**(118,115,739)**

Duke Energy Carolinas
Table 2: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2021

		Current Approved		DEC Proposed			Public Staff Proposed			
Plant	12/31/21 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from Current Approved	Accrual Rate	Accrual Amount	Difference from Current Approved	Difference from DEC Proposed
A	B	C	D	E	F	G	H	I	J	K
Steam Production										
Marshall Unit 1	544,590,024	3.94%	21,466,440	6.24%	33,979,159	12,512,719	3.45%	18,771,165	(2,695,275)	(15,207,994)
Marshall Unit 2	181,860,497	4.31%	7,847,007	8.11%	14,751,666	6,904,659	4.38%	7,959,938	112,931	(6,791,728)
Marshall Unit 3	403,390,207	4.04%	16,298,969	5.31%	21,430,568	5,131,599	4.53%	18,289,034	1,990,065	(3,141,534)
Marshall Unit 4	302,909,174	4.21%	12,744,332	5.69%	17,246,815	4,502,483	4.86%	14,727,683	1,983,351	(2,519,132)
Marshall Common	583,173,198	4.35%	25,358,770	6.72%	39,215,221	13,856,451	5.64%	32,901,374	7,542,604	(6,313,847)
Marshall	*2,015,923,099*	*4.15%*	*83,715,518*	*6.28%*	*126,623,429*	*42,907,911*	*4.60%*	*92,649,194*	*8,933,676*	*(33,974,235)*
Belews Creek Unit 1	656,048,177	3.68%	24,168,706	4.71%	30,897,160	6,728,454	3.93%	25,775,764	1,607,058	(5,121,396)
Belews Creek Unit 2	524,058,054	3.73%	19,529,443	4.82%	25,274,450	5,745,007	4.02%	21,086,523	1,557,080	(4,187,927)
Belews Creek Common	1,306,317,323	3.57%	46,619,881	4.97%	64,930,928	18,311,047	4.14%	54,131,742	7,511,861	(10,799,186)
Belews Creek	*2,486,423,554*	*3.63%*	*90,318,030*	*4.87%*	*121,102,538*	*30,784,508*	*4.06%*	*100,994,029*	*10,675,999*	*(20,108,509)*
Cliffside 5 (J.E. Rogers)	792,971,810	4.20%	33,300,423	9.48%	75,138,030	41,837,607	3.53%	28,017,696	(5,282,727)	(47,120,334)
Cliffside 6 (J.E. Rogers)	2,100,670,705	3.14%	65,929,573	3.36%	70,680,209	4,750,636	3.32%	69,718,955	3,789,382	(961,254)
Cliffside 5 and 6 Common (J.E. Rogers)	171,396,593	3.43%	5,886,660	3.57%	6,114,093	227,433	3.53%	6,048,077	161,417	(66,016)
Cliffside (J.E. Rogers)	*3,065,039,108*	*3.43%*	*105,116,656*	*4.96%*	*151,932,332*	*46,815,676*	*3.39%*	*103,784,728*	*(1,331,928)*	*(48,147,604)*
Allen	894,907,452	5.44%	48,685,456	14.34%	128,287,858	79,602,402	13.77%	123,206,709	74,521,253	(5,081,149)
Shared Department Plant	844,804	3.55%	29,950	3.58%	30,282	332	3.58%	30,282	332	0
Total Steam Production	**8,463,138,018**	**3.87%**	**327,865,610**	**6.24%**	**527,976,439**	**200,110,829**	**4.97%**	**420,664,942**	**92,799,332**	**(107,311,497)**
Nuclear Production Plant										
Oconee	4,727,334,983	2.41%	113,880,556	2.49%	117,563,438	3,682,882	2.49%	117,563,438	3,682,882	0
McGuire	3,496,435,155	1.85%	64,847,431	1.94%	67,727,208	2,879,777	1.94%	67,727,208	2,879,777	0
Catawba	902,591,426	1.74%	15,689,084	1.85%	16,694,264	1,005,180	1.85%	16,694,264	1,005,180	0
Shared Department Plant	4,251,270	2.02%	85,762	2.42%	102,989	17,227	2.42%	102,989	17,227	0

Duke Energy Carolinas
Table 2: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2021

		Current Approved		DEC Proposed			Public Staff Proposed			
Plant	12/31/21 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from Current Approved	Accrual Rate	Accrual Amount	Difference from Current Approved	Difference from DEC Proposed
A	B	C	D	E	F	G	H	I	J	K
Total Nuclear Production	**9,130,612,833**	**2.13%**	**194,502,833**	**2.21%**	**202,087,899**	**7,585,066**	**2.21%**	**202,087,899**	**7,585,066**	**0**
<u>Hydro Production Plant</u>										
Cowans Ford	144,562,585	2.27%	3,275,381	2.41%	3,477,360	201,979	2.41%	3,478,774	203,393	1,414
Bad Creek	1,075,341,164	1.58%	17,029,692	1.70%	18,334,097	1,304,405	1.68%	18,036,240	1,006,548	(297,857)
Jocassee	190,742,120	1.99%	3,801,734	2.43%	4,631,681	829,947	2.43%	4,627,189	825,455	(4,492)
Keowee	241,689,159	2.81%	6,796,552	3.40%	8,223,752	1,427,200	3.36%	8,127,605	1,331,053	(96,147)
Fishing Creek	56,492,203	2.07%	1,169,190	2.48%	1,400,391	231,201	2.41%	1,362,372	193,182	(38,019)
Cedar Creek	37,154,093	2.22%	824,871	2.55%	948,072	123,201	2.49%	923,943	99,072	(24,129)
Bridgewater	302,547,051	2.14%	6,486,081	2.39%	7,235,663	749,582	2.36%	7,136,521	650,440	(99,142)
Lookout Shoals	21,651,591	2.17%	470,750	2.46%	532,047	61,297	2.39%	516,875	46,125	(15,172)
Mountain Island	38,664,658	2.02%	782,829	2.67%	1,030,626	247,797	2.60%	1,004,270	221,441	(26,356)
99 Islands	27,652,055	3.29%	908,636	4.17%	1,151,842	243,206	4.02%	1,112,317	203,681	(39,525)
Oxford	63,492,552	2.26%	1,432,078	2.35%	1,493,825	61,747	2.32%	1,474,654	42,576	(19,171)
Rhodhiss	37,207,730	2.26%	840,708	2.57%	956,923	116,215	2.51%	932,593	91,885	(24,330)
Wateree	62,536,341	2.08%	1,297,790	2.42%	1,514,335	216,545	2.38%	1,491,457	193,667	(22,878)
Wylie	73,476,207	2.12%	1,555,251	2.59%	1,901,228	345,977	2.55%	1,877,218	321,967	(24,010)
Great Falls	10,026,395	2.95%	295,905	4.06%	406,977	111,072	3.56%	356,808	60,903	(50,169)
Dearborn	21,434,333	2.28%	488,592	2.61%	560,225	71,633	2.51%	538,035	49,443	(22,190)
NPL Bear Creek	15,919,319	3.19%	507,163	4.07%	647,504	140,341	4.02%	639,163	132,000	(8,341)
NPL Cedar Cliff	10,685,969	2.56%	274,005	4.17%	445,356	171,351	4.05%	433,300	159,295	(12,056)
NPL Nantahala	26,829,194	2.20%	589,824	2.74%	736,104	146,280	2.69%	722,281	132,457	(13,823)
NPL Queens Creek	1,306,404	5.05%	65,943	5.82%	75,994	10,051	4.51%	58,904	(7,039)	(17,090)
NPL Tennessee Creek	26,888,289	2.69%	722,722	4.65%	1,249,893	527,171	4.60%	1,236,981	514,259	(12,912)
NPL Thorpe	15,452,801	2.10%	324,955	3.56%	550,698	225,743	3.30%	509,412	184,457	(41,286)
NPL Tuckasegee	5,224,111	2.74%	143,151	5.35%	279,529	136,378	5.14%	268,397	125,246	(11,132)
Shared Department Plant	1,362,556	2.61%	35,526	2.76%	37,655	2,129	2.76%	37,655	2,129	0
Total Hydro Production	**2,508,338,881**	**2.00%**	**50,119,329**	**2.31%**	**57,821,777**	**7,702,448**	**2.27%**	**56,902,965**	**6,783,636**	**(918,812)**

Duke Energy Carolinas
Table 2: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2021

		Current Approved		DEC Proposed			Public Staff Proposed			
Plant	12/31/21 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from Current Approved	Accrual Rate	Accrual Amount	Difference from Current Approved	Difference from DEC Proposed
A	B	C	D	E	F	G	H	I	J	K
Other Production Plant										
Lincoln CTs	410,310,983	2.48%	10,167,044	2.21%	9,087,135	(1,079,909)	1.78%	7,322,160	(2,844,884)	(1,764,975)
Dan River CC	673,749,209	3.25%	21,917,647	3.97%	26,763,875	4,846,228	3.77%	25,368,709	3,451,062	(1,395,166)
Lee CTs	62,049,847	2.86%	1,775,518	2.88%	1,790,021	14,503	2.56%	1,590,372	(185,146)	(199,649)
Mill Creek CTs	251,791,572	2.58%	6,489,848	2.45%	6,170,110	(319,738)	2.07%	5,217,417	(1,272,431)	(952,693)
On-Site Diesel Generators	24,882,743	6.71%	1,669,632	8.79%	2,187,749	518,117	8.73%	2,172,263	502,631	(15,486)
Rockingham CTs	322,169,860	3.04%	9,793,010	3.36%	10,834,938	1,041,928	3.19%	10,276,751	483,741	(558,187)
Buck CC	681,472,437	2.89%	19,666,396	3.81%	25,969,143	6,302,747	3.60%	24,521,382	4,854,986	(1,447,761)
Lee CC	584,953,399	3.17%	18,548,968	4.00%	23,379,505	4,830,537	3.80%	22,220,606	3,671,638	(1,158,899)
Clemson CHP	30,074,638	3.06%	920,717	3.40%	1,021,338	100,621	3.19%	959,424	38,707	(61,914)
Lark Maintenance Facility	44,103,315	3.01%	1,329,113	2.75%	1,212,124	(116,989)	2.75%	1,212,124	(116,989)	0
Shared Department Plant	79,121	2.83%	2,239	2.94%	2,327	88	2.94%	2,327	88	0
Total Other Production	**3,085,637,124**	**2.99%**	**92,280,132**	**3.51%**	**108,418,265**	**16,138,133**	**3.27%**	**100,863,535**	**8,583,403**	**(7,554,730)**
Solar										
Community - Small	29,046,186	5.76%	1,673,801	4.92%	1,428,072	(245,729)	4.92%	1,428,072	(245,729)	0
Mocksville	31,793,561	5.09%	1,619,077	4.61%	1,466,695	(152,382)	4.51%	1,434,004	(185,073)	(32,691)
Monroe	107,411,596	5.06%	5,437,349	4.74%	5,088,690	(348,659)	4.64%	4,988,623	(448,726)	(100,067)
Woodleaf	13,910,619	4.94%	687,174	4.65%	646,326	(40,848)	4.55%	632,920	(54,254)	(13,406)
Gaston	38,771,370	5.15%	1,996,560	4.66%	1,805,484	(191,076)	4.53%	1,756,631	(239,929)	(48,853)
Maiden Creek	86,457,280	5.14%	4,442,165	4.83%	4,173,587	(268,578)	4.66%	4,029,219	(412,946)	(144,368)
Total Solar	**307,390,611**	**5.16%**	**15,856,126**	**4.75%**	**14,608,854**	**(1,247,272)**	**4.64%**	**14,269,468**	**(1,586,658)**	**(339,386)**

Duke Energy Carolinas
Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2021

			Current Approved		DEC Proposed			Public Staff Proposed			
Account	Description	12/31/21 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from Current Approved	Accrual Rate	Accrual Amount	Difference from Current Approved	Difference from DEC Proposed
	A	B	C	D	E	F	G	H	I	J	K
	Steam Production Plant										
311.00	Structures and Improvements										
	Marshall Unit 1	4,009,964	5.48%	219,746	5.01%	200,923	(18,823)	2.77%	111,076	(108,670)	(89,847)
	Marshall Unit 2	6,092,585	5.48%	333,874	5.13%	312,662	(21,212)	2.75%	167,546	(166,328)	(145,116)
	Marshall Unit 3	9,592,807	5.48%	525,686	3.91%	375,533	(150,153)	3 31%	317,522	(208,164)	(58,011)
	Marshall Unit 4	7,104,018	5.48%	389,300	3.86%	273,876	(115,424)	3 28%	233,012	(156,288)	(40,864)
	Marshall Common	168,536,269	5.48%	9,235,788	7.10%	11,968,020	2,732,232	5 96%	10,044,762	808,974	(1,923,258)
	Belews Creek Unit 1	131,857,155	3.75%	4,944,643	4.04%	5,328,694	384,051	3 35%	4,417,215	(527,428)	(911,479)
	Belews Creek Unit 2	65,951,215	3.75%	2,473,171	4.36%	2,875,885	402,714	3 60%	2,374,244	(98,927)	(501,641)
	Belews Creek Common	200,205,509	3.75%	7,507,707	5.76%	11,531,911	4,024,204	4.74%	9,489,741	1,982,034	(2,042,170)
	Cliffside 5 (J.E. Rogers)	60,758,312	3.99%	2,424,257	9.89%	6,010,355	3,586,098	3 61%	2,193,375	(230,882)	(3,816,980)
	Cliffside 6 (J.E. Rogers)	155,989,757	3.05%	4,757,688	3.25%	5,070,143	312,455	3 21%	5,007,271	249,583	(62,872)
	Cliffside 5 and 6 Common (J.E. Rogers)	147,832,931	3.47%	5,129,803	3.59%	5,303,676	173,873	3.55%	5,248,069	118,266	(55,607)
	Allen	161,355,512	8.86%	14,296,098	21.87%	35,291,996	20,995,898	21.36%	34,465,537	20,169,439	(826,459)
	Total Structures and Improvements	*1,119,286,033*	*4.67%*	*52,237,761*	*7.55%*	*84,543,674*	*32,305,913*	*6.62%*	*74,069,370*	*21,831,609*	*(10,474,304)*
312.00	Boiler Plant Equipment										
	Marshall Unit 1	482,435,560	3.79%	18,284,308	5.84%	28,158,582	9,874,274	3 23%	15,582,669	(2,701,639)	(12,575,913)
	Marshall Unit 2	113,723,954	3.79%	4,310,138	7.20%	8,188,201	3,878,063	3 89%	4,423,862	113,724	(3,764,339)
	Marshall Unit 3	306,016,158	3.79%	11,598,012	5.19%	15,871,264	4,273,252	4.44%	13,587,117	1,989,105	(2,284,147)
	Marshall Unit 4	199,256,873	3.79%	7,551,835	5.59%	11,132,382	3,580,547	4.78%	9,524,479	1,972,644	(1,607,903)
	Marshall Common	354,842,132	3.79%	13,448,517	6.72%	23,845,089	10,396,572	5 64%	20,013,096	6,564,579	(3,831,993)
	Belews Creek Unit 1	402,272,282	3.47%	13,958,848	4.68%	18,812,401	4,853,553	3 91%	15,728,846	1,769,998	(3,083,555)
	Belews Creek Unit 2	325,520,605	3.47%	11,295,565	4.62%	15,023,101	3,727,536	3 86%	12,565,095	1,269,530	(2,458,006)
	Belews Creek Common	1,007,887,248	3.47%	34,973,687	4.82%	48,537,784	13,564,097	4.03%	40,617,856	5,644,169	(7,919,928)
	Cliffside 5 (J.E. Rogers)	636,792,124	4.16%	26,490,552	9.22%	58,685,026	32,194,474	3.44%	21,905,649	(4,584,903)	(36,779,377)
	Cliffside 6 (J.E. Rogers)	1,277,318,126	3.08%	39,341,398	3.32%	42,462,547	3,121,149	3 28%	41,896,035	2,554,637	(566,512)
	Cliffside 5 and 6 Common (J.E. Rogers)	14,918,380	3.04%	453,519	3.33%	496,575	43,056	3 28%	489,323	35,804	(7,252)
	Allen	607,456,476	4.07%	24,723,479	11.53%	70,052,745	45,329,266	10.97%	66,637,975	41,914,496	(3,414,770)
	Total Boiler Plant Equipment	*5,728,439,918*	*3.60%*	*206,429,858*	*5.96%*	*341,265,697*	*134,835,839*	*4.59%*	*262,972,002*	*56,542,144*	*(78,293,695)*
314.00	Turbogenerator Units										
	Marshall Unit 1	48,514,740	5.33%	2,585,836	10.25%	4,973,809	2,387,973	5 61%	2,721,677	135,841	(2,252,132)
	Marshall Unit 2	55,070,730	5.33%	2,935,270	10.37%	5,710,109	2,774,839	5.59%	3,078,454	143,184	(2,631,655)
	Marshall Unit 3	55,000,059	5.33%	2,931,503	6.85%	3,765,330	833,827	5.77%	3,173,503	242,000	(591,827)
	Marshall Unit 4	74,442,601	5.33%	3,967,791	6.54%	4,867,433	899,642	5.56%	4,139,009	171,218	(728,424)
	Marshall Common	8,584,327	5.33%	457,545	6.43%	551,586	94,041	5 37%	460,978	3,433	(90,608)
	Belews Creek Unit 1	97,199,860	4.48%	4,354,554	5.83%	5,669,861	1,315,307	4 86%	4,723,913	369,359	(945,948)
	Belews Creek Unit 2	111,149,237	4.48%	4,979,486	5.82%	6,468,659	1,489,173	4 85%	5,390,738	411,252	(1,077,921)
	Belews Creek Common	40,782,765	4.48%	1,827,068	5.41%	2,208,238	381,170	4.47%	1,822,990	(4,078)	(385,248)

Duke Energy Carolinas
Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2021

			Current Approved		DEC Proposed			Public Staff Proposed			
Account	Description	12/31/21 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from Current Approved	Accrual Rate	Accrual Amount	Difference from Current Approved	Difference from DEC Proposed
	A	B	C	D	E	F	G	H	I	J	K
	Cliffside 5 (J.E. Rogers)	59,900,126	4.95%	2,965,056	12.83%	7,686,038	4,720,982	4 82%	2,887,186	(77,870)	(4,798,852)
	Cliffside 6 (J.E. Rogers)	267,185,630	3.32%	8,870,563	3.68%	9,844,995	974,432	3 63%	9,698,838	828,275	(146,157)
	Allen	63,590,031	9.37%	5,958,386	24.40%	15,518,984	9,560,598	23.65%	15,039,042	9,080,656	(479,942)
	Shared Department Plant	14,674	3.27%	480	3.56%	523	43	3.56%	523	43	0
	Total Turbogenerator Units	*881,434,780*	*4.75%*	*41,833,538*	*7.63%*	*67,265,565*	*25,432,027*	*6.03%*	*53,136,852*	*11,303,314*	*(14,128,713)*
315.00	Accessory Electric Equipment										
	Marshall Unit 1	7,604,504	3.66%	278,325	6.70%	509,531	231,206	3 69%	280,606	2,281	(228,925)
	Marshall Unit 2	5,922,428	3.66%	216,761	8.25%	488,645	271,884	4.41%	261,179	44,418	(227,466)
	Marshall Unit 3	29,085,683	3.66%	1,064,536	4.19%	1,219,574	155,038	3.58%	1,041,267	(23,269)	(178,307)
	Marshall Unit 4	19,892,422	3.66%	728,063	4.35%	866,071	138,008	3.72%	739,998	11,935	(126,073)
	Marshall Common	22,419,153	3.66%	820,541	5.43%	1,216,585	396,044	4.54%	1,017,830	197,289	(198,755)
	Belews Creek Unit 1	21,359,179	3.54%	756,115	4.33%	924,195	168,080	3 61%	771,066	14,951	(153,129)
	Belews Creek Unit 2	19,328,359	3.54%	684,224	4.13%	799,058	114,834	3.45%	666,828	(17,396)	(132,230)
	Belews Creek Common	31,217,295	3.54%	1,105,092	4.07%	1,271,544	166,452	3 38%	1,055,145	(49,947)	(216,399)
	Cliffside 5 (J.E. Rogers)	24,027,867	3.42%	821,753	6.91%	1,659,533	837,780	2.59%	622,322	(199,431)	(1,037,211)
	Cliffside 6 (J.E. Rogers)	153,701,998	3.14%	4,826,243	3.25%	4,995,446	169,203	3 21%	4,933,834	107,591	(61,612)
	Cliffside 5 and 6 Common (J.E. Rogers)	1,315,069	3.39%	44,581	3.71%	48,850	4,269	3 67%	48,263	3,682	(587)
	Allen	41,454,912	4.81%	1,993,981	10.09%	4,182,670	2,188,689	9.51%	3,942,362	1,948,381	(240,308)
	Total Accessory Electric Equipment	*377,328,869*	*3.54%*	*13,340,215*	*4.82%*	*18,181,702*	*4,841,487*	*4.08%*	*15,380,701*	*2,040,486*	*(2,801,001)*
316.00	Miscellaneous Power Plant Equipment										
	Marshall Unit 1	2,025,257	4.85%	98,225	6.73%	136,314	38,089	3.71%	75,137	(23,088)	(61,177)
	Marshall Unit 2	1,050,801	4.85%	50,964	4.95%	52,049	1,085	2.75%	28,897	(22,067)	(23,152)
	Marshall Unit 3	3,695,500	4.85%	179,232	5.38%	198,867	19,635	4.59%	169,623	(9,609)	(29,244)
	Marshall Unit 4	2,213,260	4.85%	107,343	4.84%	107,053	(290)	4.12%	91,186	(16,157)	(15,867)
	Marshall Common	28,791,316	4.85%	1,396,379	5.68%	1,633,941	237,562	4.74%	1,364,708	(31,671)	(269,233)
	Belews Creek Unit 1	3,359,702	4.60%	154,546	4.82%	162,009	7,463	4.01%	134,724	(19,822)	(27,285)
	Belews Creek Unit 2	2,108,637	4.60%	96,997	5.11%	107,747	10,750	4 25%	89,617	(7,380)	(18,130)
	Belews Creek Common	26,224,507	4.60%	1,206,327	5.27%	1,381,451	175,124	4 37%	1,146,011	(60,316)	(235,440)
	Cliffside 5 (J.E. Rogers)	11,493,380	5.21%	598,805	9.55%	1,097,078	498,273	3.56%	409,164	(189,641)	(687,914)
	Cliffside 6 (J.E. Rogers)	246,475,194	3.30%	8,133,681	3.37%	8,307,078	173,397	3 32%	8,182,976	49,295	(124,102)
	Cliffside 5 and 6 Common (J.E. Rogers)	7,330,213	3.53%	258,757	3.62%	264,992	6,235	3.58%	262,422	3,665	(2,570)
	Allen	21,050,521	8.14%	1,713,512	15.40%	3,241,463	1,527,951	14.83%	3,121,792	1,408,280	(119,671)
	Shared Department Plant	830,130	3.55%	29,470	3.58%	29,759	289	3.58%	29,759	289	0
	Total Miscellaneous Power Plant Equipment	*356,648,417*	*3.93%*	*14,024,238*	*4.69%*	*16,719,801*	*2,695,563*	*4.24%*	*15,106,018*	*1,081,780*	*(1,613,783)*
	Total Steam Production Plant	**8,463,138,018**	**3.87%**	**327,865,610**	**6.24%**	**527,976,439**	**200,110,829**	**4.97%**	**420,664,942**	**92,799,332**	**(107,311,497)**
	Nuclear Production Plant										

Duke Energy Carolinas
Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2021

Account	Description	12/31/21 Investment	Current Approved Accrual Rate	Current Approved Accrual Amount	DEC Proposed Accrual Rate	DEC Proposed Accrual Amount	DEC Proposed Difference from Current Approved	Public Staff Proposed Accrual Rate	Public Staff Proposed Accrual Amount	Public Staff Proposed Difference from Current Approved	Difference from DEC Proposed
	A	B	C	D	E	F	G	H	I	J	K
321.00	Structures and Improvements										
	Oconee	1,019,281,184	2.23%	22,729,970	2.32%	23,618,229	888,259	2 32%	23,618,229	888,259	0
	McGuire	721,643,972	1.56%	11,257,646	1.69%	12,195,424	937,778	1 69%	12,195,424	937,778	0
	Catawba	251,711,370	1.53%	3,851,184	1.67%	4,213,221	362,037	1 67%	4,213,221	362,037	0
	Total Structures and Improvements	*1,992,636,526*	*1.90%*	*37,838,800*	*2.01%*	*40,026,874*	*2,188,074*	*2.01%*	*40,026,874*	*2,188,074*	*0*
322.00	Reactor Plant Equipment										
	Oconee	2,067,904,613	2.38%	49,216,130	2.47%	51,161,786	1,945,656	2.47%	51,161,786	1,945,656	0
	McGuire	1,614,070,843	1.72%	27,762,018	1.78%	28,657,645	895,627	1.78%	28,657,645	895,627	0
	Catawba	387,760,121	1.65%	6,398,042	1.71%	6,621,051	223,009	1.71%	6,621,051	223,009	0
	Total Reactor Plant Equipment	*4,069,735,576*	*2.05%*	*83,376,190*	*2.12%*	*86,440,482*	*3,064,292*	*2.12%*	*86,440,482*	*3,064,292*	*0*
323.00	Turbogenerator Units										
	Oconee	430,486,729	3.03%	13,043,748	3.01%	12,942,067	(101,681)	3.01%	12,942,067	(101,681)	0
	McGuire	573,569,893	2.71%	15,543,744	2.76%	15,836,521	292,777	2.76%	15,836,521	292,777	0
	Catawba	116,116,406	2.56%	2,972,580	2.73%	3,169,176	196,596	2.73%	3,169,176	196,596	0
	Total Turbogenerator Units	*1,120,173,028*	*2.82%*	*31,560,072*	*2.85%*	*31,947,764*	*387,692*	*2.85%*	*31,947,764*	*387,692*	*0*
324.00	Accessory Electric Equipment										
	Oconee	939,193,970	2.48%	23,292,010	2.55%	23,946,128	654,118	2.55%	23,946,128	654,118	0
	McGuire	278,759,280	1.72%	4,794,660	1.84%	5,120,469	325,809	1 84%	5,120,469	325,809	0
	Catawba	92,964,813	1.66%	1,543,216	1.81%	1,684,219	141,003	1 81%	1,684,219	141,003	0
	Shared Department Plant	124,790	2.26%	2,820	2.32%	2,892	72	2 32%	2,892	72	0
	Total Accessory Electric Equipment	*1,311,042,852*	*2.26%*	*29,632,706*	*2.35%*	*30,753,708*	*1,121,002*	*2.35%*	*30,753,708*	*1,121,002*	*0*
325.00	Miscellaneous Power Plant Equipment										
	Oconee	270,468,486	2.07%	5,598,698	2.18%	5,895,228	296,530	2.18%	5,895,228	296,530	0
	McGuire	308,391,168	1.78%	5,489,363	1.92%	5,917,149	427,786	1 92%	5,917,149	427,786	0
	Catawba	54,038,717	1.71%	924,062	1.86%	1,006,597	82,535	1 86%	1,006,597	82,535	0
	Shared Department Plant	4,126,480	2.01%	82,942	2.43%	100,097	17,155	2.43%	100,097	17,155	0
	Total Miscellaneous Power Plant Equipment	*637,024,851*	*1.90%*	*12,095,065*	*2.03%*	*12,919,071*	*824,006*	*2.03%*	*12,919,071*	*824,006*	*0*
	Total Nuclear Production Plant	**9,130,612,833**	**2.13%**	**194,502,833**	**2.21%**	**202,087,899**	**7,585,066**	**2.21%**	**202,087,899**	**7,585,066**	**0**
	Hydarulic Production Plant										
331.00	Structures and Improvements										
	Cowans Ford	19,751,911	1.84%	363,435	1.94%	383,769	20,334	1 95%	385,162	21,727	1,393
	Bad Creek	234,244,262	1.61%	3,771,333	1.58%	3,709,283	(62,050)	1.56%	3,654,210	(117,123)	(55,073)
	Jocassee	33,533,952	2.18%	731,040	2.43%	815,892	84,852	2.43%	814,875	83,835	(1,017)
	Keowee	32,788,215	3.16%	1,036,108	3.59%	1,176,491	140,383	3.55%	1,163,982	127,874	(12,509)

Duke Energy Carolinas
Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2021

			Current Approved		DEC Proposed			Public Staff Proposed			
Account	Description	12/31/21 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from Current Approved	Accrual Rate	Accrual Amount	Difference from Current Approved	Difference from DEC Proposed
	A	B	C	D	E	F	G	H	I	J	K
	Fishing Creek	5,708,226	2.18%	124,439	2.38%	136,028	11,589	2 32%	132,431	7,992	(3,597)
	Cedar Creek	4,096,778	2.25%	92,177	2.25%	92,161	(16)	2.18%	89,310	(2,867)	(2,851)
	Bridgewater	66,243,977	2.33%	1,543,485	2.32%	1,538,403	(5,082)	2 29%	1,516,987	(26,498)	(21,416)
	Lookout Shoals	2,871,615	2.14%	61,453	2.27%	65,203	3,750	2 21%	63,463	2,010	(1,740)
	Mountain Island	4,116,426	2.67%	109,909	2.66%	109,294	(615)	2.59%	106,615	(3,294)	(2,679)
	99 Islands	1,206,655	4.33%	52,248	3.94%	47,549	(4,699)	3 80%	45,853	(6,395)	(1,696)
	Oxford	4,211,264	1.94%	81,699	1.96%	82,490	791	1 93%	81,277	(422)	(1,213)
	Rhodhiss	6,066,351	2.14%	129,820	2.48%	150,499	20,679	2.42%	146,806	16,986	(3,693)
	Wateree	17,453,757	2.05%	357,802	2.63%	458,757	100,955	2 60%	453,798	95,996	(4,959)
	Wylie	8,392,378	2.07%	173,722	2.24%	187,791	14,069	2 21%	185,472	11,750	(2,319)
	Great Falls	551,582	2.27%	12,521	3.11%	17,170	4,649	2 69%	14,838	2,317	(2,332)
	Dearborn	2,131,193	2.06%	43,903	2.00%	42,671	(1,232)	1 91%	40,706	(3,197)	(1,965)
	NPL Bear Creek	1,066,015	4.06%	43,280	4.05%	43,133	(147)	3 99%	42,534	(746)	(599)
	NPL Cedar Cliff	1,078,554	4.44%	47,888	4.39%	47,402	(486)	4 29%	46,270	(1,618)	(1,132)
	NPL Nantahala	2,609,433	3.51%	91,591	3.62%	94,447	2,856	3.56%	92,896	1,305	(1,551)
	NPL Queens Creek	112,213	7.96%	8,932	8.96%	10,057	1,125	7.70%	8,640	(292)	(1,417)
	NPL Tennessee Creek	355,878	3.22%	11,459	3.04%	10,818	(641)	2 98%	10,605	(854)	(213)
	NPL Thorpe	4,578,421	3.51%	160,703	4.78%	218,731	58,028	4.51%	206,487	45,784	(12,244)
	NPL Tuckasegee	2,401,434	4.54%	109,025	5.40%	129,578	20,553	5.19%	124,634	15,609	(4,944)
	Shared Department Plant	27,831	3.40%	946	3.42%	953	7	3.42%	953	7	0
	Total Structures and Improvements	*455,598,320*	*2.01%*	*9,158,918*	*2.10%*	*9,568,570*	*409,652*	*2.07%*	*9,428,803*	*269,885*	*(139,767)*
332.00	Reservoirs, Dams, and Waterways										
	Cowans Ford	38,853,208	1.81%	703,243	1.78%	692,043	(11,200)	1.78%	691,587	(11,656)	(456)
	Bad Creek	455,754,167	1.34%	6,107,106	1.29%	5,861,049	(246,057)	1 26%	5,742,503	(364,603)	(118,546)
	Jocassee	61,453,955	1.01%	620,685	1.54%	944,219	323,534	1.54%	946,391	325,706	2,172
	Keowee	17,981,009	0.86%	154,637	0.99%	178,404	23,767	0 95%	170,820	16,183	(7,584)
	Fishing Creek	23,481,095	1.81%	425,008	2.31%	541,456	116,448	2 25%	528,325	103,317	(13,131)
	Cedar Creek	12,017,600	2.15%	258,378	2.10%	252,785	(5,593)	2.05%	246,361	(12,017)	(6,424)
	Bridgewater	200,720,291	2.02%	4,054,550	2.37%	4,762,954	708,404	2 34%	4,696,855	642,305	(66,099)
	Lookout Shoals	5,580,443	1.53%	85,381	1.55%	86,475	1,094	1.49%	83,149	(2,232)	(3,326)
	Mountain Island	14,584,121	1.13%	164,801	2.47%	359,508	194,707	2.40%	350,019	185,218	(9,489)
	99 Islands	12,905,168	2.62%	338,115	2.99%	386,328	48,213	2 85%	367,797	29,682	(18,531)
	Oxford	36,203,844	2.18%	789,244	2.18%	788,410	(834)	2.15%	778,383	(10,861)	(10,027)
	Rhodhiss	10,908,630	1.66%	181,083	2.10%	228,844	47,761	2.04%	222,536	41,453	(6,308)
	Wateree	15,019,296	1.59%	238,807	1.59%	238,373	(434)	1.55%	232,799	(6,008)	(5,574)
	Wylie	29,701,234	2.09%	620,756	2.36%	700,521	79,765	2 33%	692,039	71,283	(8,482)
	Great Falls	2,869,197	1.74%	49,924	1.87%	53,517	3,593	1.47%	42,177	(7,747)	(11,340)
	Dearborn	2,394,279	1.55%	37,111	2.16%	51,657	14,546	2.07%	49,562	12,451	(2,095)
	NPL Bear Creek	8,021,219	2.02%	162,029	3.55%	284,438	122,409	3.49%	279,941	117,912	(4,497)
	NPL Cedar Cliff	5,593,887	1.14%	63,770	3.90%	218,169	154,399	3.79%	212,008	148,238	(6,161)

Duke Energy Carolinas
Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2021

			Current Approved		DEC Proposed			Public Staff Proposed			
Account	Description	12/31/21 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from Current Approved	Accrual Rate	Accrual Amount	Difference from Current Approved	Difference from DEC Proposed
	A	B	C	D	E	F	G	H	I	J	K
	NPL Nantahala	16,018,308	1.51%	241,876	2.05%	328,067	86,191	2.00%	320,366	78,490	(7,701)
	NPL Queens Creek	763,264	4.43%	33,813	4.60%	35,124	1,311	3 31%	25,264	(8,549)	(9,860)
	NPL Tennessee Creek	12,191,333	1.38%	168,240	3.66%	446,534	278,294	3 61%	440,107	271,867	(6,427)
	NPL Thorpe	6,614,546	0.10%	6,615	1.87%	123,498	116,883	1 61%	106,494	99,879	(17,004)
	NPL Tuckasegee	2,028,914	0.31%	6,290	5.17%	104,886	98,596	4 95%	100,431	94,141	(4,455)
	Shared Department Plant	324,568	2.24%	7,270	2.21%	7,170	(100)	2 21%	7,170	(100)	0
	Total Reservoirs, Dams, and Waterways	*991,983,576*	*1.56%*	*15,518,732*	*1.78%*	*17,674,429*	*2,155,697*	*1.75%*	*17,333,082*	*1,814,350*	*(341,347)*
333.00	Water Wheels, Turbines, and Generators										
	Cowans Ford	68,487,087	2.57%	1,760,118	2.82%	1,930,626	170,508	2 82%	1,931,336	171,218	710
	Bad Creek	278,478,568	1.81%	5,040,462	2.38%	6,634,555	1,594,093	2 35%	6,544,246	1,503,784	(90,309)
	Jocassee	71,420,107	2.50%	1,785,503	2.96%	2,112,877	327,374	2 95%	2,106,893	321,390	(5,984)
	Keowee	173,934,217	2.96%	5,148,453	3.66%	6,364,436	1,215,983	3 62%	6,296,419	1,147,966	(68,017)
	Fishing Creek	22,401,992	2.22%	497,324	2.65%	593,694	96,370	2.57%	575,731	78,407	(17,963)
	Cedar Creek	16,788,917	2.18%	365,998	2.90%	487,082	121,084	2 83%	475,126	109,128	(11,956)
	Bridgewater	20,780,376	2.45%	509,119	2.65%	550,930	41,811	2 62%	544,446	35,327	(6,484)
	Lookout Shoals	10,652,141	2.42%	257,782	2.91%	309,636	51,854	2 83%	301,456	43,674	(8,180)
	Mountain Island	16,306,552	2.50%	407,664	2.80%	456,974	49,310	2.73%	445,169	37,505	(11,805)
	99 Islands	12,208,893	3.76%	459,054	5.31%	648,531	189,477	5.17%	631,200	172,146	(17,331)
	Oxford	18,494,761	2.45%	453,122	2.74%	507,622	54,500	2.71%	501,208	48,086	(6,414)
	Rhodhiss	17,378,790	2.64%	458,800	2.89%	502,493	43,693	2 82%	490,082	31,282	(12,411)
	Wateree	24,103,860	2.26%	544,747	2.71%	653,807	109,060	2 67%	643,573	98,826	(10,234)
	Wylie	30,556,201	2.09%	638,625	2.90%	885,660	247,035	2 86%	873,907	235,282	(11,753)
	Great Falls	5,314,119	3.36%	178,554	4.87%	258,612	80,058	4 33%	230,101	51,547	(28,511)
	Dearborn	11,960,714	2.37%	283,469	2.82%	337,027	53,558	2.71%	324,135	40,666	(12,892)
	NPL Bear Creek	6,310,105	4.54%	286,479	4.75%	299,552	13,073	4.70%	296,575	10,096	(2,977)
	NPL Cedar Cliff	3,386,918	4.19%	141,912	4.52%	153,094	11,182	4.40%	149,024	7,112	(4,070)
	NPL Nantahala	3,876,087	2.74%	106,205	3.63%	140,855	34,650	3.58%	138,764	32,559	(2,091)
	NPL Queens Creek	38,141	1.54%	587	6.45%	2,461	1,874	4 94%	1,884	1,297	(577)
	NPL Tennessee Creek	10,886,412	3.99%	434,368	5.59%	608,947	174,579	5.55%	604,196	169,828	(4,751)
	NPL Thorpe	420,632	2.65%	11,147	3.55%	14,939	3,792	3.18%	13,376	2,229	(1,563)
	NPL Tuckasegee	250,399	3.37%	8,438	5.38%	13,473	5,035	5.15%	12,896	4,458	(577)
	Total Water Wheels, Turbines, and Generators	*824,435,989*	*2.40%*	*19,777,930*	*2.97%*	*24,467,883*	*4,689,953*	*2.93%*	*24,131,744*	*4,353,814*	*(336,139)*
334.00	Accessory Electric Equipment										
	Cowans Ford	12,978,754	2.61%	338,745	2.82%	366,271	27,526	2 82%	366,001	27,256	(270)
	Bad Creek	57,868,266	2.04%	1,180,513	2.15%	1,245,596	65,083	2.12%	1,226,807	46,294	(18,789)
	Jocassee	19,445,365	2.74%	532,803	3.24%	629,650	96,847	3 24%	630,030	97,227	380
	Keowee	14,183,983	2.78%	394,315	2.88%	408,060	13,745	2 83%	401,407	7,092	(6,653)
	Fishing Creek	4,563,859	2.48%	113,184	2.64%	120,382	7,198	2.57%	117,291	4,107	(3,091)
	Cedar Creek	3,751,305	2.50%	93,783	2.72%	101,969	8,186	2 65%	99,410	5,627	(2,559)

Duke Energy Carolinas
Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2021

			Current Approved		DEC Proposed			Public Staff Proposed			
Account	Description	12/31/21 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from Current Approved	Accrual Rate	Accrual Amount	Difference from Current Approved	Difference from DEC Proposed
	A	B	C	D	E	F	G	H	I	J	K
	Bridgewater	7,436,806	2.54%	188,895	2.64%	196,309	7,414	2 60%	193,357	4,462	(2,952)
	Lookout Shoals	2,095,204	2.55%	53,428	2.79%	58,393	4,965	2.71%	56,780	3,352	(1,613)
	Mountain Island	3,154,895	2.73%	86,129	2.90%	91,642	5,513	2 84%	89,599	3,470	(2,043)
	99 Islands	820,637	4.59%	37,667	5.48%	45,005	7,338	5 34%	43,822	6,155	(1,183)
	Oxford	3,904,495	2.32%	90,584	2.51%	98,107	7,523	2.48%	96,831	6,247	(1,276)
	Rhodhiss	2,355,053	2.46%	57,934	2.66%	62,595	4,661	2.59%	60,996	3,062	(1,599)
	Wateree	5,322,022	2.61%	138,905	2.74%	145,594	6,689	2.70%	143,695	4,790	(1,899)
	Wylie	3,962,983	2.47%	97,886	2.59%	102,617	4,731	2.56%	101,452	3,566	(1,165)
	Great Falls	888,922	4.03%	35,824	6.34%	56,352	20,528	5 63%	50,046	14,222	(6,306)
	Dearborn	3,858,306	2.61%	100,702	2.73%	105,290	4,588	2 62%	101,088	386	(4,202)
	NPL Bear Creek	303,467	2.74%	8,315	4.51%	13,686	5,371	4.47%	13,565	5,250	(121)
	NPL Cedar Cliff	372,636	3.30%	12,297	5.17%	19,273	6,976	5.06%	18,855	6,558	(418)
	NPL Nantahala	2,870,041	3.47%	99,590	4.23%	121,283	21,693	4.17%	119,681	20,091	(1,602)
	NPL Queens Creek	183,285	5.66%	10,374	7.77%	14,244	3,870	6.41%	11,749	1,375	(2,495)
	NPL Tennessee Creek	3,157,080	3.12%	98,501	5.52%	174,371	75,870	5.48%	173,008	74,507	(1,363)
	NPL Thorpe	2,536,156	3.36%	85,215	4.76%	120,746	35,531	4.48%	113,620	28,405	(7,126)
	NPL Tuckasegee	436,678	3.34%	14,585	5.94%	25,932	11,347	5.73%	25,022	10,437	(910)
	Total Accessory Electric Equipment	*156,450,197*	*2.47%*	*3,870,174*	*2.76%*	*4,323,367*	*453,193*	*2.72%*	*4,254,111*	*383,937*	*(69,256)*
335.00	Miscellaneous Power Plant Equipment										
	Cowans Ford	2,251,209	2.63%	59,207	2.64%	59,361	154	2 64%	59,432	225	71
	Bad Creek	30,106,922	2.13%	641,277	2.03%	612,281	(28,996)	2.00%	602,138	(39,139)	(10,143)
	Jocassee	4,473,233	2.83%	126,592	2.79%	124,874	(1,718)	2.79%	124,803	(1,789)	(71)
	Keowee	2,801,735	2.25%	63,039	3.44%	96,361	33,322	3 39%	94,979	31,940	(1,382)
	Fishing Creek	337,031	2.74%	9,235	2.62%	8,831	(404)	2.55%	8,594	(641)	(237)
	Cedar Creek	499,494	2.91%	14,535	2.82%	14,075	(460)	2.75%	13,736	(799)	(339)
	Bridgewater	7,365,601	2.58%	190,032	2.54%	187,067	(2,965)	2.51%	184,877	(5,155)	(2,190)
	Lookout Shoals	452,187	2.81%	12,706	2.73%	12,340	(366)	2 66%	12,028	(678)	(312)
	Mountain Island	502,664	2.85%	14,326	2.63%	13,208	(1,118)	2.56%	12,868	(1,458)	(340)
	99 Islands	510,703	4.22%	21,552	4.78%	24,429	2,877	4 63%	23,646	2,094	(783)
	Oxford	678,189	2.57%	17,429	2.54%	17,196	(233)	2.50%	16,955	(474)	(241)
	Rhodhiss	498,905	2.62%	13,071	2.50%	12,492	(579)	2.44%	12,173	(898)	(319)
	Wateree	637,407	2.75%	17,529	2.79%	17,804	275	2.76%	17,592	63	(212)
	Wylie	863,411	2.81%	24,262	2.85%	24,639	377	2 82%	24,348	86	(291)
	Great Falls	402,576	4.74%	19,082	5.30%	21,326	2,244	4 88%	19,646	564	(1,680)
	Dearborn	456,205	2.70%	12,318	2.99%	13,663	1,345	2 90%	13,230	912	(433)
	NPL Bear Creek	165,737	3.98%	6,596	3.89%	6,454	(142)	3 83%	6,348	(248)	(106)
	NPL Cedar Cliff	124,236	4.43%	5,504	4.23%	5,260	(244)	4.12%	5,119	(385)	(141)
	NPL Nantahala	1,215,355	3.87%	47,034	4.01%	48,745	1,711	3 95%	48,007	973	(738)
	NPL Queens Creek	206,671	5.91%	12,214	6.83%	14,108	1,894	5.50%	11,367	(847)	(2,741)
	NPL Tennessee Creek	224,996	4.20%	9,450	3.94%	8,859	(591)	3 89%	8,752	(698)	(107)

Duke Energy Carolinas
Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2021

			Current Approved		DEC Proposed			Public Staff Proposed			
Account	Description	12/31/21 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from Current Approved	Accrual Rate	Accrual Amount	Difference from Current Approved	Difference from DEC Proposed
	A	B	C	D	E	F	G	H	I	J	K
	NPL Thorpe	1,257,022	4.83%	60,714	5.76%	72,362	11,648	5.50%	69,136	8,422	(3,226)
	NPL Tuckasegee	98,008	4.83%	4,734	5.74%	5,626	892	5.52%	5,410	676	(216)
	Shared Department Plant	925,759	2.95%	27,310	3.19%	29,532	2,222	3.19%	29,532	2,222	0
	Total Miscellaneous Power Plant Equipment	*57,055,255*	*2.51%*	*1,429,748*	*2.54%*	*1,450,893*	*21,145*	*2.50%*	*1,424,716*	*(5,032)*	*(26,177)*
336.00	Roads, Railroads, and Bridges										
	Cowans Ford	2,240,416	2.26%	50,633	2.02%	45,290	(5,343)	2.02%	45,256	(5,377)	(34)
	Bad Creek	18,888,978	1.53%	289,001	1.44%	271,333	(17,668)	1.41%	266,335	(22,666)	(4,998)
	Jocassee	415,508	1.23%	5,111	1.00%	4,169	(942)	1.01%	4,197	(914)	28
	Dearborn	633,636	1.75%	11,089	1.57%	9,917	(1,172)	1.47%	9,314	(1,775)	(603)
	NPL Bear Creek	52,776	0.88%	464	0.46%	241	(223)	0 38%	201	(263)	(40)
	NPL Cedar Cliff	129,738	2.03%	2,634	1.66%	2,158	(476)	1.56%	2,024	(610)	(134)
	NPL Nantahala	239,971	1.47%	3,528	1.13%	2,707	(821)	1.07%	2,568	(960)	(139)
	NPL Queens Creek	2,830	0.81%	23	0.00%	0	(23)	0.00%	0	(23)	0
	NPL Tennessee Creek	72,590	0.97%	704	0.50%	364	(340)	0.43%	312	(392)	(52)
	NPL Thorpe	46,024	1.22%	561	0.92%	422	(139)	0 65%	299	(262)	(123)
	NPL Tuckasegee	8,678	0.91%	79	0.39%	34	(45)	0.05%	4	(75)	(30)
	Shared Department Plant	84,399	0.00%	0	0.00%	0	0	0.00%	0	0	0
	Total Roads, Railroads, and Bridges	*22,815,544*	*1.59%*	*363,827*	*1.48%*	*336,635*	*(27,192)*	*1.45%*	*330,510*	*(33,317)*	*(6,125)*
	Total Hydarulic Production Plant	**2,508,338,881**	**2.00%**	**50,119,329**	**2.31%**	**57,821,777**	**7,702,448**	**2.27%**	**56,902,965**	**6,783,636**	**(918,812)**
	Other Production Plant										
341.00	Structures and Improvements										
	Lincoln CTs	28,785,282	3.19%	918,250	3.15%	906,240	(12,010)	2.74%	788,717	(129,533)	(117,523)
	Dan River CC	149,165,213	2.81%	4,191,542	3.10%	4,624,152	432,610	2 89%	4,310,875	119,333	(313,277)
	Lee CTs	1,389,212	3.52%	48,900	3.93%	54,640	5,740	3 65%	50,706	1,806	(3,934)
	Mill Creek CTs	29,986,169	2.88%	863,602	3.17%	949,559	85,957	2 82%	845,610	(17,992)	(103,949)
	Rockingham CTs	3,432,573	4.10%	140,735	4.40%	151,026	10,291	4 24%	145,541	4,806	(5,485)
	Buck CC	155,526,329	2.84%	4,416,948	3.12%	4,858,707	441,759	2 91%	4,525,816	108,868	(332,891)
	Lee CC	141,116,369	2.76%	3,894,812	2.98%	4,207,946	313,134	2.78%	3,923,035	28,223	(284,911)
	Clemson CHP	8,605,539	2.82%	242,676	2.95%	253,635	10,959	2.76%	237,513	(5,163)	(16,122)
	Lark Maintenance Facility	29,706,060	2.87%	852,564	2.61%	774,622	(77,942)	2 61%	774,622	(77,942)	0
	Total Structures and Improvements	*547,712,745*	*2.84%*	*15,570,029*	*3.06%*	*16,780,527*	*1,210,498*	*2.85%*	*15,602,435*	*32,406*	*(1,178,092)*
341.66	Structures and Improvements - Solar										
	Mocksville	101,358	4.85%	4,916	4.19%	4,248	(668)	4.11%	4,166	(750)	(82)
	Monroe	2,711,076	4.64%	125,794	4.17%	113,169	(12,625)	4.09%	110,883	(14,911)	(2,286)
	Gaston	419,744	4.64%	19,476	3.95%	16,564	(2,912)	3 83%	16,076	(3,400)	(488)
	Maiden Creek	4,698,133	4.64%	217,993	4.08%	191,496	(26,497)	3 93%	184,637	(33,356)	(6,859)

Duke Energy Carolinas
Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2021

			Current Approved		DEC Proposed			Public Staff Proposed			
Account	Description	12/31/21 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from Current Approved	Accrual Rate	Accrual Amount	Difference from Current Approved	Difference from DEC Proposed
	A	B	C	D	E	F	G	H	I	J	K
	Total Structures and Improvements - Solar	*7,930,312*	*4.64%*	*368,179*	*4.10%*	*325,477*	*(42,702)*	*3.98%*	*315,762*	*(52,417)*	*(9,715)*
342.00	Fuel Holders, Producers, and Accessories										
	Lincoln CTs	12,968,504	1.47%	190,637	2.20%	284,676	94,039	1.78%	230,839	40,202	(53,837)
	Dan River CC	21,771,640	2.63%	572,594	2.94%	640,563	67,969	2.73%	594,366	21,772	(46,197)
	Lee CTS	177,613	2.44%	4,334	4.05%	7,197	2,863	3.76%	6,678	2,344	(519)
	Mill Creek CTs	15,154,441	2.16%	327,336	2.48%	375,982	48,646	2.13%	322,790	(4,546)	(53,192)
	Rockingham CTs	426,120	3.42%	14,573	4.00%	17,046	2,473	3 82%	16,278	1,705	(768)
	Buck CC	30,439,400	2.60%	791,424	2.85%	868,927	77,503	2 63%	800,556	9,132	(68,371)
	Lee CC	16,546,972	2.80%	463,315	2.98%	493,320	30,005	2.77%	458,351	(4,964)	(34,969)
	Clemson CHP	1,223,118	2.88%	35,226	2.99%	36,606	1,380	2 80%	34,247	(979)	(2,359)
	Total Fuel Holders, Producers, and Accessories	*98,707,808*	*2.43%*	*2,399,439*	*2.76%*	*2,724,317*	*324,878*	*2.50%*	*2,464,105*	*64,666*	*(260,212)*
343.00	Prime Movers										
	Lincoln CTs	257,522,093	2.42%	6,232,035	1.94%	4,994,883	(1,237,152)	1.50%	3,862,831	(2,369,204)	(1,132,052)
	Dan River CC	160,795,157	2.85%	4,582,662	3.09%	4,974,934	392,272	2 86%	4,598,741	16,079	(376,193)
	Lee CTs	57,929,945	2.81%	1,627,831	2.80%	1,624,313	(3,518)	2.48%	1,436,663	(191,168)	(187,650)
	Mill Creek CTs	184,343,825	2.54%	4,682,333	2.29%	4,215,772	(466,561)	1 90%	3,502,533	(1,179,800)	(713,239)
	Rockingham CTs	93,721,064	3.91%	3,664,494	4.50%	4,214,259	549,765	4 33%	4,058,122	393,628	(156,137)
	Buck CC	160,808,480	2.85%	4,583,042	3.04%	4,885,731	302,689	2.79%	4,486,557	(96,485)	(399,174)
	Lee CC	125,760,509	3.02%	3,797,967	3.27%	4,113,514	315,547	3.04%	3,823,119	25,152	(290,395)
	Clemson CHP	12,233,142	2.95%	360,878	3.31%	404,497	43,619	3.08%	376,781	15,903	(27,716)
	Total Prime Movers	*1,053,114,213*	*2.80%*	*29,531,242*	*2.79%*	*29,427,903*	*(103,339)*	*2.48%*	*26,145,347*	*(3,385,895)*	*(3,282,556)*
343.10	Prime Movers - Rotable Parts										
	Dan River CC	45,680,461	9.13%	4,170,626	16.50%	7,536,781	3,366,155	16.50%	7,536,781	3,366,155	0
	Buck CC	42,161,014	3.78%	1,593,686	15.56%	6,558,741	4,965,055	15.56%	6,558,741	4,965,055	0
	Lee CC	43,400,555	6.55%	2,842,736	15.39%	6,677,352	3,834,616	15.39%	6,677,352	3,834,616	0
	Clemson CHP	717,644	6.55%	47,006	12.92%	92,755	45,749	12.92%	92,755	45,749	0
	Total Prime Movers - Rotable Parts	*131,959,674*	*6.56%*	*8,654,054*	*15.81%*	*20,865,629*	*12,211,575*	*15.81%*	*20,865,629*	*12,211,575*	*0*
344.00	Generators										
	Lincoln CTs	78,436,794	2.63%	2,062,888	2.74%	2,149,369	86,481	2 33%	1,827,577	(235,311)	(321,792)
	Dan River CC	238,495,960	2.80%	6,677,887	3.03%	7,231,383	553,496	2 81%	6,701,736	23,849	(529,647)
	Lee CTs	64,369	2.83%	1,822	3.54%	2,280	458	3 25%	2,092	270	(188)
	Mill Creek CTs	1,054,904	3.89%	41,036	4.29%	45,231	4,195	3 95%	41,669	633	(3,562)
	On-Site Diesel Generators	24,882,743	6.71%	1,669,632	8.79%	2,187,749	518,117	8.73%	2,172,263	502,631	(15,486)
	Rockingham CTs	220,840,812	2.64%	5,830,197	2.86%	6,307,780	477,583	2 68%	5,918,534	88,337	(389,246)
	Buck CC	231,370,373	2.80%	6,478,370	3.01%	6,957,747	479,377	2.79%	6,455,233	(23,137)	(502,514)
	Lee CC	214,214,901	2.87%	6,147,968	3.03%	6,492,644	344,676	2 82%	6,040,860	(107,108)	(451,784)
	Clemson CHP	857,084	2.94%	25,198	3.03%	25,993	795	2 83%	24,255	(943)	(1,738)

Duke Energy Carolinas
Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2021

			Current Approved		DEC Proposed			Public Staff Proposed			
Account	Description	12/31/21 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from Current Approved	Accrual Rate	Accrual Amount	Difference from Current Approved	Difference from DEC Proposed
	A	B	C	D	E	F	G	H	I	J	K
	Total Generators	*1,010,217,939*	*2.86%*	*28,934,998*	*3.11%*	*31,400,176*	*2,465,178*	*2.89%*	*29,184,221*	*249,223*	*(2,215,955)*
344.66	Generators - Solar										
	Community - Small	28,057,290	5.80%	1,627,323	4.88%	1,370,248	(257,075)	4 88%	1,370,248	(257,075)	0
	Mocksville	29,394,130	5.11%	1,502,040	4.59%	1,350,067	(151,973)	4.49%	1,319,796	(182,244)	(30,271)
	Monroe	91,561,246	5.09%	4,660,467	4.72%	4,324,971	(335,496)	4 63%	4,239,286	(421,181)	(85,685)
	Woodleaf	13,905,691	4.94%	686,941	4.65%	646,109	(40,832)	4.55%	632,709	(54,232)	(13,400)
	Gaston	33,742,749	5.19%	1,751,249	4.66%	1,571,182	(180,067)	4.53%	1,528,547	(222,702)	(42,635)
	Maiden Creek	75,170,134	5.19%	3,901,330	4.87%	3,659,869	(241,461)	4.70%	3,532,996	(368,334)	(126,873)
	Total Generators - Solar	*271,831,240*	*5.20%*	*14,129,350*	*4.75%*	*12,922,446*	*(1,206,904)*	*4.64%*	*12,623,582*	*(1,505,768)*	*(298,864)*
345.00	Accessory Electric Equipment										
	Lincoln CTs	26,803,108	1.92%	514,620	1.86%	498,948	(15,672)	1.43%	383,284	(131,336)	(115,664)
	Dan River CC	48,409,540	2.95%	1,428,081	2.95%	1,429,549	1,468	2.73%	1,321,580	(106,501)	(107,969)
	Lee CTs	1,467,540	3.80%	55,767	4.07%	59,662	3,895	3.77%	55,326	(441)	(4,336)
	Mill Creek CTs	17,535,997	2.57%	450,675	2.56%	448,398	(2,277)	2.19%	384,038	(66,637)	(64,360)
	Rockingham CTs	2,095,877	3.66%	76,709	3.47%	72,816	(3,893)	3 30%	69,164	(7,545)	(3,652)
	Buck CC	48,520,138	2.90%	1,407,084	2.88%	1,395,620	(11,464)	2 64%	1,280,932	(126,152)	(114,688)
	Lee CC	37,322,856	3.22%	1,201,796	3.15%	1,175,587	(26,209)	2 93%	1,093,560	(108,236)	(82,027)
	Clemson CHP	4,220,737	3.33%	140,551	3.18%	134,413	(6,138)	2 97%	125,356	(15,195)	(9,057)
	Total Accessory Electric Equipment	*186,375,794*	*2.83%*	*5,275,283*	*2.80%*	*5,214,993*	*(60,290)*	*2.53%*	*4,713,241*	*(562,042)*	*(501,752)*
345.66	Accessory Electric Equipment - Solar										
	Community - Small	988,895	4.70%	46,478	5.85%	57,824	11,346	5 85%	57,824	11,346	0
	Mocksville	2,281,560	4.88%	111,340	4.89%	111,610	270	4.79%	109,287	(2,053)	(2,323)
	Monroe	12,869,692	4.96%	638,337	4.96%	638,627	290	4 87%	626,754	(11,583)	(11,873)
	Gaston	4,608,877	4.90%	225,835	4.72%	217,738	(8,097)	4 60%	212,008	(13,827)	(5,730)
	Maiden Creek	6,577,387	4.90%	322,292	4.89%	321,729	(563)	4.73%	311,110	(11,182)	(10,619)
	Total Accessory Electric Equipment - Solar	*27,326,411*	*4.92%*	*1,344,282*	*4.93%*	*1,347,528*	*3,246*	*4.82%*	*1,316,983*	*(27,299)*	*(30,545)*
346.00	Miscellaneous Power Plant Equipment										
	Lincoln CTs	5,795,202	4.29%	248,614	4.37%	253,019	4,405	3 95%	228,910	(19,704)	(24,109)
	Dan River CC	9,431,238	3.12%	294,255	3.46%	326,513	32,258	3 23%	304,629	10,374	(21,884)
	Lee CTs	1,021,168	3.61%	36,864	4.11%	41,929	5,065	3 81%	38,906	2,042	(3,023)
	Mill Creek CTs	3,716,236	3.36%	124,866	3.64%	135,168	10,302	3 25%	120,778	(4,088)	(14,390)
	Rockingham CTs	1,653,414	4.01%	66,302	4.36%	72,011	5,709	4.18%	69,113	2,811	(2,898)
	Buck CC	12,646,705	3.13%	395,842	3.51%	443,670	47,828	3 27%	413,547	17,705	(30,123)
	Lee CC	6,591,238	3.04%	200,374	3.32%	219,142	18,768	3.10%	204,328	3,954	(14,814)
	Clemson CHP	2,217,373	3.12%	69,182	3.31%	73,439	4,257	3.09%	68,517	(665)	(4,922)
	Lark Maintenance Facility	14,397,254	3.31%	476,549	3.04%	437,502	(39,047)	3.04%	437,502	(39,047)	0
	Shared Department Plant	79,121	2.83%	2,239	2.94%	2,327	88	2 94%	2,327	88	0

Duke Energy Carolinas
Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2021

			Current Approved		DEC Proposed			Public Staff Proposed			
Account	Description	12/31/21 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from Current Approved	Accrual Rate	Accrual Amount	Difference from Current Approved	Difference from DEC Proposed
	A	B	C	D	E	F	G	H	I	J	K
	Total Miscellaneous Power Plant Equipment	*57,548,950*	*3.33%*	*1,915,087*	*3.48%*	*2,004,720*	*89,633*	*3.28%*	*1,888,558*	*(26,529)*	*(116,162)*
346.66	Miscellaneous Power Plant Equipment - Solar										
	Mocksville	16,512	4.73%	781	4.66%	770	(11)	4.57%	755	(26)	(15)
	Monroe	269,582	4.73%	12,751	4.42%	11,923	(828)	4 34%	11,700	(1,051)	(223)
	Woodleaf	4,928	4.73%	233	4.40%	217	(16)	4 28%	211	(22)	(6)
	Maiden Creek	11,626	4.73%	550	4.24%	493	(57)	4.09%	476	(74)	(17)
	Total Miscellaneous Power Plant Equipment - Solar	*302,648*	*4.73%*	*14,315*	*4.43%*	*13,403*	*(912)*	*4.34%*	*13,141*	*(1,174)*	*(262)*
	Total Other Production Plant	**3,393,027,734**	**3.19%**	**108,136,258**	**3.63%**	**123,027,119**	**14,890,861**	**3.39%**	**115,133,003**	**6,996,745**	**(7,894,116)**
	Total Production Plant	**23,495,117,466**	**2.90%**	**680,624,030**	**3.88%**	**910,913,234**	**230,289,204**	**3.38%**	**794,788,810**	**114,164,780**	**(116,124,424)**
	Transmission Plant										
352.00	Structures and Improvements	189,425,366	2.00%	3,788,507	2.83%	5,360,600	1,572,093	2 83%	5,360,600	1,572,093	0
353.00	Station Equipment	2,307,608,516	2.35%	54,228,800	2.56%	58,994,987	4,766,187	2.56%	58,994,987	4,766,187	0
354.00	Towers and Fixtures	651,521,544	1.71%	11,141,018	1.74%	11,347,782	206,764	1.74%	11,347,782	206,764	0
355.00	Poles and Fixtures	662,736,805	2.69%	17,827,620	2.95%	19,534,549	1,706,929	2 95%	19,534,549	1,706,929	0
356.00	Overhead Conductors and Devices	944,879,899	2.02%	19,086,574	2.14%	20,227,497	1,140,923	1 93%	18,236,182	(850,392)	(1,991,315)
357.00	Underground Conduit	154,590	1.09%	1,685	1.28%	1,981	296	1 28%	1,981	296	0
358.00	Underground Conductors and Devices	12,171,599	1.79%	217,872	3.10%	377,688	159,816	3.10%	377,688	159,816	0
359.00	Roads and Trails	42,238	1.46%	617	1.45%	612	(5)	1.45%	612	(5)	0
	Total Transmission Plant	**4,768,540,557**	**2.23%**	**106,292,693**	**2.43%**	**115,845,696**	**9,553,003**	**2.39%**	**113,854,381**	**7,561,688**	**(1,991,315)**
	Distribution Plant										
361.00	Structures and Improvements	178,576,485	1.96%	3,500,099	2.58%	4,610,396	1,110,297	2.58%	4,610,396	1,110,297	0
362.00	Station Equipment	1,705,256,083	2.34%	39,902,992	2.19%	37,353,307	(2,549,685)	2.19%	37,353,307	(2,549,685)	0
364.00	Poles, Towers, and Fixtures	1,840,292,393	2.12%	39,014,199	2.76%	50,840,906	11,826,707	2.76%	50,840,906	11,826,707	0
364.10	Poles, Towers, and Fixtures - Storm Securitization	6,687,318	2.12%	141,771	0.00%	0	(141,771)	0.00%	0	(141,771)	0
365.00	Overhead Conductors and Devices	2,672,397,506	1.97%	52,646,231	2.24%	59,736,924	7,090,693	2 24%	59,736,924	7,090,693	0
365.10	Overhead Conductors and Devices - Storm Securit	6,179,207	1.97%	121,730	0.00%	0	(121,730)	0.00%	0	(121,730)	0
366.00	Underground Conduit	269,930,643	1.37%	3,698,050	1.47%	3,961,232	263,182	1.47%	3,961,232	263,182	0
367.00	Underground Conductors and Devices	2,592,327,369	1.96%	50,809,616	2.08%	53,838,888	3,029,272	2.08%	53,838,888	3,029,272	0
368.00	Line Transformers	1,837,487,386	2.06%	37,852,240	2.34%	42,950,247	5,098,007	2 34%	42,950,247	5,098,007	0
368.10	Line Transformers - Storm Securitization	4,855,160	2.06%	100,016	0.00%	0	(100,016)	0.00%	0	(100,016)	0
369.00	Services	1,273,824,830	1.39%	17,706,165	1.67%	21,272,013	3,565,848	1 67%	21,272,013	3,565,848	0
370.00	Meters and Metering Equipment	113,584,605	2.60%	2,953,200	6.00%	6,813,178	3,859,978	6.00%	6,813,178	3,859,978	0
370.02	Meters - Utility of the Future	475,170,483	6.88%	32,691,729	6.23%	29,585,455	(3,106,274)	6 23%	29,585,455	(3,106,274)	0

Duke Energy Carolinas
Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2021

			Current Approved		DEC Proposed			Public Staff Proposed			
Account	Description	12/31/21 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from Current Approved	Accrual Rate	Accrual Amount	Difference from Current Approved	Difference from DEC Proposed
	A	B	C	D	E	F	G	H	I	J	K
371.00	Installations on Customers' Premises	1,063,691,891	2.33%	24,784,021	2.89%	30,739,949	5,955,928	2 89%	30,739,949	5,955,928	0
373.00	Street Lighting and Signal Systems	357,015,453	2.47%	8,818,282	2.82%	10,061,953	1,243,671	2 82%	10,061,953	1,243,671	0
	Total Distribution Plant	**14,397,276,812**	**2.19%**	**314,740,341**	**2.44%**	**351,764,448**	**37,024,107**	**2.44%**	**351,764,448**	**37,024,107**	**0**
	General Plant										
390.00	Structures and Improvements	733,020,115	3.06%	22,430,416	2.72%	19,940,975	(2,489,441)	2.72%	19,940,975	(2,489,441)	0
391.00	Office Furniture and Equipment										
	Fully Accrued	990,281	0.00%	0	0.00%	0	0	0.00%	0	0	0
	Amortized	65,102,205	6.67%	4,342,317	6.67%	4,340,147	(2,170)	6 67%	4,340,147	(2,170)	0
	Total Office Furniture and Equipment	*66,092,486*	*6.57%*	*4,342,317*	*6.57%*	*4,340,147*	*(2,170)*	*6.57%*	*4,340,147*	*(2,170)*	*0*
391.10	Office Furniture and Equipment - EDP	110,038,171	12.50%	13,754,771	12.50%	13,754,006	(765)	12.50%	13,754,006	(765)	0
392.00	Transportation Equipment										
392.10	Passenger Cars and Station Wagon	60,172	3.66%	2,202	0.00%	0	(2,202)	0.00%	0	(2,202)	0
392.11	Light Trucks	2,226,721	6.21%	138,279	0.00%	0	(138,279)	0.00%	0	(138,279)	0
392.12	Medium Trucks	587,271	7.31%	42,930	4.15%	24,344	(18,586)	4.15%	24,344	(18,586)	0
392.13	Heavy Trucks	1,387,719	0.00%	0	0.00%	0	0	0.00%	0	0	0
392.15	Heavy Trucks / Power Equipped	2,379,104	0.00%	0	0.00%	0	0	0.00%	0	0	0
392.16	Tractors - Gasoline and Diesel	65,897	0.00%	0	0.00%	0	0	0.00%	0	0	0
392.18	Trailers	8,825,718	1.90%	167,689	3.65%	322,109	154,420	3 65%	322,109	154,420	0
	Total Transportation Equipment	*15,532,602*	*2.26%*	*351,100*	*2.23%*	*346,453*	*(4,647)*	*2.23%*	*346,453*	*(4,647)*	*0*
393.00	Stores Equipment										
	Fully Accrued	1,082,455	0.00%	0	0.00%	0	0	0.00%	0	0	0
	Amortized	14,999,972	5.00%	749,999	5.00%	749,336	(663)	5.00%	749,336	(663)	0
	Total Stores Equipment	*16,082,427*	*4.66%*	*749,999*	*4.66%*	*749,336*	*(663)*	*4.66%*	*749,336*	*(663)*	*0*
394.00	Tools, Shop, and Garage Equipment										
	Fully Accrued	1,168,696	0.00%	0	0.00%	0	0	0.00%	0	0	0
	Amortized	127,624,761	5.00%	6,381,238	5.00%	6,382,334	1,096	5.00%	6,382,334	1,096	0
	Total Tools, Shop, and Garage Equipment	*128,793,457*	*4.95%*	*6,381,238*	*4.96%*	*6,382,334*	*1,096*	*4.96%*	*6,382,334*	*1,096*	*0*
395.00	Laboratory Equipment	2,813,356	6.67%	187,651	6.67%	187,668	17	6 67%	187,668	17	0
396.00	Power Operated Equipment										
396.04	Mobile Cranes	2,021,360	3.91%	79,035	1.58%	31,960	(47,075)	1.58%	31,960	(47,075)	0
396.07	Miscellaneous Non-Highway Equipment	2,407,209	0.00%	0	4.14%	99,729	99,729	4.14%	99,729	99,729	0

Duke Energy Carolinas
Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2021

			Current Approved		DEC Proposed			Public Staff Proposed			
Account	Description	12/31/21 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from Current Approved	Accrual Rate	Accrual Amount	Difference from Current Approved	Difference from DEC Proposed
	A	B	C	D	E	F	G	H	I	J	K
396.09	Miscellaneous Equipment	14,611,554	0.00%	0	1.49%	218,343	218,343	1.49%	218,343	218,343	0
	Total Power Operated Equipment	*19,040,122*	*0.42%*	*79,035*	*1.84%*	*350,032*	*270,997*	*1.84%*	*350,032*	*270,997*	*0*
397.00	Communication Equipment										
	Fully Accrued	162,307	0.00%	0	0.00%	0	0	0.00%	0	0	0
	Amortized	254,854,594	10.00%	25,485,459	10.00%	25,492,774	7,315	10.00%	25,492,774	7,315	0
	Total Communication Equipment	*255,016,901*	*9.99%*	*25,485,459*	*10.00%*	*25,492,774*	*7,315*	*10.00%*	*25,492,774*	*7,315*	*0*
398.00	Miscellaneous Equipment	15,146,583	5.00%	757,329	5.00%	757,844	515	5.00%	757,844	515	0
	Total General Plant	**1,361,576,220**	**5.47%**	**74,519,315**	**5.31%**	**72,301,569**	**(2,217,746)**	**5.31%**	**72,301,569**	**(2,217,746)**	**0**
	Depreciable Rights of Way										
310.00	Rights of Way										
	Marshall	452,636	0.00%	0	0.00%	0	0	0.00%	0	0	0
	Belews Creek	1,543,811	0.00%	0	0.00%	0	0	0.00%	0	0	0
	Lee	3,106	0.00%	0	0.00%	0	0	0.00%	0	0	0
	Allen	4,303	0.00%	0	0.00%	0	0	0.00%	0	0	0
	Total Account 310	*2,003,856*	*0.00%*	*0*	*0.00%*	*0*	*0*	*0.00%*	*0*	*0*	*0*
320.00	Rights of Way										
	Oconee	425,003	0.61%	2,593	0.60%	2,544	(49)	0 60%	2,544	(49)	0
	McGuire	74,882	0.89%	666	0.89%	663	(3)	0 89%	663	(3)	0
	Catawba	456,657	1.05%	4,795	1.04%	4,748	(47)	1.04%	4,748	(47)	0
	Total Account 320	*956,542*	*0.84%*	*8,054*	*0.83%*	*7,955*	*(99)*	*0.83%*	*7,955*	*(99)*	*0*
330.00	Rights of Way										
	Cowans Ford	6,881,547	0.66%	45,418	0.66%	45,211	(207)	0 66%	45,211	(207)	0
	Bad Creek	723,692	1.22%	8,829	1.12%	8,105	(724)	1.12%	8,105	(724)	0
	Jocassee	436,179	0.84%	3,664	0.81%	3,548	(116)	0 81%	3,548	(116)	0
	Keowee	12,071,075	0.71%	85,705	0.69%	82,861	(2,844)	0 69%	82,861	(2,844)	0
	Fishing Creek	35,796	0.00%	0	0.00%	0	0	0.00%	0	0	0
	Bridgewater	393,705	0.00%	0	0.00%	0	0	0.00%	0	0	0
	Lookout Shoals	7,426	0.00%	0	0.00%	0	0	0.00%	0	0	0
	Mountain Island	323,913	0.00%	0	0.01%	18	18	0.01%	18	18	0
	99 Islands	17,102	0.00%	0	0.00%	0	0	0.00%	0	0	0
	Oxford	695,790	0.08%	557	0.09%	657	100	0.09%	657	100	0
	Rhodhiss	199,929	0.01%	20	0.02%	49	29	0.02%	49	29	0
	Wateree	204,111	0.00%	0	0.00%	0	0	0.00%	0	0	0
	Wylie	1,189,441	0.00%	0	0.03%	358	358	0.03%	358	358	0

Duke Energy Carolinas
Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2021

			Current Approved		DEC Proposed			Public Staff Proposed			
Account	Description	12/31/21 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from Current Approved	Accrual Rate	Accrual Amount	Difference from Current Approved	Difference from DEC Proposed
	A	B	C	D	E	F	G	H	I	J	K
	NPL Bear Creek	435	0.00%	0	0.00%	0	0	0.00%	0	0	0
	NPL Nantahala	80,304	0.00%	0	0.00%	0	0	0.00%	0	0	0
	NPL Queens Creek	5,782	0.00%	0	0.00%	0	0	0.00%	0	0	0
	NPL Tennessee Creek	711	0.00%	0	0.14%	1	1	0.14%	1	1	0
	NPL Thorpe	47,127	0.00%	0	0.00%	0	0	0.00%	0	0	0
	NPL Tuckasegee	1,518	0.00%	0	0.00%	0	0	0.00%	0	0	0
	Total Account 330	*23,315,583*	*0.62%*	*144,193*	*0.60%*	*140,808*	*(3,385)*	*0.60%*	*140,808*	*(3,385)*	*0*
340.00	Rights of Way										
	Dan River CC	7,693	4.98%	383	4.20%	323	(60)	4 20%	323	(60)	0
	Total Account 340	*7,693*	*4.98%*	*383*	*4.20%*	*323*	*(60)*	*4.20%*	*323*	*(60)*	*0*
350.00	Rights of Way	163,883,264	1.03%	1,687,998	1.02%	1,665,627	(22,371)	1.02%	1,665,627	(22,371)	0
360.00	Rights of Way	9,328,937	1.25%	116,612	1.24%	116,031	(581)	1 24%	116,031	(581)	0
360.20	Land Rights	561,560	1.36%	7,637	1.22%	6,879	(758)	1 22%	6,879	(758)	0
389.00	Rights of Way	550,127	1.21%	6,657	1.31%	7,198	541	1 31%	7,198	541	0
389.20	Land Rights	165	1.50%	2	1.21%	2	0	1 21%	2	0	0
	Total Depreciable Rights of Way	**200,607,727**	**0.98%**	**1,971,536**	**0.97%**	**1,944,823**	**(26,713)**	**0.97%**	**1,944,823**	**(26,713)**	**0**
	Reserve Adjustment for Amortization										
391.00	Office Furniture and Equipment			(1,091,336)		(1,220,484)	(129,148)		(1,220,484)	(129,148)	0
391.10	Office Furniture and Equipment - EDP			(6,686,253)		(2,359,626)	4,326,627		(2,359,626)	4,326,627	0
393.00	Stores Equipment			(510,479)		(396,333)	114,146		(396,333)	114,146	0
394.00	Tools, Shop, and Garage Equipment			182,044		(2,309,700)	(2,491,744)		(2,309,700)	(2,491,744)	0
395.00	Laboratory Equipment			(196,882)		(215,673)	(18,791)		(215,673)	(18,791)	0
397.00	Communication Equipment			(5,756,654)		(4,684,835)	1,071,819		(4,684,835)	1,071,819	0
398.00	Miscellaneous Equipment			152,142		115,186	(36,956)		115,186	(36,956)	0
	Total Reserve Adjustment for Amortization			**(13,907,418)**		**(11,071,465)**	**2,835,953**		**(11,071,465)**	**2,835,953**	**0**
	Total Depreciable Plant	**44,223,118,782**	**2.63%**	**1,164,240,497**	**3.26%**	**1,441,698,305**	**277,457,808**	**2.99%**	**1,323,582,566**	**159,342,069**	**(118,115,739)**

Duke Energy Carolinas
Table 4: Calculation of Depreciation Rates
As of December 31, 2021

Account	Description	12/31/21 Investment	12/31/21 Book Reserve	Percent Reserve	Future Net Salvage Percent	Remaining Life	Total Annual Rate	Total Annual Accrual
	A	B	C	D	E	F	G	H
	Steam Production Plant							
311.00	Structures and Improvements							
	Marshall Unit 1	4,009,964	2,764,307	68.94%	-3%	12.3	2.77%	111,053
	Marshall Unit 2	6,092,585	4,212,661	69.14%	-3%	12.3	2.75%	167,699
	Marshall Unit 3	9,592,807	6,003,531	62.58%	-4%	12.5	3.31%	317,839
	Marshall Unit 4	7,104,018	4,496,654	63.30%	-4%	12.4	3.28%	233,187
	Marshall Common	168,536,269	44,080,386	26.15%	-3%	12.9	5.96%	10,039,688
	Belews Creek Unit 1	131,857,155	66,970,270	50.79%	-6%	16.5	3.35%	4,412,019
	Belews Creek Unit 2	65,951,215	30,267,879	45.89%	-6%	16.7	3.60%	2,373,677
	Belews Creek Common	200,205,509	51,837,443	25.89%	-6%	16.9	4.74%	9,489,964
	Cliffside 5 (J.E. Rogers)	60,758,312	39,871,287	65.62%	-5%	10.9	3.61%	2,194,949
	Cliffside 6 (J.E. Rogers)	155,989,757	34,707,857	22.25%	-7%	26.4	3.21%	5,007,621
	Cliffside 5 and 6 Common (J.E. Rogers)	147,832,931	15,449,264	10.45%	-5%	26.6	3.55%	5,254,711
	Allen	161,355,512	98,878,375	61.28%	-4%	2.0	21.36%	34,465,678
	Total Structures and Improvements	*1,119,286,033*	*399,539,914*	*35.70%*	*-5%*	*10.4*	*6.62%*	*74,068,086*
312.00	Boiler Plant Equipment							
	Marshall Unit 1	482,435,560	303,816,511	62.98%	-3%	12.4	3.23%	15,571,945
	Marshall Unit 2	113,723,954	62,256,427	54.74%	-3%	12.4	3.89%	4,425,746
	Marshall Unit 3	306,016,158	149,881,523	48.98%	-4%	12.4	4.44%	13,578,652
	Marshall Unit 4	199,256,873	89,158,752	44.75%	-4%	12.4	4.78%	9,521,645
	Marshall Common	354,842,132	113,448,645	31.97%	-3%	12.6	5.64%	20,003,076
	Belews Creek Unit 1	402,272,282	174,523,317	43.38%	-6%	16.0	3.91%	15,742,831
	Belews Creek Unit 2	325,520,605	144,112,033	44.27%	-6%	16.0	3.86%	12,558,738
	Belews Creek Common	1,007,887,248	422,988,941	41.97%	-6%	15.9	4.03%	40,589,405
	Cliffside 5 (J.E. Rogers)	636,792,124	436,305,089	68.52%	-5%	10.6	3.44%	21,917,608
	Cliffside 6 (J.E. Rogers)	1,277,318,126	339,941,493	26.61%	-7%	24.5	3.28%	41,909,751
	Cliffside 5 and 6 Common (J.E. Rogers)	14,918,380	3,609,668	24.20%	-5%	24.6	3.28%	490,026
	Allen	607,456,476	498,431,997	82.05%	-4%	2.0	10.97%	66,661,369
	Total Boiler Plant Equipment	*5,728,439,918*	*2,738,474,396*	*47.80%*	*-5%*	*12.4*	*4.59%*	*262,970,790*
314.00	Turbogenerator Units							
	Marshall Unit 1	48,514,740	15,658,418	32.28%	-3%	12.6	5.61%	2,723,156
	Marshall Unit 2	55,070,730	18,226,536	33.10%	-3%	12.5	5.59%	3,079,705
	Marshall Unit 3	55,000,059	17,823,926	32.41%	-4%	12.4	5.77%	3,175,495
	Marshall Unit 4	74,442,601	26,472,589	35.56%	-4%	12.3	5.56%	4,142,091
	Marshall Common	8,584,327	3,218,949	37.50%	-3%	12.2	5.37%	460,894
	Belews Creek Unit 1	97,199,860	27,421,883	28.21%	-6%	16.0	4.86%	4,725,623
	Belews Creek Unit 2	111,149,237	31,482,386	28.32%	-6%	16.0	4.85%	5,395,988
	Belews Creek Common	40,782,765	15,499,948	38.01%	-6%	15.2	4.47%	1,824,328
	Cliffside 5 (J.E. Rogers)	59,900,126	32,865,561	54.87%	-5%	10.4	4.82%	2,887,459
	Cliffside 6 (J.E. Rogers)	267,185,630	52,835,866	19.77%	-7%	24.0	3.63%	9,710,532
	Allen	63,590,031	36,051,306	56.69%	-4%	2.0	23.65%	15,041,163
	Shared Department Plant	14,674	4,149	28.27%	-10%	22.9	3.57%	524
	Total Turbogenerator Units	*881,434,780*	*277,561,517*	*31.49%*	*-5%*	*12.2*	*6.03%*	*53,166,957*
315.00	Accessory Electric Equipment							
	Marshall Unit 1	7,604,504	4,324,190	56.86%	-3%	12.5	3.69%	280,676
	Marshall Unit 2	5,922,428	2,781,158	46.96%	-3%	12.7	4.41%	261,334
	Marshall Unit 3	29,085,683	17,442,387	59.97%	-4%	12.3	3.58%	1,041,197
	Marshall Unit 4	19,892,422	11,585,193	58.24%	-4%	12.3	3.72%	740,075
	Marshall Common	22,419,153	10,259,090	45.76%	-3%	12.6	4.54%	1,018,463
	Belews Creek Unit 1	21,359,179	10,162,292	47.58%	-6%	16.2	3.61%	770,274
	Belews Creek Unit 2	19,328,359	9,736,984	50.38%	-6%	16.1	3.45%	667,769
	Belews Creek Common	31,217,295	16,395,013	52.52%	-6%	15.8	3.38%	1,056,666
	Cliffside 5 (J.E. Rogers)	24,027,867	18,705,607	77.85%	-5%	10.5	2.59%	621,300

Duke Energy Carolinas
Table 4: Calculation of Depreciation Rates
As of December 31, 2021

Account	Description	12/31/21 Investment	12/31/21 Book Reserve	Percent Reserve	Future Net Salvage Percent	Remaining Life	Total Annual Rate	Total Annual Accrual
	A	B	C	D	E	F	G	H
	Cliffside 6 (J.E. Rogers)	153,701,998	39,581,360	25.75%	-7%	25.3	3.21%	4,935,960
	Cliffside 5 and 6 Common (J.E. Rogers)	1,315,069	120,060	9.13%	-5%	26.1	3.67%	48,305
	Allen	41,454,912	35,229,336	84.98%	-4%	2.0	9.51%	3,941,886
	Total Accessory Electric Equipment	*377,328,869*	*176,322,670*	*46.73%*	*-5%*	*14.3*	*4.08%*	*15,383,905*
316.00	Miscellaneous Power Plant Equipment							
	Marshall Unit 1	2,025,257	1,153,597	56.96%	-3%	12.4	3.71%	75,195
	Marshall Unit 2	1,050,801	746,895	71.08%	-3%	11.6	2.75%	28,916
	Marshall Unit 3	3,695,500	1,723,913	46.65%	-4%	12.5	4.59%	169,553
	Marshall Unit 4	2,213,260	1,179,084	53.27%	-4%	12.3	4.12%	91,277
	Marshall Common	28,791,316	12,594,426	43.74%	-3%	12.5	4.74%	1,364,850
	Belews Creek Unit 1	3,359,702	1,377,711	41.01%	-6%	16.2	4.01%	134,788
	Belews Creek Unit 2	2,108,637	773,356	36.68%	-6%	16.3	4.25%	89,681
	Belews Creek Common	26,224,507	9,225,206	35.18%	-6%	16.2	4.37%	1,146,467
	Cliffside 5 (J.E. Rogers)	11,493,380	7,732,743	67.28%	-5%	10.6	3.56%	408,991
	Cliffside 6 (J.E. Rogers)	246,475,194	61,325,038	24.88%	-7%	24.7	3.32%	8,194,470
	Cliffside 5 and 6 Common (J.E. Rogers)	7,330,213	1,057,548	14.43%	-5%	25.3	3.58%	262,418
	Allen	21,050,521	15,649,526	74.34%	-4%	2.0	14.83%	3,121,508
	Shared Department Plant	830,130	168,141	20.25%	-10%	25.0	3.59%	29,800
	Total Miscellaneous Power Plant Equipment	*356,648,417*	*114,707,184*	*32.16%*	*-6%*	*17.4*	*4.24%*	*15,117,916*
	Total Steam Production Plant	**8,463,138,018**	**3,706,605,681**	**43.80%**	**-5%**	**12.3**	**4.97%**	**420,707,654**
	Nuclear Production Plant							
321.00	Structures and Improvements							
	Oconee	1,019,281,184	375,180,447	36.81%	-4%	29.0	2.32%	23,616,275
	McGuire	721,643,972	427,262,855	59.21%	-8%	28.9	1.69%	12,183,828
	Catawba	251,711,370	150,853,755	59.93%	-8%	28.7	1.67%	4,215,837
	Total Structures and Improvements	*1,992,636,526*	*953,297,057*	*47.84%*	*-6%*	*28.9*	*2.01%*	*40,015,941*
322.00	Reactor Plant Equipment							
	Oconee	2,067,904,613	749,753,548	36.26%	-4%	27.4	2.47%	51,126,542
	McGuire	1,614,070,843	975,050,591	60.41%	-8%	26.8	1.78%	28,662,161
	Catawba	387,760,121	251,219,437	64.79%	-8%	25.3	1.71%	6,622,984
	Total Reactor Plant Equipment	*4,069,735,576*	*1,976,023,576*	*48.55%*	*-6%*	*27.0*	*2.12%*	*86,411,687*
323.00	Turbogenerator Units							
	Oconee	430,486,729	121,178,170	28.15%	-4%	25.2	3.01%	12,957,461
	McGuire	573,569,893	214,544,481	37.41%	-8%	25.6	2.76%	15,816,836
	Catawba	116,116,406	57,226,699	49.28%	-8%	21.5	2.73%	3,171,117
	Total Turbogenerator Units	*1,120,173,028*	*392,949,350*	*35.08%*	*-6%*	*25.0*	*2.85%*	*31,945,415*
324.00	Accessory Electric Equipment							
	Oconee	939,193,970	285,909,513	30.44%	-4%	28.9	2.55%	23,904,921
	McGuire	278,759,280	156,586,312	56.17%	-8%	28.2	1.84%	5,123,181
	Catawba	92,964,813	56,328,823	60.59%	-8%	26.2	1.81%	1,682,182
	Shared Department Plant	124,790	45,583	36.53%	-10%	31.7	2.32%	2,892
	Total Accessory Electric Equipment	*1,311,042,852*	*498,870,231*	*38.05%*	*-5%*	*28.6*	*2.34%*	*30,713,177*
325.00	Miscellaneous Power Plant Equipment							
	Oconee	270,468,486	114,710,199	42.41%	-4%	28.3	2.18%	5,886,114
	McGuire	308,391,168	142,919,964	46.34%	-8%	32.1	1.92%	5,923,442
	Catawba	54,038,717	26,791,059	49.58%	-8%	31.4	1.86%	1,005,438
	Shared Department Plant	4,126,480	643,505	15.59%	-5%	36.9	2.42%	99,981
	Total Miscellaneous Power Plant Equipment	*637,024,851*	*285,064,727*	*44.75%*	*-6%*	*30.3*	*2.03%*	*12,914,975*

Duke Energy Carolinas
Table 4: Calculation of Depreciation Rates
As of December 31, 2021

Account	Description	12/31/21 Investment	12/31/21 Book Reserve	Percent Reserve	Future Net Salvage Percent	Remaining Life	Total Annual Rate	Total Annual Accrual
	A	B	C	D	E	F	G	H
	Total Nuclear Production Plant	**9,130,612,833**	**4,106,204,941**	**44.97%**	**-6%**	**27.6**	**2.21%**	**202,001,194**
	Hydarulic Production Plant							
331.00	Structures and Improvements							
	Cowans Ford	19,751,911	8,824,619	44.68%	-4%	30.5	1.95%	384,176
	Bad Creek	234,244,262	117,348,991	50.10%	-8%	37.2	1.56%	3,646,097
	Jocassee	33,533,952	14,636,064	43.65%	-1%	23.6	2.43%	814,967
	Keowee	32,788,215	4,903,626	14.96%	-2%	24.5	3.55%	1,164,912
	Fishing Creek	5,708,226	2,060,393	36.10%	-11%	32.3	2.32%	132,376
	Cedar Creek	4,096,778	1,733,249	42.31%	-12%	31.9	2.18%	89,503
	Bridgewater	66,243,977	17,601,446	26.57%	-2%	32.9	2.29%	1,518,766
	Lookout Shoals	2,871,615	1,419,606	49.44%	-19%	31.5	2.21%	63,416
	Mountain Island	4,116,426	1,199,866	29.15%	-14%	32.7	2.59%	106,815
	99 Islands	1,206,655	708,253	58.70%	-13%	14.3	3.80%	45,823
	Oxford	4,211,264	1,913,091	45.43%	-6%	31.4	1.93%	81,237
	Rhodhiss	6,066,351	1,967,967	32.44%	-11%	32.5	2.42%	146,636
	Wateree	17,453,757	4,801,173	27.51%	-12%	32.5	2.60%	453,755
	Wylie	8,392,378	3,225,424	38.43%	-9%	32.0	2.21%	185,071
	Great Falls	551,582	619,668	112.34%	-95%	30.7	2.69%	14,851
	Dearborn	2,131,193	1,225,420	57.50%	-16%	30.7	1.91%	40,611
	NPL Bear Creek	1,066,015	323,682	30.36%	-7%	19.2	3.99%	42,550
	NPL Cedar Cliff	1,078,554	352,022	32.64%	-15%	19.2	4.29%	46,266
	NPL Nantahala	2,609,433	1,004,646	38.50%	-9%	19.8	3.56%	92,911
	NPL Queens Creek	112,213	116,922	104.20%	-82%	10.1	7.70%	8,644
	NPL Tennessee Creek	355,878	192,179	54.00%	-10%	18.8	2.98%	10,600
	NPL Thorpe	4,578,421	2,056,020	44.91%	-31%	19.1	4.51%	206,372
	NPL Tuckasegee	2,401,434	1,233,166	51.35%	-51%	19.2	5.19%	124,635
	Shared Department Plant	27,831	15,891	57.10%	-25%	19.8	3.43%	954
	Total Structures and Improvements	*455,598,320*	*189,483,384*	*41.59%*	*-7%*	*31.7*	*2.07%*	*9,421,947*
332.00	Reservoirs, Dams, and Waterways							
	Cowans Ford	38,853,208	17,668,487	45.47%	-4%	32.9	1.78%	691,150
	Bad Creek	455,754,167	246,203,324	54.02%	-8%	42.8	1.26%	5,747,925
	Jocassee	61,453,955	39,374,347	64.07%	-1%	24.0	1.54%	945,589
	Keowee	17,981,009	14,345,680	79.78%	-2%	23.4	0.95%	170,724
	Fishing Creek	23,481,095	8,399,794	35.77%	-11%	33.5	2.25%	527,290
	Cedar Creek	12,017,600	5,248,838	43.68%	-12%	33.4	2.05%	245,835
	Bridgewater	200,720,291	46,360,401	23.10%	-2%	33.7	2.34%	4,699,534
	Lookout Shoals	5,580,443	3,903,795	69.95%	-19%	32.9	1.49%	83,189
	Mountain Island	14,584,121	4,887,017	33.51%	-14%	33.5	2.40%	350,414
	99 Islands	12,905,168	9,277,285	71.89%	-13%	14.4	2.85%	368,441
	Oxford	36,203,844	12,311,776	34.01%	-6%	33.5	2.15%	778,039
	Rhodhiss	10,908,630	4,692,013	43.01%	-11%	33.4	2.04%	222,053
	Wateree	15,019,296	9,114,588	60.69%	-12%	33.0	1.55%	233,546
	Wylie	29,701,234	9,182,787	30.92%	-9%	33.5	2.33%	692,285
	Great Falls	2,869,197	4,223,215	147.19%	-95%	32.6	1.47%	42,077
	Dearborn	2,394,279	1,130,190	47.20%	-16%	33.3	2.07%	49,465
	NPL Bear Creek	8,021,219	3,177,473	39.61%	-7%	19.3	3.49%	280,064
	NPL Cedar Cliff	5,593,887	2,336,648	41.77%	-15%	19.3	3.79%	212,245
	NPL Nantahala	16,018,308	11,090,876	69.24%	-9%	19.9	2.00%	320,054
	NPL Queens Creek	763,264	1,131,205	148.21%	-82%	10.2	3.31%	25,288
	NPL Tennessee Creek	12,191,333	4,924,097	40.39%	-10%	19.3	3.61%	439,708
	NPL Thorpe	6,614,546	6,634,973	100.31%	-31%	19.1	1.61%	106,287
	NPL Tuckasegee	2,028,914	1,123,506	55.37%	-51%	19.3	4.95%	100,526
	Shared Department Plant	324,568	262,677	80.93%	-25%	19.9	2.21%	7,188
	Total Reservoirs, Dams, and Waterways	*991,983,576*	*467,004,992*	*47.08%*	*-7%*	*34.4*	*1.75%*	*17,338,917*

Duke Energy Carolinas
Table 4: Calculation of Depreciation Rates
As of December 31, 2021

Account	Description	12/31/21 Investment	12/31/21 Book Reserve	Percent Reserve	Future Net Salvage Percent	Remaining Life	Total Annual Rate	Total Annual Accrual
	A	B	C	D	E	F	G	H
333.00	Water Wheels, Turbines, and Generators							
	Cowans Ford	68,487,087	12,757,912	18.63%	-4%	30.3	2.82%	1,929,659
	Bad Creek	278,478,568	77,523,546	27.84%	-8%	34.1	2.35%	6,546,431
	Jocassee	71,420,107	25,499,982	35.70%	-1%	22.1	2.95%	2,110,151
	Keowee	173,934,217	27,665,672	15.91%	-2%	23.8	3.62%	6,291,900
	Fishing Creek	22,401,992	9,355,205	41.76%	-11%	26.9	2.57%	576,617
	Cedar Creek	16,788,917	5,075,144	30.23%	-12%	28.9	2.83%	475,033
	Bridgewater	20,780,376	4,616,850	22.22%	-2%	30.5	2.62%	543,578
	Lookout Shoals	10,652,141	4,481,903	42.08%	-19%	27.2	2.83%	301,255
	Mountain Island	16,306,552	6,030,189	36.98%	-14%	28.2	2.73%	445,365
	99 Islands	12,208,893	4,903,929	40.17%	-13%	14.1	5.17%	630,647
	Oxford	18,494,761	4,728,261	25.57%	-6%	29.7	2.71%	500,882
	Rhodhiss	17,378,790	4,616,338	26.56%	-11%	29.9	2.82%	490,773
	Wateree	24,103,860	9,343,679	38.76%	-12%	27.4	2.67%	644,257
	Wylie	30,556,201	7,306,148	23.91%	-9%	29.7	2.86%	875,425
	Great Falls	5,314,119	4,728,482	88.98%	-95%	24.5	4.33%	229,961
	Dearborn	11,960,714	5,118,531	42.79%	-16%	27.0	2.71%	324,293
	NPL Bear Creek	6,310,105	1,118,634	17.73%	-7%	19.0	4.70%	296,483
	NPL Cedar Cliff	3,386,918	1,106,471	32.67%	-15%	18.7	4.40%	149,117
	NPL Nantahala	3,876,087	1,674,829	43.21%	-9%	18.4	3.58%	138,593
	NPL Queens Creek	38,141	53,412	140.04%	-82%	8.5	4.94%	1,883
	NPL Tennessee Creek	10,886,412	425,532	3.91%	-10%	19.1	5.55%	604,687
	NPL Thorpe	420,632	374,589	89.05%	-31%	13.2	3.18%	13,367
	NPL Tuckasegee	250,399	160,308	64.02%	-51%	16.9	5.15%	12,887
	Total Water Wheels, Turbines, and Generators	*824,435,989*	*218,665,546*	*26.52%*	*-7%*	*27.5*	*2.93%*	*24,133,242*
334.00	Accessory Electric Equipment							
	Cowans Ford	12,978,754	2,245,835	17.30%	-4%	30.7	2.82%	366,517
	Bad Creek	57,868,266	24,213,312	41.84%	-8%	31.2	2.12%	1,227,065
	Jocassee	19,445,365	5,354,156	27.53%	-1%	22.7	3.24%	629,324
	Keowee	14,183,983	5,505,153	38.81%	-2%	22.3	2.83%	401,906
	Fishing Creek	4,563,859	1,781,652	39.04%	-11%	28.0	2.57%	117,294
	Cedar Creek	3,751,305	1,337,531	35.66%	-12%	28.8	2.65%	99,442
	Bridgewater	7,436,806	1,677,044	22.55%	-2%	30.5	2.60%	193,721
	Lookout Shoals	2,095,204	987,068	47.11%	-19%	26.5	2.71%	56,839
	Mountain Island	3,154,895	1,029,429	32.63%	-14%	28.7	2.84%	89,448
	99 Islands	820,637	336,075	40.95%	-13%	13.5	5.34%	43,796
	Oxford	3,904,495	1,400,053	35.86%	-6%	28.3	2.48%	96,774
	Rhodhiss	2,355,053	925,308	39.29%	-11%	27.7	2.59%	60,968
	Wateree	5,322,022	1,793,155	33.69%	-12%	29.0	2.70%	143,707
	Wylie	3,962,983	1,532,759	38.68%	-9%	27.5	2.56%	101,342
	Great Falls	888,922	813,093	91.47%	-95%	18.4	5.63%	50,017
	Dearborn	3,858,306	1,657,667	42.96%	-16%	27.9	2.62%	101,002
	NPL Bear Creek	303,467	76,619	25.25%	-7%	18.3	4.47%	13,557
	NPL Cedar Cliff	372,636	76,193	20.45%	-15%	18.7	5.06%	18,842
	NPL Nantahala	2,870,041	819,742	28.56%	-9%	19.3	4.17%	119,617
	NPL Queens Creek	183,285	219,700	119.87%	-82%	9.7	6.41%	11,740
	NPL Tennessee Creek	3,157,080	184,891	5.86%	-10%	19.0	5.48%	173,047
	NPL Thorpe	2,536,156	1,265,877	49.91%	-31%	18.1	4.48%	113,618
	NPL Tuckasegee	436,678	199,017	45.58%	-51%	18.4	5.73%	25,020
	Total Accessory Electric Equipment	*156,450,197*	*55,431,329*	*35.43%*	*-8%*	*26.7*	*2.72%*	*4,254,602*
335.00	Miscellaneous Power Plant Equipment							
	Cowans Ford	2,251,209	546,925	24.29%	-4%	30.2	2.64%	59,415
	Bad Creek	30,106,922	12,840,345	42.65%	-8%	32.6	2.00%	603,532
	Jocassee	4,473,233	1,751,779	39.16%	-1%	22.2	2.79%	124,603

Duke Energy Carolinas
Table 4: Calculation of Depreciation Rates
As of December 31, 2021

Account	Description	12/31/21 Investment	12/31/21 Book Reserve	Percent Reserve	Future Net Salvage Percent	Remaining Life	Total Annual Rate	Total Annual Accrual
	A	B	C	D	E	F	G	H
	Keowee	2,801,735	663,957	23.70%	-2%	23.1	3.39%	94,970
	Fishing Creek	337,031	120,493	35.75%	-11%	29.5	2.55%	8,597
	Cedar Creek	499,494	143,362	28.70%	-12%	30.3	2.75%	13,732
	Bridgewater	7,365,601	1,848,004	25.09%	-2%	30.7	2.51%	184,525
	Lookout Shoals	452,187	188,603	41.71%	-19%	29.1	2.66%	12,010
	Mountain Island	502,664	198,744	39.54%	-14%	29.1	2.56%	12,862
	99 Islands	510,703	246,018	48.17%	-13%	14.0	4.63%	23,648
	Oxford	678,189	213,448	31.47%	-6%	29.8	2.50%	16,961
	Rhodhiss	498,905	202,607	40.61%	-11%	28.9	2.44%	12,151
	Wateree	637,407	182,462	28.63%	-12%	30.2	2.76%	17,597
	Wylie	863,411	195,710	22.67%	-9%	30.6	2.82%	24,360
	Great Falls	402,576	188,084	46.72%	-95%	30.4	4.88%	19,636
	Dearborn	456,205	131,562	28.84%	-16%	30.1	2.90%	13,211
	NPL Bear Creek	165,737	59,249	35.75%	-7%	18.6	3.83%	6,349
	NPL Cedar Cliff	124,236	47,770	38.45%	-15%	18.6	4.12%	5,113
	NPL Nantahala	1,215,355	397,961	32.74%	-9%	19.3	3.95%	48,019
	NPL Queens Creek	206,671	263,608	127.55%	-82%	9.9	5.50%	11,367
	NPL Tennessee Creek	224,996	85,505	38.00%	-10%	18.5	3.89%	8,756
	NPL Thorpe	1,257,022	354,600	28.21%	-31%	18.7	5.50%	69,096
	NPL Tuckasegee	98,008	47,390	48.35%	-51%	18.6	5.52%	5,409
	Shared Department Plant	925,759	414,217	44.74%	-5%	18.9	3.19%	29,515
	Total Miscellaneous Power Plant Equipment	*57,055,255*	*21,332,403*	*37.39%*	*-8%*	*28.4*	*2.50%*	*1,425,434*
336.00	Roads, Railroads, and Bridges							
	Cowans Ford	2,240,416	861,455	38.45%	-4%	32.4	2.02%	45,326
	Bad Creek	18,888,978	9,770,014	51.72%	-8%	39.9	1.41%	266,418
	Jocassee	415,508	331,112	79.69%	-1%	21.2	1.01%	4,177
	Dearborn	633,636	447,282	70.59%	-16%	30.9	1.47%	9,312
	NPL Bear Creek	52,776	53,844	102.02%	-7%	13.1	0.38%	200
	NPL Cedar Cliff	129,738	111,554	85.98%	-15%	18.6	1.56%	2,024
	NPL Nantahala	239,971	211,312	88.06%	-9%	19.5	1.07%	2,577
	NPL Queens Creek	2,830	5,518	194.98%	-82%	0.0	0.00%	0
	NPL Tennessee Creek	72,590	75,717	104.31%	-10%	13.3	0.43%	311
	NPL Thorpe	46,024	54,505	118.43%	-31%	19.2	0.65%	301
	NPL Tuckasegee	8,678	13,055	150.44%	-51%	11.6	0.05%	4
	Shared Department Plant	84,399	84,399	100.00%	0%	0.0	0.00%	0
	Total Roads, Railroads, and Bridges	*22,815,544*	*12,019,767*	*52.68%*	*-8%*	*38.0*	*1.45%*	*330,651*
	Total Hydarulic Production Plant	**2,508,338,881**	**963,937,421**	**38.43%**	**-7%**	**30.3**	**2.27%**	**56,904,794**
	Other Production Plant							
341.00	Structures and Improvements							
	Lincoln CTs	28,785,282	15,461,456	53.71%	-2%	17.6	2.74%	789,746
	Dan River CC	149,165,213	33,588,185	22.52%	-6%	28.9	2.89%	4,308,891
	Lee CTs	1,389,212	178,164	12.82%	-4%	25.0	3.65%	50,665
	Mill Creek CTs	29,986,169	13,117,936	43.75%	-1%	20.3	2.82%	845,719
	Rockingham CTs	3,432,573	818,928	23.86%	-1%	18.2	4.24%	145,493
	Buck CC	155,526,329	35,985,231	23.14%	-5%	28.1	2.91%	4,530,869
	Lark Maintenance Facility	141,116,369	14,364,649	10.18%	-5%	34.1	2.78%	3,923,975
	Lee CC	8,605,539	534,881	6.22%	-6%	36.2	2.76%	237,210
	Clemson CHP	29,706,060	4,159,413	14.00%	-5%	34.9	2.61%	774,554
	Total Structures and Improvements	*547,712,745*	*118,208,843*	*21.58%*	*-5%*	*29.2*	*2.85%*	*15,607,121*
341.66	Structures and Improvements - Solar							
	Mocksville	101,358	12,507	12.34%	-9%	23.5	4.11%	4,169
	Monroe	2,711,076	333,829	12.31%	-12%	24.4	4.09%	110,761

Duke Energy Carolinas
Table 4: Calculation of Depreciation Rates
As of December 31, 2021

Account	Description	12/31/21 Investment	12/31/21 Book Reserve	Percent Reserve	Future Net Salvage Percent	Remaining Life	Total Annual Rate	Total Annual Accrual
	A	B	C	D	E	F	G	H
	Gaston	419,744	16,928	4.03%	-9%	27.4	3.83%	16,080
	Maiden Creek	4,698,133	65,987	1.40%	-13%	28.4	3.93%	184,609
	Total Structures and Improvements - Solar	*7,930,312*	*429,251*	*5.41%*	*-12%*	*26.9*	*3.98%*	*315,620*
342.00	Fuel Holders, Producers, and Accessories							
	Lincoln CTs	12,968,504	9,307,903	71.77%	-2%	17.0	1.78%	230,587
	Dan River CC	21,771,640	6,390,989	29.35%	-6%	28.1	2.73%	593,842
	Lee CTS	177,613	20,351	11.46%	-4%	24.6	3.76%	6,682
	Mill Creek CTs	15,154,441	8,986,267	59.30%	-1%	19.6	2.13%	322,435
	Rockingham CTs	426,120	137,154	32.19%	-1%	18.0	3.82%	16,290
	Buck CC	30,439,400	10,245,519	33.66%	-5%	27.1	2.63%	801,323
	Lee CC	16,546,972	1,946,190	11.76%	-5%	33.6	2.77%	459,171
	Clemson CHP	1,223,118	103,126	8.43%	-6%	34.9	2.80%	34,194
	Total Fuel Holders, Producers, and Accessories	*98,707,808*	*37,137,499*	*37.62%*	*-4%*	*26.6*	*2.50%*	*2,464,522*
343.00	Prime Movers							
	Lincoln CTs	257,522,093	202,549,282	78.65%	-2%	15.6	1.50%	3,854,055
	Dan River CC	160,795,157	53,671,483	33.38%	-6%	25.4	2.86%	4,597,299
	Lee CTs	57,929,945	29,687,704	51.25%	-4%	21.3	2.48%	1,434,715
	Mill Creek CTs	184,343,825	123,931,520	67.23%	-1%	17.8	1.90%	3,497,514
	Rockingham CTs	93,721,064	24,835,004	26.50%	-1%	17.2	4.33%	4,059,492
	Buck CC	160,808,480	58,381,320	36.30%	-5%	24.6	2.79%	4,490,552
	Lee CC	125,760,509	16,735,750	13.31%	-5%	30.2	3.04%	3,818,304
	Clemson CHP	12,233,142	1,174,009	9.60%	-6%	31.3	3.08%	376,777
	Total Prime Movers	*1,053,114,213*	*510,966,072*	*48.52%*	*-3%*	*22.0*	*2.48%*	*26,128,708*
343.10	Prime Movers - Rotable Parts							
	Dan River CC	45,680,461	8,195,685	17.94%	40%	2.5	16.82%	7,685,037
	Buck CC	42,161,014	7,143,141	16.94%	40%	2.8	15.38%	6,483,381
	Lee CC	43,400,555	8,645,654	19.92%	40%	2.6	15.42%	6,690,261
	Clemson CHP	717,644	105,016	14.63%	40%	3.5	12.96%	93,020
	Total Prime Movers - Rotable Parts	*131,959,674*	*24,089,496*	*18.26%*	*40%*	*2.6*	*15.88%*	*20,951,699*
344.00	Generators							
	Lincoln CTs	78,436,794	49,286,278	62.84%	-2%	16.8	2.33%	1,828,527
	Dan River CC	238,495,960	64,911,277	27.22%	-6%	28.0	2.81%	6,710,516
	Lee CTs	64,369	16,372	25.43%	-4%	24.2	3.25%	2,090
	Mill Creek CTs	1,054,904	197,724	18.74%	-1%	20.8	3.95%	41,718
	On-Site Diesel Generators	24,882,743	10,760,568	43.25%	0%	6.5	8.73%	2,172,642
	Rockingham CTs	220,840,812	122,428,609	55.44%	-1%	17.0	2.68%	5,918,859
	Buck CC	231,370,373	68,711,516	29.70%	-5%	27.0	2.79%	6,452,866
	Lee CC	214,214,901	21,631,396	10.10%	-5%	33.6	2.82%	6,050,424
	Clemson CHP	857,084	59,828	6.98%	-6%	35.0	2.83%	24,248
	Total Generators	*1,010,217,939*	*338,003,568*	*33.46%*	*-4%*	*24.3*	*2.89%*	*29,201,890*
344.66	Generators - Solar							
	Community - Small	28,057,290	15,141,142	53.97%	0%	9.4	4.90%	1,374,058
	Mocksville	29,394,130	7,596,748	25.84%	-9%	18.5	4.49%	1,321,235
	Monroe	91,561,246	19,909,175	21.74%	-12%	19.5	4.63%	4,237,919
	Woodleaf	13,905,691	2,316,184	16.66%	-10%	20.5	4.55%	633,174
	Gaston	33,742,749	2,408,869	7.14%	-9%	22.5	4.53%	1,527,588
	Maiden Creek	75,170,134	1,868,934	2.49%	-13%	23.5	4.70%	3,535,035
	Total Generators - Solar	*271,831,240*	*49,241,052*	*18.11%*	*-10%*	*19.7*	*4.65%*	*12,629,010*
345.00	Accessory Electric Equipment							
	Lincoln CTs	26,803,108	21,000,419	78.35%	-2%	16.5	1.43%	384,167
	Dan River CC	48,409,540	16,588,259	34.27%	-6%	26.3	2.73%	1,320,375

Duke Energy Carolinas
Table 4: Calculation of Depreciation Rates
As of December 31, 2021

Account	Description	12/31/21 Investment	12/31/21 Book Reserve	Percent Reserve	Future Net Salvage Percent	Remaining Life	Total Annual Rate	Total Annual Accrual
	A	B	C	D	E	F	G	H
	Lee CTs	1,467,540	232,452	15.84%	-4%	23.4	3.77%	55,290
	Mill Creek CTs	17,535,997	10,389,010	59.24%	-1%	19.1	2.19%	383,369
	Rockingham CTs	2,095,877	925,773	44.17%	-1%	17.2	3.30%	69,248
	Buck CC	48,520,138	18,302,811	37.72%	-5%	25.5	2.64%	1,280,131
	Lee CC	37,322,856	4,958,697	13.29%	-5%	31.3	2.93%	1,093,620
	Clemson CHP	4,220,737	399,329	9.46%	-6%	32.5	2.97%	125,374
	Total Accessory Electric Equipment	*186,375,794*	*72,796,750*	*39.06%*	*-4%*	*25.8*	*2.53%*	*4,711,573*
345.66	Accessory Electric Equipment - Solar							
	Community - Small	988,895	365,264	36.94%	0%	10.8	5.84%	57,744
	Mocksville	2,281,560	463,277	20.31%	-9%	18.5	4.79%	109,385
	Monroe	12,869,692	2,199,058	17.09%	-12%	19.5	4.87%	626,410
	Gaston	4,608,877	258,481	5.61%	-9%	22.5	4.60%	211,786
	Maiden Creek	6,577,387	128,471	1.95%	-13%	23.5	4.73%	310,807
	Total Accessory Electric Equipment - Solar	*27,326,411*	*3,414,551*	*12.50%*	*-11%*	*20.4*	*4.82%*	*1,316,133*
346.00	Miscellaneous Power Plant Equipment							
	Lincoln CTs	5,795,202	1,993,305	34.40%	-2%	17.1	3.95%	229,111
	Dan River CC	9,431,238	2,065,966	21.91%	-6%	26.0	3.23%	305,044
	Lee CTs	1,021,168	156,502	15.33%	-4%	23.3	3.81%	38,863
	Mill Creek CTs	3,716,236	1,505,574	40.51%	-1%	18.6	3.25%	120,851
	Rockingham CTs	1,653,414	479,820	29.02%	-1%	17.2	4.18%	69,194
	Buck CC	12,646,705	2,768,731	21.89%	-5%	25.4	3.27%	413,792
	Lee CC	6,591,238	610,093	9.26%	-5%	30.9	3.10%	204,230
	Clemson CHP	2,217,373	154,790	6.98%	-6%	32.0	3.09%	68,613
	Lark Maintenance Facility	14,397,254	1,336,248	9.28%	-5%	31.5	3.04%	437,488
	Shared Department Plant	79,121	12,346	15.60%	-5%	30.4	2.94%	2,327
	Total Miscellaneous Power Plant Equipment	*57,548,950*	*11,083,375*	*19.26%*	*-4%*	*25.9*	*3.28%*	*1,889,512*
346.66	Miscellaneous Power Plant Equipment - Solar							
	Mocksville	16,512	577	3.49%	-9%	23.1	4.57%	754
	Monroe	269,582	24,788	9.19%	-12%	23.7	4.34%	11,694
	Woodleaf	4,928	164	3.33%	-9%	24.7	4.28%	211
	Maiden Creek	11,626	361	3.11%	-13%	26.9	4.09%	475
	Total Miscellaneous Power Plant Equipment - Solar	*302,648*	*25,890*	*8.55%*	*-12%*	*23.8*	*4.34%*	*13,134*
	Total Other Production Plant	**3,393,027,734**	**1,165,396,347**	**34.35%**	**4%**	**18.0**	**3.40%**	**115,228,922**
	Total Production Plant	**23,495,117,466**	**9,942,144,390**	**42.32%**	**-4%**	**18.3**	**3.38%**	**794,842,564**
	Transmission Plant							
352.00	Structures and Improvements	189,425,366	17,119,876	9.04%	-10%	35.7	2.83%	5,357,088
353.00	Station Equipment	2,307,608,516	596,629,900	25.85%	-15%	34.9	2.55%	58,943,263
354.00	Towers and Fixtures	651,521,544	327,356,686	50.24%	-40%	51.5	1.74%	11,354,825
355.00	Poles and Fixtures	662,736,805	133,790,128	20.19%	-40%	40.6	2.95%	19,557,670
356.00	Overhead Conductors and Devices	944,879,899	374,867,240	39.67%	-30%	46.9	1.93%	18,197,796
357.00	Underground Conduit	154,590	90,840	58.76%	0%	32.2	1.28%	1,980
358.00	Underground Conductors and Devices	12,171,599	(1,819,362)	-14.95%	0%	37.0	3.11%	378,134
359.00	Roads and Trails	42,238	19,939	47.21%	0%	36.4	1.45%	613
	Total Transmission Plant	**4,768,540,557**	**1,448,055,247**	**30.37%**	**-24%**	**39.1**	**2.39%**	**113,791,368**
	Distribution Plant							
361.00	Structures and Improvements	178,576,485	21,563,467	12.08%	-10%	37.9	2.58%	4,614,002
362.00	Station Equipment	1,705,256,083	578,861,414	33.95%	-15%	37.0	2.19%	37,356,300

Duke Energy Carolinas
Table 4: Calculation of Depreciation Rates
As of December 31, 2021

Account	Description	12/31/21 Investment	12/31/21 Book Reserve	Percent Reserve	Future Net Salvage Percent	Remaining Life	Total Annual Rate	Total Annual Accrual
	A	B	C	D	E	F	G	H
364.00	Poles, Towers, and Fixtures	1,840,292,393	859,121,749	46.68%	-50%	37.4	2.76%	50,837,349
364.10	Poles, Towers, and Fixtures - Storm Securitization	6,687,318	6,687,318	100.00%	0%	0.0	0.00%	0
365.00	Overhead Conductors and Devices	2,672,397,506	843,861,451	31.58%	-30%	44.0	2.24%	59,778,530
365.10	Overhead Conductors and Devices - Storm Securitiz	6,179,207	6,179,207	100.00%	0%	0.0	0.00%	0
366.00	Underground Conduit	269,930,643	126,940,065	47.03%	-20%	49.7	1.47%	3,963,314
367.00	Underground Conductors and Devices	2,592,327,369	904,892,035	34.91%	-20%	41.0	2.08%	53,802,459
368.00	Line Transformers	1,837,487,386	689,085,795	37.50%	-15%	33.2	2.33%	42,892,310
368.10	Line Transformers - Storm Securitization	4,855,160	4,855,160	100.00%	0%	0.0	0.00%	0
369.00	Services	1,273,824,830	633,947,467	49.77%	-25%	45.1	1.67%	21,249,081
370.00	Meters and Metering Equipment	113,584,605	70,640,944	62.19%	0%	6.3	6.00%	6,816,454
370.02	Meters - Utility of the Future	475,170,483	137,434,853	28.92%	0%	11.4	6.23%	29,625,932
371.00	Installations on Customers' Premises	1,063,691,891	289,452,962	27.21%	-5%	26.9	2.89%	30,759,239
373.00	Street Lighting and Signal Systems	357,015,453	94,732,839	26.53%	-10%	29.6	2.82%	10,067,032
	Total Distribution Plant	**14,397,276,812**	**5,268,256,726**	**36.59%**	**-21%**	**34.4**	**2.44%**	**351,762,002**
	General Plant							
390.00	Structures and Improvements	733,020,115	191,602,575	26.14%	-10%	30.8	2.72%	19,958,427
391.00	Office Furniture and Equipment							
	Fully Accrued	990,281	990,281	100.00%	0%	0.0	0.00%	0
	Amortized	65,102,205	19,376,390	29.76%	0%	10.5	6.69%	4,354,840
	Total Office Furniture and Equipment	*66,092,486*	*20,366,671*	*30.82%*	*0%*	*10.5*	*6.59%*	*4,354,840*
391.10	Office Furniture and Equipment - EDP	110,038,171	49,853,815	45.31%	0%	4.4	12.43%	13,678,263
392.00	Transportation Equipment							
392.10	Passenger Cars and Station Wagon	60,172	54,154	90.00%	10%	0.0	0.00%	0
392.11	Light Trucks	2,226,721	2,004,049	90.00%	10%	0.0	0.00%	0
392.12	Medium Trucks	587,271	393,933	67.08%	10%	5.5	4.17%	24,475
392.13	Heavy Trucks	1,387,719	1,248,947	90.00%	10%	0.0	0.00%	0
392.15	Heavy Trucks / Power Equipped	2,379,104	2,141,194	90.00%	10%	0.0	0.00%	0
392.16	Tractors - Gasoline and Diesel	65,897	59,307	90.00%	10%	0.0	0.00%	0
392.18	Trailers	8,825,718	3,378,106	38.28%	10%	14.2	3.64%	321,482
	Total Transportation Equipment	*15,532,602*	*9,279,690*	*59.74%*	*10%*	*13.6*	*2.23%*	*345,956*
393.00	Stores Equipment							
	Fully Accrued	1,082,455	1,082,455	100.00%	0%	0.0	0.00%	0
	Amortized	14,999,972	3,357,515	22.38%	0%	15.5	5.01%	751,126
	Total Stores Equipment	*16,082,427*	*4,439,970*	*27.61%*	*0%*	*15.5*	*4.67%*	*751,126*
394.00	Tools, Shop, and Garage Equipment							
	Fully Accrued	1,168,696	1,168,696	100.00%	0%	0.0	0.00%	0
	Amortized	127,624,761	35,836,360	28.08%	0%	14.4	4.99%	6,374,195
	Total Tools, Shop, and Garage Equipment	*128,793,457*	*37,005,056*	*28.73%*	*0%*	*14.4*	*4.95%*	*6,374,195*
395.00	Laboratory Equipment	2,813,356	1,344,140	47.78%	0%	7.8	6.70%	188,361
396.00	Power Operated Equipment							
396.04	Mobile Cranes	2,021,360	1,237,278	61.21%	10%	18.2	1.58%	31,975
396.07	Miscellaneous Non-Highway Equipment	2,407,209	1,008,794	41.91%	10%	11.6	4.15%	99,801
396.09	Miscellaneous Equipment	14,611,554	10,619,436	72.68%	10%	11.6	1.49%	218,186
	Total Power Operated Equipment	*19,040,122*	*12,865,508*	*67.57%*	*10%*	*12.2*	*1.84%*	*349,963*
397.00	Communication Equipment							
	Fully Accrued	162,307	162,307	100.00%	0%	0.0	0.00%	0

Duke Energy Carolinas
Table 4: Calculation of Depreciation Rates
As of December 31, 2021

Account	Description	12/31/21 Investment	12/31/21 Book Reserve	Percent Reserve	Future Net Salvage Percent	Remaining Life	Total Annual Rate	Total Annual Accrual
	A	B	C	D	E	F	G	H
	Amortized	254,854,594	73,604,050	28.88%	0%	7.1	10.02%	25,528,246
	Total Communication Equipment	*255,016,901*	*73,766,357*	*28.93%*	*0%*	*7.1*	*10.01%*	*25,528,246*
398.00	Miscellaneous Equipment	15,146,583	3,729,200	24.62%	0%	15.1	4.99%	756,118
	Total General Plant	**1,361,576,220**	**404,252,982**	**29.69%**	**-3%**	**13.8**	**5.31%**	**72,285,494**
	Depreciable Land Rights							
310.00	Rights of Way							
	Marshall	452,636	452,636	100.00%	0%	12.7	0.00%	0
	Belews Creek	1,543,811	1,547,854	100.26%	0%	16.7	0.00%	0
	Lee	3,106	3,106	100.00%	0%	#REF!	0.00%	0
	Allen	4,303	4,303	100.00%	0%	2.0	0.00%	0
	Total Account 310	*2,003,856*	*2,007,899*	*100.20%*	*0%*	*0.0*	*0.00%*	*0*
320.00	Rights of Way							
	Oconee	425,003	348,441	81.99%	0%	30.1	0.60%	2,544
	McGuire	74,882	49,041	65.49%	0%	39.0	0.88%	663
	Catawba	456,657	264,750	57.98%	0%	40.4	1.04%	4,750
	Total Account 320	*956,542*	*662,232*	*69.23%*	*0%*	*37.0*	*0.83%*	*7,956*
330.00	Rights of Way							
	Cowans Ford	6,881,547	5,451,053	79.21%	0%	31.6	0.66%	45,269
	Bad Creek	723,692	362,929	50.15%	0%	44.5	1.12%	8,107
	Jocassee	436,179	350,311	80.31%	0%	24.2	0.81%	3,548
	Keowee	12,071,075	10,079,922	83.50%	0%	24.0	0.69%	82,965
	Fishing Creek	35,796	35,796	100.00%	0%	0.0	0.00%	0
	Bridgewater	393,705	393,705	100.00%	0%	0.0	0.00%	0
	Lookout Shoals	7,426	7,426	100.00%	0%	0.0	0.00%	0
	Mountain Island	323,913	323,301	99.81%	0%	34.0	0.01%	18
	99 Islands	17,102	17,102	100.00%	0%	0.0	0.00%	0
	Oxford	695,790	680,788	97.84%	0%	22.8	0.09%	658
	Rhodhiss	199,929	198,870	99.47%	0%	21.6	0.02%	49
	Wateree	204,111	204,111	100.00%	0%	0.0	0.00%	0
	Wylie	1,189,441	1,178,412	99.07%	0%	30.8	0.03%	358
	NPL Bear Creek	435	424	97.47%	0%	0.0	0.00%	0
	NPL Nantahala	80,304	80,304	100.00%	0%	0.0	0.00%	0
	NPL Queens Creek	5,782	5,782	100.00%	0%	0.0	0.00%	0
	NPL Tennessee Creek	711	696	97.89%	0%	15.0	0.14%	1
	NPL Thorpe	47,127	47,127	100.00%	0%	0.0	0.00%	0
	NPL Tuckasegee	1,518	1,518	100.00%	0%	0.0	0.00%	0
	Total Account 330	*23,315,583*	*19,419,577*	*83.29%*	*0%*	*27.6*	*0.60%*	*140,973*
340.00	Rights of Way							
	Dan River CC	7,693	4,126	53.63%	0%	11.0	4.22%	324
	Total Account 340	*7,693*	*4,126*	*53.63%*	*0%*	*11.0*	*4.22%*	*324*
350.00	Rights of Way	163,883,264	82,968,907	50.63%	0%	48.6	1.02%	1,664,904
360.00	Rights of Way	9,328,937	1,988,129	21.31%	0%	63.3	1.24%	115,969
360.20	Land Rights	561,560	315,443	56.17%	0%	35.8	1.22%	6,875
389.00	Rights of Way	550,127	255,293	46.41%	0%	41.0	1.31%	7,191
389.20	Land Rights	165	82	49.70%	0%	41.5	1.21%	2
	Total Depreciable Land Rights	**200,607,727**	**107,621,688**	**53.65%**	**0%**	**47.8**	**0.97%**	**1,944,194**
	Reserve Adjustment for Amortization							

Duke Energy Carolinas
Table 4: Calculation of Depreciation Rates
As of December 31, 2021

Account	Description	12/31/21 Investment	12/31/21 Book Reserve	Percent Reserve	Future Net Salvage Percent	Remaining Life	Total Annual Rate	Total Annual Accrual
	A	B	C	D	E	F	G	H
391.00	Office Furniture and Equipment		6,102,422					(1,220,484)
391.10	Office Furniture and Equipment - EDP		11,798,132					(2,359,626)
393.00	Stores Equipment		1,981,666					(396,333)
394.00	Tools, Shop, and Garage Equipment		11,548,499					(2,309,700)
395.00	Laboratory Equipment		1,078,366					(215,673)
397.00	Communication Equipment		23,424,173					(4,684,835)
398.00	Miscellaneous Equipment		(575,929)					115,186
	Total Reserve Adjustment for Amortization		**55,357,329**					**(11,071,465)**
	Total Depreciable Plant	**44,223,118,782**	**17,225,688,362**	**38.95%**	**-9%**	**23.5**	**2.99%**	**1,323,554,157**

Duke Energy Carolinas
Table 5: Current and Proposed Parameters
As of December 31, 2021

		Current Approved				DEC Proposed					Public Staff Proposed				
Account	Description	AYFR	Proj Life	Iowa Curve Shape	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
	Steam Production Plant														
311.00	Structures and Improvements														
	Marshall Unit 1	06-2034	100	S0 5	-5%	12-2028	90	S1	6.8	-3%	12-2034	90	S1	12.3	-3%
	Marshall Unit 2	06-2034	100	S0 5	-5%	12-2028	90	S1	6.8	-4%	12-2034	90	S1	12.3	-3%
	Marshall Unit 3	06-2034	100	S0 5	-5%	12-2032	90	S1	10.6	-4%	12-2034	90	S1	12.5	-4%
	Marshall Unit 4	06-2034	100	S0 5	-5%	12-2032	90	S1	10.6	-4%	12-2034	90	S1	12.4	-4%
	Marshall Common	06-2034	100	S0 5	-5%	12-2032	90	S1	11 0	-4%	12-2034	90	S1	12.9	-3%
	Belews Creek Unit 1	06-2037	100	S0 5	-6%	12-2035	90	S1	13.7	-6%	12-2038	90	S1	16.5	-6%
	Belews Creek Unit 2	06-2037	100	S0 5	-6%	12-2035	90	S1	13 8	-6%	12-2038	90	S1	16.7	-6%
	Belews Creek Common	06-2037	100	S0 5	-6%	12-2035	90	S1	13 9	-6%	12-2038	90	S1	16.9	-6%
	Cliffside 5 (J.E. Rogers)	06-2026	100	S0 5	-5%	12-2025	90	S1	4.0	-5%	12-2032	90	S1	10.9	-5%
	Cliffside 6 (J.E. Rogers)	06-2048	100	S0 5	-6%	12-2048	90	S1	26.4	-8%	12-2048	90	S1	26.4	-7%
	Cliffside 5 and 6 Common (J.E. Rogers)	06-2048	100	S0 5	-5%	12-2048	90	S1	26.6	-6%	12-2048	90	S1	26.6	-5%
	Allen	06-2024	100	S0 5	-4%	12-2023	90	S1	2.0	-5%	12-2023	90	S1	2.0	-4%
	Total Structures and Improvements														
312.00	Boiler Plant Equipment														
	Marshall Unit 1	06-2034	47	R2	-5%	12-2028	47	R2	6.9	-3%	12-2034	47	R2	12.4	-3%
	Marshall Unit 2	06-2034	47	R2	-5%	12-2028	47	R2	6.8	-4%	12-2034	47	R2	12.4	-3%
	Marshall Unit 3	06-2034	47	R2	-5%	12-2032	47	R2	10.6	-4%	12-2034	47	R2	12.4	-4%
	Marshall Unit 4	06-2034	47	R2	-5%	12-2032	47	R2	10.6	-4%	12-2034	47	R2	12.4	-4%
	Marshall Common	06-2034	47	R2	-5%	12-2032	47	R2	10.7	-4%	12-2034	47	R2	12.6	-3%
	Belews Creek Unit 1	06-2037	47	R2	-6%	12-2035	47	R2	13.4	-6%	12-2038	47	R2	16.0	-6%
	Belews Creek Unit 2	06-2037	47	R2	-6%	12-2035	47	R2	13.4	-6%	12-2038	47	R2	16.0	-6%
	Belews Creek Common	06-2037	47	R2	-6%	12-2035	47	R2	13 3	-6%	12-2038	47	R2	15.9	-6%
	Cliffside 5 (J.E. Rogers)	06-2026	47	R2	-5%	12-2025	47	R2	4.0	-5%	12-2032	47	R2	10.6	-5%
	Cliffside 6 (J.E. Rogers)	06-2048	47	R2	-6%	12-2048	47	R2	24 5	-8%	12-2048	47	R2	24.5	-7%
	Cliffside 5 and 6 Common (J.E. Rogers)	06-2048	47	R2	-5%	12-2048	47	R2	24.6	-6%	12-2048	47	R2	24.6	-5%
	Allen	06-2024	47	R2	-4%	12-2023	47	R2	2.0	-5%	12-2023	47	R2	2.0	-4%
	Total Boiler Plant Equipment														
314.00	Turbogenerator Units														
	Marshall Unit 1	06-2034	50	R2	-5%	12-2028	50	S0.5	6.9	-3%	12-2034	50	S0.5	12.6	-3%
	Marshall Unit 2	06-2034	50	R2	-5%	12-2028	50	S0.5	6.8	-4%	12-2034	50	S0.5	12.5	-3%
	Marshall Unit 3	06-2034	50	R2	-5%	12-2032	50	S0.5	10 5	-4%	12-2034	50	S0.5	12.4	-4%
	Marshall Unit 4	06-2034	50	R2	-5%	12-2032	50	S0.5	10 5	-4%	12-2034	50	S0.5	12.3	-4%
	Marshall Common	06-2034	50	R2	-5%	12-2032	50	S0.5	10 3	-4%	12-2034	50	S0.5	12.2	-3%
	Belews Creek Unit 1	06-2037	50	R2	-6%	12-2035	50	S0.5	13 3	-6%	12-2038	50	S0.5	16.0	-6%
	Belews Creek Unit 2	06-2037	50	R2	-6%	12-2035	50	S0.5	13 3	-6%	12-2038	50	S0.5	16.0	-6%
	Belews Creek Common	06-2037	50	R2	-6%	12-2035	50	S0.5	12.6	-6%	12-2038	50	S0.5	15.2	-6%
	Cliffside 5 (J.E. Rogers)	06-2026	50	R2	-5%	12-2025	50	S0.5	3.9	-5%	12-2032	50	S0.5	10.4	-5%
	Cliffside 6 (J.E. Rogers)	06-2048	50	R2	-6%	12-2048	50	S0.5	23 9	-8%	12-2048	50	S0.5	24.0	-7%
	Allen	06-2024	50	R2	-4%	12-2023	50	S0.5	2.0	-5%	12-2023	50	S0.5	2.0	-4%
	Shared Department Plant	06-2048	50	R2	-5%	12-2048	50	S0.5	22 9	-10%	12-2048	50	S0.5	22.9	-10%
	Total Turbogenerator Units														
315.00	Accessory Electric Equipment														
	Marshall Unit 1	06-2034	60	S1	-5%	12-2028	60	S1	6.9	-3%	12-2034	60	S1	12.5	-3%
	Marshall Unit 2	06-2034	60	S1	-5%	12-2028	60	S1	6.9	-4%	12-2034	60	S1	12.7	-3%
	Marshall Unit 3	06-2034	60	S1	-5%	12-2032	60	S1	10 5	-4%	12-2034	60	S1	12.3	-4%
	Marshall Unit 4	06-2034	60	S1	-5%	12-2032	60	S1	10 5	-4%	12-2034	60	S1	12.3	-4%
	Marshall Common	06-2034	60	S1	-5%	12-2032	60	S1	10.7	-4%	12-2034	60	S1	12.6	-3%
	Belews Creek Unit 1	06-2037	60	S1	-6%	12-2035	60	S1	13 5	-6%	12-2038	60	S1	16.2	-6%
	Belews Creek Unit 2	06-2037	60	S1	-6%	12-2035	60	S1	13 5	-6%	12-2038	60	S1	16.1	-6%
	Belews Creek Common	06-2037	60	S1	-6%	12-2035	60	S1	13.1	-6%	12-2038	60	S1	15.8	-6%
	Cliffside 5 (J.E. Rogers)	06-2026	60	S1	-5%	12-2025	60	S1	3.9	-5%	12-2032	60	S1	10.5	-5%
	Cliffside 6 (J.E. Rogers)	06-2048	60	S1	-6%	12-2048	60	S1	25 3	-8%	12-2048	60	S1	25.3	-7%
	Cliffside 5 and 6 Common (J.E. Rogers)	06-2048	60	S1	-5%	12-2048	60	S1	26.1	-6%	12-2048	60	S1	26.1	-5%
	Allen	06-2024	60	S1	-4%	12-2023	60	S1	2.0	-5%	12-2023	60	S1	2.0	-4%
	Total Accessory Electric Equipment														
316.00	Miscellaneous Power Plant Equipment														
	Marshall Unit 1	06-2034	45	R2.5	-5%	12-2028	45	R2.5	6.8	-3%	12-2034	45	R2 5	12.4	-3%
	Marshall Unit 2	06-2034	45	R2.5	-5%	12-2028	45	R2.5	6.6	-4%	12-2034	45	R2 5	11.6	-3%
	Marshall Unit 3	06-2034	45	R2.5	-5%	12-2032	45	R2.5	10.7	-4%	12-2034	45	R2 5	12.5	-4%

Duke Energy Carolinas
Table 5: Current and Proposed Parameters
As of December 31, 2021

		Current Approved				DEC Proposed					Public Staff Proposed				
Account	Description	AYFR	Proj Life	Iowa Curve Shape	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
	Marshall Unit 4	06-2034	45	R2.5	-5%	12-2032	45	R2.5	10 5	-4%	12-2034	45	R2 5	12.3	-4%
	Marshall Common	06-2034	45	R2.5	-5%	12-2032	45	R2.5	10.6	-4%	12-2034	45	R2 5	12.5	-3%
	Belews Creek Unit 1	06-2037	45	R2.5	-6%	12-2035	45	R2.5	13 5	-6%	12-2038	45	R2 5	16.2	-6%
	Belews Creek Unit 2	06-2037	45	R2.5	-6%	12-2035	45	R2.5	13.6	-6%	12-2038	45	R2 5	16.3	-6%
	Belews Creek Common	06-2037	45	R2.5	-6%	12-2035	45	R2.5	13.4	-6%	12-2038	45	R2 5	16.2	-6%
	Cliffside 5 (J.E. Rogers)	06-2026	45	R2.5	-5%	12-2025	45	R2.5	4.0	-5%	12-2032	45	R2 5	10.6	-5%
	Cliffside 6 (J.E. Rogers)	06-2048	45	R2.5	-6%	12-2048	45	R2.5	24.7	-8%	12-2048	45	R2 5	24.7	-7%
	Cliffside 5 and 6 Common (J.E. Rogers)	06-2048	45	R2.5	-5%	12-2048	45	R2.5	25 3	-6%	12-2048	45	R2 5	25.3	-5%
	Allen	06-2024	45	R2.5	-4%	12-2023	45	R2.5	2.0	-5%	12-2023	45	R2 5	2.0	-4%
	Shared Department Plant	06-2048	45	R2.5	-5%	12-2048	45	R2.5	25 0	-10%	12-2048	45	R2 5	25.0	-10%
	Total Miscellaneous Power Plant Equipment														
	Total Steam Production Plant														
	Nuclear Production Plant														
321.00	Structures and Improvements														
	Oconee	07-2054	55	S1 5	-4%	07-2054	55	S1.5	29 0	-4%	07-2054	55	S1.5	29.0	-4%
	McGuire	03-2063	55	S1 5	-7%	03-2063	55	S1.5	28 9	-8%	03-2063	55	S1.5	28.9	-8%
	Catawba	12-2063	55	S1 5	-7%	12-2063	55	S1.5	28.7	-8%	12-2063	55	S1.5	28.7	-8%
	Total Structures and Improvements														
322.00	Reactor Plant Equipment														
	Oconee	07-2054	45	R2	-4%	07-2054	45	R2	27.4	-4%	07-2054	45	R2	27.4	-4%
	McGuire	03-2063	45	R2	-7%	03-2063	45	R2	26 8	-8%	03-2063	45	R2	26.8	-8%
	Catawba	12-2063	45	R2	-7%	12-2063	45	R2	25 3	-8%	12-2063	45	R2	25.3	-8%
	Total Reactor Plant Equipment														
323.00	Turbogenerator Units														
	Oconee	07-2054	45	R2	-4%	07-2054	40	R2	25 2	-4%	07-2054	40	R2	25.2	-4%
	McGuire	03-2063	45	R2	-7%	03-2063	40	R2	25.6	-8%	03-2063	40	R2	25.6	-8%
	Catawba	12-2063	45	R2	-7%	12-2063	40	R2	21 5	-8%	12-2063	40	R2	21.5	-8%
	Total Turbogenerator Units														
324.00	Accessory Electric Equipment														
	Oconee	07-2054	50	R2.5	-4%	07-2054	45	R3	28 9	-4%	07-2054	45	R3	28.9	-4%
	McGuire	03-2063	50	R2.5	-7%	03-2063	45	R3	28 2	-8%	03-2063	45	R3	28.2	-8%
	Catawba	12-2063	50	R2.5	-7%	12-2063	45	R3	26 2	-8%	12-2063	45	R3	26.2	-8%
	Shared Department Plant					12-2063	45	R3	31.7	-10%	12-2063	45	R3	31.7	-10%
	Total Accessory Electric Equipment														
325.00	Miscellaneous Power Plant Equipment														
	Oconee	07-2054	50	R2.5	-4%	07-2054	50	R2.5	28 3	-4%	07-2054	50	R2 5	28.3	-4%
	McGuire	03-2063	50	R2.5	-7%	03-2063	50	R2.5	32.1	-8%	03-2063	50	R2 5	32.1	-8%
	Catawba	12-2063	50	R2.5	-7%	12-2063	50	R2.5	31.4	-8%	12-2063	50	R2 5	31.4	-8%
	Shared Department Plant	12-2063	50	R2.5	-5%	12-2063	50	R2.5	36 9	-5%	12-2063	50	R2 5	36.9	-5%
	Total Miscellaneous Power Plant Equipment														
	Total Nuclear Production Plant														
	Hydarulic Production Plant														
331.00	Structures and Improvements														
	Cowans Ford	06-2055	75	S2	-11%	10-2055	75	S2	30 5	-4%	10-2055	75	S2	30.5	-4%
	Bad Creek	06-2058	75	S2	-6%	07-2067	75	S2	37 2	-9%	07-2067	75	S2	37.2	-8%
	Jocassee	06-2046	75	S2	-4%	08-2046	75	S2	23.6	-1%	08-2046	75	S2	23.6	-1%
	Keowee	06-2046	75	S2	-5%	08-2046	75	S2	24 5	-3%	08-2046	75	S2	24.5	-2%
	Fishing Creek	06-2055	75	S2	-16%	10-2055	75	S2	32 3	-13%	10-2055	75	S2	32.3	-11%
	Cedar Creek	06-2055	75	S2	-15%	10-2055	75	S2	31 9	-14%	10-2055	75	S2	31.9	-12%
	Bridgewater	06-2055	75	S2	-3%	10-2055	75	S2	32 9	-3%	10-2055	75	S2	32.9	-2%
	Lookout Shoals	06-2055	75	S2	-22%	10-2055	75	S2	31 5	-21%	10-2055	75	S2	31.5	-19%
	Mountain Island	06-2055	75	S2	-22%	10-2055	75	S2	32.7	-16%	10-2055	75	S2	32.7	-14%
	99 Islands	06-2036	75	S2	-17%	05-2036	75	S2	14 3	-15%	05-2036	75	S2	14.3	-13%
	Oxford	06-2055	75	S2	-7%	10-2055	75	S2	31.4	-7%	10-2055	75	S2	31.4	-6%
	Rhodhiss	06-2055	75	S2	-16%	10-2055	75	S2	32 5	-13%	10-2055	75	S2	32.5	-11%
	Wateree	06-2055	75	S2	-15%	10-2055	75	S2	32 5	-13%	10-2055	75	S2	32.5	-12%

Duke Energy Carolinas
Table 5: Current and Proposed Parameters
As of December 31, 2021

		Current Approved				DEC Proposed					Public Staff Proposed				
				Iowa	Future			Iowa	Avg				Iowa	Avg	
			Proj	Curve	Net		Proj	Curve	Rem	Future Net		Proj	Curve	Rem	Future Net
Account	Description	AYFR	Life	Shape	Salvage	AYFR	Life	Shape	Life	Salvage	AYFR	Life	Shape	Life	Salvage
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
	Wylie	06-2055	75	S2	-14%	10-2055	75	S2	32 0	-10%	10-2055	75	S2	32.0	-9%
	Great Falls	06-2055	75	S2	-100%	10-2055	75	S2	30.7	-108%	10-2055	75	S2	30.7	-95%
	Dearborn	06-2055	75	S2	-23%	10-2055	75	S2	30.7	-19%	10-2055	75	S2	30.7	-16%
	NPL Bear Creek	06-2041	75	S2	-10%	04-2041	75	S2	19 2	-8%	04-2041	75	S2	19.2	-7%
	NPL Cedar Cliff	06-2041	75	S2	-22%	04-2041	75	S2	19 2	-17%	04-2041	75	S2	19.2	-15%
	NPL Nantahala	06-2042	75	S2	-10%	01-2042	75	S2	19 8	-10%	01-2042	75	S2	19.8	-9%
	NPL Queens Creek	06-2032	75	S2	-72%	02-2032	75	S2	10.1	-95%	02-2032	75	S2	10.1	-82%
	NPL Tennessee Creek	06-2041	75	S2	-18%	04-2041	75	S2	18 8	-11%	04-2041	75	S2	18.8	-10%
	NPL Thorpe	06-2041	75	S2	-16%	04-2041	75	S2	19.1	-36%	04-2041	75	S2	19.1	-31%
	NPL Tuckasegee	06-2041	75	S2	-30%	04-2041	75	S2	19 2	-55%	04-2041	75	S2	19.2	-51%
	Shared Department Plant	06-2042	75	S2	-25%	01-2042	75	S2	19 8	-25%	01-2042	75	S2	19.8	-25%
	Total Structures and Improvements														
332.00	Reservoirs, Dams, and Waterways														
	Cowans Ford	06-2055	100	S2 5	-11%	10-2055	100	S2.5	32 9	-4%	10-2055	100	S2.5	32.9	-4%
	Bad Creek	06-2058	100	S2 5	-6%	07-2067	100	S2.5	42 8	-9%	07-2067	100	S2.5	42.8	-8%
	Jocassee	06-2046	100	S2 5	-4%	08-2046	100	S2.5	24 0	-1%	08-2046	100	S2.5	24.0	-1%
	Keowee	06-2046	100	S2 5	-5%	08-2046	100	S2.5	23.4	-3%	08-2046	100	S2.5	23.4	-2%
	Fishing Creek	06-2055	100	S2 5	-16%	10-2055	100	S2.5	33 5	-13%	10-2055	100	S2.5	33.5	-11%
	Cedar Creek	06-2055	100	S2 5	-15%	10-2055	100	S2.5	33.4	-14%	10-2055	100	S2.5	33.4	-12%
	Bridgewater	06-2055	100	S2 5	-3%	10-2055	100	S2.5	33.7	-3%	10-2055	100	S2.5	33.7	-2%
	Lookout Shoals	06-2055	100	S2 5	-22%	10-2055	100	S2.5	32 9	-21%	10-2055	100	S2.5	32.9	-19%
	Mountain Island	06-2055	100	S2 5	-22%	10-2055	100	S2.5	33 5	-16%	10-2055	100	S2.5	33.5	-14%
	99 Islands	06-2036	100	S2 5	-17%	05-2036	100	S2.5	14.4	-15%	05-2036	100	S2.5	14.4	-13%
	Oxford	06-2055	100	S2 5	-7%	10-2055	100	S2.5	33 5	-7%	10-2055	100	S2.5	33.5	-6%
	Rhodhiss	06-2055	100	S2 5	-16%	10-2055	100	S2.5	33.4	-13%	10-2055	100	S2.5	33.4	-11%
	Wateree	06-2055	100	S2 5	-15%	10-2055	100	S2.5	33 0	-13%	10-2055	100	S2.5	33.0	-12%
	Wylie	06-2055	100	S2 5	-14%	10-2055	100	S2.5	33 5	-10%	10-2055	100	S2.5	33.5	-9%
	Great Falls	06-2055	100	S2 5	-100%	10-2055	100	S2.5	32.6	-108%	10-2055	100	S2.5	32.6	-95%
	Dearborn	06-2055	100	S2 5	-23%	10-2055	100	S2.5	33 3	-19%	10-2055	100	S2.5	33.3	-16%
	NPL Bear Creek	06-2041	100	S2 5	-10%	04-2041	100	S2.5	19 3	-8%	04-2041	100	S2.5	19.3	-7%
	NPL Cedar Cliff	06-2041	100	S2 5	-22%	04-2041	100	S2.5	19 3	-17%	04-2041	100	S2.5	19.3	-15%
	NPL Nantahala	06-2042	100	S2 5	-10%	01-2042	100	S2.5	19 9	-10%	01-2042	100	S2.5	19.9	-9%
	NPL Queens Creek	06-2032	100	S2 5	-72%	02-2032	100	S2.5	10 2	-95%	02-2032	100	S2.5	10.2	-82%
	NPL Tennessee Creek	06-2041	100	S2 5	-18%	04-2041	100	S2.5	19 3	-11%	04-2041	100	S2.5	19.3	-10%
	NPL Thorpe	06-2041	100	S2 5	-16%	04-2041	100	S2.5	19.1	-36%	04-2041	100	S2.5	19.1	-31%
	NPL Tuckasegee	06-2041	100	S2 5	-30%	04-2041	100	S2.5	19 3	-55%	04-2041	100	S2.5	19.3	-51%
	Shared Department Plant	06-2042	100	S2 5	-25%	01-2042	100	S2.5	19 9	-25%	01-2042	100	S2.5	19.9	-25%
	Total Reservoirs, Dams, and Waterways														
333.00	Water Wheels, Turbines, and Generators														
	Cowans Ford	06-2055	65	S1	-11%	10-2055	60	L2	30 3	-4%	10-2055	60	L2	30.3	-4%
	Bad Creek	06-2058	65	S1	-6%	07-2067	60	L2	34.1	-9%	07-2067	60	L2	34.1	-8%
	Jocassee	06-2046	65	S1	-4%	08-2046	60	L2	22.1	-1%	08-2046	60	L2	22.1	-1%
	Keowee	06-2046	65	S1	-5%	08-2046	60	L2	23 8	-3%	08-2046	60	L2	23.8	-2%
	Fishing Creek	06-2055	65	S1	-16%	10-2055	60	L2	26 9	-13%	10-2055	60	L2	26.9	-11%
	Cedar Creek	06-2055	65	S1	-15%	10-2055	60	L2	28 9	-14%	10-2055	60	L2	28.9	-12%
	Bridgewater	06-2055	65	S1	-3%	10-2055	60	L2	30 5	-3%	10-2055	60	L2	30.5	-2%
	Lookout Shoals	06-2055	65	S1	-22%	10-2055	60	L2	27 2	-21%	10-2055	60	L2	27.2	-19%
	Mountain Island	06-2055	65	S1	-22%	10-2055	60	L2	28 2	-16%	10-2055	60	L2	28.2	-14%
	99 Islands	06-2036	65	S1	-17%	05-2036	60	L2	14.1	-15%	05-2036	60	L2	14.1	-13%
	Oxford	06-2055	65	S1	-7%	10-2055	60	L2	29.7	-7%	10-2055	60	L2	29.7	-6%
	Rhodhiss	06-2055	65	S1	-16%	10-2055	60	L2	29 9	-13%	10-2055	60	L2	29.9	-11%
	Wateree	06-2055	65	S1	-15%	10-2055	60	L2	27.4	-13%	10-2055	60	L2	27.4	-12%
	Wylie	06-2055	65	S1	-14%	10-2055	60	L2	29.7	-10%	10-2055	60	L2	29.7	-9%
	Great Falls	06-2055	65	S1	-100%	10-2055	60	L2	24 5	-108%	10-2055	60	L2	24.5	-95%
	Dearborn	06-2055	65	S1	-23%	10-2055	60	L2	27 0	-19%	10-2055	60	L2	27.0	-16%
	NPL Bear Creek	06-2041	65	S1	-10%	04-2041	60	L2	19 0	-8%	04-2041	60	L2	19.0	-7%
	NPL Cedar Cliff	06-2041	65	S1	-22%	04-2041	60	L2	18.7	-17%	04-2041	60	L2	18.7	-15%
	NPL Nantahala	06-2042	65	S1	-10%	01-2042	60	L2	18.4	-10%	01-2042	60	L2	18.4	-9%
	NPL Queens Creek	06-2032	65	S1	-72%	02-2032	60	L2	8.5	-95%	02-2032	60	L2	8.5	-82%
	NPL Tennessee Creek	06-2041	65	S1	-18%	04-2041	60	L2	19.1	-11%	04-2041	60	L2	19.1	-10%
	NPL Thorpe	06-2041	65	S1	-16%	04-2041	60	L2	13 2	-36%	04-2041	60	L2	13.2	-31%
	NPL Tuckasegee	06-2041	65	S1	-30%	04-2041	60	L2	16 9	-55%	04-2041	60	L2	16.9	-51%
	Total Water Wheels, Turbines, and Generators														

Duke Energy Carolinas
Table 5: Current and Proposed Parameters
As of December 31, 2021

		Current Approved				DEC Proposed					Public Staff Proposed				
Account	Description	AYFR	Proj Life	Iowa Curve Shape	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
334.00	Accessory Electric Equipment														
	Cowans Ford	06-2055	65	S1	-11%	10-2055	60	S1	30.7	-4%	10-2055	60	S1	30.7	-4%
	Bad Creek	06-2058	65	S1	-6%	07-2067	60	S1	31 2	-9%	07-2067	60	S1	31.2	-8%
	Jocassee	06-2046	65	S1	-4%	08-2046	60	S1	22.7	-1%	08-2046	60	S1	22.7	-1%
	Keowee	06-2046	65	S1	-5%	08-2046	60	S1	22 3	-3%	08-2046	60	S1	22.3	-2%
	Fishing Creek	06-2055	65	S1	-16%	10-2055	60	S1	28 0	-13%	10-2055	60	S1	28.0	-11%
	Cedar Creek	06-2055	65	S1	-15%	10-2055	60	S1	28 8	-14%	10-2055	60	S1	28.8	-12%
	Bridgewater	06-2055	65	S1	-3%	10-2055	60	S1	30 5	-3%	10-2055	60	S1	30.5	-2%
	Lookout Shoals	06-2055	65	S1	-22%	10-2055	60	S1	26 5	-21%	10-2055	60	S1	26.5	-19%
	Mountain Island	06-2055	65	S1	-22%	10-2055	60	S1	28.7	-16%	10-2055	60	S1	28.7	-14%
	99 Islands	06-2036	65	S1	-17%	05-2036	60	S1	13 5	-15%	05-2036	60	S1	13.5	-13%
	Oxford	06-2055	65	S1	-7%	10-2055	60	S1	28 3	-7%	10-2055	60	S1	28.3	-6%
	Rhodhiss	06-2055	65	S1	-16%	10-2055	60	S1	27.7	-13%	10-2055	60	S1	27.7	-11%
	Wateree	06-2055	65	S1	-15%	10-2055	60	S1	29 0	-13%	10-2055	60	S1	29.0	-12%
	Wylie	06-2055	65	S1	-14%	10-2055	60	S1	27 5	-10%	10-2055	60	S1	27.5	-9%
	Great Falls	06-2055	65	S1	-100%	10-2055	60	S1	18.4	-108%	10-2055	60	S1	18.4	-95%
	Dearborn	06-2055	65	S1	-23%	10-2055	60	S1	27 9	-19%	10-2055	60	S1	27.9	-16%
	NPL Bear Creek	06-2041	65	S1	-10%	04-2041	60	S1	18 3	-8%	04-2041	60	S1	18.3	-7%
	NPL Cedar Cliff	06-2041	65	S1	-22%	04-2041	60	S1	18.7	-17%	04-2041	60	S1	18.7	-15%
	NPL Nantahala	06-2042	65	S1	-10%	01-2042	60	S1	19 3	-10%	01-2042	60	S1	19.3	-9%
	NPL Queens Creek	06-2032	65	S1	-72%	02-2032	60	S1	9.7	-95%	02-2032	60	S1	9.7	-82%
	NPL Tennessee Creek	06-2041	65	S1	-18%	04-2041	60	S1	19 0	-11%	04-2041	60	S1	19.0	-10%
	NPL Thorpe	06-2041	65	S1	-16%	04-2041	60	S1	18.1	-36%	04-2041	60	S1	18.1	-31%
	NPL Tuckasegee	06-2041	65	S1	-30%	04-2041	60	S1	18.4	-55%	04-2041	60	S1	18.4	-51%
	Total Accessory Electric Equipment														
335.00	Miscellaneous Power Plant Equipment														
	Cowans Ford	06-2055	55	R2	-11%	10-2055	57	R2	30 2	-4%	10-2055	57	R2	30.2	-4%
	Bad Creek	06-2058	55	R2	-6%	07-2067	57	R2	32.6	-9%	07-2067	57	R2	32.6	-8%
	Jocassee	06-2046	55	R2	-4%	08-2046	57	R2	22 2	-1%	08-2046	57	R2	22.2	-1%
	Keowee	06-2046	55	R2	-5%	08-2046	57	R2	23.1	-3%	08-2046	57	R2	23.1	-2%
	Fishing Creek	06-2055	55	R2	-16%	10-2055	57	R2	29 5	-13%	10-2055	57	R2	29.5	-11%
	Cedar Creek	06-2055	55	R2	-15%	10-2055	57	R2	30 3	-14%	10-2055	57	R2	30.3	-12%
	Bridgewater	06-2055	55	R2	-3%	10-2055	57	R2	30.7	-3%	10-2055	57	R2	30.7	-2%
	Lookout Shoals	06-2055	55	R2	-22%	10-2055	57	R2	29.1	-21%	10-2055	57	R2	29.1	-19%
	Mountain Island	06-2055	55	R2	-22%	10-2055	57	R2	29.1	-16%	10-2055	57	R2	29.1	-14%
	99 Islands	06-2036	55	R2	-17%	05-2036	57	R2	14 0	-15%	05-2036	57	R2	14.0	-13%
	Oxford	06-2055	55	R2	-7%	10-2055	57	R2	29 8	-7%	10-2055	57	R2	29.8	-6%
	Rhodhiss	06-2055	55	R2	-16%	10-2055	57	R2	28 9	-13%	10-2055	57	R2	28.9	-11%
	Wateree	06-2055	55	R2	-15%	10-2055	57	R2	30 2	-13%	10-2055	57	R2	30.2	-12%
	Wylie	06-2055	55	R2	-14%	10-2055	57	R2	30.6	-10%	10-2055	57	R2	30.6	-9%
	Great Falls	06-2055	55	R2	-100%	10-2055	57	R2	30.4	-108%	10-2055	57	R2	30.4	-95%
	Dearborn	06-2055	55	R2	-23%	10-2055	57	R2	30.1	-19%	10-2055	57	R2	30.1	-16%
	NPL Bear Creek	06-2041	55	R2	-10%	04-2041	57	R2	18.6	-8%	04-2041	57	R2	18.6	-7%
	NPL Cedar Cliff	06-2041	55	R2	-22%	04-2041	57	R2	18.6	-17%	04-2041	57	R2	18.6	-15%
	NPL Nantahala	06-2042	55	R2	-10%	01-2042	57	R2	19 3	-10%	01-2042	57	R2	19.3	-9%
	NPL Queens Creek	06-2032	55	R2	-72%	02-2032	57	R2	9.9	-95%	02-2032	57	R2	9.9	-82%
	NPL Tennessee Creek	06-2041	55	R2	-18%	04-2041	57	R2	18 5	-11%	04-2041	57	R2	18.5	-10%
	NPL Thorpe	06-2041	55	R2	-16%	04-2041	57	R2	18.7	-36%	04-2041	57	R2	18.7	-31%
	NPL Tuckasegee	06-2041	55	R2	-30%	04-2041	57	R2	18.6	-55%	04-2041	57	R2	18.6	-51%
	Shared Department Plant	06-2042	55	R2	-5%	01-2042	57	R2	18 9	-5%	01-2042	57	R2	18.9	-5%
	Total Miscellaneous Power Plant Equipment														
336.00	Roads, Railroads, and Bridges														
	Cowans Ford	06-2055	75	R4	-11%	10-2055	75	R4	32.4	-4%	10-2055	75	R4	32.4	-4%
	Bad Creek	06-2058	75	R4	-6%	07-2067	75	R4	39 9	-9%	07-2067	75	R4	39.9	-8%
	Jocassee	06-2046	75	R4	-4%	08-2046	75	R4	21 2	-1%	08-2046	75	R4	21.2	-1%
	Dearborn	06-2055	75	R4	-23%	10-2055	75	R4	30 9	-19%	10-2055	75	R4	30.9	-16%
	NPL Bear Creek	06-2041	75	R4	-10%	04-2041	75	R4	13.1	-8%	04-2041	75	R4	13.1	-7%
	NPL Cedar Cliff	06-2041	75	R4	-22%	04-2041	75	R4	18.6	-17%	04-2041	75	R4	18.6	-15%
	NPL Nantahala	06-2042	75	R4	-10%	01-2042	75	R4	19 5	-10%	01-2042	75	R4	19.5	-9%
	NPL Queens Creek	06-2032	75	R4	-72%	02-2032	75	R4	0.0	-95%	02-2032	75	R4	0.0	-82%
	NPL Tennessee Creek	06-2041	75	R4	-18%	04-2041	75	R4	13 3	-11%	04-2041	75	R4	13.3	-10%
	NPL Thorpe	06-2041	75	R4	-16%	04-2041	75	R4	19 2	-36%	04-2041	75	R4	19.2	-31%
	NPL Tuckasegee	06-2041	75	R4	-30%	04-2041	75	R4	11.6	-55%	04-2041	75	R4	11.6	-51%
	Shared Department Plant	06-2042	75	R4	0%	01-2042	75	R4	0.0	0%	01-2042	75	R4	0.0	0%

Duke Energy Carolinas
Table 5: Current and Proposed Parameters
As of December 31, 2021

		Current Approved				DEC Proposed					Public Staff Proposed				
Account	Description	AYFR	Proj Life	Iowa Curve Shape	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
	Total Roads, Railroads, and Bridges														
	Total Hydarulic Production Plant														
	Other Production Plant														
341.00	Structures and Improvements														
	Lincoln CTs	06-2035	50	R3	-3%	12-2040	55	R3	17.6	-9%	12-2040	55	R3	17.6	-2%
	Dan River CC	06-2052	50	R3	-3%	06-2052	55	R3	28 9	-12%	06-2052	55	R3	28.9	-6%
	Lee CTs	06-2047	50	R3	-3%	06-2047	55	R3	25 0	-11%	06-2047	55	R3	25.0	-4%
	Mill Creek CTs	06-2043	50	R3	-3%	06-2043	55	R3	20 3	-8%	06-2043	55	R3	20.3	-1%
	Rockingham CTs	06-2040	50	R3	-1%	06-2040	55	R3	18 2	-4%	06-2040	55	R3	18.2	-1%
	Buck CC	06-2051	50	R3	-3%	06-2051	55	R3	28.1	-11%	06-2051	55	R3	28.1	-5%
	Lee CC	06-2058	50	R3	-4%	06-2058	55	R3	34.1	-12%	06-2058	55	R3	34.1	-5%
	Clemson CHP	12-2059	50	R3	-6%	12-2059	55	R3	36 2	-13%	12-2059	55	R3	36.2	-6%
	Lark Maintenance Facility					12-2059	55	R3	34 9	-5%	12-2059	55	R3	34.9	-5%
	Total Structures and Improvements														
341.66	Structures and Improvements - Solar														
	Mocksville	06-2041	40	S2 5	-10%	06-2046	40	S2.5	23 5	-11%	06-2046	40	S2.5	23.5	-9%
	Monroe					06-2047	40	S2.5	24.4	-14%	06-2047	40	S2.5	24.4	-12%
	Gaston					06-2050	40	S2.5	27.4	-12%	06-2050	40	S2.5	27.4	-9%
	Maiden Creek					06-2051	40	S2.5	28.4	-17%	06-2051	40	S2.5	28.4	-13%
	Total Structures and Improvements - Solar														
342.00	Fuel Holders, Producers, and Accessories														
	Lincoln CTs	06-2035	50	R2.5	-3%	12-2040	50	R2.5	17 0	-9%	12-2040	50	R2 5	17.0	-2%
	Dan River CC	06-2052	50	R2.5	-3%	06-2052	50	R2.5	28.1	-12%	06-2052	50	R2 5	28.1	-6%
	Lee CTS					06-2047	50	R2.5	24.6	-11%	06-2047	50	R2 5	24.6	-4%
	Mill Creek CTs	06-2043	50	R2.5	-3%	06-2043	50	R2.5	19.6	-8%	06-2043	50	R2 5	19.6	-1%
	Rockingham CTs	06-2040	50	R2.5	-1%	06-2040	50	R2.5	18 0	-4%	06-2040	50	R2 5	18.0	-1%
	Buck CC	06-2051	50	R2.5	-3%	06-2051	50	R2.5	27.1	-11%	06-2051	50	R2 5	27.1	-5%
	Lee CC	06-2058	50	R2.5	-4%	06-2058	50	R2.5	33.6	-12%	06-2058	50	R2 5	33.6	-5%
	Clemson CHP	12-2059	50	R2.5	-6%	12-2059	50	R2.5	34 9	-13%	12-2059	50	R2 5	34.9	-6%
	Total Fuel Holders, Producers, and Accessories														
343.00	Prime Movers														
	Lincoln CTs	06-2035	45	R1.5	-3%	12-2040	40	R1.5	15.6	-9%	12-2040	40	R1 5	15.6	-2%
	Dan River CC	06-2052	45	R1.5	-3%	06-2052	40	R1.5	25.4	-12%	06-2052	40	R1 5	25.4	-6%
	Lee CTs	06-2047	45	R1.5	-3%	06-2047	40	R1.5	21 3	-11%	06-2047	40	R1 5	21.3	-4%
	Mill Creek CTs	06-2043	45	R1.5	-3%	06-2043	40	R1.5	17 8	-8%	06-2043	40	R1 5	17.8	-1%
	Rockingham CTs	06-2040	45	R1.5	-1%	06-2040	40	R1.5	17 2	-4%	06-2040	40	R1 5	17.2	-1%
	Buck CC	06-2051	45	R1.5	-3%	06-2051	40	R1.5	24.6	-11%	06-2051	40	R1 5	24.6	-5%
	Lee CC	06-2058	45	R1.5	-4%	06-2058	40	R1.5	30 2	-12%	06-2058	40	R1 5	30.2	-5%
	Clemson CHP	12-2059	45	R1.5	-6%	12-2059	40	R1.5	31 3	-13%	12-2059	40	R1 5	31.3	-6%
	Total Prime Movers														
343.10	Prime Movers - Rotable Parts														
	Dan River CC	06-2052	5	R5	40%	06-2052	6	L4	2.5	40%	06-2052	6	L4	2.5	40%
	Buck CC	06-2051	5	R5	40%	06-2051	6	L4	2.8	40%	06-2051	6	L4	2.8	40%
	Lee CC					06-2058	6	L4	2.6	40%	06-2058	6	L4	2.6	40%
	Clemson CHP					12-2059	6	L4	3.5	40%	12-2059	6	L4	3.5	40%
	Total Prime Movers - Rotable Parts														
344.00	Generators														
	Lincoln CTs	06-2035	50	R2	-3%	12-2040	50	R2.5	16 8	-9%	12-2040	50	R2 5	16.8	-2%
	Dan River CC	06-2052	50	R2	-3%	06-2052	50	R2.5	28 0	-12%	06-2052	50	R2 5	28.0	-6%
	Lee CTs					06-2047	50	R2.5	24 2	-11%	06-2047	50	R2 5	24.2	-4%
	Mill Creek CTs	06-2043	50	R2	-3%	06-2043	50	R2.5	20 8	-8%	06-2043	50	R2 5	20.8	-1%
	On-Site Diesel Generators	06-2028	50	R2	0%	06-2028	50	R2.5	6.5	0%	06-2028	50	R2 5	6.5	0%
	Rockingham CTs	06-2040	50	R2	-1%	06-2040	50	R2.5	17 0	-4%	06-2040	50	R2 5	17.0	-1%
	Buck CC	06-2051	50	R2	-3%	06-2051	50	R2.5	27 0	-11%	06-2051	50	R2 5	27.0	-5%
	Lee CC	06-2058	50	R2	-4%	06-2058	50	R2.5	33.6	-12%	06-2058	50	R2 5	33.6	-5%
	Clemson CHP	12-2059	50	R2	-6%	12-2059	50	R2.5	35 0	-13%	12-2059	50	R2 5	35.0	-6%
	Total Generators														

Duke Energy Carolinas
Table 5: Current and Proposed Parameters
As of December 31, 2021

		Current Approved				DEC Proposed					Public Staff Proposed				
Account	Description	AYFR	Proj Life	Iowa Curve Shape	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
344.66	Generators - Solar														
	Community - Small		20	S2.5	0%		20	S2.5	9.4	0%		20	S2.5	9.4	0%
	Mocksville	06-2041	25	S2.5	-10%	06-2046	25	S2.5	18.5	-11%	06-2046	25	S2.5	18.5	-9%
	Monroe	06-2042	25	S2.5	-11%	06-2047	25	S2.5	19.5	-14%	06-2047	25	S2.5	19.5	-12%
	Woodleaf	06-2043	25	S2.5	-9%	06-2048	25	S2.5	20.5	-12%	06-2048	25	S2.5	20.5	-10%
	Gaston					06-2050	25	S2.5	22.5	-12%	06-2050	25	S2.5	22.5	-9%
	Maiden Creek					06-2051	25	S2.5	23.5	-17%	06-2051	25	S2.5	23.5	-13%
	Total Generators - Solar														
345.00	Accessory Electric Equipment														
	Lincoln CTs	06-2035	40	S0	-3%	12-2040	45	R1.5	16.5	-9%	12-2040	45	R1.5	16.5	-2%
	Dan River CC	06-2052	40	S0	-3%	06-2052	45	R1.5	26.3	-12%	06-2052	45	R1.5	26.3	-6%
	Lee CTs	06-2047	40	S0	-3%	06-2047	45	R1.5	23.4	-11%	06-2047	45	R1.5	23.4	-4%
	Mill Creek CTs	06-2043	40	S0	-3%	06-2043	45	R1.5	19.1	-8%	06-2043	45	R1.5	19.1	-1%
	Rockingham CTs	06-2040	40	S0	-1%	06-2040	45	R1.5	17.2	-4%	06-2040	45	R1.5	17.2	-1%
	Buck CC	06-2051	40	S0	-3%	06-2051	45	R1.5	25.5	-11%	06-2051	45	R1.5	25.5	-5%
	Lee CC	06-2058	40	S0	-4%	06-2058	45	R1.5	31.3	-12%	06-2058	45	R1.5	31.3	-5%
	Clemson CHP	12-2059	40	S0	-6%	12-2059	45	R1.5	32.5	-13%	12-2059	45	R1.5	32.5	-6%
	Total Accessory Electric Equipment														
345.66	Accessory Electric Equipment - Solar														
	Community - Small		20	S2.5	0%		20	S2.5	10.8	0%		20	S2.5	10.8	0%
	Mocksville	06-2041	25	S2.5	-10%	06-2046	25	S2.5	18.5	-11%	06-2046	25	S2.5	18.5	-9%
	Monroe	06-2042	25	S2.5	-11%	06-2047	25	S2.5	19.5	-14%	06-2047	25	S2.5	19.5	-12%
	Gaston					06-2050	25	S2.5	22.5	-12%	06-2050	25	S2.5	22.5	-9%
	Maiden Creek					06-2051	25	S2.5	23.5	-17%	06-2051	25	S2.5	23.5	-13%
	Total Accessory Electric Equipment - Solar														
346.00	Miscellaneous Power Plant Equipment														
	Lincoln CTs	06-2035	40	S1.5	-3%	12-2040	40	R2	17.1	-9%	12-2040	40	R2	17.1	-2%
	Dan River CC	06-2052	40	S1.5	-3%	06-2052	40	R2	26.0	-12%	06-2052	40	R2	26.0	-6%
	Lee CTs	06-2047	40	S1.5	-3%	06-2047	40	R2	23.3	-11%	06-2047	40	R2	23.3	-4%
	Mill Creek CTs	06-2043	40	S1.5	-3%	06-2043	40	R2	18.6	-8%	06-2043	40	R2	18.6	-1%
	Rockingham CTs	06-2040	40	S1.5	-1%	06-2040	40	R2	17.2	-4%	06-2040	40	R2	17.2	-1%
	Buck CC	06-2051	40	S1.5	-3%	06-2051	40	R2	25.4	-11%	06-2051	40	R2	25.4	-5%
	Lee CC	06-2058	40	S1.5	-4%	06-2058	40	R2	30.9	-12%	06-2058	40	R2	30.9	-5%
	Clemson CHP	12-2059	40	S1.5	-6%	12-2059	40	R2	32.0	-13%	12-2059	40	R2	32.0	-6%
	Lark Maintenance Facility					12-2059	40	R2	31.5	-5%	12-2059	40	R2	31.5	-5%
	Shared Department Plant	06-2058	40	S1.5	0%	12-2059	40	R2	30.4	-5%	12-2059	40	R2	30.4	-5%
	Total Miscellaneous Power Plant Equipment														
346.66	Miscellaneous Power Plant Equipment - Solar														
	Mocksville					06-2046	35	R2.5	23.1	-11%	06-2046	35	R2.5	23.1	-9%
	Monroe					06-2047	35	R2.5	23.7	-14%	06-2047	35	R2.5	23.7	-12%
	Woodleaf	06-2043	35	R2.5	-9%	06-2050	35	R2.5	24.7	-12%	06-2050	35	R2.5	24.7	-9%
	Maiden Creek					06-2051	35	R2.5	26.9	-17%	06-2051	35	R2.5	26.9	-13%
	Total Miscellaneous Power Plant Equipment - Solar														
	Total Other Production Plant														
	Total Production Plant														
	Transmission Plant														
352.00	Structures and Improvements		55	R2	-10%		43	R2	35.7	-10%		43	R2	35.7	-10%
353.00	Station Equipment		48	R1.5	-20%		45	R1.5	34.9	-15%		45	R1.5	34.9	-15%
354.00	Towers and Fixtures		75	R2	-50%		70	R2.5	51.5	-40%		70	R2.5	51.5	-40%
355.00	Poles and Fixtures		48	R1	-30%		48	R1	40.6	-40%		48	R1	40.6	-40%
356.00	Overhead Conductors and Devices		60	R2.5	-40%		60	R2.5	46.9	-40%		60	R2.5	46.9	-30%
357.00	Underground Conduit		55	S4	0%		55	S4	32.2	0%		55	S4	32.2	0%
358.00	Underground Conductors and Devices		50	S4	0%		40	S2	37.0	0%		40	S2	37.0	0%
359.00	Roads and Trails		65	R4	0%		65	R4	36.4	0%		65	R4	36.4	0%
	Total Transmission Plant														
	Distribution Plant														

Duke Energy Carolinas
Table 5: Current and Proposed Parameters
As of December 31, 2021

		Current Approved				DEC Proposed					Public Staff Proposed				
Account	Description	AYFR	Proj Life	Iowa Curve Shape	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
361.00	Structures and Improvements		55	S0 5	-10%		45	S0.5	37 9	-10%		45	S0.5	37.9	-10%
362.00	Station Equipment		44	R1	-20%		45	R1	37 0	-15%		45	R1	37.0	-15%
364.00	Poles, Towers, and Fixtures		50	R2	-30%		52	R2	37.4	-50%		52	R2	37.4	-50%
364.10	Poles, Towers, and Fixtures - Storm Securitization		50	R2	-30%										
365.00	Overhead Conductors and Devices		52	R0.5	-25%		52	R0.5	44 0	-30%		52	R0 5	44.0	-30%
365.10	Overhead Conductors and Devices - Storm Securitization		52	R0.5	-25%										
366.00	Underground Conduit		60	R3	-15%		65	R3	49.7	-20%		65	R3	49.7	-20%
367.00	Underground Conductors and Devices		55	R3	-20%		54	R3	41 0	-20%		54	R3	41.0	-20%
368.00	Line Transformers		45	R1.5	-10%		45	R1.5	33 2	-15%		45	R1 5	33.2	-15%
368.10	Line Transformers - Storm Securitization		45	R1.5	-10%										
369.00	Services		52	R1.5	-15%		55	R1.5	45.1	-25%		55	R1 5	45.1	-25%
370.00	Meters and Metering Equipment		17	L0	0%		13	L0	6.3	0%		13	L0	6.3	0%
370.02	Meters - Utility of the Future		15	S2 5	0%		15	S2.5	11.4	0%		15	S2.5	11.4	0%
371.00	Installations on Customers' Premises		40	R1	-5%		35	R1	26 9	-5%		35	R1	26.9	-5%
373.00	Street Lighting and Signal Systems		36	R0.5	-10%		36	R0.5	29.6	-10%		36	R0 5	29.6	-10%
	Total Distribution Plant														
	General Plant														
390.00	Structures and Improvements		40	S1	-10%		40	S0.5	30 8	-10%		40	S0.5	30.8	-10%
391.00	Office Furniture and Equipment														
	Fully Accrued														
	Amortized		15	SQ	0%		15	SQ	10 5	0%		15	SQ	10.5	0%
	Total Office Furniture and Equipment														
391.10	Office Furniture and Equipment - EDP		8	SQ	0%		8	SQ	4.4	0%		8	SQ	4.4	0%
392.00	Transportation Equipment														
392.10	Passenger Cars and Station Wagon		5	S2 5	10%		5	S2.5	0.0	10%		5	S2.5	0.0	10%
392.11	Light Trucks		6	L3	10%		6	L3	0.0	10%		6	L3	0.0	10%
392.12	Medium Trucks		8	L2	10%		8	L2	5.5	10%		8	L2	5.5	10%
392.13	Heavy Trucks		10	L2	10%		10	L2	0.0	10%		10	L2	0.0	10%
392.15	Heavy Trucks / Power Equipped		10	L2	10%		10	L2	0.0	10%		10	L2	0.0	10%
392.16	Tractors - Gasoline and Diesel		13	L3	10%		13	L3	0.0	10%		13	L3	0.0	10%
392.18	Trailers		16	L0 5	10%		16	L0.5	14 2	10%		16	L0.5	14.2	10%
	Total Transportation Equipment														
393.00	Stores Equipment														
	Fully Accrued														
	Amortized		20	SQ	0%		20	SQ	15 5	0%		20	SQ	15.5	0%
	Total Stores Equipment														
394.00	Tools, Shop, and Garage Equipment														
	Fully Accrued														
	Amortized		20	SQ	0%		20	SQ	14.4	0%		20	SQ	14.4	0%
	Total Tools, Shop, and Garage Equipment														
395.00	Laboratory Equipment		15	SQ	0%		15	SQ	7.8	0%		15	SQ	7.8	0%
396.00	Power Operated Equipment														
396.04	Mobile Cranes		19	S1 5	10%		19	S1.5	18 2	10%		19	S1.5	18.2	10%
396.07	Miscellaneous Non-Highway Equipment		13	L2	10%		13	L2.5	11.6	10%		13	L2.5	11.6	10%
396.09	Miscellaneous Equipment		13	L2	10%		13	L2.5	11.6	10%		13	L2.5	11.6	10%
	Total Power Operated Equipment														
397.00	Communication Equipment														
	Fully Accrued														
	Amortized		10	SQ	0%		10	SQ	7.1	0%		10	SQ	7.1	0%
	Total Communication Equipment														
398.00	Miscellaneous Equipment		20	SQ	0%		20	SQ	15.1	0%		20	SQ	15.1	0%
	Total General Plant														

Duke Energy Carolinas
Table 5: Current and Proposed Parameters
As of December 31, 2021

		Current Approved				DEC Proposed					Public Staff Proposed				
Account	Description	AYFR	Proj Life	Iowa Curve Shape	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
	Depreciable Land Rights														
310.00	Rights of Way														
	Marshall	06-2034	100	R4	0%	12-2032	100	R4	0.0	0%	12-2034	100	R4	12.7	0%
	Belews Creek	06-2037	100	R4	0%	12-2035	100	R4	0.0	0%	12-2038	100	R4	16.7	0%
	Lee	#REF!	100	R4	0%	#REF!	100	R4	0.0	0%	#REF!	100	R4	####	0%
	Allen	06-2024	100	R4	0%	12-2023	100	R4	0.0	0%	12-2023	100	R4	2.0	0%
	Total Account 310														
320.00	Rights of Way														
	Oconee	07-2054	100	R4	0%	07-2054	100	R4	30.1	0%	07-2054	100	R4	30.1	0%
	McGuire	03-2063	100	R4	0%	03-2063	100	R4	39 0	0%	03-2063	100	R4	39.0	0%
	Catawba	12-2063	100	R4	0%	12-2063	100	R4	40.4	0%	12-2063	100	R4	40.4	0%
	Total Account 320														
330.00	Rights of Way														
	Cowans Ford	06-2055	110	R4	0%	10-2055	110	R4	31.6	0%	10-2055	110	R4	31.6	0%
	Bad Creek	06-2058	110	R4	0%	07-2067	110	R4	44 5	0%	07-2067	110	R4	44.5	0%
	Jocassee	06-2046	110	R4	0%	08-2046	110	R4	24 2	0%	08-2046	110	R4	24.2	0%
	Keowee	06-2046	110	R4	0%	08-2046	110	R4	24 0	0%	08-2046	110	R4	24.0	0%
	Fishing Creek	06-2055	110	R4	0%	10-2055	110	R4	0.0	0%	10-2055	110	R4	0.0	0%
	Bridgewater	06-2055	110	R4	0%	10-2055	110	R4	0.0	0%	10-2055	110	R4	0.0	0%
	Lookout Shoals	06-2055	110	R4	0%	10-2055	110	R4	0.0	0%	10-2055	110	R4	0.0	0%
	Mountain Island	06-2055	110	R4	0%	10-2055	110	R4	34 0	0%	10-2055	110	R4	34.0	0%
	99 Islands	06-2036	110	R4	0%	05-2036	110	R4	0.0	0%	05-2036	110	R4	0.0	0%
	Oxford	06-2055	110	R4	0%	10-2055	110	R4	22 8	0%	10-2055	110	R4	22.8	0%
	Rhodhiss	06-2055	110	R4	0%	10-2055	110	R4	21.6	0%	10-2055	110	R4	21.6	0%
	Wateree	06-2055	110	R4	0%	10-2055	110	R4	0.0	0%	10-2055	110	R4	0.0	0%
	Wylie	06-2055	110	R4	0%	10-2055	110	R4	30 8	0%	10-2055	110	R4	30.8	0%
	NPL Bear Creek	06-2041	110	R4	0%	04-2041	110	R4	0.0	0%	04-2041	110	R4	0.0	0%
	NPL Nantahala	06-2042	110	R4	0%	01-2042	110	R4	0.0	0%	01-2042	110	R4	0.0	0%
	NPL Queens Creek	06-2032	110	R4	0%	02-2032	110	R4	0.0	0%	02-2032	110	R4	0.0	0%
	NPL Tennessee Creek	06-2041	110	R4	0%	04-2041	110	R4	15 0	0%	04-2041	110	R4	15.0	0%
	NPL Thorpe	06-2041	110	R4	0%	04-2041	110	R4	0.0	0%	04-2041	110	R4	0.0	0%
	NPL Tuckasegee	06-2041	110	R4	0%	04-2041	110	R4	0.0	0%	04-2041	110	R4	0.0	0%
	Total Account 330														
340.00	Rights of Way														
	Dan River CC	06-2052	60	R4	0%	06-2052	65	R4	11 0	0%	06-2052	65	R4	11.0	0%
	Total Account 340														
350.00	Rights of Way		80	R4	0%		80	R4	48.6	0%		80	R4	48.6	0%
360.00	Rights of Way		80	R3	0%		80	R3	63 3	0%		80	R3	63.3	0%
360.20	Land Rights		80	R3	0%		80	R3	35 8	0%		80	R3	35.8	0%
389.00	Rights of Way		60	R3	0%		65	R3	41 0	0%		65	R3	41.0	0%
389.20	Land Rights		60	R3	0%		65	R3	41 5	0%		65	R3	41.5	0%
	Total Depreciable Land Rights														

Duke Energy Carolinas
Table 6: Calculation of Weighted Net Salvage Percent for Generation Plant
As of December 31, 2021

	Terminal				Interim				Combined		
Location	Retirements ($)	Net Salvage ($)	Percent of Total Retire	Net Salvage (%)	Retirements ($)	Net Salvage ($)	Percent of Total Retire	Net Salvage (%)	Total Net Salvage ($)	Total Retirements	Estimated Net Salvage (%)
A	B	C	D = C/K	E = C/B	F	G = F*I	H = F/K	I	J = C+G	K = B+F	L = J/K
Steam Production											
Marshall Unit 1	(524,080,734)	12,625,812	96 23%	-2%	(20,509,290)	3,691,672	3.77%	-18%	16,317,485	(544,590,024)	-3%
Marshall Unit 2	(171,604,544)	4,134,185	94 36%	-2%	(10,255,952)	1,846,071	5.64%	-18%	5,980,257	(181,860,497)	-3%
Marshall Unit 3	(368,788,356)	8,884,609	91.42%	-2%	(34,601,851)	6,228,333	8.58%	-18%	15,112,943	(403,390,207)	-4%
Marshall Unit 4	(274,563,163)	6,614,597	90 64%	-2%	(28,346,010)	5,102,282	9.36%	-18%	11,716,879	(302,909,174)	-4%
Marshall Common	(553,402,879)	13,332,223	94 90%	-2%	(29,770,319)	5,358,657	5.10%	-18%	18,690,880	(583,173,198)	-3%
Marshall	*(1,892,439,677)*	*45,591,427*	*93.87%*	*-2%*	*(123,483,422)*	*22,227,016*	*6.13%*	*-18%*	*67,818,443*	*(2,015,923,099)*	*-3%*
Belews Creek Unit 1	(597,433,849)	26,873,156	91.07%	-4%	(58,614,327)	10,550,579	8.93%	-18%	37,423,735	(656,048,177)	-6%
Belews Creek Unit 2	(476,296,144)	21,424,264	90 89%	-4%	(47,761,910)	8,597,144	9.11%	-18%	30,021,408	(524,058,054)	-6%
Belews Creek Common	(1,161,407,118)	52,241,223	88 91%	-4%	(144,910,205)	26,083,837	11.09%	-18%	78,325,060	(1,306,317,323)	-6%
Belews Creek	*(2,235,137,112)*	*100,538,644*	*89.89%*	*-4%*	*(251,286,442)*	*45,231,560*	*10.11%*	*-18%*	*145,770,204*	*(2,486,423,554)*	*-6%*
Cliffside 5 (J.E. Rogers)	(776,196,947)	35,222,380	97 88%	-5%	(16,774,863)	3,019,475	2.12%	-18%	38,241,855	(792,971,810)	-5%
Cliffside 6 (J.E. Rogers)	(1,653,433,709)	75,029,759	78.71%	-5%	(447,236,996)	80,502,659	21.29%	-18%	155,532,418	(2,100,670,705)	-7%
Cliffside 5 and 6 Common (J.E. Rogers)	(160,866,694)	7,299,833	93 86%	-5%	(10,529,899)	1,895,382	6.14%	-18%	9,195,214	(171,396,593)	-5%
Cliffside (J.E. Rogers)	*(2,590,497,350)*	*117,551,971*	*84.52%*		*(474,541,758)*	*85,417,516*	*15.48%*	*-18%*	*202,969,487*	*(3,065,039,108)*	*-7%*
Allen	(888,949,746)	35,323,378	99 33%	-4%	(5,957,706)	1,072,387	0.67%	-18%	36,395,765	(894,907,452)	-4%
Total Steam Production	**(7,607,023,885)**	**#REF!**	**89.89%**	**0%**	**(855,269,329)**	**153,948,479**	**10.11%**	**-18%**	**452,953,899**	**(8,462,293,213)**	**-5%**
Nuclear Production Plant											
Oconee	(2,815,093,624)	0	59.55%	0%	(1,912,241,359)	191,224,136	40.45%	-10%	191,224,136	(4,727,334,983)	-4%
McGuire	(827,832,708)	0	23 68%	0%	(2,668,602,447)	266,860,245	76.32%	-10%	266,860,245	(3,496,435,155)	-8%
Catawba	(193,105,458)	0	21 39%	0%	(709,485,968)	70,948,597	78.61%	-10%	70,948,597	(902,591,426)	-8%
Total Nuclear Production	**(3,836,031,790)**	**0**	**42.03%**	**0%**	**(5,290,329,774)**	**529,032,977**	**57.97%**	**-10%**	**529,032,977**	**(9,126,361,563)**	**-6%**
Hydro Production Plant											
Cowans Ford	(109,426,780)	(1,610,885)	75.70%	1%	(35,135,805)	7,027,161	24.30%	-20%	5,416,276	(144,562,585)	-4%
Bad Creek	(653,132,267)	1,410,263	60.74%	0%	(422,208,897)	84,441,779	39.26%	-20%	85,852,042	(1,075,341,164)	-8%
Jocassee	(154,637,439)	(5,796,449)	81.07%	4%	(36,104,681)	7,220,936	18.93%	-20%	1,424,487	(190,742,120)	-1%
Keowee	(215,847,703)	258,996	89 31%	0%	(25,841,455)	5,168,291	10.69%	-20%	5,427,287	(241,689,159)	-2%
Fishing Creek	(41,487,800)	3,327,813	73.44%	-8%	(15,004,403)	3,000,881	26.56%	-20%	6,328,694	(56,492,203)	-11%

Duke Energy Carolinas
Table 6: Calculation of Weighted Net Salvage Percent for Generation Plant
As of December 31, 2021

	Terminal				Interim				Combined		
Location	Retirements ($)	Net Salvage ($)	Percent of Total Retire	Net Salvage (%)	Retirements ($)	Net Salvage ($)	Percent of Total Retire	Net Salvage (%)	Total Net Salvage ($)	Total Retirements	Estimated Net Salvage (%)
A	B	C	D = C/K	E = C/B	F	G = F*I	H = F/K	I	J = C+G	K = B+F	L = J/K
Cedar Creek	(27,362,546)	2,520,807	73 65%	-9%	(9,791,548)	1,958,310	26.35%	-20%	4,479,117	(37,154,093)	-12%
Bridgewater	(279,958,043)	3,009,803	92.53%	-1%	(22,589,007)	4,517,801	7.47%	-20%	7,527,604	(302,547,051)	-2%
Lookout Shoals	(14,126,714)	2,609,252	65 25%	-18%	(7,524,876)	1,504,975	34.75%	-20%	4,114,227	(21,651,591)	-19%
Mountain Island	(28,337,158)	3,263,562	73 29%	-12%	(10,327,500)	2,065,500	26.71%	-20%	5,329,062	(38,664,658)	-14%
99 Islands	(26,205,234)	3,253,240	94.77%	-12%	(1,446,821)	289,364	5.23%	-20%	3,542,604	(27,652,055)	-13%
Oxford	(52,727,625)	1,677,219	83.05%	-3%	(10,764,927)	2,152,985	16.95%	-20%	3,830,204	(63,492,552)	-6%
Rhodhiss	(28,654,198)	2,470,680	77.01%	-9%	(8,553,532)	1,710,706	22.99%	-20%	4,181,386	(37,207,730)	-11%
Wateree	(44,750,713)	3,719,565	71.56%	-8%	(17,785,628)	3,557,126	28.44%	-20%	7,276,691	(62,536,341)	-12%
Wylie	(57,779,686)	3,176,390	78 64%	-5%	(15,696,521)	3,139,304	21.36%	-20%	6,315,694	(73,476,207)	-9%
Great Falls	(5,368,223)	8,573,985	53.54%	-160%	(4,658,172)	931,634	46.46%	-20%	9,505,620	(10,026,395)	-95%
Dearborn	(13,278,916)	1,829,683	61 95%	-14%	(8,155,417)	1,631,083	38.05%	-20%	3,460,766	(21,434,333)	-16%
NPL Bear Creek	(15,109,049)	975,960	94 91%	-6%	(810,269)	162,054	5.09%	-20%	1,138,014	(15,919,319)	-7%
NPL Cedar Cliff	(10,022,813)	1,421,172	93.79%	-14%	(663,156)	132,631	6.21%	-20%	1,553,803	(10,685,969)	-15%
NPL Nantahala	(22,517,927)	1,427,980	83 93%	-6%	(4,311,267)	862,253	16.07%	-20%	2,290,233	(26,829,194)	-9%
NPL Queens Creek	(1,214,981)	1,055,771	93.00%	-87%	(91,423)	18,285	7.00%	-20%	1,074,056	(1,306,404)	-82%
NPL Tennessee Creek	(25,595,270)	2,384,433	95.19%	-9%	(1,293,019)	258,604	4.81%	-20%	2,643,037	(26,888,289)	-10%
NPL Thorpe	(12,680,874)	4,309,152	82.06%	-34%	(2,771,928)	554,386	17.94%	-20%	4,863,538	(15,452,801)	-31%
NPL Tuckasegee	(4,842,241)	2,568,859	92 69%	-53%	(381,870)	76,374	7.31%	-20%	2,645,233	(5,224,111)	-51%
Total Hydro Production	**(1,845,064,199)**	**47,837,251**	**73.60%**	**-3%**	**(661,912,126)**	**132,382,425**	**26.40%**	**-20%**	**180,219,676**	**(2,506,976,324)**	**-7%**
Other Production Plant											
Lincoln CTs	(268,737,672)	(446,023)	65.50%	0%	(141,573,312)	7,078,666	34.50%	-5%	6,632,643	(410,310,983)	-2%
Dan River CC	(459,442,766)	29,722,661	68.19%	-6%	(214,306,442)	10,715,322	31.81%	-5%	40,437,983	(673,749,209)	-6%
Lee CTs	(39,004,217)	1,089,438	62 86%	-3%	(23,045,630)	1,152,281	37.14%	-5%	2,241,719	(62,049,847)	-4%
Mill Creek CTs	(167,592,510)	(949,361)	66.56%	1%	(84,199,062)	4,209,953	33.44%	-5%	3,260,592	(251,791,572)	-1%
Rockingham CTs	(264,840,803)	216,217	82 21%	0%	(57,329,057)	2,866,453	17.79%	-5%	3,082,670	(322,169,860)	-1%
Buck CC	(472,503,626)	22,707,008	69 34%	-5%	(208,968,811)	10,448,441	30.66%	-5%	33,155,449	(681,472,437)	-5%
Lee CC	(390,296,625)	19,181,082	66.72%	-5%	(194,656,774)	9,732,839	33.28%	-5%	28,913,921	(584,953,399)	-5%
Clemson CHP	(19,549,085)	1,352,595	65.00%	-7%	(10,525,553)	526,278	35.00%	-5%	1,878,873	(30,074,638)	-6%
Total Other Production	**(2,081,967,304)**	**72,873,617**	**69.02%**	**-4%**	**(934,604,641)**	**46,730,232**	**30.98%**	**-5%**	**119,603,849**	**(3,016,571,945)**	**-4%**

Duke Energy Carolinas
Table 6: Calculation of Weighted Net Salvage Percent for Generation Plant
As of December 31, 2021

	Terminal				Interim				Combined		
Location	Retirements ($)	Net Salvage ($)	Percent of Total Retire	Net Salvage (%)	Retirements ($)	Net Salvage ($)	Percent of Total Retire	Net Salvage (%)	Total Net Salvage ($)	Total Retirements	Estimated Net Salvage (%)
A	B	C	D = C/K	E = C/B	F	G = F*I	H = F/K	I	J = C+G	K = B+F	L = J/K
Solar											
Mocksville	(8,545,547)	2,821,462	26 88%	-33%	(23,248,014)	0	73.12%	0%	2,821,462	(31,793,561)	-9%
Monroe	(30,269,964)	12,416,408	28.18%	-41%	(77,141,632)	0	71.82%	0%	12,416,408	(107,411,596)	-12%
Woodleaf	(3,708,492)	1,444,372	26 66%	-39%	(10,202,126)	0	73.34%	0%	1,444,372	(13,910,619)	-10%
Gaston	(10,559,960)	3,569,753	27 24%	-34%	(28,211,410)	0	72.76%	0%	3,569,753	(38,771,370)	-9%
Maiden Creek	(25,635,174)	11,091,570	29 65%	-43%	(60,822,106)	0	70.35%	0%	11,091,570	(86,457,280)	-13%
Total Solar	**(78,719,138)**	**31,343,565**	**28.28%**	**-40%**	**(199,625,287)**	**0**	**71.72%**	**0%**	**31,343,565**	**(278,344,425)**	**-11%**
	(15,448,806,315)	**#REF!**	**66.05%**	**0%**	**(7,941,741,156)**	**862,094,114**	**33.95%**	**-11%**	**1,313,153,967**	**(23,390,547,471)**	**-6%**

Sources:
Spanos Exhibit 1
DEC Response to PS DR 1-8

Duke Energy Carolinas
Table 7: Calculation of Terminal Net Salvage Percent
As of December 31, 2021

Plant	Estimated Total Decommissioning Cost (Current Year $)	Current Dollar Year	Retirement Year	2.50% Escalated Decommissioning Cost (Rate Year $)
A	B	C	D	E=B*(1+2.5%)^[D-C]
Steam Production				
Marshall	33,072,950	2021	2034	45,591,427
Belews Creek	66,073,500	2021	2038	100,538,644
Cliffside (J.E. Rogers)	60,351,150	2021	2048	117,551,971
Allen	33,621,300	2021	2023	35,323,378
Total Steam Production	**193,118,900**			**299,005,420**
Nuclear Production Plant				
Oconee				
McGuire				
Catawba				
Total Nuclear Production	**0**			**0**
Hydro Production Plant				
Cowans Ford	(695,750)	2021	2055	(1,610,885)
Bad Creek	452,900	2021	2067	1,410,263
Jocassee	(3,126,550)	2021	2046	(5,796,449)
Keowee	139,700	2021	2046	258,996
Fishing Creek	1,437,300	2021	2055	3,327,813
Cedar Creek	1,088,750	2021	2055	2,520,807
Bridgewater	1,299,950	2021	2055	3,009,803
Lookout Shoals	1,126,950	2021	2055	2,609,252
Mountain Island	1,409,550	2021	2055	3,263,562
99 Islands	2,246,250	2021	2036	3,253,240
Oxford	724,400	2021	2055	1,677,219
Rhodhiss	1,067,100	2021	2055	2,470,680
Wateree	1,606,500	2021	2055	3,719,565
Wylie	1,371,900	2021	2055	3,176,390
Great Falls	3,703,150	2021	2055	8,573,985
Dearborn	790,250	2021	2055	1,829,683
NPL Bear Creek	595,600	2021	2041	975,960
NPL Cedar Cliff	867,300	2021	2041	1,421,172
NPL Nantahala	850,200	2021	2042	1,427,980
NPL Queens Creek	804,650	2021	2032	1,055,771
NPL Tennessee Creek	1,455,150	2021	2041	2,384,433
NPL Thorpe	2,629,750	2021	2041	4,309,152

Duke Energy Carolinas
Table 7: Calculation of Terminal Net Salvage Percent
As of December 31, 2021

Plant	Estimated Total Decommissioning Cost (Current Year $)	Current Dollar Year	Retirement Year	Escalated Decommissioning Cost (Rate Year $) 2.50%
A	B	C	D	E=B*(1+2.5%)^[D-C]
Steam Production				
NPL Tuckasegee	1,567,700	2021	2041	2,568,859
Total Hydro Production	**23,412,700**			**47,837,251**
Other Production Plant				
Lincoln CTs	(279,000)	2021	2040	(446,023)
Dan River CC	13,824,450	2021	2052	29,722,661
Lee CTs	573,300	2021	2047	1,089,438
Mill Creek CTs	(551,450)	2021	2043	(949,361)
Rockingham CTs	135,250	2021	2040	216,217
Buck CC	10,825,400	2021	2051	22,707,008
Lee CC	7,692,900	2021	2058	19,181,082
Clemson CHP	529,250	2021	2059	1,352,595
Total Other Production	**32,750,100**			**72,873,617**
Solar				
Mocksville	1,521,870	2021	2046	2,821,462
Monroe	6,533,945	2021	2047	12,416,408
Woodleaf	741,540	2021	2048	1,444,372
Gaston	1,744,400	2021	2050	3,569,753
Maiden Creek	5,287,825	2021	2051	11,091,570
Total Solar	**15,829,580**			**31,343,565**
Total Production	**265,111,280**			**451,059,853**

Sources:
Spanos Exhibit 1 (2021 Depreciation Rate Study)
Speros Exhibit 3 (6/10/2022 DEC Decommissioning Cost Estimate)
Testimony of Public Staff Witness Jay Lucas

Duke Energy Carolinas
Table 8: Calculation of Weighted Interim Net Salvage Percent
As of December 31, 2021

Account	Description	Estimated Future Interim Retirement	Original Cost as a Percent of Total	DEC Proposed: Interim Net Salvage %	DEC Proposed: Weighted Average of Interim Net Salvage (%)	Public Staff Proposed: Interim Net Salvage %	Public Staff Proposed: Weighted Average of Interim Net Salvage (%)
	A	B	C	D	E	F	G
Steam Production							
311.00	Structures and Improvements	32,774,148	3.78%	-25%	-1%	-25%	-1%
312.00	Boiler Plant Equipment	603,117,275	69.63%	-20%	-14%	-20%	-14%
314.00	Turbogenerator Units	123,386,279	14.24%	-10%	-1%	-10%	-1%
315.00	Accessory Electric Equipment	42,752,358	4.94%	-15%	-1%	-15%	-1%
316.00	Miscellaneous Power Plant Equipment	64,142,538	7.41%	-10%	-1%	-10%	-1%
Total Steam Production		**866,172,598**	**100.00%**		**-18%**		**-18%**
Nuclear Production							
321.00	Structures and Improvements	1,017,030,882	19.22%	-15%	-3%	-15%	-3%
322.00	Reactor Plant Equipment	2,516,208,120	47.56%	-10%	-5%	-10%	-5%
323.00	Turbogenerator Units	782,347,268	14.79%	-8%	-1%	-8%	-1%
324.00	Accessory Electric Equipment	634,917,702	12.00%	-10%	-1%	-10%	-1%
325.00	Miscellaneous Power Plant Equipment	339,825,802	6.42%	-5%	0%	-5%	0%
Total Nuclear Production		**5,290,329,774**	**100.00%**		**-10%**		**-10%**
Hydro Production							
331.00	Structures and Improvements	139,928,129	21.14%	-25%	-5%	-25%	-5%
332.00	Reservoirs, Dams, and Waterways	132,192,962	19.97%	-25%	-5%	-25%	-5%
333.00	Water Wheels, Turbines, and Generators	289,090,906	43.68%	-20%	-9%	-20%	-9%
334.00	Accessory Electric Equipment	65,059,243	9.83%	-10%	-1%	-10%	-1%
335.00	Miscellaneous Power Plant Equipment	26,455,189	4.00%	-5%	0%	-5%	0%
336.00	Roads, Railroads, and Bridges	9,185,697	1.39%	0%	0%	0%	0%
Total Hydro Production		**661,912,126**	**100.00%**		**-20%**		**-20%**

Duke Energy Carolinas
Table 8: Calculation of Weighted Interim Net Salvage Percent
As of December 31, 2021

				DEC Proposed		Public Staff Proposed	
Account	Description	Estimated Future Interim Retirement	Original Cost as a Percent of Total	Interim Net Salvage %	Weighted Average of Interim Net Salvage (%)	Interim Net Salvage %	Weighted Average of Interim Net Salvage (%)
	A	B	C	D	E	F	G
Other Production							
341.00	Structures and Improvements	79,992,515	9.97%	-10%	-4%	-10%	-1%
342.00	Fuel Holders, Producers, and Accessories	22,338,758	2.78%	-10%	-1%	-10%	0%
343.00	Prime Movers	404,650,991	50.41%	-5%	-10%	-5%	-3%
344.00	Generators	220,324,327	27.45%	-5%	-6%	-5%	-1%
345.00	Accessory Electric Equipment	59,936,995	7.47%	-5%	-2%	-5%	0%
346.00	Miscellaneous Power Plant Equipment	15,401,382	1.92%	-5%	0%	-5%	0%
Total Other Production		**802,644,967**	**100.00%**		**-23%**		**-5%**
Solar Production							
341.66	Structures and Improvements	1,426,576	0.71%	0%	0%	0%	0%
344.66	Generators	178,814,353	89.58%	0%	0%	0%	0%
345.66	Accessory Electric Equipment	19,319,952	9.68%	0%	0%	0%	0%
346.66	Miscellaneous Power Plant Equipment	64,406	0.03%	0%	0%	0%	0%
Total Solar Production		**199,625,287**	**100.00%**		**0%**		**0%**

Source:
DEC PS DR 6-7

Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 6

Docket No. E-7, Sub 1276

Date of Request: **January 30, 2023**
Date of Response: **February 9, 2023**

[ ] **CONFIDENTIAL**

[X] **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 6-7, was provided to me by the following individual(s): Denise Lepisto, Manager Accounting I, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

North Carolina Public Staff
Data Request No. 6
DEC Docket No. E-7, Sub 1276
Item No. 6-7
Page 1 of 1

Request:

7. Please provide the source for the Interim Retirements Net Salvage percent shown in column (5) on page 311 of Spanos Exhibit 1. If available, please provide the workpapers requested electronically in Excel.

Response:

See the attached file named "DEC PS DR 6-7 Attachment.xlsx" which provides the calculation of the Net Salvage percent shown in column (5) of page 311 of Spanos Exhibit 1. Also, see pages 314 through 356 of Spanos Exhibit 1 which sets forth the interim net salvage data for all production accounts.

DUKE ENERGY CAROLINAS
ELECTRIC ASSETS

INTERIM NET SALVAGE CALCULATION

	ACCOUNT	INTERIM NET SALVAGE %	ESTIMATED FUTURE INTERIM RETIREMENTS	2021 ORIGINAL COST AS A PERCENT OF TOTAL	WEIGHTED AVERAGE OF INTERIM NET SALVAGE (%)
	(1)	(2)	(3)	(4)	(5)=(2)*(4)
	STEAM PRODUCTION				
31100	311.00	(25)	32,774,147.51	3.78%	(1)
31200	312.00	(20)	603,117,275.46	69.63%	(14)
31400	314.00	(10)	123,386,279.13	14.24%	(1)
31500	315.00	(15)	42,752,358.03	4.94%	(1)
31600	316.00	(10)	64,142,537.83	7.41%	(1)
	TOTAL STEAM PRODUCTION		**866,172,597.96**		**(18)**
	NUCLEAR PRODUCTION				
32100	321.00	(15)	1,017,030,882.40	19.22%	(3)
32200	322.00	(10)	2,516,208,120.19	47.56%	(5)
32300	323.00	(8)	782,347,267.62	14.79%	(1)
32400	324.00	(10)	634,917,701.80	12.00%	(1)
32500	325.00	(5)	339,825,801.58	6.42%	0
	TOTAL NUCLEAR PRODUCTION		**5,290,329,773.59**		**(10)**
	HYDRO PRODUCTION				
33100	331.00	(25)	139,928,128.54	21.14%	(5)
33200	332.00	(25)	132,192,961.94	19.97%	(5)
33300	333.00	(20)	289,090,906.11	43.68%	(9)
33400	334.00	(10)	65,059,243.45	9.83%	(1)
33500	335.00	(5)	26,455,189.13	4.00%	0
33600	336.00	0	9,185,696.71	1.39%	0
	TOTAL HYDRO PRODUCTION		**661,912,125.88**		**(20)**
	OTHER PRODUCTION				
34100	341.00	(10)	79,992,515.23	40.07%	(4)
34200	342.00	(10)	22,338,757.68	11.19%	(1)
34300	343.00	(5)	404,650,990.72	202.71%	(10)
34400	344.00	(5)	220,324,326.56	110.37%	(6)
34500	345.00	(5)	59,936,994.64	30.02%	(2)
34600	346.00	(5)	15,401,381.68	7.72%	0
	TOTAL OTHER PRODUCTION		**802,644,966.51**		**(23)**
	SOLAR PRODUCTION				
34166	341.66	0	1,426,576.44	0.71%	0
34466	344.66	0	178,814,353.47	89.58%	0
34566	345.66	0	19,319,951.66	9.68%	0
34666	346.66	0	64,405.73	0.03%	0
	TOTAL SOLAR PRODUCTION		**199,625,287.30**		**0**

BEFORE

THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1276

In the Matter of:	)	
	)	**DIRECT TESTIMONY OF**
Application of Duke Energy Carolinas, LLC	)	**JOHN J. SPANOS**
For Adjustment of Rates and Charges	)	**FOR DUKE ENERGY**
Applicable to Electric Service in North	)	**CAROLINAS, LLC**
Carolina and Performance-Based Regulation	)	

DUKE ENERGY CAROLINAS

ACCOUNT 356.00 OVERHEAD CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2003	4,156,930	1,635,759	39	55	0	1,635,704-	39-
2004	2,859,739	1,129,672	40	28,730	1	1,100,942-	38-
2005	1,704,855	443,888	26	43,814	3	400,073-	23-
2006	6,729,653	1,064,455	16	202,284	3	862,171-	13-
2007	709,287	930,555	131	36,826	5	893,729-	126-
2008	1,056,029	774,086	73	66,412	6	707,674-	67-
2009	2,446,335	67,468	3	102,510	4	35,042	1
2010	1,087,544		0		0		0
2011	985,619	2,462,467	250	1,294	0	2,461,174-	250-
2012	1,077,061	48,511	5		0	48,511-	5-
2013	1,575,879		0		0		0
2014	298,356	229,126	77	13,723	5	215,403-	72-
2015	1,587,465	1,216,053	77		0	1,216,053-	77-
2016	2,290,689	2,549,520	111	7,215	0	2,542,306-	111-
2017	1,711,557	1,128,044	66		0	1,128,044-	66-
2018	448,767	33,320	7		0	33,320-	7-
2019	5,643,045	177,138	3		0	177,138-	3-
2020	7,651,115	2,850,454	37		0	2,850,454-	37-
2021	7,955,536	8,959	0		0	8,959-	0
TOTAL	51,975,461	16,749,476	32	502,863	1	16,246,613-	31-

THREE-YEAR MOVING AVERAGES

03-05	2,907,175	1,069,773	37	24,200	1	1,045,573-	36-
04-06	3,764,749	879,338	23	91,609	2	787,729-	21-
05-07	3,047,932	812,966	27	94,308	3	718,658-	24-
06-08	2,831,656	923,032	33	101,841	4	821,192-	29-
07-09	1,403,884	590,703	42	68,583	5	522,121-	37-
08-10	1,529,969	280,518	18	56,307	4	224,211-	15-
09-11	1,506,499	843,312	56	34,601	2	808,711-	54-
10-12	1,050,075	836,993	80	431	0	836,562-	80-
11-13	1,212,853	836,993	69	431	0	836,562-	69-
12-14	983,765	92,546	9	4,574	0	87,971-	9-
13-15	1,153,900	481,726	42	4,574	0	477,152-	41-
14-16	1,392,170	1,331,567	96	6,979	1	1,324,587-	95-
15-17	1,863,237	1,631,206	88	2,405	0	1,628,801-	87-
16-18	1,483,671	1,236,962	83	2,405	0	1,234,557-	83-
17-19	2,601,123	446,167	17		0	446,167-	17-

DUKE ENERGY CAROLINAS

ACCOUNT 356.00 OVERHEAD CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
18-20	4,580,976	1,020,304	22		0	1,020,304-	22-
19-21	7,083,232	1,012,183	14		0	1,012,183-	14-
FIVE-YEAR AVERAGE							
17-21	4,682,004	839,583	18		0	839,583-	18-

Duke Energy Carolinas
Comparison of DEC and Public Staff Proposed Net Cost of Removal Accrual and Five-Year Average Net Cost of Removal Actually Incurred as of December 31, 2021

Account	Description	Five-year Average Net COR Actually Incurred	Net Cost of Removal Recovery included in DEC's Proposed Depr Rates	DEC's Proposed / Actually Incurred	Net Cost of Removal Recovery included in Public Staff's Proposed Depr Rates	Public Staff's Proposed / Actually Incurred
Transmission Plant						
352.00	Structures and Improvements	254,758	487,327	1.9	487,327	1.9
353.00	Station Equipment	4,148,308	7,694,998	1.9	7,694,998	1.9
354.00	Towers and Fixtures	317,491	3,242,223	10.2	3,242,223	10.2
355.00	Poles and Fixtures	4,330,501	5,581,300	1.3	5,581,300	1.3
356.00	Overhead Conductors and Devices	839,583	5,779,285	6.9	4,208,350	5.0
357.00	Underground Conduit	0	0	0.0	0	0.0
358.00	Underground Conductors and Devices	0	0	0.0	0	0.0
359.00	Roads and Trails	0	0	0.0	0	0.0
Total Transmission Plant		**9,890,641**	**22,785,134**	**2.3**	**21,214,198**	**2.1**
Distribution Plant						
361.00	Structures and Improvements	236,189	419,127	1.8	419,127	1.8
362.00	Station Equipment	1,456,029	4,872,170	3.3	4,872,170	3.3
364.00	Poles, Towers, and Fixtures	9,435,943	16,946,969	1.8	16,946,969	1.8
365.00	Overhead Conductors and Devices	10,580,274	13,785,444	1.3	13,785,444	1.3
366.00	Underground Conduit	113,618	660,205	5.8	660,205	5.8
367.00	Underground Conductors and Devices	2,002,273	8,973,148	4.5	8,973,148	4.5
368.00	Line Transformers	1,731,314	5,602,206	3.2	5,602,206	3.2
369.00	Services	2,781,571	4,254,403	1.5	4,254,403	1.5
370.00	Meters and Metering Equipment	139,746	0	0.0	0	0.0
370.02	Meters - UOF	0	0	0.0	0	0.0
371.00	Installations on Customers' Premises	1,014,521	1,463,807	1.4	1,463,807	1.4
373.00	Street Lighting and Signal Systems	337,735	914,723	2.7	914,723	2.7
Total Distribution Plant		**29,829,214**	**57,892,202**	**1.9**	**57,892,202**	**1.9**

STRATEGEN

/A

Nikhil Balakumar

Manager

Nikhil is a Manager at Strategen where he provides legislative, regulatory and technology expertise to both state government and private sector clients on issues relating to distributed energy resource (DER) integration, electric vehicles, distribution system planning, grid modernization, data access & platforms, power system architectures and performance-based ratemaking.

Before joining Strategen, Nikhil worked at Utilidata advocating for investments to digitize and enable real-time visibility & control of the grid. He also helped enact legislation and regulations in New York, New Hampshire, and the District of Columbia related to data access on behalf of the Greentel Group.

Contact

Location
Washington, DC

Email
nbalakumar@strategen.com

Phone
+1 (240)-672-7049

Education

BS
Management
University of Maryland
2014

STRATEGEN.COM

Work Experience

Strategen

Manager / Washington, DC / 2022 – Present

+ Manages consulting projects focused on grid modernization and market development strategy for state government and private sector clients.
+ Leverages subject matter expertise in distributed energy resource (DER) integration, electric vehicles, distribution system planning, grid modernization, data access & platforms, power system architectures and performance-based ratemaking

Rohe Homes

Senior Advisor / Washington, DC / 2020 – Present

+ Serves as primary advisor to CEO to help guide strategic direction of Rohe Homes with the goal of building smart, sustainable and resilient communities.
+ Works with leadership team to streamline & grow market development, platform and manufacturing capabilities.

Utilidata

Head of Market Development, East / Washington, DC / 2020 – 2021

+ Advocated for future proof grid architecture to support grid modernization, clean energy and resiliency goals.
+ Engaged utilities including National Grid, Avangrid and Eversource on leveraging grid-edge technologies to achieve their grid modernization objectives.
+ Worked with the Utilidata product team to develop a grid operations platform roadmap based on insights from utilities, regulators, and the clean energy industry.

Nikhil Balakumar

Manager

STRATEGEN

Domain Expertise

Grid Modernization

Planning and Operations

Distribution System Operators (DSO) Models

Data Access and Platforms

Distributed Energy Resources (DERs)

Advanced Metering Infrastructure (AMI)

Grid-edge Technologies

Power System Architectures

Market Development

Energy Software Development

Legislative Development

Work Experience Continued

Greentel Group

Principal / Washington, DC / 2016 – 2020

District of Columbia

+ Drafted & helped passed the Clean Energy Omnibus DC Act of 2018 to codify climate goals into law.
+ Drafted the Distributed Energy Resources Authority (DERA) Act of 2018 to establish an independent distribution market authority responsible for creating the DSP.

New York

+ Led the 'DER Industry Data Initiative' which helped facilitate the landmark regulatory order issued by the New York Department of Public Service (NY DPS) establishing the Integrated Energy Data Resource (IEDR) – the first of its kind independent, statewide data platform opening access to customer, system and market energy data.

New Hampshire

+ Advocated for the passing of SB-284 which established a statewide platform to provide energy data to market players.
+ Led broad coalition to shape the regulatory proceeding (DE 19-197) to implement SB-284 leading to an approved settlement by the New Hampshire Public Utilities Commission (NH PUC)

Incentive Technology Group (ITG)

Product Manager, R&D/ Washington, DC / 2014 – 2018

+ Designed product architecture and developed requirements for a residential energy management platform.
+ Managed 8-member team and $1.2 million budget for product delivery of platform.
+ Developed product go-to-market strategy
+ Built extensive networks in the smart home and utility sectors to facilitate partnerships.

Nikhil Balakumar

Manager

STRATEGEN

Selection of Relevant Project Experience

Massachusetts Attorney General's Office

Eversource and National Grid Capital Investment Projects ("CIP") Proposals / 2022 - Present

+ Strategen was retained by the Massachusetts Attorney General's Office to provide expert consulting service related to Eversource Energy's various CIP proposals and National Grid's Shutesbury CIP proposals, under D.P.U. 22-47, 22-51, 22-52, 22-53, 22-54, 22-55.

Eversource, National Grid and Unitil Electric Vehicle (EV) Proposals / 2022

+ Strategen was retained by the Massachusetts Attorney General's Office to provide expert consulting services to review Eversource, National Grid and Unitil's electric vehicle (EV) proposals, under D.P.U 21-90, 21-91 and 21-92

Maryland Office of the People's Counsel

Delmarva Power & Light Rate Case/ 2022

+ Strategen was retained by the Maryland Office of the People's Counsel to provide expert consulting services related to Delmarva Power and Light's new three-year multi-year rate plan. Strategen specifically provided expertise regarding the bill stabilization adjustment mechanism and reviewed the capital investment proposals.

National Resources Defense Council

Ameren and ComEd Performance-based Ratemaking Plans / 2022 - Present

+ Strategen was retained by the Natural Resources Defense Council to provide expert consulting services related to Ameren and ComEd's performance-based ratemaking proposals. Strategen specifically provided expertise regarding the evaluation and design of both utilities' proposed peak load reduction metric.

Ameren and ComEd Beneficial Electrification Plans / 2022 - Present

+ Strategen was retained by the Natural Resources Defense Council to provide expert consulting services related to Ameren and ComEd's beneficial electrification proposals. Strategen specifically provided expertise regarding EV rate design.

South Carolina Office of Regulatory Staff

Duke Electric Vehicle (EV) Proposals / 2022 – Present

+ Strategen was retained by the South Carolina Office of Regulatory Staff to provide expert consulting services related to Duke's electric vehicle (EV) proposal which included proposals for a Make Ready Credit program and Electric Vehicle Supply Equipment program.

Dominion Electric Vehicle (EV) Proposals / 2023 – Present

+ Strategen was retained by the South Carolina Office of Regulatory Staff to provide expert consulting services related to Dominion's electric vehicle (EV) proposal which included proposals for a selling and providing on-bill finance for EV chargers to commercial customers.

Nikhil Balakumar

Manager

STRATEGEN

Expert Testimony

On behalf of the Maine Governor's Energy Office

Grid Modernization and Electric Vehicles

+ Case No. 2022-00152. Request for Approval of a Rate Change - 307 (7/30/23) Pertaining to Central Maine Power Company.
    + Direct Testimony with panelists Ron Nelson and Nikhil Balakumar

On behalf of Environmental Law & Policy Center, Natural Resources Defense Council, Union of Concerned Scientists and Vote Solar ("Joint NGOs")

Grid Modernization and Multi-Year Integrated Grid Plan

+ Docket No. 22-0487. Order requiring Ameren Illinois Company to file a Multi-Year Integrated Grid Plan.
    + Direct Testimony
    + Rebuttal Testimony

Smart Electric Power Alliance

2019 Utility Demand Response Market Snapshot

September 2019

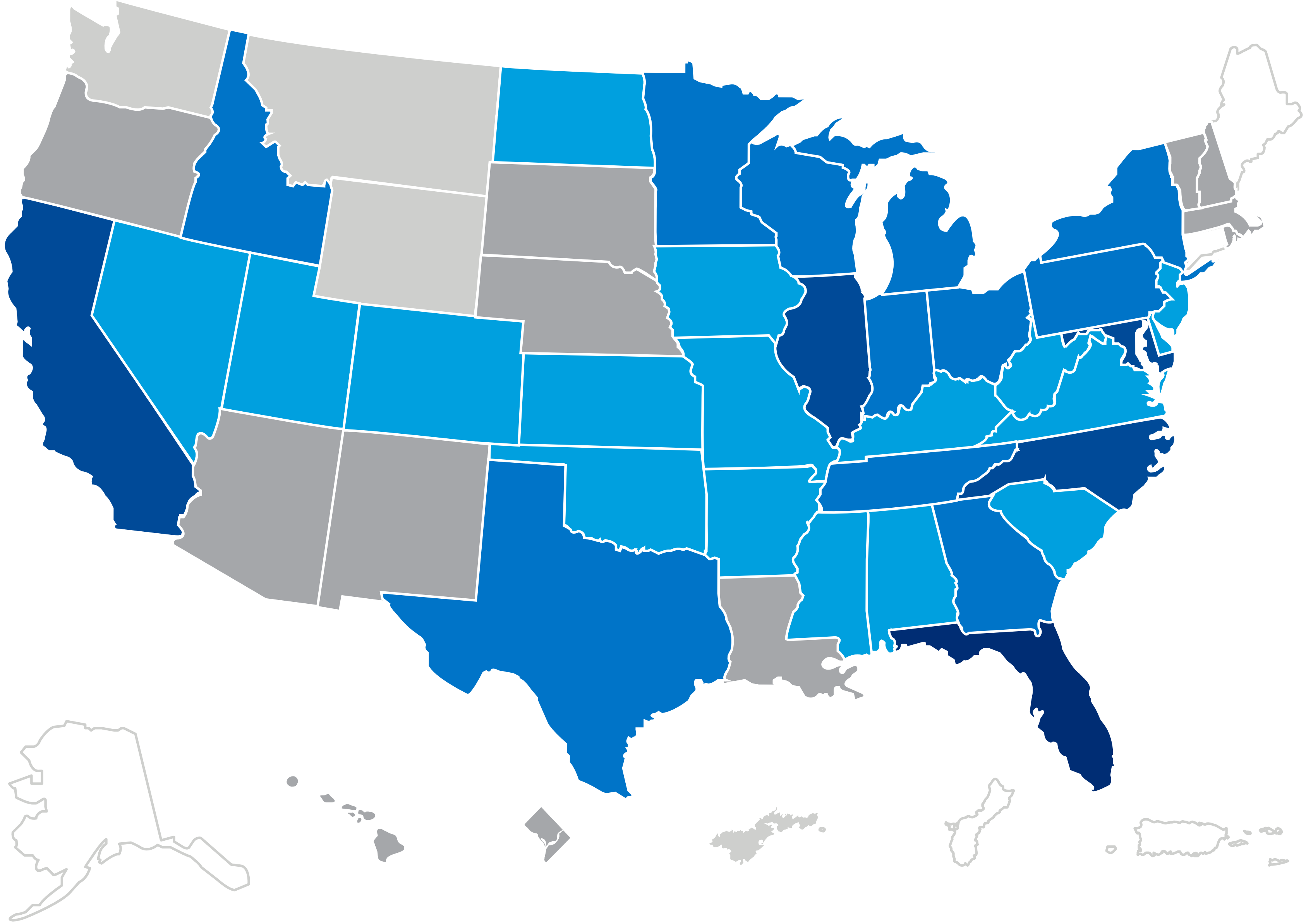


Table of Contents

List of Tables

List of Figures

Acknowledgements

SEPA would like to thank our report partners: Autumn Proudlove and her team at North Carolina Clean Energy Technology Center, Brett Feldman at Navigant Research, Ryan Hledik at The Brattle Group, and Elizabeth Parks from Parks Associates for their contributions to this report. We also would like to thank Erika Diamond, Aakriti Gupta, and Matthew Johnson at EnergyHub; Neel Gulhar, Jessica Lin and Scott Tiazkun at Oracle; and Clare Valentine and Esmond Snell at ESource for their contributions and review.

Additionally, we would like to acknowledge the following individuals for their industry insights and support during data collection: Forrest Frizzel and Randy Fish at Shifted Energy, Orly Hasidim at Universal Devices, Anthony Saucedo and Carl Besaw at Southern California Edison, John Reinhart at Great River Energy, Phil Dion at American Electric Power, Teague Douglas and Tamara Dzubay at ecobee, Matt Carlson at Aquanta, and Mark Knight at Burns & McDonnell. We also would like to thank Paul Miles and the team at Peak Load Management Alliance for their support historically and to date.

Special thanks to Nora Jang for her research, data collection, and development of this report. Additional thanks to SEPA staff members for their contributions to the data collection, development and review: Jen Szaro, Robert Tucker, Greg Merritt, Maliya Scott, Erika Myers, Ian Motley, Harry Cutler, Nick Esch, Conor Hanvey, and Forrest Pasturel.

Authors

Medha Surampudy, Senior Research Analyst

Brenda Chew, Senior Manager of Research

Mac Keller, Research Analyst

Trevor Gibson, Research Analyst

About SEPA

The Smart Electric Power Alliance (SEPA) is dedicated to helping electric power stakeholders address the most pressing issues they encounter as they pursue the transition to a clean and modern electric future and a carbon-free energy system by 2050. We are a trusted partner providing education, research, standards, and collaboration to help utilities, electric customers, and other industry players across four pathways: Transportation Electrification, Grid Integration, Regulatory Innovation and Utility Business Models. Through educational activities, working groups, peer-to-peer engagements and advisory services, SEPA convenes interested parties to facilitate information exchange and knowledge transfer to offer the highest value for our members and partner organizations. For more information, visit www.sepapower.org.

Copyright

Disclaimer

As some information may be unintentionally missing, SEPA advises readers to perform necessary due diligence before making decisions using the report's content. Please contact SEPA at research@sepapower.org for additional information.

About the Report

The 2019 Utility Demand Response Market Snapshot is the result of SEPA's 2019 Utility Survey. Analysis of data collected from SEPA's 2019 Utility Survey seeks to provide deeper insight into utility demand response (DR) programs throughout the U.S., and represents 64% of total U.S. customer accounts (or 93 million customers). Data collected through this survey did not include third-party providers or aggregators, regional transmission organizations (RTOs), or independent system operators (ISOs). However, a more complete picture of the DR market, including efforts by third-party providers, and ISOs and RTOs, is provided in this report by Navigant Research. Please see the SEPA Survey Methodology for more information on scope and coverage.

SEPA began its annual survey of electric utilities in 2007, to track the capacity of new solar power interconnected to the grid each year. Now in its 12th year, the survey, since being expanded to cover additional topics, has collected three years of DR deployment data.

SEPA received additional content from Navigant Research, The Brattle Group, North Carolina Clean Energy Technology Center, and Parks Associates. Additional inputs included data and interviews with utilities as well as insights from industry stakeholders as noted in the acknowledgments.

Survey Methodology and Survey Coverage

SEPA conducted its annual Utility Survey between January and March 2019 using an online survey platform to collect data on utility DR programs through December 31, 2018.

SEPA encouraged participation through marketing efforts and direct outreach to key utility contacts. SEPA received DR data representing 190 utilities from across the U.S. Utilities with service territories in multiple states reported data from each state separately. Additionally, some utilities offer multiple programs under the same program type; these programs were counted as separate lines of data under the utility. Generation and transmission companies and federal utilities were counted as single lines of data and were not counted as responses for their distribution utilities. Please note that due to rounding, some totals may not correspond with the sum of the separate figures.

Smart Electric Power Alliance

Demand Response Programs

Survey data was categorized into two customer segments and by respective DR programs: (1) **mass market** and (2) **commercial and industrial** (C&I) customers. Programs included in the survey were as follows:

Mass market includes DR programs offered to residential and small business customers.

- **AC switch**—A program allowing a grid operator to shed air conditioning load by using a control switch to remotely interrupt or cycle AC compressors.
- **Thermostat**—A program that uses smart thermostats to cycle air conditioners or home heating on and off or to adjust the temperature setting during the day.
- **Water heater**—A program that restricts customers' electric water heaters to run only at specific periods during the day. Water heater programs may also incorporate other DR strategies, such as storing hot water to shift load from on-peak to off-peak periods.
- **Behavioral**—Programs that incentivize customers to reduce use during peak periods with and without a supporting technology like those listed above. These programs may not have direct financial incentives for participation but can be tied to a time-varying rates program. Such programs include time-of-use, critical peak pricing, peak time rebates, and variable peak pricing. An example would be asking customers to reduce consumption through email, texts, social media, app notifications, or other communications during a system peak event.
- **Other**—Programs that are not covered by the above category definitions. Examples include ice storage, pool pumps, electric vehicle smart charging programs, or behind-the-meter generation combined with electric storage.

Commercial and industrial includes DR programs or agreements offered to medium and large commercial and industrial customers.

- **Automated**—A program under which a utility can remotely and automatically reduce a customer's load, or increase the output of behind-the-meter generation or storage, during a DR event.
- **Customer initiated with notification**—A program that allows a utility to send a signal or other notification informing its customers of a DR event and asking them to reduce their load or increase the output of behind-the-meter generation or storage by a specified amount over a period of time.
- **Other**—A DR program for large consumers that is not covered by the above categories (e.g., irrigation control).

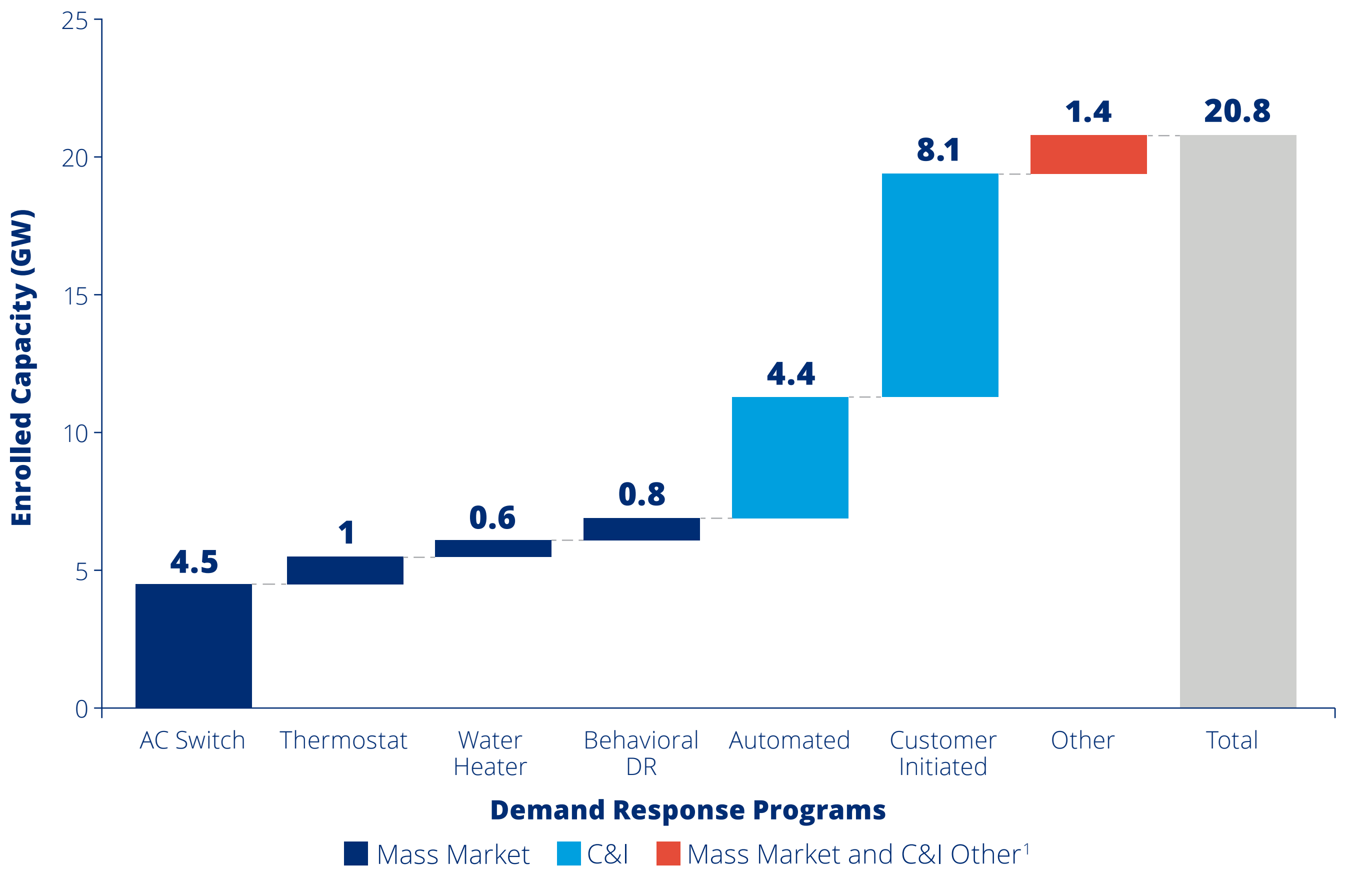
Results in each of these market segments are reported in terms of megawatts (MW) of enrolled and dispatched demand reduction capacity:

- **Enrolled capacity (MW)**—The total potential demand reduction available to the company for dispatch, based on customer enrollment in this DR program through the end of 2018.
- **Dispatched capacity (MW)**—The average actual demand reduction achieved during a dispatch of this DR program through the end of 2018.

Executive Summary

National Utility Demand Response Market Insights

Figure 1: 2018 Enrolled Demand Response Capacity (GW) by Program Type



Source: Smart Electric Power Alliance, 2019. N=190 Utility Survey participants.

MW = Megawatts-ac

- Utilities reported a demand response (DR) **enrolled capacity of 20.8 GW**, and a **dispatched capacity of 12.3 GW** (59.2% of total enrolled capacity) in 2018, across both customer segments and 190 utilities.
- **Mass market** DR accounted for 7.4 GW of enrolled capacity, and 4.3 GW of dispatched capacity.
  - **Air conditioning switches** and **water heaters** continue to be popular offerings, with 35.8% of utility respondents offering AC switch programs and 27.9% offering water heater programs. These programs provide energy services, such as deferring capacity and encouraging economic energy usage.
  - The survey indicated an increase in advanced customer programs. Some legacy programs (e.g., 1-way AC switch thermostat programs) are being retired or phased out to introduce better tools in customers' homes, accommodate for new and decentralized generating sources, and provide more flexibility for demand-side resources.
- The **commercial and industrial** (C&I) market segment contributed over half of the total reported enrolled DR capacity in 2018 (13.3 GW).
  - Utilities are beginning to offer a suite of C&I program and technology options, thus increasing their ability to call on events more frequently and match customers to programs that meet their unique needs.
  - Utilities are interested in using C&I DR programs to defer or replace generation capacity (with 31.8% citing this as their primary purpose for C&I programs).
  - Additionally, C&I DR programs are being leveraged as non-wires alternatives for utilities seeking to defer traditional transmission and distribution upgrades.

1 Includes mass market other programs (e.g., pool pumps) and C&I other programs (e.g., irrigation control).

Policy Update

- Multiple states are drafting proposals for clean peak standards. On January 1, 2019, **Massachusetts** began requiring the Department of Energy Resources (DOER) to regulate a minimum percentage of retail electricity sales with clean generation sources or peak seasonal load reductions.
- Regulatory mandates are motivating utilities to integrate programs that have typically been operated independently (i.e., energy efficiency and DR). A few states, specifically **New York**, **Hawaii**, and **California**, are leading the integration of distributed energy resources (DER), including DR.
- State efficiency legislation, such as the **Missouri Energy Efficiency Investment Act**, permits utilities to implement DR programs and earn an incentive for the demand reductions achieved similar to the rate of return they would get for electricity sales. Such legislation incentivizes demand savings and peak load shaving. Additionally, the **Clean Energy DC Omnibus Amendment Act** requires the DC Commission to establish a working group to guide the development of utility-administered energy efficiency and DR programs. Previously only the DC Sustainable Energy Utility (DCSEU) could offer such programs. This action acknowledges the importance of EE and DR in meeting clean energy and climate-related goals.

Demand Response Market Trends

- The Brattle Group estimates 200 GW of economically-feasible load potential in the U.S. by 2030. This potential equates to 20% of 2030 U.S. peak load levels. The benefits of this load flexibility could save the U.S. energy sector more than $15 billion per year by 2030.
- Regulatory and market trends, coupled with technological innovations and a diversity of resources, are creating an ecosystem where DR programs can begin integrating more technology types.
- The embrace of carbon reduction programs in integrated resource planning is driving increased DR adoption. **Xcel Energy** announced in 2018 that it would deliver 100% carbon-free electricity to customers by 2050. According to their Upper Midwest Energy Plan proposal, Xcel commits to reducing carbon emissions by more than 80% in their eight upper midwest customer states by 2030. Xcel filed the plan with the Minnesota Public Utilities Commission on July 1st, 2019.[2] DR programs help meet these carbon reduction goals.
- Utilities are incorporating programs that leverage multiple technology types (for example, thermostats and battery storage) to create a portfolio of integrated DR programs, as opposed to individual programs. These programs aim to provide larger savings, appeal to more customers, provide multiple grid services, to be called on more frequently due to their flexibility, than traditional DR programs. New software and increased penetration of DERs are enabling this approach.
- Energy storage, electric vehicle managed charging programs, smart home technology, and transactive energy represent new applications and techniques for DR. These developments, arriving in the form of utility pilot programs, can allow for a more integrated approach to DR and the provision of grid services.

2 Xcel Energy. (2018). Xcel Energy aims for zero-carbon electricity by 2050. Retrieved from https://www.xcelenergy.com/company/media_room/news_releases/xcel_energy_aims_for_zero-carbon_electricity_by_2050

MW = Megawatts-ac

Smart Electric Power Alliance

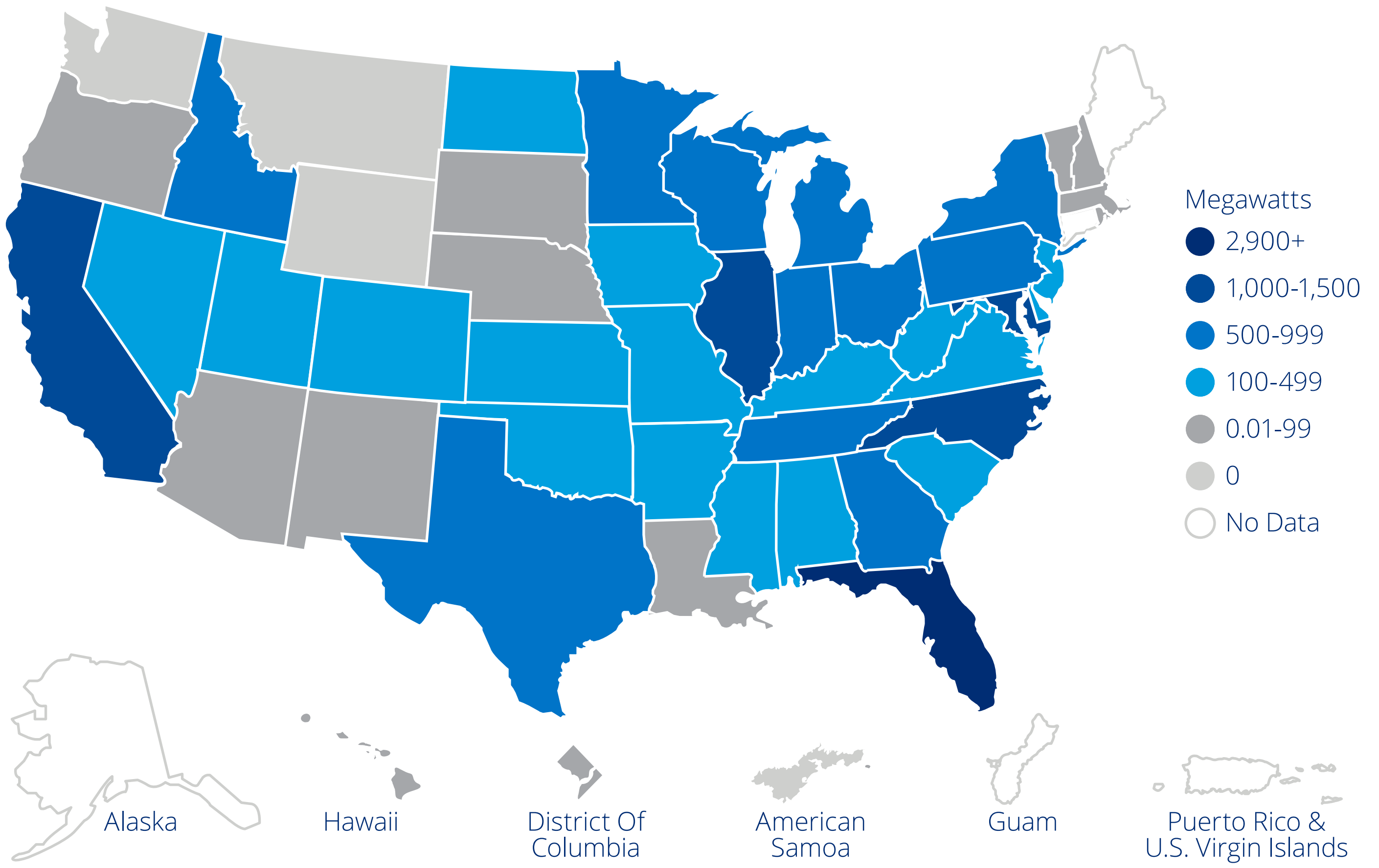
Introduction

SEPA's 2019 Utility Market Snapshot report builds upon its 2018 report with increased utility coverage (from 155 to 190 survey participants), updates on DR in the wholesale markets, and a fresh look at market trends.

Key Topic Areas:

- **Utility DR Market Summary:** This section includes results from the annual SEPA Utility Survey, and updates by utility DR program type (e.g., thermostat programs, water heaters) and customer segment.
- **Policy Updates:** This section, augmented by North Carolina Clean Energy Technology Center, provides updates on policies encouraging the growth of DR programs.
- **Wholesale DR Market Summary:** This section draws from Navigant Research and includes a market summary and analysis of DR changes in the wholesale markets.
- **DR Market Trends:** The final section of the report provides short summaries on DR market trends, including demand flexibility (contributed by The Brattle Group), energy storage, electric vehicle managed charging, smart home devices (contributed by Parks Associates), and transactive energy.

Figure 2: 2018 Enrolled Demand Response Capacity Map (MW)



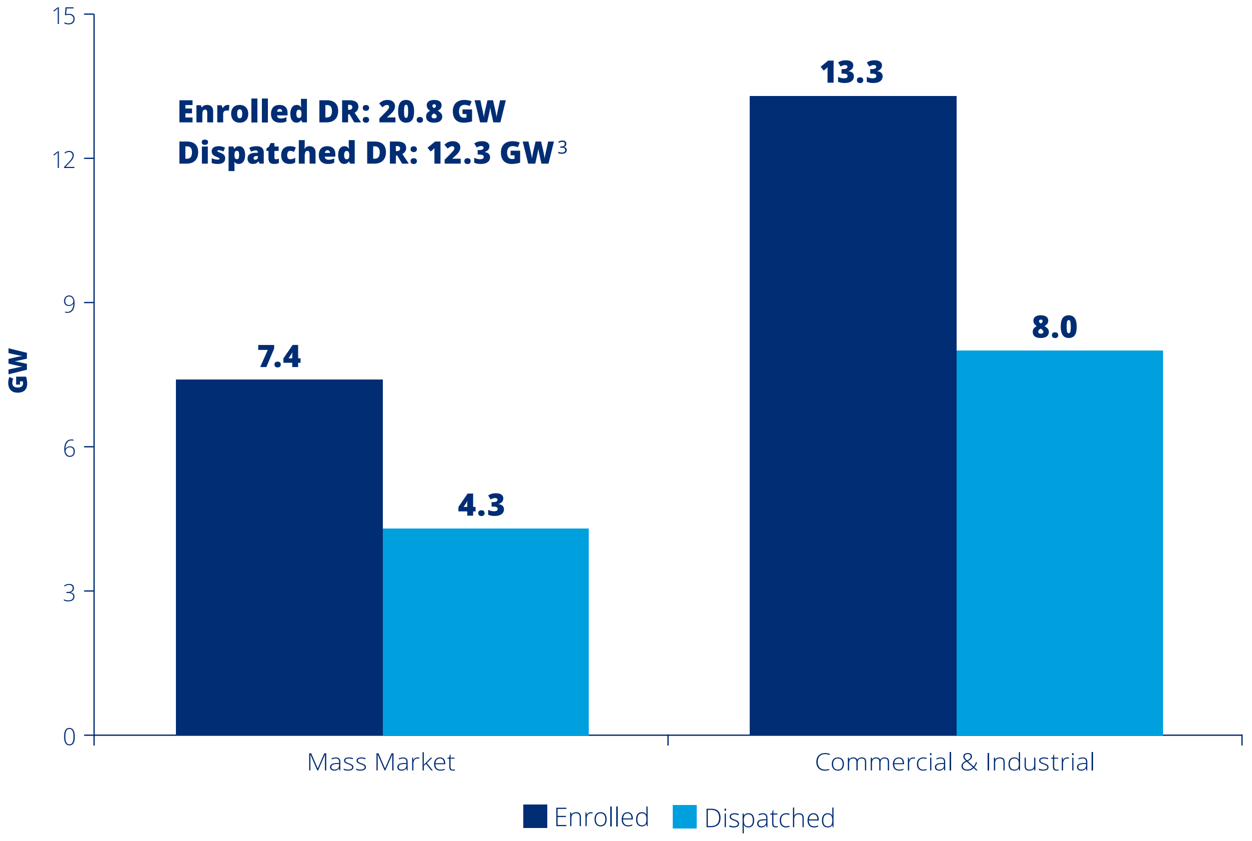
Source: Smart Electric Power Alliance, 2019. N=190 Utility Survey participants.

MW = Megawatts-ac

Utility Demand Response Market Summary

National Utility Demand Response Market Insights

Figure 3: 2018 Enrolled Demand Response Capacity (GW) by Market Segment



Source: Smart Electric Power Alliance, 2019. N=190 Utility Survey participants.

SEPA's 2019 Utility Survey captured dispatchable DR in both the mass market and commercial and industrial (C&I) segments representing approximately 64.7% of total U.S. customer accounts. Utility participants reported 20.8 GW of enrolled DR capacity in 2018.

Mass Market DR:

- Enrolled mass market DR was reported as 7.4 GW, 35.8% of total enrolled DR captured for 2018.
- At 4.5 GW, AC Switch programs provided the largest enrolled capacity of any mass market technology.

Commercial & Industrial DR:

- C&I DR accounted for 13.3 GW, or 64.2% of total enrolled DR.
- Customer initiated programs accounted for 8.1 GW or 38.9% of the total enrolled DR, making it the largest C&I contributor.

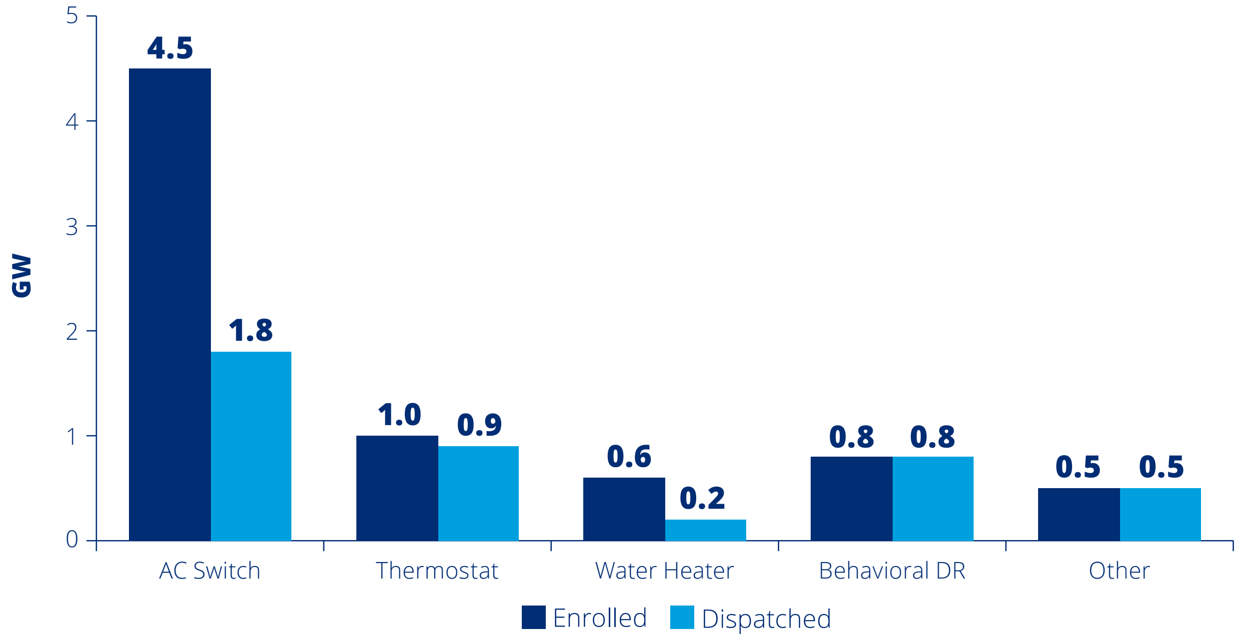
Through the survey and conversations with industry stakeholders, SEPA identified movement to more advanced DR programs. Expanded Bring Your Own Device (BYOD) programs, more integrated DR portfolios to leverage multiple technology types, and the adoption of smart home technology are all driving a transition from legacy programs and traditional DR to newer, more flexible programs and technologies.

3 Some utilities did not provide dispatched data, but reported calling numerous events during 2018.

MW = Megawatts-ac

Smart Electric Power Alliance

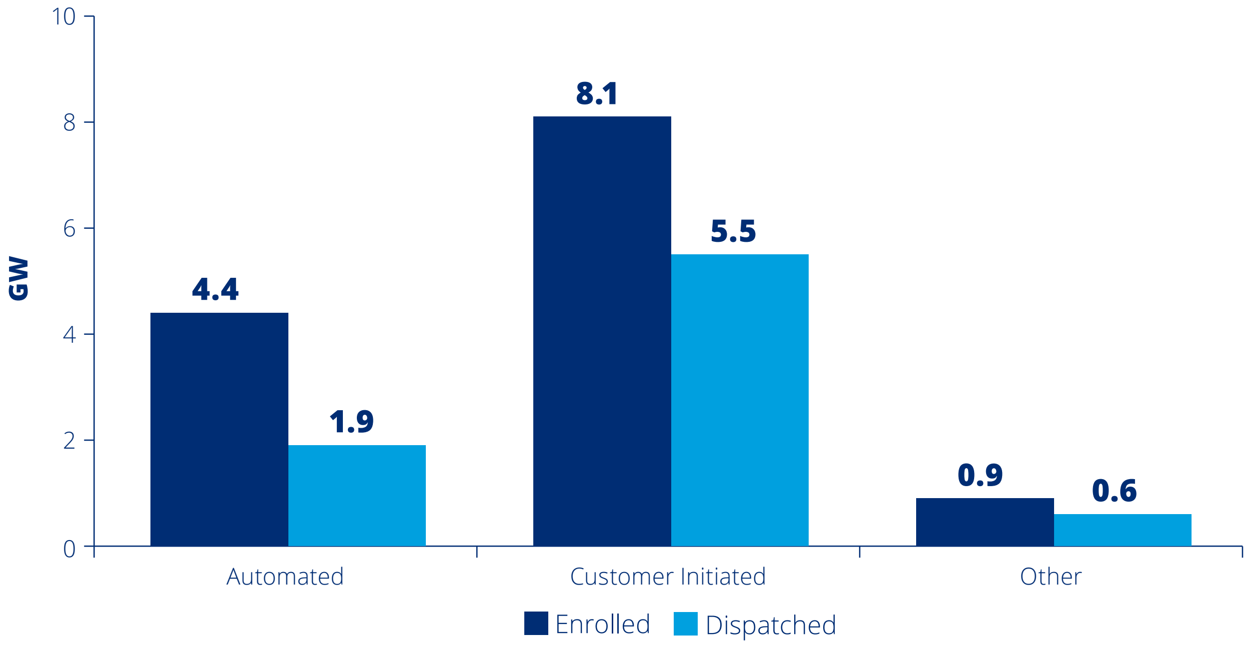
Figure 4: 2018 Mass Market Demand Response Capacity by Program Type (GW)



Source: Smart Electric Power Alliance, 2019. N=190 Utility Survey participants.

- AC switch programs continue to represent a majority (60.4%) of mass market enrolled capacity.
- A large majority of utilities using mass market programs (e.g., AC switch, thermostats, thermal storage) do so to defer or replace generation capacity. Additional motivators include: encouraging economical energy use and deferring transmission and distribution (T&D) capacity upgrades.

Figure 5: 2018 Commercial and Industrial Demand Response Capacity by Program Type (GW)



Source: Smart Electric Power Alliance, 2019. N=190 Utility Survey participants.

- Customer initiated programs represent a majority of enrolled capacity for C&I customers, at 8.1 MW (60.6%).
- Utilities using C&I programs primarily do so to defer or replace generation capacity and encourage economical energy use.
- Only 32 of the 190 utilities that participated in this year's survey had no DR programs (16.8% of survey participants). Of the 158 utilities with a DR program, 130 had a mass market program, 106 had a C&I program, and 76 utilities had both C&I and mass market programs.

MW = Megawatts-ac

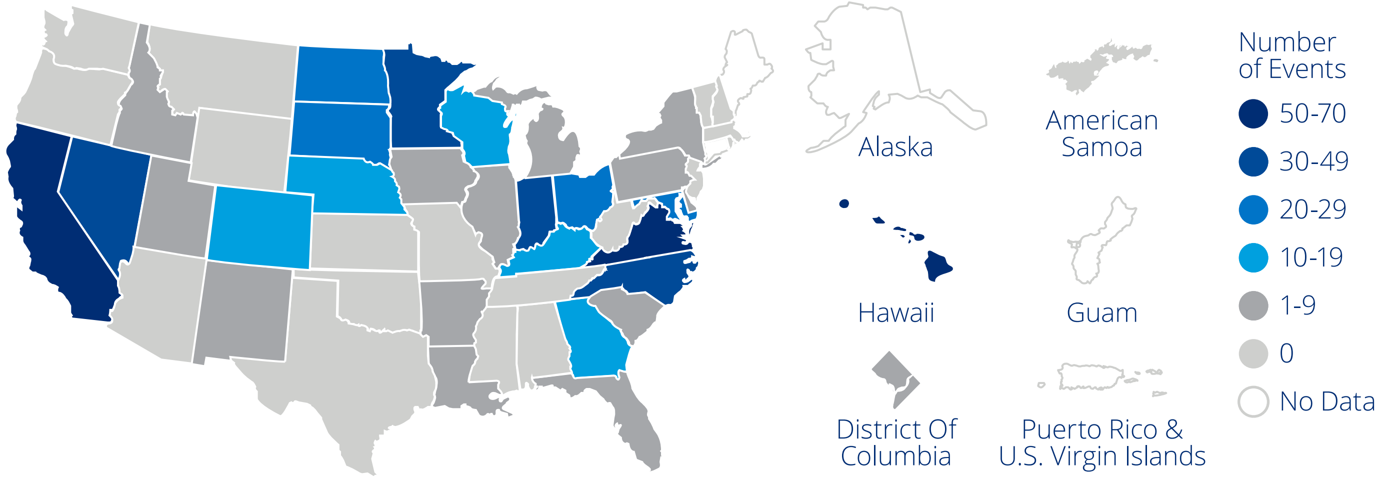
Smart Electric Power Alliance

AC Switch Programs

Figure 6: 2018 AC Switch Program Summary

Enrolled Capacity: **4,491.2 MW**		Dispatched Capacity: **1,828.2 MW**	
68 Utilities with Programs	**62** Utilities that Called an Event	**3.7** Hours Average Event Duration	**4.1** Million Customers Enrolled

AC Switch Events Called in 2018



Average Number of Events Called: **9.7**

Source: Smart Electric Power Alliance, 2019

AC switch programs are an established form of DR used by utilities over the past few decades. Many of these legacy programs rely on one-way communications (e.g., one-way radio paging).

Key Observations:

- Almost 21.6% of total DR enrolled capacity came from mass market AC switches.
- Programs use multiple AC switch technologies and delivery models, with 82.9% of programs using switches with one-way paging, 26.8% using two-way, and 9.8% offering both.
- 34% of respondents indicated that these programs are primarily used to reduce demand during load peaks.
- AC switch programs also serve to defer or replace transmission capacity (30.2%), provide operating reserves (17%), and encourage economic use (13.2%).

MW = Megawatts-ac

Moving Beyond the AC Switch

While the AC switch has been a key component of utilities' DR suites, this year's data showed a decrease in the number of enrolled customer devices (down about 10.7%) from utilities that participated in both 2017 and 2018 surveys.

A number of utilities reported significantly decreasing their AC Switch programs in 2018. Three utilities reported ending their program in 2018, and others reported reducing their programs by over half of their capacity.

Utilities cited multiple reasons for this move away from AC switches:

- AC switches are not cost-effective
- There is a lack of visibility into the devices
- Accounts were not performing due to removals, tampers, or inoperable devices and were no longer being included in utilities' DR numbers
- Customer participation was decreasing
- Customers were no longer being enrolled in the program
- The programs were no longer being marketed to customers
- The technology is old and there was no support for continuing the program
- Regulators did not support continued investment in AC switches

Additional reasons for retiring programs were gathered from industry interviews:

- Increasing customer choice through new programs
- Responding to customer satisfaction
- Lowering ongoing program costs

Differences Across Utility Types

Industry interviews indicated utilities are moving away from AC switch programs at different rates. Investor-owned utilities, which have significant investments in large AC switch programs, might be slower to move away from them. Whereas municipal utilities and cooperative utilities are able to adopt more device-based DR programs at a faster rate.

MW = Megawatts-ac

Smart Electric Power Alliance

Electric Water Heater Programs

Figure 7: 2018 Water Heater Program Summary

Enrolled Capacity: **585.6 MW**

Dispatched Capacity: **202.7 MW**

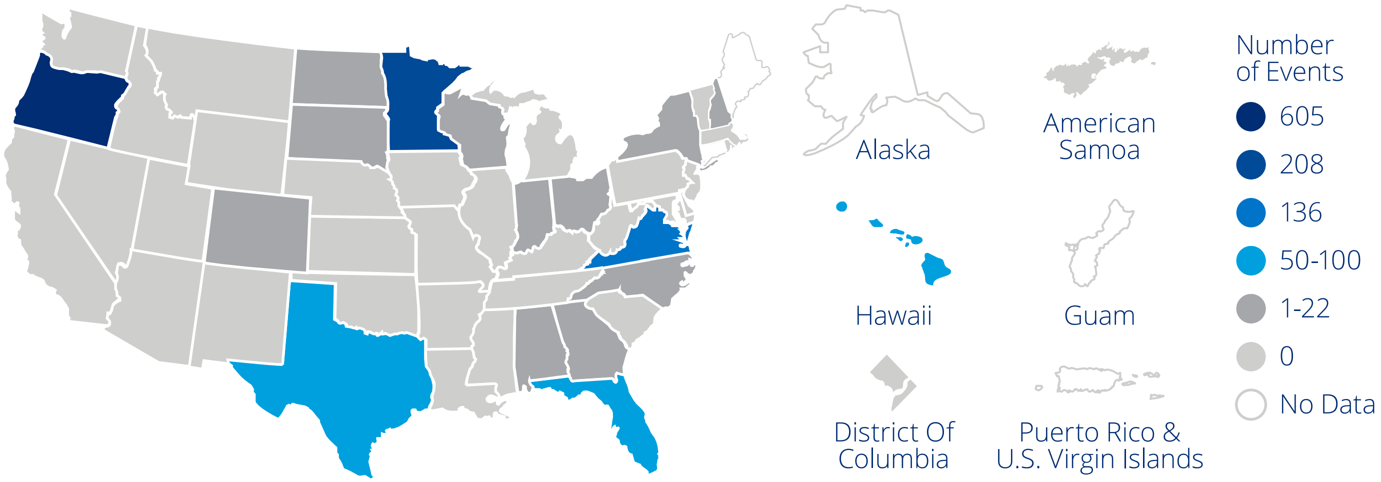
53 Utilities with Programs

27 Utilities that Called an Event

6.0 Hours Average Event Duration

1.3 Million Customers Enrolled

Water Heater Events Called in 2018



Average Number of Events Called: **42**

Source: Smart Electric Power Alliance, 2019

MW = Megawatts-ac

Electric water heaters with switches constitute a widespread and low-cost storage opportunity. Across 53 utilities, electric water heater DR programs have a total enrolled capacity of 585.6 MW, representing 2% of the total enrolled DR capacity.

Because utilities consider water heater programs as non-disruptive to customers, they are called upon more frequently than other devices, indicated by the high average number of events. Additionally, water heater programs in areas like the Northwest can address winter peaking.

Key Observations:

- 11 states currently have grid interactive water heaters (GIWH) pilot programs: Arizona, California, Florida, Georgia, Hawaii, Minnesota, North Carolina, Oregon, South Dakota, Washington, and Wisconsin.[4] See pilot program highlights on page 15.
- Of the utilities that listed a primary program purpose for calling on water heaters, 51.7% said they utilized the program to defer or replace generation and transmission or distribution capacity.

4 Results from SEPA Utility Survey and interviews with industry experts.

Water Heater Program Highlights

In 2018, **Bonneville Power Administration**, **Portland General Electric**, and the **Northwest Energy Efficiency Alliance** completed the largest smart water heater pilot program to date; a three-year study that included 277 participants across eight utilities in the Northwest. The study found that heat pump water heaters can successfully participate in DR events, and be called on hundreds of times a year to reduce renewable curtailment and support increased penetration of renewables through load shifting. The study concluded that if 26% of Oregon's and Washington's electric water heaters participate in DR programs, the region could create 300 MW of storage capacity.[5]

In 2019, **EnergyHub** and **Rheem** partnered with **United Illuminating (UI)** in Connecticut to introduce an intelligent heat pump water heater pilot program. The pilot, which is part of UI's low-income program, plans to offer customers no-cost replacements of older electric water heaters with Rheem intelligent heat pump water heaters, which are integrated with EnergyHub's Mercury distributed energy resource management system (DERMS). The integration of Rheem water heaters and EnergyHub's platform can allow UI to predict, schedule, and dispatch DR calls to the fleet of GIWHs in order to shift energy usage during peak demand events.[6]

In 2019, **Pacific Gas and Electric (PG&E)** introduced the WatterSaver program, a behind-the-meter thermal energy storage program utilizing both heat-pump and electric-resistance water heaters to provide peak load reduction. PG&E set a goal of providing up to 5 MW of peak load reduction capacity by 2025. Initial estimates predict 2,500 to 6,600 units will participate in the program, which is currently still in the approval process.[7]

Shifted Energy is partnering with **Open Access Technology International (OATI)** to deliver 2.5 MW of GIWH to **Hawaiian Electric (HECO)** through Hawaii's recently launched Grid Services Purchase Agreement (GSPA) contract.

Following a 20-minute installation, Shifted Energy's off-tank controller and virtual power plant software converts traditional electric water heaters into distributed energy resources capable of providing valuable grid services such as DR, load building, and fast frequency response. Shifted's GIWH technology utilizes cellular communications and machine learning to accurately monitor and forecast a customer's hot water usage, enabling utilities to maximize each tank's grid service capacity while minimizing impact to the host customer's hot water availability. In return for allowing their water heaters to support Hawaii's grid, residents that participate in the GSPA will receive a monthly bill credit between $3 and $5 over the next 5 years.

Previous GIWH pilots between Shifted and HECO demonstrated that: (1) water heaters are one of the few ways that a multi-family building dweller or renter can participate in utility programs; (2) customers are excited to support state clean energy goals when offered a participation pathway; and (3) intelligently controlled water heaters can successfully provide multiple grid services.

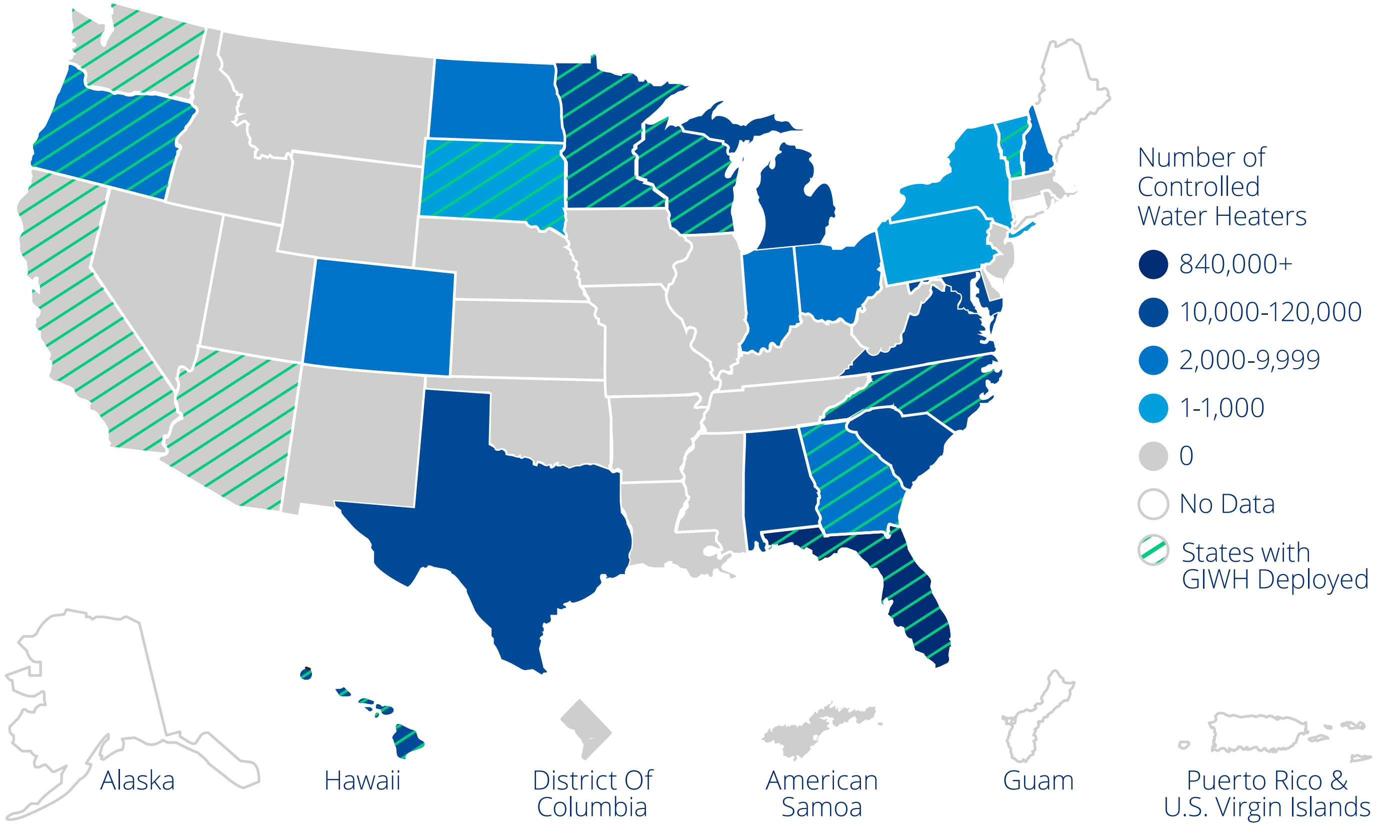
5 Bonneville Power Authority. (2019). Water heater innovation could boost NW renewable energy development. Retrieved from https://www.bpa.gov/news/newsroom/Pages/Water-heater-innovation-could-boost-NW-renewable-energy-development.aspx
6 EnergyHub. (2019). United Illuminating announces successful income-eligible water heater program in partnership with EnergyHub and Rheem. Retrieved from https://www.energyhub.com/blog/united-illuminating-der-program
7 Pacific Gas and Electric. (2019). WatterSaver Program: Behind-the-Meter Thermal Energy Storage Program Implementer. Retrieved from https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/purchasing-program/bid-opportunities/COA-RFP-WatterSaver-Program.pdf

MW = Megawatts-ac

Unlocking the potential of water heaters

A number of utilities with water heater programs are exploring the value of smart water heaters and wireless communication to control products through a switch. In addition, utilities and third-party aggregators have the opportunity to retrofit or replace existing water heaters with GIWHs.

Figure 8: 2018 Mass Market Water Heaters (Number of Devices)



Source: Smart Electric Power Alliance, 2019. Results from survey and interviews with industry experts.

MW = Megawatts-ac

Table 1: One-Way vs. Two-Way Water Heater Capabilities

	Communication Capabilities	Age of Technology	Benefits and Services	Limitations / Barriers to Adoption
Traditional Water Heaters	One-way control	~30 years (established)	▪ Load-shifting: thousands of electric water heaters are connected to one-way load control devices, allowing utilities to shift load to off-peak hours. In this case, one-way electric water heaters act as thermal energy storage systems.	▪ Limited grid services. ▪ No visibility into unit-level performance. ▪ Do not allow customer-specific cold water prevention strategies. ▪ As systems grow older and reach end-of-life, utilities do not have the ability to track which systems respond during dispatched DR events.
Grid-Interactive Water Heaters (GIWH)	Two-way control	~5 years (nascent)	▪ Rapid, stackable services: frequency regulation, load shifting, load building, and ancillary services. ▪ Allow for dynamic grouping and dispatch of varying sized fleets of GIWHs to respond to circuit level contingencies. ▪ Provide data on customer usage habits, allowing utilities and 3rd party aggregators to maximize the available grid service capacity while minimizing negative impacts on customers.	▪ Technology adoption: delays are often encountered when introducing new technology programs. ▪ Consumer mindshare: behind-the-meter storage and smart thermometers are trendy and customer facing. Many customers are not aware of GIWHs and the benefits they offer. ▪ Accessibility: GIWHs and retrofit controllers are not readily available at commercial appliance stores.

Source: Smart Electric Power Alliance, 2019

MW = Megawatts-ac

Thermostat Programs

Figure 9: 2018 Thermostat Program Summary

Enrolled Capacity: **1,042.7 MW**

Dispatched Capacity: **936.1 MW**

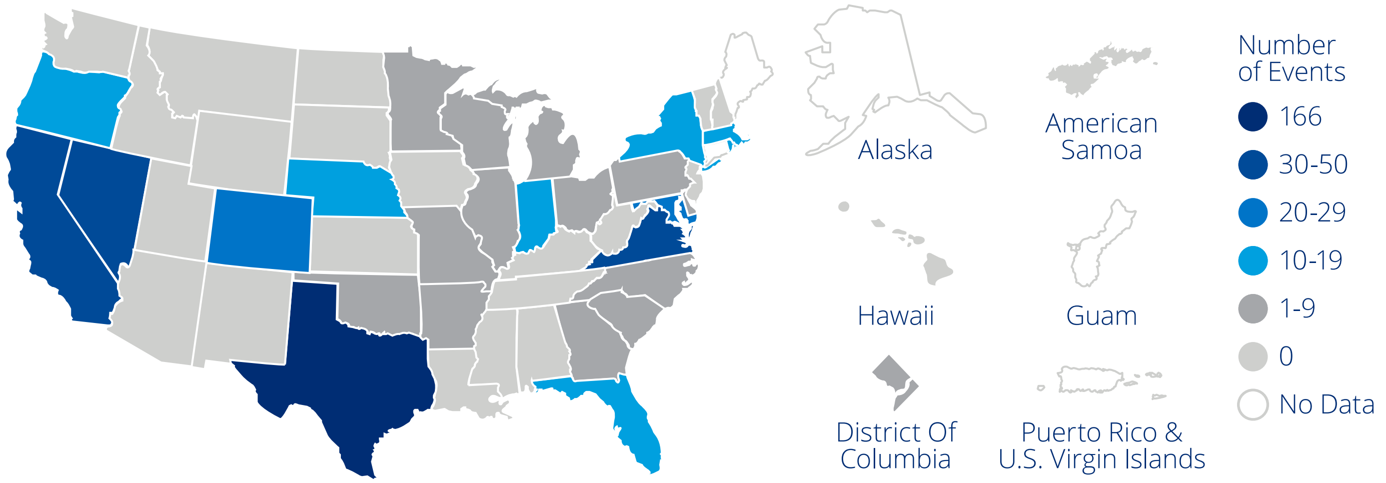
58 Utilities with Programs

53 Utilities that Called an Event

2.6 Hours Average Event Duration

1.1 Million Customers Enrolled

Thermostat Events Called in 2018



Average Number of Events Called: **8.9**

Source: Smart Electric Power Alliance, 2019

This year's survey found that thermostat programs continue to be a popular utility option. Thermostat programs are largely fully implemented (82.5%), as opposed to in the piloting phase (17.5%). Additionally, Bring Your Own Thermostat (BYOT) business models are now the industry standard, and smart thermostats are prevalent throughout the country. These connected thermostats are capable of receiving DR control signals and sharing data with the utility.

Key Observations:

- Utilities use thermostat programs to serve four primary purposes: deferring generation capacity (20.6%), encouraging economical energy use (12.7%), deferring/replacing transmission and/or distribution capacity (11.1%), and peak shaving (11.1%).
- Thermostat programs will continue to expand, with 11 utilities reporting thermostat pilot programs and six utilities reporting full program implementation in 2019 or beyond.
  - Programs include a mix of thermostat technologies and delivery models, including: Wi-fi enabled/smart thermostats (84.8%), one-way communicating thermostats (8.7%), and mixed-metered gateways (6.5%).

MW = Megawatts-ac

Thermostat Program Highlights

Thermostats serve as the entry into the smart home and demand side management programs for utilities, with smart thermostats and BYOT programs becoming common utility offerings. As utilities have seen the successful implementation of these programs, some are now moving beyond the BYOT model to thermostat programs that incorporate precooling, other devices, or pair BYOT with energy efficiency. Additionally, utilities are exploring the intersection of thermostats with time-based pricing. These expansions on traditional thermostat programs show that utilities can successfully implement the BYO model as part of an orchestrated approach to DR.

In 2018, **Arizona Public Service (APS)** and **EnergyHub** launched "Cool Rewards", a program that uses smart thermostats to strategically lower peak demand during summer DR events. The program incorporates pre-cooling optimized for time-of-use pricing and also maintains customer comfort during events by shifting load to times when solar energy is abundant. Along with "Cool Rewards", APS and EnergyHub partnered on a program that uses a DR and energy storage suite to deliver peak demand reduction, load shifting and renewables matching. Using EnergyHub's Mercury platform, APS can enroll, monitor, and manage residential batteries in the Storage Rewards program, as well as grid-interactive water heaters in the Reserve Rewards program. In addition to its DR and energy storage aggregations, APS will manage residential and commercial solar fleets. This suite of managed technologies is designed for peak demand reduction, load shifting and renewables matching, solar fleet operations, and advanced load and capacity forecasting based on machine learning. By modernizing its demand side management programs, APS is able to use these services year round and multiple times a day, and integrate DERs.[8]

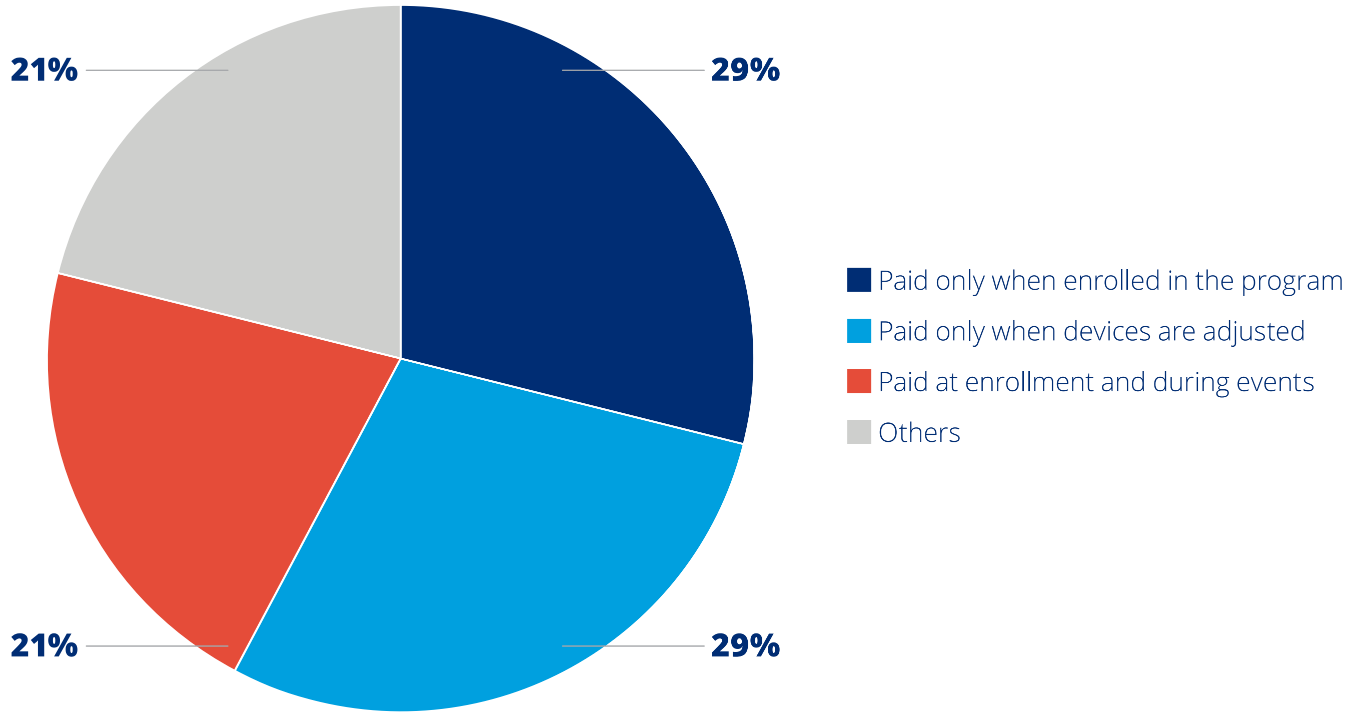
Pepco and **Delmarva Power** are working to bridge energy efficiency (EE) programs and DR programs. Within these utilities, the EE and DR teams collaborated to leverage smart thermostats installed in their territory. The companies offer customers the opportunity to simultaneously enroll in a new energy efficiency program, "Thermostat Optimization Program" (TOP), and participate in their DR program, "Energy Wise Rewards™", through a Bring Your Own Device (BYOD) option.

8 Energy Hub. (2018). Arizona Public Service chooses EnergyHub's Mercury DERMS to deliver innovative grid-edge DER management strategies. Retrieved from: https://www.energyhub.com/blog/arizona-public-service-energyhub-mercury-derms

MW = Megawatts-ac

Smart Electric Power Alliance

Figure 10: Rewards for Participation in Peak Load Program (Q4/18)



"Q7890. In which of the following ways are you rewarded for participating in the peak load control program?"
Among U.S. BB HHs Participating in Peak Load Control Program, n=336, + 5.35%

Rewarding Participation

Recruiting, engaging, and incentivizing customers in DR programs is critically important for increasing participation in peak time programs. As BYOD programs gain popularity, they have the potential to reward participation in different ways. Based on a Parks Associates survey of 10,000 U.S. broadband households and 336 people who participate in peak load programs, it appears that programs are almost evenly split in methods for incentivizing customer participation in peak load events. While there appears to be no majority method for rewarding participation, it should be noted that, between devices, program structures, and rewards, the industry is becoming increasingly diverse in its offerings.

MW = Megawatts-ac

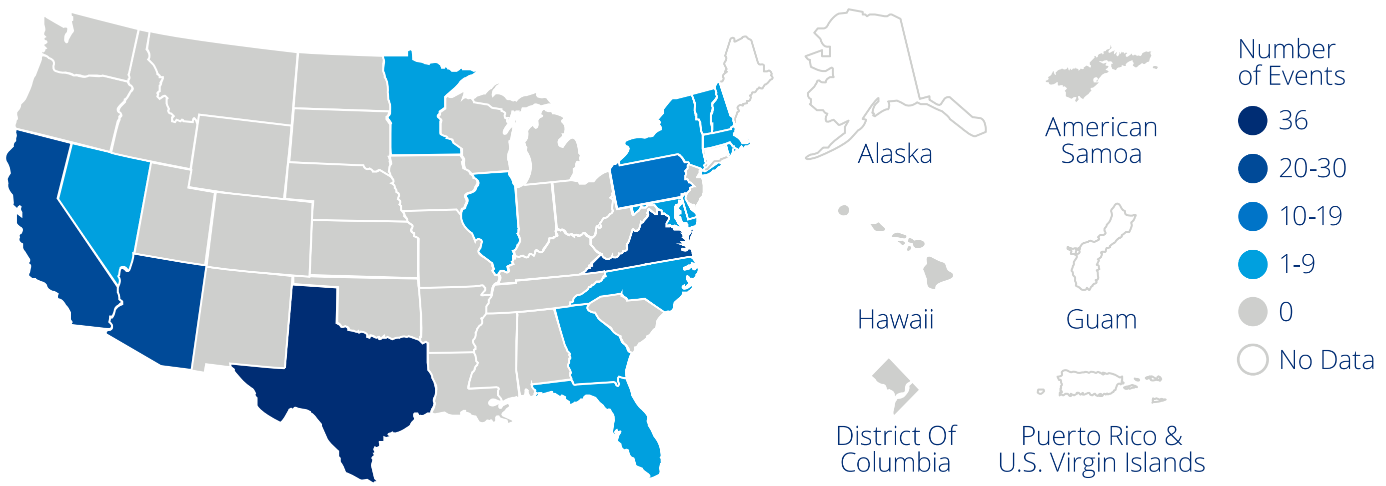
Behavioral Programs

Figure 11: 2018 Utility Behavioral Program Summary

Enrolled Capacity: **785.1 MW**

54 Utilities with Programs	**27** Utilities that Called an Event	**3.6** Hours Average Event Duration	**2.7** Million Customers Enrolled

Behavioral Programs Events Called in 2018



Average Number of Events Called: **7.1**

Source: Smart Electric Power Alliance, 2019

MW = Megawatts-ac

Behavioral DR, as traditionally understood, refers to programs that encourage or incentivize participation in peak events, through direct communication or education. Today, utilities are using some of these traditional communication methods to encourage participation in time of use (TOU) programs.

For the purposes of the survey, SEPA asked utilities to identify dispatchable DR events. Some utility programs may use messaging to encourage participation in TOU programs, thus including these as events. SEPA's survey captured legacy behavioral DR programs, as well as programs that use behavioral methods such as messaging to encourage participation in some time-based programs.

Key Observations:

- Of the utilities that listed a primary program purpose for calling behavioral DR programs, 66.7% reported peak shaving as the main reason for offering the program.
- Survey results indicated 54 active behavioral programs with 47 fully implemented and 7 that are in pilot phases. Additionally, two utilities noted that they have programs set to begin in 2019 and two planned for 2019.

Table 2: Approaches to Behavioral Demand Response	
Behavioral DR can encompass different methods of dispatching load. Methods for signaling events, integrating customer experience across new platforms, and managing customer communications to encourage participation are changing as new devices are being introduced into customers' homes. Successful behavioral DR programs have employed various methods, such as an opt-out approach (versus opt-in) or using existing customer interfaces and apps, to encourage customer participation. The following programs illustrate the different approaches to behavioral DR and reducing peak demand.	
Traditional behavioral demand response (event-based)	**Time-based behavioral demand response (habitual)**
Oracle's "SmartEnergy Rewards", a peak time rebate program, shows how traditional behavioral DR can be successfully deployed. This program has been implemented at multiple utilities. Its implementation at **Baltimore Gas and Electric (BGE)** is the largest digital DR program in the U.S., with 1.1 million homes enrolled in peak time rebates, over 70% participation in peak savings, and 300 MW cleared on the PJM capacity market. BGE notifies customers the day before a savings event and participating customers receive a bill credit. The program automatically enrolls customers with installed smart meters (making it an opt-out program), and combines a peak rewards program that uses traditional DR with an AC switch or thermostat that pays a small fee for participation, with a smart energy rewards program that is behavioral and pays out as a peak rebate. Customers can participate in both and claim the greater benefit.	Along with their SmartEnergy Rewards program, Oracle's "Behavioral Load Shaping" program uses "Time of Use Coach" and "High Bill Alert" to personalize weekly update emails to customers showing peak usage to prevent bill shock. The program aims to reduce peak demand and increase customers' satisfaction and engagement with TOU rates, making them less likely to opt out. The program began enrolling customers in April 2019 and is currently in pilot phase; participating utilities include: **Baltimore Gas and Electric**, **Delmarva Power**, and **Pepco**.

Source: Smart Electric Power Alliance, 2019

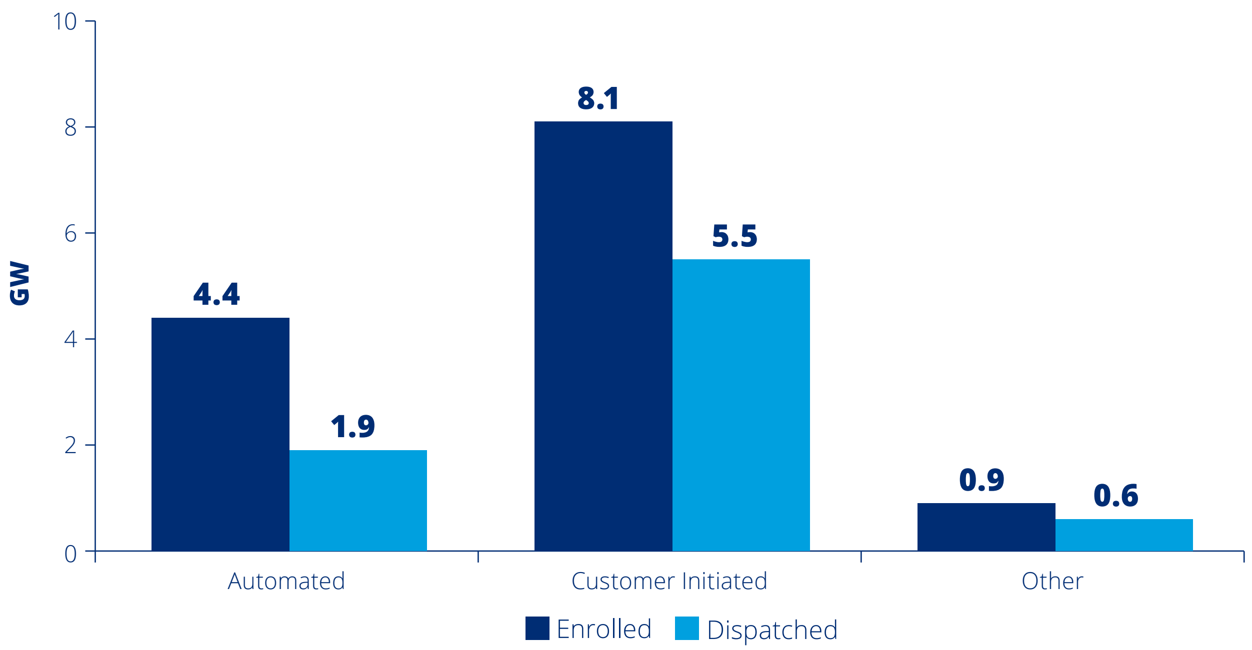
MW = Megawatts-ac

Smart Electric Power Alliance

C&I Demand Response Programs

C&I programs contributed 13.3 GW of enrolled DR capacity in 2018, representing 64.9% of the total enrolled capacity in 2018.

Figure 12: 2018 Commercial and Industrial Demand Response Enrolled and Dispatched Capacity (GW)



Source: Smart Electric Power Alliance, 2019. N=190 Utility Survey participants.

Table 3: 2018 Utility Commercial and Industrial Program Summary

	Automated	Customer Initiated	Other
Number of Utilities with Programs	60	78	32
Number of Utilities that Called Events	47	49	10
Total Number of Customers Enrolled	72,353	31,397	1,825
Average Number of Events Called	13.7	7.4	6.1

Source: Smart Electric Power Alliance, 2019

Key Observations:

- C&I DR programs serve three primary purposes: defer or replace generation capacity (31.8%), emergency load management/reduction (22.4%), and to encourage economical energy use (14.1%).
- Six utilities in Pennsylvania have utilized customer initiated DR programs to meet requirements for demand reduction established by the Pennsylvania Public Utility Commission in 2008.
- Other C&I programs accounted for in this survey include those that do not fall under “automated” or “customer initiated” such as irrigation control.

MW = Megawatts-ac

C&I Program Highlights

In 2019, **Ameren (Missouri)** partnered with **Enel X** to finalize its Business Demand Response Program. The partnership will allow Enel X to manage Ameren's C&I DR porfolio. The program will reduce load during times of peak demand, and has delivered 25 MW of DR resources so far in 2019, with a projected demand reduction capacity of 100 MW from the utility's C&I customers for the 2019-2021 program period.[9] In addition to helping reduce peak demand, this program will provide capacity resources to the MISO transmission system.

In 2018, **Eversource** introduced a new software platform that has allowed the utility to integrate a variety of technologies to address C&I peak demand and provide customers with solutions specific to their needs. Eversource has implemented open communication protocols to allow for easy integration of a diverse range of devices (smart thermostats, battery storage, etc.). Utilizing this approach, Eversource successfully reduced regional peak demand by nearly 9 MW in 2018.

C&I Non-Wire Alternatives

C&I programs represent an important option for utilities that are considering non-wire alternatives (NWA) projects. In a recent NWA report from SEPA, E4TheFuture, and PLMA, three of the ten NWAs that were highlighted leveraged C&I DR to defer traditional transmission and distribution (T&D) upgrades.[10]

- **Bonneville Power Authority**'s South of Allston project explored the local impacts of a new $1 billion transmission line, but the utility ultimately chose to implement a more flexible and scalable NWA solution. One of the two solutions in the project portfolio involved managing large C&I customer end-user demand.
- **Consumers Energy**'s Swartz Creek Energy Savers Club was able to successfully reduce demand through increased program participation. Although C&I customers were challenging to recruit, commercial lighting programs offered the majority of savings along with residential DR programs.
- **Southern California Edison** solicited offers to meet long-term local capacity requirements (LCR) resulting from nuclear and natural gas generation plant closures. **STEM** was awarded the project in 2016 and has integrated over 100 C&I battery storage systems to meet the LCR by operating as a virtual power plant and meeting critical peak capacities.

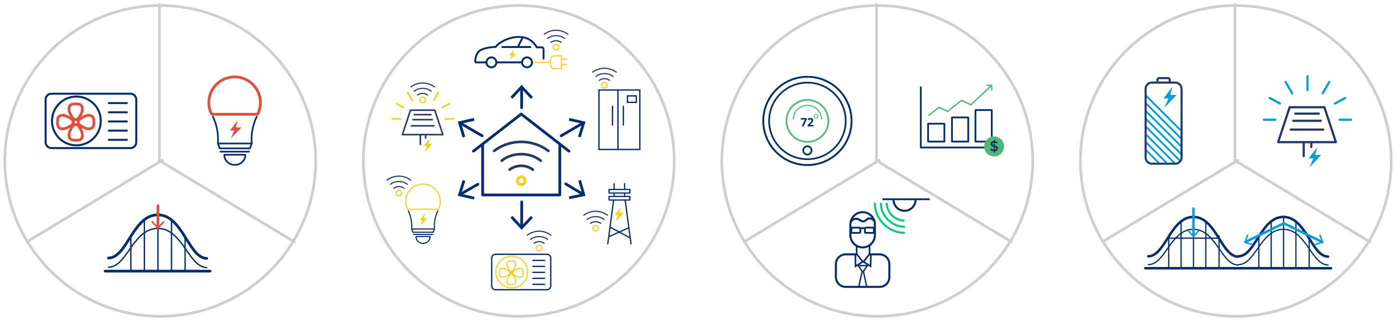
9 ENEL X. (2019). Enel X Signs 100 MW Demand Response Agreement with Ameren Missouri. Retrieved from https://www.enelx.com/n-a/en/news-media/all-press/enel-x-signs-100mw-demand-response-agreement-ameren-missouri
10 SEPA (2018). Non-Wires Alternatives: Case Studies from Leading U.S. Projects. Retrieved from https://sepapower.org/resource/non-wires-alternatives-case-studies-from-leading-u-s-projects/

MW = Megawatts-ac

Grid-Interactive Efficient Buildings

With the growing number of DERs interconnected on the grid, C&I demand flexibility is as important as ever. Grid-interactive efficient buildings play an important role by integrating energy-efficient measures like high-quality walls, windows, and lights that reduce peak demand with grid connectivity to respond to grid needs and integrate DERs. As shown below in Figure 13 , grid-interactive efficient buildings can provide efficient, connected, smart, and flexible power to provide generation and transmission services as well as ancillary service benefits.

Figure 13: Characteristics of Grid-Interactive Efficient Buildings



Efficient

Persistent low energy use minimizes demand on grid resources and infrastructure

Connected

Two-way communication with flexible technologies, the grid, and occupants

Smart

Analytics supported by sensors and controls co-optimize efficiency, flexibility, and occupant preferences

Flexible

Flexible loads and distributed generation/storage can be used to reduce, shift, or modulate energy use

Source: Department of Energy. (2019). Grid-Interactive Efficient Buildings. Retrieved from https://www.energy.gov/sites/prod/files/2019/04/f61/bto-geb_overview-4.15.19.pdf.

Table 4: Potential Benefits/Avoided Costs Provided by Commercial and Industrial Demand Flexibility

Grid Services	Potential Benefits/Avoided Costs
Generation Services	The deferment/replacement of generation capacity has become an important benefit for utilities integrating DR on a C&I level.
Transmission & Distribution Services	DR offers an opportunity as a Non-Wire Alternative (NWA) to defer or avoid the need for traditional transmission and distribution (T&D) investments or reduce constraints along the grid.
Ancillary Services	C&I demand flexibility can offer the important role of regulating frequency and voltage as well as providing spinning reserves through reduced demand over short periods of time.

Source: Department of Energy. (2019). Grid-Interactive Efficient Buildings. Retrieved from https://www.energy.gov/sites/prod/files/2019/04/f61/bto-geb_overview-4.15.19.pdf.

MW = Megawatts-ac

Demand Response Policy Updates

Time-Varying Rates

Many utilities offer time-of-use (TOU) rate options for customers as a mechanism to shift energy use from periods of peak system demand to off-peak periods. While the majority of these are offered on an opt-in basis, some utilities are implementing default, or opt-out, TOU rates. Recent state activity related to TOU rates includes:

- **California:** Responding to the California Commission's decision to reform residential rate structures, the state's major IOUs have begun transitioning residential customers to default TOU rates aiming to complete the transition by the end of 2019.
- **Maryland:** The Public Service Commission approved TOU rate pilots in 2018, as part of the state's PC 44 grid modernization proceeding.
- **Michigan:** The Michigan Public Service Commission directed DTE Electric to begin implementing default TOU rates in 2018, and approved default residential TOU rates for the utility in May 2019.
- **New Hampshire:** A working group is developing TOU rate pilots in New Hampshire that will help to inform future changes to net metering rules.
- **Virginia:** Legislation enacted in March 2019 directs Dominion Energy to convene a stakeholder group to produce TOU rate recommendations.

Innovative Rate Designs

Some utilities are piloting new rate structures beyond time-varying rates, including those that contain critical peak pricing, demand charges, subscription rates, and time-varying rates designed specifically to encourage electric vehicle charging.

Table 5: Innovative Rate Design Actions

Arizona	Arizona's three investor-owned utilities offer a pilot "R-TECH" rate to residential ratepayers with certain customer-sited resources. The tariff features time-varying rates and two demand charges.
Minnesota	Xcel Energy filed a proposal for a new residential electric vehicle subscription rate in February 2019, which would provide participants with unlimited off-peak charging at home.
North Carolina	Duke Energy Carolinas proposed dynamic price pilots in April 2019, pursuant to a Commission order. The pilots include critical peak pricing and daily peak pricing for residential and small commercial customers.

Source: DSIRE Insight, NC Clean Energy Technology Center, 2019

MW = Megawatts-ac

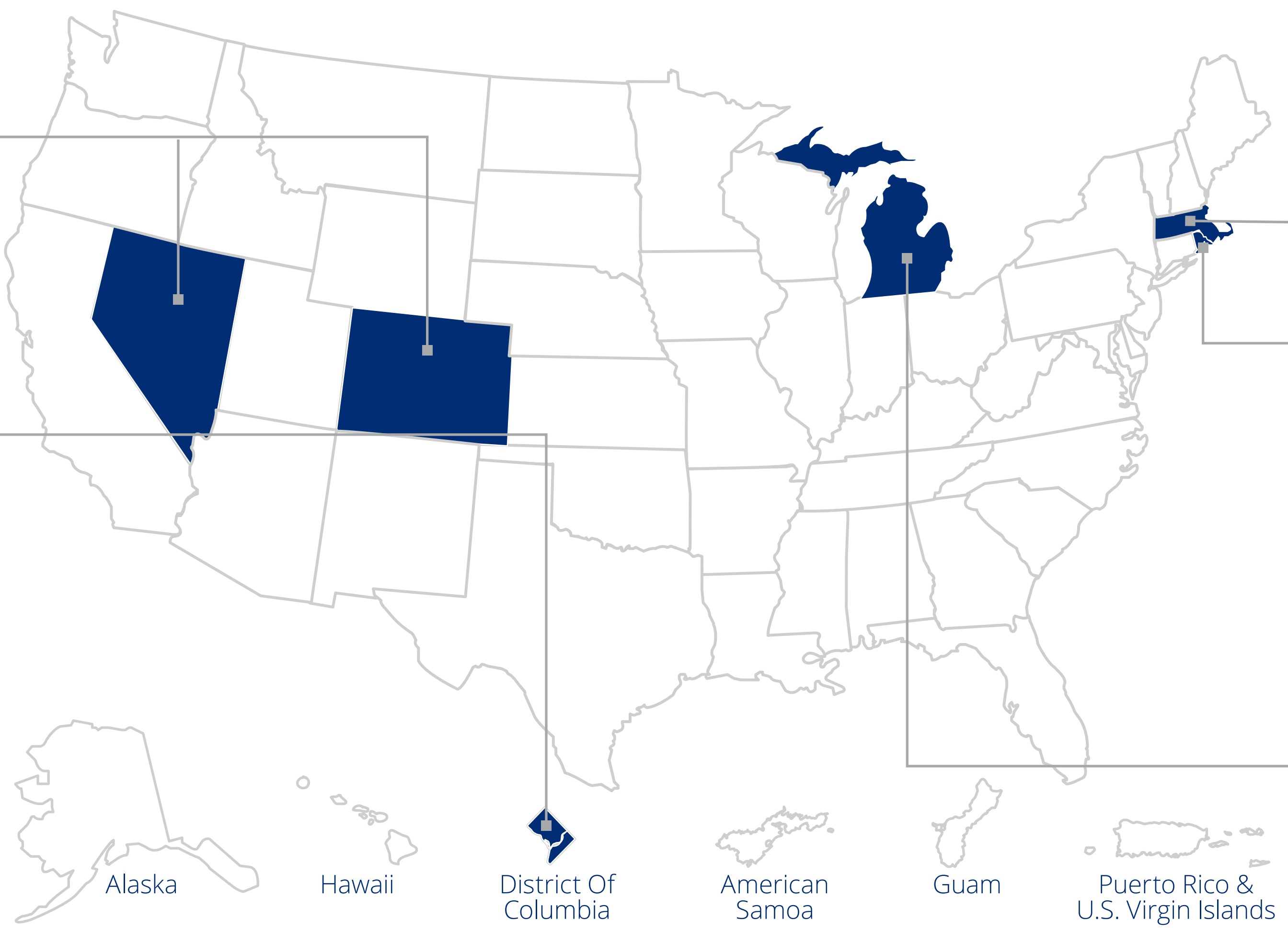
NC CLEAN ENERGY TECHNOLOGY CENTER | DSIRE insight | Smart Electric Power Alliance

Demand Response Policy Activity

Distribution System Planning and Non-Wires Alternatives: Colorado legislators enacted S.B. 236 in June 2019, directing the Public Utilities Commission to develop distribution system planning rules and a methodology to evaluate the use of distributed energy resources, including DR, as NWAs. In October 2018, the Public Utilities Commission of Nevada adopted distributed resource planning rules encompassing DR resources.

Energy Efficiency and Demand Response Programs: The Clean Energy DC Omnibus Amendment Act of 2018 requires the DC Commission to establish a working group to guide the development of utility-administered EE and DR programs to primarily benefit low and moderate-income residential ratepayers. The Act authorizes the Commission to approve efficiency and demand reduction programs and new cost recovery mechanisms proposed by utilities.

Figure 14: States with Recent Demand Response Policy Activity



Source: DSIRE Insight, NC Clean Energy Technology Center, 2019

Clean Peak Standards: Massachusetts lawmakers adopted the first Clean Peak Standard in the country in 2018, which will allow DR resources to be used for compliance. Additionally, a straw proposal was released in 2019, which specifies the types of resources that may be used for compliance and designates four hours for each season as peak periods.

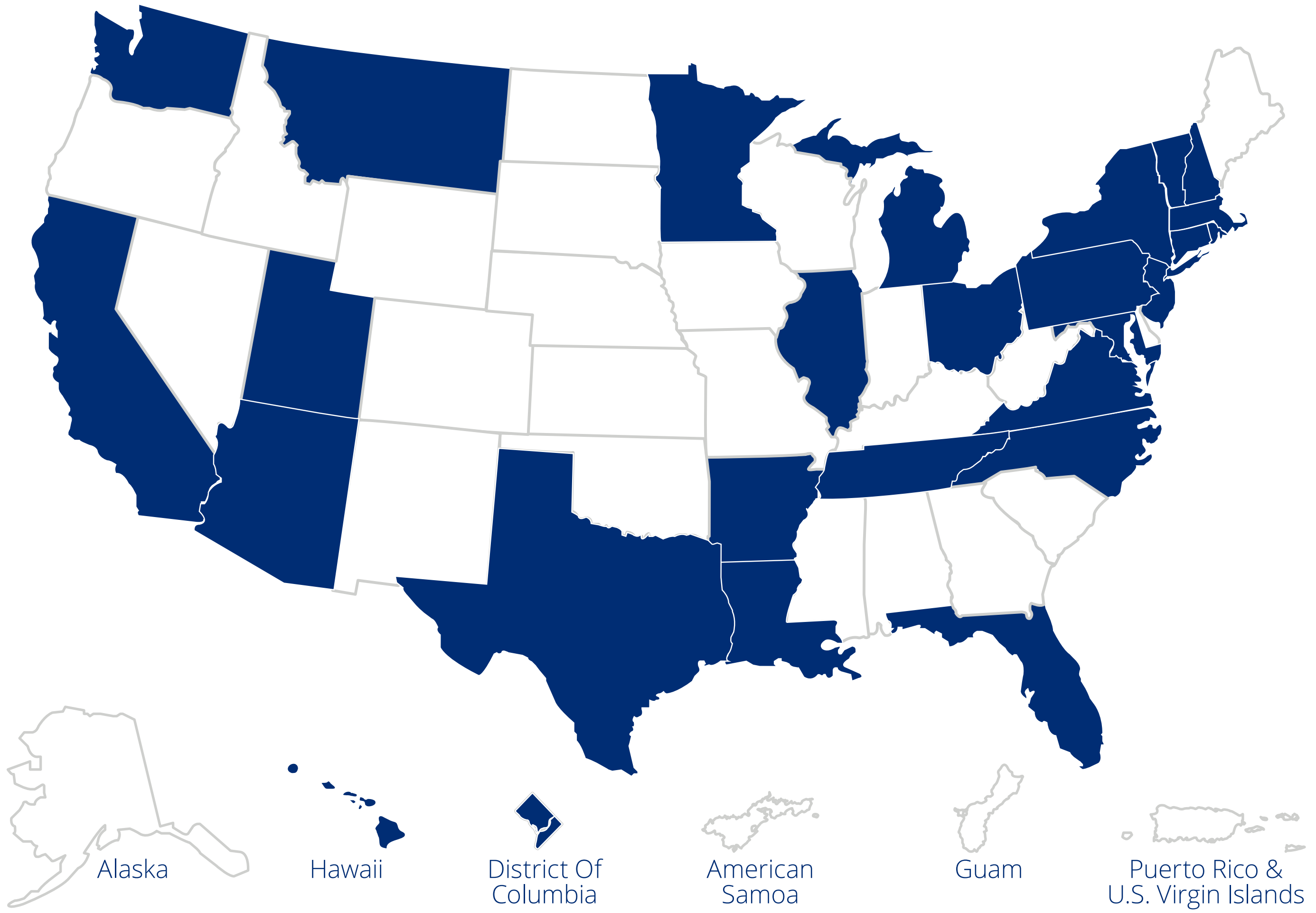
Performance Incentive Mechanisms: In an August 2018 decision, Rhode Island regulators approved a new performance incentive mechanism for National Grid based on capacity savings. In Massachusetts, National Grid proposed a new performance incentive mechanism based on peak reduction in November 2018.

Demand Response Aggregation: In November 2018, the Michigan Public Service Commission opened a proceeding to investigate DR aggregation issues.

MW = Megawatts-ac

Customer Data Access Policies

Figure 15: States Recently Considering Data Access Policies



Source: DSIRE Insight, NC Clean Energy Technology Center, 2019

At least 26 states and DC have considered rules for access to customer energy usage since the start of 2018. Access to such data could provide increased opportunities for DR.

Recent State Activity:

Recent state activity addresses customer access to their energy usage data, allowing customers to designate third parties to access their data, and providing access to aggregated energy usage data.

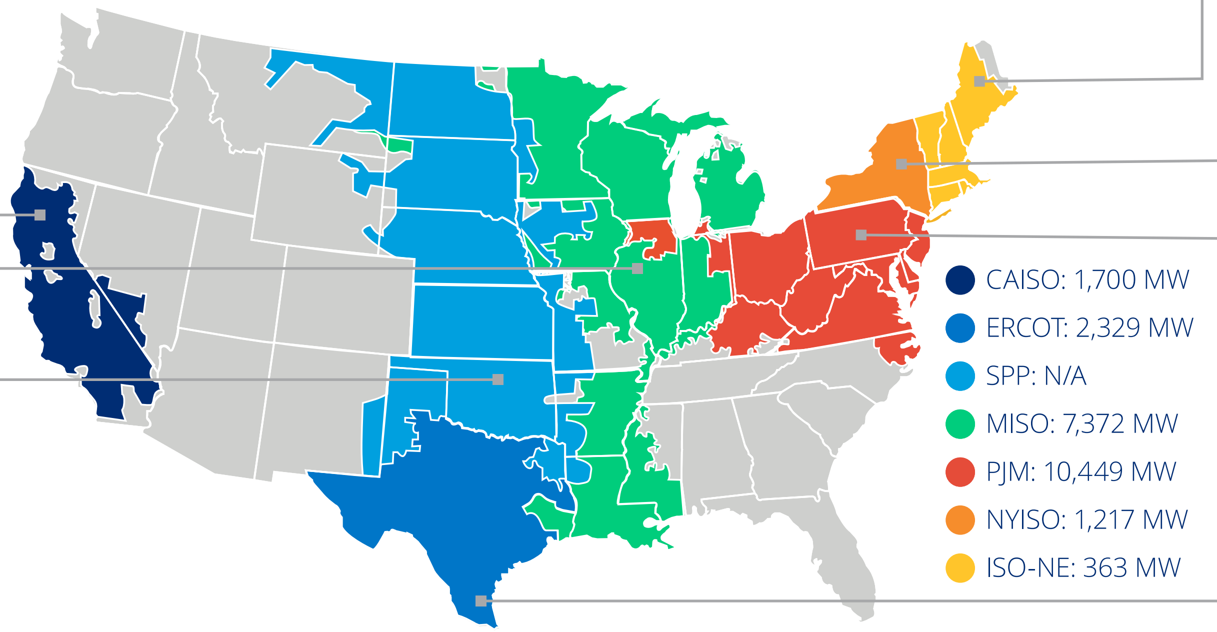
- **Hawaii:** Lawmakers enacted a bill in May 2019 giving ratepayers access to their consumption and production data and the ability to authorize third-party access.
- **Montana:** H.B. 267, enacted in April 2019, requires that customers have access to usage data collected by advanced metering infrastructure and have the authority to designate a third party to gain access. The bill also allows utilities to disclose aggregated and anonymized usage data.
- **North Carolina:** The North Carolina Utilities Commission opened a new proceeding on customer data access rules in February 2019.
- **Ohio:** Following completion of the PowerForward grid modernization investigation, regulators opened a new proceeding on data and the modern grid.
- **Virginia:** Lawmakers enacted legislation in March 2019 directing the State Corporation Commission to convene a data access stakeholder group.

MW = Megawatts-ac

Demand Response in Wholesale Power Markets

- **California Independent System Operator (CAISO): 1,700 MW** of total available capacity from reliability DR resources in 2017 was integrated into the CAISO market.[11] This represented 3.5% of the 2018 resource adequacy capacity for CAISO.
- **Midcontinent Independent System Operator (MISO): 7,372 MW** of DR was cleared in the 2019-2020 planning resource auction results for meeting resource adequacy requirements. This represented 5% of the 2019 capacity for MISO. Note however that DR in the MISO market is primarily retail DR with utilities and is not actively traded in wholesale power markets, unlike the other ISOs/RTOs.[12]
- **Southwest Power Pool (SPP): N/A**

Figure 16: Demand Response Capacity by Regional Transmission Organization and Independent System Operator



Source: Navigant Research, 2019

Navigant's Methodology for ISO and RTO DR capacity

These numbers are based on publicly available data from the ISOs and RTOs and communication with ISO and RTO members. For PJM, NYISO, and ISO New England, the numbers shown are capacity market obligations. For MISO, ERCOT, and CAISO, they are a combination of the enrollment in the different DR programs that each RTO offers.

- **ISO New England: 363 MW** of DR assets had capacity obligations in the ISO-NE market in May 2019. This represented 1.4% of the 2019 capacity for ISO-NE.[13]
- **New York Independent System Operator (NYISO): 1,217 MW** of capacity was enrolled (as of June 2019) in the reliability-based program, Installed Capacity-Special Case Resources (ICAP/SCR), offered by NYISO. This represented 3% of the 2019 capacity for NYISO.[14]
- **PJM Interconnection (PJM): 10,449 MW** of DR is participating in the PJM market for the 2019/20 delivery year, which represents 6% of the total PJM capacity in that year.[15]
- **Electric Reliability Council of Texas (ERCOT): 2,329 MW** in combination awarded in ERCOT's Responsive Reserve Service (RRS) and procured in Emergency Response Service (ERS) programs by the end of 2018.[16] This represented 3% of the 2018 capacity for ERCOT.

11 California ISO. (2018, page 42). Annual Report on Market Issues and Performance. http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf
12 MISO. (2019). 2019/2020 Planning Resource Auction (PRA) Results. This was the total amount of Demand Response cleared in the MISO market in 2019-2020. Retrieved from https://cdn.misoenergy.org/20190412_PRA_Results_Posting336165.pdf
13 ISO-NE. (2019). Demand Resources Working Group Monthly Report. Retrieved from https://www.iso-ne.com/committees/markets/demand-resources/
14 NYISO. (2019). Special Case Resources Monthly Report. Retrieved from https://www.nyiso.com/documents/20142/4341980/2019-06-SCR-Monthly-Report-June-After-Close-of-Partial-Sales.pdf
15 PJM. (2019). 2019 Demand Response Operations Markets Activity Report: September 2019. Retrieved from https://www.pjm.com/-/media/markets-ops/dsr/2019-demand-response-activity-report.ashx?la=en
16 ERCOT. (2018). 2017 Annual Report of Demand Response in the ERCOT Region. Retrieved from http://www.ercot.com/content/wcm/lists/94805/2017_Annual_Report_of_Demand_Response_in_the_ERCOT_Region.docx

MW = Megawatts-ac

Table 6: Regional Transmission Organization/Independent System Operator Updates

RTO/ ISO	Update
CAISO	▪ DR providers or aggregators and retail customers can participate in day-ahead and real-time energy markets, and the ancillary services market. ▪ 2019 Demand Response Auction Mechanism (DRAM) for bidding retail DR into the wholesale market reported a total bid of 167 MW for both residential and non-residential DR. DRAM auctions are conducted by utilities, but DRAM resources are required to bid into the CAISO market. ▪ CAISO's DR availability assessment hours changed to 4pm-9pm year round. This change from mid-day will help flatten the neck of the duck curve in the evening when solar goes offline and demand increases.
ERCOT	▪ Loads controlled by high-set, under-frequency relays continue to dominate the number and capacity volume of DR resources that participate in the ancillary service market (Responsive Reserve). ▪ Prior to summer 2019, experts predicted that ERCOT's reserve margin would drop to a record low (7.4%). If ERCOT's capacity reserve drops too far below its target, the market's scarcity pricing mechanism can trigger, meaning higher prices available for DR participation in the market. ▪ In August 2019, ERCOT called an energy emergency alert twice in one week as capacity reserves dipped below ERCOT's set reserve margin.
MISO	▪ DR is eligible to provide energy, capacity, and ancillary services; the majority of participation is from utilities. ▪ The total amount of DR cleared in MISO's 2019-2020 Planning Resource Auction (PRA) was almost 6% greater than the previous year's amount. This change was due to an increase in the planning reserve margin requirement, a decrease in supply, and changes in market participants' offer behavior. The current DR amount in the PRA represents 5% of MISO's total planned resource for 2019-2020.
ISO-NE	▪ The implementation of the ISO-NE price-responsive demand construct has led to several key changes for 2019 in its DR programs: (1) DR programs are now dispatched based on economic (instead of emergency) conditions, (2) DR is now considered fast-acting and must be dispatched within 30 minutes of the grid's call for curtailment, and (3) DR resources can be offered into both day-ahead and real-time energy markets.
PJM	▪ In late 2018 PJM approved a summer-only DR proposal to accommodate utility air conditioning-focused programs that could be ineligible for annual capacity payments. Rather than earning capacity payments, the reliability requirement will be lowered by the MW committed in the program, and the utility will receive an avoided capacity cost. This change will take effect for the 2019 capacity auction for the 2022/23 Delivery Year. ▪ In 2019, a new rule allows customers to contribute different seasonal load values in the capacity market if their curtailment service provider (CSP) can find an offsetting capacity match from another DR customer within that same load zone. ▪ In June 2019, FERC rejected a proposal by PJM that would have required DR resources to participate year-round.
NYISO	▪ In 2018, NYISO proposed changes to the capacity market dictating how long a resource must be able to run to be eligible to receive the full value of capacity. ▪ NYISO initially proposed that resources would need to be able to run for 8-hours in order to obtain full capacity value. But, it soon modified its proposal following feedback from DR and energy storage providers. NYISO's modified proposal created an incremental scale of duration times and the corresponding portion of the full value of capacity a resource would receive. The modified proposal also considers the capacity (MW) of each resource.

Source: Navigant Research, 2019

Challenges and Opportunities

- Turnover of FERC Commissioners, and lack of replacements and quorum, may delay approval of RTO market reforms, including decisions on DER and energy storage specifically.
- Capacity and energy market prices have stabilized and even decreased in many markets as low-cost renewables enter the market, which may lower the incentives for DR to participate.
- Many RTOs are investigating ways to address DR and DER as a more-diverse set of resources enter the market. This includes determining mechanisms to limit and/or accommodate seasonal resources like air conditioning-based DR, and hours of run-time limits for resources like energy storage.
- RTOs are devising more effective processes to aggregate DR and DER resources to enhance market participation opportunities as individual contributors shrink (at the residential level and for electric vehicles) and for pairing summer and winter resources to create annual resources.
- Value-stacking potential of wholesale and retail DR programs is growing in importance as utilities build up DR programs for distribution-level purposes where customers can participate in both types of programs/markets concurrently.
- The growth of intermittent renewable capacity like solar and wind may require new types of grid flexibility services for DR.

MW = Megawatts-ac

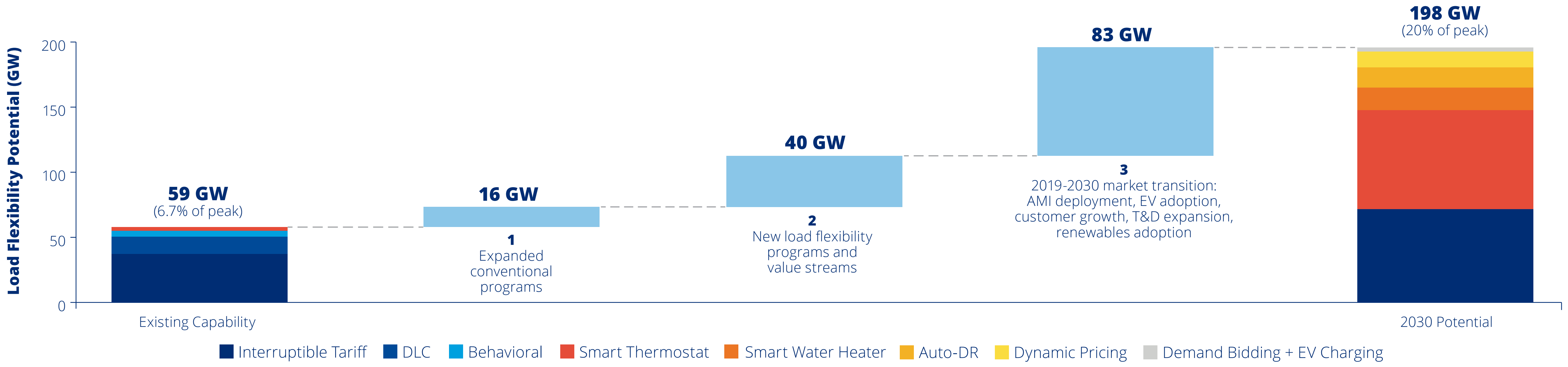
THE Brattle GROUP

Smart Electric Power Alliance

Demand Flexibility and Advanced Applications of Demand Response

In a recent study, The Brattle Group identified 200 GW of economically-feasible load flexibility potential in the U.S. by 2030.[17] This potential equates to 20% of 2030 U.S. peak load levels. The benefits of this load flexibility could save the U.S. energy sector more than $15 billion per year by 2030. **Load flexibility** refers to load being managed to provide value beyond total system peak demand reduction, such as geographically targeting demand reductions, load building, and system balancing.

Figure 17: U.S. Cost-Effective Load Flexibility Potential by 2030



Source: The Brattle Group, 2019

17 The Brattle Group. (2019). The National Potential for Load Flexibility. Retrieved from https://brattlefiles.blob.core.windows.net/files/16639_national_potential_for_load_flexibility_-_final.pdf

MW = Megawatts-ac

THE Brattle GROUP

Smart Electric Power Alliance

The Brattle Group identified three main factors that contribute to the projected growth in DR capacity:

1. **Expansion of Conventional Programs (potential increase over existing capability: 16 GW [27%])**
   - By expanding conventional programs through increased customer marketing and outreach, altering program regulations, and improving incentive measures, DR programs can see increased enrollment and capacity.
   - Conventional programs offer value due to their ability to address peak load concerns by leveraging existing program infrastructure.
2. **New Load Flexibility Programs (potential increase over existing capability: 40 GW [16%])**
   - Managing load through load flexibility programs, such as adopting advanced consumer technologies like smart thermostats and dynamic pricing, has the potential to increase DR capacity.
   - Load flexibility programs introduce new value streams and utilize emerging load control technologies and load sources.
3. **Market Transition Impacts from 2019 to 2030 (potential increase over existing capability: 83 GW [140%])**
   - Increased adoption of advanced metering infrastructure, EVs, smart thermostats, and other smart technologies is driving more participation in load flexibility programs.
   - Acceleration of renewable energy generation and associated generation variability increases the need for ancillary services that load flexibility programs can provide.
   - Non-wires alternatives will also see growing opportunity due to a need to expand and modernize T&D systems.
   - These developments justify greater customer participation and expansion of load flexibility programs.

Case Study: Xcel Energy Carbon Reduction Efforts

Xcel Energy announced in 2018 that it would deliver 100% carbon-free electricity to customers by 2050, and committed to reducing carbon emissions by more than 80% in their eight upper midwest customer states by 2030. Carbon reduction and electrification are supported through the incorporation of DR, as it can be used to address fluctuating power and load supplies.

The Brattle Group and Xcel Energy recently explored how DR can help meet these carbon reduction goals by expanding the impacts of cost-effective DR and load flexibility. They found that DR potential would increase by at least 37% by broadening conventional DR programs and would increase by an additional 18% through implementation of load flexibility programs.[18]

18 The Brattle Group. (2019). The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory. Retrieved from https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7b10FBAE6B-0000-C040-8C1D-CC55491FE76D%7d&documentTitle=20197-154051-03

MW = Megawatts-ac

THE Brattle GROUP

Smart Electric Power Alliance

Going Beyond "DR 1.0":

In SEPA's 2017 Demand Response Market Snapshot, the evolution of DR along a DR 1.0, 2.0, and 3.0 framework was introduced, pulling from Peak Load Management Alliance's original model.[19] Figure 18 illustrates how Brattle's assessment of load flexibility market potential fits into this framework.

Figure 18: Load Flexibility Market Potential and Value

		Generation Capacity Avoidance	Reduced Peak Energy Costs	System Peak Related T&D Deferral	Targeted T&D Capacity Deferral	Load Shifting/ Building	Ancillary Services	
DR 1.0	Direct Load	■	■	■	■			Traditional DR (e.g., DR 1.0) typically includes one-way communication devices and is called upon less frequently during peak events.
	Interruptible Tariff	■	■	■				
	Demand Bidding	■	■	■		■		
	Time-of-Use (TOU) Rates	■	■	■				
DR 2.0 → DR 3.0	Dynamic Pricing	■	■	■				The DR industry is evolving to encompass 2.0 attributes (i.e., two-way communication devices, shifting of loads, more frequency and voltage regulation). Utilities and solution providers are starting to approach grid services with a technology agnostic lens, increase automation, and orchestrate DERs together to provide grid flexibility. Thus bringing us into the era of DR 3.0.
	Behavioral DR	■	■	■	■			
	Smart Thermostat	■	■	■		■		
	Timed Water Heating	■	■	■		■	■	
	EV Managed Charging	■	■	■	■	■	■	
	Ice-Based Thermal Storage	■	■	■	■	■		
	C&I Auto-DR	■	■	■	■	■	■	

DR 1.0: Utilities, through customer notifications or one-way communication load-control devices, focus mostly on demand mitigation during constrained peak.
DR 2.0: Uses bilateral communications, and greater locational capabilities to shift loads and provide frequency and voltage regulation services on a more automated level.
DR 3.0: Integrates DR into the larger ecosystem of DERs. Along with other DERs, DR can provide services to the grid, be called upon regularly, and is orchestrated across technologies.

Source: Smart Electric Power Alliance and The Brattle Group, 2019

19 Peak Load Management Alliance. (2017). Evolution of Demand Response in the United States Electricity Industry. Retrieved from http://www.peakload.org/default.asp?page=DefiningEvolutionDR.

MW = Megawatts-ac

Advanced Applications of DR

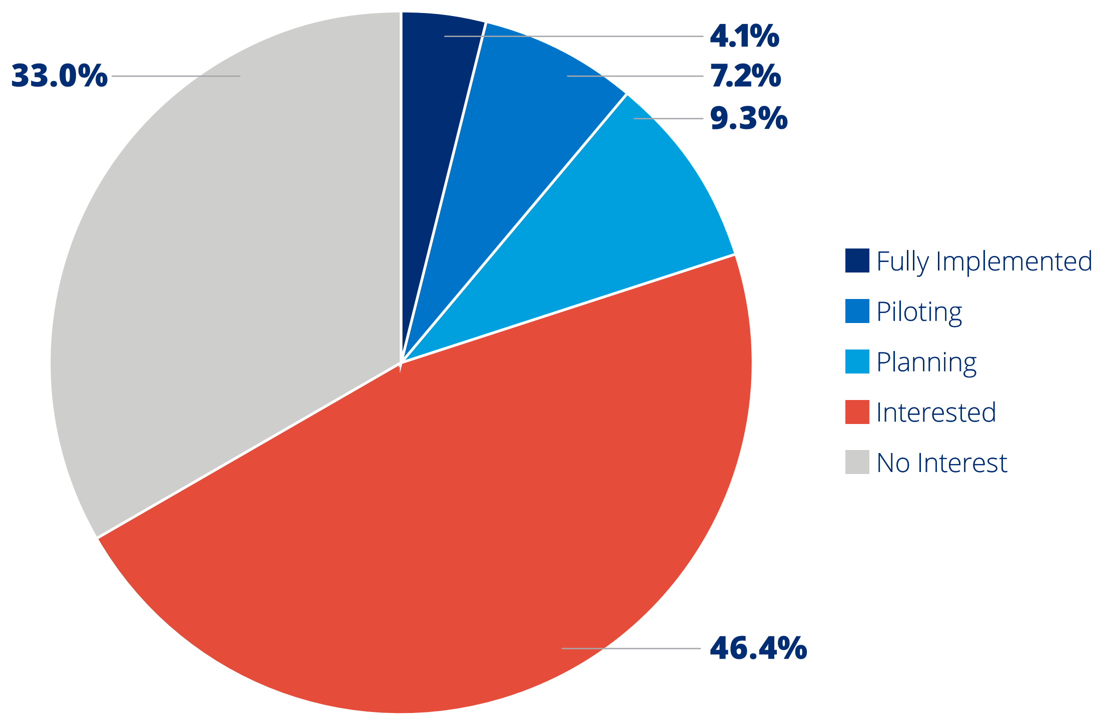
Industry Trends

Utilities are beginning to pair programs with different technology types to deliver holistic DR programs and provide additional grid services. SEPA Utility Survey results show interest in pairing DR with solar, storage and other technologies to provide more reliable demand reduction, with 68% of participating utilities interested, planning, piloting, or currently offering a DR pairing.

Energy storage, electric vehicles, and smart home devices all allow utilities the opportunity to use different DERs to help manage load, better account for increasing penetration of renewables, provide diverse solutions, and engage with customers. As the number of participants on the grid increases, and the nature of their interactions change, DR technologies will also see applicability in transactive energy systems.

The following section spotlights these advanced applications of DR, as already being explored in various utility pilots.

Figure 19: Advanced Applications of DR with Solar, Storage, and Energy Efficiency



Source: Smart Electric Power Alliance, 2019. N = 97 Utility Survey participants.

MW = Megawatts-ac

Energy Storage and Demand Management

As the energy storage market expands, it will play a growing role in demand management and renewable energy integration. Utilities are recognizing the value that aggregated energy storage can offer in DR efforts, by reducing renewable energy curtailment, leading to increased renewable energy penetration.

Energy Storage Program Highlights

In 2019, **Green Mountain Power (GMP)** started a Resilient Home pilot program—intending to shift away from meters by using Powerwall batteries to measure energy usage. Customers can enroll through GMP or a third party, and receive two batteries which provide clean backup power during outages and also measure energy usage. This makes homes more resilient while reducing carbon emissions. GMP calls on the network to reduce load during peak demand events, reducing costs for all customers. If the regional peak set this earlier summer holds, this network will offset about $800,000 in costs.

In February, 2019, **Southern California Edison**, in partnership with **Ice Energy**, completed the installation of 100 thermal storage cooling units at C&I sites, as the first phase of a project expected to grow to more than 1,200 systems over the next two years. By 2021, the project is expected to have a total storage capacity of 21.6 MW, 130 MWh. The systems, known as Ice Bears®, perform rate arbitrage, freezing ice during off-peak hours and then cooling in place of traditional air conditioners during peak demand to decrease C&I customers peak energy consumption.[20]

In 2018, **United Power** in Colorado interconnected two battery storage systems, totalling 4.5 MW, 18 MWh of energy storage. The two systems are called upon four to five times a month to shave peak demand and are then recharged from the grid during the night. United Power estimates that the battery storage systems will save the cooperative and its members $1 million annually from reduced generation charges during peak demand events.[21]

National Grid and **EnergyHub** are currently expanding the "ConnectedSolutions" program from a BYOT to a BYOD program, allowing customers to install and enroll their own battery storage devices. The program includes nine thermostat brands and five storage vendors. The expansion of this program shows that the BYO model is a successful way to engage with customers, and potentially yield a year-round resource. By developing a more robust and advanced system, customer incentives can expand and utilities can create a more sustainable business model. The expansion of this program to include battery energy storage allows behind-the-meter solar plus storage to export excess electricity to the grid.[22]

20 PV Magazine. (2019). Ice Energy brings the deep freeze to U.S. energy storage. Retrieved from https://pv-magazine-usa.com/2019/02/13/ice-energy-brings-the-deep-freeze-to-u-s-energy-storage/
21 Marizza, J. (2019, June 11). Phone Interview.
22 EnergyHub. (2018). National Grid selects EnergyHub as the platform provider to enhance its Bring Your Own Device demand response program. Retrieved from https://www.energyhub.com/blog/national-grid-bring-your-own-device-demand-response-program

MW = Megawatts-ac

Smart Electric Power Alliance

Electric Vehicles as Grid Assets

By 2030, over 20 million electric vehicles (EVs) are expected to be on U.S. roads, representing 93 TWh of added electric load.[23] Without managed charging functionality, these vehicles could lead to grid constraints and unplanned costs. Managed charging will be a key part of utilities' DR portfolios, and implemented properly, can lower the cost of electricity grid payments for customers and provide benefits to the grid.

Table 7: Examples of Active and Passive Managed Charging

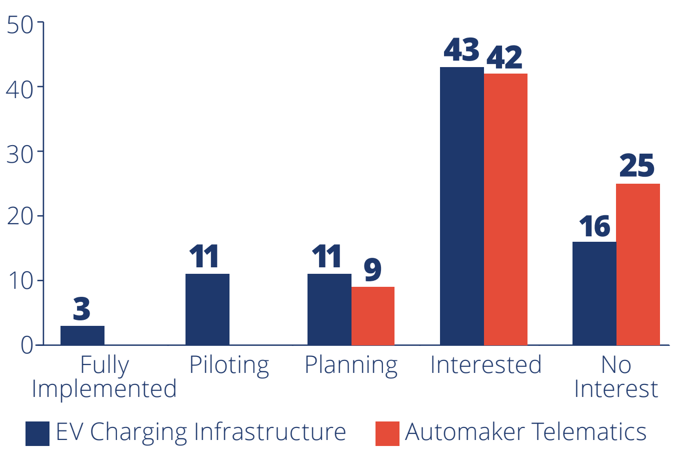
Passive	Active
EV time-varying rates, including time-of-use rates and hourly dynamic rates	Direct load control via the charging device
Communication to customer to voluntarily reduce charging load (e.g., behavioral DR event)	Direct load control via automaker telematics
Incentive programs rewarding off-peak charging	Direct load control via a smart circuit breaker or panel

Source: Smart Electric Power Alliance, A Comprehensive Guide to EV Managed Charging, 2019.

Utility Managed Charging Landscape

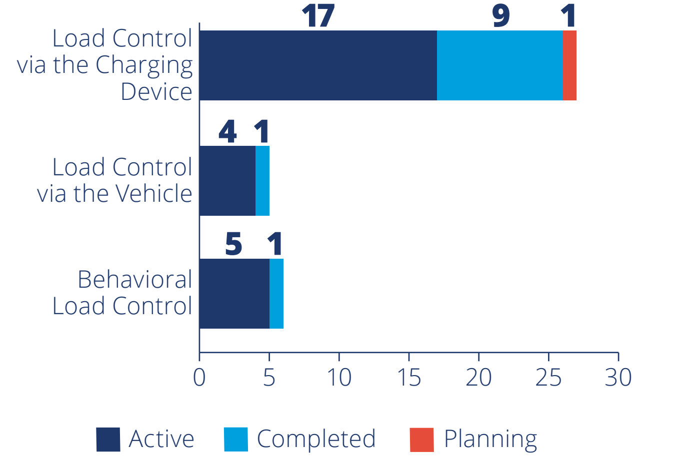
From SEPA's 2019 Utility Demand Response Survey of 84 respondents, 53% were interested in EV managed charging DR programs and only 26% expressed no interest (aggregated results from managed charging via charging infrastructure and automaker telematics). The survey revealed more utility interest in direct load control via the charging infrastructure than through automaker telematics.

Figure 20: Utility Interest in Managed Charging Programs by Technology Type



Source: Smart Electric Power Alliance, A Comprehensive Guide to EV Managed Charging, 2019. N=84

Figure 21: Utility-Run Managed Charging Projects by Type and Stage, United States, 2012-2019



Source: Smart Electric Power Alliance, A Comprehensive Guide to EV Managed Charging, 2019. N=38

23 Gartner J. (2018, February 19). Email Correspondence.

MW = Megawatts-ac

Electric Vehicle Program Highlights

Some utilities are using pilot programs in limited service areas to understand the effectiveness of managed charging. **Avista Utilities** was able to curtail loads during DR events and **PG&E** utilized automaker telematics and second-life batteries to ensure load-gaps were met.

Avista created a managed charging pilot in Washington state to test its ability to shift EV demand to off-peak hours. Avista collected data on the charging habits of customers and ran DR events. Customers could be notified a day before a DR event and then had the option to opt out. The pilot program was successful in shifting EV charging load to off-peak hours without disrupting customers. Avista was able to curtail load up to 75% with no customer complaints. If customers' cars were charged when needed then no issues arose with managed charging. Avista found that currently the costs of the program are higher than the savings, and it is difficult to estimate at what level of EV penetration these programs will make fiscal sense.

PG&E partnered with **BMW** in a managed charging pilot program that enrolled 96 model i3 drivers. BMW developed proprietary aggregation software, which could delay charging via cellular telematics. BMW also implemented second-life stationary batteries to meet load gaps in DR. BMW met 90% of the load requirements for DR events with an average 20% contribution from EVs and 80% from the battery system. Limited availability of EVs for DR events highlighted a potential concern. This program also used a TOU rate for EV charging. In a second phase, the program was expanded to 350 participants and supported the use of EV managed charging to optimize for load conditions. Managed charging was able to shift EV charging to times when it was cheapest and cleanest.

PG&E expects more than 1.5 million EVs in its region by 2030.[24] From Phase 1 results, the potential load drop of a single event in 2030 could be as much as 77.6 MW, enough to power 58,000 California homes.[25]

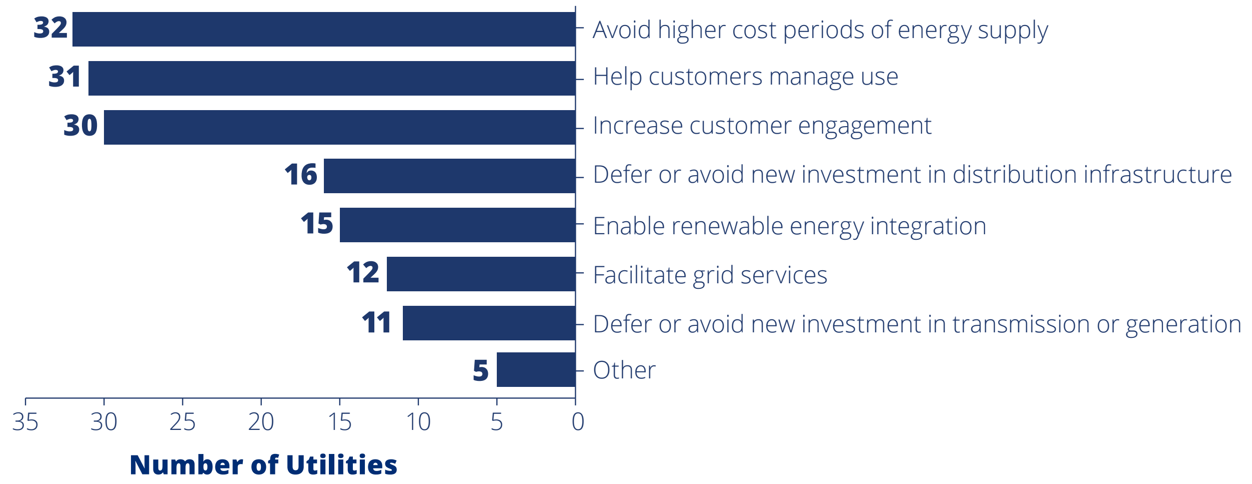
24 Pacific Gas and Electric Company And BMW Group (2017). BMW I ChargeForward PG&E's Electric Vehicle Smart Charging Pilot. Retrieved from https://efiling.energy.ca.gov/GetDocument.aspx?tn=221489
25 Smart Electric Power Alliance (SEPA). (2019). A Comprehensive Guide to EV Managed Charging. Retrieved from https://sepapower.org/resource/a-comprehensive-guide-to-electric-vehicle-managed-charging/

MW = Megawatts-ac

The 2019 Utility Demand Response Survey also asked how utilities planned to use or were using managed charging. Utilities indicated the most common use for managed charging was to avoid periods of higher cost energy (22%). Utilities' next most common use was to help customers manage their energy use (21%). Third, was using managed charging to increase customer engagement (20%). The potential uses for managed charging are not mutually exclusive and better developed managed charging systems should capture savings and customer engagement in energy management.

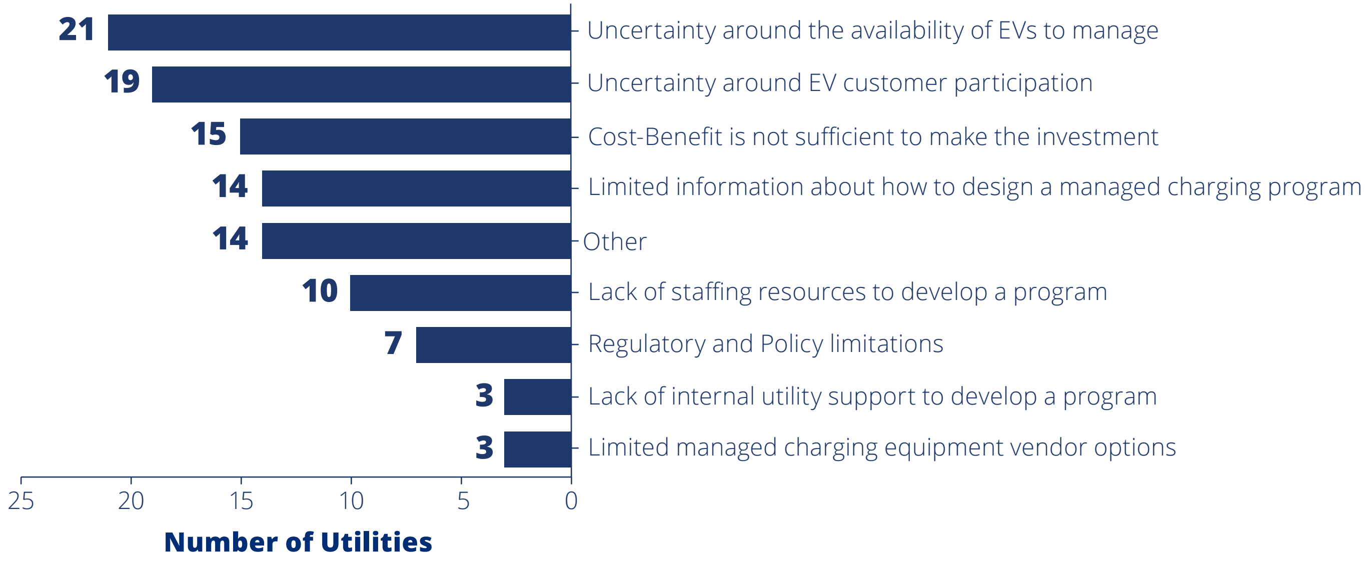
The survey asked these same utilities what barriers existed to implementing managed charging programs. Top concerns were the availability of EVs to manage via these programs (20%), uncertainty about customer participation in managed charging programs (18%), concern that the cost-benefit ratio would be insufficient to justify investment (14%), and limited information about implementation and design of managed charging programs (13%). Some utilities were unsure how to prioritize managed charging with other DR programs, or did not have sufficient EV penetration to justify investments, making up "other" barriers.

Figure 22: How Utilities are Using or Planning to Use Managed Charging



Source: Smart Electric Power Alliance, 2019. N=48. Note: Utilities selected all that applied.

Figure 23: Barriers to Implementing a Managed Charging Program



Source: Smart Electric Power Alliance, 2019. N=45. Note: Utilities selected all that applied.

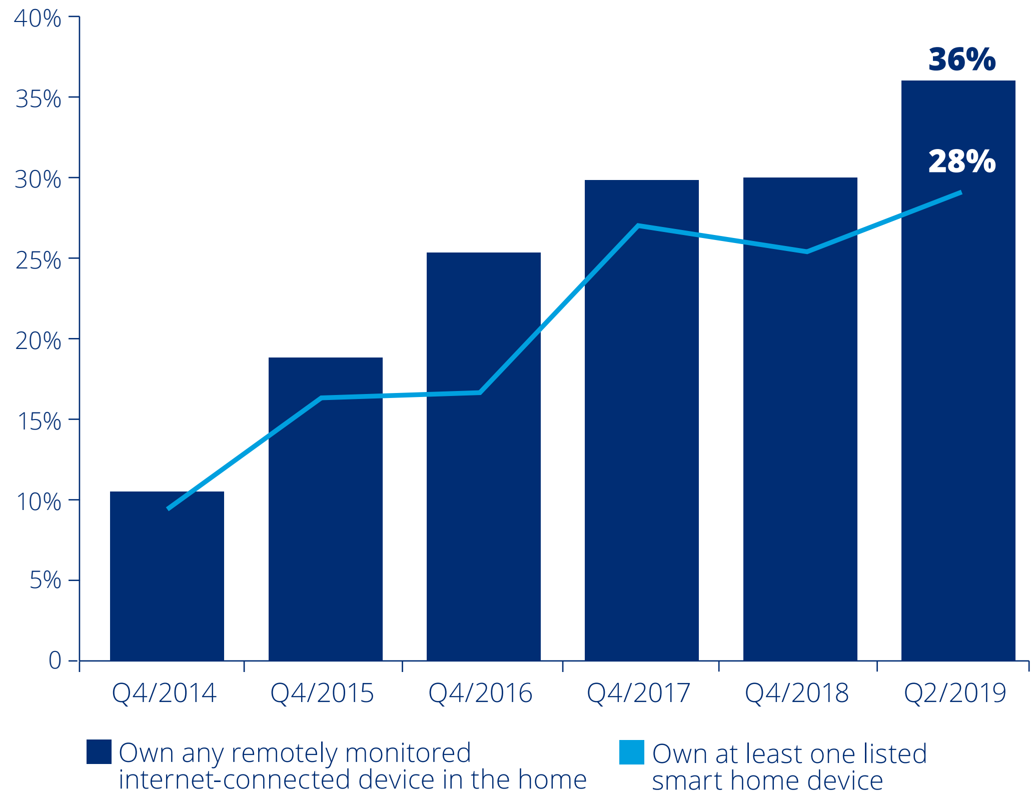
MW = Megawatts-ac

Demand Flexibility: Opportunities in the Smart Home

Opportunities continue to expand at the residential level as technology opens up new business models for utilities and third parties in the industry. Smart energy device ownership in U.S. broadband households has trended upwards over the last 4 years, with Parks Associates estimating nearly 36% of households own remotely monitored internet-connected smart home devices in their home. Smart energy devices remain the most popular, with smart thermostats ranking #1 and smart light bulbs ranking #3 in ownership of smart home devices.

Additionally, opportunities are continuing to expand with growing partnerships between third parties and utilities. Google recently announced a program allowing utility companies to integrate with the tech giant's platform, allowing greater integration to take advantage of Google's voice platform and capabilities while providing consumers with a more personalized and interactive experience with their utility provider.

Figure 24: Smart Home Device Ownership: Among All U.S. Broadband Households



Smart Home Devices Surveyed (Q2 2019)*

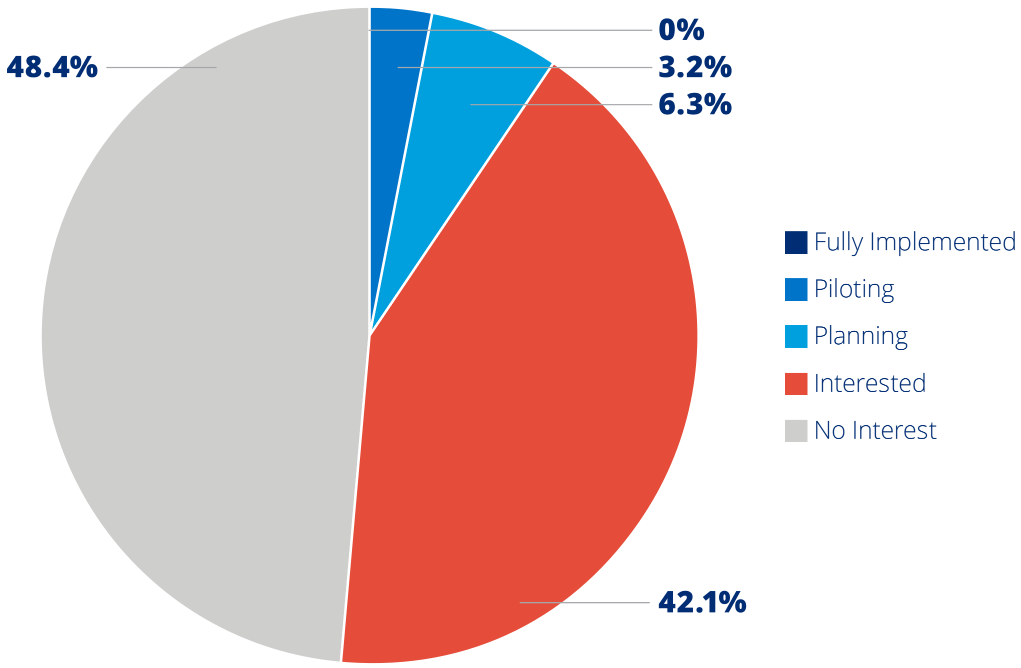
- Thermostats
- Door Locks
- Video Door Bells
- IP Cameras
- Light Bulbs
- Lighting Control Systems
- Outdoor Light Fixtures with Video Cameras
- Outlets/Switches/Dimmers
- Smart Plugs/Adapters
- Sprinkler Systems
- Garage Door Openers
- Smoke/CO Detectors
- Water Leak Detectors
- Water Shut-off Valve
- Smart Appliance

*This list of devices has changed slightly over the years to include new products.

MW = Megawatts-ac

Wood Mackenzie Power & Renewables estimates 48 million U.S. households will be using voice-assistants as the central interface for smart home functions in the years to come.[26] With a growing number of consumers adopting smart home devices at the grid edge (e.g., Google Home, Amazon Alexa devices), utilities and solution providers have opportunities to further integrate and automate energy management at the home level.

Figure 25: Integrating Voice-enabled Smart Home Devices Into Any New or Existing DR Programs



Source: Smart Electric Power Alliance, 2019. N=95 Utility Survey participants.

Utilities are starting to leverage new smart home assistants and device integration to increase customer engagement with their energy use. A handful of utilities are exploring demand flexibility at the smart home level. The SEPA Utility Survey found that 3.1% of utilities piloted the integration of voice-enabled smart home devices into their DR programs, 6.2% are planning programs, and over 40% are interested. These responses demonstrate that utilities are interested in pursuing a more integrated approach to home energy management and customer education.

Voice Control & Activation

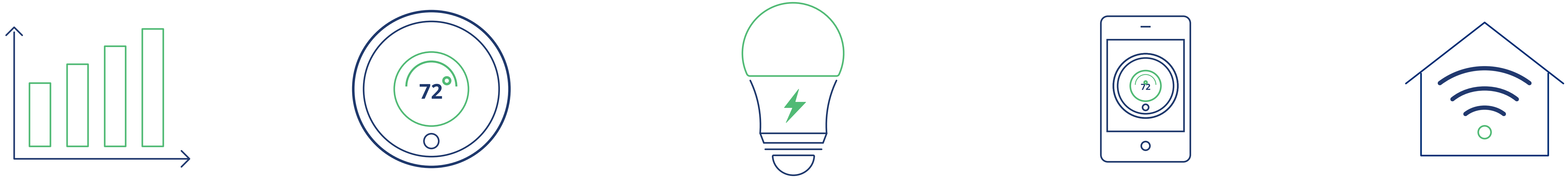
Uplight (formerly known as Tendril), working with **Indiana Michigan Power**, developed voice assistant applications for Google Assistant and Amazon Alexa that enable consumers to learn about and manage their energy usage through voice interactivity. The program can use integrated display functionality for screen-enabled voice assistants--including Amazon's Echo Show and Google's Nest Hub--to display relevant energy usage visuals and other supplemental content. The program provides a foundation for expanding functionality for optimized home energy management and automated control of Smart Home devices such as lighting and appliances. It currently allows users to inquire about their energy usage, real-time bill amount and payment status, and provides personal suggestions to improve energy efficiency. Uplight provides unique insights using data insights from more than 123 million homes. The key goal of the program is to improve customer engagement and inform them about their usage to promote behavioral energy efficiency.

26 Wood Mackenzie. (2018). Energy Management in the Connected Home: Competitive Landscape, Forecasts and Case Studies. Retrieved from https://www.woodmac.com/reports/power-markets-energy-management-in-the-connected-home-competitive-landscape-forecasts-and-case-studies-58129606

MW = Megawatts-ac

Opportunities in home energy management can be represented as 5 levels, as laid out in a Powerly framework (see Figure 26)—initial data visualization (level 0), real-time energy monitoring (level 1), smart connected devices (level 2), providing personalized insights to customers based on their energy use (level 3), and full home optimization (level 4). Today, utilities are mostly at the initial stage of historical data visualization, although SEPA Utility Survey results show movement into levels 2 and 3, with interest in full home optimization (level 4).

Figure 26: Four Levels of Autonomous Home Energy Management



Level 0

Hitorical Data Visualization

Access to historical energy data, typically through online portals or Home Energy Reports.

Level 1

Real-Time Energy Monitoring

A real-time connection to a home's energy use.

Level 2

Real-time w/Connected Devices

Connectivity to smart devices, allowing for control and management of appliances

Level 3

Insight Assisted Change

Provide personalized insights of home and appliance health.

Level 4

Full Home Optimization

A personalized and autonomous optimization engine for the home that balances comfort and efficiency.

Source: Powerly, 2019

MW = Megawatts-ac

Transactive Energy

DR has the potential to play a large role in meeting the needs and challenges of an evolving grid. With increasing distributed renewable energy resources and more grid participants, the grid is becoming more decentralized, variable, and complex. Additionally, consumers are generating power, interacting and transacting with each other or their utilities, and actively managing their energy consumption.

In this increasingly complex environment, DR has the potential to serve the important role of ensuring that load supply and demand are matched. Transactive energy is one potential system that can leverage DR in order to create and sustain a complex system of consumers, producers, and prosumers, while enabling distributed control and balancing.[27]

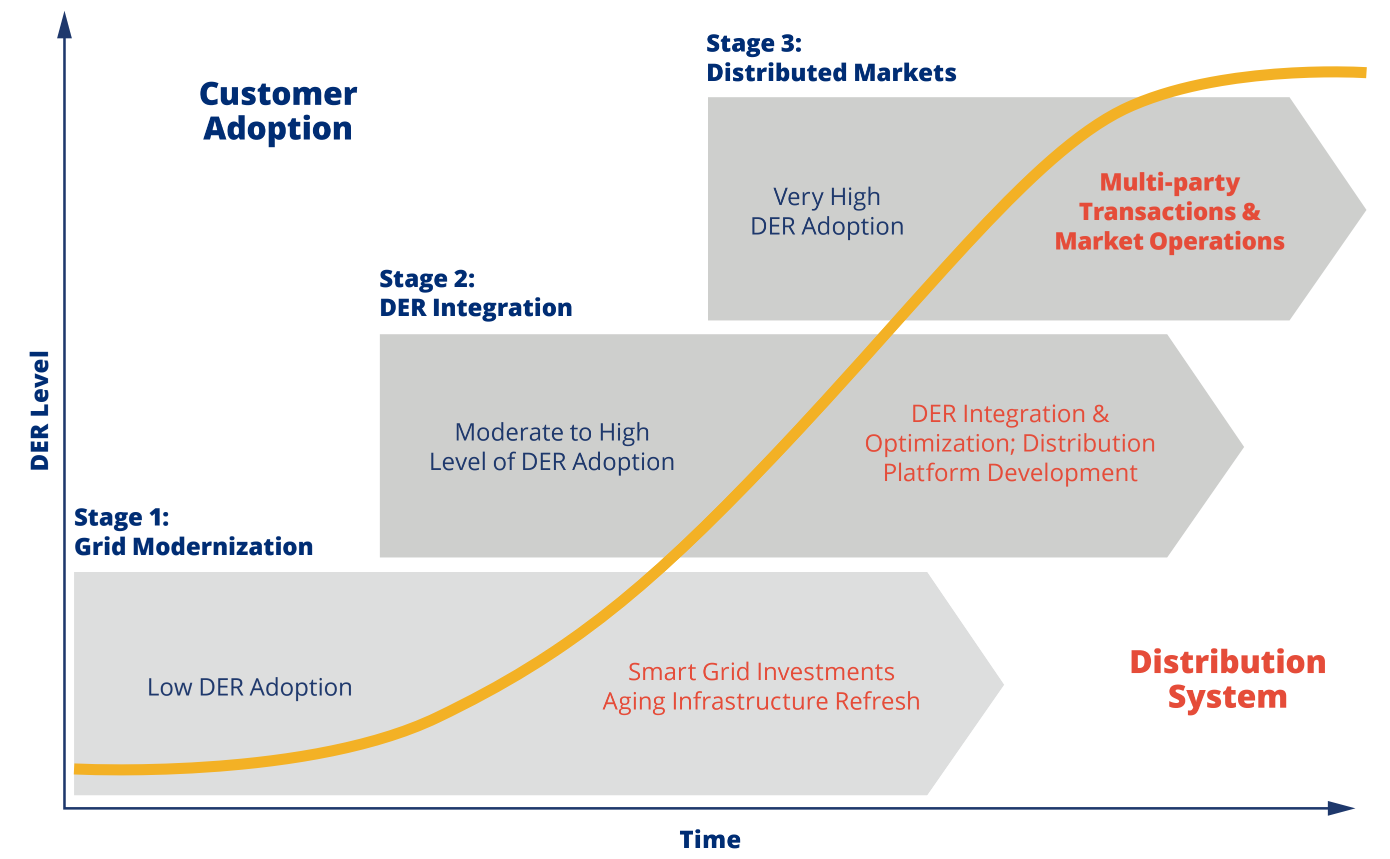
Transactive energy is a system comprised of coordinated participants (i.e., devices and equipment) that use automation tools to communicate and exchange energy based on value and grid reliability constraints.[28] Participants buy and sell energy and ancillary services, and negotiate between themselves through market mechanisms. Many of the existing transactive energy pilots incorporate DR technology, and are an expansion of DR principles. Transactive energy systems can automate DR by using devices that are able to read utility signals while also allowing a diversity of smart home technologies and customer preferences. Grid needs, value and price, and customer preferences are incorporated to enable transactions between participants. The following cases demonstrate this integration of DR into transactive energy systems.

27 CGI. (2019). Optimized Network Utilities and Demand Response. Retrieved from https://www.cgi.com/sites/default/files/white-papers/cgi-onu-demand-response-wp.pdf
28 SEPA. (2019). Transactive Energy: Real-World Applications for the Modern Grid. Retrieved from https://sepapower.org/resource/transactive-energy-real-world-applications-for-the-grid/

MW = Megawatts-ac

Smart Electric Power Alliance

Figure 27: Evolution of the Distribution System with Increasing Levels of DERs



Source: Paul De Martini and Lorenzo Kristov, 2015

Figure 27 illustrates a three-stage evolutionary framework for a distribution system with increasing levels of DERs. Each level expands on the capabilities of the earlier stage, and includes additional functionalities needed to support greater amounts of DER adoption. Most distribution systems in the U.S. are currently at Stage 1.

Stage 1 is characterized by: grid modernization and reliability investments that are underway or planned for the near term; low customer adoption of DER; and limited or non-existent DER participation in wholesale markets.

In **Stage 2**, DER adoption reaches higher levels, requiring enhanced functional capabilities to maintain reliable distribution system operation. Two-way power flows will be needed on high-DER circuits, requiring more advanced protection and control technologies and operational capabilities to ensure safety and reliability. Additionally, the increased level of DERs may provide an opportunity to deliver services to the bulk power system.

In **Stage 3**, DER providers and consumers go beyond providing traditional services, and seek to engage in energy transactions, requiring regulatory and operational changes to enable such transactions. These transactions will require more coordination between retailers, distribution system operators (DSOs), and transmission system operators at the point where transmission and distribution systems interconnect.

MW = Megawatts-ac

Transactive Energy Program Highlights

National Grid and **Opus One Solutions** launched a pilot program on the Buffalo Niagara Medical Campus (BNMC) to create a distribution-level transactive energy marketplace for DER owners and operators. The pilot tested the communications between a DSP and network-connected DERs using DR, combined heat and power, and existing backup generators. Energy storage and renewable generation are also being evaluated for possible inclusion. This pilot program was designed to evaluate a financial model for DER market participation based on the value of DER, using the New York Independent System Operator's (NYISO) locational marginal price plus the value of DER to the distribution grid. The project demonstrated that there is customer interest.

Pacific Northwest National Laboratory launched the The Olympic Peninsula pilot in Washington state and used two-way exchange of load price/quantity curves and electric market-cleared price signals to coordinate four municipal water pumps, two backup diesel generators, and residential DR from electric water and space heating systems in 112 homes. The project demonstrated the ability of transactive energy to manage system peak load and distribution constraints; enable utility wholesale price purchases; enable generators, loads, and appliances to automatically bid or offer into a real-time energy market; and provide cost savings for customers and the municipality.

Southern California Edison (SCE), **TeMix Inc.** and **Universal Devices**, introduced a pilot in 2015 that uses smart home devices to coordinate and automate customer device management and transactions with SCE distribution operators, energy service providers, and the California ISO.

Device operations are automated through cloud-hosted energy management systems that use machine learning, customer preference, optimization, and sensor input to automatically respond to current and forward tender prices. Customer input is simplified with the use of Amazon Alexa voice responses. The pilot includes a retail two-way subscription tariff which allows customers to subscribe to fixed amounts of electricity, shaped to match their typical hourly kWh quantity. The pilot was deployed successfully, with two-way price signals occurring between CAISO and SCE, and SCE and its customers.

SCE is using the lessons learned from the pilot to implement smart home platforms. These efforts target energy efficiency and universal devices, where automated assistants are increasing customer interaction and helping people communicate with the system for improved comfort and energy savings. SCE is also engaged in a pilot that shifts load by sharing information about time of use rates via a smart speaker.

MW = Megawatts-ac

Smart Electric Power Alliance

Appendix A: Survey Participants

A&N Electric Cooperative
AEP Texas
Aiken Electric Cooperative, Inc.
Alliant Energy
Ameren Illinois
American Samoa Power Authority
Anaheim Public Utilities
Appalachian Power Company - Tennessee
Appalachian Power Company - West Virginia
Arizona Public Service
Atlantic City Electric Company
Austin Energy
Austin Utilities - Minnesota
Avista Utilities - Idaho
Avista Utilities - Washington
Baltimore Gas & Electric
Belmont Light
Berkeley Electric Cooperative, Inc.
Big Bend Electric Cooperative, Inc.
Black River Electric Cooperative, Inc.
Blue Ridge Electric Cooperative
Blue Ridge Electric Membership Corporation
Bonneville Power Authority - California
Bonneville Power Authority - Idaho
Bonneville Power Authority - Montana
Bonneville Power Authority - Nevada
Bonneville Power Authority - Oregon
Bonneville Power Authority - Utah
Bonneville Power Authority - Washington
Bonneville Power Authority - Wyoming
Braintree Electric Light Department
Broad River Electric Cooperative, Inc.
City of Fort Collins
City of Holyoke
City of Palo Alto Utilities
City of Tallahassee
City Utilities of Springfield, Missouri
Coastal Electric Cooperative, Inc.
Cobb Electric Membership Corporation
Commonwealth Edison Company
Consolidated Edison Company of New York, Inc.
Consumers Energy
CoServ Electric
CPS Energy
Cumberland Valley Electric
Dairyland Power Cooperative
Delaware Electric Cooperative
Delmarva Power - Delaware
Delmarva Power - Maryland
Detroit Edison
Dominion Energy North Carolina
Dominion Energy Virginia
Duke Energy (FL)
Duke Energy Carolinas, LLC - North Carolina
Duke Energy Carolinas, LLC - South Carolina
Duke Energy Indiana
Duke Energy Ohio Inc. - Kentucky
Duke Energy Ohio Inc. - Ohio
Duke Energy Progress - North Carolina
Duke Energy Progress - South Carolina
Edisto Electric Cooperative, Inc.
El Paso Electric
Entergy Arkansas
Entergy Louisiana
Entergy Mississippi
Entergy New Orleans
Entergy Texas
Eversource
Fairfield Electric Cooperative, Inc.
Farmers Electric Cooperative, Inc.
Fitchburg Gas and Electric Light Company
Flint Energies
Florida Power & Light Company
Georgia Power Company

MW = Megawatts-ac

Smart Electric Power Alliance

Glendale Water & Power
Great River Energy
Guadalupe Valley Electric Cooperative, Inc.
Gulf Power Company
Hancock-Wood Electric Cooperative, Inc.
Hawaii Electric Light Company
Hawaiian Electric Company
Heber Light & Power
Hoosier Energy Rural Electric Cooperative, Inc.
Horry Electric Cooperative
Idaho Power Company
Indiana Michigan Power
Indianapolis Power & Light Company (AES)
Jersey Central Power & Light
Kansas City Power & Light
Lakeland Electric
Laurens Electric Cooperative
Lincoln Electric System

Little River Electric Cooperative
Los Angeles Dept of Water and Power
Lynches River Elec Cooperative, Inc.
Madison Gas & Electric Company
Marlboro Electric Cooperative, Inc.
Massachusetts Electric Company
Medina Electric Cooperative, Inc.
Memphis Light, Gas and Water Division
Metropolitan Edison Company
Mid-Carolina Electric Cooperative Inc.
Middleborough Gas and Electric Department
Modesto Irrigation District
Monongahela Power Company
Nebraska Public Power District
New Braunfels Utilities

New Hampshire Electric Cooperative, Inc.
Newberry Electric Cooperative
Niagara Mohawk Power Corporation
Northern Neck Electric Cooperative, Inc.
Northern States Power Minnesota (Xcel) - Colorado
Northern States Power Minnesota (Xcel) - Minnesota
Northern States Power Minnesota (Xcel) - North Dakota
Northern States Power Minnesota (Xcel) - South Dakota
Northern States Power Texas (Xcel) - New Mexico
Northern States Power Texas (Xcel) - Texas
Northern States Power Wisconsin (Xcel) - Michigan
Northern States Power Wisconsin (Xcel) - Wisconsin

Northwest Rural Public Power District
NV Energy
Ohio Edison Company
Oklahoma Gas & Electric
Omaha Public Power District
Orange and Rockland Utilities, Inc.
Otter Tail Power Company - Minnesota
Otter Tail Power Company - North Dakota
Otter Tail Power Company - South Dakota
Pacific Gas & Electric
PacifiCorp - Idaho
PacifiCorp - Oregon
PacifiCorp - Utah
Palmetto Electric Cooperative
PECO Energy Company
Pedernales Electric Cooperative, Inc.

Pee Dee Electric Cooperative, Inc.
Penn Power Company
Pennsylvania Electric Company
Portland General Electric
Potomac Edison Company
Potomac Edison Company
Potomac Edison Company - Virginia
Potomac Electric Power Company - DC
Potomac Electric Power Company - Maryland
PowerSouth Energy Cooperative
PPL Electric Utilities Company
Public Service Company of Oklahoma
Public Service Electric & Gas
Randolph Electric Membership Corporation
Rappahannock Electric Cooperative
Riverside Public Utilities

MW = Megawatts-ac

Roseville Electric

Sacramento Municipal Utility District

San Diego Gas & Electric

Santee Electric Cooperative

Seattle City Light

Southern California Edison

Southern Maryland Electric Cooperative, Inc.

Southwestern Electric Power Company - Arkansas

Southwestern Electric Power Company - Texas

Sterling Municipal Light Department

Tampa Electric Company

Tennessee Valley Authority - Alabama

Tennessee Valley Authority - Georgia

Tennessee Valley Authority - Kentucky

Tennessee Valley Authority - Mississippi

Tennessee Valley Authority - North Carolina

Tennessee Valley Authority - Tennessee

Tennessee Valley Authority - Virginia

The Illuminating Company

The Narragansett Electric Company

Toledo Edison Company

Town of Littleton

Town of Middleton

Tri-County Electric Cooperative

Trico Electric Cooperative, Inc.

Turlock Irrigation District

United Power, Inc.

Unitil Energy Systems

Vectren Corporation

Vermont Electric Cooperative

Village of Bergen

Village of Sherburne

Vineland Municipal Utilities

We Energies

West Penn Power Company

Westar Energy

Wisconsin Public Service

WPPI Energy

York Electric Cooperative, Inc.

Smart Electric Power Alliance

Appendix B: 2018 Reported Demand Response Capacity State and Select Territories (MW)

Table 8: Total Demand Response Enrolled and Dispatched Capacity by State and Select Territory

Operating State/ Territory	Sum of Total Enrolled Capacity	Sum of Total Dispatched Capacity
Alabama	468.0	329.0
Alaska	-	-
American Samoa	0	0
Arizona	40.0	26.9
Arkansas	181.7	199.2
California	1,335.4	1,002.8
Colorado	499.6	265.4
Connecticut	-	-
Delaware	136.2	130.2
District of Columbia	23.0	21.0
Florida	2,911.4	611.4
Georgia	973.1	50.9
Guam	-	-

Table 8: Total Demand Response Enrolled and Dispatched Capacity by State and Select Territory

Operating State/ Territory	Sum of Total Enrolled Capacity	Sum of Total Dispatched Capacity
Hawaii	34.9	34.9
Idaho	628.5	527.0
Illinois	1,146.5	196.6
Indiana	842.3	790.2
Iowa	440.0	440.0
Kansas	291.7	44.7
Kentucky	170.8	150.8
Louisiana	0.4	0.4
Maine	-	-
Marshall Islands	-	-
Maryland	1,212.8	1,200.5
Massachusetts	75.3	72.3
Michigan	651.4	112.6

Table 8: Total Demand Response Enrolled and Dispatched Capacity by State and Select Territory

Operating State/ Territory	Sum of Total Enrolled Capacity	Sum of Total Dispatched Capacity
Minnesota	805.6	423.6
Mississippi	392.0	64.0
Missouri	170.0	164.0
Montana	0.0	0.0
Nebraska	82.6	64.9
Nevada	207.2	190.1
New Hampshire	6.5	4.5
New Jersey	121.0	55.0
New Mexico	7.7	3.7
New York	981.1	903.9
North Carolina	1,319.8	968.4
North Dakota	109.0	42.6
Ohio	745.9	678.2
Oklahoma	172.4	75.4
Oregon	84.0	16.4
Pennsylvania	606.4	552.1

Table 8: Total Demand Response Enrolled and Dispatched Capacity by State and Select Territory

Operating State/ Territory	Sum of Total Enrolled Capacity	Sum of Total Dispatched Capacity
Puerto Rico	-	-
Rhode Island	19.4	19.4
South Carolina	398.6	310.6
South Dakota	49.0	16.9
Tennessee	631.0	476.8
Texas	574.8	490.9
Utah	249.0	211.0
Vermont	0.1	0.0
Virgin Islands	-	-
Virginia	259.7	75.5
Washington	0	0
West Virginia	129.2	129.2
Wisconsin	590.6	160.3
Wyoming	0	0
Total	20,775.4	12,304.1

Source: Smart Electric Power Alliance, 2019.

Smart Electric Power Alliance

Smart Electric Power Alliance

1220 19th Street NW, Suite 800
Washington, DC 20036-2405
202-857-0898

Duke Energy Carolinas
Response to
Attorney General's Office
Data Request No. 4

Docket No. E-7, Sub 1276

Date of Request: June 9, 2023
Date of Response: June 19, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to AGO Data Request No. 4-1, was provided to me by the following individual(s): Glen Snider, Managing Director IRP and Analytics, and was provided to AGO under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolina

Request:

1. Please provide the past 5 years of annual historical data (2017-2022) on curtailable load (MW) available to address summer and winter peaks.

Response:

The data below shows the curtailable load (MW) available to address summer and winter peaks for the years 2017 through 2022.

Summer
2017 - 661
2018 - 659
2019 - 695
2020 - 635
2021 - 650
2022 - 646
Winter
2017 - 314
2018 - 282
2019 - 285
2020 - 264
2021 - 268
2022 - 230

AGO Balakumar Exhibit 4

NORTH CAROLINA ENERGY REGULATORY PROCESS

In Fulfillment of the North Carolina Clean Energy Plan B-1 Recommendation

DECEMBER 22, 2020

SUMMARY REPORT AND COMPILATION OF OUTPUTS

AUTHORS & ACKNOWLEDGMENTS

AUTHORS

Josh Brooks[1], Dan Cross-Call[1], Heather House[1], and Jessica Shipley[2]

[1]Rocky Mountain Institute
[2]Regulatory Assistance Project

ACKNOWLEDGMENTS

The authors thank the North Carolina Department of Environmental Quality for initiating the process that led to the work represented in this report. We would also like to thank all NERP participants for their dedication to the work conducted in 2020 and for their review of this summary report.

This report is written by RMI and RAP to consolidate and record solutions explored by NERP in 2020. It does not necessarily represent consensus viewpoints or unanimously held positions of all participating organizations.

Cover image courtesy of GYPSY FROM NOWHERE IMAGES/ALAMY STOCK PHOTO

ABOUT ROCKY MOUNTAIN INSTITUTE

Rocky Mountain Institute (RMI)—an independent nonprofit founded in 1982—transforms global energy use to create a clean, prosperous, and secure low-carbon future. It engages businesses, communities, institutions, and entrepreneurs to accelerate the adoption of market-based solutions that cost-effectively shift from fossil fuels to efficiency and renewables.

ABOUT THE REGULATORY ASSISTANCE PROJECT

The Regulatory Assistance Project (RAP) is an independent, non-partisan, non-governmental organization dedicated to accelerating the transition to a clean, reliable, and efficient energy future. RAP helps energy and air quality policymakers and stakeholders navigate the complexities of power sector policy, regulation, and markets.

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. This report is a summary of the 2020 process, written by the convenors.

Table of Contents

Foreword

This summary report reflects the collaborative work of a committed group of North Carolina energy stakeholders, who dedicated themselves and their organizations to the NC Energy Regulatory Process (NERP) throughout the year of 2020. Building upon the foundational efforts of the 2019 North Carolina Clean Energy Plan, NERP is among a set of critical next steps to advance the state's energy transition. The regulatory reforms explored in NERP during the last year are critical topics that will shape North Carolina's electricity system for decades to come.

NERP was conducted in a collaborative, consultative manner, featuring nine workshops, multiple topic-focused webinars, and regularly occurring study group meetings among subsets of participants. In consultation with the NC Department of Environmental Quality, Rocky Mountain Institute (RMI) and the Regulatory Assistance Project (RAP) convened and facilitated NERP, providing direction, organizing support, technical expertise, workshop agenda design, and professional facilitation. Through that approach, stakeholders held open, wide-ranging dialogues exploring reform options and strove to advance proposals best suited to North Carolina's context, values, and public policy goals.

Throughout the 2020 NERP process, participants worked in good faith to identify broadly supported, meaningful reforms that balance stakeholder interests and state policy goals. The numerous outputs produced by NERP—fact sheets, guidance documents, and draft legislative language—reflect the collaborative work of the stakeholders and areas of general alignment for the State's energy transition.

This summary report is written by RMI and RAP to consolidate and record solutions explored by NERP in 2020. This report does not necessarily represent consensus viewpoints or unanimously held positions of all participating organizations. Throughout the report, we sought to reflect points of agreement and disagreement among participants, including areas for future attention by regulatory bodies or other processes, while also indicating where general agreement supports certain reforms moving forward—whether in the form of implementation, legislative direction for new regulations, or further study. The specific details of how reforms get advanced will be subject to pending developments and further dialogue among a diverse set of North Carolina stakeholders.

It is RMI and RAP's pleasure and honor to work with North Carolina on these important issues. The State's leadership, including its nationally recognized community of energy system leaders, showcase how critical North Carolina is to our nation's energy transition. Thank you for your good work, your leadership, and this opportunity to collaborate.

Executive Summary

North Carolina's 2019 Clean Energy Plan (CEP) established a goal to reduce greenhouse gas emissions in the state's electric power sector 70% below 2005 levels by 2030, and to attain carbon neutrality by 2050. It encouraged updates to energy system planning processes and regulations that achieve these goals, while maintaining long-term affordability and price stability for North Carolina residents and businesses, and also spurring innovation that grows the economy of the state.

From February to December 2020, a group of North Carolina energy stakeholders collaborated through the North Carolina Energy Regulatory Process (NERP) to consider updates to utility regulations and electricity market structures. NERP served as a platform for exploration and advancement of CEP recommendations, specifically fulfilling the "B1" recommendation to "launch a North Carolina 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." Through NERP, additional recommendations of the CEP were considered, including in-depth attention to:

- Adoption of a performance-based regulatory framework (B-2)
- Enabling securitization for retirement of fossil assets (B-3)
- Studying options to increase competition in the electricity system (B-4)
- Implement competitive procurement of resources by investor-owned utilities (C-3)

Participants engaged in extensive dialogue on these topics to investigate how each has been implemented in other parts of the country and to consider their potential application to North Carolina. Picking up where the CEP left off, NERP provided a venue for education and shared research on these topics, leading to development of policy proposals that are tailored for North Carolina's unique context.

Rocky Mountain Institute (RMI) and the Regulatory Assistance Project (RAP) convened and facilitated NERP, in consultation with the NC Department of Environmental Quality (DEQ). As independent, outside organizations, RMI and RAP supported NERP through process design and coordination, regulatory expertise and technical assistance, and national perspective to help compare reforms to approaches taken in other states.

This report summarizes key recommendations of NERP as of December 2020, along with context on how the content development evolved. The report has been prepared by RMI and RAP with input from NERP participants to provide a distillation of discussions that occurred throughout the past eleven months, in order to provide a common reference from which reforms can be carried forward in 2021.

The report is accompanied by a set of "outputs" produced by NERP participants, through their work in four study groups: performance-based regulation, wholesale markets, asset retirement, and competitive procurement. Those outputs were developed to aid briefings to decision-makers on the detailed findings for each of the four focus areas of NERP. Due to the multi-stakeholder nature of NERP with organizations and individuals comprising differing viewpoints and priorities, policy positions and recommendations described in this report do not necessarily reflect full consensus or unanimous support for a reform. In authoring this summary report, RMI and RAP have made every effort to communicate areas of alignment and to identify issues for continued consideration in future work.

NERP Recommendations

In support of the Clean Energy Plan and B1, B2, B3, B4 and C3 recommendations, NERP participants have recommended regulatory changes in four key reform areas. Those are summarized here, with additional detail provided in the relevant sections of the report as well as in topic-specific briefing documents and other outputs produced by NERP study groups.

NERP participants recommend the following:

- The General Assembly and the North Carolina Utilities Commission (NCUC) pursue a comprehensive package of PBR reforms to include a multi-year rate plan (MYRP), revenue decoupling, and performance incentive mechanisms (PIMs).
- The General Assembly direct the NCUC to conduct a study on the benefits and costs of wholesale market reform and implications for the North Carolina electricity system.
- The General Assembly expand securitization to be an available tool for electric utilities to retire undepreciated assets, in addition to the current authorization related to storm recovery costs.
- The General Assembly expand existing procurement practices to utilize competitive procurement as a tool for electric utilities to meet energy and capacity needs defined in utility Integrated Resource Plans (IRPs) and where otherwise deemed appropriate by the NCUC.

Many participants expressed a desire to combine above recommendations into a “package” of legislation in the 2021 legislative session that also includes other provisions related to climate and clean energy. That is, there was agreement to combine NERP produced policy concepts into one piece of legislation, and that such legislation should also include other enabling policies not discussed in NERP. Agreement was not reached on what that additional enabling policy ought to be. Multiple participants believe an enabling policy specifically directed at increasing clean energy deployment beyond currently authorized levels or reducing carbon emissions is a necessary complement to the NERP reforms. A handful of participants expressed that legislation to study a wholesale market should be considered separately.

While the bullets above represent general agreement among NERP participants regarding components of a suggested reform package, no one reform enjoys the full support of every NERP participant and there are nuances to participants’ views. Those nuances are explored more fully in this report. In addition, study groups produced detailed outputs to help advance respective reforms, which are attached in the Appendix.

Advancement of the identified reforms will require continued dialogue and negotiation between North Carolina energy stakeholders. To that end, participants agreed at the completion of the 2020 NERP process to remain in dialogue with each other and carry forward these recommendations to brief North Carolina lawmakers, decision makers, and constituents, in an effort to support their passage in the 2021 legislative session.

Background

North Carolina Governor Roy Cooper's Executive Order 80 (EO 80) laid out an emission reduction goal for North Carolina of 40% by 2025 and DEQ to develop the CEP for the state.[1] The CEP was meant to encourage the use of clean energy resources and technologies and to foster the development of a modern and resilient electricity system. In response to EO 80, DEQ launched a multi-month public stakeholder process to collect input and conduct analysis of North Carolina's energy systems. This input and analysis was used to identify policies and strategies to guide policymakers and decision-makers on ways to implement a clean energy vision for the state. The resulting CEP, released in October 2019, contains short, medium, and long-term recommendations in five strategy areas. It lays out a vision that includes the following overarching goals:

1. Reduce electric power sector greenhouse gas emissions by 70% below 2005 levels by 2030 and attain carbon neutrality by 2050.
2. Foster long-term energy affordability and price stability for North Carolina's residents and businesses by modernizing regulatory and planning processes.
3. Accelerate clean energy innovation, development, and deployment to create economic opportunities for both rural and urban areas of the state.

The stakeholder process conducted as part of the CEP development sought input on the key issues that need to be addressed in order to make the CEP vision a reality. The process of developing the CEP's analysis and recommendations involved extensive stakeholder engagement including six large workshops attended by a cross-section of diverse North Carolina energy stakeholders, nine public meetings, and hundreds of pages of written comments and online engagement by the public. Stakeholders were asked to identify ways in which the current policy and regulatory framework in the state is working to accomplish their goals, and ways in which it needs to be modified in order to accomplish those goals.

The CEP stakeholders prioritized three recommendations that would move the state forward toward achieving the goals above:

1. Develop carbon reduction policy designs for accelerated retirement of uneconomic coal assets and other market-based and clean energy policy options.
2. 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.
3. Modernize the grid to support clean energy resource adoption, resilience, and other public interest outcomes.

Among the CEP's many insights, it found that new policy priorities and current and emerging trends in the electricity industry are forcing a reconsideration of traditional regulation and utilities' responsibilities. Stakeholders generally agreed that the existing electricity regulatory system has been successful at accomplishing historical policy goals, but that it is not set up to support 21st century policy goals such as enhanced customer access to energy choices, rapid expansion of clean energy deployment, and environmental outcomes. The CEP stated that these responsibilities are "expanding to include new expectations for environmental performance, carbon reduction, customer choice, resilience, equity, and adapting to (or enabling) sector-wide innovation, among others, while retaining long-standing responsibilities such as reliability and affordability."

---

[1] https://files.nc.gov/ncdeq/climate-change/EO80--NC-s-Commitment-to-Address-Climate-Change---Transition-to-a-Clean-Energy-Economy.pdf

The CEP identified multiple trends in the electricity industry that necessitate updating North Carolina's energy regulatory framework. In light of this, the CEP identified a need for a deeper, sustained engagement from stakeholders outside of traditional legislative and regulatory forums to "design policies that align regulatory incentives and processes with 21st Century public policy goals, customer expectations, utility needs, and technology innovation." The CEP identified topics such as regulatory incentives, integration of distributed generation, transparent and efficient regulatory processes, and holistic resource planning as being ripe for consideration. In addition, other sections of the CEP identified the introduction of more competition into the North Carolina energy market, possible wholesale electricity market reform, and coal power plant retirement as needing further analysis and discussion. The CEP identified the need for such a process to build on, not duplicate, the work that dedicated North Carolina stakeholders accomplished in the CEP process.

NERP Overview

The CEP B-1 recommendation, "launch a North Carolina 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," led to the creation of the North Carolina Energy Regulatory Process (NERP) in 2020. NERP was formed to advance components of the CEP that could accomplish the B-1 recommendation. Several other CEP recommendations were explored in NERP due to strong interest from participants, including recommendations around wholesale market reform, securitization for fossil asset retirements, and competitive procurement (CEP recommendations B-2, B-3, B-4, and C-3).

Purpose

NERP worked to produce recommendations for policy and regulatory changes that can be delivered by the participants to the North Carolina General Assembly, North Carolina Governor, NCUC, and other entities as appropriate. These take the form of issue briefs, policy proposals, and draft proposed legislation developed by participants during the process.

Objectives

The work of stakeholders was set to focus on priority items of the CEP which were identified as actionable in 6-12 months, through an ongoing, policy-oriented convening process. In particular, NERP applied the following process objectives to advance CEP goals on electricity market design and utility regulatory reform:

1. Build expertise and trust among North Carolina energy stakeholders through shared principles, foundation setting, education, and identification of priority action areas
2. Examine alternatives to the traditional utility regulatory model and incentives, carbon reduction policies, and as needed, energy market reforms identified by stakeholder group
3. Produce specific policy proposals that participants can work to implement

The objectives of the NERP process were meant to build upon the work already completed in the CEP process and to address the substantive issues identified by the CEP B-1 recommendation, as well as other related CEP recommendations.

The policy proposals and other work products that NERP participants created can be found in the Appendix and at the DEQ's Clean Energy Plan website.[2] They are also being distributed directly to decision-makers throughout the State.

[2] https://deq.nc.gov/CEP-NERP

Process Overview

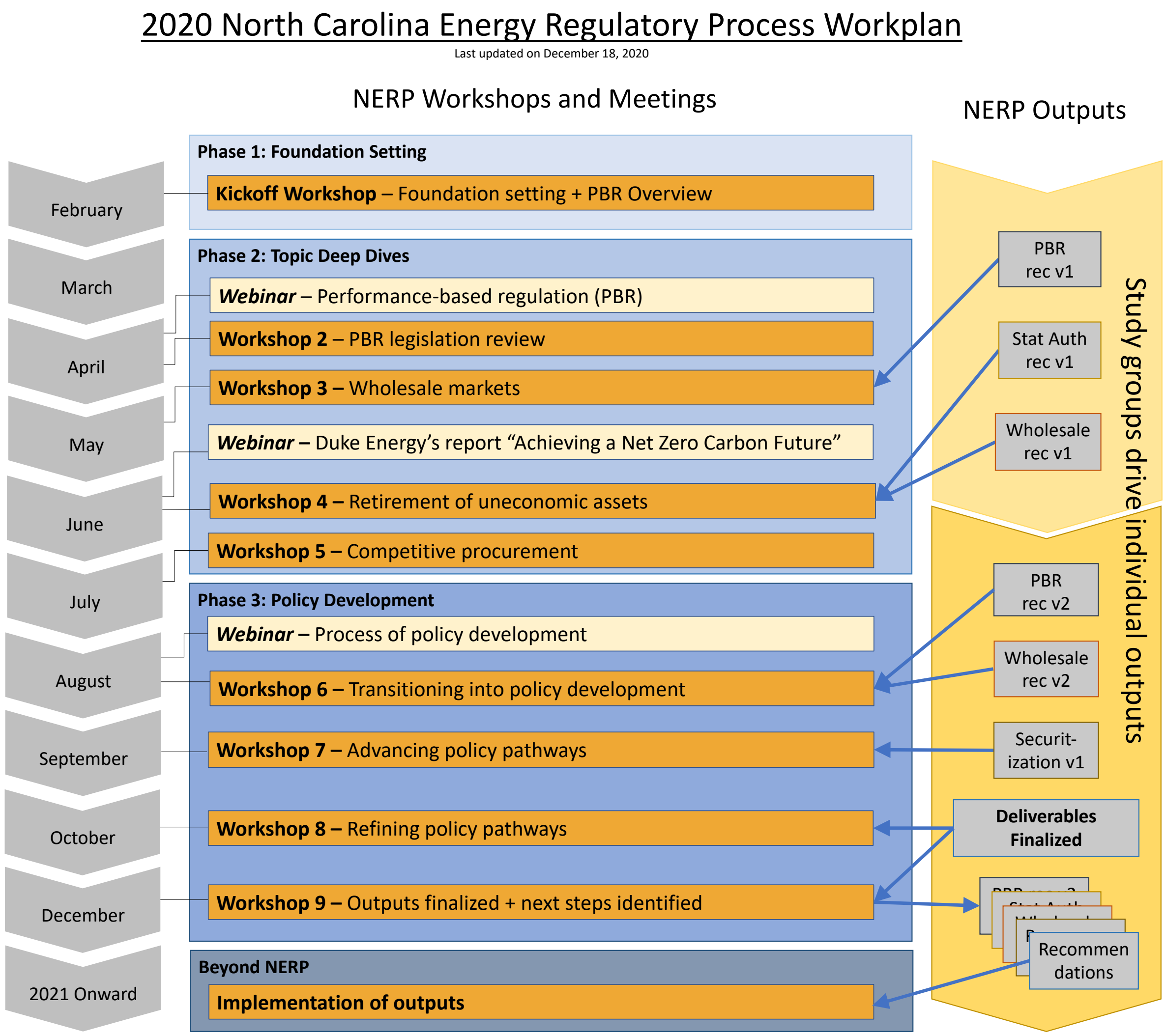
NERP included nine workshops during 2020, supplemented by four webinars, and extensive study group research and discussion. Workshops were intended to be in-person, but due to limitations on travel and in-person meetings imposed by the COVID-19 pandemic, all workshops were held virtually with the exception of the February kickoff workshop.

NERP proceeded according to three phases: foundation setting, topical deep dives, and policy development. Foundation setting took place during the first workshop to align stakeholders around the purpose and objectives of the process. At this workshop, participants identified priority outcomes for attention in future NERP work, reviewed CEP recommended topics, and gave input on which topics should be the focus of future work. In the second phase of NERP, spanning workshops 2 through 5, topical deep dives provided dedicated time for participants to learn about priority topics of CEP and stakeholder interest:

- Performance-based regulation (PBR),
- Accelerated retirement of generation assets including through securitization,
- Wholesale market design and competition, and
- Competitive procurement for resource acquisition.

The third phase of NERP focused on turning topics of interest into policy proposals. Four study groups formed, one for each of the topical deep dive focus areas. Study groups consisted of 5-15 members of NERP who self-selected to participate in the development of policy ideas within each topic area. Study groups each had two co-chairs that helped organize and lead the advancement of policy proposals. Study groups were responsible for proposal development, presenting to the full stakeholder group on their progress, and for soliciting feedback and incorporating that feedback into proposals. Study groups shared drafts of their proposals and other outputs in NERP workshops 6, 7, and 8 where they received substantive feedback and incorporated the views of other stakeholders not involved in the study group deliberations. Study groups produced proposals that were presented at the final workshop in December 2020.

Stakeholders were not required to endorse final recommendations. While work products and final recommendations received broad support and general agreement on the elements contained within them, there is not full consensus on all details. RAP and RMI sought to include areas of disagreement in this report, noted in the “Key Points of Discussion and Content Development” sections of each topic.



Convening Team

The Regulatory Assistance Project (RAP) and Rocky Mountain Institute (RMI) partnered to convene NERP. RMI and RAP served in two primary roles through the process. The first role was as convenor and facilitators of the process. The organizations collectively designed the year-long process and the individual workshops. In addition, RMI and RAP provided technical expertise and assistance to guide NERP activities and support output development. This was necessary to design effective workshops, design the content for the topical deep dives, and to invite additional content experts to serve as presenters. RMI and RAP also provided technical expertise to study groups when requested by participants.

NERP Participants

To support the most constructive stakeholder process, participation at meetings was limited to 30-40 individuals spanning North Carolina organizations representing a wide variety of interests. This multi-stakeholder approach allowed broad and diverse representation among participants while promoting progress on the specific topic areas within the scope of NERP. Based on review of organizations and individuals that participated in the CEP process, the North Carolina DEQ helped identify the organizations to invite to participate in NERP. A list of participant organizations can be found in the appendix.

In limited cases, organizations were allowed to send additional observers to attend meetings in order to support learning and product development. After NERP settled on its ambitious agenda and scope of topics, the convening team offered delegates to include additional participants from their organizations to support study group content development.

Expectations of Participants

- Due to restrictions on attendance, participants were asked to represent a broader set of stakeholders and/or constituents at meetings. This required additional outreach and engagement between meetings to solicit input.
- Participants (or a pre-determined designee) were expected to attend every session of the process.
- Participants were asked to work together between meetings to develop presentations for the broader group and materials that support the summary report.
- Participants were expected to work in good faith to achieve process objectives. This included bringing a collaborative spirit, and a willingness to challenge assumptions and consider new ideas to support North Carolina energy goals.
- Participants were not required to explicitly endorse final written products or policy ideas that emerge from NERP.

Guiding Outcomes

At the February kickoff workshop, participants identified outcomes that they would like to see for the process and for resulting energy reforms. The list of outcomes is shown below, grouped by the following outcome categories: improve customer value, improve utility regulation, improve environmental quality, and conduct a quality stakeholder process. When asked to prioritize three outcomes, affordability, carbon neutrality, and regulatory incentives aligned with cost control and policy goals rose to the top and became the agreed upon priorities of NERP. Outcomes are seen categorized below, with the top three priorities highlighted. These outcomes served as a guiding framework for NERP's work, against which energy reform options were considered.

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

Priority Areas

After the second phase of NERP that consisted of topical deep dives on PBR, wholesale markets, accelerated retirement of generation assets, and competitive procurement, the group decided not to narrow the list of reforms, believing that all four topics were important for the state of North Carolina to consider to fulfill state clean energy goals. Thus, study groups were formed for each topic. In workshops 8 and 9, NERP considered how the priority areas could interact or be combined as a package of reforms.

The following sections summarize the work of the four study groups and related NERP discussions.

Performance-based Regulation

PBR in Brief

- Performance-based regulation was a significant focus of NERP stakeholder work, following its identification in the CEP as a key tool to realign utility financial incentives with social and policy goals.
- A PBR study group conducted extensive research of PBR mechanisms and their applicability to North Carolina utilities, including multi-year rate plans, revenue decoupling, and performance incentive mechanisms. In combination with other updates to utility regulations, these PBR mechanisms can motivate utility achievement of key outcomes while balancing customer costs with utility financial considerations.
- The primary recommendation on PBR from NERP is for the legislature and the NC Utilities Commission to pursue a comprehensive package of PBR reforms to include a multi-year rate plan (MYRP), revenue decoupling, and performance incentive mechanisms (PIMs).

Background

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 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 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). This incentive leads utilities to be reluctant to pursue activities and programs that lead to a decrease in sales throughput, such as energy efficiency measures or enabling customer installation of distributed generation.

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.

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 by rewarding utilities for making progress on these outcomes. There is no one uniformly adopted combination of PBR tools. Some states have implemented one or two reforms; others are examining comprehensive measures. Many states have been using revenue decoupling for quite some time and are more recently considering the addition of multi-year rate planning and performance mechanisms.

NERP primarily discussed three PBR mechanisms: revenue decoupling, multi-year rate plans, and performance mechanisms. A brief description and explanation of these three mechanisms is provided below.

Revenue Decoupling

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). Decoupling goes a step further than NC's existing "net lost revenue" mechanism, which targets only approved efficiency or demand-side management (DSM) programs, by removing the disincentive to reduce sales in all situations. This would include reduced sales from distributed energy resource (DER) deployment, reduced sales from efficiency and conservation efforts by customers 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/energy efficiency (EE) program.

Multi-Year Rate Plan (MYRP)

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 an approved plan 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 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.

Performance Incentive Mechanisms

Introduction of carefully designed performance incentive mechanisms (PIMs) into ratemaking procedures could create new incentives for utilities to accomplish new policy goals by linking a portion of utility revenues to utility performance in achieving those goals. PIMs provide positive and/or negative incentives to utilities to perform certain tasks or accomplish certain outcomes. 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.

In 2007, North Carolina passed Session Law 2007-397 ("Senate Bill 3"), which encourages renewable energy and energy efficiency. That legislation authorized the NCUC to approve performance incentives for utilities related to adopting and implementing new DSM and EE measures. The PBR proposal by NERP would expend that to include performance incentives for other areas of public policy interest. In the rules adopting Senate Bill 3, the NCUC stated that recovery of net lost revenues could be included as an incentive for DSM/EE programs, and the NCUC subsequently approved the recovery of net lost revenues for DSM/EE programs for utilities within the state, effectively decoupling sales from utility profits for reductions in sales caused by utility DSM/EE programs. As discussed above, the PBR proposal by NERP goes a step further by removing the disincentive to reduce sales in all situations.

Key Points of Discussion and Content Development

NERP participants generally agreed that a package of PBR reforms as described above is desirable for the state of North Carolina, and that the reforms should be implemented together.[3]

Some stakeholders believe that individual PBR mechanisms could be successfully implemented in isolation. As described above, each of the mechanisms studied in NERP has the ability to address different challenges identified in the current regulatory framework. NERP participants tended to agree that the three mechanisms are complimentary and should be implemented together.

Points of Discussion and Agreement: Decoupling

Stakeholders agreed upon many design details and recommendations for the NCUC regarding decoupling. Some of the key points of consensus were that residential customers and all utility functions (generation, transmission, distribution) should be included. The group also agreed that small/medium general service customers should be included but noted that there may be some technical challenges with doing so given the current structure of the net lost revenue mechanism. The group also generally agreed that lighting and large general service customers would not need to be included, but that this design detail would need to be decided upon in the context of implementing PBR at the NCUC. Stakeholders also agreed that there were two methods for adjusting revenue in a decoupling mechanism that ought to be considered but did not come to agreement on a recommendation because there were pros and cons identified for both methods. Stakeholders agreed that annual adjustments to rates should be transparent, and that there should be a cap on the annual size of any adjustment to rates with any additional amount deferred to a future period. Finally, the group agreed that if electric vehicle charging sales are included in a decoupling mechanism, then other approaches (e.g., a PIM) should be used to incentivize the utility to enable EV adoption.

Points of Discussion and Agreement: Multi-Year Rate Plan

Stakeholders generally agreed that the concept of a MYRP could work for North Carolina. MYRPs can encourage cost containment and can remove the current disincentive utilities face in making smaller scale investments needed for the clean energy transition by reducing regulatory lag on those investments. Many of the implementation details were not agreed upon in NERP and would need to be discussed in greater detail through the process of filing and approving a PBR Application at the NCUC. The group believes that MYRP can work well with decoupling and PIMs as part of a broader package of reforms and that the cost containment incentive in a MYRP could motivate the utility to choose the most cost-effective solutions for grid needs, leading to cost control that would benefit customers. At least one stakeholder expressed a concern that a MYRP can reduce NCUC oversight and the ability of all stakeholders to advocate on points important to them on a regular basis, as they are currently able to do in rate cases.

Stakeholders did not agree on a revenue adjustment mechanism to be used to adjust rates between rate cases but did agree that it should be clearly defined at the outset in the initial rate case and closely coordinated with the revenue adjustment mechanism chosen in the decoupling mechanism. The group recommends using a three-year term for an initial MYRP in order to gain experience with the mechanism. The scope of costs to be included within the MYRP was a point of disagreement among the stakeholders. Historically, MYRPs implemented elsewhere have covered most utility base costs in order to create the strongest cost-containment incentive possible. However, a MYRP would not necessarily need to apply to a broad swath of utility costs. Stakeholders within the PBR study group had varying opinions on whether the scope of costs covered by the MYRP should be broad or narrow. Some stakeholders expressed concerns that a MYRP of broader scope could increase risks to ratepayers and favored an approach that limited MYRP to known and

[3] Deeper explanation can be found in the NERP PBR study group document titled *NERP Guidance on Performance-Based Regulation*.

measurable capital projects. The PBR study group recommends that an earnings sharing mechanism (ESM) be used in order to protect both customers and shareholders from over- and under-earnings. However, the group did not agree on whether there ought to be a "dead-band" of over- or under-earning in which no adjustment is made, and how sharing tiers within the ESM ought to be designed.

Points of Discussion and Agreement: Performance Incentive Mechanisms

Stakeholders agreed that there ought to be some underlying principles that would guide the design of PIMs and help align around shared objectives. Specifically, PIMs should: advance public policy goals and drive new areas of utility performance; be clearly defined, measurable, and verifiable; comprise a financially meaningful portion of utility earnings opportunities; avoid duplication of other rewards or penalties created by other regulatory mechanisms; not penalize the utility for metrics or outcomes that are not at least somewhat in its control; and reward outcomes rather than inputs. The group agreed that once a PIM is established, it should be revisited on a regular basis to evaluate whether it is helping to achieve the outcome in question. The stakeholders developed an extensive list of possible PIMs and metrics and recommends that the commission require utilities to track as many of the metrics as deemed useful and cost-effective in order to inform future PIM development. The group recommends tracking the performance separately in low-income counties, where feasible. The following outcome areas were discussed: peak demand reduction, integration of utility-scale renewable energy and storage, integration of DER, low-income affordability, energy efficiency, carbon emissions reduction, electrification of transportation, equity in contracting, resilience, reliability, and customer service. Most of these were assigned "preferred" metrics and "alternative" metrics by the group. It should be noted that not all members of the study group agrees with every metric, but general agreement exists that the outcome areas targeted are the right ones.

NERP Recommendations

NERP recommends that the legislature and the utilities commission pursue a comprehensive package of PBR reforms to include a multi-year rate plan, revenue decoupling, and performance incentive mechanisms.

Additional context about these mechanisms and key design decisions that need to be made are discussed below.

Revenue Decoupling

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.

Key design decisions that states must make when implementing decoupling include what rate classes to include within the mechanism, what utility cost functions (e.g., generation, transmission) to include, how to adjust allowed utility revenue over time (if at all), and how to handle surcharges and refunds to customers.

Multi-Year Rate Plan (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. MYRPs can mitigate the regulatory lag associated with certain utility assets, such as grid investments and distributed energy resources, give an incentive for utility cost containment, by setting a framework for predictable revenue increases into the future.

The terms of a MYRP often include the following:

1. Moratoriums on general rate cases for the term of the MYRP.
2. Attrition relief mechanisms (ARMs) in the interim years that automatically adjust rates or revenue requirement to reflect changing conditions, such as inflation and population growth.
3. To maintain or pursue other regulatory and policy goals, MYRPs should be combined with PIMs (sometimes considered “backstop” protections for reliability or other services), an ESM, and other tools.
4. Off-ramp or other course correction tools can be built in to ensure that the commission or other parties have the ability to raise concerns and make adjustments to the plan under certain circumstances.

As discussed above, MYRPs work well with decoupling. 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.

Key design decisions that states must make when implementing multi-year rate plans include: choosing the mechanisms with which to adjust rates between rate cases; the term (or length) of the MYRP which sets the amount of time the utility must “stay out” between rate cases; the scope of the utility costs to be included or covered by the MYRP; whether and how to structure an ESM by which the utility and its customers share the benefits and costs of earnings above and below the allowed return; and how to structure an off-ramp or course correction.

Performance Incentive Mechanisms

Development of PIMs requires setting desired outcomes, identifying metrics that can be used to measure utility performance toward those outcomes, and collecting data to determine how a utility has performed historically. This data can be used simply to track and report utility performance, or to score that performance against a target or benchmark that has been set. It can also be tied to financial rewards or penalties, at which point the mechanism is formally referred to as a PIM. If a utility achieves its performance target, it can receive a financial reward or it can avoid a penalty.

Key design decisions that states must make when developing PIMs include the prioritization of key outcomes to be targeted, identification of potential data sources for tracking utility performance, identification of metrics that will usefully track utility performance toward outcomes, the design of a financial penalty or reward (which can take many different forms), and the time period over which to measure achievement and deliver financial rewards or penalties.

Process Recommendations

The NC General Assembly would need to authorize the NCUC to implement PBR. The NCUC would then need to lead a rulemaking process to set up all of the filing requirements and procedures that a utility would need to follow in a PBR application. The group recommends that the NCUC determine whether and in what form a stakeholder process should take place to gather input prior to a utility filing a PBR application. The group also recommends that the NCUC monitor utility performance and system outcomes and make adjustments to guide utilities to continued improvement and value creation for customers.

PBR Outputs

NERP produced the following documents for dissemination, to inform subsequent policy discussions with various audiences:

1. **Draft PBR legislative language authorizing certain PBR mechanisms in North Carolina:** Legislation that allows the NCUC to use performance-based regulation, specifically revenue decoupling, multi-year rate plans, and performance incentive mechanisms. Directs the NCUC to develop rules related to PBR filings, their reviews, and the decision-making process.
2. **PBR regulatory guidance for the NCUC:** Guidance and recommendations for the NCUC in implementing PBR reforms in ways that reflect the NERP stakeholder discussions
3. **PBR fact sheet:** Three-page fact sheet explaining PBR mechanisms for legislative or similar audiences
4. **Two PBR case studies:** One examining Minnesota's process and experience with PBR; another looking at North Carolina's process and experience with gas decoupling

Wholesale Electricity Markets

Wholesale Electricity Markets in Brief

- Reform of the State wholesale electricity market was a significant focus of NERP stakeholder work, due to its relevance to the CEP broadly, mention in key publications, and recent developments in North Carolina including southeast utilities' proposal for an energy exchange market.
- A study group investigated market reforms and mechanisms specifically where applicable to existing or proposed studies.
- NERP assessed reforms and market designs including the Southeast energy exchange market (SEEM) proposed by utilities in the Southeast U.S., a potential energy imbalance market (EIM), and a regional transmission organization (RTO) for the Carolinas or a larger southeast footprint.
- NERP recommends that the General Assembly direct the NCUC to conduct a study on the benefits and costs of wholesale electricity market reform and implications for the North Carolina electricity system.

Background

Wholesale electricity markets are markets where electricity is bought and sold for resale. Unlike retail transactions – electricity sales to the end user – wholesale transactions consist of power sales from generators to electricity providers. The rates and service standards, as well as reliability and market design of interstate transmission is regulated by the Federal Energy Regulatory Commission (FERC). FERC, established by the Federal Power Act of 1935, oversees all interstate wholesale power sales and markets. State-specific regulators, serving on public utility commissions (PUCs), provide oversight to ensure reasonable rates for end-use customers.

There are seven organized wholesale markets in the U.S. These territories are managed by a Regional Transmission Operator (RTO) or an Independent System Operator (ISO) and regulated by FERC. RTOs & ISOs are balancing authorities; they are responsible for bulk system reliability, transmission system access, and operation of the competitive market mechanisms that allow independent power producers and other non-utility generators to trade and dispatch power. Neither RTOs nor ISOs own generation or transmission but rather control how these assets operate, serving as independent, non-profit, system operators.

The Southeastern and Western U.S. markets are traditionally regulated; a single entity owns and operates the three major grid components - generation, transmission, distribution - within a designated service territory. In a vertically integrated utility market like North Carolina, the regulated utilities own and operate the transmission system, are responsible for bulk system reliability, non-discriminatory transmission system access and are the balancing authority responsible for constant grid operation. In exchange for performing those services, these utilities have prices set by the NC Utilities Commission and are legally obligated to provide reliable electric service to all customers per the regulatory compact.

North Carolina features 3 investor-owned utilities (IOUs), more than 70 municipal utilities, and 26 electric cooperatives. Duke Energy Carolinas and Duke Energy Progress represent the majority of supplied electricity in the state - 96% in 2018. Dominion Energy North Carolina, in the northeast corner of the state, supplied the remaining 4% of utility-supplied electricity. Combined, 23% of IOU sales in 2018 were to the wholesale market where state electric cooperatives, municipalities, or agencies representing those parties, procured electric power for their retail markets. North Carolina's wholesale market makeup and processes, therefore, have significant relevance to the State population, markets, and industries.

While the NERP was initiated by the CEP: B-1 Recommendation, the CEP listed multiple recommendations related to the state's wholesale market:

- **B-4**: Initiate a study on the potential costs and benefits of different options to increase competition in the electricity sector, including but not limited to joining an existing wholesale market and allowing retail energy choice.
- **C-1:** Establish comprehensive utility system planning process that connects generation, transmission, and distribution planning in a holistic, iterative, and transparent process that involves stakeholder input throughout, starting with a Commission-led investigation into desired elements of utility distribution system plans.
- **C-3:** Implement competitive procurement of resources by investor-owned utilities.
- **D-2:** Use comprehensive utility planning processes to determine the sequence, needed functionality, and costs and benefits of grid modernization investments. Create accountability by requiring transparency, setting targets, timelines and metrics of progress made toward grid modernization goals.
- **H-1:** Identify and advance legislative and/or regulatory actions to foster development of North Carolina's offshore wind energy resources.

Discussions about the potential for wholesale market reform in North Carolina are not new. The North Carolina General Assembly enacted legislation in 1999 to study the use of wholesale and retail electricity markets in the state. The study recommended a more competitive system, but such a system was never implemented due to numerous factors including the California energy crisis in the late 1990's.

Likewise, enacting state wholesale reform has recent precedent. In 2007, North Carolina adopted the Renewable Energy and Energy Efficiency Portfolio Standard (REPS). The REPS, coupled with stable, long term avoided cost contracts, and a state tax credit, enabled NC to diversify its electricity supply and offset over 10% of its electricity demand with renewables and efficiency.

More recently, in 2020, the South Carolina state legislature authorized, via SC HB 4940, a study to evaluate a broad variety of electric wholesale, retail, and operational reforms and a study committee to review resulting options. NERP stakeholders have identified that any resulting reform in South Carolina could impact North Carolina as both states share utilities and electric infrastructure. Key provisions specifically mention creation of broader wholesale markets with states neighboring S.C. and the separation of existing vertically integrated electric utilities into two distinct entities: companies that generate electricity and companies that transmit and distribute electricity.

Key Points of Discussion and Content Development

Many NERP stakeholders are interested in wholesale market reforms because increased competition and transparency to generation economics may lower prices, diversify supply, and aid both system planning, and the integration of renewables. Conversely, N.C. has low prices compared to the national average, and diverse generation with respect to its integration of more solar electric generation than any state except California. Joining or creating an RTO does not ensure perfect competition, nor would it inherently lower emissions. In addition, due to typical RTO governance structures, RTOs may not protect stakeholder interests outside of participating buyers, sellers, and transmission owners. Thus, there is agreement that any proposed or potential wholesale market reform in the state must first be carefully studied as the implications of wholesale reforms affect many parties- retail, wholesale, and otherwise.

Throughout NERP, stakeholders reviewed, proposed, refined, and in some cases rejected, a number of wholesale electricity market reforms based on potential to meet net-zero greenhouse gas emissions by 2050, align regulatory incentives with cost control and policy, and maintain affordability and bill stability.

Points of Discussion: North Carolina Joins PJM Interconnection

Early in the process, stakeholders investigated the potential benefits and costs of joining PJM – the wholesale electricity market bordering North Carolina – as Dominion Energy had previously joined PJM and PJM's proximity to NC, along with some shared infrastructure, suggested ease of process. In investigating Dominion Energy's path to PJM, the Wholesale study group found the NCUC decision explicitly stated that such a ruling was not to serve as precedent and further, Dominion Energy did not own any generation in NC (the power it supplies the State is generated outside NC). PJM's Minimum Offer Price Rule (MOPR), a mechanism which accounts for state policy support of renewables by increasing renewable bid prices into the market, is a concerning factor as well. Given NC's established success as a utility scale solar state, MOPR is viewed as particularly detrimental to NC's dispatch into the PJM market and the NC solar industry. It's impact to state's ability to carry out its own energy and environmental policies has resulted in certain PJM states taking legal action related to MOPR.

Ultimately, NERP recommends that joining PJM should not be evaluated at this time. The nature of the PJM market could make North Carolina state goals, such as REPS, clean energy standards, greenhouse gas reduction targets, and other state policies more difficult and costly to implement. Further, integration into PJM takes minimally 24 months and any associated integration expenses are billed directly to the transmission owner impacting customer rates. While NERP does not support NC joining PJM at this time, it is acknowledged that changes in Federal policy and a new FERC could warrant reconsideration of this item at a future date.

Points of Discussion: Form a Joint Carolinas RTO

NERP discussed the merits of investigating a North and South Carolina RTO. Duke Energy and Dominion Energy operate in each state. These utilities have critical high-voltage infrastructure in each state, and perhaps just as important, experience with each states' process and regulatory compliance. Because of these factors, some NERP stakeholders postulated a joint Carolinas RTO could be easier to implement and less costly than joining an existing RTO. NERP stakeholders caution that the further apart the Carolinas' power market structure become, the more complex the challenges of managing costs, environmental impact/compliance, and broader system operation become.

A Carolinas RTO concept presents a number of considerations worthy of investigation. Conventional understanding holds that geographic footprint of the RTO is a key factor of cost and benefits. NERP questioned whether a Carolinas RTO could achieve significant cost savings when compared to larger RTOs and regardless, what methodology would best represent such a comparison. Further, if the benefits did prove limited, could that difference be mitigated? NERP ultimately decided that due to the above considerations, the RTO in the proposed study could be defined by the geographic barriers of North and South Carolina or a larger area such as the southeastern United States.

Of specific relevance to this process, traditional RTOs do not feature robust, non-stakeholder processes such as NERP by default nor are RTOs regulated by any one state. While most RTO decision making does happen through a participant-driven process, most RTOs restrict voting-member participants to transmission system owners, buyers, and sellers. Similarly, the role of each state's utilities commission could be limited under an RTO as FERC is the regulatory agency with jurisdiction over interstate electricity and wholesale markets. Stakeholders agreed that any proposed reform should protect processes such as NERP, which include broader system, environmental, and social concerns, and also ensure that both states' regulatory agencies have roles in system oversight to the extent FERC jurisdiction and RTO rules allow.

Points of Discussion: EIM & SEEM

NERP identified energy imbalance markets (EIMs) as a less timely and costly alternative compared to the Carolinas or Southeastern RTO concept. An EIM is voluntary market for dispatching real-time energy across utility service territories. Each participating utility retains ownership and control of its transmission assets but opts to bid generation into a centralized dispatch authority. EIMs allow utilities to optimize intersystem imbalances without the added operational or structural requirements of an RTO.

A Carolinas, or Southeastern, EIM could bring benefits to the region via gains in broad system efficiencies, lower operational reserve requirements, generator price transparency, and a governance structure that allows input by non-utility participants such as states or independent power producers. Existing EIMs are extensions of RTOs and operated as such; PJM would likely be the Carolinas RTO operator. Yet this function would not require utility RTO membership and benefit by avoiding transmission operations, compliance, and transmission allocation costs. While not as expensive as creating an RTO, EIMs have required costly, multi-year processes in other regions of the country. Critical to some NERP stakeholder interests, while EIMs may provide better integration of variable renewable production, they do not inherently provide non-balancing authority entities, such as Independent Power Producers (IPPs), a platform for market access.

Publicly announced in mid-2020, SEEM, the Southeastern Energy Exchange Market, is a proposed 15-minute automated energy exchange market between balancing authorities of the Southeastern U.S. While full details of the market construct are not yet known, what is proposed indicates a simpler market than a traditional EIM with a contracted platform administrator that operates the system that follows market transactions and a market auditor tracking market rules. Further, SEEM will not depend on utility RTO membership and thus avoids additional significant infrastructure, compliance costs administrative, and transmission allocation costs.

NERP stakeholders agreed in principle to the lower setup costs of SEEM as compared to an EIM. However, some stakeholders viewed the marginal reforms proposed by SEEM to be unsatisfactory. SEEM, per that perspective, does not appear to expand market opportunities to non-utility participants, nor does it expose incumbent generators to competition, provide operational transparency or public interest governance, nor a framework for additional market expansion. Ultimately, each of the proposed wholesale market reforms feature potential benefits and costs to North Carolina.

NERP Recommendations

NERP recommends the General Assembly of North Carolina direct the NCUC to conduct a study on the benefits and costs of wholesale market reform and implications for the North Carolina electricity system.

A proposed study rationale, elements, authorization, and funding accompanies this report. NERP recommends the following market structures be evaluated:

1. An RTO as defined by a) geographical boundaries of North Carolina and South Carolina or b) a larger region such as the Southeast.
2. An EIM as defined by a) geographical boundaries of North Carolina and South Carolina or b) a larger region such as the Southeast.
3. The energy exchange market proposed by a consortium of over 15 entities in the Southeast U.S. in 2020 and referred to as the Southeastern Energy Market (SEEM).

Additionally, the study should be required to offer recommendations to the General Assembly as to whether any of these market structures should be pursued further. This includes:

1. Recommending whether legislation is to be brought forward to allow reform of the wholesale electricity marketplace,
2. Recommending a model for wholesale competition that should be implemented if applicable, and
3. Recommending a stepwise approach to incorporating municipal and cooperative electricity generators and providers into wholesale market reforms, as needed.

Wholesale Market Outputs

NERP produced the following documents for dissemination, to inform subsequent policy discussions with various audiences:

1. **Legislative language authorizing the NCUC to conduct a wholesale market reform study:** A number of wholesale reforms are relevant to NERP stakeholder organizations, recent academic research, and adjacent state policies. The study authorized by this language considers the costs and benefits of wholesale electricity market reform at the state and regional level.
2. **Wholesale market reform study scope and criteria:** This document reviews the proposed market reforms in greater detail and offers guidance to study process, structure, and funding.
3. **A meta-analysis of proposed market reforms:** As each market reform features a number of similarities and points of comparison, the group provides a high-level review of key market criteria.
4. **Electricity market structure factsheets:** Each construct outlined in the meta-analysis are featured in 2- to 3-page factsheets which provide greater detail on the respective markets.

Securitization for Generation Asset Retirement

Asset Retirement in Brief

- NERP participants' interest in asset retirement was primarily focused on securitization, which is the focus of the content in this report.
- Securitization is a financing mechanism involving the issuance of bonds to raise funds to refinance remaining undepreciated value of existing coal plants.
- If properly designed, securitization used with a coal retirement plan, can lower customer bills, reduce air and water pollution, support coal plant communities in the transition, and allow utilities to reinvest in clean energy to replace lost revenue from legacy coal plant investments.
- NERP's primary recommendation is to expand the use of securitization in North Carolina beyond storm recovery costs to include generation asset retirements.

Background

The declining costs of renewable energy and higher cost of operating coal plants relative to other resources, in addition to the state priority of reducing greenhouse gas emissions, particularly carbon dioxide, has increased interest in retiring coal plants in a low-cost way. However, these coal units remain in the portfolio due to the utilities' need to recover their investment and maintain reliability. As North Carolina has a significant amount of coal capacity that could be financed to provide ratepayer benefits, the large amount of generation needing to be replaced must be planned carefully to ensure costs are minimized, utilities are fairly compensated, system reliability is maintained, cleaner technology solutions are deployed, and pollution levels are reduced.

In order to retire coal plants, the remaining undepreciated value must be addressed. Securitization is a refinancing mechanism involving the issuance of bonds to raise funds to refinance the remaining undepreciated value of existing coal plants. The bonds are paid back over time through a dedicated surcharge on customer bills. Because the surcharge is irrevocable and payment to the lender is basically "guaranteed" through the legislation, the bonds can typically be issued at an interest rate even lower than the usual utility bond interest rate. In addition, most major credit rating agencies do not include securitization debt, up to certain limits, in assessing the utilities debt to equity ratio for credit rating purposes. Therefore, the utility can generally refinance the outstanding undepreciated value with 100% securitization financing instead of using its standard combination of debt and equity financing. Both of these factors combined lead to cost savings for customers.

By itself, securitization would translate to a loss in earnings for the regulated utility by reducing the total amount of capital in which the utility is invested. However, securitization can also be paired with utility reinvestment in replacement capacity to maintain reliability. Because this replacement generation would be financed using a combination of debt and equity, this option has the potential to recoup and even grow utility earnings.

Duke Energy currently operates six coal plants totaling about 10,000 MW of capacity. The low cost of natural gas and renewables, along with additional environmental compliance costs, has shifted electricity generation toward cheaper sources of energy in recent years, and the trend is expected to continue as the economic gap widens. Coal plants in the state, originally built to run 75-80% of the time, are now running, on average, only 35% of the time.

Early economic retirement of North Carolina's coal plants and replacement with zero emitting resources is estimated to achieve the 70% reduction in greenhouse gas emissions goal specified in the Clean Energy Plan by itself, provided the amount of imported electricity and its carbon intensity remain at or below historic levels.

Key Points of Discussion and Content Development

NERP participants discussed several topics related to securitization that fed into the development of the draft legislation. These included the savings for customers, reinvestment by the utility, transition assistance for affected communities, and replacement of coal assets.

Many believed that, at a minimum, securitization should be a tool available in North Carolina, as an option for utilities to retire fossil generating assets. Some participants believed that securitization should at least be neutral on customer cost impact, but would ideally save money for customers. For others, savings to customers should be a mandatory precondition for securitizing undepreciated assets.

There was a strong consensus among participants that the utility needs a clear path to reinvest in something — whether it be capital assets or a portfolio — after the securitization and closure of fossil assets. All supported making utility reinvestment a required element of securitization in order to make the utility whole and reduce the disincentive for utilities to use securitization for undepreciated assets. Related, there were early conversations about limiting utility ownership to a lesser, undetermined percentage (i.e., 50% of new procurements could be utility-owned and 50% of new procurements would be third-party owned). Stakeholders could not agree on an appropriate path forward, and ultimately concluded that the legislation should not prescribe a percentage of allowable utility ownership. However, there was an emphasis on recognizing that competition would be critical to ensuring least cost; thus, the asset should be owned by whoever can provide it or a portfolio at the lowest cost to customers.

As for replacement resources, there was more debate among participants of NERP. One subset of stakeholders believe that coal should be replaced through a competitive, all-source RFP process, another subset of stakeholders believe that replacement resources should be required to be clean energy resources that reduce GHG emissions and support the North Carolina Clean Energy Plan, and another subset of stakeholders believe that the IRP process should continue to dictate replacement resource planning. Another issue was raised that the state does not need a 1:1 replacement for coal capacity because those plants are currently running at low-capacity factors.

Near the end of the process, a majority of the study group aligned around the following points:

- The procurement system of the future should be one that balances carbon reduction with affordability and reliability in order to achieve the goals in the Clean Energy Plan and the prioritized outcomes of NERP.
- Natural gas systems might appear least-cost today in some cases, but may, as a result of declining costs of alternative resources, changes to public policy, or other factors, become stranded assets within 10 years.
- In order to avoid stranded assets, risk should be weighted in analysis of resource selection. There is risk to procuring new gas assets. There is a need to ensure that assets are not just cheaper today, but will be fully functional and cost effective for the entirety of their lifetime.
- Utilities should consider portfolios instead of single, specific assets.

Transition assistance to help communities affected by plant shutdowns was of importance to most participants in NERP. It was of interest to have communities be in control of how funds are used and make decisions appropriately, with some specific interest in supporting schools and local governments that will be affected by reduced tax bases. There was also interest in developing solar in locations that previously had coal to bring some level of tax base back to the community. Two areas of discussion arose around which participants did not reach a conclusion. First, there was discussion about whether transition assistance should come from securitization savings or from the state's general fund, with some believing that "it's a state policy, not a utility policy, so all state taxpayers should pay."

The study group determined that the legislation would outline that the NCUC could approve up to 15% of savings, or less, to be used for transition assistance. The study group decided it would be best not to prescribe how the funds should be allocated, as to preserve that responsibility for those on the ground who have the best sense for what is needed in the community. Therefore, the group aligned around ensuring that local governments are involved in the process.

NERP Recommendation

The asset retirement study group recommends that the North Carolina General Assembly expand securitization to be an available tool for electric utilities to retire undepreciated assets, in addition to the current use around storm recovery costs.

- The recommendation is modeled after best practices from the Colorado statute.
- Legislation would be enabling a tool, not mandating that a utility use it.
- Up to 15% of savings could be used to create a transition fund; the Commission would make this final determination.
- Any replacement capacity needed should be procured through a competitive process and approved by the Commission.
- The recommendation does not include restrictions on utility ownership of replacement resources.

Asset Retirement Outputs

NERP produced the following documents for dissemination, to inform subsequent policy discussions with various audiences:

1. **Legislative language expanding the use of securitization for retirement of uneconomic power plants:** An act to permit financing for certain undepreciated utility plant costs and for transition assistance for affected workers and communities.
2. **Securitization statute comparison:** A comparison of securitization statues which include recovery of undepreciated plant balances and transition assistance for workers and communities affected by early plant retirements as allowable uses for securitized bonds.
3. **A fact Sheet, *Expanding Securitization: Accelerating the Clean Energy Transition & Building the North Carolina* Economy:** Describes what securitization is, what the opportunity is, and highlights national precedent for any audience needing to learn more about securitization, such as the North Carolina General Assembly.
4. **Early asset retirement analysis accompanied by a two-page summary:** Analysis that evaluates accelerated depreciation, regulatory asset treatment, securitization (with and without reinvestment) and compares them to business-as-usual. It examines the tradeoffs between the different scenarios for utility earnings and customer rates on a first-year and levelized basis and can also be used to determine these impacts on an asset-by-asset or a portfolio level. The analysis is described in a two-pager that compares securitization to regulatory asset treatment and showcases the relative impacts on ratepayer savings, utility earnings, and community assistance.

Competitive Procurement

Competitive Procurement in Brief

- Competitive procurement and all-source solicitations are an area of significant interest among many of the NERP stakeholders.
- The study group evaluated issues related to the use of competitive processes for purposes of meeting future resource capacity and generation needs.
- State policy regarding utility competitive procurement should take into account unique characteristics of each utility service territory
- Subject to details provided in the group's policy paper, NERP identified competitive solicitations as an important tool that should be utilized to meet energy and capacity needs identified in IRPs and as otherwise deemed appropriate by the NCUC.

Background

North Carolina investor-owned utilities are required to submit IRPs to the NCUC to forecast, and address, grid needs at least cost. Federal and state policies, as well as utilities themselves, are increasingly recognizing the opportunity for competition to drive these costs down as more technologies qualify as grid resources. In 2017, NC HB 589 created the competitive procurement of renewable energy program which provided a competitive bidding process for renewable energy projects in Duke Energy's North Carolina service territory. North Carolina's Executive Order 80 and DEQ further identified many non-generating resources, such as efficiency and battery storage as grid scale technologies — technology not traditionally in line with the utility capital expenditure and return model.

Due to its relatively small customer base and small geographic service territory in North Carolina compared to Duke Energy, and because Dominion Energy North Carolina serves its customers primarily with energy generated in Virginia and the larger PJM region, Dominion Energy North Carolina was exempt from the competitive procurement provisions of HB 589. Additionally, the Virginia Clean Economy Act (VCEA) enacted by the Virginia legislature in 2020 established comprehensive competitive procurement requirements for Dominion Energy in connection with the renewable portfolio standard (RPS) also enacted as part of the legislation. The VCEA RPS requires Dominion Energy to achieve an RPS of 100% renewable energy by 2045 in its Virginia service territory.

Competitive procurements do not restrict utility self-build or utility ownership by definition. Instead, utility-built resources or utility owned generation, become one of many potential options. Competition by this design has resulted in cost savings generally and should continue to provide lower cost investments and lower customer bills in the future. Further, utilities could potentially benefit via more innovative business structures, expanded generation options, a cleaner grid, and optimization of existing grid investments.

Key Points of Discussion and Content Development

Points of Discussion and Agreement: Defining Competitive Procurement

Given the impact of existing procurement in North Carolina, and the vast number of stakeholders interested in potential procurement reform, the competitive procurement study group began by proposing definitions to the broader NERP group. The majority of participants agree with the following definition:

Competitive procurement is an IRP-driven, all-source procurement to meet all identified needs for new resources in a manner that is consistent with policy directives and at the best available overall price.

While this definition was ultimately selected, stakeholders offered a number of suggestions as to the scope of competitive procurement. Some participants wondered for example if demand side management, energy efficiency, and distributed energy resources qualified as potential resources. Regarding the scale of competition, stakeholders asked whether new resources could compete against existing assets if their prices were advantageous. Finally, stakeholders identified cost as an area to further define as cost could include impact of stranded asset costs to ratepayers and whether carbon or other environmental considerations could be added.

Points of Discussion and Agreement: Participation

The VCEA enacted by the Virginia legislature in 2020 established comprehensive competitive procurement requirements for Dominion Energy in connection with the renewable portfolio standard (RPS) also enacted as part of the legislation. The VCEA RPS requires Dominion Energy to achieve an RPS of 100% renewable energy by 2045 in its Virginia service territory. Dominion Energy holds that any such expanded competitive procurement program in North Carolina should not apply to it as Dominion Energy owns no generation in North Carolina and further, VCEA established a number or relevant and similar processes for the utility to abide by.

While the study group did not discuss this item in detail, the group agreed that any State policy regarding competitive procurement should take into account the unique characteristics of each utility service territory and other relevant features such as, but not limited to, location of generation assets, geographic footprint, and generation portfolio.

Points of Discussion and Agreement: Utility Ownership

One of the primary points of discussion within the Competitive Procurement study group was utility participation or utility ownership of generation assets procured. Historically, utilities' ability to rate-base (i.e., allow recovery of capital costs plus a return on equity) has provided low-cost, reliable generation for NC. However, some stakeholders asserted that this model was best utilized when generation was viewed as part of the natural monopoly.

There are potential benefits to ratepayers and utilities as utility ownership ensures the financial health and growth of the utility and offers more direct operational control of the generation, diversifies life-cycle risk of the assets (due to declining revenue requirement), along with other benefits. On the other hand, rate-basing can create risks to both entities in the form of potentially higher costs, construction delays, and cost overruns.

Stakeholders have considered a myriad of issues, including whether utility ownership models are best for specific types of generation — large, thermal generation for example which are high capital cost investment that traditionally provide baseload, year-round grid support. Additionally, stakeholders discussed if there is an ideal amount of utility purchases of assets from the broader developer community.

Stakeholders have yet to come to a determination and formal recommendation on these questions. The key question that will inform this work is whether there should be a pre-determined allocation between utility, rate-based ownership and third-party ownership

NERP Recommendations

NERP recommends that the North Carolina General Assembly expand existing procurement practices to utilize competitive procurement as a tool for State electric utilities to meet energy and capacity needs defined in their respective IRPs and where otherwise deemed appropriate by the NCUC.

State policy regarding utility competitive procurement should take into account unique characteristics of each utility service territory, e.g. number of customers, geographic size, amount of utility-owned generation in the service territory, and proportion of existing generation from renewable sources located in the service territory and serving utility customers.

Competitive Procurement Outputs

NERP produced the following documents for dissemination, to inform subsequent policy discussions with various audiences:

1. **Competitive procurement policy recommendation for the North Carolina General Assembly:** An overall policy recommendation which, subject to the more detailed recommendations outlined in the document, states that competitive solicitations are an important tool that should be utilized to meet energy and capacity needs identified in an IRP and as otherwise deemed appropriate by the North Carolina Utilities Commission.
2. **A case study into the Public Service Company of Colorado's recent procurement cycle:** The subcommittee evaluated a number of states but focused primarily on a recent procurement cycle in Colorado for the Public Service Company of Colorado (Xcel Energy), which was ultimately determined to be a successful generation procurement framework.
3. **A case study into key generation procurements enacted by the Virginia Clean Economy Act:** The summary outlines the sweeping package of energy reforms established in March, 2020 that set Virginia on a path toward a 100% carbon-free electricity grid by 2050.

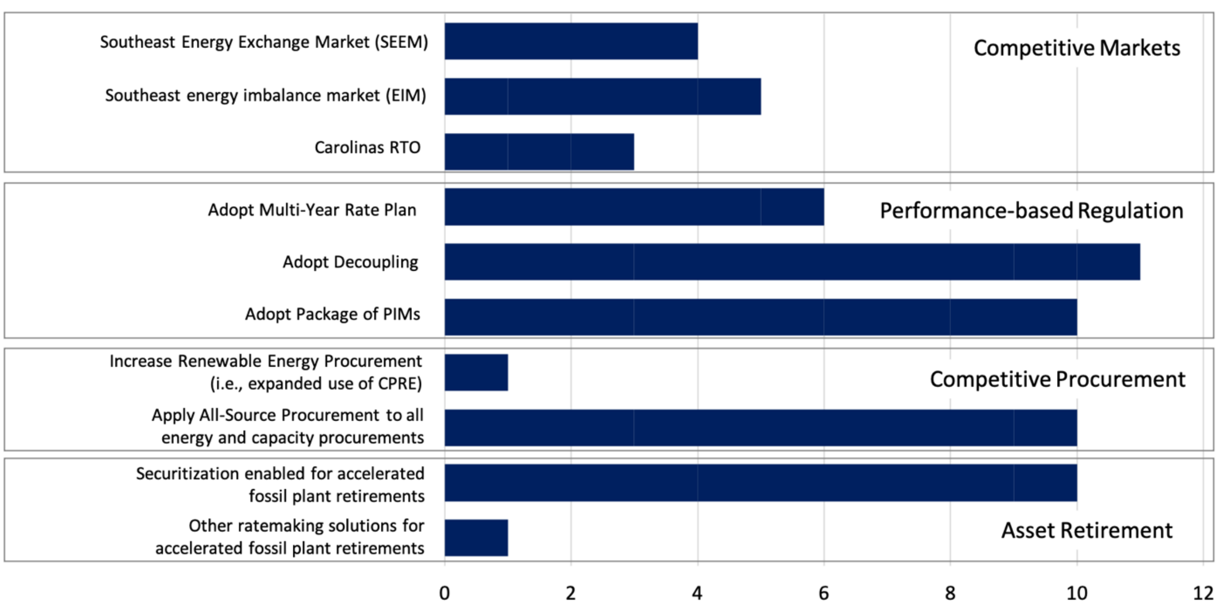
Conclusion

Achieving full consensus on reforms was not an objective of NERP, but NERP participants remain dedicated to continuing the conversation and arriving at a reform package that best meets the needs of North Carolina. Despite strong support for several reforms discussed in this report, no one reform enjoys the full support of every NERP participant, and there are nuances to participants' views. To achieve priority outcomes, this work will need to move forward through actions of the North Carolina General Assembly, NC Utilities Commission, by the state's utilities, and through continued input and support from stakeholders.

To aid in those continued conversations, this section explores where interest and alignment emerged through NERP dialogue, as well as how reform options may be combined in upcoming legislative action.

Stakeholder Support for Reforms

Throughout NERP in 2020, participants were asked to express their level of support for various reforms and to prioritize the work that NERP should pursue according to what reforms were (i) most important to those represented and (ii) most likely to lead to priority outcomes (carbon reduction, affordability, and alignment of regulatory incentives with 21st century public policy goals). The facilitators conducted polls and surveys of participants to assist in guiding the work of the group and inform the next steps in North Carolina. Summary results of one of those surveys is provided below, in which participants responded to the question, "Which reforms are priorities for you or your organization to immediately advance at the conclusion of this 2020 NERP process?" Each respondent could select up to three reforms; bars show the number of people who selected each reform.



The results of this informal survey, as well as other similar exercises conducted throughout NERP, demonstrate that all potential reforms discussed during 2020 have some level of support among NERP participants. Several reforms, particularly revenue decoupling, performance incentive mechanisms, all-source competitive procurement, and enabling securitization to accelerate fossil plant retirements, are high priorities for many participants at the conclusion of NERP.

A Possible Package of Reforms

Multiple possible paths forward emerged at the conclusion of the 2020 NERP process. The following describes some of the options for putting forward a package of reforms. Options 1 through 3 describe paths forward for NERP-specific topics and recommendations, whereas Option 4 recognizes the desire among many participants to ensure that a legislative package includes other provisions related to climate and clean energy.

Option 1	Option 2	Option 3	Option 4
One legislative package combines: (1) PBR authorization, (2) wholesale market study direction, (3) direction to NCUC to use competitive procurement, and (4) expansion of securitization for retirement of coal assets	One legislative package combines PBR, new securitization authorization, and direction to NCUC to use competitive procurement Separate legislation creates wholesale market study	One legislative package combines PBR and new securitization authorization Competitive procurement is pursued at the NCUC Standalone legislation creates wholesale market study	Some combination of Options 1-3, with the addition of other policy provisions such as a Clean Energy Standard, carbon reduction policy, economic growth policy, or other enabling actions

NERP briefly discussed these options in the final workshop of 2020. A majority of participants expressed support for some version of Option 4 as the best path forward. That is, there was agreement to combine policy concepts into one piece of legislation, and that such legislation should also include other enabling policies not discussed in NERP.

Agreement was not reached on what that additional enabling policy ought to be. Multiple participants believe a clean energy standard (CES) is a necessary complementary policy to the NERP reforms. Others believe that some policy that enables or requires carbon reductions, as informed by the modeling being conducted in the "A1" process, should be included in the package.

Some participants prefer including additional enabling policies in this package, including revisions to House Bill 589 (2017), inclusion of a "carbon adder" in utility planning, and IRP reform to make competitive procurement more viable. These ideas were not fully explored in the final workshop.

A handful of participants argued that Option 4 was the best path, but that legislation to create a wholesale market study should be considered separately from other reforms.

Some participants were reluctant to state their opinions about these options without having more information, particularly what the recommendations will be from the CEP A1 process on carbon reduction policy designs. Although NERP in 2020 did not negotiate a "final agreement" on a package of reforms, participants acknowledged the need to continue the conversation to further refine the details to be included.

Next Steps

A combination of the reforms discussed in this paper, combined with other energy reforms including those described in the Clean Energy Plan and the parallel "A1 process", can support the state's transition to a cleaner energy system. Following the NERP 2020 process, stakeholders will continue to refine details and find areas of alignment in the proposals to advance collectively. Conversations may be supported by RMI and RAP; however, participants will also consult independently with NC policymakers, decision-makers, and other constituents to brief and educate them on potential reforms. The study group outputs produced during NERP (and attached to this report) can aid in briefings and further refinement of policies for advancement through legislative and regulatory processes. Draft legislation produced during NERP will be subject to continued refinement and development through the legislative session; drafts attached to this report represent their status at the conclusion of 2020 NERP discussions.

Appendix

Full List of NERP Participating Organizations

Organization Type
North Carolina Department of Environmental Quality (DEQ)
North Carolina Utilities Commission (NCUC)
NCUC Public Staff
North Carolina Legislature
North Carolina Governor's Office
North Carolina Attorney General's Office
Duke Energy
Dominion North Carolina Power
North Carolina Electric Cooperatives
ElectriCities of North Carolina
City of Charlotte
City of Asheville
Durham County
North Carolina Chamber of Commerce
Smithfield Foods
North Carolina Retail Merchants Association
Appalachian Voices
North Carolina Manufacturers Association
Carolina Utility Customer Association
North Carolina Clean Energy Business Alliance
North Carolina Sustainable Energy Association
DEQ Environmental Justice & Equity Board
North Carolina Justice Center
Environmental Defense Fund
Southern Environmental Law Center
North Carolina Conservation Network
NC WARN
Sierra Club
Duke University Nicholas Institute
North Carolina Clean Energy Technology Center

Contact Information

Contact	Organization	Email
NERP Contact		
Sushma Masemore	NC DEQ	sushma.masemore@ncdenr.gov
PBR Study Group Co-Chairs		
Sally Robertson	NC WARN	sally@ncwarn.org
Laura Bateman	Duke Energy	laura.bateman@duke-energy.com
Wholesale Market Study Group Chair		
Chris Carmody	NCCEBA	director@ncceba.com
Asset Retirement Study Group Co-Chairs		
David Rogers	Sierra Club	david.rogers@sierraclub.org
Tobin Freid	Durham County	tfreid@dconc.gov
Competitive Procurement Study Group Co-Chairs		
Steve Levitas	NCCEBA Board	slevitas@pgrenewables.com
Jack Jirak	Duke Energy	jack.jirak@duke-energy.com

Study Group Outputs

Outputs attached to this report represent their status at the conclusion of 2020 NERP discussions, as of December 18, 2020. If substantive revisions were received too late to allow study group discussion or full NERP feedback, it was not incorporated. Draft legislation produced during NERP will be subject to continued refinement and development through the legislative session.

Performance Based Regulation

Study Group Work Products

2020 NC Energy Regulatory Process

Contents of this packet:

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.

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

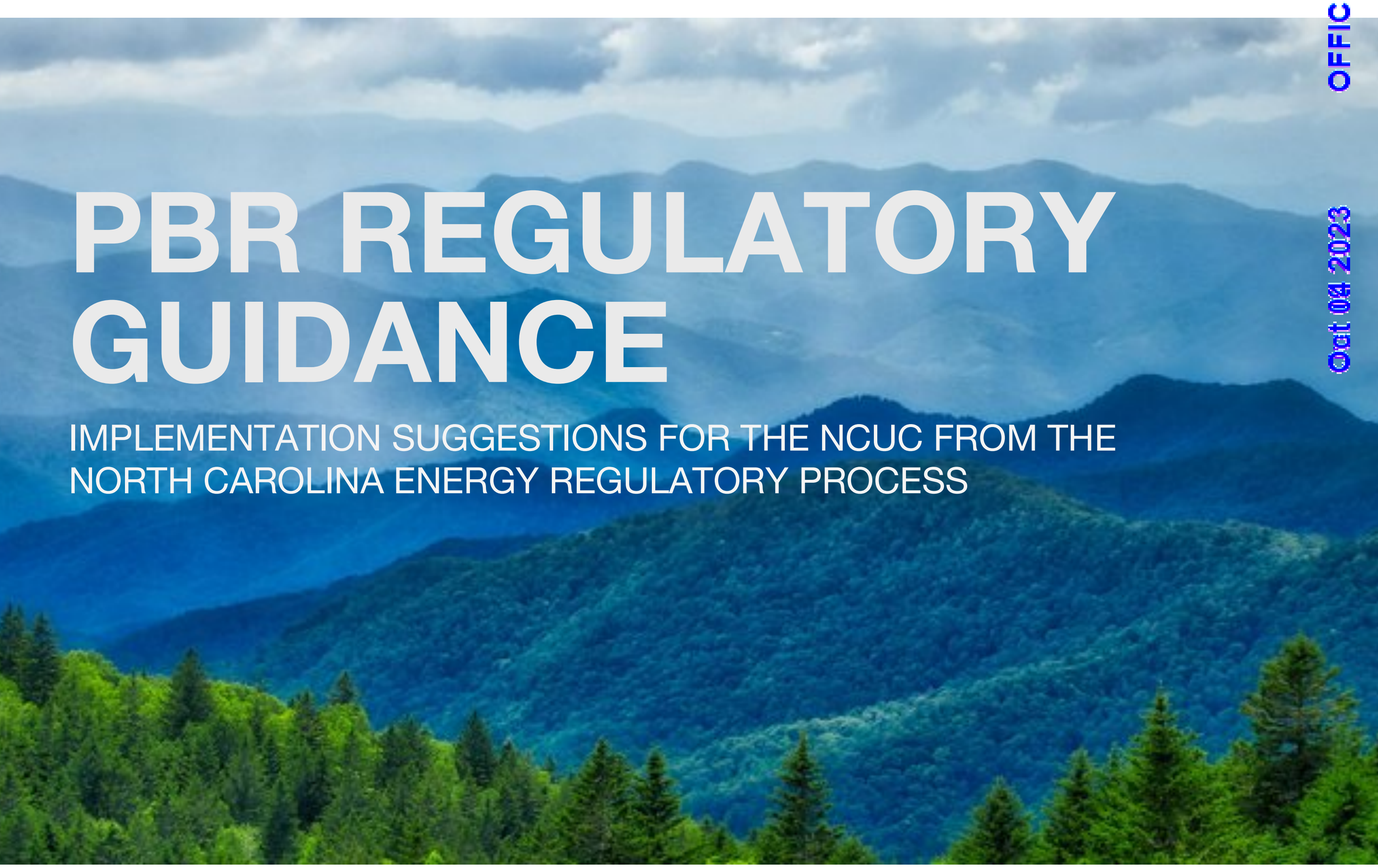
Governor Cooper's Executive Order 80 mandated the development of a clean energy plan for the state of North Carolina. The Clean Energy Plan recommended the launch of a stakeholder process to design policies that align regulatory incentives with 21st century public policy goals, customer expectations, 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

[6] See the Minnesota case study, available with all other NERP outputs on the website at the end of this fact sheet.



PBR REGULATORY GUIDANCE

IMPLEMENTATION SUGGESTIONS FOR THE NCUC FROM THE NORTH CAROLINA ENERGY REGULATORY PROCESS

AUTHORS & ACKNOWLEDGMENTS

STUDY GROUP MEMBERS

Laura Bateman, Duke Energy, co-lead[1]
Sally Robertson, NC WARN, co-lead[2]
Dionne Delli-Gatti, Environmental Defense Fund[2]
Paula Hemmer, Dept. of Environmental Quality[1]
Preston Howard, NC Manufacturers Alliance[3]
Steve Kalland, NC Clean Energy Technology Center
Munashe Magarira, NC Attorney General's office[2]
Sushma Masemore, Dept. of Environmental Quality[1]
Rory McIlmoil, Appalachian Voices[1,3]
Mark McIntire, Duke Energy[2]
Jeremy Tarr, Governor's office
Gudrun Thompson, Southern Environmental Law Center
Peter Toomey, Duke Energy[3]

[1] Revenue decoupling subteam
[2] Performance-incentive mechanisms subteam
[3] Multi-year rate plan subteam

CONTACTS

Sally Robertson, sally@ncwarn.org
Laura Bateman, laura.bateman@duke-energy.com

ACKNOWLEDGMENTS

NERP thanks the following individuals/organizations for offering their insights and perspectives on this work.

Josh Brooks, Rocky Mountain Institute
Daniel Brookshire, NC Sustainable Energy Association
Dan Cross-Call, Rocky Mountain Institute
Matthew Davis, NC Dept. of Environmental Quality
Tim Duff, Duke Energy
Jack Floyd, NC Public Staff
Rachel Gold, American Council for an Energy-Efficient Economy
Cara Goldenberg, Rocky Mountain Institute
Heather House, Rocky Mountain Institute
Lon Huber, Duke Energy
Matthew McDonnell, Strategen Consulting
Kevin O'Donnell, Nova Energy Consultants
Doug Scott, Great Plains Institute
Richard Sedano, Regulatory Assistance Project
Jessica Shipley, Regulatory Assistance Project

This work was last updated on 12/18/2020.

Cover image courtesy of GYPSY FROM NOWHERE IMAGES/ALAMY STOCK PHOTO

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.

TABLE OF CONTENTS

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.

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.

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.

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.

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).

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.

- 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.

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.

---

[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

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.

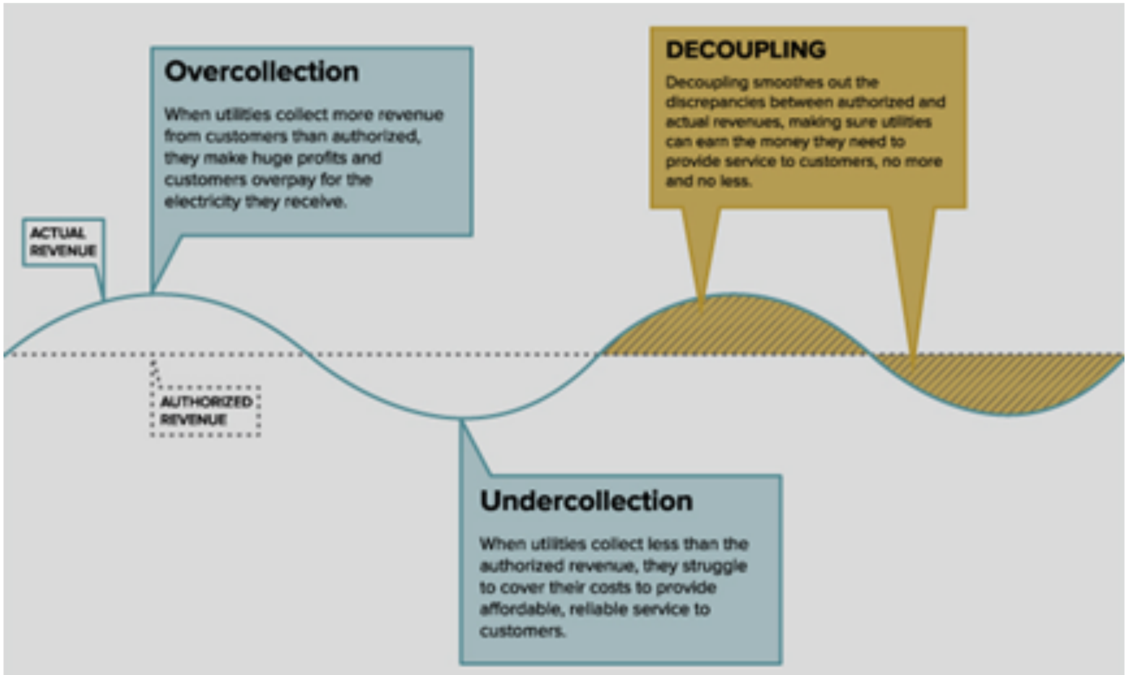


FIGURE 2: HOW DECOUPLING SMOOTHS OUT REVENUE FLUCTUATIONS[14]

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

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.

- 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.

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.

"…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.

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.

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 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").

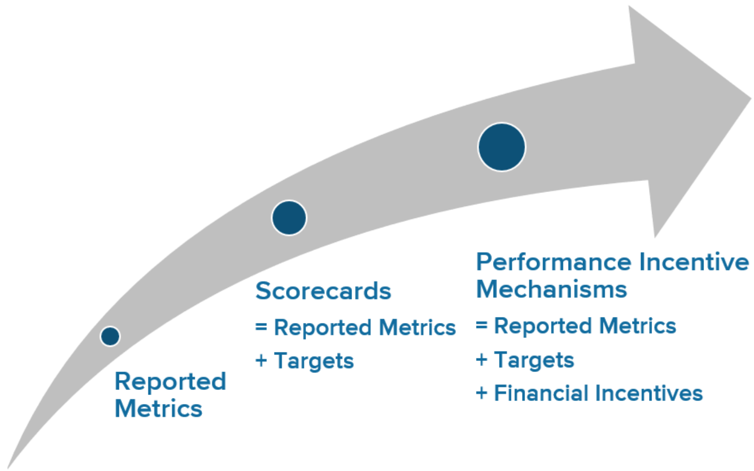


FIGURE 3: STAGES OF PERFORMANCE TRACKING
MCDONNELL, M., PBR DEEP DIVE WEBINAR: EXAMINING THE HAWAII EXPERIENCE, POWERPOINT, APRIL 2 2020.

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/.

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.

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.

- 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.

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

• 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.

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.

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.

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

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

    - 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.

REFERENCES

There are many resources on PBR. Here are some that NERP found most useful.

Cross-Call, Gold, Goldenberg, Guccione, and O'Boyle, *Navigating Utility Business Model Reform*, Rocky Mountain Institute (2018). Available at https://www.rmi.org/insight/navigating-utility-business-model-reform/.

Gold, R. et al. *North Carolina Can Boost Economy, Cut Utility Bills and Carbon with Energy Efficiency Efforts*, American Council for an Energy-Efficient Economy, September 23, 2020. https://www.aceee.org/research-report/u2007.

Goldenberg, Cara, Dan Cross-Call, Sherri Billimoria, and Oliver Tully, *PIMs for Progress: Using Performance Incentive Mechanisms to Accelerate Progress on Energy Policy Goals*, Rocky Mountain Institute, 2020, https://rmi.org/insight/pims-for-progress/.

Hawaii PUC, Proceeding to Investigate Performance-Based Regulation (Docket 2018-0088). Information and filings available at https://puc.hawaii.gov/energy/pbr/.

Lazar, Jim, et al. *Revenue Regulation and Decoupling: A Guide to Theory and Application*, Regulatory Assistance Project; 2016. Available at https://www.raponline.org/knowledge-center/revenue-regulation-and-decoupling-a-guide-to-theory-and-application-incl-case-studies/.

Littell, et al, *Next Generation Performance Based Regulation: Emphasizing Utility Performance to Unleash Power Sector Innovation*, Regulatory Assistance Project, 2017. Available at https://www.raponline.org/knowledge-center/next-generation-performance-based-regulation-emphasizing-utility-performance-unleash-power-sector-innovation/.

Lowry and Makos, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, 2017. Available at https://eta.lbl.gov/sites/default/files/publications/multiyear_rate_plan_gmlc_1.4.29_final_report071217.pdf.

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.

Whited, M., Woolf, T., Napoleon, A. *Utility Performance Incentive Mechanisms: A Handbook for Regulators*, Synapse Energy Economics; 2015. Available at

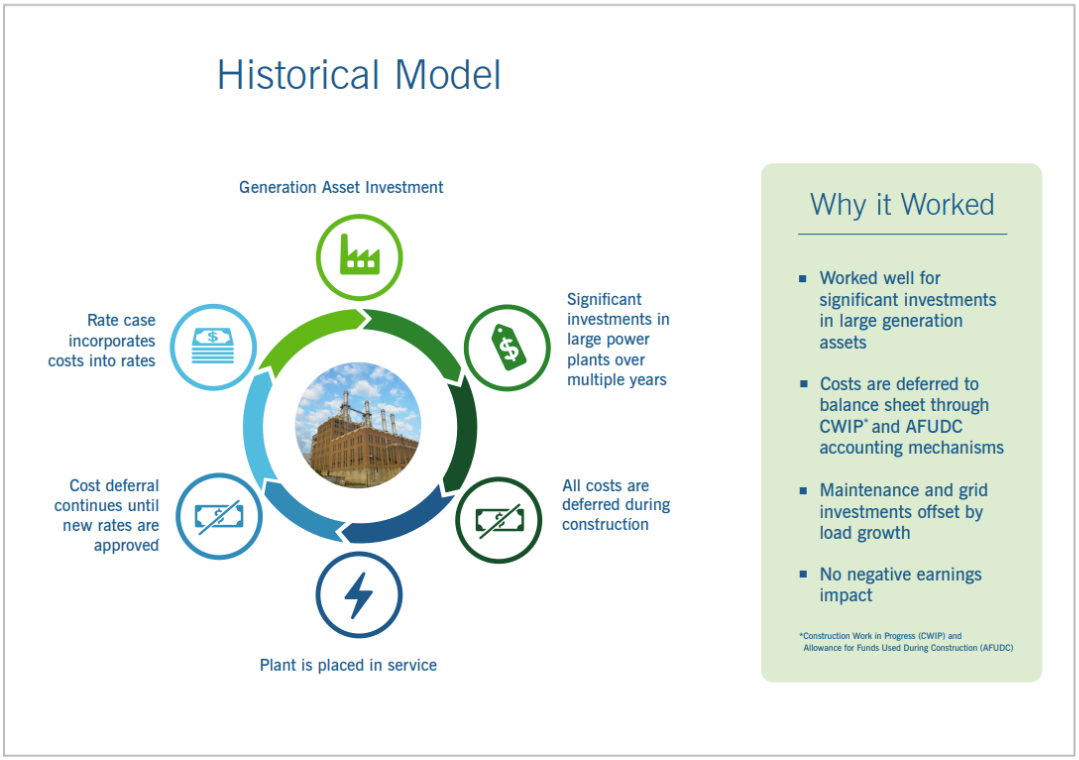
http://www.synapseenergy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf.

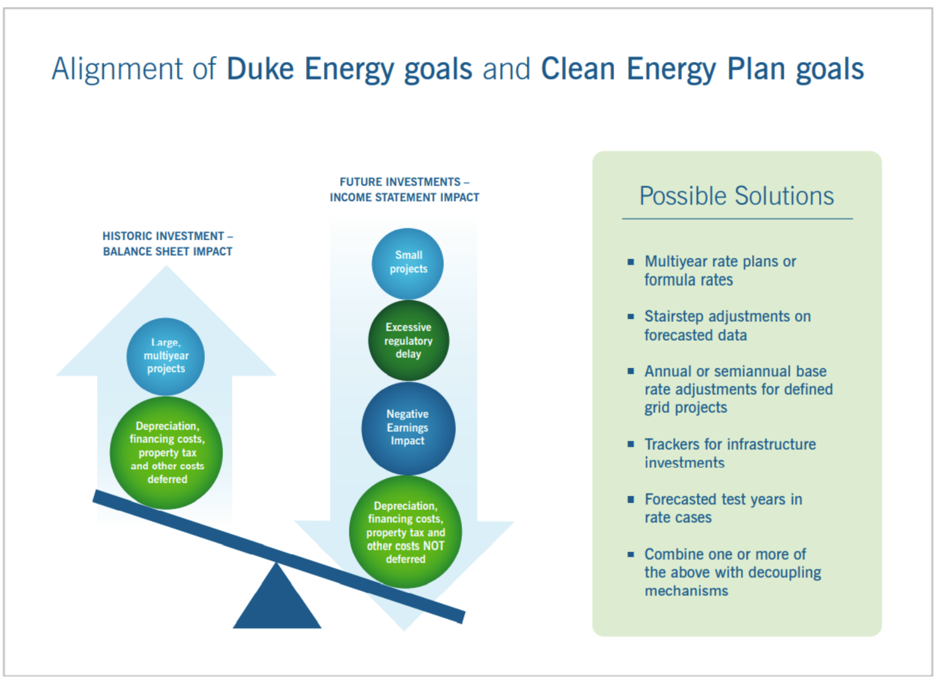
APPENDIX A

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.





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:

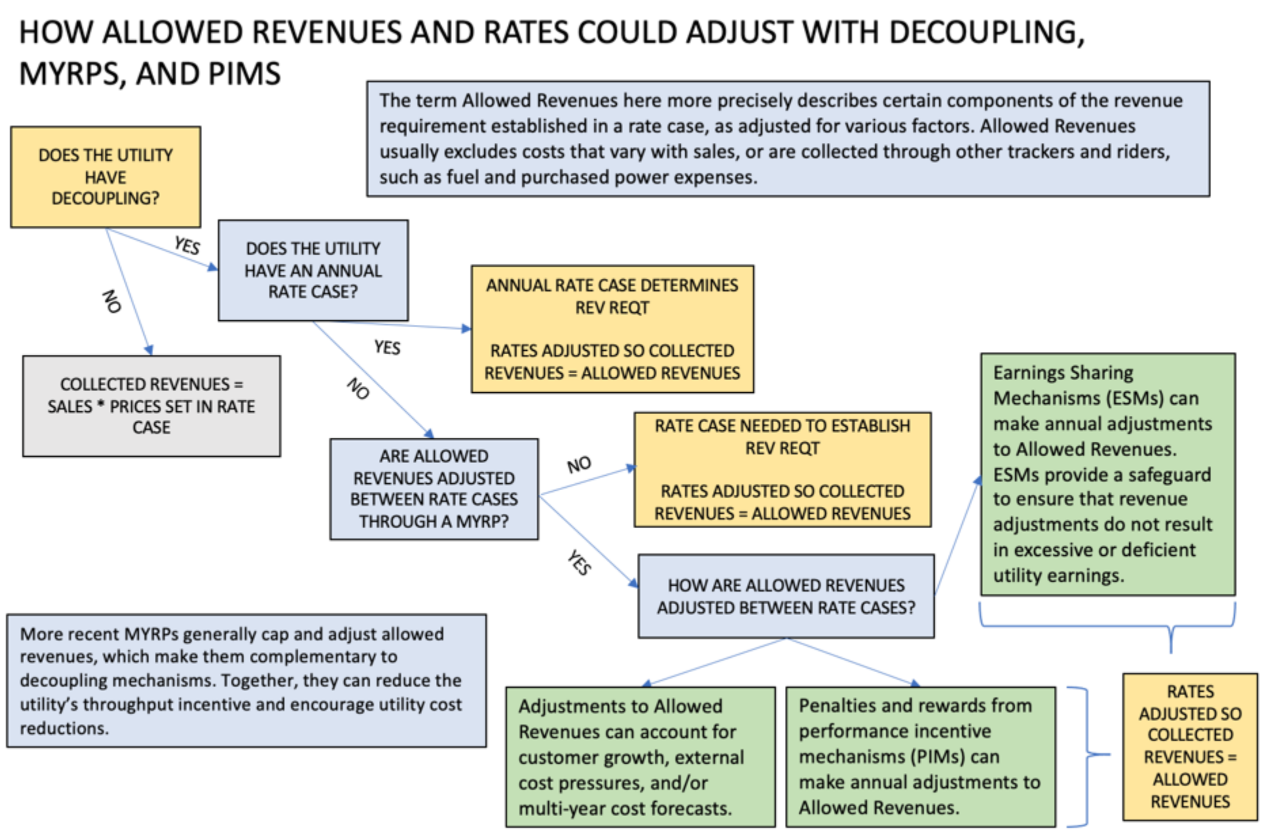
- 24 states have multi-year rate plans or formula rates
- 23 states have trackers for grid/electric infrastructure investments
- 30 states have forward test years (full or partial)
- Only 7 states have none of these mechanisms – including North Carolina

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.



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.

(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

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.

(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.

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.

- 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.

---

[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"

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:
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

[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

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;

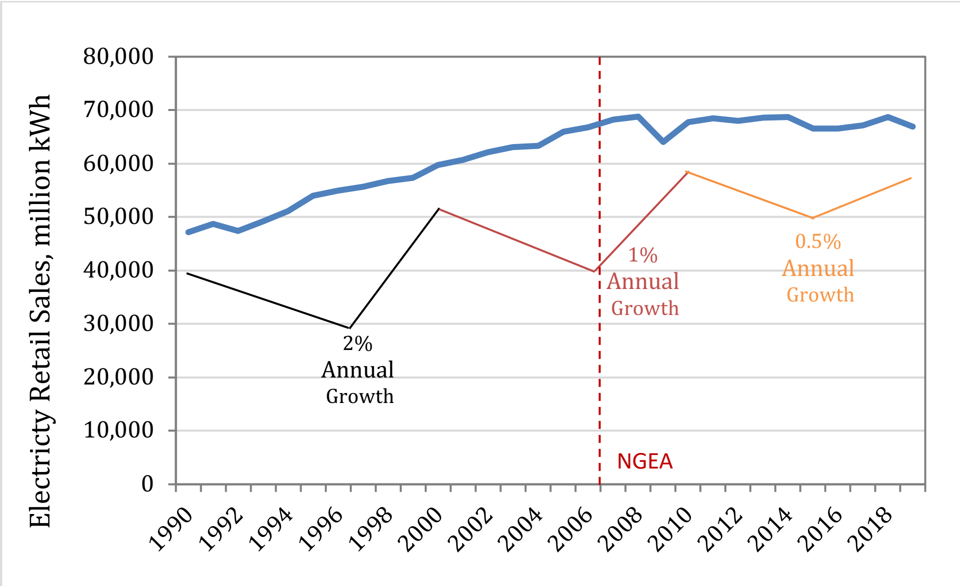
1. Reduce energy sales,
2. Spend a minimum percentage of annual operating revenues on energy efficiency, demand-side management and renewable energy starting in 2010, and
3. Incorporate a **shared savings financial incentive** model for energy efficiency.

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.

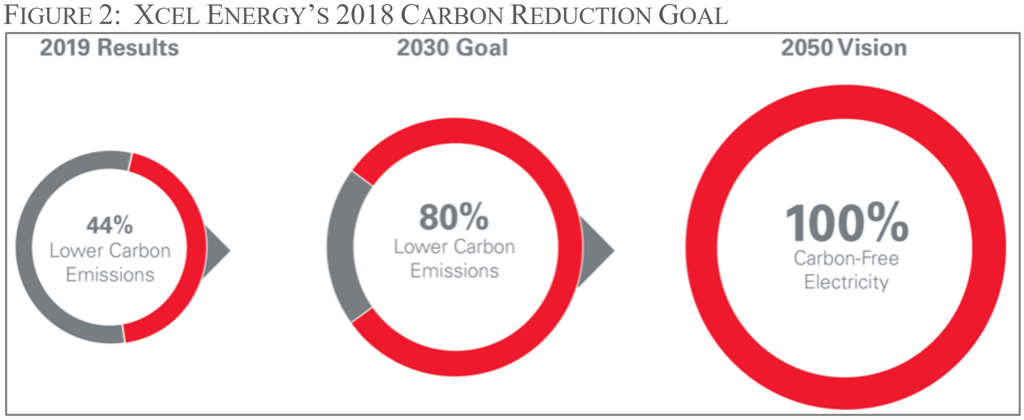
FIGURE 1: MINNESOTA RETAIL SALES OF ELECTRICITY SINCE 1990



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

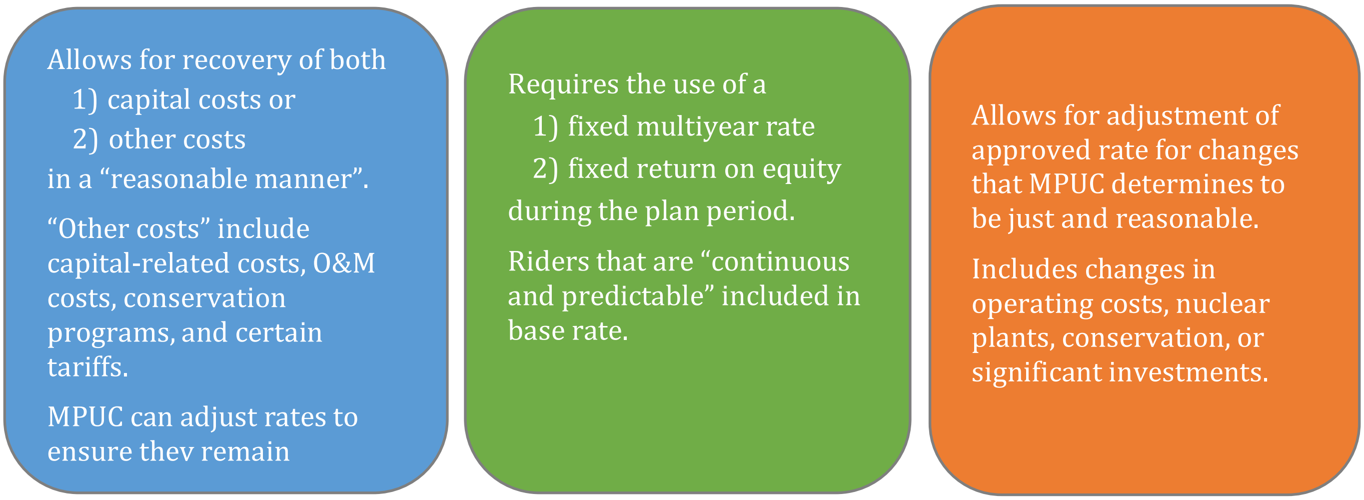
[2] Xcel Energy Clean Energy Transition, https://www.xcelenergy.com/environment/carbon_reduction_plan

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

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:

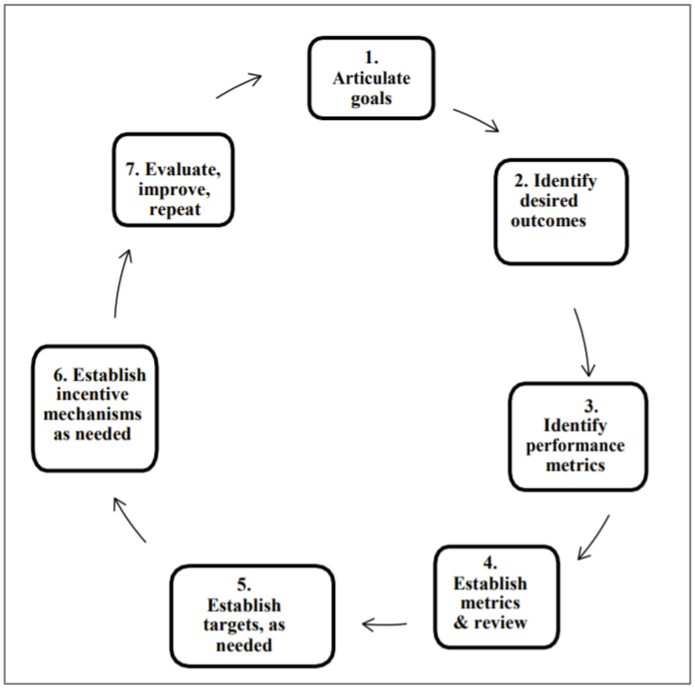
- Specifying goals for PIMs,
- Determining data points to measure in order to evaluate utility performance,
- Limiting the specific number of metrics and prioritizing implementation of certain metrics,
- Developing concrete procedures for calculating, verifying, and reporting metrics, and
- Specifying 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.

FIGURE 4: MINNESOTA PUBLIC UTILITIES COMMISSION PROCESS TO ESTABLISH PIMS

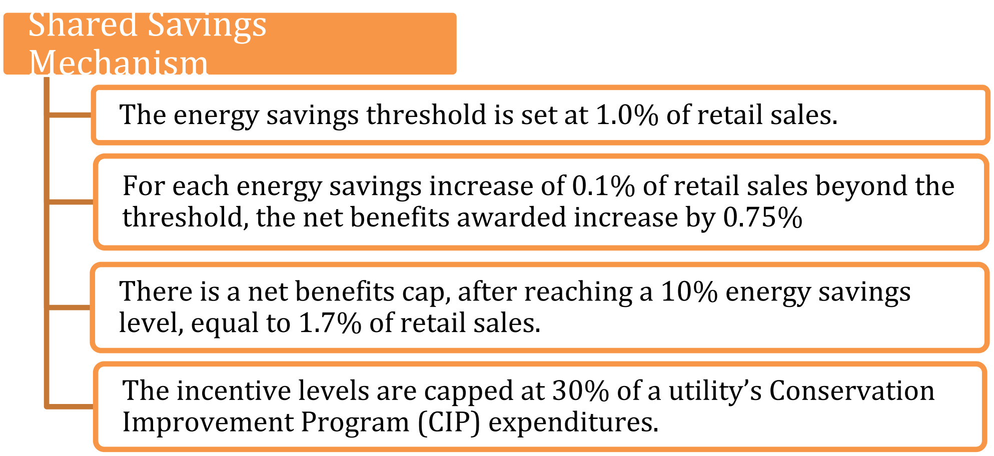


SOURCE: MPUC

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

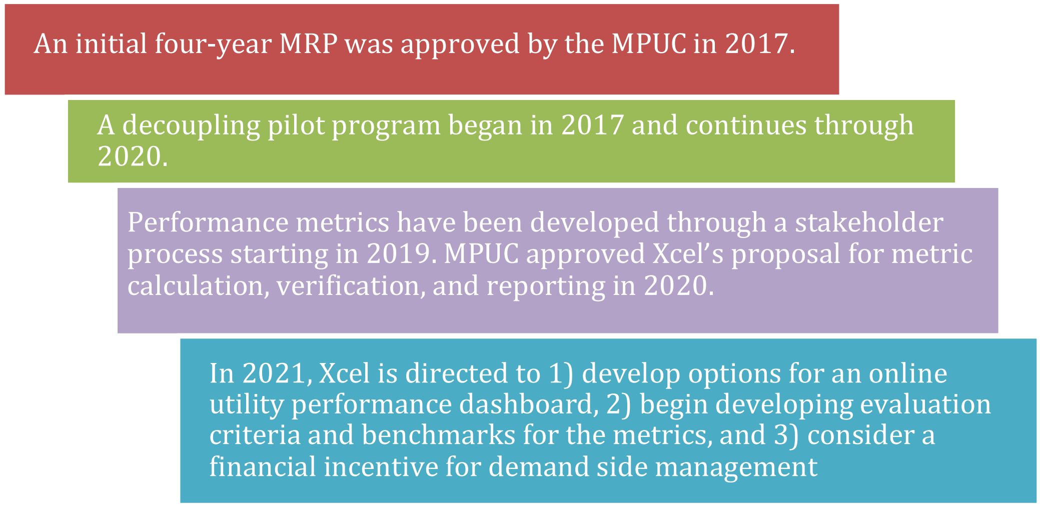


XCEL ENERGY IMPLEMENTATION OF PBR

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



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

FIGURE 7: STRUCTURE OF XCEL'S MRP

Weather normalized actual sales used to set base rates.

Rates include capital costs, operations and maintenance (O&M) expenses, specific riders, and taxes.

Excludes fuel costs.

Stated return on equity of 9.20%

No increase in fixed customer charges.

Monthly service charge for residential/small commercial.

True-up mechanisms subject to caps including:

1) sales true-up for non-decoupled classes;

2) capital true-up; and

3) property tax true-up.

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.

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

Revenues and Customers

a) Decoupled using Revenue per Customer
b) Full Decoupling (omits weather normalization)
   - Residential,
   - Residential *with* Space Heating, and
   - Small Commercial/Industrial (non-demand customers)
c) Partial Decoupling (includes weather normalization)
   - All other classes
   - Proposed – electric vehicles & lighting
d) Excludes non-fuel revenue and fixed customer charges

Adjustments

a) Calculated once a year
b) Rates adjusted up/down in the following year to "true-up" difference
c) Adjustments presented as either a surcharge or a credit on customer bills
d) Limitations on any upward rate adjustment:
   - Upward rate adjustments are capped at 3% of the customer group's revenues, excluding the fuel clause or other riders;
   - Costs over the cap are recovered via the following year's adjustment, assuming declining sales were triggered by DSM or similar programs;
   - If Xcel fails to achieve 1.2% in energy savings, it forgoes its rate increase in following year.

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.

- developing evaluation criteria and benchmarks, and
- using a standardized method to ensure consistency with other utility reporting.

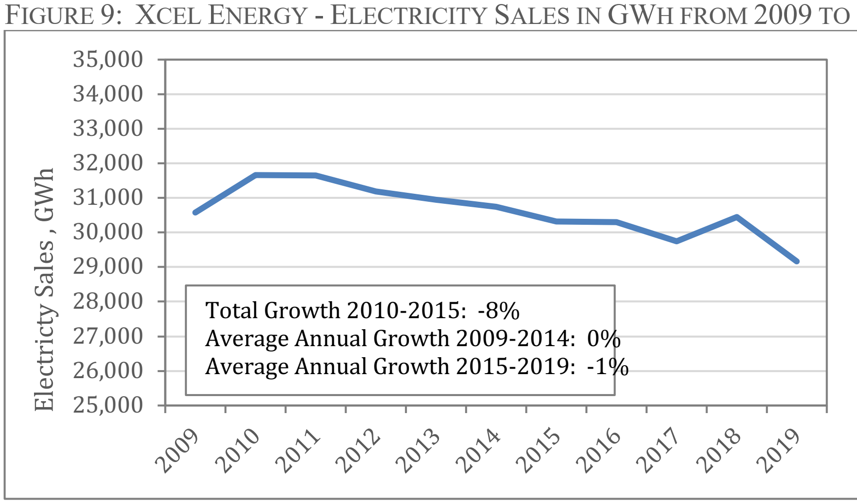
OUTCOMES FROM PBR FOR MINNESOTA AND XCEL ENERGY

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/

FIGURE 10: XCEL ENERGY – NUMBER OF CUSTOMERS IN THOUSANDS FROM 2009 TO 2019

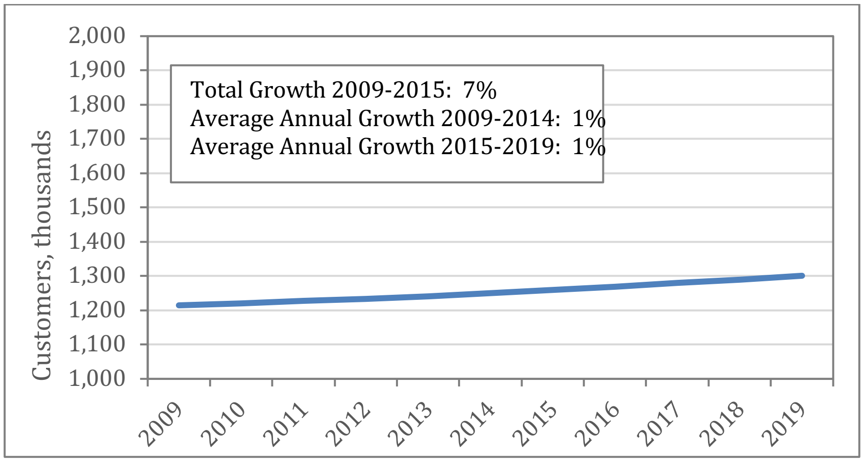
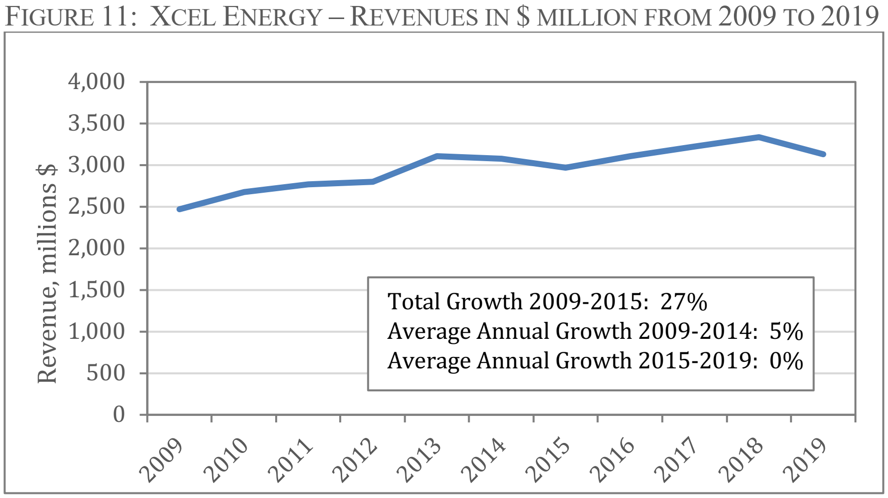


Figure 11 presents Xcel Energy's revenues over the past 10 years. Revenues have increased by 27% since 2009. However, the average annual growth in the first 5-year period was 5% while the average annual growth was 0% in the last five years. This indicates revenues are stable and increasing at a slower 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.

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.

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-

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

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

Wholesale Electricity Markets

Study Group Work Products

2020 NC Energy Regulatory Process

Contents of this packet:

1. Wholesale Electricity Markets Regulatory Guidance
2. Regional Transmission Organization Fact Sheet
3. Energy Imbalance Market Fact Sheet
4. Southeastern Energy Exchange (SEEM) Market Fact Sheet
5. Wholesale Electricity Markets Meta Analysis Comparison
6. Electricity Market Reform Bill

WHOLESALE ELECTRICITY MARKETS STUDY GUIDANCE

SUGGESTED STUDY FRAMEWORK AND SCOPE FOR THE NCGA & NCUC FROM THE NORTH CAROLINA ENERGY REGULATORY PROCESS

AUTHORS & ACKNOWLEDGMENTS

STUDY GROUP MEMBERS

Chris Carmody, NCCEBA, group chair
Charles Bayless, NC Electric Cooperatives
Drew Elliot, ElectriCities of North Carolina
Paula Hemmer, Dept. of Environmental Quality
Stephen Kalland, NC Clean Energy Technology Center
Kate Konschnik, Duke University Nicholas Institute
Peter Ledford, NCSEA
Stewart Leeth, Smithfield Foods
Kevin Martin, Carolina Utility Customer Association
Sushma Masemore, Dept. of Environmental Quality
David Rogers, Sierra Club
Peter Toomey, Duke Energy

CONTACTS

Chris Carmody, director@ncceba.com

ACKNOWLEDGMENTS

The authors thank the following individuals/organizations for offering their insights and perspectives on this work.

Josh Brooks, Rocky Mountain Institute
Kendal Bowman, Duke Energy
Dan Cross-Call, Rocky Mountain Institute
Jennifer Chen, Duke University Nicholas Institute
Matthew Davis, NC Dept. of Environmental Quality
Max Dupey, Regulatory Assistance Project
Heather House, Rocky Mountain Institute
Jack Jirak, Duke Energy
Carl Linvill, Regulatory Assistance Project
Joshua Rhodes, Webber Energy Group
Ben Serrurier, Rocky Mountain Institute
Jessica Shipley, Regulatory Assistance Project

This work was last updated on 12/21/2020.

Cover image courtesy of GYPSY FROM NOWHERE IMAGES/ALAMY STOCK PHOTO

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 wholesale electricity market mechanisms with a specific focus on regional transmission operators, energy imbalance markets, and the southeast energy exchange market. It includes recommendations for the NCGA and the NCUC to consider if and when the NCGA authorizes the NCUC to conduct a study of wholesale electricity market reform. The document represents the consensus work of the NERP process stakeholders, however, NERP stakeholders do not necessarily endorse all of the ideas or recommendations herein.

TABLE OF CONTENTS

SUMMARY OF RECOMMENDATIONS

This document contains the recommended framework, authorization, context, and key elements of a study into wholesale electricity market reform for North Carolina developed by the North Carolina Energy Regulatory Process (NERP) participants. The primary intended audience is the NC General Assembly (NCGA) and the NC Utilities Commission (NCUC), as the NCGA may authorize the NCUC to conduct such a study. The document contains detailed descriptions of each wholesale mechanism reviewed by NERP: regional transmission operator (RTO), energy imbalance market (EIM), and the southeast energy exchange market (SEEM) defined below. NERP participants met throughout 2020 and developed the following guidance document to assist any study into wholesale electricity market reform for North Carolina.

Study scope

1. The study, and any resulting reform proposed or enacted, 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. The study must be required to offer recommendations to the General Assembly as to whether any of the market structures should be pursued further.
3. The study must recommend whether legislation is to be brought forward to allow reform of the wholesale electricity marketplace.
4. The study must recommend a model for wholesale competition that should be implemented if applicable.
5. The study must recommend a stepwise approach to incorporating municipal and cooperative electricity generators and providers into wholesale market reforms, as needed.

NERP recommendations

NERP recommends the General Assembly of North Carolina direct the NCUC to conduct a study on the benefits and costs of the following wholesale electricity market reforms and implications for the North Carolina electricity system.

1. A regional transmission organization (RTO) with the geographical boundaries of North Carolina and South Carolina or a larger area such as the southeast U.S.,
2. An energy imbalance market (EIM) with the geographical boundaries of North Carolina and South Carolina or a larger area such as the southeast U.S.,
3. The Southeastern Energy Exchange Market (SEEM), defined below, and
4. Any other structures that the NCUC determines worth investigating, such as,
    a. Joining an existing RTO,
    b. Developing joint dispatch agreements (JDA) beyond the current Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) agreement to include additional utilities in neighboring states and/or regionally, and
    c. Developing a customer choice program that allows large customers, either at a single site or as an aggregate of multiple sites, to choose an independent electricity provider over the existing provider.

INTRODUCTION

Purpose

The purpose of this document is to communicate the findings of the NC Energy Regulatory Process (NERP) to the NC General Assembly (NCGA) and the NC Utilities Commission (NCUC), as the NCGA may authorize the NCUC to conduct a study into the potential costs and benefits of wholesale electricity market reform and implications for the North Carolina electricity system. It may also be of interest to other parties who want more information on wholesale electricity market mechanisms or the NERP process that is provided in the companion fact sheet.[i]

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*.[ii] The Order established the North Carolina Climate Change Interagency Council and tasked the Department of Environmental Quality (DEQ) with producing a clean energy plan.

DEQ convened a group of stakeholders that met throughout 2019. In October 2019, DEQ released the *North Carolina Clean Energy Plan: Transitioning to a 21 Century Electricity System* (CEP).[iii] 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.

Although initiated by CEP: B-1, the CEP listed multiple recommendations related to the state's wholesale market:

- B-4: Initiate a study on the potential costs and benefits of different options to increase competition in the electricity sector, including but not limited to joining an existing wholesale market and allowing retail energy choice.
- C-1: Establish comprehensive utility system planning process that connects generation, transmission, and distribution planning in a holistic, iterative, and transparent process that involves stakeholder input throughout, starting with a Commission-led investigation into desired elements of utility distribution system plans.
- C-3: Implement competitive procurement of resources by investor-owned utilities.
- D-2: Use comprehensive utility planning processes to determine the sequence, needed functionality, and costs and benefits of grid modernization investments. Create accountability by requiring transparency, setting targets, timelines and metrics of progress made toward grid modernization goals.
- H-1: Identify and advance legislative and/or regulatory actions to foster development of North Carolina's offshore wind energy resources.

---

[i] https://deq.nc.gov/CEP-NERP

[ii] Executive Order 80. https://governor.nc.gov/documents/executive-order-no-80-north-carolinas-commitment-address-

[iii] NC Dept. of Environmental Quality. "North Carolina Clean Energy Plan" https://files.nc.gov/governor/documents/files/NC_Clean_Energy_Plan_OCT_2019_.pdf

NERP

The NERP, 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

These stakeholders identified ten desired outcomes of reform in North Carolina, as shown below in Figure 1. Of those, the wholesale committee focused on:

1. Reducing emissions to net-zero by 2050,
2. Maintaining affordability and bill stability,
3. Developing regulatory incentives that are aligned with cost control and policy goals, and
4. Improving integration of distributed energy resources (DERs) onto distribution and transmission systems.

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

Wholesale Electricity Markets Study Group

A subset of NERP participants volunteered to serve on a wholesale market study group and began meeting in late May 2020 (see page 2 for a list of groups members). The group met regularly to advance research into wholesale electricity market mechanisms deemed relevant to North Carolina due to physical proximity or because said mechanisms were either proposed or technically possible in NC.

The study group presented a series of mechanism studies to the broader NERP group, detailing the potential implications of each market reform, and why further investigation into each reform is warranted. Feedback was received from NERP participants and incorporated into a proposed wholesale electricity markets reform study outlined detailed below.

NERP companion documents

NERP produced the following documents for dissemination, to inform subsequent policy discussions with various audiences:

Legislative Language Authorizing the NCUC to conduct a wholesale market reform study: A number of wholesale reforms are relevant to NERP stakeholder organizations, recent academic research, and adjacent state policies. The study authorized by this language considers the costs and benefits of wholesale electricity market reform at the state and regional level.

A Meta-Analysis of proposed market reforms. As each market reform features a number of similarities and points of comparison, the group provides a high-level review of key market criteria.

Market Structure Factsheets:
Each construct outlined in the meta-analysis are featured in 2-to-3-page factsheets which provide greater detail on the respective markets.

Definitions

The following terms are used throughout the document:

- Regional transmission organization (RTO) - (also known as an Independent System Operator (ISO)) - a nonprofit entity that independently manages the transmission system of participating utilities. RTOs/ISOs run energy markets and centrally dispatch energy subject to economic and reliability constraints. (Less flexible generation may also self-schedule to continuously run.) RTOs/ISOs sometimes also run capacity and other grid services markets. FERC has encouraged the creation of RTOs/ISOs but has not required them.
- Energy imbalance market (EIM) - a voluntary market for dispatching real-time energy across utility service territories. Each participating utility retains ownership and control of its transmission assets but opts to bid generation into a centralized dispatch authority.
- Energy exchange market (EEM) - a voluntary market for facilitating bilateral sales of real-time energy across utility service territories. Each participating utility retains ownership and control of its transmission assets but may buy or sell excess power from/to neighboring utilities.
- Southeastern Energy Market (SEEM) - A proposed 15-minute automated energy exchange market between balancing authorities of the southeastern U.S. involving over fifteen entities.
- Wholesale electricity market – a market where electric energy is bought and sold for resale. Under the Federal Power Act, wholesale electricity transactions including those conducted through organized markets are regulated by the Federal Energy Regulatory Commission.
- Retail electricity market – a market where electric energy is sold to end users/consumers. Under the Federal Power Act, retail electricity transactions are regulated by state public utility commissions.
- Distributed energy resources (DERs) - small electricity generators that are connected to the local distribution system or installed behind the meter of an electricity consumer. These resources may include rooftop solar, EV charging stations, smart appliances, and on-site fuel cells.
- Joint dispatch agreements (JDA) - a type of power pool arrangements where utilities agree to jointly dispatch generation resources to meet load requirements across their footprints. Here, one of the utilities will conduct the dispatch; by contrast, for an energy imbalance market or an RTO, an independent nonprofit entity is in charge of dispatch. Each participating utility retains ownership and control of its transmission assets.
- Greenhouse gases – air pollutants that trap and emit radiant heat, warming the earth’s atmosphere.

STUDY SCOPE AND FRAMEWORK

Rationale

The large majority of the electric service in North Carolina is currently provided by vertically integrated utilities that provide electric generation, transmission and distribution services to customers in the state, including approximately 85% of the state's electricity generation.

The adoption of North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (REPS) in 2007, enabled the state to:

1. Diversify its electricity resources with solar, wind and biofuels,
2. Offset over 10% of its electricity demand with renewable resources and energy efficiency measures,
3. Create over $2 billion worth of new businesses and 4,307 jobs in renewable energy and energy efficiency, and[iv]
4. Reduce emissions of carbon dioxide by 9%.

North Carolina seeks to

1. Expand its development of new, low-cost electricity resources in the state,
2. Encourage additional private investment in these resources as well as ancillary businesses,
3. Create new tax bases and economic opportunities, and
4. Accelerate the deployment of zero emitting resources.[v]

The North Carolina Energy Regulatory Process (NERP) has identified that reforming the structure of the existing wholesale electricity market and electricity transmission services could potentially promote the development of, and access to, low-cost electricity resources for the benefit of North Carolina consumers.

The NERP also identified several key goals for North Carolina's electricity system, in addition to developing low-cost electricity resources, that could potentially be promoted with restructuring wholesale electricity markets and transmission systems including:

1. Reducing greenhouse gas emissions to net-zero by 2050,
2. Maintaining affordability and bill stability,
3. Developing regulatory incentives that are aligned with cost control and policy goals, and
4. Improving integration of distributed energy resources (DERs) onto distribution and transmission systems.

Discussions about a more competitive electricity market are not new. The North Carolina General Assembly enacted legislation in 1999 to study the use of wholesale and retail electricity markets in the state, which recommended a more competitive system but was never implemented. More recently, the South Carolina legislature authorized a study (SC HB 4940) to be completed on November 1, 2021 that examines the benefits of various restructuring options for electricity markets associated with electricity generators, transmitters and distributors in South Carolina including the following:

1. Creating a regional transmission organization (RTO) or an energy imbalance market (EIM) with energy providers in neighboring states to enable a competitive wholesale market for electricity, and
2. Separating the existing vertically integrated electric utilities into two distinct entities: companies that generate electricity and companies that transmit and distribute electricity, and
3. Giving customers in the state the ability to choose their electricity provider.

In a similar fashion, NERP participants have identified that a study of competitive markets in North Carolina be also conducted. Changes to the electricity sector regulatory framework, such as restructuring the existing wholesale electricity markets and transmission services may require changes to state law as well as federal authorization. The

---

[iv] *The Solar Economy Widespread Benefits for North Carolina*, Center on Globalization, Governance & Competitiveness (CGGC), Social Science Research Institute at Duke University, February 2015, https://www.seia.org/sites/default/files/resources/Duke_CGGC_NCSolarEnergyReport.pdf

[v] *North Carolina Clean Energy Plan*, North Carolina Department of Environmental Quality, Octber 2019, https://deq.nc.gov/energy-climate/climate-change/nc-climate-change-interagency-council/climate-change-clean-energy-16

purpose of this document is to define the study scope and describe elements to be examined that equips policy makers on the pos and cons of future decision making.

Study authorization

The General Assembly of the State of North Carolina would need to authorize the North Carolina Utilities Commission (NCUC) to conduct a study of wholesale competitive market structures, the respective transmission services, and their potential impact on achieving the NERP goals set out above for the state's electricity system, consumers, environment, and economy in a cost-effective manner while also providing low-cost electricity and other ancillary benefits to North Carolina electricity customers.

NERP recommendations

NERP recommends the General Assembly of North Carolina direct the NCUC to conduct a study on the benefits and costs of the following wholesale electricity market reforms and implications for the North Carolina electricity system.

1. A regional transmission organization (RTO) with the geographical boundaries of North Carolina and South Carolina or a larger area such as the southeast U.S.,
2. An energy imbalance market (EIM) with the geographical boundaries of North Carolina and South Carolina or a larger area such as the southeast U.S.,
3. The Southeastern Energy Exchange Market (SEEM),
4. Any other structures that the NCUC determines worth investigating, such as,
    a. Joining an existing RTO,
    b. Developing joint dispatch agreements (JDA) beyond the current Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) agreement to include additional utilities in neighboring states and/or regionally, and
    c. Developing a customer choice program that allows large customers, either at a single site or as an aggregate of multiple sites, to choose an independent electricity provider over the existing provider.

Study Outputs

A study should determine the overall impacts due to changing wholesale electricity regulation in North Carolina to a more competitive market structure.

The study must be required to offer recommendations to the General Assembly as to whether any of these market structures should be pursued further. This includes:

1. Recommending whether legislation is to be brought forward to allow reform of the wholesale electricity marketplace,
2. Recommending a model for wholesale competition that should be implemented if applicable, and
3. Recommending a stepwise approach to incorporating municipal and cooperative electricity generators and providers into wholesale market reforms, as needed

Relevant context and potential study criteria

While not agreed to by all of the involved stakeholders, some stakeholders recommend that the following options should also be studied:

1. Join an existing regional transmission organization (particularly if this is an option studied in South Carolina),
2. Develop joint dispatch agreements (JDA) beyond the agreement that currently exists between Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) to include additional utilities in neighboring states and/or regionally, and
3. Develop a customer choice program that allows large customers, either at a single site or as an aggregate of multiple sites, to choose an independent electricity provider over the existing provider.

North Carolina recognizes the value of its existing nuclear resources to provide zero-greenhouse gas (GHG) emitting, reliable, base load electricity to North Carolina. Given this, the study should consider the impacts new wholesale market structures would have on the ability of these resources to continue to provide electricity generation and remain financially secure.

North Carolina recognizes the value of ongoing efforts to modernize North Carolina's electricity transmission and distributions system and the study should address whether or not any of the market structures would impact that any improvements resulting from these efforts.

The North Carolina Clean Energy Plan recommended GHG emissions reduction targets of 70% by 2030 and net-zero GHG emissions by 2050 and Duke Energy's stated corporate-wide carbon dioxide (CO2) emissions reduction targets of 50% by 2030 and net-zero by 2050. The NCUC should consider achievability of these emissions targets for each market structures studied. North Carolina is potentially pursuing other aspects of utility regulatory reform and environmental policy related to the electricity sector, including a policy to reduce GHG emissions from the electricity sector, and the study should consider these reforms and policies where possible, given the level of detail on the polices and reforms available when this study is conducted.

North Carolina values a) stakeholder input into electricity regulatory and policy development processes and b) social equity in providing utilities to all communities and customer classes. The NCUC should consider how to maintain these values when performing the study.

While developing the study criteria, the NCUC should consider: a) the "Study Commission on the Future of Electric Service in North Carolina dated May 16, 2000 b) the proposed legislation regarding Grid South developed in the late 1990's through 2002, and c) the current study authorized by South Carolina House Bill 4940.[vi]

[vi] South Carolina House Bill 4940 accessed at https://www.scstatehouse.gov/sess123_2019-2020/bills/4940.htm

STUDY SCOPE AND FRAMEWORK

The study should examine impacts, including quantifying costs and benefits where possible, to the following aspects of the electricity system:

I. Electricity generation and capacity adequacy and diversity
II. Transmission systems
III. Customer service and rates
IV. Environmental quality
V. Economic opportunity
VI. Affect on State regulatory authority of electricity systems.
VII. A comparison of the costs, benefits and impacts between the current system and the various market structures.

Electricity generation and capacity adequacy and diversity

Competitive wholesale electricity markets create more competition primarily on the power generation side, where market participants are plentiful as opposed to transmission, which has very few providers due to its highly regulated nature and obligations to serve. Over time, wholesale market reform could have a major influence on the selection of which new energy resources get added to the electricity grid to serve North Carolina. Competitive markets create advantages for lower cost power plants that can be located inside or outside the former power company's territory. Some stakeholders believe that third party ownership lowers risk for ratepayers and creates opportunities for newer technologies. Other stakeholders are concerned that wholesale market reform structures would remove some of North Carolina's control over its sources of electricity.

There are different levels of wholesale markets reform. More modest levels of reform such as the proposed SEEM and an EIM maintain the current generation and transmission ownership structure and allow companies to participate in a limited wholesale power market to trade energy – an energy market. Others such as an RTO could create a level of separation between companies that generate power from those that transmit. If the size and type of the competitive market is expanded beyond the existing structure sufficiently, competition among base load power suppliers can also be created - a capacity market.

A larger, more competitive electricity grid system may also change how clean, intermittent energy is deployed. Lastly, it may impact the growth of electricity demand based on new or existing programs that create incentives to either increase or decrease electricity use.

The current wholesale electricity market structure must be evaluated against the three options discussed above, SEEM, EIM and RTO to develop the relative advantages and disadvantages for North Carolina electricity generators and electric customers. Areas to examine include:

1. Impacts to resource adequacy, or ensuring there are sufficient electricity generation resources to supply power to meet demand at any given time with adequate reserve margin,
2. Impacts to the existing power plants on the system and their parent companies, especially in regard to plant economics, financial security and depreciation,
3. Impacts from the new power plants which are built and their parent companies, especially in regard to clean generation such as solar, wind and storage systems,
4. Financial impacts and efficiencies from sharing generation resources outside of the current system, especially in regard to clean energy,
5. Impacts to wholesale prices in the existing region due to more competitive procurement, and
6. Impacts to energy efficiency and demand side management including both existing programs and any future goals, and
7. Impacts to future changes in electricity demand, especially in regard to "beneficial electrification", which is a shift to the use of clean electricity over existing fossil fuel energy.

Transmission systems

Some wholesale market forms would functionally unbundle power generation from transmission services. Others market forms merely create opportunities to purchase and transmit generation from other systems. Regardless of the market type, there will be changes to how the electricity grid system currently operates including its physical, operational and financial aspects. Some market structure options will create new entities that are involved in generating and transmitting electricity. The impacts from this increased complexity of the electricity system must be examined including the following:

1. Cost and complexity versus economic benefit of managing of a larger regional transmission system with increased flexibility in generation procurement on a sub-hourly timeframe,
2. Impacts to the reliability of the power supply at all times, especially during peak demand times, extreme weather events, and physical/cyber-attacks
3. Impacts to the resilience of the whole power system to recover quickly from extreme events,
4. Impacts to technical aspects of procuring and managing generation for the grid and grid support services, including interconnection to new grid regions, integration of new generation resources, grid congestion, and system balancing and operation,
5. Impacts to financial aspects of procuring generation, including regional system operational efficiencies, wholesale power prices, financial security of transmission and distribution entities, shifting from bilateral electricity contracts to near real-time energy markets, regional tariffs, and
6. Impacts to planning and developing grid infrastructure, including efforts to modernize the electricity grid to integrate clean energy and distributed energy and to provide new customer-oriented data and services.

Customer service and rates

The primary reason for studying potential moving to regional competitive wholesale electricity markets is to examine the impacts and benefits to electricity consumers, including financial and environmental. This would occur as a result of allowing competitive bidding among electricity generators from a larger region. The largest cost benefit comes from reducing the need to build more power plants in North Carolina by functionally sharing power plants in other grid regions. While numerous studies point to the financial benefits for electricity consumers, North Carolina consumers have goals for the electricity sector beyond low electricity rates that must be examined. Therefore, this study should examine both the financial impacts as well as other customer-oriented requirements and goals for the electricity sector including:

1. Quantifying the rate impacts to all customer classes and areas of North Carolina,
2. Impacts to fairness and equity in both electricity pricing and access among all customer classes and all areas of North Carolina,
3. Impacts to consumer protections,
4. Impacts of increased access to data and other new services desired by consumers, and
5. Impacts of transparency in wholesale pricing for customers.

Environmental quality

Most environmental issues associated with electricity generation and procurement are not directly impacted by switching to competitive wholesale markets. One direct impact may be increased transmission infrastructure. Other environmental issues could be indirectly impacted. For instance, air emissions are decreasing in some RTO and EIM regions due to building lower cost, cleaner power plants. However, some of these market structures pose greater challenges in implementing state level environmental policy, specifically RTOs. Recently, the federal government has considered changes to existing RTOs regulations that would resolve some of the issues faced by states pursuing environmental goals within the RTO framework.

Economic incentives for lower cost electricity generation could influence a) the type of power plants constructed in the future and b) the type of power that is purchased to meet electricity demand in North Carolina. These economic decisions would impact environmental and public health outcomes not just inside North Carolina's borders, but outside our borders as well. Such impacts include the following:

1. Greenhouse gas emissions per megawatt-hour of electricity generated and/or consumed from the electricity system supplying power to North Carolina (i.e., both in-state and imported generation),
2. Impacts to air quality from the electricity system supplying power to North Carolina,
3. Impacts to land and water resources due to both building new power plants and transmission systems and decommissioning existing plants in North Carolina,
4. Public health outcomes from the increased/decreased operation of power plants supplying power to North Carolina, and
5. Impacts to the current or future use of clean energy resources to supply power to North Carolina, where these resources may be located either inside or outside the state,
6. Environmental justice and equity concerns where specific community impacts are identified, and
7. Just transition concerns to communities affected by retiring assets.

Economic opportunity

Competitive wholesale electricity markets could create economic opportunities in North Carolina due to independent power producers being able to more readily access North Carolina electricity markets as well as the potential impacts of lower electricity rates. However, there may be some negative economic impacts as well. Therefore, the study should quantify the economic impacts from the proposed wholesale market structures options including:

1. Impacts to the economy from changes to electricity technological and infrastructure investments,
2. Responses to changes in wholesale pricing of electricity for North Carolina businesses,
3. Impacts to the creation and/or retention of jobs in the state,
4. Impacts to rural and disadvantaged communities, and
5. Impact of competition on tax revenues and/or subsidies in various areas of North Carolina.

Impact on State regulatory authority of electric systems

Competitive markets, depending on their structure, would potentially create additional administrative entities within the electricity system. Combined, these entities would be responsible for overseeing the newly created market and electricity procurement and transmission to consumers across a wider grid region and at sub-hourly timeframes. At a minimum, it could require increased coordination among existing electricity generation and transmission entities. Therefore, there are administrative issues which must be studied that may result in impacts to the critical areas discussed above, as well as potential changes to the role of the NCUC. Administrative concerns that should be evaluated for the wholesale market structures include:

1. Electricity system governance structure and administrative costs versus benefits,
2. Delegation of authority,
3. Reciprocity between states,
4. Clarification of state and federal jurisdiction, including reliance on other states joining North Carolina to implement wholesale market reform options,
5. Impacts to energy regulatory and policy innovation, including stakeholder involvement in its development,
6. Responsibilities of owners and operators of electricity grid generation and transmission, and
7. Impacts to state government regulation of electricity supply, transmission and distribution.

Comparison of market approaches

Lastly, the study should clearly layout the fundamental differences between the current market structure and the three proposed competitive markets systems being studied. A key element in this comparison is determining the a) size of the region and b) level of competition that is necessary for benefits to outweigh the costs of the proposed reforms. Such differences should include the following:

1. Overall effectiveness of each mechanism in meeting NERP goals,
2. Comparison of costs, benefits, and risks for each mechanism,
3. Level of competition resulting from each mechanism,
4. Impacts to system adequacy and reliability,
5. Level of administrative impacts from each mechanism,
6. Level of transparency in procurement of electricity, wholesale pricing, and customer data for each mechanism, and
7. Implementation timelines for each mechanism.

CONCLUSION

To summarize, NERP recommends the General Assembly of North Carolina direct the NCUC to conduct a study on the benefits and costs of the following wholesale electricity market reform options and the related implications for the North Carolina electricity system:

1. A regional transmission organization (RTO) with the geographical boundaries of North Carolina and South Carolina or a larger area such as the southeast U.S.,
2. An energy imbalance market (EIM) with the geographical boundaries of North Carolina and South Carolina or a larger area such as the southeast U.S.,
3. The Southeastern Energy Exchange Market (SEEM), defined above,
4. Any other structures that the NCUC determines worth investigating, such as,
    a. Joining an existing RTO,
    b. Developing joint dispatch agreements (JDA) beyond the current Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) agreement to include additional utilities in neighboring states and/or regionally, and
    c. Developing a customer choice program that allows large customers, either at a single site or as an aggregate of multiple sites, to choose an independent electricity provider over the existing provider.

Members of this NERP stakeholder group will continue to collaborate in early 2021 to assist the State and parties interested in the work conducted by this group.

APPENDIX

The following documents were prepared by the wholesale electricity markets study committee to supplement this guidance document and the proposed legislative language.

- RTO fact sheet
- EIM fact sheet
- SEEM fact sheet - produced by utilities sponsoring SEEM; included here to provide additional detail on this proposal
- Meta-analysis of market structures
- Wholesale electricity market reform study bill

NERP FACT SHEET

REGIONAL TRANSMISSION ORGANIZATION

A FACTSHEET PRODUCED BY THE WHOLESALE ELECTRICITY MARKETS STUDY GROUP

The 2020 North Carolina Energy Regulatory Process identified wholesale electricity market reforms that could potentially benefit North Carolina consumers.

WHAT IS REGIONAL TRANSMISSION ORGANIZATION?

A Regional Transmission Organization (RTOs) is a type of electricity market over a large region that uses an independent operator to manage the transmission system of the utilities participating in the market. Some characteristics of RTOs include the following:

- Administers and operates the transmission system through an independent entity,
- Fosters competition among generators with an open-access approach to transmission,
- Provides centralized, automated, real-time balancing of supply and demand,
- Dispatches all electricity across the system using a least-cost approach, and
- Requires mandatory participation by utilities and independent power producers in the market.

A similar market system to an RTO is an Independent System Operator (ISO).[1] About two-thirds of U.S. customer electricity demand is served by RTOs or ISOs as shown in Figure 1.

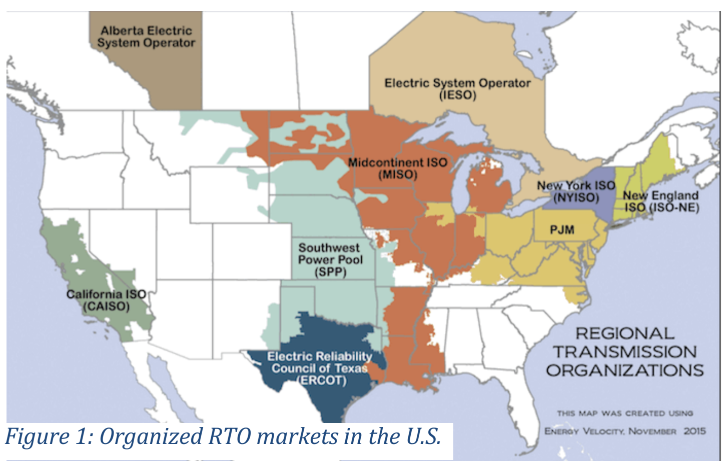


Figure 1: Organized RTO markets in the U.S.

[1] See https://www.ferc.gov/industries-data/electric/power-sales-and-markets/rtos-and-isos for more information on RTOs and ISOs.

There are additional markets and services provided by RTOs. These include the following:

- Voluntary or mandatory capacity markets where generators commit to provide electricity in the future (also called the day-ahead market), and

- Voluntary ancillary markets related to grid operation such as voltage regulation.

HOW DOES THE ENERGY MARKET WORK?

RTOs create competitive wholesale electricity markets. A simplified overview of the market is outlined below.

1. RTO grid operators balance supply and demand for all electricity used in the market over 5-minute intervals in real-time using an automated system.

2. Each generator is required to supply a bid to the grid operator for a specific amount and price of electricity.

3. The grid operator puts together a set of bids, starting with the least-cost bids, until the demand for that interval is met. All other bids remain unfilled.

4. Less flexible nuclear and coal generation may still self-schedule to run continuously.

5. The grid operator must ensure a reliable supply of energy at all times and deal with any outages.

Recent FERC orders have directed RTOs to change their rules in a way that accommodates demand response programs (Order 745), energy storage (Order 841) and aggregations of distributed energy resources (Order 2222). Therefore, new market participants could develop to offer these products and services into the RTO's energy, capacity, and ancillary services markets.

HOW IS THE MARKET MANAGED?

RTOs and ISOs have an independent, non-profit entity with complete authority over the following aspects of the system:

- Transmission facilities and their operation,
- Transmission planning, expansion, administration and management,
- Non-discriminatory transmission service,
- Short-term reliability of the grid, and
- Fair, competitive energy market supplying least-cost generation.

RTOs and ISOs are regulated by Federal Energy Regulatory Commission (FERC) with specific rules and requirements for administering and operating these markets. Any changes to the market operation must be approved by FERC. Changes also require multi-state and multi-utility engagement in this process as well.

WHAT ARE THE BENEFITS OF AN RTO?

The primary benefit of an RTO is lowering wholesale energy costs and transferring these cost-savings to rate payers. Specific examples of these cost-savings are given below.

- PJM Interconnection estimates its services produce annual savings of $3.2–$4 billion.[2]

- Midcontinent Independent System Operator (MISO) estimates that its services produced savings in 2019 of $3.2–$4 billion compared to standard industry practice.[3]

- Southwest Power Pool (SPP) estimates that for 2018, its services provided $2.2 billion in annual net benefits with a benefit-to-cost ratio of 14:1.[4]

Utilities have achieved cost savings from joining an RTO. For example, Dominion's economy energy purchases from PJM's day-ahead market saved about $75 million in 2013 alone, compared to if Dominion had self-generated the same energy.[5] Entergy, joined MISO in December 2013. Entergy has estimated the five-year savings realized by its customers from joining MISO to be about $1.3 billion, an average of $261 million annually.[6]

While there are cost-savings from joining an RTO, there may be costs associated with the transition into an RTO, and

[2] See, e.g., FERC Docket No. ER20-2100-000, Motion to Lodge of PJM Interconnection, LLC (Oct. 19, 2020), https://www.pjm.com/-/media/documents/ferc/filings/2020/20201019-er20-2100-000-er20-1068-000.ashx.

[3] MISO Value Proposition 2019: Detailed Calculation Description, https://cdn.misoenergy.org/2019%20MISO%20Value%20Proposition%20Calculation%20Details425713.pdf.

[4] Southwest Power Pool, 14 to 1: The Value of Trust (2019), https://spp.org/documents/58916/14-to-1%20value%20of%20trust%2020190524%20web.pdf.

[5] "Potential Benefits of a Regional Wholesale Power Market to North Carolina's Electricity Customers", Prepared by Judy Chang, Johannes Pfeifenberger, John Tsoukalis, for the Brattle Group, April 2019, accessed at https://brattlefiles.blob.core.windows.net/files/16092_nc_wholesale_power_market_whitepaper_april_2019_final.pdf

[6] Entergy Newsroom, "Entergy Utility Customers Realize Significant Benefits After 5 Years as MISO Member" (Dec. 16, 2019), https://www.entergynewsroom.com/news/entergy-utility-customers-realize-significant-benefits-after-5-years-as-miso-member/.

administering the RTO, which should be accounted for in any cost-benefit analysis conducted for North Carolina.

Another benefit of the RTO is creating economic incentives for new independent power producers. More equitable access to transmission allows these producers to enter the energy, capacity and ancillary services markets if they can provide a lower-cost power supply.

Lastly, an RTO can improve power system efficiency, reliability and flexibility. Fluctuations in supply and demand in the smaller balancing areas can be mitigated by pooling electricity resources from a larger area. Outages can be better supported as well.

RTOs do not create specific benefits to lower greenhouse gas (GHG) emissions. However, an RTO may decrease the use of fossil-fuel based resources and decrease GHG emissions by creating a more favorable market for low-cost, non-emitting energy resources.

WHAT IS THE GOVERNANCE STRUCTURE FOR THE MARKET?

RTO governance structures are not dictated by FEC, therefore, each of the RTOs/ISOs have the different governance structures. However, there are some commonalities presented below.

- A Board of Directors that is independent from the RTO/ISO management with 5 to 9 members who are nominated to serve by a committee, the governance board, stakeholders, or elected officials.
- Set of Standing Committees under the Board that oversee development of policies and performance of functional activities. Examples of committees include finance, audit, human resources, and legal.
- An Advisory Committee that receives, reviews, and adjudicates recommendations and concerns from stakeholder sectors.
- A Stakeholder Committee, which is a collection of members that advocate for various aspects of the electricity sector and public good while also respecting members' common interests within the broad diversity of RTO/ISO stakeholders. Members include representatives from transmission owners, generators, transmission users, other suppliers, state regulators and consumer organizations.

HOW ARE EXISTING UTILITIES IMPACTED BY THE MARKET?

Vertically integrated utilities (VIUs), those that own and operate generation, transmission and distribution systems, are most impacted by joining an RTO due to the independence of the transmission system. Utilities such as municipal and rural electric cooperatives can actually compete more fairly with VIUs in an RTO by both supplying and purchasing low-cost wholesale electricity. The impacts for utilities are discussed below.

- VIUs maintain ownership of the transmission system but cede control over its operation and planning to the independent RTO Utilities continue to own, operate and expand their distribution systems and customers.
- Utilities might, or might not continue to own, operate and expand their generation resources. In some RTOs, but not all, utilities were required to sell their generation assets. Some RTOs have optional or mandated generation capacity markets that determine which generation resources enter and exit the market.
- Utilities' generating resources must compete with each other and independent power producers.
- Utilities can decrease their capacity reserves.
- Utilities with state-mandated environmental or clean energy goals can continue to meet these goals, however, least-cost dispatch may impact how these goals are met.

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 Wholesale Market Reform Study Group Lead:
Chris Carmody, NCCEBA, director@ncceba.com
Access the NERP summary report and other NERP documents at:
https://deq.nc.gov/CEP-NERP

NERP FACT SHEET

ENERGY IMBALANCE MARKET

A FACTSHEET PRODUCED BY THE WHOLESALE ELECTRICITY MARKETS STUDY GROUP

The 2020 North Carolina Energy Regulatory Process identified wholesale electricity market reforms that could potentially benefit North Carolina consumers.

WHAT IS AN ENERGY IMBALANCE MARKET?

An energy imbalance market is a type of electricity market that uses an independent entity to manage the energy imbalances between supply and demand within multiple balancing authority areas (BAAs). Some characteristics of an EIM include the following:

- Administers and operates the market through an independent entity,
- Provides centralized, automated, and region-wide generation dispatch for imbalances,
- Fosters competition among generators using a least-cost approach to supply energy,
- Allows voluntary participation in the market by utilities and independent power producers.

There is currently only one EIM in the U.S., the Western Energy Imbalance Market operated by the California Independent System Operator (ISO). In 2021, the Southwest Power Pool (SPP) plans to launch a new energy imbalance service market over a broader geographic area. Figure 1 presents the Western EIM and its active and pending participants.[1]

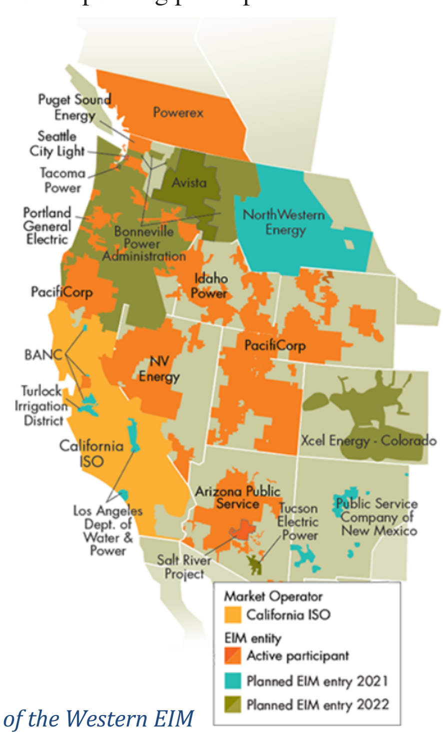


Figure 1: Map of the Western EIM

[1] Active and pending participants in the Western Energy Imbalance Market, accessed at https://www.westerneim.com/Pages/About/default.aspx.

An EIM does not provide day-ahead capacity markets. It may provide voluntary ancillary markets related to grid operation such as voltage regulation.

HOW DOES THE ENERGY MARKET WORK?

An EIM is a platform for balancing fluctuations in electricity supply and demand across multiple BAAs to meet real-time demand. A simplified overview of the market is outlined below.

1. The EIM platform balances supply and demand in the market over sub-hourly intervals in real-time using an automated system.
2. Each BAA voluntarily participates by issuing requests for energy to the EIM platform.
3. Generators volunteer to supply energy outside their balancing area via a bid in the market platform for a specific amount and price of electricity.
4. The platform matches least-cost energy bids with demand in each BAA until the demand for that interval is met.
5. Utilities/balancing authorities continue to control and schedule their generation resources as before.
6. The market is security-constrained, meaning transmission and reliability constraints must be honored.

Recent FERC orders have directed wholesale markets to change their rules in a way that accommodates demand response programs (Order 745), energy storage (Order 841) and aggregations of distributed energy resources (Order 2222). These orders could potentially extend to the voluntary participants in EIMs as well, and facilitate participants offering these products and services to the EIM's energy market.
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.

HOW IS THE MARKET MANAGED?

EIMs have an independent, non-profit entity with complete authority over the following aspects of the system:

- Non-discriminatory transmission balancing service,
- Short-term reliability of the grid, and
- Fair, competitive energy market supplying least-cost generation.

EIMs are regulated by Federal Energy Regulatory Commission (FERC) with specific rules and requirements for administering and operating these markets. Any changes to the market operation must be approved by FERC. Changes also require multi-state and multi-utility engagement in this process as well.

WHAT ARE THE BENEFITS OF AN EIM?

- Lowers wholesale energy costs by ensuring least-cost dispatch to meet energy imbalances in the market.
- Reduces costs for participants by lowering the amount of capacity reserves utilities need to carry, and more efficient use of the regional transmission system.
- The Western EIM has quantified the gross and annual cost-savings.2
    - Gross benefits for the entire EIM are $1.11 billion between Nov 2014 through October 2020,
    - Annual benefits for 2019 were $297 million,
    - Annual benefits for 2018 were 276 million, and
    - Annual benefits for 2017 were $145 million
- Enhances reliability by increasing operational visibility across electricity grids and improves management of transmission line congestion.
- Creates a market where there is more efficient use and integration of renewable energy across a larger region.
- EIMs do not create specific benefits to lower greenhouse gases (GHGs). However, an EIM may decrease the use of fossil-fuel based resources and decrease GHG emissions by creating a more favorable market for low-cost, non-emitting energy resources.

WHAT IS THE GOVERNANCE STRUCTURE FOR THE MARKET?

Governing Body

The Western EIM has a five-member board nominated by participating members. Board members come from a variety of backgrounds, and include utility executives, regulators, and energy economists.

2 See Western Energy Imbalance Market: Benefits at https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx

Regulatory Committee

The Western EIM has a regulatory committee made up of a utility commissioner from every participating state. Members are regularly briefed on EIM developments, plans, and results, and have input into decisions.

Transparency & Public Involvement

The Western EIM has a Regional Issues Forum held three times a year, which is a "public meeting for stakeholders to discuss broad issues about the Western EIM. The Forum encourages collaboration and helps shape policy and find solutions to challenges in the energy industry."3

HOW ARE EXISTING UTILITIES IMPACTED BY THE MARKET?

Vertically integrated utilities (VIUs), those that own and operate generation, transmission and distribution systems, are not significantly impacted by joining an EIM. Utilities such as municipal and rural electric cooperatives can actually compete more fairly with VIUs in an EIM by both supplying and purchasing low-cost wholesale electricity to meet energy imbalances. The impacts for utilities are discussed below.

- Utilities continue to own, operate and expand their transmissions and distribution systems.
- Utilities continue to own, operate and expand their generation resources.
- Utilities' generating resources must compete with each other and independent power producers.
- Utilities can decrease their capacity reserves.
- Utilities with state-mandated environmental or clean energy goals can continue to meet these goals, however, least-cost dispatch may impact how these goals are met.

WHAT IS BEING RECOMMENDED?

The North Carolina Energy Regulatory Process (NERP) has proposed a study, conducted by the NCUC, into the benefits and costs of wholesale market reform and implications for the NC electricity system.

A proposed study rationale, elements, authorization, and funding, titled North Carolina Wholesale Market Reform Study Scope and Criteria, accompanies this report. NERP recommends the following market structures be evaluated:

1. A regional transmission organization (RTO) with the geographical boundaries of North Carolina and South Carolina or a larger area such as the southeast U.S.,
2. An energy imbalance market (EIM) with the geographical boundaries of North Carolina and South Carolina or a larger area such as the southeast U.S.,
3. The Southeastern Energy Exchange Market (SEEM), and,
4. Any other structures that the NCUC determines worth investigating,

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 Wholesale Market Reform Study Group Lead:
Chris Carmody, NCCEBA, director@ncceba.com

Access the NERP summary report and other NERP documents at:
https://deq.nc.gov/CEP-NERP

3 California ISO: Western EIM Fact Sheet

Southeastern Energy Exchange Market (SEEM)

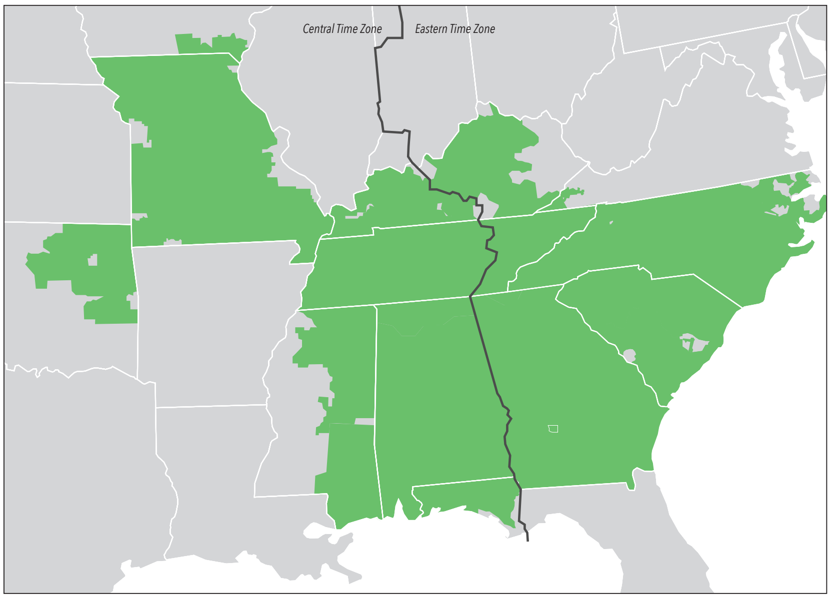
SEEM

Fact Sheet

What is SEEM?

A group of energy companies serving electricity customers across a wide geographic region in the southeastern U.S. is exploring an integrated, automated intra-hour energy exchange with goals of lowering costs to customers, optimizing renewable energy resources and helping maintain the reliable service we provide today.

> Companies exploring the energy exchange market include Associated Electric Cooperative Inc., Dalton Utilities, Dominion Energy South Carolina, Duke Energy Carolinas, Duke Energy Progress, ElectriCities of North Carolina, Inc., Georgia System Operations Corporation, Georgia Transmission Corporation, LG&E and KU Energy, MEAG Power, NCEMC, Oglethorpe Power Corp., PowerSouth, Santee Cooper, Southern Company, and TVA.



Members

- The members represent 16 entities in parts of 11 states with more than 160,000 MWs (summer capacity; winter capacity is nearly 180,000 MWs) across two time zones. These companies serve the energy needs of more than 32 million retail customers (roughly more than 50 million people).
- SEEM members would maintain existing control of generation and transmission assets, and membership is voluntary.

Benefits

- This is the first of its kind in our region and is a low-cost, low-risk way to provide immediate customer benefits through a shared market structure.
- SEEM would be a 15-minute energy exchange market that would use technology and advanced market systems to find low-cost, clean and safe energy to serve customers across a wide geographic area.
- Potential benefits include cost savings for customers and better integration of diverse generation resources, including rapidly growing renewables and fewer solar curtailments. An independent third-party consultant estimated that total benefits to grid operators and customers range from $40 million to $50 million annually in the near-term, to $100 million to $150 million annually in later years as more solar and other variable energy resources are added. (This is dependent, of course, on the number of member companies.)
- We expect customer savings to be realized through lower fuel costs as we're able to select lower-cost and more efficient generation resources to serve customer demand. As sellers identify a use for their excess energy, those profits also benefit customers.

Is SEEM an energy imbalance market?

No, while this market would share some of the same principles as an energy imbalance market (to assist with imbalances and reduce energy costs), it's less complex, less costly and less time intensive compared with setting up an EIM. It also does not rely on centralized unit dispatch.

How is SEEM similar or different from the Western Energy Imbalance Market?

	Western EIM	Southeast EEM
Resource Dispatch	5-minute nodal SCED market platform sends individual resource dispatch signals to participating resources every 5 minutes	15-minute block schedule via electronic interchange tags – BA/BA interface transactions – the Market Platform tool matches bids and offers to maximize benefit savings, while adhering to transmission capability (ATC) constraints
Complexity	Moderately complex due to establishing marketing system that also assesses security constraints	Simple due to leveraging existing bilateral trading processes
Costs	Significant startup costs	Low startup and ongoing costs
Transmission Service Charge	$0/MWh	$0/MWh
Ancillary Services	Limited	Limited
Manual/Automated	Automated	Automated
Day Ahead Market	No	No
Resource Offer into Market	Voluntary	Voluntary
Manages Imbalance	Directly	Indirectly

Regulatory approvals

FERC approval will be required to implement the SEEM. The FERC filing and approval process will provide an opportunity for the members of the SEEM to demonstrate the benefits of the proposed market design and for interested parties to provide feedback and comments for FERC to consider. State jurisdiction is limited to the affiliate component, if triggered, while FERC governs the structure and wholesale nature of the transactions.

What does this potential market mean for state utilities commissions and governing boards?

A primary objective is to maintain the same level of jurisdictional control and oversight as currently exists, where applicable, while facilitating more interchange transactions that support the cost-effective use of a diverse resource mix. FERC will have oversight authority as they do today to ensure those transactions occur with just and reasonable rates, terms and conditions.

SEEM

Wholesale Electricity Markets Meta-Analysis: High-level comparison of market structures relevant to North Carolina

	Current State	SEEM	EIM	RTO
Scope	**Business**	**Current state, plus the addition of Proposed SEEM**	**An EIM operating along the lines of the Western EIM**	**An RTO that meets the FERC definition**
Examples		None exists in US, one being developed	One EIM exists in US, one being developed	Seven RTOs exist in US, none developed after 2008
Customer Benefit *(For entire footprint – see notes)*	N/A – Baseline	• Forecasted net savings range from $40 to $50 million in early years, not net of costs[1]	• Western EIM self-reported energy savings in a recent year were $296 million, not net of costs[2]	• RTOs self-reported net savings in a recent year ranged from $2.2 to $4 Billion each[2]
Time and Costs to Implement		• 18-24 months, depending on regulatory approval • One-time costs: estimated around $5M	• 2-5 years (e.g., Western EIM took ~ 2 years, SPP WEIS > 2 years) • One-time costs – SPP WEIS early estimate was $65-75M	• 6-7+ years • Benchmarks point to one-time costs of $500-750M[3] • Brattle group estimate of $59M annual operating costs for Duke's NC system
Energy Market	• Generation Offers: N/A • Bilateral: day-ahead, hourly	• Generation Offers: voluntary • Bi-lateral: day-ahead, hourly • 15-minute bilateral transaction market	• Generation Offers: voluntary • Bi-lateral: day-ahead, hourly • 15-minute to 5-minute energy imbalance market	• Generation Offers: mandatory • Real-time dispatch: day-ahead and sub-hourly market (varies: 15-minute to 1-minute)
Capacity Planning	Utility IRPs: States			RTO Design Dependent: • If no capacity market, then Utility IRPs: States • If in capacity market, then RTO: FERC
Support of Carbon Policies / Renewables	• Carbon policy: Utilities aligned with state efforts • RE Integration: Utilities aligned with state efforts	• Carbon policy: Utilities, aligned with state efforts • Renewables Integration: Utilities aligned with state efforts • More robust energy trading reduces needed curtailments of renewable resources		If in capacity market, then resource additions subject to market pricing, RTO rules and FERC regulations; recent conflict re: FERC MOPR[4]
Regional Allocation of Costs / Exit fees	N/A – Baseline	• Operation: minimal • Allocations for operations only • Exit Charges: None		• Operation: substantial • Substantial regional cost allocations, exit charges can be material[5]
Governance / Stakeholder Processes		• No independent Board • Platform Auditor • Annual public stakeholder meeting[6]	• Board with some independent members • State regulators committee • Stakeholders meetings 3X per year[7]	• Independent Board • State regulators committee • Stakeholder approaches vary[8]
Pricing info/ transparency	FERC Electric Quarterly Reports (EQR)	• FERC EQR • SEEM aggregated data provided daily, monthly, quarterly	• FERC EQR • Current pricing data provided by EIM	• Current pricing data provided by RTO

Note: See accompanying fact sheets on SEEM, EIM, and RTO's for further details and explanation.
[1] SEEM benefit and cost information are projections.
[2] Benefit and cost information for EIMs and RTOs were taken from the most recent annual published statements of benefits from the existing markets. RTOs reported net savings, SEEM and EIM reflect energy savings, not net of costs.
None of the benefits figures were "scaled" to try to match just the NC or NC/SC market. Final market size and footprint is not determined yet and benefits will depend on the scale and diversity of region, resource mix, entities' profiles, and EIM / RTO rules.
[3] From "Potential Benefits of a Regional Wholesale Power Market to North Carolina's Electricity Customers," The Brattle Group, Table 3..
[4] In recent years, public conflict between FERC MOPR and states' climate and energy policies; subject to potential policy changes at FERC going forward.
[5] Allocations for operations, transmission system expansion, compliance, enforcement of rules/penalties; exit charges can be substantial, particularly for Transmission Owners, based on design to keep the RTO financially whole on open commitments.
[6] SEEM governance described more fully in the recently filed Southeast Energy Exchange Market Agreement.
[7] EIM Governance info shown here was taken from Western EIM; actual governance in new EIM would be determined when created.
[8] RTO Governance info shown here was taken from existing RTOs which all differ somewhat; actual governance in new RTO would be determined when created.

GENERAL ASSEMBLY OF NORTH CAROLINA
SESSION 2021

Short Title:

Sponsors:

Referred to:

A BILL TO BE ENTITLED

AN ACT TO (I) DIRECT THE NORTH CAROLINA UTILITIES COMMISSION TO CONDUCT A STUDY OF NORTH CAROLINA WHOLESALE ELECTRICITY MARKET REFORMS AND (II) ISSUE A REPORT TO THE NORTH CAROLINA GENERAL ASSEMBLY REGARDING PUBLIC BENEFITS AND ANY PROPOSED REFORMS

Whereas, much of the electric service provided in North Carolina is currently provided by vertically integrated providers of electric distribution and transmission services; and

Whereas, the State has adopted legislation including Session Law 2007-397 and Session Law 2017-192 to diversify the resources used to reliably meet the energy needs of consumers and provide economic benefits in the State; and

Whereas, North Carolina seeks to 1) expand its development of new, low-cost electricity resources in the state, 2) encourage additional private investment in these resources as well as ancillary businesses, 3) create new tax bases and economic opportunities, and 4) accelerate the deployment of zero emitting resources; and

Whereas, stakeholders that participated in the North Carolina Energy Regulatory Process ("NERP") identified common outcomes to reduce greenhouse gas emissions, improve integration of distributed energy resources ("DERs"), improve customer choice of energy sources, provide energy affordability and bill stability, and align regulatory incentives with cost control and policy goals; and

Whereas, electricity sector regulatory framework changes to the wholesale electricity market may require changes to state law as well as federal authorization; and

Whereas, South Carolina legislature authorized a study (SC HB 4940) to be completed on November 1, 2021 that examines the benefits of various restructuring options for electricity markets associated with electricity generators, transmitters and distributors in South Carolina; and

Whereas, regional and interstate arrangements may require changes to laws in states other than North Carolina; Now, therefore,

The General Assembly of North Carolina directs:

SECTION 1. The North Carolina Utilities Commission (NCUC) to conduct a study and issue a final report to the General Assembly evaluating reform of the regulatory wholesale electricity market in North Carolina.

(a) The proposed market structures to be evaluated by the NCUC in the study include:

(1) A regional transmission organization (RTO) with the geographical boundaries of North Carolina and South Carolina or a larger area such as the southeast U.S.,

(2) An energy imbalance market (EIM) with the geographical boundaries of North Carolina and South Carolina or a larger area such as the southeast U.S.,

(3) The Southeastern Energy Exchange Market (SEEM) as defined in Section 4, and

(4) Any other structures that the NCUC determines worth investigating, such as,

(i) Joining an existing RTO,

(ii) Developing joint dispatch agreements (JDA) beyond the current Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) agreement to include additional utilities in neighboring states and/or regionally, and

(iii) Developing a customer choice program that allows large customers, either at a single site or as an aggregate of multiple sites, to choose an independent electricity provider over the existing provider;

(b) The NCUC is authorized to hire an independent consulting firm with experience and expertise in wholesale electricity markets to assist the NCUC with the study for $500,000.

(c) The study shall begin within one month of the legislation being enacted and the final report shall be delivered to the General Assembly within a reasonable timeline considering both SC HB 4940 and other ongoing activities occuring in North Carolina related to energy, environment, affordability, and other related policy goals.

(d) The study shall address:

(1) The cost, benefits and risks to state and local government, utilities, independent power producers, buisnesses, and customers of all classes regarding the following aspects of the electricity system:

(i) Electricity generation and capacity adequacy and diversity;

(ii) Transmission systems;

(iii) Customer service and rates;

(iv) Environmental quality;

(v) Economic opportunity;

(vi) Affect on State regulatory authority of electricity systems.

(2) The legal and procedural requirements in North Carolina, at FERC, or in other states associated with adoption of any recommended electricity market reform measures, including identification of existing laws, regulations, and policies that may need to be amended in order to implement the electricity market reform measures;

(3) The impact to existing interstate and interregional arrangements from electricity market reform measures.

(4) Existing nuclear power plant units, in operation and located in this State or in the balancing authority of electrical utilities or public power agencies operating in this State, provide an emissions-free source of power while also providing significant employment and economic benefits, and this study is not intended to force divestiture of ownership or cessation of the operation of these nuclear power plants.

(5) The potential impacts, including costs and benefits, of electricity market reform measures on disadvantaged or vulnerable populations and/or communities.

(6) The NCUC should consider how to maintain the following values under the proposed wholesale market reform structures;

(i) Stakeholder input into electricity regulatory and policy development processes, and

(ii) Social equity in providing affordable electricity to all communities and customer classes.

SECTION 2. The NCUC shall develop recommendations for North Carolina's wholesale electricity market based on the study outcome. The recommendations shall be included in the final report submitted to the legislature.

(a) The recommendations shall include the following information:

    (1) Whether legislation is to be brought forward to allow reform of North Carolina's wholesale electricity marketplace; and

    (2) What type of model of wholesale reform should be implemented.

(b) If the NCUC recommends that the State take action, the report shall include draft legislation and identify applicable requirements and schedule that should be established such that the recommended wholesale market reform will result in net benefits without undue risk for the State, utilities, businesses, and residents.

SECTION 3. The NCUC shall appoint an advisory board to ensure the broad concerns of North Carolina are considered; at minimum the advisory board must be comprised of:

(a) The Executive Director of the North Carolina Public Staff, or designee;

(b) The North Carolina President of Duke Energy, or designee;

(c) The North Carolina President of Dominion Energy, or designee;

(d) Executive Leadership from municipal and cooperative utilities, or designees;

(e) The North Carolina State Energy Director, or designee;

(f) The North Carolina Attorney General, or designee;

(g) Executive Directors of NCCEBA and NCSEA or their designees

(h) A representative set of stakeholders from NERP selected by the NCUC, including but not limited to:

    (1) Two representatives of residential consumers of electricity;

    (2) Two representatives of commercial consumers of electricity;

    (3) Two representatives of industrial consumers of electricity;

    (4) Two representatives of power producers;

    (5) Two representatives with subject matter expertise from the academic community;

    (6) Two representatives of the environmental advocacy community; and

    (7) Two representative of the social equity and justice community.

SECTION 4. For purposes of this Bill, the following definitions apply:

(a) "RTO" means regional transmission organization or other entity established for the purpose of promoting the efficiency and reliability in the operation and planning of the electric transmission grid and ensuring nondiscrimination in the provision of electric transmission services meeting the minimum criteria established by the Federal Energy Regulatory Commission under 18 C.F.R. Section 35.34.

(b) "EIM" means energy imbalance market, a voluntary market for dispatching real-time energy across utility service territories. Each participating utility retains ownership and control of its transmission assets but opts to bid generation into a centralized dispatch authority.

(c) "SEEM" means southeastern energy exchange market, a proposed 15-minute automated energy exchange market between balancing authorities of the southeastern U.S. involving over fifteen entities.

(d) "JDA" means joint dispatch agreement, a type of arrangement where utilities agree to jointly dispatch generation resources to meet load requirements across their footprints. Here, one of the utilities will conduct the dispatch; by contrast, for an energy imbalance market or an RTO, an independent nonprofit entity is in charge of dispatch. Each participating utility retains ownership and control of its transmission assets.

Securitization for Generation Asset Retirement

Study Group Work Products

2020 NC Energy Regulatory Process

Contents of this packet:

NERP FACT SHEET

EXPANDING SECURITIZATION:

ACCELERATING THE CLEAN ENERGY TRANSITION AND BUILDING THE NC ECONOMY

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 THE OPPORTUNITY?

The declining costs of renewable energy and higher cost of operating coal plants relative to other resources has increased interest in retiring coal plants in a low-cost way. However, these coal units remain in the portfolio due to the utilities' need to recover their investment and maintain reliability.

In order to retire coal plants, the remaining undepreciated value must be addressed. Securitization, an innovative financing mechanism, has the potential to create a win-win-win for customers, utilities, and communities. If properly designed, it can be a tool to help facilitate a system-wide transformation - lowering customers' bills, reducing air and water pollution, supporting coal plant communities in the transition, and allowing utilities to reinvest in clean energy to replace lost revenue from legacy coal plant investments. This tool is already available to North Carolina utilities to recover storm costs. Expanding securitization to retire coal plants requires enabling legislation and subsequent implementation to provide creditors with assurances that sufficient funds will be collected to cover the costs of the bonds over its lifetime.

WHAT IS SECURITIZATION?

Securitization is a refinancing mechanism involving the issuance of bonds to raise funds to refinance the remaining undepreciated value of existing coal plants. The bonds are paid back over time through a dedicated surcharge on customer bills. Because the surcharge is irrevocable and payment to the lender is basically "guaranteed" through the legislation, the bonds can typically be issued at an interest rate even lower than the usual utility bond interest rate. In addition, most major credit rating agencies do not include securitization debt, up to certain limits, in assessing the utilities debt to equity ratio for credit rating purposes. Therefore, the utility can generally refinance the outstanding undepreciated value with 100% securitization financing instead of using its standard combination of debt and equity financing. Both of these factors combined lead to cost savings for customers.

By itself, securitization would translate to a loss in earnings for the regulated utility by reducing the total amount of capital in which the utility is invested. However, securitization can also be paired with utility reinvestment in replacement capacity to maintain reliability. Because this replacement generation would be financed using a combination of debt and equity, this option has the potential to recoup and even grow utility earnings.

HOW BIG IS THE OPPORTUNITY IN NC?

Duke Energy currently operates six coal plants totaling more than 10,000 MW of capacity. The low cost of natural gas and renewables, along with additional environmental compliance costs, has shifted electricity generation toward cheaper sources of energy in recent years, and the trend is expected to continue as the economic gap widens. Coal plants in the state, originally built to run 75-80% of the time, are now running, on average, only 35% of the time.

Recognizing the significant potential in ratepayer savings, the North Carolina Utilities Commission ordered Duke Energy to evaluate the merits of continuing to operate the coal units by examining the most economic and the earliest practicable dates of retirements. In its 2020 IRP, for the most economic case, Duke Energy recommended the retirement of 11 of 18 units by 2030, even without securitization. For the earliest practicable retirement case, Duke Energy identified that all coal units could be retired by 2030, with one unit converted to natural gas. Securitization should be a tool made available to North Carolina regulators and utilities for cases where it would provide a benefit in customer rates to retire and replace the coal plant.

HOW DOES SECURITIZATION SOLVE THE PROBLEM?

Through the refinancing of the plant using low-cost debt, securitization has the potential to:

- Create customer savings on day-one and for the remainder of the plant's life due to lower costs of financing
- Create funds for transition assistance to workers and communities affected by plant closures
- Keep the utility whole through reinvestment in replacement renewable generation and/or storage

Early economic retirement of North Carolina's coal plants and replacement with zero emitting resources is estimated to achieve the 70% reduction in greenhouse gas emissions goal specified in the Clean Energy Plan by itself, provided the amount of imported electricity and its carbon intensity remain at or below historical levels.

As North Carolina has a significant amount of coal capacity that could be financed to provide ratepayer benefits, the large amount of generation needing to be replaced must be planned carefully to ensure costs are minimized, utilities are fairly compensated, system reliability is maintained, cleaner technology solutions are deployed, and pollution levels are reduced.

HOW IS SECURITIZATION DIFFERENT FROM CURRENT OPTIONS TO FINANCE COAL PLANT RETIREMENTS?

The three options currently available to utilities and regulators all have drawbacks and benefits, especially for customers.

Accelerate the retirement of these plants through a rapid return of unrecovered investment (e.g., through accelerated schedule of undepreciated assets than normally allowed over the project life). This helps get the uneconomic plant offline more quickly and likely saves ratepayers money long term. But accelerated depreciation could cause short-term rate spikes, which would impact businesses and low-to-moderate income customers acutely.

Retire a plant and create a regulatory asset**.** This allows the utility to continue to earn a return on a plant that is no longer in service, until the plant is fully depreciated. The downside of this path is that customers are paying for an asset that provides no benefits. For the utility there is also the risk of future disallowance, as there is no guarantee that the public utilities commission will continue to let the regulatory asset be charged to ratepayers.

Disallow the utility from recovering any remaining plant balance. The public utilities commission could decide that the uneconomic plant is no longer "used and useful" and prohibit the utility from recovering any remaining plant balance. This has obvious downsides for the utility, possibly impacting their credit rating, impacting customers over the long run, and potentially chilling interest in future investments.

HAS SECURITIZATION BEEN USED BEFORE?

In 2019, following the significant disaster recovery and response expenses incurred from hurricanes Matthew and Florence, the North Carolina General Assembly passed SB559 (SL 2019-244) to permit financing for certain storm recovery costs.

Though securitization's proposed use for early coal retirement is recent, it has been used extensively in the past for a variety of reasons – ranging from recovering costs from a damaged plant[1] to financing pollution control upgrades[2] to enabling electricity market restructuring[3]. It is a financial mechanism that Wall Street is both familiar and comfortable with.

Securitization for early plant retirement is already enabled in four states, three of which passed legislation in 2019. PNM Resources in New Mexico is in the process of securitizing its San Juan coal plant[4] and replacing it with a portfolio of renewable energy and storage. Duke Energy Florida securitized $1.3 billion of the remaining plant balance of the Crystal River nuclear plant, resulting in more than $700 million in customer savings. Many other states are expected to introduce supporting legislation in the 2021 session.

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 Securitization Study Group Leads:
David Rogers, Sierra Club, david.rogers@sierraclub.org
Tobin Freid, Durham County, tfreid@dconc.gov

Access the NERP summary report and other NERP documents at:
https://deq.nc.gov/CEP-NERP

1 *See* https://www.tampabay.com/news/business/energy/duke-energy-florida-customers-will-see-a-new-charge-on-their-bill-starting/2282006/

2 *See* https://saberpartners.com/press/allegheny-closes-pollution-control-issue/

3 *See* http://nescoe.com/resource-center/restructuring-dec2015/

4 *See* https://www.abqjournal.com/1439120/prc-approves-san-juan-abandonment.html

NERP STATUTE COMPARISON

SECURITIZATION STATUTE COMPARISON

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

Securitization is a financial mechanism allowing bonds to be used to recover undepreciated capital costs of assets and, in some cases, replace other losses of revenue. Securitized bonds, also called ratepayer backed bonds, must be authorized by state legislation. A comparison of securitization statutes that include recovery of undepreciated plant balances and transition assistance for workers and communities affected by early plant retirements can be useful as North Carolina decision makers consider this issue.

Key provisions in legislation typically include:

- Creation of the property right which underlies the bonds
- Definition of allowable uses for the bonds
- Key protections for bond purchasers
- Process for defining bond issuance amount and procedures
- Role of the Public Utilities Commission
- Role of the Public Utility

The North Carolina securitization legislation passed in 2019 contains the basic legal and financial components for creating securitized bonds in statute. However, the only allowable use for the bonds was is recovery of costs incurred from storm damage.

Statutes in other states provide for different or additional uses for the bonds. Specifically, use of bonds for utility capital recovery in the event of early plant retirement and for transition assistance for communities and workers affected by early plant retirements. Statutes permitting these uses also define acceptable capital reinvestment opportunities for the utility retiring an uneconomic plant. Inclusion of a reinvestment or “capital recycling” pathway is a key to securing utility support for securitization legislation with the plant retirement bond use.

Securitization statutes specify the role of the public utilities commission in issuing the financing order for the bonds and its oversight in the bond issuance process. Commission oversight is key to protecting ratepayer interests. Comparisons between the commission’s role as defined in the North Carolina Statute, and statutes in Colorado, Montana, New Mexico and Michigan are provided.

COMPARISON OF SECURITIZATION STATUES

State	Specified Bond Uses				Utility	Regulator
	Storm Costs	*Plant Retirement*	Retire Debt/Equity	*Transition Assistance*	Reinvestment Options	*Strength of PUC Role*
North Carolina	**X**					medium
Colorado		**X**		**X**	**X**	strong
Montana		**X**			**X**	strong
New Mexico		**X**		**X**	**X**	weak
Michigan		**X**	**X**			weak

BEYOND STORM COSTS: BOND USES AUTHORIZED IN CO, MT, NM, MI STATUTES

1. PLANT RETIREMENT

Using low-interest securitized bonds to replace higher cost utility capital remaining in a retired plant saves ratepayers money. Utility concerns about maintaining rate base often require the legislation include a pathway for reinvestment or "recycling" the returned utility capital into other approved uses. Securitization statutes in Colorado, Montana and Michigan allow securitized bonds to be used for recovering the remaining utility capital invested in a retired power generating station. The New Mexico statute allows bond use for the retirement of a specific power generating station defined in the statute.

Colorado
CO SB19-236, Article 41 – The Colorado Energy Impact Bond Act, part of the Public Utility Commission Sunset/Reauthorization Act

Allowable Use: The allowable uses for the bonds extend to the "pretax costs", including unrecovered capitalized cost of a retired electric generating facility that will be retired, and also the "pretax costs" incurred previously related to a commission-approved closure of an electric generating facility retired before the statute was in effect. (CO SB19-236 - page 52, lines 15-24; line 27; page 53, lines 1-3)

Montana
2019 MT HB 467, placed securitization in Statute.

Allowable Use: The two allowable bond uses are the "pretax costs" incurred when the utility retires or replaces electric generating infrastructure or facilities located in Montana, and the "pretax costs" previously incurred related to the closure or replacement or electric generating infrastructure or facilities. (2019 MT HB 467 – page 4, (13)(a))

New Mexico
NM 2019 Energy Transition Act. Securitization is a centerpiece of this act which also included a renewable portfolio standard and climate goals.

Allowable Use: The act allows bond use for the abandonment costs of a "qualifying generating facility", and specifies cap on the amount of money which may be securitized. Other specific dollar amounts for decommissioning and mine reclamation costs, and job retraining are listed as allowable uses. The specificity of the dollar amounts and retirement date for the generating station are tied to a specific plant owned by Public Service of New Mexico (PNM), one of the primary advocates for the bill. The qualifying generating facility language does have some flexibility for application to other plants in New Mexico. (2019 NM SB 489 – page 4, lines 9-24; page 9, lines 6-19)

Michigan
MI 2000, Act 142, Customer Choice and Electricity Reliability Act included securitization. It was used in 2016 by Consumers Energy for the early retirement of a 950MW coal-fired electric generating station. The bond issue amount was $389.6M. Recently, Consumers Energy filed for a $702.8M financing order related to the early retirement of Units 1 & 2 at the Karn coal-fired generating station.

Allowable Use: Refinancing or retirement of debt or equity. (MI 1939 PA 3, Sec. 10h (g); Sec. 10j (1)(a))

2. TRANSITION ASSISTANCE: AUTHORIZED IN CO AND NM STATUES

When securitization is used for the early retirement of an electric generating facility, some statutes passed in 2019 added a new use for securitized bonds, providing transition assistance to workers and communities affected by the closure.

Colorado
The introduced 2019 bill, HB19-1037, included a formula for sharing the savings realized by refinancing the remaining capital in a retired plant between ratepayers (85% of the savings) and the affected workers and communities (15% of the savings). The savings would be calculated as the net present value of the savings over the tenor (life) of the bonds, compared to the amount ratepayers would have paid to retire the plant without the lower-cost bonds. However, this formula did not survive the legislative process. Instead, the bill includes a simple phase allowing bonds to be used for transition assistance. The decision on the amount of funds for transition assistance will be made by the Commission as part of the financing order.

Allowable Use: The statute allows the bonds to be used for "amounts for assistance to affected workers and communities, if approved by the Commission". (CO SB19-236 - page 52, lines 25-26)

New Mexico
The Energy Transition act contains very detailed guidelines, establishing three different funds for state agencies to administer transition funding for affected Indian communities, affected communities and workers.

Allowable Use: 0.5% of amount bonded is earmarked for the energy transition Indian affairs fund; 1.65% of the bonded amount goes to the energy transition economic development fund; and 3.35% of the bonded amount goes to the energy transition displaced worker assistance fund. (2019 NM SB 489 – page 4, lines 24-25; page 5, lines 1-3; 20-21; SECTION 16, page 40-47)

UTILITY REINVESTMENT: INCLUDED IN CO, MT, NM STATUTES

Colorado
Reinvestment/Capital Recycling: Specific opportunities for the utility to reinvest capital recovered from securitizing a retired plant are not listed in Article 41. Instead, reinvestment opportunities for the utility are defined earlier in the statute in the section describing the Clean Energy Plan the utility is required to submit to the Commission. This plan requires the utility to adopt carbon reduction goals, strategies for achieving the goals, projected costs and proposed new clean energy acquisitions required to meet the goals. The utility is awarded up to 50% ownership of the new clean energy acquisitions. (CO SB19-236 - page 17, lines 1-17)

Montana
Reinvestment/Capital Recycling: The statute provides guidance on how the utility shall expend or invest the funds received from a bond issue. It will first reduce the balance owed on the retired electric generating facility. Following that, the utility may invest or expend funds to own least-cost generation resources, electric storage, network modernization, or to replace any damaged or destroyed electric transmission facilities. (2019 MT HB 467 – page 18-19, Section 18)

New Mexico
Reinvestment/Capital Recycling: The statute provides a detailed process for how PNM must replace the power from the abandoned generating facility. The specificity is partially a means to replace property tax base for the affect school district and community. (2019 NM SB 489 – page 10, lines 2-25; page 11, lines 1-23)

ROLE OF THE PUBLIC UTILITIES COMMISSION: STATUES IN CO, MT, NM, MI

Securitization statutes should describe the role of the public utilities commission in issuing a financing order that 1) allows the issuance of bonds; 2) establishes oversight of the bond issuance process; and 3) protects ratepayer interests throughout both processes. The stronger the commission's role, and the more oversight it exercises, the better the outcome for ratepayers.

During the legislative process, the utility has an interest in limiting the commission's role and oversight authority; ratepayer advocates typically push for the opposite outcome, with compromises occurring to achieve bill passage. Among the state statutes we review in this memo, the Colorado statute creates the strongest commission oversight role, followed by Montana, Michigan, and then New Mexico. A key component for empowering a commission to conduct effective oversight is the authority to hire outside financial advisors to assist the commission. Funds for outside advisors or additional staff to manage the bond issuance process may not be covered in a commission's normal staff budget. Statutes typically allow commission expenses related to a bond issue to be covered as a part of the bond issue expenses. If a utility receives a financing order, but decides not to issue the bonds, commission expenses incurred in producing the financing order would have to be paid by the utility, which can recover those expenses in a future rate case.

The existing North Carolina securitization statute provides reasonable oversight authority for the commission. The Commission can hire outside financial advisors, with their costs paid as part of the bond issue. The North Carolina statute, however, does not address the situation of recovery of commission expenses when the utility does not follow through and issue bonds.

Colorado

Public Utility Commission Role: The Statute gives the Commission the authority to:

- Require the bonds provide maximum net present value savings for ratepayers (CO SB19-236 - page 59, lines 14-27)
- Conduct oversight of how the bond issue will be structured, priced and marketed to achieve maximum savings for ratepayers (CO SB19-236 - page 60, lines 14-22)
- Attach conditions to the financing order to maximize benefits and minimize risks for all parties (CO SB19-236 - page 66, lines 4-8)
- Hire outside financial advisors to assist the Commission in its oversight work (CO SB19-236 - page 67, lines 9-20)
- Require the utility to simultaneously add a negative cost rider to ratepayer bills to reflect the decreased cost of service and counterbalance the bond repayment charge (CO SB19-236 - page 62, lines 19-24)
- Conduct a rule making for how to manage the securitization financing order process. (CO SB19-236 - page 65, line 27)

Montana

Public Utility Commission Role: The Statute gives the Commission the authority to:

- Require the bonds to provide substantial quantifiable savings for ratepayers (2019 MT HB 467, Section 5 (iv)(c) (I)(ii)
- Include findings determined by the commission to be in the best interests of consumers. (2019 MT HB 467, Section 5 (vii)
- Require the utility to reduce rates simultaneously with the addition of the bond repayment charge on ratepayer bills (2019 MT HB 467, Section 5 (B))
- Hire outside financial advisors to assist the Commission in its oversight work. (2019 MT HB 467, Section 5 (B)(3)(f))
- Conduct a rule making for how to manage the securitization financing order process (2019 MT HB 467, Section 19)

Michigan

Public Utility Commission Role: The Statute gives the Commission limited authority:

- Oversight to ensure customer savings is weak – savings must be "tangible and quantifiable", but no reference is made to maximize savings or how savings should be calculated. ((MI 1939 PA 3, Sec.10i (2)(b)(c))
- The authority to hire outside financial advisors to assist the Commission in its oversight work is included. ((MI 1939 PA 3, Sec.10i (10))

New Mexico

Public Commission Utility Role: The Statute gives the Commission very limited authority:

- No oversight to ensure customer savings. Savings are calculated by applicant utility as it deems appropriate, and submitted to the Commission as part of the financing order. (2019 NM SB 489 – page 10, lines 2-25; page 13, lines 17-25)
- Commission has no authority to determine the amount to be securitized for plant retirement or transition assistance. These amounts were determined by the legislature and are in Statute. (2019 NM SB 489 – page 4, lines 9-25; page 40-47, Section 16)
- Commission is required to approve a financing order from qualified applicant utility, if financing order application meets Statute requirements. (2019 NM SB 489 – page 17, lines 7-17)
- Commission does have the power to review and approve replacement generation options. (2019 NM SB 489 – page 10, lines 2-25; page 11, lines 1-23)

RECOMMENDATIONS

- The North Carolina Storm Recovery Costs securitization statute could be amended to include additional permitted uses for the bonds. Additional uses could include plant retirement costs and transition assistance for affected communities and workers.
- If plant retirement becomes an allowable use for the bonds, the bill should also include guidance on re-investment opportunities for the utility.
- The existing statute permits the Commission to hire outside financial advisors with the costs paid as part of the bond issue. Adding a provision for Commission cost recovery in the event that bonds are not issued by the utility, similar to the language in the Colorado statute, may be helpful.
- The North Carolina statute provides reasonable oversight authority for the commission. Attempting to strengthen commission authority might trigger utility resistance to the bill.

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 Securitization Study Group Leads:
David Rogers, Sierra Club, david.rogers@sierraclub.org
Tobin Freid, Durham County, tfreid@dconc.gov

Access the NERP summary report and other NERP documents at: https://deq.nc.gov/CEP-NERP

NERP ANALYSIS SUMMARY

GENERATION ASSET RETIREMENT FINANCIAL ANALYSIS

COMPARISON OF SECURITIZATION AND REGULATORY ASSET TREATMENT: RELATIVE IMPACTS ON RATEPAYER SAVINGS, UTILITY EARNINGS, AND COMMUNITY ASSISTANCE

The 2020 North Carolina Energy Regulatory Process prioritized energy reforms that would drive affordability, carbon-reduction, and align regulatory incentives with policy goals.

SUMMARY OF FINDINGS

Based on financial analysis performed for a select group of Duke Energy Progress (DEP) coal plants, Rocky Mountain Institute (RMI) finds that securitization (with reinvestment) leads to greater ratepayer savings (in the short and long term) than using regulatory asset treatment as a method for early retirement. Furthermore, securitization with reinvestment provides the utility opportunity for earnings through additions to rate base and could fund transition assistance for impacted communities.

For example, securitizing Mayo (with utility reinvestment) could save ratepayers between $13-19/MWh (or $18-29MM) in the first year and between $3-5/MWh (or $46-96MM) on a levelized basis, compared to a regulatory asset treatment. The utility has a significant earnings opportunity with securitization, though less than through the regulatory asset treatment – up to $600-800MM with the former vs. up to $800-1100MM (on a levelized basis and including tax credits) with the latter. Finally, securitization could result in between $8-15MM in community assistance.

While RMI's analysis shows securitization generating ratepayer savings compared to a regulatory asset treatment, the magnitude of that difference varies. In Roxboro 3, for example, securitization with reinvestment could save ratepayers between $4-6/MWh (or $9-13MM) in the first year and between $17-21MM on a levelized basis, compared to regulatory asset treatment. The earnings opportunity for the utility in retiring and replacing Roxboro 3 is similar for both securitization & regulatory assets – up to $700-800MM. Finally, between $2-4MM in community assistance could be made available for this plant.

The ratepayer savings, utility earnings and community assistance opportunity for Roxboro 4 is similar to that of Roxboro 3, for both securitization and regulatory asset treatment.

IMPORTANT CAVEATS AND ASSUMPTIONS

RMI's financial model was used to provide *relative* and *illustrative* modeling results – in their current form, the results are not meant to estimate the absolute size of ratepayer savings or utility earnings from any retirement method.

Rather, the results aim to show the tradeoffs (for the utility, customer and community) between two different methods of early plant retirement, and the relative magnitude of the differences in the two approaches.

If a decision is made to investigate the actual implementation of securitization, the analysis would have to be revisited to more accurately account for (among other items):

- The expected 'ramp down' of existing coal plants, prior to retirement
- The sequencing of replacement generation and storage, relative to early retirement
- Implications of early retirement at the fleet level (vs. the individual plant level)

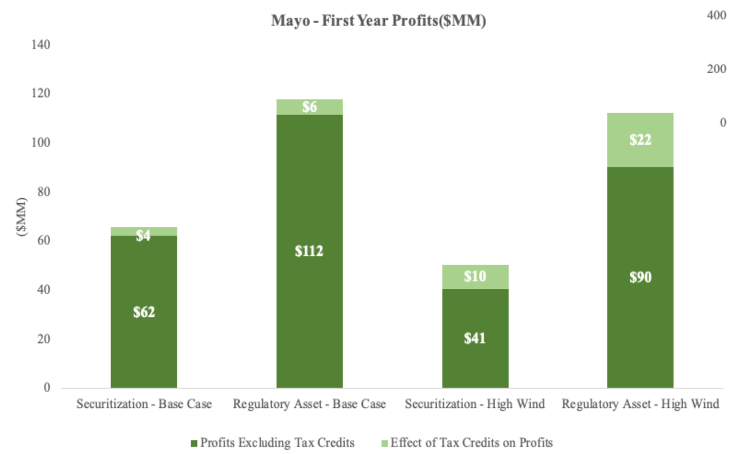
RMI believes that, while the above considerations are critical to implementation, they do not significantly alter the potential *opportunity* presented by securitization for customers, the utility and the community, relative to a regulatory asset treatment.

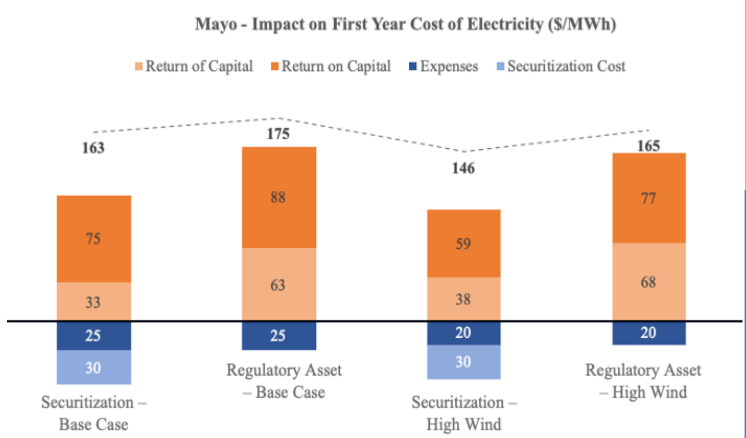
ILLUSTRATIVE MODELING RESULTS

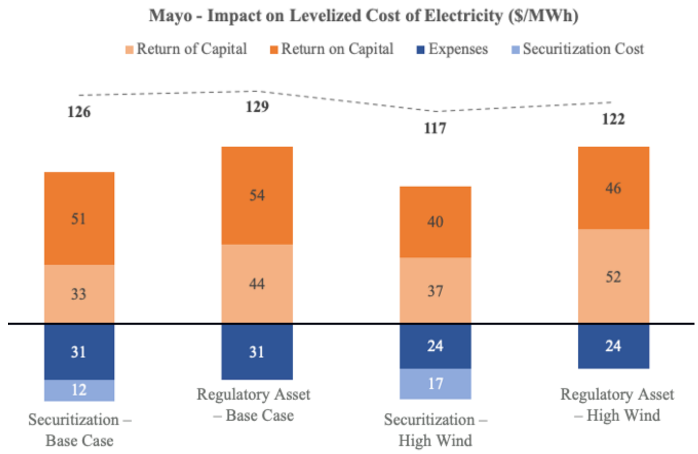
RMI modeled three DEP plants – Mayo 1, Roxboro 3 and Roxboro 4. For each of the plants, two methods of retirement were considered: i) securitization with reinvestment and, ii) regulatory asset treatment.

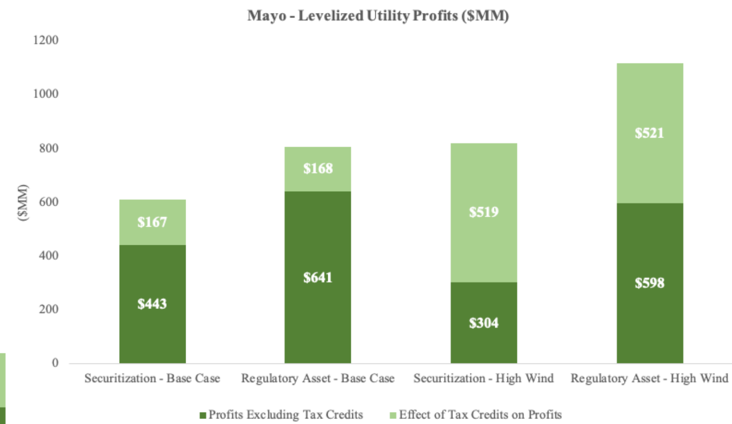
Furthermore, to determine the retirement year and subsequent replacement portfolio for each plant, Scenario A (Base Case without Carbon Policy) and Scenario D (High Wind) from the DEP 2020 Integrated Resource Plan were used.

The results for Mayo 1 are shown below as an illustrative example:









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 Securitization Study Group Leads:
David Rogers, Sierra Club, david.rogers@sierraclub.org
Tobin Freid, Durham County, tfreid@dconc.gov

Access the NERP summary report and other NERP documents at:
https://deq.nc.gov/CEP-NERP

OFFICIAL COPY Oct 04 2023

GENERAL ASSEMBLY OF NORTH CAROLINA SESSION 2021

SENATE/HOUSE BILL XXX

A BILL TO BE ENTITLED
"AN ACT TO PERMIT FINANCING FOR CERTAIN UNDEPRECIATED UTILITY PLANT COSTS AND FOR TRANSITION ASSISTANCE FOR AFFECTED WORKERS AND COMMUNITIES"

The General Assembly of North Carolina enacts:

SECTION 1. Article 8 of Chapter 62 of the General Statutes is amended by adding a new section to read:

"**§ 62-173. Financing for certain energy transition costs.**

(a) Definitions. – The following definitions apply in this section:

(1) Ancillary agreement. – A bond, insurance policy, letter of credit, reserve account, surety bond, interest rate lock or swap arrangement, hedging arrangement, liquidity or credit support arrangement, or other financial arrangement entered into in connection with energy transition bonds.

(2) Assignee. – A legally recognized entity to which a public utility assigns, sells, or transfers, other than as security, all or a portion of its interest in or right to energy transition property. The term includes a corporation, limited liability company, general partnership or limited partnership, public authority, trust, financing entity, or any entity to which an assignee assigns, sells, or transfers, other than as security, its interest in or right to energy transition property.

(3) Bondholder. – A person who holds an energy transition bond.

(4) Code. – The Uniform Commercial Code, Chapter 25 of the General Statutes.

(5) Commission. – The North Carolina Utilities Commission.

(6) Customer securitization savings – The arithmetic difference between the net present value of the costs to customers that are estimated to result from the issuance of energy transition bonds and the net present value of the costs that would result from the application of the traditional method of financing and recovering energy transition costs from customers.

(7) Energy transition bonds. – Bonds, debentures, notes, certificates of participation, certificates of beneficial interest, certificates of ownership, or other evidences of indebtedness or ownership that are issued by a public utility or an assignee pursuant to a financing order, the proceeds of which are used directly or indirectly to recover, finance, or refinance Commission-approved energy transition costs and financing costs, and that are secured by or payable from energy transition property. If certificates of participation or ownership are issued, references in this section to principal, interest, or premium shall be construed to refer to comparable amounts under those certificates.

(8) Energy transition charge. – The amounts authorized by the Commission to repay, finance, or refinance energy transition costs and financing costs and

that are nonbypassable charges (i) imposed on and part of all retail customer bills, (ii) collected by a public utility or its successors or assignees, or a collection agent, in full, separate and apart from the public utility's base rates, and (iii) paid by all existing or future retail customers receiving transmission or distribution service, or both, from the public utility or its successors or assignees under Commission-approved rate schedules or under special contracts, even if a customer elects to purchase electricity from an alternative electricity supplier following a fundamental change in regulation of public utilities in this State.

(9) Energy transition costs. – All of the following:

(a) (i) at the option of and upon petition by an public utility, and as approved by the commission, any of the pretax costs that the electric utility has incurred or will incur that are caused by, associated with, or remain as a result of the retirement of an electric generating facility located in the state.

(ii) as used in this subsection, "pretax costs," include, but are not limited to, the unrecovered capitalized cost of a retired electric generating facility, costs of decommissioning and restoring the site of the electric generating facility, and other applicable capital and operating costs, accrued carrying charges, deferred expenses, reductions for applicable insurance and salvage proceeds and the costs of retiring any existing indebtedness, fees, costs, and expenses to modify existing debt agreements or for waivers or consents related to existing debt agreements.

(b) amounts for transition assistance to affected workers and communities if approved by the commission;

(c) pretax costs that an electric utility has previously incurred related to the commission-approved closure of an electric generating facility occurring before the effective date of this section.

(d) energy transition costs do not include any monetary penalty, fine, or forfeiture assessed against an electric utility by a government agency or court under a federal or state environmental statute, rule, or regulation.

(10) Energy transition property. – All of the following:

a. All rights and interests of a public utility or successor or assignee of the public utility under a financing order, including the right to impose, bill, charge, collect, and receive energy transition charges authorized under the financing order and to obtain periodic adjustments to such charges as provided in the financing order.

b. All revenues, collections, claims, rights to payments, payments, money, or proceeds arising from the rights and interests specified in the 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.

(11) Financing costs. – The term includes all of the following:
a. Interest and acquisition, defeasance, or redemption premiums payable on energy transition bonds.
b. Any payment required under an ancillary agreement and any amount required to fund or replenish a reserve account or other accounts established under the terms of any indenture, ancillary agreement, or other financing documents pertaining to energy transition bonds.
c. Any other cost related to issuing, supporting, repaying, refunding, and servicing energy transition bonds, including, servicing fees, accounting and auditing fees, trustee fees, legal fees, consulting fees, structuring adviser fees, administrative fees, placement and underwriting fees, independent director and manager fees, capitalized interest, rating agency fees, stock exchange listing and compliance fees, security registration fees, filing fees, information technology programming costs, and any other costs necessary to otherwise ensure the timely payment of energy transition bonds or other amounts or charges payable in connection with the bonds, including costs related to obtaining the financing order.
d. Any taxes and license fees or other fees imposed on the revenues generated from the collection of the energy transition charge or otherwise resulting from the collection of energy transition charges, in any such case whether paid, payable, or accrued.
e. Any State and local taxes, franchise, gross receipts, and other taxes or similar charges, including regulatory assessment fees, whether paid, payable, or accrued.
f. Any costs incurred by the Commission or public staff for any outside consultants or counsel retained in connection with the securitization of energy transition costs, except as provided in subparagraph (d)(1)c.

(12) Financing order. – An order that authorizes the issuance of energy transition bonds; the imposition, collection, and periodic adjustments of an energy transition charge; the creation of energy transition property; and the sale, assignment, or transfer of energy transition property to an assignee.

(13) Financing party. – Bondholders and trustees, collateral agents, any party under an ancillary agreement, or any other person acting for the benefit of bondholders.

(14) Financing statement. – Defined in Article 9 of the Code.

(15) Pledgee. – A financing party to which a public utility or its successors or assignees mortgages, negotiates, pledges, or creates a security interest or lien on all or any portion of its interest in or right to energy transition property.

(16) Public utility. – A public utility, as defined in G.S. 62-3, that sells electric power to retail electric customers in the State.

(b) Financing Orders. –

(1) A public utility may petition the Commission for a financing order. The petition shall include all of the following:
a. The energy transition costs incurred by the utility and an estimate of the costs that are being undertaken but are not completed.

b. A statement of whether the public utility proposes to finance all or a portion of the energy transition costs using energy transition bonds. If the public utility proposes to finance a portion of the costs, the public utility must identify the specific portion in the petition. By electing not to finance a portion of such energy transition costs using energy transition bonds, a public utility shall not be deemed to waive its right to recover such costs pursuant to a separate proceeding with the Commission.

c. A proposed amount, for Commission consideration, to be included in energy transition costs for use as transition assistance for workers and local governments negatively affected by the retirement of an electric generating facility.

d. An estimate of the financing costs related to the energy transition bonds.

e. An estimate of the energy transition charges necessary to recover the energy transition costs and financing costs and the proposed period for recovery of such costs.

f. An estimate of the quantifiable customer securitization savings resulting from the use of energy transition bonds instead of traditional cost recovery methods.

g. Direct testimony and exhibits supporting the petition.

(2) If a public utility is subject to a settlement agreement that governs the type and amount of costs that could be included in energy transition costs and the public utility proposes to finance all or a portion of the costs using energy transition bonds, then the public utility must file a petition with the Commission for review and approval of those costs no later than 90 days before filing a petition for a financing order pursuant to this section.

(3) Petition and order. –

a. Proceedings on a petition submitted pursuant to this subdivision begin with the petition by a public utility, filed subject to the time frame specified in subdivision (2) of this subsection, if applicable, and shall be disposed of in accordance with the requirements of this Chapter and the rules of the Commission, except as follows:

1. Within 14 days after the date the petition is filed, the Commission shall establish a procedural schedule that permits a Commission decision no later than 210 days after the date the petition is filed.

2. No later than 210 days after the date the petition is filed, the Commission shall issue a financing order or an order rejecting the petition. A party to the Commission proceeding may petition the Commission for reconsideration of the financing order within five days after the date of its issuance.

b. A financing order issued by the Commission to a public utility shall include all of the following elements:

1. Except for changes made pursuant to the formula-based mechanism authorized under this section, the amount of energy transition costs to be financed using energy transition

bonds. The Commission shall describe and estimate the amount of financing costs that may be recovered through energy transition charges and specify the period over which energy transition costs and financing costs may be recovered.

2. A finding that the proposed issuance of energy transition bonds and the imposition and collection of an energy transition charge are expected to provide quantifiable benefits to customers as compared to the costs that would have been incurred absent the issuance of energy transition bonds and a statement of the net present value of those benefits to customers.

3. A finding that the structuring and pricing of the energy transition bonds are reasonably expected to result in the lowest energy transition charges consistent with market conditions at the time the energy transition bonds are priced, and with the terms set forth in such financing order.

4. A determination of the portion, up to 15%, of the customer securitization savings that shall be included in transition bond costs and used to provide transition assistance to workers and local governments negatively affected by the retirement of the electric generating facility.

5. A requirement that, for so long as the energy transition bonds are outstanding and until all financing costs have been paid in full, the imposition and collection of energy transition charges authorized under a financing order shall be nonbypassable and paid by all existing and future retail customers receiving transmission or distribution service, or both, from the public utility or its successors or assignees under Commission-approved rate schedules or under special contracts, even if a customer elects to purchase electricity from an alternative electric supplier following a fundamental change in regulation of public utilities in this State.

6. A formula-based true-up mechanism for making, at least annually, expeditious periodic adjustments in the energy transition charges that customers are required to pay pursuant to the 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 energy transition bonds and financing costs and other required amounts and charges payable in connection with the energy transition bonds.

7. The energy transition property that is, or shall be, created in favor of a public utility or its successors or assignees and that shall be used to pay or secure energy transition bonds and all financing costs.

8. The degree of flexibility to be afforded to the public utility in

establishing the terms and conditions of the energy transition bonds, including, but not limited to, repayment schedules, expected interest rates, and other financing costs.

9. How energy transition charges will be allocated among customer classes.

10. A requirement that, after the final terms of an issuance of energy transition bonds have been established and before the issuance of energy transition bonds, the public utility determines the resulting initial energy transition charge in accordance with the financing order and that such initial energy transition charge be final and effective upon the issuance of such energy transition bonds without further Commission action so long as the energy transition charge is consistent with the financing order.

11. A requirement that the applicant public utility, simultaneously with the inception of the collection of energy transition charges, reduce its rates through a reduction in base rates or by a negative rider on customer bills in an amount equal to the revenue requirement associated with the utility assets being financed by energy transition bonds

12. A method of tracing funds collected as energy transition charges, or other proceeds of energy transition property, and determine that such method shall be deemed the method of tracing such funds and determining the identifiable cash proceeds of any energy transition property subject to a financing order under applicable law.

13. Any other conditions not otherwise inconsistent with this section that the Commission determines are appropriate.

c. A financing order issued to a public utility may provide that creation of the public utility's energy transition property is conditioned upon, and simultaneous with, the sale or other transfer of the energy transition property to an assignee and the pledge of the energy transition property to secure energy transition bonds.

d. If the Commission issues a financing order, the public utility shall file with the Commission at least annually a petition or a letter applying the formula-based mechanism and, based on estimates of consumption for each rate class and other mathematical factors, requesting administrative approval to make the applicable adjustments. The review of the filing shall be limited to determining whether there are any mathematical or clerical errors in the application of the formula-based mechanism relating to the appropriate amount of any overcollection or undercollection of energy transition charges and the amount of an adjustment. The adjustments shall ensure the recovery of revenues sufficient to provide for the payment of principal, interest, acquisition, defeasance, financing costs, or redemption premium and other fees, costs, and charges in respect of energy transition bonds approved under the financing order. Within 30 days after receiving a public utility's request pursuant to this paragraph, the Commission shall either approve the request or inform the public utility of any mathematical or clerical errors in its calculation. If the Commission informs the utility of mathematical or clerical errors in its calculation, the utility may correct its error and refile its request. The time frames previously described in this paragraph shall apply to a refiled request.

e. Subsequent to the transfer of energy transition property to an assignee or the issuance of energy transition bonds authorized thereby, whichever is earlier, a financing order is irrevocable and, except for changes made pursuant to the formula-based mechanism authorized in this section, the Commission may not amend, modify, or terminate the financing order by any subsequent action or reduce, impair, postpone, terminate, or otherwise adjust energy transition charges approved in the financing order. After the issuance of a financing order, the public utility retains sole discretion regarding whether to assign, sell, or otherwise transfer energy transition property or to cause energy transition bonds to be issued, including the right to defer or postpone such assignment, sale, transfer, or issuance.

f. Transition assistance funds, if included in the bond issue, may be transferred to a third-party entity designated by the commission to administer transition assistance on behalf of displaced workers and affected communities.

(4) At the request of a public utility, the Commission may commence a proceeding and issue a subsequent financing order that provides for refinancing, retiring, or refunding the energy transition bonds issued pursuant to the original financing order if the Commission finds that the subsequent financing order satisfies all of the criteria specified in this section for a financing order. Effective upon retirement of the refunded energy transition bonds and the issuance of new energy transition bonds, the Commission shall adjust the related energy transition charges accordingly.

(5) Within 60 days after the Commission issues a financing order or a decision denying a request for reconsideration or, if the request for reconsideration is granted, within 30 days after the Commission issues its decision on reconsideration, an adversely affected party may petition for judicial review in the Supreme Court of North Carolina. Review on appeal shall be based solely on the record before the Commission and briefs to the court and is limited to determining whether the financing order, or the order on reconsideration, conforms to the State Constitution and State and federal law and is within the authority of the Commission under this section.

(6) Duration of financing order. –

a. A financing order remains in effect and energy transition property under the financing order continues to exist until energy transition bonds issued pursuant to the financing order have been paid in full or defeased and, in each case, all Commission-approved financing costs of such energy transition bonds have been recovered in full.

b. A financing order issued to a public utility remains in effect and unabated notwithstanding the reorganization, bankruptcy or other insolvency proceedings, merger, or sale of the public utility or its successors or assignees.

(c) Exceptions to Commission Jurisdiction. –

(1) The Commission may not, in exercising its powers and carrying out its duties regarding any matter within its authority pursuant to this Chapter, consider the energy transition bonds issued pursuant to a financing order to be the debt of the public utility other than for federal income tax purposes, consider the energy transition charges paid under the financing order to be the revenue of the public utility for any purpose, or consider the energy transition costs or financing costs specified in the financing order to be the costs of the public utility, nor may the Commission determine any action taken by a public utility which is consistent with the financing order to be unjust or unreasonable.

(2) The Commission may not order or otherwise directly or indirectly require a public utility to use energy transition bonds to finance any project, addition, plant, facility, extension, capital improvement, equipment, or any other expenditure. After the issuance of a financing order, the public utility retains sole discretion regarding whether to cause the energy transition bonds to be issued, including the right to defer or postpone such sale, assignment, transfer, or issuance. Nothing shall prevent the public utility from abandoning the issuance of energy transition bonds under the financing order by filing with the Commission a statement of abandonment and the reasons therefor. The Commission may not refuse to allow a public utility to recover energy transition costs in an otherwise permissible fashion, or refuse or condition authorization or approval of the issuance and sale by a public utility of securities or the assumption by the public utility of liabilities or obligations, solely because of the potential availability of energy transition bond financing.

(d) Public Utility Duties. –

(1) The electric bills of a public utility that has obtained a financing order and caused energy transition bonds to be issued must comply with the provisions of this subsection; however, the failure of a public utility to comply with this subsection does not invalidate, impair, or affect any financing order, energy transition property, energy transition charge, or energy transition bonds. The public utility must do the following:

a. Explicitly reflect that a portion of the charges on such bill represents energy transition charges approved in a financing order issued to the public utility and, if the energy transition property has been transferred to an assignee, must include a statement to the effect that the assignee is the owner of the rights to energy transition charges and that the public utility or other entity, if applicable, is acting as a collection agent or servicer for the assignee. The tariff applicable to customers must indicate the energy transition charge and the ownership of the charge.

b. Include the energy transition 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.

c. If a public utility's petition for a financing order is denied or withdrawn or for any reason no energy transition bonds are issued, any costs of retaining expert consultants and counsel on behalf of the commission or the public staff, as authorized by Section and approved by the commission, shall be paid by the applicant public utility and shall be eligible for recovery by the public utility, including carrying costs, in the electric utility's future rates.

(e) Energy transition Property. –

(1) Provisions applicable to energy transition property. –

a. All energy transition property that is specified in a financing order constitutes an existing, present intangible property right or interest therein, notwithstanding that the imposition and collection of energy transition charges depends on the public utility, to which the financing order is issued, performing its servicing functions relating to the collection of energy transition charges and on future electricity consumption. The property exists (i) regardless of whether or not the revenues or proceeds arising from the property have been billed, have accrued, or have been collected and (ii) notwithstanding the fact that the value or amount of the property is dependent on the future provision of service to customers by the public utility or its successors or assignees and the future consumption of electricity by customers.

b. Energy transition property specified in a financing order exists until energy transition bonds issued pursuant to the financing order are paid in full and all financing costs and other costs of such energy transition bonds have been recovered in full.

c. All or any portion of energy transition property specified in a financing order issued to a public utility may be transferred, sold, conveyed, or assigned to a successor or assignee that is wholly owned, directly or indirectly, by the public utility and created for the limited purpose of acquiring, owning, or administering energy transition property or issuing energy transition bonds under the financing order. All or any portion of energy transition property may be pledged to secure energy transition bonds issued pursuant to the financing order, amounts payable to financing parties and to counterparties under any ancillary agreements, and other financing costs. Any transfer, sale, conveyance, assignment, grant of a security interest in or pledge of energy transition property by a public utility, or an affiliate of the public utility, to an assignee, to the extent previously authorized in a financing order, does not require the prior consent and approval of the Commission.

d. If a public utility defaults on any required payment of charges arising from energy transition property specified in a financing order, a court, 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 the energy transition property to the financing parties or their assignees. Any such financing order remains in full force and effect notwithstanding any reorganization, bankruptcy, or other insolvency proceedings with respect to the public utility or its successors or assignees.

e. The interest of a transferee, purchaser, acquirer, assignee, or pledgee in energy transition property specified in a financing order issued to a public utility, and in the revenue and collections arising from that property, is not subject to setoff, counterclaim, surcharge, or defense by the public utility or any other person or in connection with the reorganization, bankruptcy, or other insolvency of the public utility or any other entity.

f. Any successor to a public utility, whether pursuant to any reorganization, bankruptcy, or other insolvency proceeding or whether pursuant to any merger or acquisition, sale, or other business combination, or transfer by operation of law, as a result of public utility restructuring or otherwise, must perform and satisfy all obligations of, and have the same rights under a financing order as, the public utility under the financing order in the same manner and to the same extent as the public utility, including collecting and paying to the person entitled to receive the revenues, collections, payments, or proceeds of the energy transition property. Nothing in this sub-subdivision is intended to limit or impair any authority of the Commission concerning the transfer or succession of interests of public utilities.

g. Energy transition bonds shall be nonrecourse to the credit or any assets of the public utility other than the energy transition property as specified in the financing order and any rights under any ancillary agreement.

(2) Provisions applicable to security interests. –

a. The creation, perfection, and enforcement of any security interest in energy transition property to secure the repayment of the principal and interest and other amounts payable in respect of energy transition bonds; amounts payable under any ancillary agreement and other financing costs are governed by this subsection and not by the provisions of the Code.

b. A security interest in energy transition property is created, valid, and binding and perfected at the later of the time: (i) the financing order is issued, (ii) a security agreement is executed and delivered by the debtor granting such security interest, (iii) the debtor has rights in such energy transition property or the power to transfer rights in such energy transition property, or (iv) value is received for the energy transition property. The description of energy transition property in a security agreement is sufficient if the description refers to this section and the financing order creating the energy transition property.

c. A security interest shall attach without any physical delivery of collateral or other act, and, upon the filing of a financing statement with the office of the Secretary of State, the lien of the security interest shall be valid, binding, and perfected against all parties having claims of any kind in tort, contract, or otherwise against the person granting the security interest, regardless of whether the parties have notice of the lien. Also upon this filing, a transfer of an interest in the energy transition property shall be perfected against all parties having claims of any kind, including any judicial lien or other lien creditors or any claims of the seller or creditors of the seller, and shall have priority over all competing claims other than any prior security interest, ownership interest, or assignment in the property previously perfected in accordance with this section.

d. The Secretary of State shall maintain any financing statement filed to perfect any security interest under this section in the same manner that the Secretary maintains financing statements filed by transmitting utilities under the Code. The filing of a financing statement under this section shall be governed by the provisions regarding the filing of financing statements in the Code.

e. The priority of a security interest in energy transition property is not affected by the commingling of energy transition charges with other amounts. Any pledgee or secured party shall have a perfected security interest in the amount of all energy transition charges that are deposited in any cash or deposit account of the qualifying utility in which energy transition charges have been commingled with other funds and any other security interest that may apply to those funds shall be terminated when they are transferred to a segregated account for the assignee or a financing party.

f. No application of the formula-based adjustment mechanism as provided in this section will affect the validity, perfection, or priority of a security interest in or transfer of energy transition property.

g. If a default or termination occurs under the energy transition bonds, the financing parties or their representatives may foreclose on or otherwise enforce their lien and security interest in any energy transition property as if they were secured parties with a perfected and prior lien under the Code, and the Commission may order amounts arising from energy transition charges be transferred to a separate account for the financing parties' benefit, to which their lien and security interest shall apply. On application by or on behalf of the financing parties, the Superior Court of Wake County shall order the sequestration and payment to them of revenues arising from the energy transition charges.

(3) Provisions applicable to the sale, assignment, or transfer of energy transition property. –

a. Any sale, assignment, or other transfer of energy transition property shall be an absolute transfer and true sale of, and not a pledge of or secured transaction relating to, the seller's right, title, and interest in, to, and under the energy transition property if the documents governing the transaction expressly state that the transaction is a sale or other absolute transfer other than for federal and State income tax purposes. For all purposes other than federal and State income tax purposes, the parties' characterization of a transaction as a sale of an interest in energy transition property shall be conclusive that the transaction is a true sale and that ownership has passed to the party characterized as the purchaser, regardless of whether the purchaser has possession of any documents evidencing or pertaining to the interest. A transfer of an interest in energy transition property may be created only when all of the following have occurred: (i) the financing order creating the energy transition property has become effective, (ii) the documents evidencing the transfer of energy transition property have been executed by the assignor and delivered to the assignee, and (iii) value is received for the energy transition property. After such a transaction, the energy transition property is not subject to any claims of the transferor or the transferor's creditors, other than creditors holding a prior security interest in the energy transition property perfected in accordance with subdivision (2) of subsection (e) of this section.

b. The characterization of the sale, assignment, or other transfer as an absolute transfer and true sale and the corresponding characterization of the property interest of the purchaser, shall not be affected or impaired by the occurrence of any of the following factors:

1. Commingling of energy transition charges with other amounts.
2. The retention by the seller of (i) a partial or residual interest, including an equity interest, in the energy transition 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 energy transition charges.
3. Any recourse that the purchaser may have against the seller.
4. Any indemnification rights, obligations, or repurchase rights made or provided by the seller.
5. The obligation of the seller to collect energy transition charges on behalf of an assignee.
6. The transferor acting as the servicer of the energy transition charges or the existence of any contract that authorizes or requires the public utility, to the extent that any interest in energy transition 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, will collect amounts in respect of the energy transition charges 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. The granting or providing to bondholders a preferred right to the energy transition property or credit enhancement by the public utility or its affiliates with respect to such energy transition bonds.
9. Any application of the formula-based adjustment mechanism as provided in this section.

c. Any right that a public utility has in the energy transition property before its pledge, sale, or transfer or any other right created under this section or created in the financing order and assignable under this section or assignable pursuant to a financing order is property in the form of a contract right or a chose in action. Transfer of an interest in energy transition property to an assignee is enforceable only upon the later of

(i) the issuance of a financing order, (ii) the assignor having rights in such energy transition property or the power to transfer rights in such energy transition property to an assignee, (iii) the execution and delivery by the assignor of transfer documents in connection with the issuance of energy transition bonds, and (iv) the receipt of value for the energy transition property. An enforceable transfer of an interest in energy transition property to an assignee is perfected against all third parties, including subsequent judicial or other lien creditors, when a notice of that transfer has been given by the filing of a financing statement in accordance with sub-subdivision c. of subdivision (2) of this subsection. The transfer is perfected against third parties as of the date of filing.

d. The Secretary of State shall maintain any financing statement filed to perfect any sale, assignment, or transfer of energy transition property under this section in the same manner that the Secretary maintains financing statements filed by transmitting utilities under the Code. The filing of any financing statement under this section shall be governed by the provisions regarding the filing of financing statements in the Code. The filing of such a financing statement is the only method of perfecting a transfer of energy transition property.

e. The priority of a transfer perfected under this section is not impaired by any later modification of the financing order or energy transition property or by the commingling of funds arising from energy transition property with other funds. Any other security interest that may apply to those funds, other than a security interest perfected under subdivision (2) of this subsection, is terminated when they are transferred to a segregated account for the assignee or a financing party. If energy transition property has been transferred to an assignee or financing party, any proceeds of that property must be held in trust for the assignee or financing party.

f. The priority of the conflicting interests of assignees in the same interest or rights in any energy transition property is determined as follows:

1. Conflicting perfected interests or rights of assignees rank according to priority in time of perfection. Priority dates from the time a filing covering the transfer is made in accordance with sub-subdivision c. of subdivision (2) of this subsection.
2. A perfected interest or right of an assignee has priority over a conflicting unperfected interest or right of an assignee.
3. A perfected interest or right of an assignee has priority over a person who becomes a lien creditor after the perfection of such assignee's interest or right.

(f) Description or Indication of Property. – The description of energy transition property being transferred to an assignee in any sale agreement, purchase agreement, or other transfer agreement, granted or pledged to a pledgee in any security agreement, pledge agreement, or other security document, or indicated in any financing statement is only sufficient if such description or indication refers to the financing order that created the energy transition property and states that the agreement or financing statement covers all or part of the property described in the financing order. This section applies to all purported transfers of, and all purported grants or liens or security interests in, energy transition property, regardless of whether the related sale agreement, purchase agreement, other transfer agreement, security agreement, pledge agreement, or other security document was entered into, or any financing statement was filed.

(g) Financing Statements. – All financing statements referenced in this section are subject to Part 5 of Article 9 of the Code, except that the requirement as to continuation statements does not apply.

(h) Choice of Law. – The law governing the validity, enforceability, attachment, perfection, priority, and exercise of remedies with respect to the transfer of an interest or right or the pledge or creation of a security interest in any energy transition property shall be the laws of this State.

(i) Energy transition Bonds Not Public Debt. – Neither the State nor its political subdivisions are liable on any energy transition bonds, and the bonds are not a debt or a general obligation of the State or any of its political subdivisions, agencies, or instrumentalities, nor are they special obligations or indebtedness of the State or any agency or political subdivision. An issue of energy transition bonds does not, directly, indirectly, or contingently, obligate the State or any agency, political subdivision, or instrumentality of the State to levy any tax or make any appropriation for payment of the energy transition bonds, other than in their capacity as consumers of electricity. All energy transition bonds must contain on the face thereof a statement to the following effect: "Neither the full faith and credit nor the taxing power of the State of North Carolina is pledged to the payment of the principal of, or interest on, this bond."

(j) Legal Investment. – All of the following entities may legally invest any sinking funds, moneys, or other funds in energy transition bonds:

(1) Subject to applicable statutory restrictions on State or local investment authority, the State, units of local government, political subdivisions, public bodies, and public officers, except for members of the Commission.

(2) Banks and bankers, savings and loan associations, credit unions, trust companies, savings banks and institutions, investment companies, insurance companies, insurance associations, and other persons carrying on a banking or insurance business.

(3) Personal representatives, guardians, trustees, and other fiduciaries.

(4) All other persons authorized to invest in bonds or other obligations of a similar nature.

(k) Obligation of Nonimpairment. –

(1) The State and its agencies, including the Commission, pledge and agree with bondholders, the owners of the energy transition property, and other financing parties that the State and its agencies will not take any action listed in this subdivision. This paragraph does not preclude limitation or alteration if full compensation is made by law for the full protection of the energy transition charges collected pursuant to a financing order and of the bondholders and any assignee or financing party entering into a contract with the public utility. The prohibited actions are as follows:

a. Alter the provisions of this section, which authorize the Commission to create an irrevocable contract right or chose in action by the issuance of a financing order, to create energy transition property, and make the energy transition charges imposed by a financing order irrevocable, binding, or nonbypassable charges.

b. Take or permit any action that impairs or would impair the value of energy transition property or the security for the energy transition bonds or revises the energy transition costs for which recovery is authorized.

c. In any way impair the rights and remedies of the bondholders, assignees, and other financing parties.

d. Except for changes made pursuant to the formula-based adjustment mechanism authorized under this section, reduce, alter, or impair energy transition 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 energy transition bonds have been paid and performed in full.

(2) Any person or entity that issues energy transition bonds may include the language specified in this subsection in the energy transition bonds and related documentation.

(l) Not a Public Utility. – An assignee or financing party is not a public utility or person providing electric service by virtue of engaging in the transactions described in this section.

(m) Conflicts. – If there is a conflict between this section and any other law regarding the attachment, assignment, or perfection, or the effect of perfection, or priority of, assignment or transfer of, or security interest in energy transition property, this section shall govern.

(n) Consultation. – In making determinations under this section, the Commission or public staff or both may engage an outside consultant and counsel.

(o) Effect of Invalidity. – If anyprovision of this section is held invalid or is invalidated, superseded, replaced, repealed, or expires for any reason, that occurrence does not affect the validity of any action allowed under this section which is taken by a public utility, an assignee, a financing party, a collection agent, or a party to an ancillary agreement; and any such action remains in full force and effect with respect to all energy transition bonds issued or authorized in a financing order issued under this section before the date that such provision is held invalid or is invalidated, superseded, replaced, or repealed, or expires for any reason."

(p) **Conditions for selecting replacement capacity and energy [DISCLAIMER: This section received support by the majority, but not by all NERP participants.]**

(1) the public utility shall employ a competitive bidding process, approved by the commission as to its structure, to procure energy resources required to fill the resource need resulting from the closure of generating facilities under this Section.

(2) The Commission may permit the utility or its affiliates to compete in the bidding process and own a portion of the replacement resources, including associated infrastructure, if the Commission finds –

a. The utility bids were evaluated in the same manner as other bids;
b. the cost of utility or affiliate ownership of the replacement resources is reasonable and is the least cost choice, with an acceptable rate impact; and
c. that utility ownership of replacement resources is necessary to assure the utility's financial health.

(3) Utility ownership may consist of utility or affiliate self-builds, build-transfers from independent power producers, or sales of existing assets from independent power producers or similar commercial arrangements.

(4) In determining whether to approve proposed replacement resources, the Commission shall consider –

a. the risk that future federal environmental regulations could increase the life-cycle cost of the resource and create future stranded assets; and

b. whether the proposed replacement resources support the state's energy goals, as expressed by the governor and the legislature.

SECTION 2. G.S. 25-9-109(d) reads as rewritten:

"(d) Inapplicability of Article. – This Article does not apply to:

…

(13) An assignment of a deposit account in a consumer transaction, but G.S. 25-9-315 and G.S. 25-9-322 apply with respect to proceeds and priorities in proceeds; ~~or~~

(14) The creation, perfection, priority, or enforcement of any lien on, assignment of, pledge of, or security in, any revenues, rights, funds, or other tangible or intangible assets created, made, or granted by this State or a governmental unit in this State, including the assignment of rights as secured party in security interests granted by any party subject to the provisions of this Article to this State or a governmental unit in this State, to secure, directly or indirectly, any bond, note, other evidence of indebtedness, or other payment obligations for borrowed money issued by, or in connection with, installment or lease purchase financings by, this State or a governmental unit in this State. However, notwithstanding this subdivision, this Article does apply to the creation, perfection, priority, and enforcement of security interests created by this State or a governmental unit in this State in equipment or fixtures; ~~or~~

(15) The creation, perfection, priority, or enforcement of any sale, assignment of, pledge of, security interest in, or other transfer of, any interest or right or portion of any interest or right in any storm recovery property as defined G.S. 62-172;

"or

(16) The creation, perfection, priority, or enforcement of any sale, assignment of, pledge of, security interest in, or other transfer of, any interest or right or portion of any interest or right in any energy transition property as defined G.S. 62-173."

SECTION 3. This act is effective when it becomes law.

Competitive Procurement

Study Group Work Products

2020 NC Energy Regulatory Process

Contents of this packet:

1. Competitive Procurement Regulatory Guidance
2. Case Study: Colorado Electric Resource Plan
3. Case Study: Virginia Clean Economy Act Generation Procurement

COMPETITIVE PROCUREMENT GUIDANCE DOCUMENT

COMPETITIVE PROCUREMENT POLICY GUIDANCE ADDRESSED TO THE NCUC FROM THE NORTH CAROLINA ENERGY REGULATORY PROCESS

AUTHORS & ACKNOWLEDGMENTS

STUDY GROUP MEMBERS

Jack Jirak, Duke Energy, co-chair
Steve Levitas, NCCEBA, co-chair
Charles Bayless, NC Electric Cooperatives
Chris Carmody, NCCEBA, group chair
Marshall Conrad, NC General Assembly
Peter Daniel, NC Chamber of Commerce
Drew Elliot, ElectriCities of North Carolina
Paula Hemmer, Dept. of Environmental Quality
Preston Howard, NC Manufacturers Alliance
Stephen Kalland, NC Clean Energy Technology Center
Peter Ledford, NCSEA
Kevin Martin, Carolina Utility Customer Association
Sushma Masemore, Dept. of Environmental Quality
Rory McIlmoil, Appalachian Voices
Sally Robertson, NC Warn
David Rogers, Sierra Club
Will Scott, NC Conservation Network
Jeff Thomas, NCUC Public Staff
Peter Toomey, Duke Energy

CONTACTS

Jack Jirak, Duke Energy, co-chair
Steve Levitas, NCCEBA, co-chair

ACKNOWLEDGMENTS

The authors thank the following individuals/organizations for offering their insights and perspectives on this work.

Laura Bateman, Duke Energy
Josh Brooks, Rocky Mountain Institute
Kendal Bowman, Duke Energy
Dan Cross-Call, Rocky Mountain Institute
Matthew Davis, NC Dept. of Environmental Quality
Max Dupey, Regulatory Assistance Project
Heather House, Rocky Mountain Institute
Jessica Shipley, Regulatory Assistance Project
Lauren Shwisberg, Rocky Mountain Institute
Kim Smith, Duke Energy
Matt Wasson, Appalachian Voices

This work was last updated on 12/21/2020.

Cover image courtesy of GYPSY FROM NOWHERE IMAGES/ALAMY STOCK PHOTO

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

The Competitive Procurement Subcommittee has evaluated a number of competitive procurement models across the country. Ultimately, the recent procurement cycle in Colorado for the Public Service Company of Colorado (Xcel Energy), offered a good example of a successful generation procurement framework. Based on such review, the Subcommittee supports the following policy recommendations details.

TABLE OF CONTENTS

INTRODUCTION

Purpose

The purpose of this document is to communicate the findings of the NC Energy Regulatory Process (NERP) to the NC General Assembly and the NC Utilities Commission (NCUC), as the NCUC may determine it appropriate to consider competitive solicitations as an important tool to meet energy and capacity needs identified in an IRP.

The Competitive Procurement Subcommittee evaluated issues related to the use of competitive processes to meet demands of the recent procurement cycle in Colorado for the Public Service Company of Colorado (Xcel Energy). The Subcommittee determined the PSCo offered a good example of a successful generation procurement framework. Based on such review, the Subcommittee supports the following policy recommendations.

NERP Recommendations

Subject to the more detailed policy recommendations below, NERP has identified competitive solicitations as an important tool that should be utilized to meet energy and capacity needs identified in an IRP and as otherwise deemed appropriate by the North Carolina Utilities Commission ("Commission").

NERP also holds that State policy regarding utility competitive procurement should take into account unique characteristics of each utility service territory, e.g., number of customers, geographic size, amount of utility-owned generation in the service territory, and proportion of existing generation from renewable sources located in the service territory and serving utility customers.

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*.[i] The Order established the North Carolina Climate Change Interagency Council and tasked the Department of Environmental Quality (DEQ) with producing a clean energy plan.

DEQ convened a group of stakeholders that met throughout 2019. In October 2019, DEQ released the *North Carolina Clean Energy Plan: Transitioning to a 21 Century Electricity System* (CEP).[ii] 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.

[i] Executive Order 80. https://governor.nc.gov/documents/executive-order-no-80-north-carolinas-commitment-address-
[ii] NC Dept. of Environmental Quality. "North Carolina Clean Energy Plan"
https://files.nc.gov/governor/documents/files/NC_Clean_Energy_Plan_OCT_2019_.pdf

NERP

The NERP, 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

These stakeholders identified ten desired outcomes of reform in North Carolina, as shown below in Figure 1.

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

Competitive Procurement Study Group

A subset of NERP participants volunteered to serve on a competitive procurement subcommittee. This group (see page 2 for a list of groups members) first met in the summer of 2020. The group met regularly to advance research into competitive markets mechanisms relevant to NC.

The study group presented a series of case studies and recommendations to the broader NERP group, detailing the potential implications of each market reform, and why further investigation into each reform is warranted. Feedback from NERP participants shaped the proposed markets outlined below.

NERP companion documents

NERP produced the following documents for dissemination, to inform subsequent policy discussions with various audiences:

1. ***Competitive Procurement Policy Recommendation for*** the North Carolina General Assembly:
    - An overall policy recommendation which, subject to the more detailed recommendations outlined in the document, states that competitive solicitations are an important tool that should be utilized to meet energy and capacity needs identified in an IRP and as otherwise deemed appropriate by the North Carolina Utilities Commission.

2. ***A Case Study into The Public Service Company of Colorado's Recent Procurement Cycle:***
    - The subcommittee evaluated a number of other states but focused primarily on a recent procurement cycle in Colorado for the Public Service Company of Colorado (Xcel Energy), which was ultimately determined to be a successful generation procurement framework.

3. ***A Case Study into Key Generation Procurements Enacted by the Virginia Clean Economy Act:***
    - The summary outlines the sweeping package of energy reforms established in March 2020 that set Virginia on a path toward a 100% carbon-free electricity grid by 2050.

DETAILED POLICY RECOMMENDATIONS

General principles

1. Competitive solicitations benefit customers by ensuring the most cost-effective generation resources are selected.
    a. Except where other policy considerations give rise to the need for resource-specific solicitations (as discussed further below), competitive generation solicitations should permit participation from all resources that satisfy the operational, reliability and other requirements sought in the RFP.
    b. Except where otherwise directed by statute, the Utility that is responsible for maintaining reliability should be also be responsible for defining the necessary operational, reliability and other requirements. It may be appropriate to require Commission oversight or approval of such parameters.

2. Independent oversight or administration should be utilized for all competitive generation procurement.
    a. The exact parameters of the independent oversight or administration may vary depending on the nature of the procurement.

3. In all competitive generation procurements, communications and separation protocols similar to CPRE should be implemented.

4. Consistent with the policy direction of numerous other states, there is value in diversity of generation ownership. A mixture of third-party ownership and utility rate-based ownership diversifies risk for customers and provides a variety of benefits.
    a. The appropriate allocation between utility and third-party ownership should be determined based on the particular context of the procurement and/or the type of generation resource.

b. It may be appropriate to determine the allocation between utility and third-party ownership on a technology-specific basis (*i.e.*, percentage allocations differ between solar, wind, storage, and gas).
c. Utility-owned, rate-based assets should be procured through competitive processes to ensure the most cost-effective resources are selected.
    - Maximum flexibility should be provided for such RFP and should allow for bids involving (A) sale of constructed assets, (B) Build Own Transfer ("BOT"), and (C) sale of development assets plus EPC.
d. Where a particular utility ownership target is established, it is generally preferable to procure utility-owned and rate-based assets through separate "silos."
e. No clear quantifiable basis for the allocation has been identified to date but parties should continue to work to identify quantitatively and qualitative factors that may inform the allocation, including (1) the potential loss of investment opportunity that might occur as a result of early retirement of coal assets and the potential need for replacement generation (depending on the nature of the cost recovery for any remaining NBV), (2) the examples of other states, or (3) impacts of any alternative ratemaking constructs.[iii]
f. Where the utility receives a significant ownership allocation, it may be reasonable and appropriate not to allow it and its affiliates to participate in the PPA procurement silo. In addition to creating equity between the utility and independent power producers, this would simplify oversight of the PPA procurement process.

5. A formal RFP should not be required in the case of uniquely advantageous opportunities, unexpected emergencies, pilot projects, or other circumstances identified by the Commission.

6. The appropriateness of utilizing an avoided price cost cap or other cost effectiveness parameters in the RFP evaluation process should be evaluated on a case-by-case basis to determine whether necessary in light of the nature or context of the RFP.

7. It may be appropriate to consider financial incentives to the utility in connection with third party PPAs in order to foster diversity of generation ownership.

8. Any state policy regarding utility competitive procurement should take into account unique characteristics of each utility service territory, e.g., number of customers, geographic size, amount of utility-owned generation in the service territory, and proportion of existing generation from renewable sources located in the service territory and serving utility customers.

Competitive Generation Procurement in Specific Scenarios

1. Competitive Solicitation: Connection between IRP – RFP

a. In the event that a specific capacity or energy need is identified in any IRP, such need should be filled through an all-source RFP that clearly defines the operational and other characteristics of the needed resource absent any unique circumstance as discussed above.

[iii] Examples:
- Colorado (Xcel) 2017 RFP: 50/50 split for renewable resources and 75/25 (utility/third party) split for dispatchable and semi-dispatchable resources to be added. Utility-owned assets are rate-based.
- Virginia (Dominion) Clean Energy Act: CEA provides for utility ownership of up to 75% utility ownership for solar and 65% for storage (and potentially up to 100%) by 2035. CEA enables Dominion to own 100% offshore wind (5.2GW by 2035) by demonstrating LCOE<1.4x that of gas. Utility-owned assets are rate-based.
- New Mexico (PNM) 2017 RFP: PNM owned 46% nameplate capacity of preferred portfolio from 2017 RFP. Utility-owned assets are rate-based.
- Michigan (CMS) 2019 RFP: Procurement split 50/50 between PPA and BTA utility-ownership. Utility-owned assets are rate-based.

b. The inputs and assumptions for any such RFP should be generally consistent with the most recent IRP but with updates as appropriate to reflect changing conditions.
c. It may be appropriate for the Commission to pre-approve inputs and other modeling assumption to be used in the evaluations.

2. Competitive Solicitation: Potential Coal Retirements

a. If determined to be reasonable as part of an IRP, the Commission should direct the utility to conduct one or more all source RFPs to assess whether particular coal units can be retired in a cost-effective manner (after accounting for recovery of the remaining NBV of such units in a manner deemed appropriate) through the procurement of replacement generation.

3. Competitive Solicitation: Future Clean Energy Standard or Renewable Energy Target

b. If future legislation or regulatory changes requires the procurement of additional renewable or low-carbon resources in order to comply with particular policy mandates or directives, resource-specific or otherwise more tailored competitive procurements may be needed.

NERP recommendations

NERP recommends that the North Carolina General Assembly expand existing procurement practices to utilize competitive procurement as a tool for State electric utilities to meet energy and capacity needs defined in their respective IRPs and where otherwise deemed appropriate by the NCUC.

NERP recommends that state policy regarding utility competitive procurement should take into account unique characteristics of each utility service territory, e.g., number of customers, geographic size, amount of utility-owned generation in the service territory, and proportion of existing generation from renewable sources located in the service territory and serving utility customers.

Competitive Procurement Outputs

NERP recommends that the North Carolina General Assembly expand existing procurement practices to utilize competitive procurement as a tool for State electric utilities to meet energy and capacity needs defined in their respective IRPs and where otherwise deemed appropriate by the NCUC.

a. Competitive procurement policy recommendation for the North Carolina General Assembly: An overall policy recommendation which, subject to the more detailed recommendations outlined in the document, states that competitive solicitations are an important tool that should be utilized to meet energy and capacity needs identified in an IRP and as otherwise deemed appropriate by the North Carolina Utilities Commission.
b. A case study into the Public Service Company of Colorado’s recent procurement cycle:
c. A case study into key generation procurements enacted by the Virginia Clean Economy Act: The summary outlines the sweeping package of energy reforms established in March 2020 that set Virginia on a path toward a 100% carbon-free electricity grid by 2050.

CONCLUSION

To summarize, NERP recommends that the North Carolina General Assembly expand existing procurement practices to utilize competitive procurement as a tool for State electric utilities to meet energy and capacity needs defined in their respective IRPs and where otherwise deemed appropriate by the NCUC.
the General Assembly of North Carolina direct the NCUC.

NERP produced the following documents for dissemination, to inform subsequent policy discussions with various audiences:

1. Competitive procurement policy recommendation for the North Carolina General Assembly: An overall policy recommendation which, subject to the more detailed recommendations outlined in the document, states that competitive solicitations are an important tool that should be utilized to meet energy and capacity needs identified in an IRP and as otherwise deemed appropriate by the North Carolina Utilities Commission.

2. A case study into the Public Service Company of Colorado's recent procurement cycle,

3. The subcommittee evaluated a number of other states but focused primarily on a recent procurement cycle in Colorado for the Public Service Company of Colorado (Xcel Energy), which was ultimately determined to be a successful generation procurement framework.

4. A case study into key generation procurements enacted by the Virginia Clean Economy Act: The summary outlines the sweeping package of energy reforms established in March 2020 that set Virginia on a path toward a 100% carbon-free electricity grid by 2050.

Members of this NERP stakeholder group will continue to collaborate in early 2021 to assist the State and parties interested in the work conducted by this group.

APPENDIX

The following documents were prepared by the competitive procurement study committee to supplement this guidance document.

- Colorado electric resource plan case study
- Virginia clean economy act generation procurement case study

NERP CASE STUDY

COLORADO ELECTRIC RESOURCE PLAN

A CASE STUDY PRODUCED BY THE COMPETITIVE PROCUREMENT STUDY GROUP

The 2020 North Carolina Energy Regulatory Process identified competitive solicitations as an important tool that should be utilized to meet energy and capacity needs

WHAT ARE COMPETITIVE SOLICITATIONS?

NERP has defined competitive procurement as an Integrated Resource Plan (IRP) -driven, all-source procurement to meet all identified needs for new resources in a manner that is consistent with policy directives and at the best available overall price.

WHAT IS THE COLORADO ELECTRIC RESOURCE PLAN?

- Similar to the IRP process in NC, the electric resource plan (ERP) is how the Public Service Company of Colorado (Xcel Energy, or, referred to as PSCo) forecast and plan to meet customer needs.[1]

- Key provisions include ensuring power reliability, cost effective power delivery, increasing clean energy generation, planning for a grid flexibility, and supporting Colorado's energy and economic needs.

OVERVIEW

The Public Service Company of Colorado's (PSCo) request for proposals process (RFP) is inextricably linked to PSCo's (ERP). Therefore, the RFP process must be understood within the context of the overall ERP. This includes broader policy issues and consensus stipulation informing both the design of the RFP and the selection of generation resources.

The Subcommittee evaluated a number of states but focused primarily on the recent procurement cycle in Colorado for the Public Service Company of Colorado (Xcel Energy), as the Subcommittee viewed it as a good example of a successful generation procurement framework. The timeline and process of the 2017 ERP/RFP process is outlined below:

1. **Phase 1 Decision**
2. **Stipulation**
3. **Phase 2 Decision**

Following the process details, the subcommittee outlines a list of key items of relevance to NERP stakeholders and the NC community.

[1] https://www.xcelenergy.com/staticfiles/xe/PDF/Electric%20Resource%20Plan%20Fact%20Sheet.pdf

PSCo ERP Fact Sheet: 12/18/2020

PROCESS TIMELINE AND KEY DETAILS

1. **Phase 1 Decision – April 28, 2017**

   a. Approved two resource scenarios (0 MW resource need and second scenario showing approximately 400 MW of need based on updated load forecast)
      i These two resource scenarios drove the structure of the RFP

   b. Approved evaluation methodology, including the inputs and assumptions to bid evaluation models (e.g., natural gas prices, coal prices, carbon costs, discount rates, and integration costs for intermittent resources).
      i Importantly, Colorado commission approved use of carbon price for modeling purposes.

   c. Confirmed IE's role which was primarily:
      i Provide a report to the Commission, containing an analysis of whether Public Service conducted a fair bid solicitation and bid evaluation process, with any deficiencies specified in the report.
      ii Review the inputs and outputs from the bid evaluation modeling, including in the report an assessment as to whether the resulting outputs are feasible, and alerting the Commission and parties through the report where there may be deficiencies in the outputs.

2. **Stipulation – August 29, 2017**
   a. Stipulation reached between PSCo and diverse set of stakeholders.

   b. Specified that PS would model a third resource scenario—the CEP Portfolio, which involves retirement of two coal units (Comanche 1 and 2).
      i The Company would compare the costs of the CEP Portfolio against a baseline portfolio, where Comanche 1 and 2 are not retired early, to determine the cost-effectiveness of the CEP Portfolio.
         - If the CEP Portfolio keeps customers "neutral" or results in savings for customers on a present value basis, the Stipulation proposed that Public Service would present the CEP Portfolio(s) in its ERP Phase II 120-Day Report.

   c. Stipulation specified utility ownership of a portion of resources.
      i 50% of the renewable resources to be added, and 75% of the dispatchable and semi-dispatchable resources to be added.
      ii PS Co also agreed not to bid into the CEP any new self-build projects other than for gas-fired projects.

WHY ISSUE AN RFP?

1. **Identified Capacity/Energy**
   a. Colorado had a potential identified capacity/energy need based solely on project load growth and an alternative capacity/energy need based on potential coal retirement (CEP Portfolio from Stipulation)

> **Discussion Item:**
> *Should future RFPs be designed to test the market to see whether new generation could be procured to cost-effectively replace particular coal generation?*

   b. Comparison to IRP/CPRE:
      i Duke IRP does not lead directly into RFP where resource need is identified.
      ii CPRE procurements were not tied to IRP.

2. **Targeted Renewable Amounts - CPRE / REPs approach.**

> **Discussion Item:**
> *What is the regulatory/policy basis for any targeted amounts apart from identified need?*

3. **Is there flexibility for the utility in unique situations?**
   a. Colorado ERP rules provide flexibility to the utility if competitive solicitation process is perhaps not needed in unique situations. (See 4 CCR 723-3(g)(II)(A)-(B)).

STRUCTURE OF RFP MECHANICS

1. **What is the role of the IE?**
   a. Comparison to CPRE:
      i Role of IE in Colorado RFP was substantially different than role of IA in CPRE
         - Utility was primarily responsible for defining technical needs, structuring evaluation methodology (subject to Commission approval) and performing evaluation of bids
         - The IE provided oversight, vetted evaluation models and tested results.

   b. Communication restrictions:
      i Comparison to CPRE: Separation Protocols were consistent with CPRE with the exception of evaluation issues.

STRUCTURE OF RFP MODELING

1. Avoided Cost Caps

> **Discussion Item:**
>
> *In what types of RFPs does it make sense to utilize avoided cost cap?*

a. Comparison to CPRE:
   i No avoided cost cap used because resources were being procured to replace existing generation.

b. Does the analysis assume a carbon cost?
   i Colorado ERP regulations permitted inclusion of carbon cost in analysis (4 CCR 723-3(g)(III)(C)(i)).

> **Discussion Item:**
>
> *Is NCUC or General Assembly authorization required for future RFP to assume carbon price during selection?*

c. In the case of consideration of early retirement, what assumptions are made about future revenue requirements?

UTILITY OWNERSHIP

1. Colorado stipulation, agreed to by diverse set of stakeholders, contemplated 50% utility, rate-based ownership of renewable resources and 75% utility, rate-based ownership of dispatchable resources (gas/storage).

2. Colorado Commission expressly recognized benefits of balance of utility-ownership and third-party ownership (consistent with past precedent).

3. Allowed for rate-base recovery of utility-owned assets.

WHAT IS BEING RECOMMENDED?

The North Carolina Energy Regulatory Process recommends that the North Carolina General Assembly expand existing procurement practices to utilize competitive procurement as a tool for State electric utilities to meet energy and capacity needs defined in their respective IRPs and where otherwise deemed appropriate by the NCUC.

NERP recommends that state policy regarding utility competitive procurement should take into account unique characteristics of each utility service territory, e.g., number of customers, geographic size, amount of utility-owned generation in the service territory, and proportion of existing generation from renewable sources located in the service territory and serving utility customers.

NERP produced the following documents for dissemination, to inform subsequent policy discussions with various audiences:

1. Competitive procurement policy recommendation for the North Carolina General Assembly.

2. A case study into key generation procurements enacted by the Virginia Clean Economy Act.

3. This case study into the PSCo recent procurement cycle

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 Competitive Procurement Committee Leads:
Jack Jirak, Duke Energy, Jack.Jirak@duke-energy.com
Steve Levitas, NCCEBA, slevitas@pgrenewables.com

Access the NERP summary report and other NERP documents at:
https://deq.nc.gov/CEP-NERP

NERP CASE STUDY

VIRGINIA CLEAN ECONOMY ACT GENERATION PROCUREMENT

A CASE STUDY PRODUCED BY THE COMPETITIVE PROCUREMENT STUDY GROUP

The 2020 North Carolina Energy Regulatory Process identified competitive solicitations as an important tool that should be utilized to meet energy and capacity needs

WHAT ARE COMPETITIVE SOLICITATIONS?

NERP has defined competitive procurement as an Integrated Resource Plan (IRP) -driven, all-source procurement to meet all identified needs for new resources in a manner that is consistent with policy directives and at the best available overall price.

WHAT IS THE VIRGINIA CLEAN ECONOMY ACT?

- On March 5, 2020, the Virginia legislature passed the Virginia Clean Economy Act ("VCEA"), a sweeping package of energy legislation that sets Virginia on a path toward a 100% carbon-free electricity grid by 2050.[1]
- The following is a summary of the key generation procurement elements of the VCEA.

OVERVIEW

1. Renewable Portfolio Standard ("RPS") mandating 100% renewable energy by 2045 for Dominion Energy with, annual increases of 3%-4% per year according to a defined schedule, including the following (Va. Code § 56-585.5(C)):
    - 14% by 2021
    - 41% by 2030
    - 59% by 2035
    - 79% by 2040
    - 100% by 2045
2. Beginning 2025 and thereafter, at least 75% of all RECs used by Dominion Energy in a compliance period shall come from RPS eligible resources located in Virginia. (Va. Code § 56-585.5(C)).
3. Not primarily cost-based. Mandatory RPS paired with obligation for Dominion Energy to retire nearly all coal units by 2024 and all carbon-emitting power plants by 2045 (Va. Code § 56-585.5(B)(1) and (3)).

[1]https://lis.virginia.gov/cgi-bin/legp604.exe?201+sum+HB1526

PROCUREMENT DIRECTIVES

Layered on top of the RPS are the following specific statutory generation procurement directives:

1. **<u>Overview</u>**
   a. Appalachian Power Company must procure 600 MW of solar or onshore wind located in Virginia by Dec. 31, 2030. (*Va. Code § 56-585.5(D)(1))*

   b. Dominion Energy must procure 16,100 MW of solar or onshore wind located in Virginia by Dec. 31, 2035 (*Va. Code § 56-585.5(D)(2)*):
      i. Must include 1,100 megawatts of solar generation of a small projects (less than 3 MW).

   c. Construction or purchase by a public utility of one or more offshore wind facilities with an aggregate capacity of up to 5,200 MW off Virginia's Atlantic shorelines of in federal waters and interconnected into Virginia is predetermined to be in the public interest (*Va. Code § 56-585.1:11(B)*).

   d. Construction by Dominion Energy of one or more new utility-owned and utility operated offshore wind facilities located off Virginia's Atlantic shoreline of between 2,500 – 3,000 MW predetermined to be in the public interest. (*Va. Code § 56-585.1:11(C)(1)*).
      i. Cost cannot exceed 1.4 times the comparable cost, on an unweighted average basis, of a conventional simple cycle combustion turbine generating facility as estimated by the U.S. Energy Information Administration in its Annual Energy Outlook 2019; and must either commence construction prior to 2024 or have a plan to be placed in service prior to January 1, 2028. (*Va. Code § 56-585.1:11(C)(1)*).

   e. Appalachian Power Company must construct or acquire energy storage projects up to 400 MW by 2035 (*Va. Code § 56-585.5(E)(1)*).

   f. Dominion Energy must construct or acquire energy storage projects up to 2,700 MW by 2035. (*Va. Code § 56-585.5(E)(2)*).
      i. Public interest finding for up to 2,700 MW of energy storage facilities located in Virginia. (*Va. Code § 56-585.1:4)*

2. **<u>Ownership Allocation</u>**
   a. **Solar or Onshore Wind:** 35% third party ownership and 65% utility ownership (*Va. Code §56-585.5(D)(2)*).
   b. **Storage:** 35% third-party ownership and 65% - 100% utility ownership (*Va. Code §56-585.5(E)(5)*).
   c. **Offshore Wind:** 100% utility ownership. (*Va. Code § 56-585.1:11(B) and § 56-585.5(D)(2)*).

3. **<u>RFP Administration</u>**
   a. All resources required to be procured through competitive process. (*see e.g., Va. Code § 56-585.1:4(D)* (solar)*, Va. Code § 56-585.1:11(E)* (offshore wind)*, Va. Code § 56-585.1:4 (G)*) (storage)).
      i. Primarily price-based, but up to 25% of solar may be selected on non-price criteria where it would materially advance non-price criteria, including favoring geographic distribution of generating capacity, areas of higher employment, or regional economic development.

   b. RFP requirements include the following (*Va. Code § 56-585.5(D)(3)*):
      i. Annual RFP for new solar and wind resources that quantifies and describes the utility's need for energy, capacity, or renewable energy certificates.
      ii. RFP must provide certain minimum information including major assumptions to be used by the utility in the bid evaluation process, including environmental emission standards; detailed instructions for preparing bids so that bids can be evaluated on a consistent basis; the preferred general location of additional capacity; and specific information concerning the factors involved in determining the price and non-price criteria used for selecting winning bids.
      iii. Energy storage requirements are also be competitively procured with regulations relating to competitive solicitations to be established through a Commission rulemaking. (*Va. Code § 56-585.5(E)(5)*).

c. Utility is responsible for evaluation and may evaluate responses to requests for proposals based on any criteria that it deems reasonable but must consider (*Va. Code § 56-585.5(D)(3)*):
   i. the status of a particular project's development,
   ii. the age of existing generation facilities,
   iii. the demonstrated financial viability of a project and the developer,
   iv. a developer's prior experience in the field,
   v. the location and effect on the transmission grid of a generation facility,
   vi. benefits to the Commonwealth that are associated with particular projects, including regional economic development and the use of goods and services from Virginia businesses; and
   vii. the environmental impacts of particular resources, including impacts on air quality within the Commonwealth and the carbon intensity of the utility's generation portfolio.

d. Selected portfolio of resources to be reviewed by the Virginia Commission.

WHAT IS BEING RECOMMENDED?

The North Carolina Energy Regulatory Process recommends that the North Carolina General Assembly expand existing procurement practices to utilize competitive procurement as a tool for State electric utilities to meet energy and capacity needs defined in their respective IRPs and where otherwise deemed appropriate by the NCUC.

NERP recommends that state policy regarding utility competitive procurement should take into account unique characteristics of each utility service territory, e.g., number of customers, geographic size, amount of utility-owned generation in the service territory, and proportion of existing generation from renewable sources located in the service territory and serving utility customers.

NERP produced the following documents for dissemination, to inform subsequent policy discussions with various audiences:

1. Competitive procurement policy recommendation for the North Carolina General Assembly.

2. A case study into Colorado's recent procurement cycle.

3. This case study into key generation procurements enacted by the Virginia Clean Economy Act.

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 Competitive Procurement Committee Leads:
Jack Jirak, Duke Energy, Jack.Jirak@duke-energy.com
Steve Levitas, NCCEBA, slevitas@pgrenewables.com

Access the NERP summary report and other NERP documents at:
https://deq.nc.gov/CEP-NERP

AGO Burgess Exhibit 1

STRATEGEN

/A

Edward Burgess

Senior Director

Ed leads the integrated resource planning practice at Strategen. Ed has served clients including consumer advocates, public interest organizations, Fortune 500 companies, energy project developers, trade associations, utilities, government agencies, universities, and foundations. He has led or contributed to expert testimony, formal comments, technical analyses, and strategic grid planning efforts for clients in over 25 states. These have focused on a range of topics including resource planning and procurement, utility system operations, transmission planning, energy storage, electric vehicles, utility rates and rate design, demand-side management, and distributed energy resources.

Contact

Location
Berkeley, CA

Email
eburgess@strategen.com

Phone
+1 (941) 266-0017

Education

PSM
Solar Energy Engineering and Commercialization
Arizona State University
2012

MS
Sustainability
Arizona State University
2011

BA
Chemistry
Princeton
2007

STRATEGEN.COM

Work **Experience**

Senior Director

Strategen / Berkeley, CA / 2015 - Present

+ Focuses on energy system planning via economic analysis, technical regulatory support, integrated resource planning and procurement, utility rates, and policy & program design.
+ Supports clients such as trade associations, project developers, public interest nonprofits, government agencies, consumer advocates, utilities commissions and more.

Senior Policy Director

Vehicle-Grid Integration Council / Berkeley, CA / 2019 - Present

+ Leads advocacy and regulatory policy for a group representing major auto OEMs and EVSEs
+ Advances state level policies and programs to ensure the value from EV deployments and flexible EV charging and discharging is recognized and compensated
+ Leads all policy development, education, outreach, and research efforts

Consultant

Kris Mayes Law Firm / Phoenix, AZ / 2012 - 2015

+ Consulted on policy and regulatory issues related to the electricity sector in the Western U.S.

Consultant

Schlegel & Associates / Phoenix, AZ / 2012 - 2015

+ Conducted analysis and helping draft legal testimony in support of energy efficiency for a utility rate case.

Edward Burgess

Senior Director

STRATEGEN

Selected Recent Publications

+ New York BEST, 2020. *Long Island Fossil Peaker Replacement Study.*
+ Ceres, 2020. *Arizona Renewable Energy Standard and Tariff: 2020 Progress Report*.
+ Virginia Department of Mines and Minerals, 2020. "*Commonwealth of Virginia Energy Storage Study*.
+ Sierra Club, 2019. *Arizona Coal Plant Valuation Study.*
+ Strategen, 2018. *Evolving the RPS: Implementing a Clean Peak Standard*."
+ SunSpec Alliance for California Energy Commission.,2018. *Analysis Report of Wholesale Energy Market Participation by Distributed Energy Resources (DERs) in California*.

Domain Expertise

Vehicle Grid Integration

Distributed Energy Resources

Electric Vehicle Rates, Programs and Policies

Energy Resource Planning

Benefit Cost Analysis

Electricity Expert Testimony

Stakeholder Engagement

Energy Policy & Regulatory Strategy

Energy Product Development & Market Strategy

STRATEGEN.COM

Relevant Project Experience

Arizona Residential Utility Consumer Office (RUCO)

IRP Analysis and Impact Assessment / 2015 - 2018

+ Supported drafting of expert witness testimony on multiple rate cases regarding utility rate design, distributed solar PV, and energy efficiency.
+ Performed analytical assessments to advance consumer-oriented policy including rate design, resource procurement/planning, and distributed generation consumer protection.
+ Ed was the lead author on the white paper published by RUCO introducing the concept of a Clean Peak Standard.

Western Resource Advocates

Nevada Energy IRP Analysis / 2018 - 2019

+ Conducted a thorough technical analysis and report on the NV Energy IRP (Docket No. 18-06003)
+ Investigated resource mixes that included higher levels of demand side management, renewable energy, battery storage, and decreased reliance on existing and/or planned fossil fuel plants.

Massachusetts Office of the Attorney General

SMART Program / 2016 - 2017

+ Appeared as an expert witness and supported drafting of testimony on the implementation of the MA SMART program (D.P.U. 17-140), which is expected to deploy 1600 MW of solar PV (and PV + storage) resources over the next several years. Ed served as an expert consultant on multiple rate cases regarding utility rate design and implications for ratepayers and distributed energy resource deployment.

New Hampshire Office of Consumer Advocate

NEM Successor Tariff Design / 2016

+ Worked with the state's consumer advocate to develop expert testimony on a case reforming the state's market for distributed energy resources, developing a new methodology for designing retail electricity rates that is intended to support greater deployment of energy storage.

Relevant Project Experience (con't)

Southwest Energy Efficiency Project

IRP Technical Analysis and Modeling / 2018 - 2020

+ Provided critical analysis and alternatives to the 2020 integrated resource plans (IRPs) of the state's major utilities, Arizona Public Service (APS) and Tucson Electric Power (TEP).
+ Provided analysis on Salt River Project's resource plan as part of its 2035 planning process.
+ Evaluated different levels of renewable energy and energy efficiency and identify any changes to the resources needed to meet these requirements and ensure reliability.
+ Worked with Strategen technical team on utilizing a sophisticated capacity expansion model to optimize the clean energy portfolio used in the analysis of the IRPs.

California Energy Storage Alliance

California Hybridization Assessment / 2018 - 2019

+ Managed a special initiative of this leading industry trade group to conduct technical analysis and stakeholder outreach on the value of hybridizing existing gas peaker plants with energy storage

Portland General Electric

Energy Storage Strategy / 2016

+ Provided education and strategic guidance to a major investor-owned utility on the potential role of energy storage in their planning process in response to state legislation (HB 2193).
+ Participated in public workshop before the Oregon Public Utilities Commission on behalf of PGE.
+ Supported development of a competitive solicitation process for storage technology solution providers.

Xcel Energy

Time-of-use Rates / 2017 - 2018

+ Conducted analysis supporting the design of a new residential time-of-use rate for Northern States Power (Xcel Energy) in Minnesota.

Sierra Club

PacifiCorp 2021 IRP Technical Support / 2020 - 2021

+ Provided technical support for Sierra Club in analyzing issues of interest during Pacificorp's IRP stakeholder input process.
+ Prepared analysis, technical comments, discovery requests in advance of drafting formal comments to be submitted before the Oregon Public Utility Commission.

North Carolina, Office of the Attorney General

Duke Energy 2020 IRP Technical Support / 2020 - 2021

+ Provided technical support and analysis to the state's consumer advocate on utility integrated resource plans and their implications for customers and public policy goals.
+ Presented original analysis at multiple IRP-related technical workshops hosted by the NCUC

University of Minnesota

Energy Storage Stakeholder Workshops / 2016 - 2017

+ Facilitated multiple stakeholder workshops to understand and advance the appropriate role of energy storage as part of Minnesota's energy resource portfolio.
+ Conducted study on the use of storage as an alternative to natural gas peaker.
+ Presented workshop and study findings before the Minnesota Public Utilities Commission.

Edward Burgess

Senior Director

STRATEGEN

Expert Testimony

California Public Utilities Commission
- Pacific Power 2020 Energy Cost Adjustment Clause (Docket No. A.19-08-002)
- Pacific Power 2021 Energy Cost Adjustment Clause (Docket No. A.20-08-002)
- Pacific Power 2022 Energy Cost Adjustment Clause (Docket No. A.21-08-004)
- Pacific Gas and Electric's Day-Ahead Real Time Rate and Pilot (Docket No. A.20-10-011)
- Pacific Gas and Electric's Electric Vehicle Charge 2 Application (Docket No. A.21-10-010)
- CPUC Rulemaking on Emergency Summer Reliability (Docket No. R.20-11-003)

Colorado Public Utilities Commission
- Tri-State Generation and Transmission Application for a CPCN (Docket No. 22A-0085E)

Indiana Utility Regulatory Commission
- Duke Energy Fuel Adjustment Clause (Cause No. 38707 FAC 125)
- Duke Energy Fuel Adjustment Clause – Sub-docket Investigation (Cause No. 38707 FAC 123 S1)

Louisiana Public Service Commission
- Entergy Certification to Deploy Natural Gas Distributed Generation (Docket No. U-36105)

Massachusetts Department of Public Utilities
- National Grid General Rate Case (D.P.U. 18-150)
- Eversource, National Grid, and Until SMART Tariff (D.P.U. 17-140)

Michigan Public Service Commission
- Consumers Energy 2021 Integrated Resource Plan (Docket No. U-21090)

Nevada Public Utilities Commission
- NV Energy's Integrated Resource Plan in (Docket No. 20-07023)

North Carolina Utilities Commission
- Duke Energy Carbon Plan (Docket No. E-100, Sub 179)

Oregon Public Utilities Commission
- Pacific Power 2021 Transition Adjustment Mechanism (Docket No. UE-375)
- Pacific Power 2022 Transition Adjustment Mechanism (Docket No. UE-390)
- Northwest Natural 2022 General Rate Case (Docket No. UG-435)

Expert Testimony (con't)

South Carolina Public Service Commission

- Dominion Energy South Carolina 2019 Avoided Cost Methodologies (Docket No. 2019-184-E)
- Duke Energy Carolinas 2019 Avoided Cost Methodologies (Docket No. 2019-185-E)
- Dominion Energy Progress 2019 Avoided Cost Methodologies (Docket No. 2019-186-E)
- Dominion Energy South Carolina 2021 Avoided Cost Methodologies (Docket No. 2021-88-E)

Washington Utilities and Transportation Commission

- Avista Utilities 2020 General Rate Case (Docket No. UE-200900)
- Avista Utilities 2022 General Rate Case (Docket No. UE-220053/UG-220054)
- Puget Sound Energy 2022 General Rate Case (Docket No. UE-220066/UG-220067)

Unlocking the Queue with Grid-Enhancing Technologies

CASE STUDY OF THE SOUTHWEST POWER POOL

FINAL REPORT – PUBLIC VERSION

PRESENTED BY

T. Bruce Tsuchida

Stephanie Ross

Adam Bigelow

PREPARED FOR

WATT (Working for Advanced Transmission Technologies) Coalition

FEBRUARY 1, 2021

Brattle

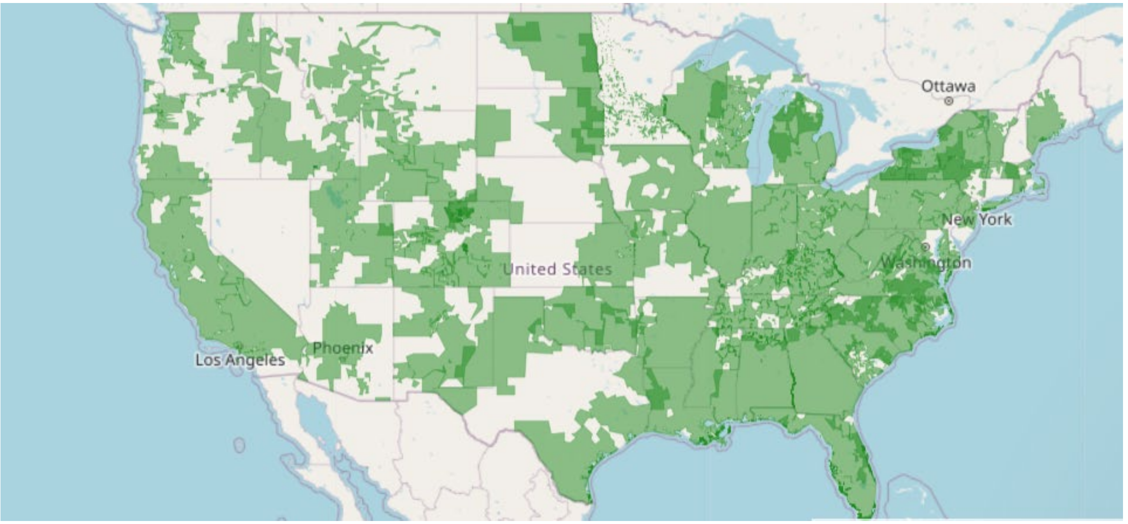
Disclaimer

- This report was prepared for the WATT (Working for Advanced Transmission Technologies) Coalition with support from GridLab, EDF Renewables North America, NextEra Energy Resources, and Duke Energy Renewables. The WATT Coalition includes Ampacimon, Lindsey Manufacturing, LineVision, NewGrid, Smart Wires, and WindSim. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group (Brattle) or its clients.
- The analyses that we provide here are necessarily based on assumptions with respect to conditions that may exist or events that may occur in the future. Most of these assumptions are based on publicly-available industry data. Brattle and their clients are aware that there is no guarantee that the assumptions and methodologies used will prove to be correct or that the forecasts will match actual results of operations. Our analysis, and the assumptions used, are also dependent upon future events that are not within our control or the control of any other person, and do not account for certain regulatory uncertainties. Actual future results may differ, perhaps materially, from those indicated. Brattle does not make, nor intends to make, nor should anyone infer, any representation with respect to the likelihood of any future outcome, can not, and does not, accept liability for losses suffered, whether direct or consequential, arising out of any reliance on our analysis. While the analysis that Brattle is providing may assist WATT Coalition members and others in rendering informed views of how advanced transmission technologies could help integrate additional amounts of renewable resources, it is not meant to be a substitute for the exercise of their own business judgments.
- This Report may be redistributed. If only a portion of Report is redistributed, the redistributed portion(s) must be accompanied by a citation to the full Report.

Issue at Hand - 1/2

Increasing renewable resources (often associated with carbon reduction) is a common goal.

- Many private entities including utilities, corporations, and academic institutes.
- Across jurisdictions from federal, state, to local (e.g., cities) levels.
- Increasing renewable projects provide jobs and other local benefits, and help boost the economy out from the current COVID-associated downturn.



Utility Carbon Reduction Tracker (Feb 2021)

Issue at Hand - 2/2

What are the roadblocks to integrating more renewables?

- Utilities and system operators have good understandings of the variability of renewable resources.
  - Wind became SPP’s leading resource in 2020.
- Transmission availability is a major limiting factor.
  - Many renewable projects are locked up in the Generation Interconnection Queue.
  - There is a timing gap: renewables are developed (in months to years) much faster than transmission (in years to sometimes decades).
  - Utility-scale renewables are usually more cost efficient (on a $/MWh basis) compared to distributed resources.

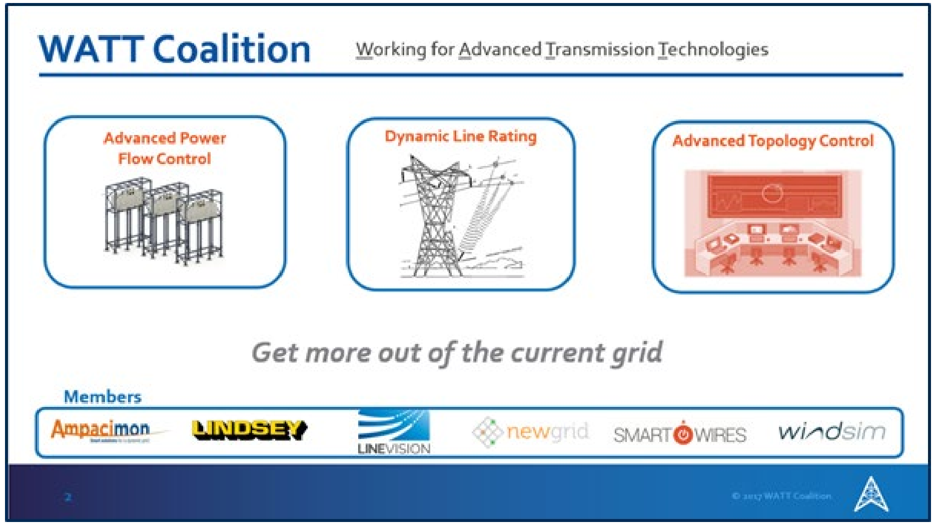
Can Grid-Enhancing Technologies (GETs) help integrate more renewables?

- GETs quickly and cost-effectively help maximize the capability of the existing transmission system

Study Overview - 1/2

Goal: Analyze how much additional renewables can be added to the grid using Grid-Enhancing Technologies (GETs):

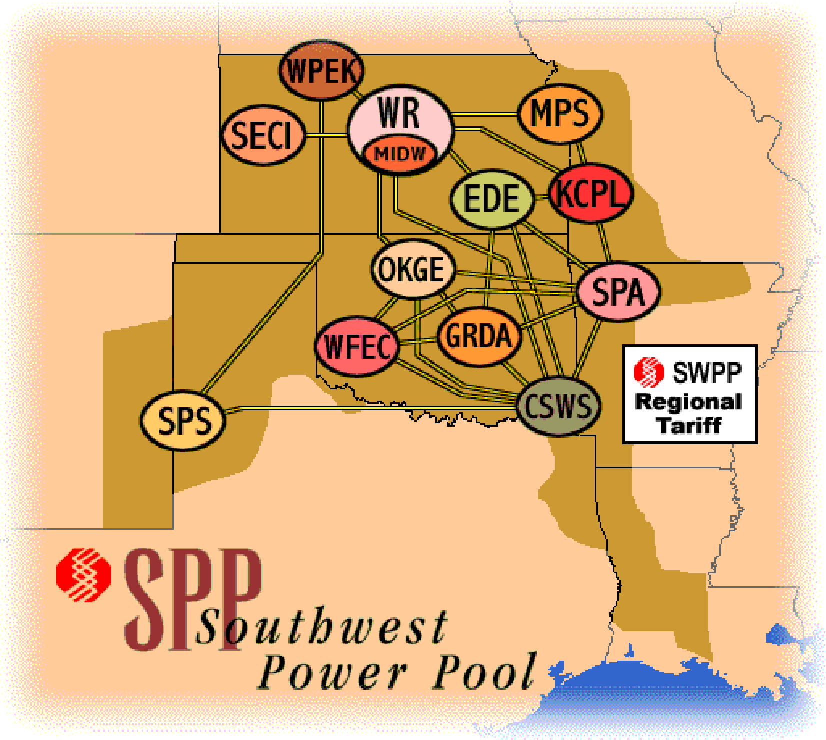
- GETs enhance transmission operations and planning.
- GETs complement building new transmission—they can bridge the timing gap until permanent expansion solutions can be put in place.
- While there are various types of GETs, this study focuses on the combined impact of the following three technologies:
  - **Advanced Power Flow Control**: Injects voltage in series with a facility to increase or decrease effective reactance, thereby pushing power off overloaded facilities or pulling power on to under-utilized facilities.
  - **Dynamic Line Ratings (DLR)**: Adjusts thermal ratings based on actual weather conditions including, at a minimum, ambient temperature and wind, in conjunction with real-time monitoring of resulting line behavior.
  - **Topology Optimization**: Automatically finds reconfiguration to re-route flow around congested or overloaded facilities while meeting reliability criteria.



Study Overview - 2/2

Goal: Analyze how much additional renewables can be added to the grid using Grid-Enhancing Technologies (GETs):

- Use the Southwest Power Pool (SPP) grid (focused on Kansas and Oklahoma, looking at 2025) as an illustrative case study.
  - SPP Generation Interconnection Queue* (GI Queue) shows ~9 GW of renewable resources with an Interconnection Agreement (IA) executed in Kansas and Oklahoma.
  - SPP Integrated Transmission Planning (ITP) Reports** show high congestion.
- Results metrics for the **combined** (not for individual) three GETs include:
  - Renewables added (capacity [GW] and energy [GWh]).
  - Economic benefits (production costs, investments, jobs, etc.)
  - Carbon emissions reduction.



SPP figure from http://opsportal.spp.org/Images/SPPMap.gif
* SPP GI Queue as of September 28, 2020
** 2019 Integrated Transmission Planning (available at: https://spp.org/Documents/60937/2019%20ITP%20Report_v1.0.pdf) and Q3 2020 Quarterly Project Tracking Report (available at: https://www.spp.org/documents/62710/q3%202020%20qpt%20report%20draft.pdf)

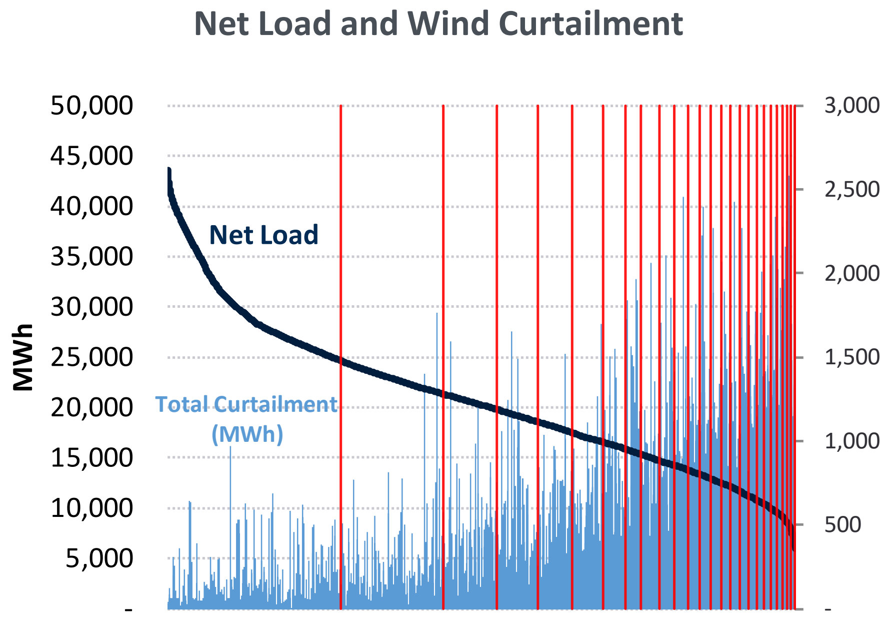
Study Approach - 1/2

Study purpose

- Quantify the benefits of **the three GETs combined** for integrating renewable resources (largely wind) using SPP as a test bed.

Analysis approach

- Select 24 representative historical power flow snapshots of SPP operations (2019 – 2020) that together reasonably represent a full year.
- Modify the snapshots to reflect new transmission upgrades, renewable projects from the GI queue, announced retirements, load change, etc.
- Find the maximum renewables amount (GW and GWh) that can be integrated under a business as usual scenario (Base Case) and then with GETs (With GETs Case), sequentially in the order of DLR, Topology Optimization, and Advanced Power Flow Control, by simulating the entire SPP system using the 24 power flow cases.
- Assess benefits of GETs including economic values (production costs, jobs, local benefits etc.) and carbon emissions reduction.



Areas between red line indicates the bins from which snapshots were selected, blue bars indicate curtailment of renewables. Each bin contains equal amounts of curtailment.

Study Approach - 2/2

Study purpose

- Quantify the benefits of **the three GETs combined** for integrating renewable resources (largely wind) using SPP as a test bed.

Finding the maximum amount of renewables that can be integrated

- Analysis is performed separately for the Base Case and With GETs Case for all 24 snapshots.
- Analysis is done using an iterative process:
  - Determine feasible reduction in thermal unit generation to accommodate additional renewable resources.
  - Dispatch wind and solar to their max output by running Security Constrained Optimal Power Flow (SCOPF).
  - Iteratively solve SCOPF (i.e., solve SCOPF, take out renewable projects with high curtailments, then resolve SCOPF, and repeat).
- Analysis assumes a 5% curtailment threshold for viability assessment (i.e., projects are viable if analysis indicates annual curtailments to be less than 5%).
  - Curtailment occurs largely for two reasons—transmission congestion (which the GETs will help solve) and minimum generation constraints of other generation resources.

Study Results - 1/5

GETs enable more than twice the amount of additional new renewables to be integrated.

- Potential Renewables Considered: 9,430 MW
  - Based on queue projects with IA executed.
- Integrated Renewables (without further transmission upgrades)
  - Base Case: 2,580 MW
  - With GETs Case: 5,250 MW
  - Delta (With GETs Case – Base Case): 2,670 MW

RENEWABLE POTENTIAL ASSUMED FOR KANSAS AND OKLAHOMA

State	Wind	Solar	Total
Kansas	3,410	120	3,530
Oklahoma	5,760	140	5,900
Total	9,170	260	9,430

[Rounded to the nearest 10 MW]

~1.5 times the amount of wind SPP integrated in 2019 (1.8 GW).

ADDITIONAL RENEWABLES INTEGRATED

State	Base Case			With GETs Case			Delta (GETs - Base)		
	Wind	Solar	Total	Wind	Solar	Total	Wind	Solar	Total
Kansas	1,710	0	1,710	1,910	0	1,910	200	0	200
Oklahoma	770	100	870	3,200	140	3,340	2,430	40	2,470
Total	2,480	100	2,580	5,110	140	5,250	2,630	40	2,670

X2

[Rounded to the nearest 10 MW]

Study Results - 2/5

GETs enable more than twice the amount of additional new renewables to be integrated.

- Additional renewables enabled by GETs: **2,670 MW / 8,776 GWh**.
  - 2,630 MW of **new wind** is assumed to produce over 8,640 GWh of energy per year.
  - 40 MW of **new solar** is assumed to produce about 60 GWh of energy per year.
  - GETs lower curtailment of **existing wind** by over 76,000 MWh per year.
- GETs installation cost is about $90 million.
  - Annual O&M costs is estimated to be around $10 million.
- GETs benefits (other than the value of additional renewables) include:

ANNUAL PRODUCTION COST SAVINGS

$175 million

ANNUAL REDUCED CARBON EMISSIONS

3 million tons

LOCAL JOBS

650 long-term jobs and
11,300 short-term jobs

OTHER LOCAL BENEFITS

$15 million land lease and
$32 million tax revenues per year

Study Results - 3/5

GETs enable more than twice the amount of additional new renewables to be integrated.

- Estimated annual production cost savings: **$175 million**.
  - Pay-back for GETs investment (~$90 million) is about half a year.
  - $175 million conservatively assumes $20/MWh savings for 8,776 GWh of energy.
  - $20/MWh is at the lower end of the generation cost of a new natural gas-fueled combined cycle plant or coal plant and lower than average 2019 LMP (both day-ahead and real-time).
- Estimated job benefits associated with the increased renewables (2,670 MW):
  - Over 11,300 direct short-term jobs (largely construction of renewables).
  - Over 650 direct long-term jobs for operation and maintenance of the renewable resources.
- Estimated carbon emissions reduction: **Over 3 million tons per year.**
  - Conservatively assumes the renewables replace carbon emissions from natural gas-fueled combined cycle plants.
  - Less efficient resources with higher heat rates and emission rates are more likely to be replaced.
- Other estimated benefits include:
  - Local benefits estimated to be over $32 million annual tax revenues and $15 million land lease revenues (based on literature research).

Study Results - 4/5

Key benefits of GETs for Kansas and Oklahoma

- Enable more than **twice** the amount of additional new renewables to be integrated.
  - This is 1.5x the amount of wind SPP integrated in 2019.
- Estimated annual production cost savings: $175 million.
  - Payback for GETs investment is about 0.5 years.
- Estimated carbon emissions reduction: Over 3 million tons per year.
- Over 11,300 direct short-term and 650 direct long-term jobs.
- Over $32 million annual tax revenues and $15 million land lease revenues.

Potential Nation-Wide Benefits

Extrapolating these results to a nation-wide level* indicate GETs to provide **annual benefits** in the range of:

- Over **$5 billion** (~$5.3 billion) in production cost savings.
- **$90 million tons** of reduced carbon emission (more than enough to offset **ALL NEW** automobiles sold in the U.S. a year).
- About **$1.5 billion** in local benefits (local taxes and land lease revenues).
- More than 330,000 short-term (only for first year) and nearly 20,000 long-term jobs.
- Investment cost is $2.7 billion (only for first year). Ongoing costs would be around $300 million per year.

https://www.eia.gov/electricity/state/kansas/, https://www.eia.gov/electricity/state/oklahoma/, and https://www.eia.gov/electricity/annual/html/epa_01_01.html

Study Results - 5/5

GETs utilized in this study include:

- **Hardware solutions**: DLR on 56 lines and Advanced Power Flow Control on 8 locations.

Hardware Solutions by Voltage Level	345	230	161	138	115	69	Total
DLR*	10	3	11	22	3	7	56
Advanced Power Flow Control	3	0	4	1	0	0	8

- **Software solutions**: 204 unique Topology Optimization reconfigurations, averaging 13 per snapshot.**

Software Solutions by Voltage Level	345	230	161	138	115	69	Total
Lines	20	10	31	75	4	30	170
Substations	4	0	1	1	0	0	6
Transformers (high voltage terminal)	10	1	4	13	0	0	28

- Estimated costs for implementing the above GETs: ~$90 million.
  - Initial investment costs is estimated to be around $90 million.***
  - Ongoing costs of around $10 million per year.***

* Every DLR installation requires 15 to 30 sensors.

** Average actions represent the average number of actions that remain per case, not actions per hour. Based on other studies the average number of actions per hour is expected to be smaller, typically less than the number of topology changes due to planned outages.

*** Costs can vary project by project, and also on how the GETs service is provided—for example, Topology Optimization can be provided as a software subscription service to reduce the initial cost. We also assume utilities can incorporate these technologies without large costs.

Table of Contents

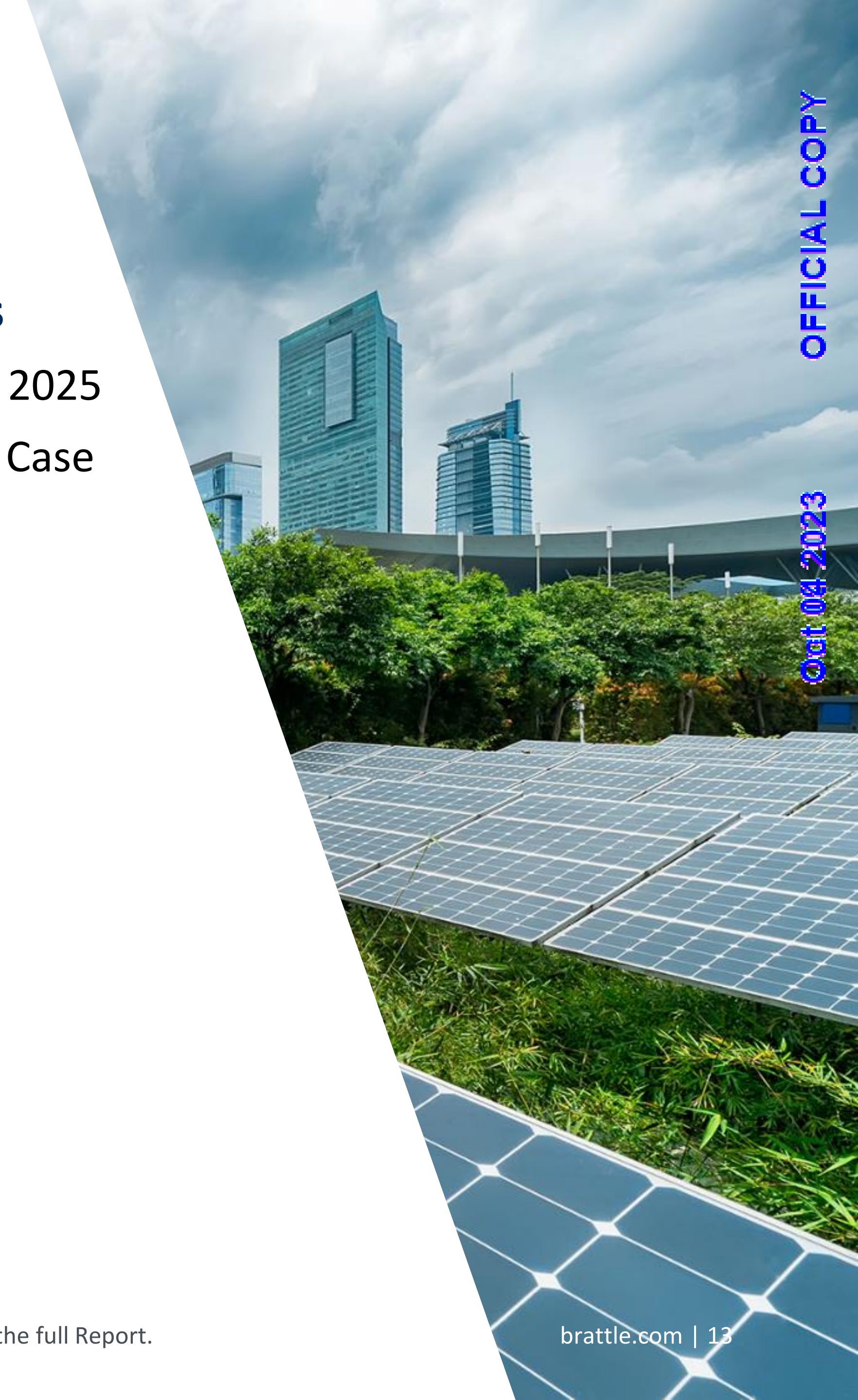
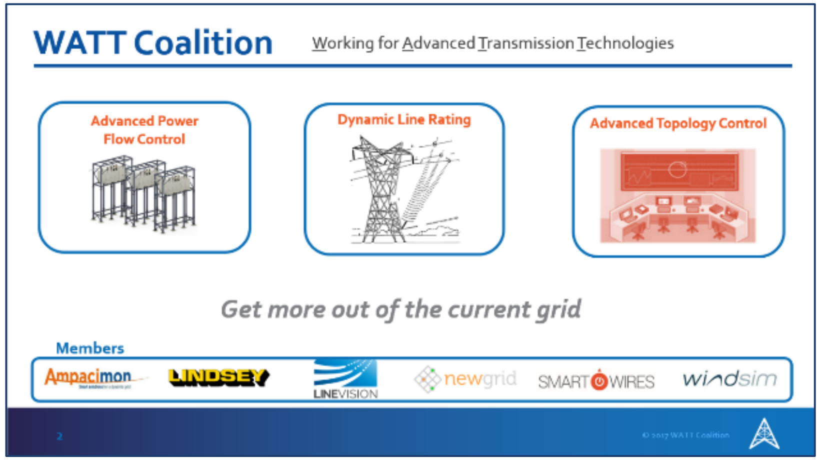


Table of Contents

Study Scope and Purpose

Study purpose

- Analyze how much additional renewables can be added to the grid using three GETs:
  - Advanced Power Flow Control
  - Dynamic Line Ratings (DLR)
  - Topology Optimization



Study scope

- Use the Southwest Power Pool (SPP) grid with the focus on **Kansas and Oklahoma** looking at 2025 as an illustrative case study.
  - SPP Generation Interconnection Queue* shows ~9 GW of renewable resources with Interconnection Agreements executed.
  - SPP Integrated Transmission Planning (ITP) reports** shows high congestion.
- Results metrics for the **combined** (not for individual)*** GETs include:
  - Renewables added (capacity [GW] and energy [GWh]).
  - Economic benefits (production costs, jobs, local benefits, etc.)
  - Carbon emissions reduction.

* SPP GI Queue as of September 28, 2020.

** 2019 Integrated Transmission Planning (available at: https://spp.org/Documents/60937/2019%20ITP%20Report_v1.0.pdf) and Q3 2020 Quarterly Project Tracking Report (available at: https://www.spp.org/documents/62710/q3%202020%20qpt%20report%20draft.pdf)

*** This is because the order of analysis matters—being the first GETs to be analyzed will likely show more benefits than being the last.

GETs – Introduction

Traditional thinking treated transmission as if it is fixed and cannot be operated dynamically.

- Transmission has a fixed capacity, much like roads or railways do (e.g., the number of cars or trains that can go through at any given time).
- Advancements in maps and GPS technology have allowed for safer, easier and more efficient driving on the same roads and railways.
- Are there similar technologies that allow for such innovation in transmission **operations** (and planning)?

GETs enhance transmission operations and planning.

- GETs considered in this study: DLR, Topology Optimization, and Advanced Power Flow Control.
- These technologies have matured over the past several decades, are commercially proven and **actively operating** on grids around the world.
- They **focus on operational improvements** and have a much lower cost and faster implementation than traditional transmission technologies.
  - Similar to the comparison between building a road to reduce congestion (long-term investment) and having a good map/GPS system to avoid congested roads (operational improvements).

Dynamic Line Ratings - 1/2

Historical practice was largely based on Static Line Ratings (SLR).

- Maximum operating temperature for a given line is pre-determined.
  - Uses conservative assumptions, such as low wind, high temperature, high solar irradiance, etc., to accommodate most conditions.
  - It is similar to setting highway speed limit based on snowy road conditions.
  - Recently more transmission operators have adopted ambient adjusted rating (AAR).

DLR enhances AAR further and utilize real-time data.

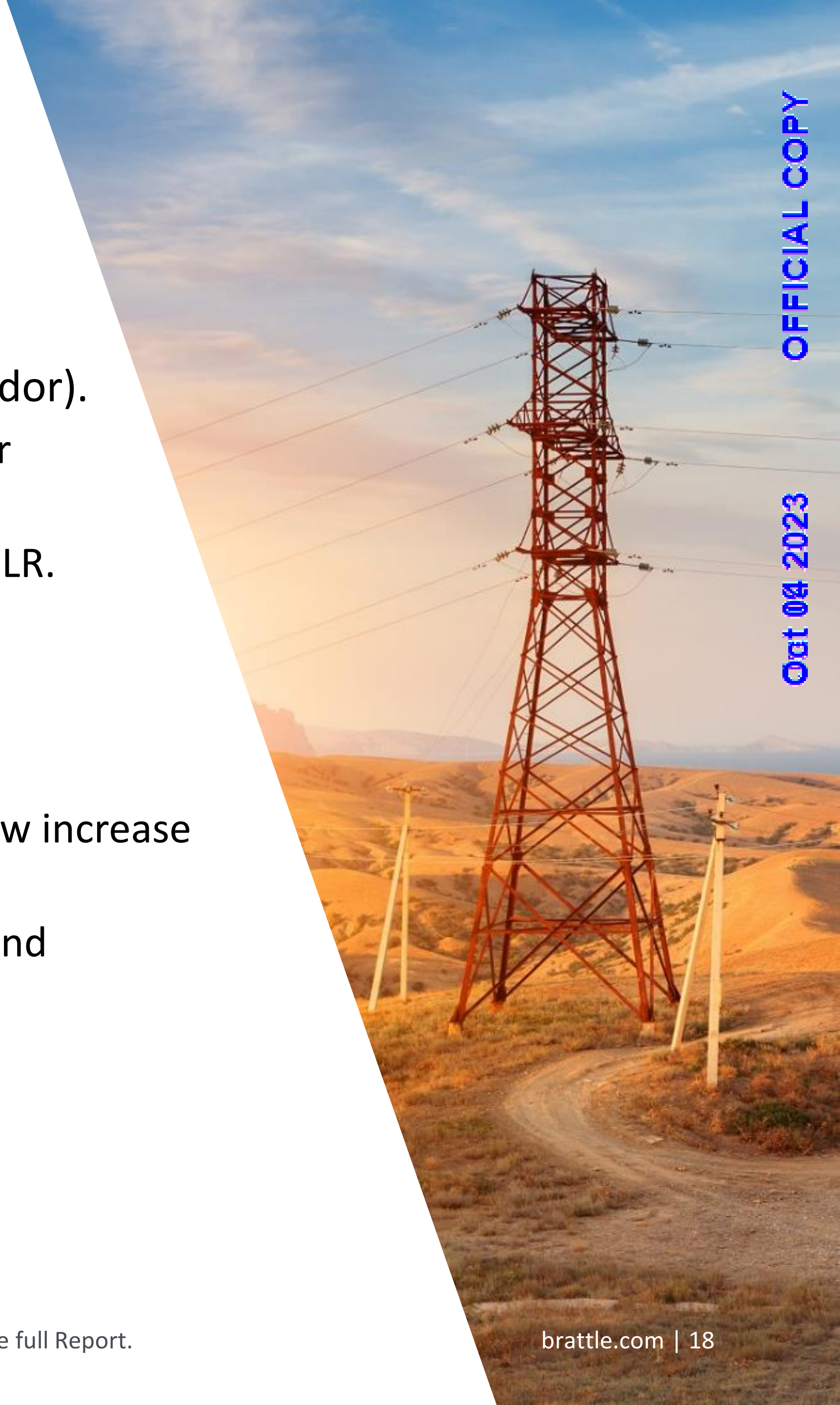
- Commonalities between SLR, AAR, and DLR.
  - Minimum allowable electrical clearance is the same.
- Differences between SLR, AAR, and DLR.
  - SLR applies uniform weather conditions to all lines and is generally lower than AAR and DLR that applies line-specific conditions.
  - AAR requires line-specific data and ambient temperature, but has a ≥ 15% risk of exceeding electrical clearance limitations (as commonly implemented in the U.S.)*
  - DLR requires line-specific data in conjunction with real-time monitoring of ambient temperature, wind and conductor position, and can provide forecasts for operations planning.*

* Post-Technical Conference Comments of the WATT Coalition, November 2019, available at: https://watttransmission.files.wordpress.com/2019/11/post-technical-conference-of-the-watt-coalition.pdf, pp 2-5.

Dynamic Line Ratings - 2/2

DLR adjust limits based on ambient conditions.

- Thermal ratings use real-time measurements the line location (along line corridor).
  - Line temperature, line sagging, ambient conditions (temperature, humidity, solar irradiance, wind, precipitation etc.).
  - DOE/ONCOR study indicates DLR transfer capability to be 5 to 25% higher than SLR.
- Accumulation of real-time data can be used for future calibration.
  - DLR is variable and requires a forecast for operations planning.
- High wind leads to higher cooling and allows for increased flow.
  - High degree of overlap between wind production and DLR-induced allowable flow increase has been observed.
  - European studies indicate DLR contributes to approximately 15% reduction in wind curtailments in some areas.



Advanced Power Flow Control - 1/2

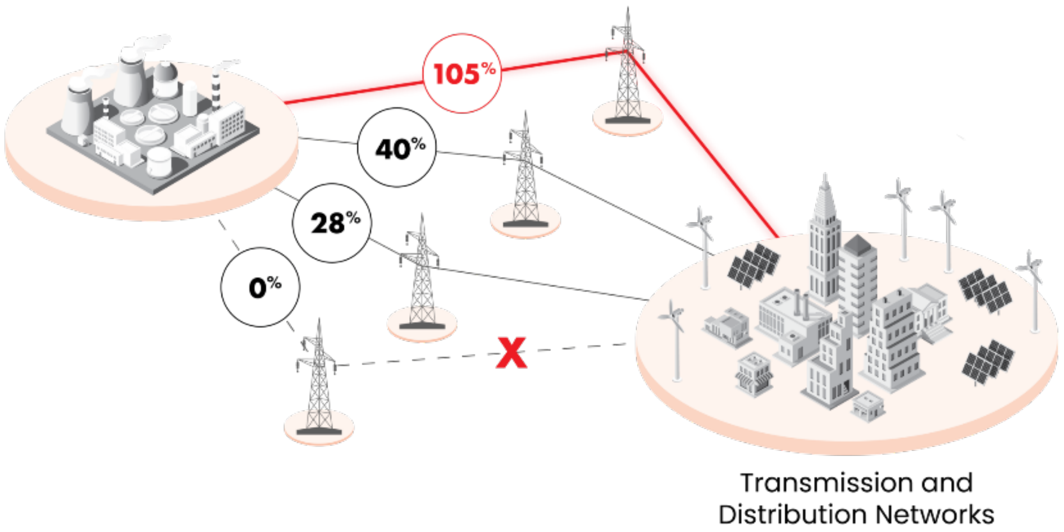
Phase Shifting Transformers (PSTs)* and Flexible Alternating Current Transmission Systems (FACTS) devices help the operator control flow through a given path.

- These devices are widely accepted in the industry.
  - The largest drawback is the cost—for example, a recently-installed PAR* between Michigan and Ontario has an annual carrying cost of over $10 million.
- FACTS devices are power-electronic-based static devices that allow for flexible and dynamic control of flow on transmission lines or the voltage of the system.
  - Some FACTS devices alter the reactance of a line to control the flow (i.e., increasing the reactance will push away flows while decreasing the reactance will pull in more flow to the line).
  - FACTs devices typically cost less than PARs, can be manufactured and installed in a shorter time, are scalable, and in many cases, are available in mobile form that can be easily deployed (or redeployed, as needed) while providing flexible layout options.

* Phase Shifting Transformers are also called Phase Angle Regulators (PARs).

Advanced Power Flow Control - 2/2

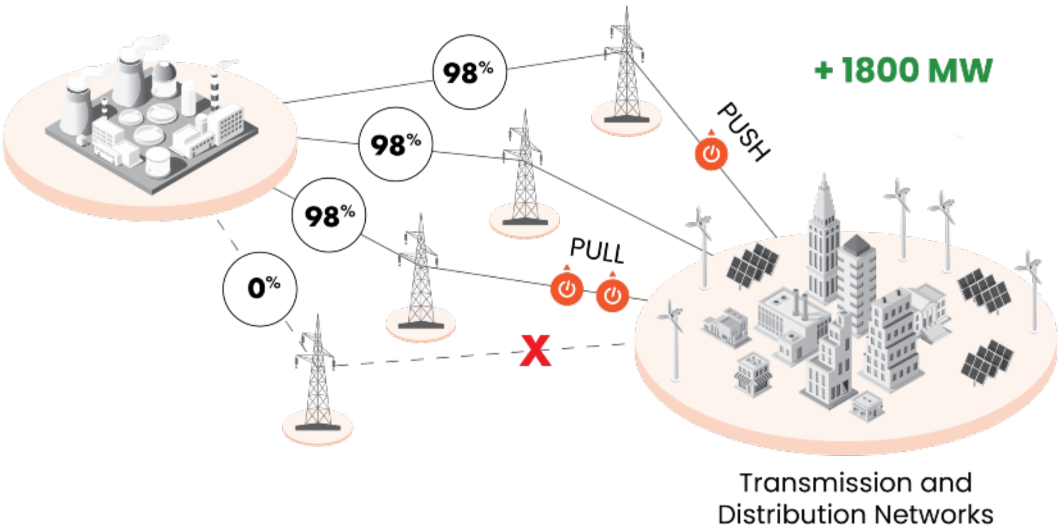
Before FACTS Device*



Traditional solutions include:

1. Redispatch generation
2. Reconductor constraining element
3. Install PSTs/Series Capacitor/Series Reactor
4. Construct a new parallel circuit

After FACTS Device



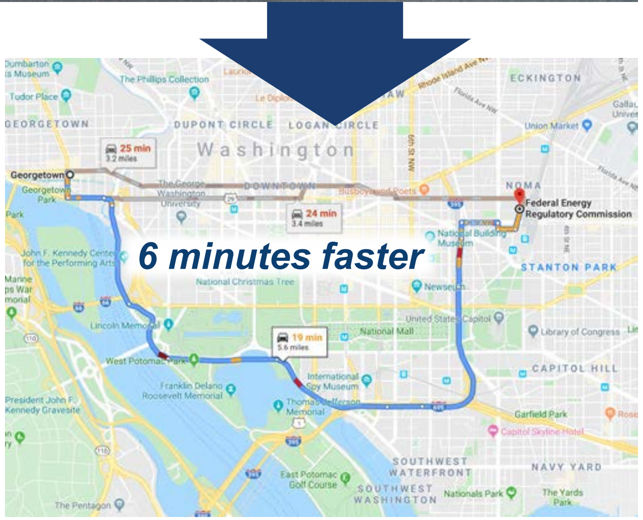
Power can be **PUSHED** and **PULLED** to alternate lines with spare capacity—leading to maximum utilization (typically obtained by a number of small applications on more than one circuit.)

* Illustrative example from Smart Wires, https://www.smartwires.com/smartvalve/

Topology Optimization - 1/2

Topology Optimization is analogous to Waze: "Arrive to destination reliably, with minimum delay even when there are events on the road" by re-routing.

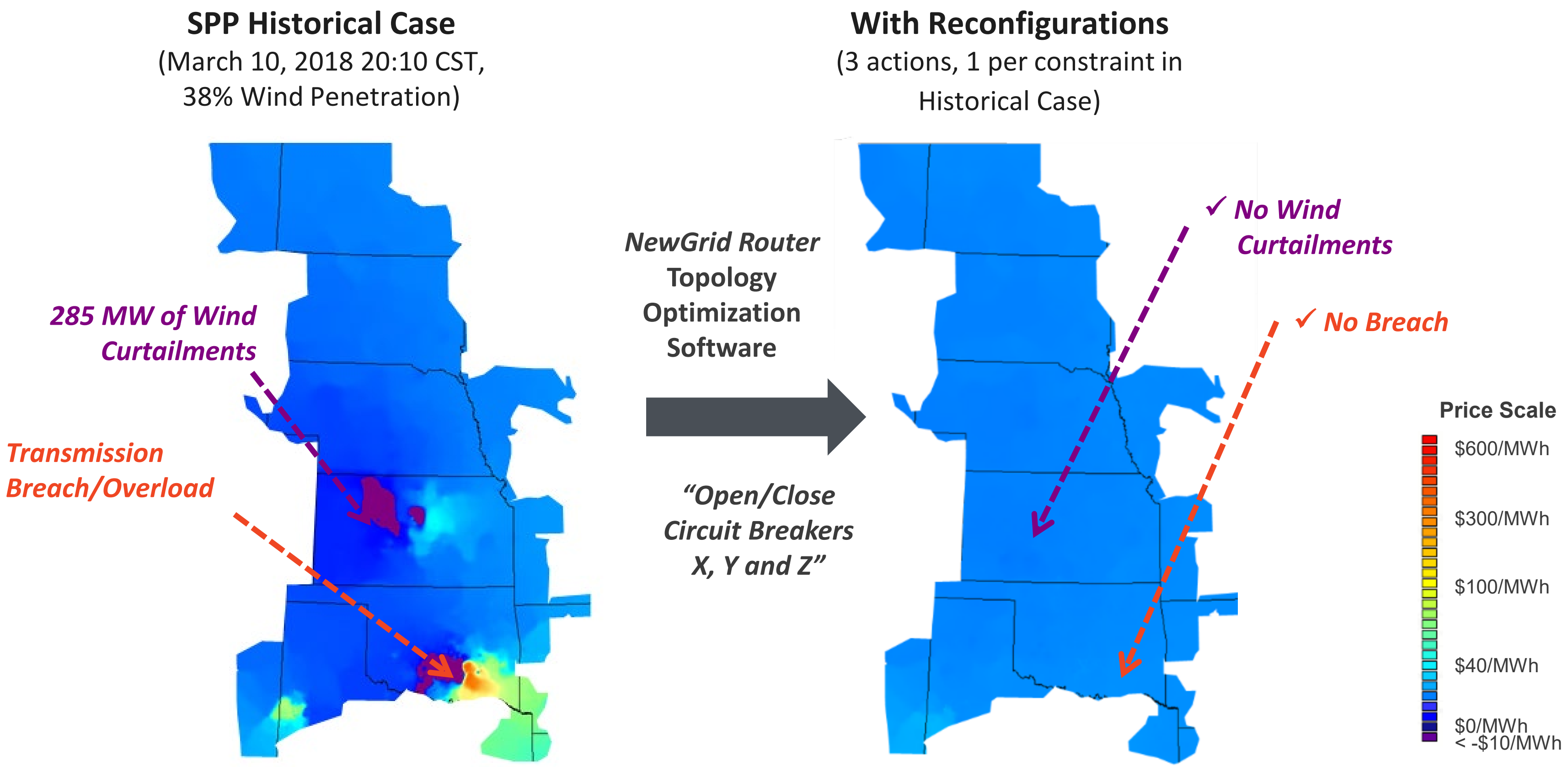
- Re-routing is achieved by grid reconfigurations: switching circuit breakers open or close.
  - Analogous to temporarily diverting traffic away from congested roads to make traffic smoother.
  - Similar effect as advanced flow control devices, using existing equipment.
- Reconfiguring the grid in operations is feasible today.
  - Circuit breakers are capable of high duty cycles and extremely reliable—some breakers are switched very frequently today, e.g., those connecting generating units with daily start and stop operations.
  - Switching infrastructure is already in place—most breakers are controlled remotely over SCADA by the TO.
  - Low cost: usually $10-$100 per switching cycle.



Road closure picture from https://www.islandecho.co.uk/plea-motorists-heed-road

Topology Optimization - 2/2

Topology Optimization software technology automatically finds reconfigurations to route flow around congested elements ("Waze for the transmission grid").

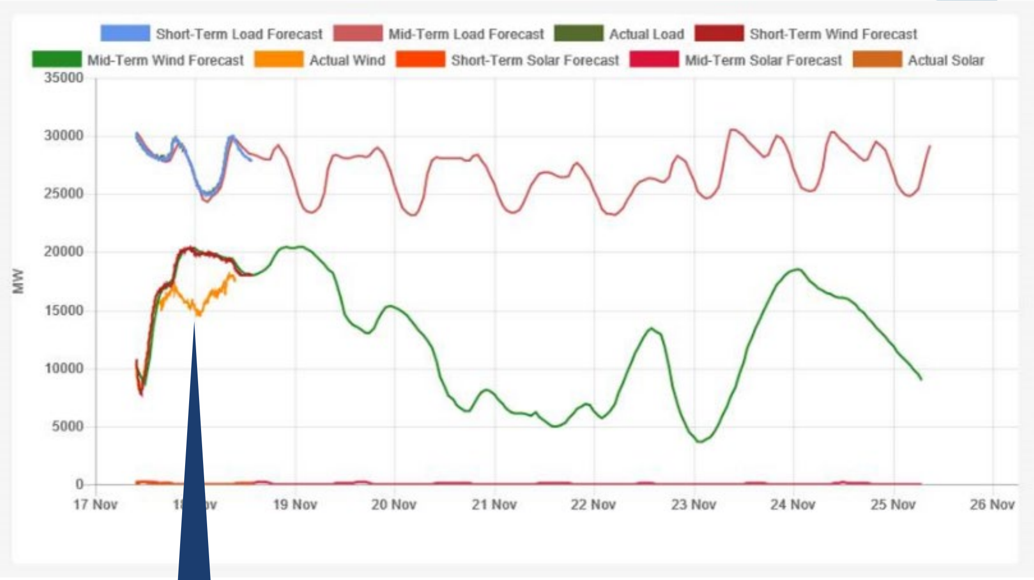


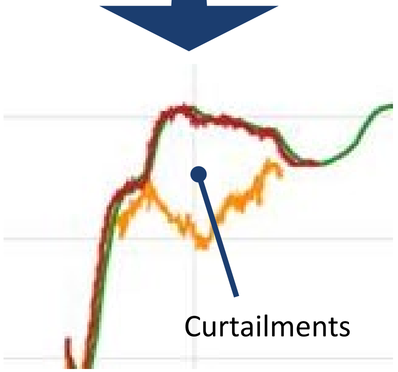
Why GETs?

GETs enhance transmission operations and planning.

- GETs **focus on operational improvements** and can be implemented quicker and at a lower cost than traditional transmission technologies.
  - Similar to the comparison between building a road to reduce congestion (long-term investment) and having a good map/GPS system to avoid congested roads (operational improvements).
- SPP operations data shows renewable curtailments likely caused by transmission congestion (indicated by transmission shadow prices).

SPP REAL-TIME MARKET DATA SNAPSHOT FROM NOVEMBER 18, 2020





Actual wind production (shown in yellow) is lower than forecasts. Wind (and load) forecasts for both the short- and mid-term trend are over each other, indicating that the reduced wind production is likely due to curtailments.

Table of Contents

Study Objective, Approach, and Steps

Overall study objective

- Quantify the combined benefits of three GETs for integrating renewables:
  - For a future year 2025.
  - For a select area within SPP.
  - Using 24 representative snapshots (power flow cases) to represent a full year.

Analysis approach and steps

Step 1: **Identify preferred area** for analysis.

Step 2: **Select 24 representative snapshots** from SPP operational power flow cases.

Step 3: **Modify the snapshots** to reflect new transmission upgrades, renewable plants from the generation interconnection queue, announced retirements, etc.

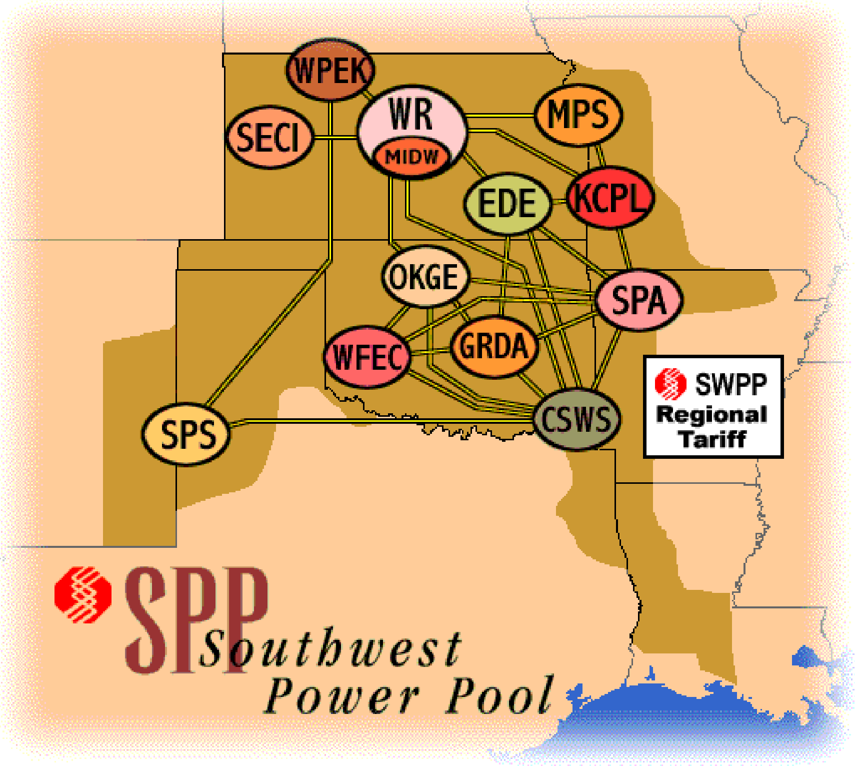
Step 4: **Find the maximum amount of renewables** that can be integrated under a business as usual scenario (Base Case) and then with GETs (With GETs Case) in the order of DLR, Topology Optimization, Advanced Power Flow Control. This will be done by solving the power flow cases (for the entire SPP footprint) prepared in Step 3, with and without GETs.

Step 5: **Assess benefits** including economic values (production cost savings, job creation, local benefits, etc.) and carbon emissions reduction.

Step 1: Identify Preferred Areas - 1/4

Step 1: Identify preferred area for analysis.

- GETs focuses on transmission operation.
  - These technology options are particularly helpful in increasing renewable penetration when transmission congestion is curtailing renewables (or preventing interconnection).
  - More renewables (largely wind in SPP) will likely to higher transmission congestion.
- Therefore, the preferred areas would be:
  - Areas with transmission constraints identified in SPP transmission studies.
    - Preferred areas to be identified by studying the SPP Integrated Transmission Planning (ITP) Assessment Report and quarterly updates.
  - Areas with significant generation resource changes (large amounts of new renewable projects and retirements of existing resources).
    - Preferred areas to be identified by studying the SPP GI Queue.



SPP figure from http://opsportal.spp.org/Images/SPPMap.gif

Step 1: Identify Preferred Areas - 2/4

Based on the observations from the ITP report and GI queue, **Kansas and Oklahoma** are selected as the focus areas.

- Selection criteria for new renewables projects are set to those where Interconnection agreement has been fully executed.*
  - GI queue status of IA Fully Executed/On Schedule or IA Fully Executed/Suspended.
- This approach will include over 9,400 MW of renewable projects:

RENEWABLE POTENTIAL ASSUMED FOR KANSAS AND OKLAHOMA

State	Wind	Solar	Total
Kansas	3,410	120	3,530
Oklahoma	5,760	140	5,900
Total	9,170	260	9,430

[Rounded to the nearest 10 MW]

WIND SITING PLANS FROM 2019 ITP

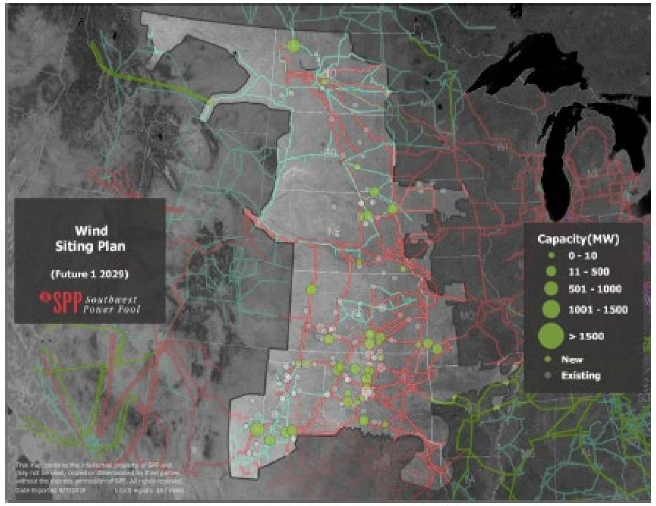


Figure 2.19: 2029 Future 1 Wind Siting Plan

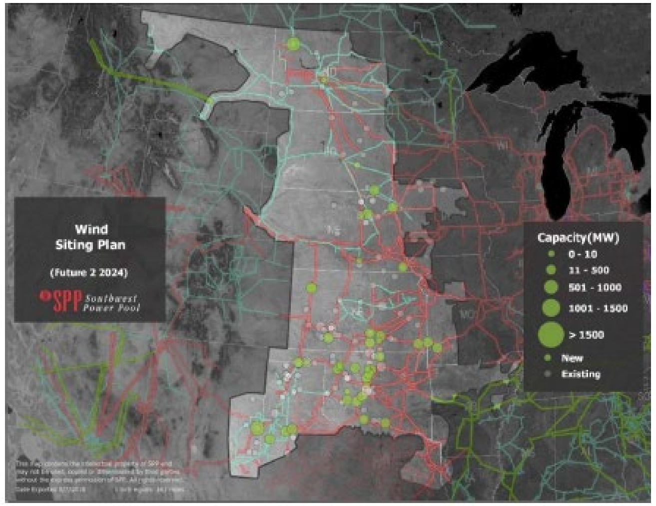


Figure 2.20: 2024 Future 2 Wind Siting Plan

* The 2010 SPP Wind Integration Study uses a similar approach.

Step 1: Identify Preferred Areas - 3/4

SPP identifies two target areas in its 2019 Integrated Transmission Planning (ITP) Assessment Report as areas that needed additional analysis and could benefit from closer attention.

4.1.1.1 Southeast Kansas/Southwest Missouri Target Area (Target Area 1)

Southeast Kansas/Southwest Missouri was identified as Target Area 1, requiring additional analysis for several reasons. The area has been the site of historic and projected congestion on the EHV system and has had unresolved transmission limits identified in multiple studies, most recently in the 2018 ITPNT. By defining this corridor as a target area in the 2019 ITP, SPP is able to address the TWG's direction to provide a path forward for the area to properly evaluate and resolve the issues present in day-to-day operations and in the planning horizon.

4.1.1.2 Central/Eastern Oklahoma Target Area (Target Area 2)

Central/Eastern Oklahoma was identified as Target Area 2 due to heavy congestion and parallel system correlation with Target Area 1. Additional analysis was unnecessary for Target Area 2 because system issues in this area were only related to congestion and underlying voltage stability concerns. The main point of congestion in Target Area 2 is related to the Cleveland 345/138 kV station west of Tulsa, Oklahoma. The renewable forecast in the 2019 ITP drives increased bulk transfers across central Oklahoma. EHV contingencies in the area shift congestion mostly to the lower-voltage system.

Step 1: Identify Preferred Areas - 4/4

SPP's GI Queue shows significant renewable additions and material retirements of existing generation resources for Kansas and Oklahoma.

Planned Capacity and Retirement 2020-2025

KS/OK

Control Area	Entity	**Planned Capacity** (MW) Total	Solar	Wind	Battery	**Planned Retirement** (MW) Total	Fuel Oil	Coal	Natural Gas
OKGE	**Oklahoma Gas & Electric Co**	**10,837**	**2,036**	**7,623**	**1,178**	**339**	**28**		**312**
Evergy	**Evergy**	**10,276**	**1,812**	**8,148**	**316**	**1,223**	**410**		**813**
KCPL	Kansas City Power & Light	2,911	550	2,361	-	727	297		431
WERE	Westar Energy	7,365	1,262	5,787	316	893	114		382
SPS	**Southwestern Public Service Co**	**13,122**	**6,985**	**5,088**	**1,049**	**920**			**920**
AEPW	American Electric Power West	**9,335**	**3,249**	**5,344**	**742**	**474**	**12**	**-**	**462**
BEPC	Basin Electric Power Coop	2,740	700	2,040	-				
LES	Lincoln Electric System	1,065	306	659	100	99			99
MIDW	Midwest	948	50	878	20				
NPPD	Nebraska Public Power District	6,806	2,025	4,707	74	354	178		176
OPPD	Omaha Public Power District	1,808	1,027	135	646	605	136	199	270
SUNC	Sunflower Electric Power Corp	4,163	1,110	3,003	50	431	84		346
WAPA	WAPA Upper Great Plains West	3,441	388	3,053	-				
WFEC	Western Farmers Electric Coop	2,265	1,404	677	184	130			130
AR	Other AR Utilities	126	126	-	-	5	5		
IA	Other IA Utilities	300	-	300	-	6	6		
KS	Other KS Utilities	7,465	5,041	1,729	695	166	66		100
LA	Other LA Utilities	440	330	-	110				
MN	Other MN Utilities	-	-	-	-	43	43		
MO	Other MO Utilities	5,176	3,031	1,642	503	427	74	165	188
MT	Other MT Utilities	510	75	385	50				
ND	Other ND Utilities	1,033	72	887	74	4	4		
NE	Other NE Utilities	3,497	2,026	1,171	300				
NM	Other NM Utilities	500	500	-	-				
OK	Other OK Utilities	3,396	2,001	1,143	252	540		540	
SD	Other SD Utilities	1,832	63	1,705	63	34	10		24
TX	Other TX Utilities	2,482	920	852	710				
Total		**94,920**	**36,092**	**51,712**	**7,116**	**6,197**	**1,097**	**904**	**4,197**

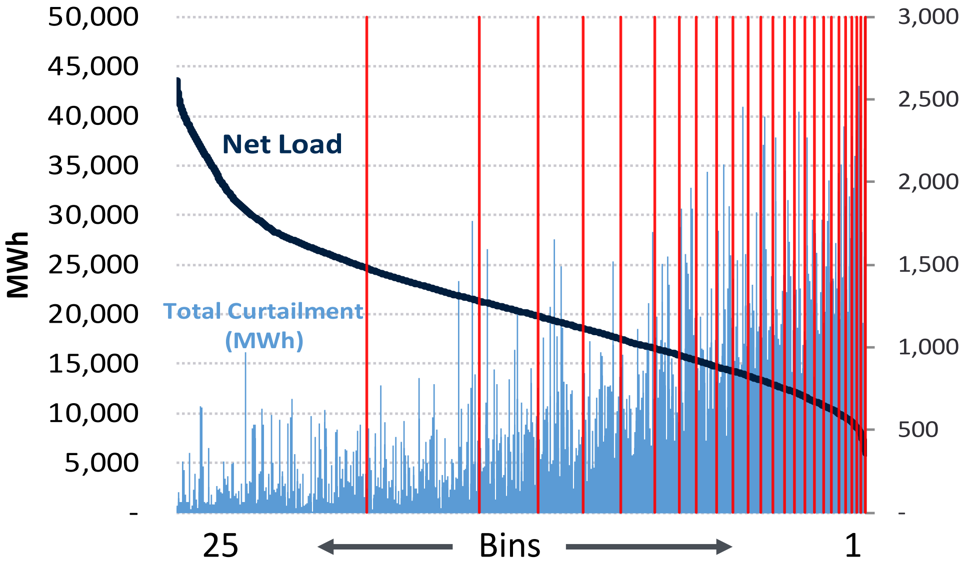
Planned Capacity Source: SPP GI Queue accessed September 28, 2020

Step 2: Identify 24 Snapshots - 1/5

Step 2: Select 24 representative snapshots from SPP operational power flow cases.

- The 24 snapshots should represent varying conditions over a full year.
  - This is an alternative approach to performing production simulation type analyses.
  - This approach may reflect historical operational conditions better than production simulations.
- Create 25 bins (numbered 1 through 25) using historical data (one full year).
  - Sort all hours in the year by decreasing net load.
  - Create 25 bins (separated by red lines in the chart to contain about 1/25th of the total (annual) curtailment observed.
  - Curtailment is higher in hours where net load (shown as the thick black line in the chart to the right) is lower.
  - Analysis will be for 24 bins, excluding the first bin (bin 25) with minimal average curtailment.
- Select appropriate snapshots to represent each bin.

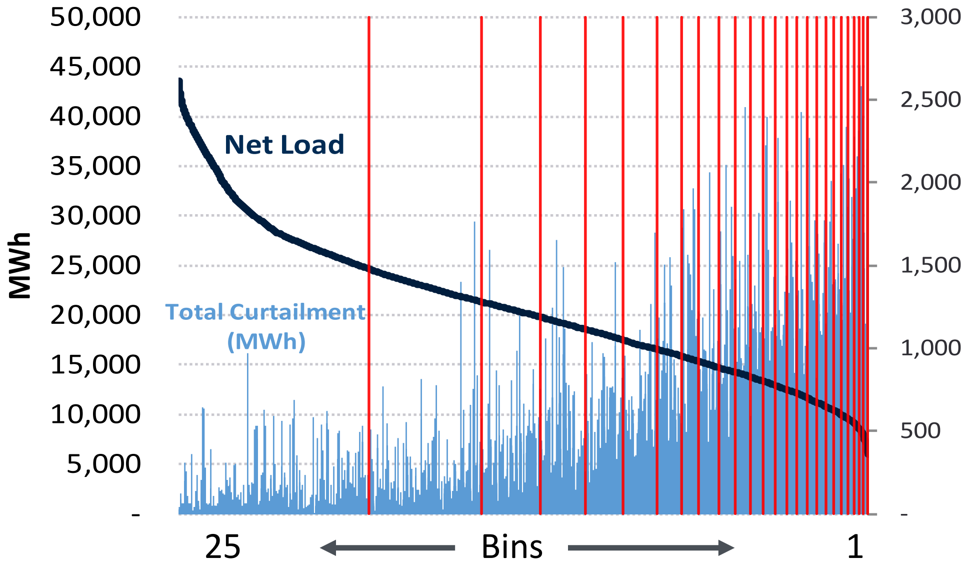
NET LOAD AND WIND CURTAILMENT



Step 2: Identify 24 Snapshots - 2/5

25 bins (numbered 1 through 25) created using historical data (one full year).

- Each bin (separated by red lines in the chart to the below) contains approximately 1/25th of the total (annual) curtailment observed.



Areas between red line indicates the bins from which snapshots were selected, blue bars indicate curtailment of renewables. Each bin contains equal amounts of curtailment.

To be analyzed

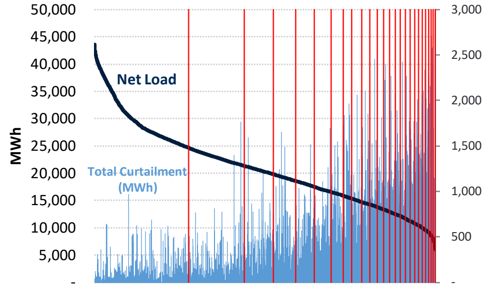
BIN INFORMATION

Bin	Wind Production Potential [MWh]	Wind Curtailment [MWh]	Average Curtailment [%]	Average Curtailment [MWh]	No of Hours
1	930,179	56,420	6%	973	58
2	801,517	57,229	7%	1,122	51
3	995,079	55,534	6%	868	64
4	1,190,204	56,178	5%	711	79
5	1,272,130	56,782	4%	668	85
6	1,418,124	56,184	4%	579	97
7	1,454,767	56,198	4%	573	98
8	1,690,406	57,186	3%	485	118
9	1,734,496	55,497	3%	455	122
10	1,916,544	56,104	3%	422	133
11	1,743,862	56,538	3%	449	126
12	2,054,919	55,794	3%	374	149
13	2,111,623	56,131	3%	364	154
14	2,154,600	56,823	3%	351	162
15	2,569,128	56,044	2%	289	194
16	2,698,718	56,007	2%	269	208
17	3,225,928	56,365	2%	217	260
18	2,680,982	56,487	2%	262	216
19	3,792,959	56,089	1%	179	313
20	4,647,197	56,480	1%	130	434
21	4,940,542	56,082	1%	117	480
22	5,436,156	56,237	1%	98	575
23	6,560,518	56,340	1%	75	750
24	10,239,766	56,239	1%	39	1436
25	13,951,550	56,266	0%	23	2421

Step 2: Identify 24 Snapshots - 3/5

Select a representative hour from each bin to obtain 24 snapshots that span the conditions where wind curtailment occurs.

- Maintain daily and seasonal spread.
  - No same day.
  - More than 4 per season (4 Winter, 6 Spring, 6 Summer, 8 Fall).



To be analyzed

BIN Information

Bin	Wind Production Potential [MWh]	Wind Curtailment [MWh]	Average Curtailment [%]	Average Curtailment [MWh]	No of Hours
1	930,179	56,420	6%	973	58
2	801,517	57,229	7%	1,122	51
3	995,079	55,534	6%	868	64
4	1,190,204	56,178	5%	711	79
5	1,272,130	56,782	4%	668	85
6	1,418,124	56,184	4%	579	97
7	1,454,767	56,198	4%	573	98
8	1,690,406	57,186	3%	485	118
9	1,734,496	55,497	3%	455	122
10	1,916,544	56,104	3%	422	133
11	1,743,862	56,538	3%	449	126
12	2,054,919	55,794	3%	374	149
13	2,111,623	56,131	3%	364	154
14	2,154,600	56,823	3%	351	162
15	2,569,128	56,044	2%	289	194
16	2,698,718	56,007	2%	269	208
17	3,225,928	56,365	2%	217	260
18	2,680,982	56,487	2%	262	216
19	3,792,959	56,089	1%	179	313
20	4,647,197	56,480	1%	130	434
21	4,940,542	56,082	1%	117	480
22	5,436,156	56,237	1%	98	575
23	6,560,518	56,340	1%	75	750
24	10,239,766	56,239	1%	39	1436
25	13,951,550	56,266	0%	23	2421

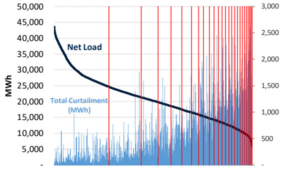
Bin	Date	Time*
1	April 12, 2020	Early Morning
2	September 28, 2020	Early Morning
3	June 1, 2020	Early Morning
4	September 21, 2020	Early Morning
5	June 13, 2020	Early Morning
6	September 9, 2020	Early Morning
7	March 8, 2020	Mid Day
8	January 9, 2020	Early Morning
9	November 11, 2019	Late Afternoon
10	January 8, 2020	Late Afternoon
11	April 18, 2020	Early Morning
12	September 10, 2020	Early Morning
13	December 7, 2019	Late Afternoon
14	April 16, 2020	Late Afternoon
15	March 4, 2020	Late Night
16	December 19, 2019	Late Afternoon
17	May 10, 2020	Late Night
18	November 15, 2019	Late Afternoon
19	December 11, 2019	Late Afternoon
20	November 16, 2019	Mid Day
21	August 13, 2020	Early Morning
22	September 6, 2020	Mid Day
23	August 20, 2020	Late Night
24	June 26, 2020	Late Night

* SPP provides limited snapshots (Early Morning: 0500, Mid Day: 1100, Late Afternoon: 1700 Late Night: 2300)

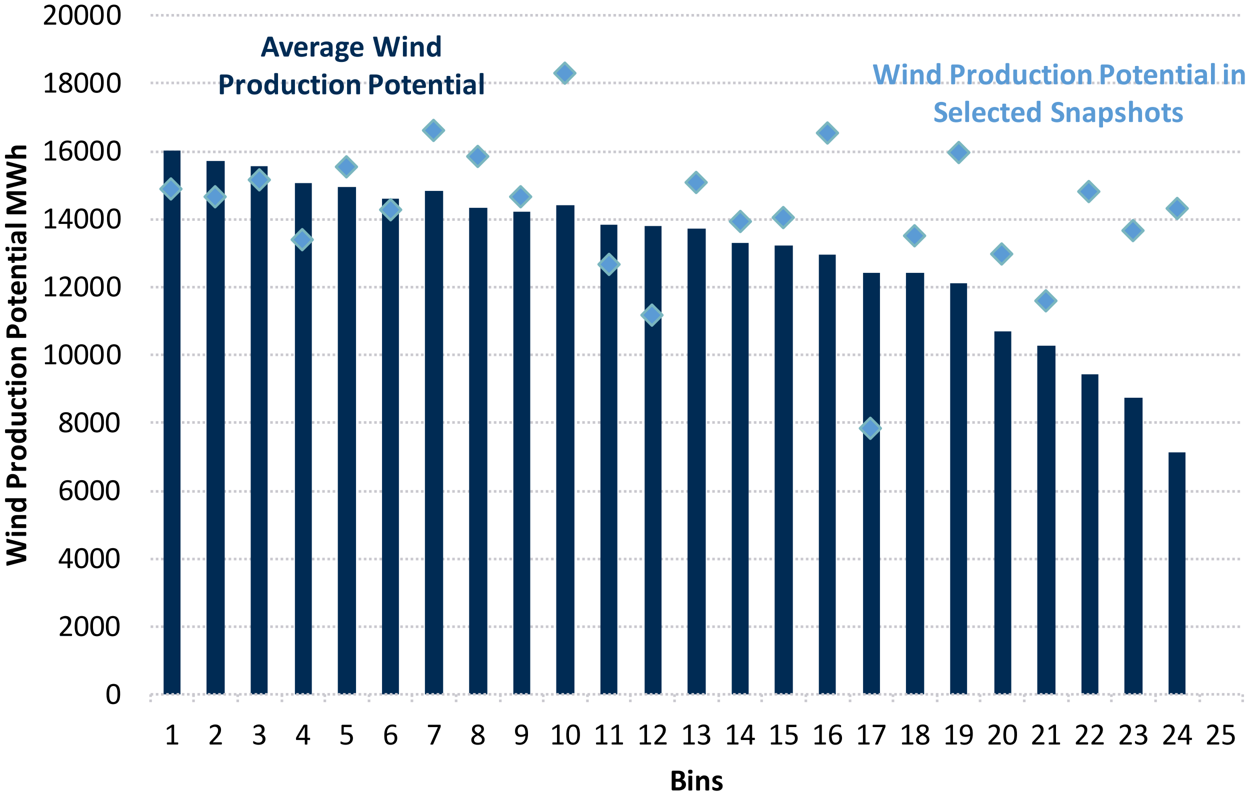
Step 2: Identify 24 Snapshots - 4/5

Select a representative hour from each bin to obtain 24 snapshots that span the conditions where wind curtailment occurs.

- Average wind production potential in sample: 14.3 GW.
  - Sample wind production potential ranges from 7.9 GW to 18.3 GW.



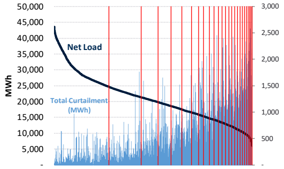
Bin	Date	Time*
1	April 12, 2020	Early Morning
2	September 28, 2020	Early Morning
3	June 1, 2020	Early Morning
4	September 21, 2020	Early Morning
5	June 13, 2020	Early Morning
6	September 9, 2020	Early Morning
7	March 8, 2020	Mid Day
8	January 9, 2020	Early Morning
9	November 11, 2019	Late Afternoon
10	January 8, 2020	Late Afternoon
11	April 18, 2020	Early Morning
12	September 10, 2020	Early Morning
13	December 7, 2019	Late Afternoon
14	April 16, 2020	Late Afternoon
15	March 4, 2020	Late Night
16	December 19, 2019	Late Afternoon
17	May 10, 2020	Late Night
18	November 15, 2019	Late Afternoon
19	December 11, 2019	Late Afternoon
20	November 16, 2019	Mid Day
21	August 13, 2020	Early Morning
22	September 6, 2020	Mid Day
23	August 20, 2020	Late Night
24	June 26, 2020	Late Night



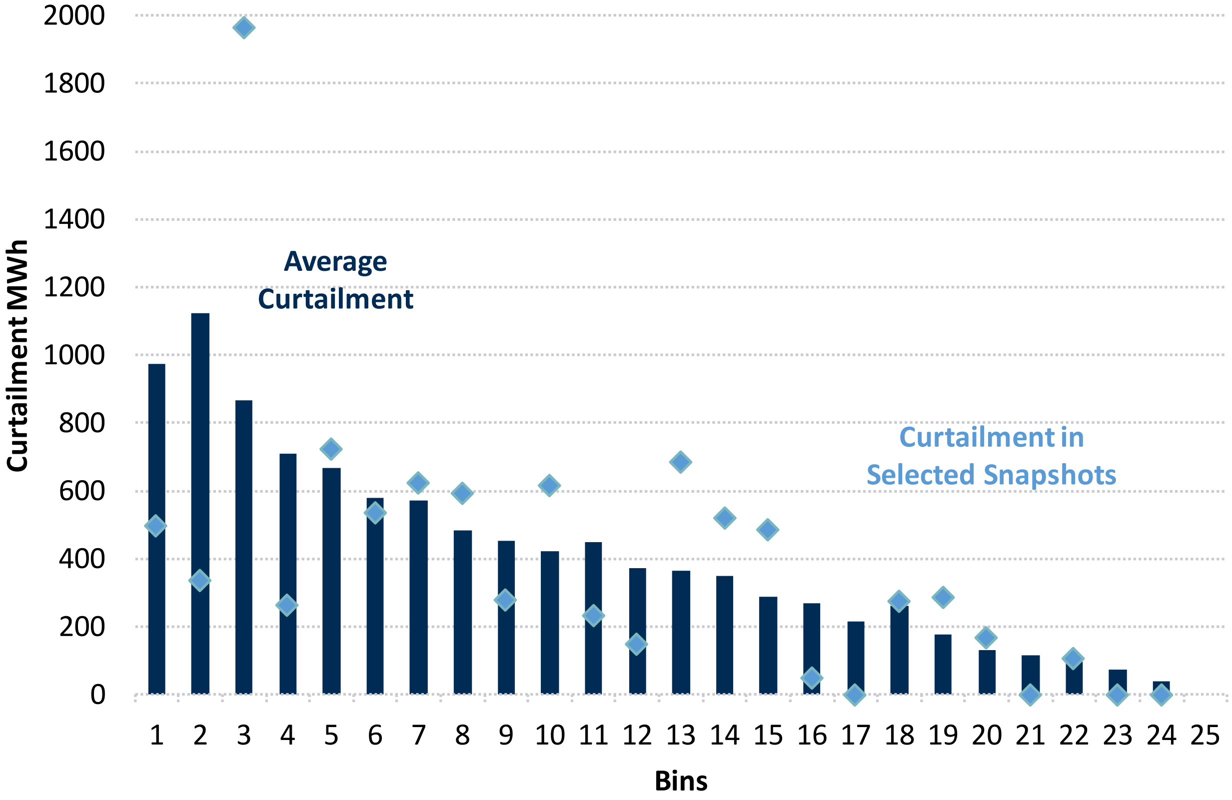
Step 2: Identify 24 Snapshots - 5/5

Select a representative hour from each bin to obtain 24 snapshots that span the conditions where wind curtailment occurs.

- Average capacity factor: 63.2% (annual SPP CF 41.5%).
- Average curtailment in sample: 2.8%.



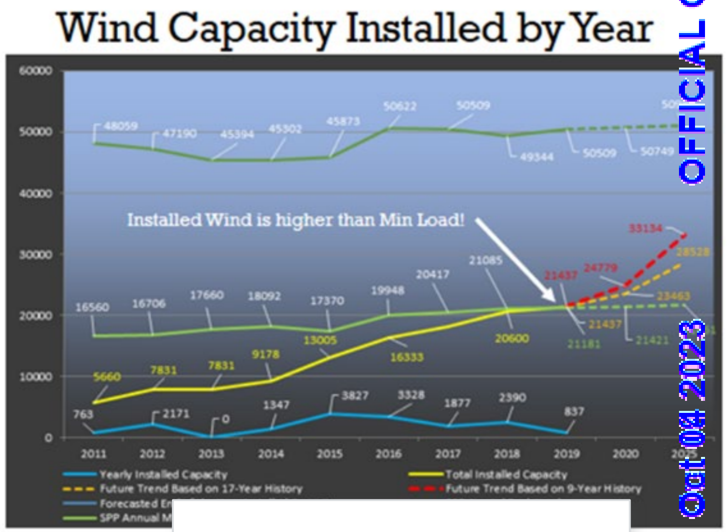
Bin	Date	Time*
1	April 12, 2020	Early Morning
2	September 28, 2020	Early Morning
3	June 1, 2020	Early Morning
4	September 21, 2020	Early Morning
5	June 13, 2020	Early Morning
6	September 9, 2020	Early Morning
7	March 8, 2020	Mid Day
8	January 9, 2020	Early Morning
9	November 11, 2019	Late Afternoon
10	January 8, 2020	Late Afternoon
11	April 18, 2020	Early Morning
12	September 10, 2020	Early Morning
13	December 7, 2019	Late Afternoon
14	April 16, 2020	Late Afternoon
15	March 4, 2020	Late Night
16	December 19, 2019	Late Afternoon
17	May 10, 2020	Late Night
18	November 15, 2019	Late Afternoon
19	December 11, 2019	Late Afternoon
20	November 16, 2019	Mid Day
21	August 13, 2020	Early Morning
22	September 6, 2020	Mid Day
23	August 20, 2020	Late Night
24	June 26, 2020	Late Night

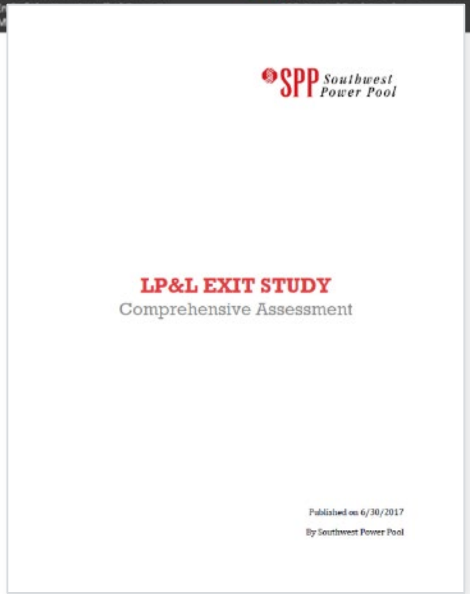


Step 3: Modify the 24 Snapshots - 1/2

Step 3: Modify the snapshots from SPP to reflect new transmission upgrades, wind and solar units from the generation interconnection queue, announced retirements, load changes, etc., to model 2025.

- Generation
  - Add/retire announced thermal generation.
  - Add new wind and solar units from interconnection queue. Assume added units' max potential output based on capacity factor from nearby units of the same type (this will be done by snapshot).
  - Adjust wind/solar dispatch to reverse curtailment by observing historical data on LMPs to identify units that may have been be curtailed (e.g., LMP less than -$20/MWh).
  - For assumed curtailments, estimate what the non-curtailed dispatch might have been using nearby wind/solar units.
- Load
  - Adjust load to 2025 level.
  - Remove portion of Lubbock load that is scheduled to transfer to ERCOT.*
  - Keep imports/exports with neighboring areas constant.





* LP&L Exit Study, available at https://www.spp.org/documents/52338/2017-lpl%20exit%20study%20-%2020170630_final.pdf

Step 3: Modify the 24 Snapshots - 2/2

Step 3: Modify the snapshots from SPP to reflect new transmission upgrades, wind and solar units from the generation interconnection queue, announced retirements, load changes, etc., to model 2025.

- Transmission
  - Adjust transmission constraint limits by comparing binding constraints against historical data (and adjust as necessary.)
  - Add new transmission projects. Transmission projects that are planned to be in service by 2025 are selected from SPP's Integrated Transmission Planning (ITP) reports (See appendix for the list of projects.)
  - Identify outages in snapshots that correspond to capital projects, and put them back in service.
  - Setup single-element contingencies in SPP and neighboring areas (Mid-American, Associated Electric, Entergy etc.).

Step 4: Find Max Renewables - 1/3

Step 4: Find the maximum amount of renewables that can be integrated under a business as usual scenario (Base Case) and then with GETs.

- Dispatch wind and solar to their max output by running Security Constrained Optimal Power Flow (SCOPF).
  - Adjust output of non-renewable units. For fossil-fuel thermal units:
    - If capacity is < 100 MW, allow the unit to shut down.
    - If capacity is >= 100 MW, assume the unit's min-gen is 30% of max-capacity.
    - For night time snapshots, allow natural gas-fueled combined cycle units and simple cycle units to shut down as needed.
    - Leave nuclear units and units outside of SPP operating as is (i.e., no redispatch).
  - Set priority order for different generator units by unit type.
    - Prioritize wind and solar over other units, and prioritize existing wind/solar over new wind/solar.

Step 4: Find Max Renewables - 2/3

Step 4: Find the maximum amount of renewables that can be integrated under a business as usual scenario (Base Case) and then with GETs (With GETs Case). This will be performed by solving the power flow cases for the entire SPP footprint.

- Without GETs implemented (Business as Usual).
  - Assess curtailment without GETs.
  - Solve SCOPF (i.e., run contingency analysis to get violations, add interfaces to represent violations and re-run OPF, repeat these steps until no new violations are identified.) In doing so, enforce 69 kV and higher constraints within SPP, and 100 kV and higher constraints for external regions.
  - Save power flow case as Base Case.
  - Tally curtailment by comparing dispatch with limits for all wind and solar units. For new renewable projects (9,430 MW-worth from GI Queue), assume 5% curtailment thresholds for viability assessment (i.e., projects are considered viable if analysis indicates annual curtailments to be less than 5%). This will be an iterative process (i.e., run SCOPF, take out renewable projects with high curtailments, then resolve SCOPF, and repeat).

Step 4: Find Max Renewables - 3/3

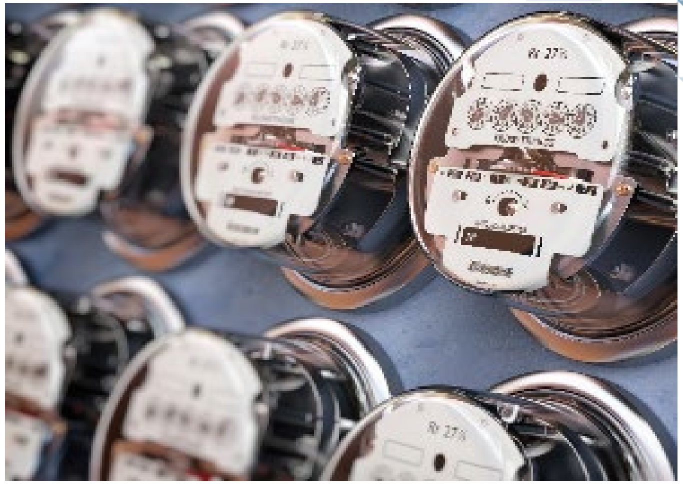
Step 4: Find the maximum amount of renewables that can be integrated under a business as usual scenario and then with GETs (in the order of DLR, Topology Optimization, and Advanced Power Flow Control). This will be performed by solving the power flow cases for the entire SPP footprint.

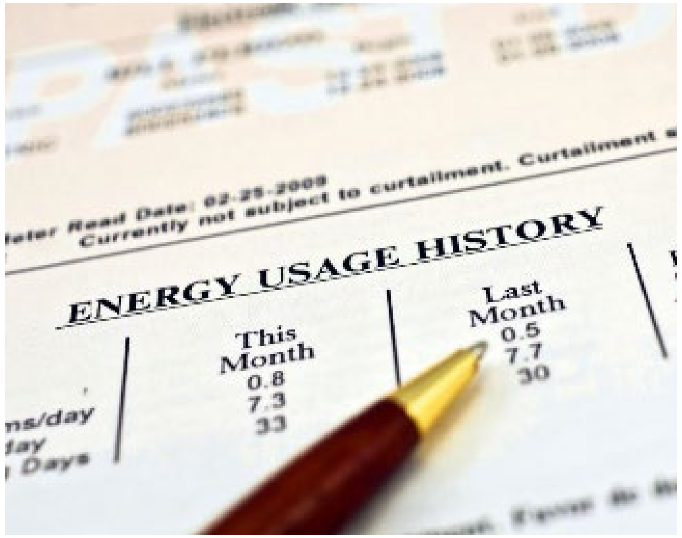
- With GETs implemented (repeat the analysis from the previous slide).
  - Perform DLR analysis on Base Case and save power flow case as DLR Case.
  - Perform Topology Optimization analysis on DLR Case, save power flow case as TC Case.
  - Perform Flow Control analysis on TC Case, save power flow case as FC Case.
  - Revisit FC Case to identify additional DLR and/or Topology Optimization opportunities.
  - Tally curtailment by comparing dispatch with limits for all wind and solar units. Apply the same 5% threshold to assess project viability.
- Results will be for the **combined benefits**, rather than individual GETs.
  - The order of GETs implemented in the analysis will likely change the benefits reaped by the individual technologies (i.e., being the first technology to be added would likely show larger benefits than being last).

Step 5: Assess Benefits - 1/3

Step 5: Assess benefits including economic values (production cost savings, job creation, local benefits, etc.) and carbon emissions reduction.

- Calculate production costs benefits and carbon emission benefits utilizing SPP market data where applicable.
- Review public studies on the economic impacts to estimate "per unit" benefits, and apply to the findings.
- GETs Vendors provide economic impacts associated with their respective technology installments.
  - Cost data for both initial investment, and ongoing operational costs once installed, provided by GETs vendors.



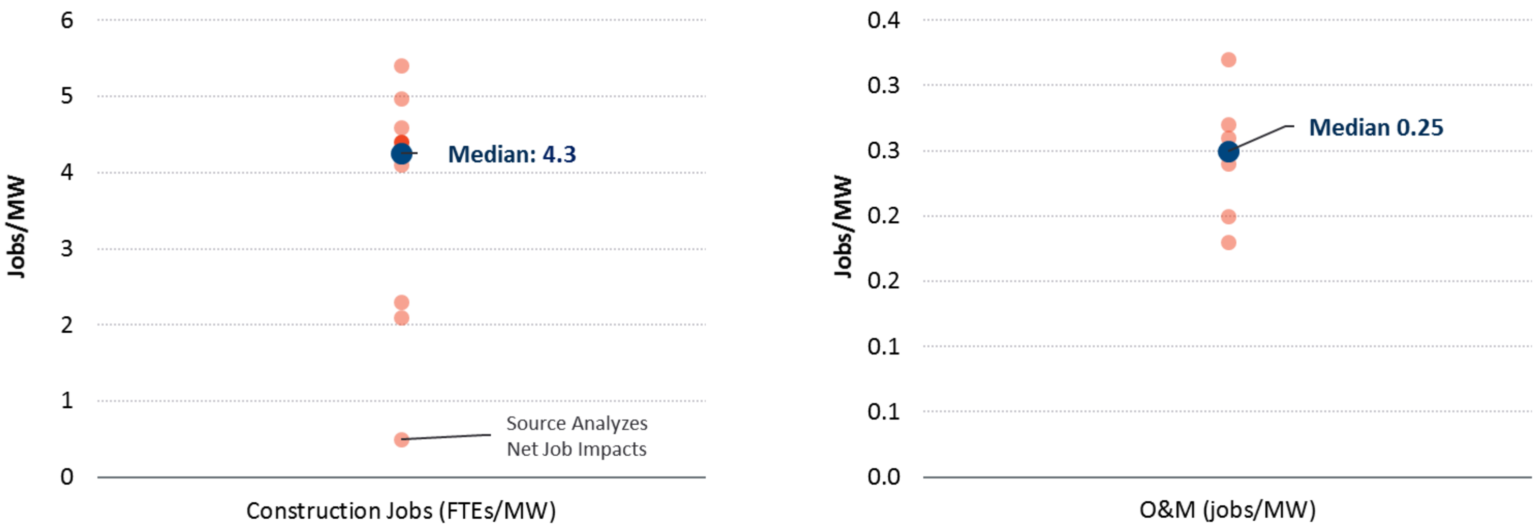


Step 5: Assess Benefits - 2/3

Adding more renewables produces jobs.

- Review of various public reports (14)* to assess job impacts through wind investments.
  - Direct, indirect, and induced jobs are included.
  - Data generally reflects short term jobs (e.g., construction jobs) rather than long term O&M jobs.
  - Impacts are at the state level (or smaller geographical areas).

COMPARISON OF JOB IMPACTS ACROSS STUDIES



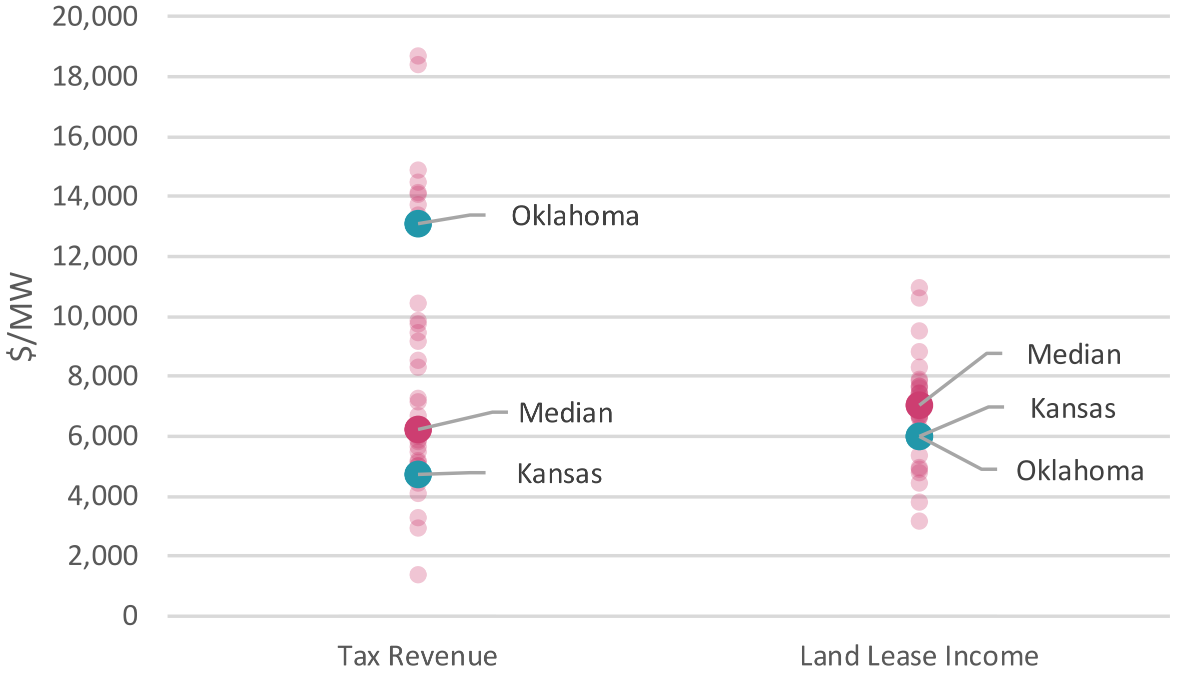
* See Appendix-B for list of reports reviewed.

Step 5: Assess Benefits - 3/3

Adding more renewables produces additional local benefits.

- Review of various public reports (7)* to assess land lease and tax revenues from wind development.

COMPARISON OF LEASE AND TAX REVENUES ACROSS STUDIES AND STATES



* See Appendix-B for list of reports reviewed.

Table of Contents

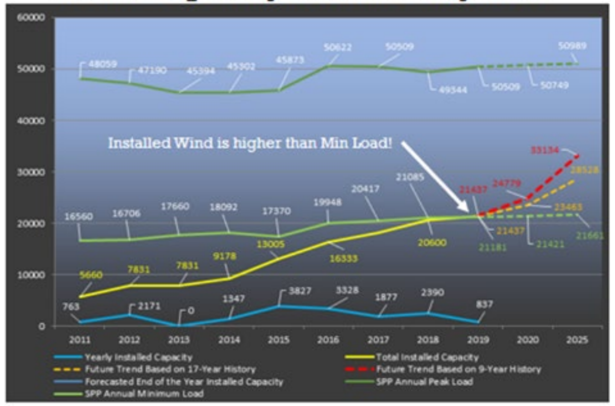
System Assumptions for 2025

Study focus area: Kansas and Oklahoma.

- Load Change
  - SPP estimates 240 MW load growth between 2020 and 2025.
  - Approximately 470 MW (summer peak) of Lubbock load estimated to transfer to ERCOT in 2021.
    - Load connected to the Xcel Energy system by four 230 kV nodes (LP-Milwakee, LP-Southeast, LP-Holly, and LP-Wadswrth) is scheduled to transfer. Roughly 180 MW will remain in SPP.
- Over 9,400 MW of potential renewable projects.
  - Projects in the SPP GI queue projects with IA executed.
- Over 70 new transmission projects added.
  - Based on status from ITP Assessment reports.

Detail data are included in the Appendix.

Wind Capacity Installed by Year



POTENTIAL RENEWABLE PROJECTS

State	Wind	Solar	Total
Kansas	3,410	120	3,530
Oklahoma	5,760	140	5,900
Total	9,170	260	9,430

[Rounded to the nearest 10 MW]

TRANSMISSION PROJECTS

Voltage Level	Project Counts
230 KV and Above	16
169 kV and 138 kV	27
115 kV	16
69 kV	14
Total	73

Renewables Under Base Case

Study focus area: Kansas and Oklahoma.

- Base Case (business as usual) allows for over 2,500 MW of new renewables to be integrated.
  - Retirements of existing thermal resources contribute.
  - While limited, load growth also contributes.
  - Lubbock load departure works against integrating more renewables.

ADDITIONAL RENEWABLES INTEGRATED – BASE CASE

State	Potential (MW)			Base Case (MW)			Realization (%)		
	Wind	Solar	Total	Wind	Solar	Total	Wind	Solar	Total
Kansas	3,410	120	3,530	1,710	0	1,710	50%	0%	48%
Oklahoma	5,760	140	5,900	770	100	870	13%	71%	15%
Total	9,170	260	9,430	2,480	100	2,580	27%	38%	27%

[Rounded to the nearest 10 MW]

Renewables Under With GETs Case - 1/3

GETs utilized in this study include:

- **Hardware solutions**: DLR on 56 lines and Advanced Power Flow Control on 8 locations.

Hardware Solutions by Voltage Level	345	230	161	138	115	69	Total
DLR*	10	3	11	22	3	7	56
Advanced Power Flow Control	3	0	4	1	0	0	8

- **Software solutions**: 204 unique Topology Optimization reconfigurations, averaging 13 per snapshot.**

Software Solutions by Voltage Level	345	230	161	138	115	69	Total
Lines	20	10	31	75	4	30	170
Substations	4	0	1	1	0	0	6
Transformers (high voltage terminal)	10	1	4	13	0	0	28

- Estimated costs for implementing the above GETs: ~$90 million.
  - Initial investment costs is estimated to be around $90 million.***
  - Ongoing costs of around $10 million per year.***

* Every DLR installation requires 15 to 30 sensors.

** Average actions represent the average number of actions that remain per case, not actions per hour. Based on other studies the average number of actions per hour is expected to be smaller, typically less than the number of topology changes due to planned outages.

*** Costs can vary project by project, and also on how the GETs service is provided—for example, Topology Optimization can be provided as a software subscription service to reduce the initial cost. We also assume utilities can incorporate these technologies without large costs.

Renewables Under With GETs Case - 2/3

Study focus area: Kansas and Oklahoma.

- GETs allow for **over 5,200 MW** of new renewables to be integrated.
  - This is **more than twice the amount** of renewables integrated in the Base Case.

ADDITIONAL RENEWABLES INTEGRATED – WITH GETS CASE

State	Potential (MW)			With GETs Case (MW)			Realization (%)		
	Wind	Solar	Total	Wind	Solar	Total	Wind	Solar	Total
Kansas	3,410	120	3,530	1,910	0	1,910	56%	0%	54%
Oklahoma	5,760	140	5,900	3,200	140	3,340	56%	100%	57%
Total	9,170	260	9,430	5,110	140	5,250	56%	54%	56%

[Rounded to the nearest 10 MW]

- Curtailment levels of existing renewables (wind) are also reduced.
  - Existing wind curtailment reduced by over 76,000 MWh.
  - No change for solar.

Renewables Under With GETs Case - 3/3

GETs enable more than twice the amount of additional new renewables to be integrated.

- Potential Renewables Considered: 9,430 MW
  - Based on queue projects with IA executed.
- Integrated Renewables (without further transmission upgrades)
  - Base Case: 2,580 MW
  - With GETs Case: 5,250 MW
  - Delta (With GETs Case – Base Case): 2,670 MW

RENEWABLE POTENTIAL ASSUMED FOR KANSAS AND OKLAHOMA

State	Wind	Solar	Total
Kansas	3,410	120	3,530
Oklahoma	5,760	140	5,900
Total	9,170	260	9,430

[Rounded to the nearest 10 MW]

~1.5 times the amount of wind SPP integrated in 2019 (1.8 GW).

ADDITIONAL RENEWABLES INTEGRATED

State	Base Case			With GETs Case			Delta (GETs - Base)		
	Wind	Solar	Total	Wind	Solar	Total	Wind	Solar	Total
Kansas	1,710	0	1,710	1,910	0	1,910	200	0	200
Oklahoma	770	100	870	3,200	140	3,340	2,430	40	2,470
Total	2,480	100	2,580	5,110	140	5,250	2,630	40	2,670

X2

[Rounded to the nearest 10 MW]

Benefits of Increased Renewables - 1/7

GETs enable more than twice the amount of additional renewables to be integrated.

- 2,670 MW = 5,250 MW (With GETs Case) – 2,580 MW (Base Case)
- 2,670 MW = 2,630 MW (Wind) + 40 MW (Solar)
- GETs investment cost is around $90 million.

SUMMARY OF BENEFITS OF INCREMENTAL 2,670 MW OF RENEWABLES - 1/2

Annual Renewables Benefits			Notes
Additional Generation	New Wind	8,640 GWh	Wind assumes 37.5% capacity factor, solar assumes 18.0% capacity facto, see slide 51.
	New Solar	60 GWh	
	Total	8,700 GWh	
Reduction in Curtailment from Existing Wind		76 GWh	
Total Increase in Renewable Generation		8,776 GWh	
Annual Production Costs Savings		$175 million	Assumes $20/MWh is avoided, see slide 52.
Annual Carbon Reduction		3 million tons	Assumes Combined Cycle Plant (350g per kWh), see slides 53 & 54.

Benefits of Increased Renewables - 2/7

GETs enable more than twice the amount of additional renewables to be integrated.

- 2,670 MW = 5,250 MW (With GETs Case) – 2,580 MW (Base Case)
- 2,670 MW = 2,630 MW (Wind) + 40 MW (Solar)
- GETs investment cost is around $90 million.

SUMMARY OF BENEFITS OF INCREMENTAL 2,670 MW OF RENEWABLES - 2/2

Renewables Benefits			Notes
Direct Jobs from Renewables	Short-term (Construction etc)	Over 11,300 person-year	See slide 55.
	Long-term (O&M etc)	Over 650 person-year	
Estimated Local Tax Revenues (Annual)		$32 million	
Estimated Land Lease Revenues (Annual)		$15 million	

- There are additional job benefits associated with the installation and operations of GETs.
  - 50 to 60 long-term jobs.
  - 20 to 30 short-term jobs (for installation).

Benefits of Increased Renewables - 3/7

GETs enable additional new renewables by: 2,670 MW / 8,776 GWh.

- 2,630 MW of Wind is assumed to produce over 8,640 GWh of energy per year.
  - Assumes 37.5% capacity factor for wind.
  - 2019 SPP State of the Market Report* shows wind producing roughly 74,000 GWh of power and SPP having 22,482 MW of wind at the end of 2019.
  - These figures conservatively suggest the realized average capacity factor of wind is 37.5% (after accounting for outages and curtailments).
  - In reality newer wind plants show higher capacity factors. SPP State of the Market Report shows real time capacity factors for wind in 2019 to be 39.4%.
- 40 MW of Solar is assumed to produce about 60 GWh of energy per year.
  - Assuming 18% capacity factor for solar.
- Curtailment of existing wind is reduced by more than 76 GWh a year.
  - Total increase in renewables generation enabled by GETs is 8,776 GWh.

* 2019 SPP State of the Market Report, available at: https://www.spp.org/documents/62150/2019%20annual%20state%20of%20the%20market%20report.pdf

Benefits of Increased Renewables - 4/7

GETs enable additional 8,776 GWh of generation from renewables.

- Estimated annual production cost savings: **Over $175 million**.
  - Conservatively assumes $20/MWh savings for 8,776 GWh of energy.
  - Generation cost of a new natural gas-fueled combined cycle plants would be in the $20/MWh to $25/MWh range (assuming $2.5-3.0/MMBtu fuel cost and 7,000 Btu/kWh heat rate plus VOM).
  - Generation cost of coal plants would be in the $20/MWh to $25/MWh range (assuming $2/MMBtu fuel cost and 10,000 Btu/kWh heat rate plus VOM).
  - LMPs can be used as an indicator for the marginal cost of power. The SPP State of the Market Report shows 2019 day-ahead prices averaged around $22/MWh and real-time prices averaged around $21/MWh. 2018 average was $25/MWh for both.
  - This value does **NOT** include any Production Tax Credit-driven savings.
  - Pay-back for GETs investment ($90 million) is about half a year.

Benefits of Increased Renewables - 5/7

GETs enable additional 8,776 GWh of generation from renewables.

- Estimated carbon emissions reduction: **Over 3 million tons per year**.
  - Conservatively assumes the additional new renewables replace carbon emissions from natural gas-fueled combined cycle plants (with emission estimated to be 350g per kWh, or 0.8 pound per kWh).
  - Less efficient resources with higher heat rates and emission rates are more likely to be replaced. The average coal plant produces approximately twice the amount of carbon emissions, compared to a combined cycle plant. An average natural gas-fueled simple cycle gas turbine (a.k.a. peakers) produces approximately 20% to 30% more carbon emissions, compared to a combined cycle plant.
  - Additional benefits include **reduced water usage**. By enabling twice the amount of renewables to be integrated, reduction in water usage for power production is doubled.

Benefits of Increased Renewables - 6/7

GETs, through enabling more renewables, is estimated to reduce carbon emission by over 3 million tons per year.

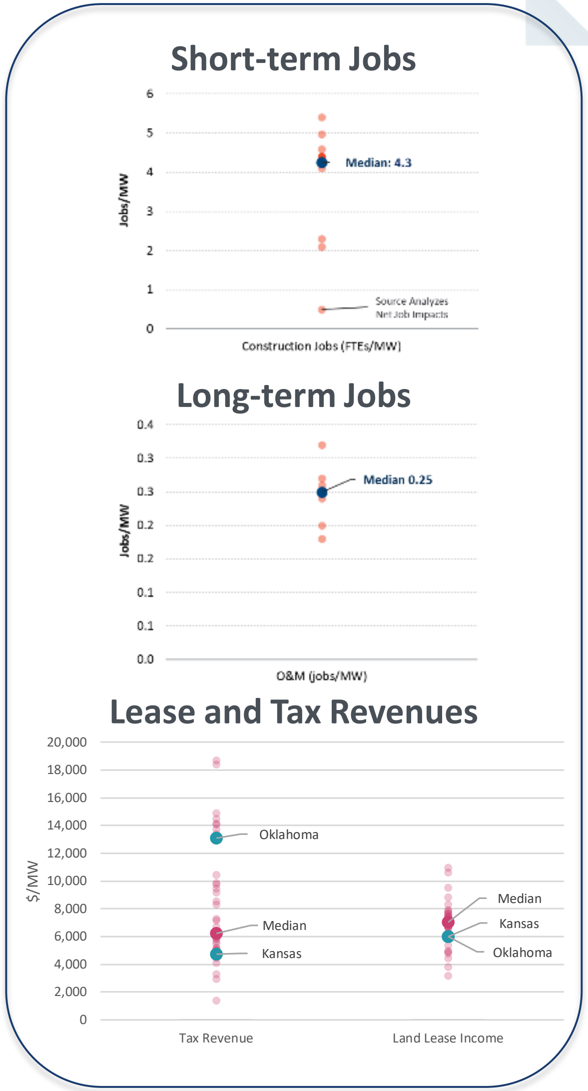
- Cumulative greenhouse gas (GHG) in the atmosphere is what causes warming, not the rate at which they are emitted in any given year (and they persist in the atmosphere for decades or longer).
  - Therefore, early reductions in GHG emissions are in many ways more important than eventual depth of reductions, because of the cumulative and persistent nature of GHGs in the atmosphere.
  - A recent whitepaper published by Brattle* illustrates how earlier adoption can lead to lower cumulative GHG emission (through 2050).
- Utilizing GETs could set an example for early adoption of existing technology to curb GHG emission.

* Clean Energy and Sustainability Accelerator, available at: https://brattlefiles.blob.core.windows.net/files/20809_clean_energy_and_sustainability_accelerator.pdf

Benefits of Increased Renewables - 7/7

The additional 2,670 MW (2,430 in Oklahoma and 200 MW in Kansas) of renewables enabled by GETs will provide jobs and other local benefits.

- Over 11,300 direct short-term jobs (largely construction of renewables).
  - Assumes 4.3 jobs (person-year) / MW for wind and 1.3 jobs (person-year) / MW for solar.
- Over 650 direct long-term jobs for operation and maintenance of the renewable resources.
  - Assumes 0.25 jobs (person-year) / MW for wind and 0.005 jobs (person-year) / MW for solar.
- Other estimated local benefits include over $32 million annual tax revenues and $15 million land lease revenues.
  - Tax revenues assumes $13,000/MW for the 2,430 MW in Oklahoma and $4,700/MW for the 200 MW in Kansas.
  - Land lease revenues assumes $5,900/MW for both Kansas and Oklahoma.



Summary of Benefits - 1/2

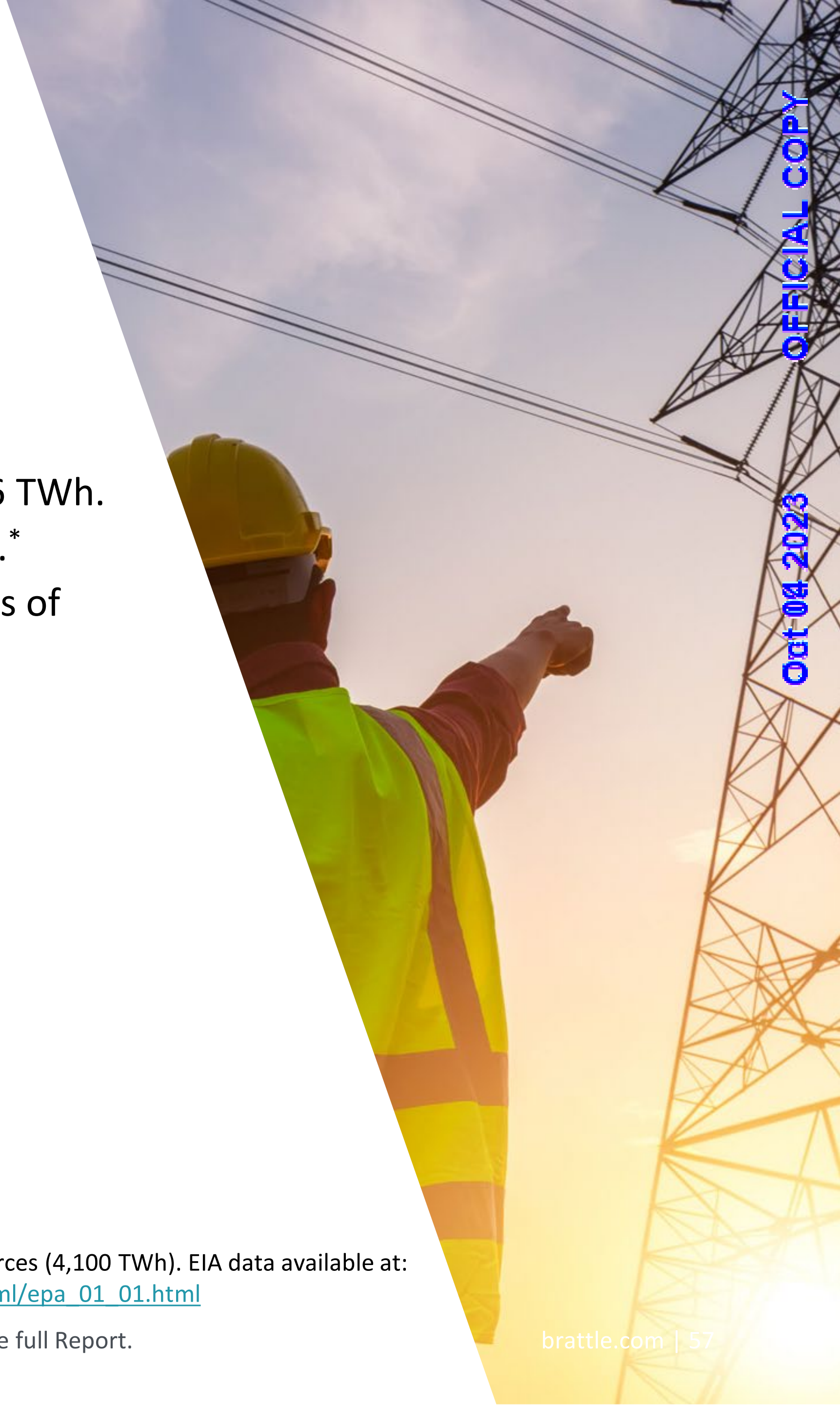
Key benefits of GETs for Kansas and Oklahoma

- Enable more than **twice** the amount of additional new renewables to be integrated.
  - This is 1.5x the amount of wind SPP integrated in 2019.
- Estimated annual production cost savings: **$175 million**.
  - This suggests the payback for GETs investment is about 0.5 years.
- Estimated carbon emissions reduction: **Over 3 million tons per year**.
- Other benefits include:
  - Over 11,300 direct short-term jobs (largely construction of renewables).
  - Over 650 direct long-term jobs for operation and maintenance of the renewable resources.
  - Over $32 million annual tax revenues.
  - Over $15 million land lease revenues.

Summary of Benefits - 2/2

- 2019 generation in Kansas and Oklahoma combined was about 136 TWh.*
- 8,700 GWh from the GETs enabled new renewable generation equates to 6.4% of 136 TWh.
- The nationwide generation from utility-scale resources in 2019 was about 4,100 TWh.*
- 6.4% of 4,100 TWh would equate to 260 TWh worth of clean power, or 90 million tons of carbon reduction assuming wind replaces natural gas burning CCs – the most clean conventional fossil-fuel based power generation technology.

- Over **$5 billion** (~$5.3 billion) in production cost savings.
- **$90 million tons** of reduced carbon emission.
  - More than enough to offset **all new automobiles** sold in the U.S. in a year.
- About **$1.5 billion** in local benefits (local taxes and land lease revenues).
- More than 330,000 short-term (only for first year) and nearly 20,000 long-term jobs.
- Investment cost is $2.7 billion (only for first year).
- Ongoing costs would be around $300 million per year.



* EIA shows 2019 generation in Kansas and Oklahoma combined (136 TWh) was about 1/30 of the nationwide generation from utility-scale resources (4,100 TWh). EIA data available at: https://www.eia.gov/electricity/state/kansas/, https://www.eia.gov/electricity/state/oklahoma/, and https://www.eia.gov/electricity/annual/html/epa_01_01.html

APPENDIX

Table of Contents

Glossary

AAR	Ambient Adjusted Ratings
DLR	Dynamic Line Ratings
FACTS	Flexible Alternating Current Transmission Systems
GETs	Grid-Enhancing Technologies
GHG	Greenhouse Gas
GI Queue	Generation Interconnection Queue
IA	Interconnection Agreement
ITP	Integrated Transmission Planning
LMP	Locational Marginal Price
PARs	Phase Angle Regulators
PSTs	Phase Shifting Transformers
SCOPF	Security Constrained Optimal Power Flow
SLR	Static Line Ratings
SPP	Southwest Power Pool

Potential Renewables from SPP GI Queue

Potential renewable generation projects selected from SPP's GI Queue.

Generation Interconnection Number	IFS Queue Number	Nearest Town or County	State	CA	Commercial Operation Date	Capacity	Generation Type	Substation or Line	Status
GEN-2010-005	0	Harper County	KS	WERE	12/31/2020	299.2	Wind	Viola 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2011-019	0	Woodward County	OK	OKGE	12/31/2020	175	Wind	Woodward EHV 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2011-020	0	Ellis	OK	OKGE	12/31/2020	165.6	Wind	Woodward EHV 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-013	IFS-2015-001-18	Kiowa County	OK	WFEC	12/1/2022	120	Solar	Snyder 138kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-029	IFS-2015-001-12	Dewey & Blaine County	OK	OKGE	12/1/2020	161	Wind	Tatonga 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-048	IFS-2015-002-11	Major County	OK	OKGE	10/1/2020	200	Wind	Cleo Corner 138kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-055	IFS-2015-002-25	Beckham County	OK	WFEC	12/1/2022	40	Solar	Erick 138kV Substation	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-062	IFS-2015-002-15	Garfield County	OK	OKGE	12/31/2021	4.5	Wind	Breckinridge 138kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-092	IFS-2015-002-36	Grady	OK	AEPW	12/31/2020	250	Wind	Lawton East Side-Sunnyside (Terry Road) 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-093	IFS-2015-002-37	Caddo	OK	OKGE	12/31/2022	250	Wind	Gracemont 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-095	IFS-2016-001-20	Woods County	OK	OKGE	6/1/2020	176	Wind	Tap Mooreland - Knob Hill 138kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-003	IFS-2016-001-45	Ellis	OK	OKGE	8/31/2021	248.4	Wind	Badger-Woodward EHV Dbl Ckt 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-016	IFS-2016-001-07	Edwards	KS	MIDW	11/1/2021	78.2	Wind	North Kinsley 115 kV	IA FULLY EXECUTED/ON SUSPENSION
GEN-2016-030	IFS-2016-001-26	Johnston County	OK	OKGE	12/1/2021	100	Solar	Brown 138kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-032	IFS-2016-001-11	Kingfisher County	OK	OKGE	12/31/2023	200	Wind	Crescent Substation 138 kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-045	IFS-2016-001-34	Cimarron, Texas County	OK	OKGE	12/31/2021	499.1	Wind	Mathewson 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-057	IFS-2016-001-35	Cimarron, Texas County	OK	OKGE	12/31/2021	499.1	Wind	Mathewson 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-071	IFS-2016-001-19	Kay	OK	OKGE	11/30/2021	200.1	Wind	Middleton Tap 138kV Substation	IA FULLY EXECUTED/ON SUSPENSION
GEN-2016-073	IFS-2016-001-48	Kingman County	KS	WERE	10/30/2022	220	Wind	Thistle-Wichita Dbl Ckt (Buffalo Flats) 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-102	IFS-2016-002-01	Pontotoc	OK	OKGE	12/1/2023	150.9	Wind	Blue River 138kV	IA FULLY EXECUTED/ON SUSPENSION
GEN-2016-118	IFS-2016-002-05	Kingfisher	OK	WFEC	10/1/2021	288	Wind	Dover Switchyard 138 kV Line	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-126	IFS-2016-002-06	Murray	OK	OKGE	10/15/2021	172.5	Wind	Arbuckle 138kV substation	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-131	IFS-2016-002-37	Grady	OK	OKGE	10/31/2020	2.5	Wind	Minco 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-132	IFS-2016-002-61	Roger Mills	OK	AEPW	5/6/2020	6.1	Wind	Sweetwater 230kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-150	IFS-2016-002-15	Nemaha	KS	WERE	12/30/2022	302	Wind	Stranger Creek 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-157	IFS-2016-002-20	Allen County	KS	KCPL	12/31/2022	252	Wind	West Gardner 345kV	IA FULLY EXECUTED/ON SUSPENSION
GEN-2016-158	IFS-2016-002-17	Allen County	KS	KCPL	12/31/2022	252	Wind	West Gardner 345kV	IA FULLY EXECUTED/ON SUSPENSION
GEN-2016-174	IFS-2016-002-19	Nemaha	KS	WERE	11/6/2020	302	Wind	Stranger Creek 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-176	IFS-2016-002-67	Nemaha County	KS	WERE	11/30/2021	302	Wind	Stranger Creek 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2014-001	IFS-2014-001-08	Marion	KS	WERE	7/28/2020	200.6	Wind	Tap Wichita - Emporia Energy Center 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-034	IFS-2015-002-08	Kay County	OK	OKGE	10/31/2020	200	Wind	Rose Hill (Open Sky)-Sooner (Ranch Road) 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-052	IFS-2015-002-03	Sumner	KS	WERE	12/1/2019	300	Wind	Open Sky-Rose Hill 345kV	IA FULLY EXECUTED/ON SUSPENSION
GEN-2015-066	IFS-2015-002-38	Roosevelt County	OK	OKGE	12/31/2022	248.4	Wind	Sooner - Cleveland 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-046	IFS-2016-001-12	Ford County	KS	SUNC	11/15/2021	299	Wind	Clark County-Ironwood 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-051	IFS-2016-001-13	Custer	OK	AEPW	12/31/2020	9.8	Wind	Clinton Junction-Weatherford Southeast 138kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-063	IFS-2016-001-17	Johnston	OK	OKGE	9/1/2021	200	Wind	Hugo-Sunnyside 345 kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-091	IFS-2016-002-22	Caddo	OK	AEP	12/31/2021	303.6	Wind	Gracemont-Lawton East Side 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-036	IFS-2016-001-44	Johnston County	OK	OKGE	8/30/2020	303	Wind	Johnston County 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-082	IFS-2016-001-28	Beaver	OK	OKGE	12/1/2020	198	Wind	Beaver County - Woodward EHV Dbl Ckt (Badger) 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-020	IFS-2016-001-27	Woodward County	OK	WFEC	12/15/2020	148.4	Wind	Moreland 138kV Substation	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-068	IFS-2016-001-40	Garfield	OK	OKGE	10/21/2020	250	Wind	Woodring 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-149	IFS-2016-002-14	Washington	KS	WERE	12/31/2022	300	Wind	Stranger Creek 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-061	IFS-2016-001-15	Garfield/Noble	OK	OKGE	8/1/2020	248.16	Wind	Sooner-Woodring 345 kV line	IA FULLY EXECUTED/ON SCHEDULE
GEN-2017-009	0	Neoshoe County	KS	WERE	10/31/2020	302.5	Wind	Neosho - Caney River 345 kV	DISIS STAGE

List of Transmission Projects - 1/4

PLANNED TRANSMISSION PROJECTS FROM 2019 ITP FOR 2020-2025 (230 KV AND HIGHER)

Project Name	Project Type	Owner	Project Status	In-Service Date
Multi - Gentleman - Cherry Co. - Holt Co. 345 kV	Regional Reliability	NPPD	Delay - Mitigation	6/1/2022
XFR - Thedford 345/115 kV	High Priority	NPPD	Delay - Mitigation	5/1/2021
XFR - Wolfforth 230/115 kV Ckt 1 Transformer	Regional Reliability	SPS	On Schedule < 4	4/15/2021
Sub - Amarillo South 230 kV Terminal Upgrades	Regional Reliability	SPS	On Schedule < 4	4/1/2020
XFR - Sundown 230/115 kV Transformer	Regional Reliability	SPS	Delay - Mitigation	12/15/2020
Multi - Tuco - Yoakum 345/230 kV Ckt 1	Regional Reliability	SPS	Delay - Mitigation	6/1/2020
Sub - Nichols - 230 kV	Regional Reliability	SPS	Delay - Mitigation	5/15/2020
Multi - Sheldon - Monolith 115 kV	Regional Reliability	NPPD	Delay - Mitigation	1/1/2021
XFR - Lawrence Hill 230/115kV	Regional Reliability	WR	Delay - Mitigation	6/1/2021
XFR - McDowell 230/115 kV Ckt 1	Regional Reliability	SPS	Delay - Mitigation	5/28/2021
Multi - China Draw - Road Runner 345 kV	Regional Reliability	SPS	Delay - Mitigation	11/15/2021
Line - Eddy County - Kiowa 345 kV New Line	Regional Reliability	SPS	On Schedule < 4	11/15/2020
Multi - S1361	Regional Reliability	OPPD	On Schedule < 4	6/1/2021
Multi - Cimarron - Northwest - Mathewson 345kV	Economic	OGE	On Schedule < 4	7/1/2020
Multi - Neset - New Town 230 kV	Regional Reliability	BEPC	Re-evaluation	12/31/2022
Sub - Neosho 345 kV	Sponsored Upgrade	WR	On Schedule < 4	7/1/2020

List of Transmission Projects - 2/4

Transmission projects that are planned to be in service by 2025 are selected from SPP's 2019 Integrated Transmission Planning (ITP) Assessment Report.

PLANNED TRANSMISSION PROJECTS FROM 2019 ITP FOR 2020-2025 (138 KV AND 169 KV)

Project Name	Project Type	Owner	Project Status	In-Service Date
Line - Cedar Grove - South Shreveport 138 kV	Transmission Service	AEP	On Schedule < 4	6/1/2020
Line - Keystone Dam - Wekiwa 138 kV Ckt 1 Rebuild	Regional Reliability	AEP	On Schedule < 4	6/1/2021
Line - Lincoln - Meeker 138 kV Ckt 1 New Line	Regional Reliability	OGE	Delay - Mitigation	7/31/2020
Multi - Driftwood 138/69 kV Substation and Transformer	Regional Reliability	WFEC	Delay - Mitigation	4/1/2022
Multi - DeGrasse - Knob Hill 138 kV New Line and DeGrasse 345/138 kV	Regional Reliability	WFEC	Delay - Mitigation	12/1/2024
Sub - Cleo Junction 138 kV Terminal Upgrades	Regional Reliability	WFEC	Delay - Mitigation	5/31/2023
Line - Crosstown - Blue Valley 161 kV New Line	Regional Reliability	KCPL	Re-evaluation	6/30/2023
Sub - Tupelo - Tupelo Tap 138 kV Terminal Upgrades	Economic	WFEC	Delay - Mitigation	12/31/2020
XFR - Creswell 138/69/13.2 kV Transformers	Regional Reliability	WR	On Schedule < 4	6/1/2021
Multi - Park Community - Sunshine 138 kV	Regional Reliability	WFEC	Delay - Mitigation	5/31/2021
Line - Cogar - OU SW 138 kV	Regional Reliability	WFEC	Delay - Mitigation	3/1/2024
Sub - Westmoore 138 kV	Regional Reliability	OGE	On Schedule < 4	12/31/2020
Sub - Santa Fe 138 kV	Regional Reliability	OGE	Re-evaluation	6/1/2021
Sub - Riverside Station 138 kV	Regional Reliability	AEP	Delay - Mitigation	11/1/2022
Sub - Southwestern Station 138 kV	Regional Reliability	AEP	Delay - Mitigation	11/1/2022
Sub - Moore 13.8 kV Breaker	Regional Reliability	NPPD	On Schedule < 4	6/1/2021
Sub - Craig 161 kV	Regional Reliability	KCPL	On Schedule < 4	12/31/2021
Sub - Leeds 161 kV	Regional Reliability	KCPL	On Schedule < 4	12/31/2020
Sub - Southtown 161 kV	Regional Reliability	KCPL	On Schedule < 4	12/31/2021
Sub - Mooreland 138/69 kV Breakers	Regional Reliability	WFEC	On Schedule < 4	5/1/2022
Line - Tulsa SE - S Hudson 138kV Ckt 1	Regional Reliability	AEP	Delay - Mitigation	11/1/2021
Line - Tulsa SE - 21st Street Tap 138kV Ckt 1	Regional Reliability	AEP	Delay - Mitigation	11/1/2021
Line - East Kingfisher - Kingfisher 138kV	Economic	WFEC	On Schedule < 4	1/1/2021
Line - Neosho - Riverton 161 kV	Transmission Service	EDE	NTC-C Project Estimate	10/1/2023
XFR - Pryor Junction 138/115	Regional Reliability	AEP	Delay - Mitigation	11/30/2021
Line - Anadarko - Gracemont 138kV	Economic	WFEC	On Schedule < 4	1/1/2021
Jayhawk Wind 161/69kV Transformer	Sponsored Upgrade	Apex		12/31/2021

List of Transmission Projects - 3/4

PLANNED TRANSMISSION PROJECTS FROM 2019 ITP FOR 2020-2025 (115 KV)

Project Name	Project Type	Owner	Project Status	In-Service Date
Line - Northwest - Rolling Hills 115 kV Ckt 1	Regional Reliability	SPS	On Schedule < 4	5/15/2021
Line - Ainsworth - Ainsworth Wind 115 kV Ckt 1 Rebuild	Regional Reliability	NPPD	On Schedule < 4	6/1/2020
Sub - Carlsbad - Pecos 115 kV Terminal Upgrades	Regional Reliability	SPS	On Schedule < 4	6/1/2021
Carlisle - Murphy 115kV Terminal Upgrades	Regional Reliability	SPS	On Schedule < 4	6/1/2022
Sub - Carlsbad Interchange 115 kV	Regional Reliability	SPS	On Schedule < 4	6/1/2021
Sub - Hale Cty Interchange 115 kV	Regional Reliability	SPS	On Schedule < 4	6/1/2021
Sub - Denver City Interchange 115 kV North	Regional Reliability	SPS	On Schedule < 4	6/1/2021
Sub - Canaday 115 kV	Regional Reliability	NPPD	On Schedule < 4	6/1/2021
Sub - Hastings 115 kV	Regional Reliability	NPPD	On Schedule < 4	6/1/2021
Multi - Marshall County - Smittyville - Baileyville - South Seneca 115 kV	Regional Reliability	WR	Delay - Mitigation	6/1/2023
Sub - Firth 115kV	Regional Reliability	NPPD	Delay - Mitigation	6/1/2023
Sub - Amoco - Sundown 115 kV	Economic	SPS	On Schedule < 4	6/1/2020
Line - Hansford - Spearman 115kV	Economic	SPS	On Schedule < 4	1/1/2021
Multi-Hobbs Interchange-Millen 115kV	Regional Reliability	SPS	On Schedule < 4	6/1/2022
Sub - Denver City Interchange South 115 kV	Regional Reliability	SPS	On Schedule < 4	6/1/2021
Line - Aberdeen City - Aberdeen Industrial Park 115 kV	Sponsored Upgrade	NWE	On Schedule < 4	12/31/2021

List of Transmission Projects - 4/4

PLANNED TRANSMISSION PROJECTS FROM 2019 ITP FOR 2020-2025 (69 KV AND LOWER)

Project Name	Project Type	Owner	Project Status	In-Service Date
Line - Elmore - Paoli 69 kV Rebuild	Regional Reliability	WFEC	Delay - Mitigation	3/1/2022
Line - Sara Road - Sunshine Canyon 69 kV Ckt 1 Rebuild	Regional Reliability	WFEC	Delay - Mitigation	12/31/2019
Device - S964 69 kV Cap Bank	Regional Reliability	OPPD	On Schedule < 4	6/1/2020
Line - Atoka - Atoka Pump - Pittsburg - Savanna - Army Ammo - McAlester City	Zonal Reliability	AEP	Delay - Mitigation	11/20/2020
Line - City of Winfield - Oak 69 kV Reconductor	Regional Reliability	KPP	On Schedule < 4	12/30/2020
Device - Dover SW 69 kV Cap Bank	Regional Reliability	WFEC	Delay - Mitigation	9/1/2023
Device - Cherokee SW 69 kV Cap Bank	Regional Reliability	WFEC	Delay - Mitigation	8/1/2023
Device - Clear Creek Tap 69 kV Cap Bank	Regional Reliability	WFEC	Delay - Mitigation	12/1/2020
Sub - Washita 69 kV	Regional Reliability	WFEC	On Schedule < 4	6/1/2021
Device- Gypsum 69 kV Capacitor Bank	Regional Reliability	WFEC	On Schedule < 4	6/1/2021
Sub - Cleo Corner - Cleo Junction 69kV	Regional Reliability	OGE	On Schedule < 4	6/1/2022
SUB - Marietta - Rocky Point 69 kV	Regional Reliability	WFEC	On Schedule < 4	12/1/2021
SUB - Forest Hill 69 kV Terminal Upgrades	Regional Reliability	OGE	On Schedule < 4	1/1/2021
DPNS-2019-March-1011 Shell Rock and Bauman Substation	Regional Reliability	CBPC	NTC - Commitment	6/1/2020

Review of Public Reports - 1/2

Adding more renewables produces jobs.

- Various (14) public reports were reviewed to estimating the jobs and other economic benefits of wind development (out of 11 had useful information).

11 STUDIES ON THE ECONOMIC BENEFITS OF WIND DEVELOPMENT

Study	Region
Aldieri et. al, Wind Power and Job Creation, 2019	U.S. and other countries
AWEA, Wind Powers America Annual Report, 2019	Nationwide
Brattle, Job and Economic Benefits of Transmission and Wind Generation Investments in the SPP Region, 2010	SPP
EIG, Statewide Economic Impact of Wind Energy Development in Oklahoma, 2014	Oklahoma
NREL, Economic Impacts from Wind Energy in Colorado Case Study, 2019	Rush Creek Wind Farm, Colorado
NREL, Economic Development Impact of 1,000 MW of Wind Energy in Texas, 2011	Texas
NREL, Economic Impacts from Indiana's First 1,000 MW of Wind Power, 2014	Indiana
NREL, Estimated Economic Impacts of Utility Scale Win Power in Iowa, 2013	Iowa
NREL, Jobs and Economic Development from New Transmission and Generation in Wyoming, 2011	Wyoming
UC Berkeley, Job Impacts of California's Existing and Proposed RPS, 2015	California
USDA, Ex-Post Analysis of Economic Impacts from Wind Power Development in U.S. Counties, 2012	Great Plains and Rocky Mountains

Note: Three additional studies reviewed (whose data was not directly applicable to the analysis) are: NREL, Analysis of the Renewable Energy Projects Supported by 1603 Treasury Grant Program, 2012; NYSERDA, New York Clean Energy Industry Report, 2019; and NREL, Counting Jobs and Economic Impacts From Distributed Wind in the United States, 2014.

Review of Public Reports - 2/2

Adding more renewables produces additional local benefits.

- Various (7) public reports were reviewed specifically to estimate the other economic benefits (tax and lease revenue) of wind development.

7 STUDIES ON THE ECONOMIC BENEFITS OF WIND DEVELOPMENT

Study	Region
EIG, Statewide Economic Impact of Wind Energy Development in Oklahoma, 2014	Oklahoma
NREL, Economic Impacts from Wind Energy in Colorado Case Study, 2019	Rush Creek Wind Farm, Colorado
NREL, Economic Development Impact of 1,000 MW of Wind Energy in Texas, 2011	Texas
NREL, Economic Impacts from Indiana's First 1,000 MW of Wind Power, 2014	Indiana
NREL, Estimated Economic Impacts of Utility Scale Win Power in Iowa, 2013	Iowa
NREL, Jobs and Economic Development from New Transmission and Generation in Wyoming, 2011	Wyoming
Wind Powers America Annual Report, 2019	USA state-level data

Note: The WPA annual report contained data for each state. All other sources report values from a single project.

About Brattle

Authors

T. Bruce Tsuchida

PRINCIPAL | BOSTON

Bruce.Tsuchida@brattle.com

+1.617.234.5686

Stephanie Crocker Ross

ASSOCIATE | BOSTON

Stephanie.Ross@brattle.com

+1.617.234.5754

Adam Bigelow

RESEARCH ANALYST

Adam.Bigelow@brattle.com

+1.415.217.1000

About Brattle

The Brattle Group answers complex economic, finance, and regulatory questions for corporations, law firms, and governments around the world. We are distinguished by the clarity of our insights and the credibility of our experts, which include leading international academics and industry specialists. Brattle has over 400 talented professionals across three continents. For more information, please visit **brattle.com**.

Our Services	Our People	Our Insights
Research and Consulting	Renowned Experts	Thoughtful Analysis
Litigation and Support	Global Teams	Exceptional Quality
Expert Testimony	Intellectual Rigor	Clear Communication

Our Practices and Industries

ENERGY & UTILITIES

- Competition & Market Manipulation
- Distributed Energy Resources
- Electric Transmission
- Electricity Market Modeling & Resource Planning
- Electrification & Growth Opportunities
- Energy Litigation
- Energy Storage
- Environmental Policy, Planning & Compliance
- Finance and Ratemaking
- Gas/Electric Coordination
- Market Design
- Natural Gas & Petroleum
- Nuclear
- Renewable & Alternative Energy

LITIGATION

- Accounting
- Alternative Investments
- Analysis of Market Manipulation
- Antitrust/Competition
- Bankruptcy & Restructuring
- Big Data & Document Analytics
- Commercial Damages
- Consumer Protection & False Advertising Disputes
- Cryptocurrency and Digital Assets
- Environmental Litigation & Regulation
- Intellectual Property
- International Arbitration
- International Trade
- Mergers & Acquisitions Litigation
- Product Liability
- Regulatory Investigations & Enforcement
- Securities Class Actions
- Tax Controversy & Transfer Pricing
- Valuation
- White Collar Investigations & Litigation

INDUSTRIES

- Electric Power
- Financial Institutions
- Infrastructure
- Natural Gas & Petroleum
- Pharmaceuticals & Medical Devices
- Telecommunications, Internet & Media
- Transportation
- Water

Our Offices


BOSTON


BRUSSELS


CHICAGO


LONDON


MADRID


NEW YORK


ROME


SAN FRANCISCO


SYDNEY


TORONTO


WASHINGTON, DC

Clarity in the face of complexity

Brattle

UTILITY DIVE

OPINION

Tapping into DOE's $250B of loan authority for projects that reinvest in US clean energy infrastructure

DOE recently released program guidance for its Title 17 Clean Energy Financing Program, including how it will support projects that reinvest in U.S. energy infrastructure for the clean energy future.

Published July 6, 2023

By Jigar Shah

bombermoon via Getty Images

Jigar Shah is the director of the Loan Programs Office at the U.S. Department of Energy.

The United States has a massive fleet of existing and legacy energy infrastructure. To meet the nation's climate goals and support communities with energy-based economies, we must reinvest in that infrastructure and skilled workforce to build our clean energy future. Now, the federal government has up to $250 billion to do just that.

Through the Energy Infrastructure Reinvestment (EIR) category of the Title 17 Clean Energy Financing Program, the Department of Energy Loan Programs Office (LPO) can provide low-cost debt financing for large-scale energy infrastructure projects that retool, repower, repurpose or replace existing or legacy infrastructure, or that help operating energy infrastructure prepare for a cleaner future by making new investments to avoid, reduce, utilize or sequester air pollutants, including greenhouse gas emissions.

EIR is as vast as utilities' needs and domains and includes financing for investments in operating systems as well as retired assets. The program is technology-agnostic, meaning LPO can finance entire Integrated Resource Plans as long as they relate to existing or legacy infrastructure.

Potential projects are wide-ranging. They may include replacing retired infrastructure with nuclear energy or renewables with or without storage, leveraging existing interconnections, repurposing pipelines, retrofitting power plants, reconductoring transmission lines, repowering legacy nuclear or hydro plants, and more. The program may also finance environmental remediation at brownfield sites to accompany site redevelopment.

Here are just a few examples of projects that could be eligible for EIR financing.

- **Fossil replacement with solar and storage:** An independent power producer owns the site of a 300-MW coal-fired power plant that has ceased operations. The plant has been demolished, but the interconnection and road infrastructure remain. The company plans to reuse the site and repurpose the existing interconnection to build 30 MW of solar and 250 MW of 4-hour battery storage. The project is eligible for, and the company is exploring, relevant federal Investment Tax Credits. The company has developed a plan to retrain and provide new employment opportunities for plant employees. The company is seeking a loan guaranteed by LPO to support construction of the solar and storage, which will be repaid through a combination of tax credits and revenue from the new solar-plus-storage facility. A portion of the loan will also be used to finance the remediation of several on-site coal ash ponds.

- **Transition to nuclear:** A utility plans to install a small modular reactor on the site of a retired coal-fired power plant. The SMR's 300-MW electric generation capacity is similar to that of the retired coal plant, therefore making it well-suited for reusing the existing grid interconnection. Several balance-of-plant systems, such as the plant makeup water and water storage systems, cooling towers, and chemical stores from the coal plant can be repurposed for use with an SMR. The SMR has the potential to benefit from the existing pool of skilled workers able to transition from their prior employment at the coal plant. Further cost savings include avoiding land acquisition costs for the SMR, utilizing rail and road infrastructure, and having an existing water source. The SMR design has been certified by the U.S. Nuclear Regulatory Commission, and the utility's plans have received state regulatory approval. The utility is seeking a loan guaranteed by LPO to finance the construction of the SMR, with repayment assured through a long-term power purchase agreement and the regulatory approval for cost recovery via customer rate base.

- **Power plant replacement with an energy-related industrial facility:** A private developer has purchased the site of a retired gas-fired power plant and plans to repurpose the site through the construction of several large, clean energy manufacturing facilities. The developer has identified the existing electrical, pipeline, rail and road infrastructure as attractive assets that will accelerate and simplify site conversion. The manufacturing facilities will create numerous construction and permanent jobs. The developer is working closely with the local community and labor organizations.

- **Transmission reconductoring:** A utility plans to upgrade several high-voltage transmission lines through reconductoring. The utility estimates that replacing the conductive core of older

> transmission lines will double the electricity carrying capacity compared to the existing conductors, while reducing line losses by up to 50%. The reconductoring plan will retool the existing towers and utilize established rights-of-way. This investment will significantly increase the utility's ability to interconnect new clean energy generation without requiring the time and expense associated with the permitting and construction of new transmission lines. The reconductoring plan has received regulatory approval for cost recovery, which LPO considers sufficient to ensure reasonable prospect of repayment on the loan.

LPO looks forward discussing whether our low-cost debt can support your organization's reinvestment in energy infrastructure. We'll need to begin these conversations soon. Conditional commitments (agreed upon term sheets with stipulations the borrower must meet before financial close) must be made by Sept. 30, 2026, for loan disbursements available through Sept. 30, 2031.

If you'd like to learn more about how LPO can support some or all of your IRP, please request a pre-application consultation to get connected with a member of our team.

Duke Energy Carolinas
Response to
Attorney General's Office
Data Request No. 2

Docket No. E-7, Sub 1276

Date of Request: June 6, 2023
Date of Response: June 16, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to AGO Data Request No. 2-1, was provided to me by the following individual(s): Alisa Ewald, Developmental Assignment, and was provided to AGO under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolina

Request:

1. Refer to the Direct Testimony of Daniel Maley (Maley Direct).
    a. Please explain whether Duke Energy Carolinas (DEC) considered including any investments in Grid Enhancing Technologies (GETs) in the transmission portion of its MYRP. This includes technologies such as Dynamic Line Ratings, Advanced Power Flow Control, Topology Optimization, or other approaches (outside of traditional equipment) that can increase the real-time transfer capacity of the transmission network.
    b. Please provide any studies or analyses (including cost-benefit analyses) Duke performed to determine whether GETs investments should be included in the MYRP to improve the performance of existing lines or new projects planned for the MYRP period.
    c. If such studies were not performed, please explain why not.

Response:

Duke Energy considers a variety of investment alternatives when developing solutions to reliability concerns. Generally, investments that add to system resiliency and have well understood as low reliability risks are preferred in meeting expectations to achieve least cost planning objectives. Alternative investments to new transmission infrastructure (line, transformer, station) that are local impact in nature are preferred to avoid concerns with mis-operation or failure resulting in widespread impacts as well. Traditional solutions include:

- Line upgrade
- Redispatch
- Additional transformer capacity
- Ancillary equipment upgrade
- Capacitor addition
- Topology configuration change
- Improve line clearance
- Allowable Load shed – DCC (distribution control center)
- Allowable Load shed – ECC (transmission control center)
- Relay scheme – non-RAS (e.g., additional overcurrent)
- Redundant bus differential protection
- Redundant transformer differential protection
- Generator Runback
- Series bus junction (bus tie) breaker
- Series station
- Shift load on transmission or distribution

GETs that Duke Energy has utilized and/or considers when evaluating potential investments include:

- Phase shifting transformers
- High Temperature Wire
- Variable/Switched/fixed reactors
- Automated topology management/automated power flow controls (may be considered similar to RAS or phase shifters but broader applications)
- Remedial Action Schemes (RAS)
- Battery Energy Storage Systems
- Dynamic Line Rating Monitoring
- Synchronous Condenser
- Static Var Compensator
- Static Synchronous Compensator

DEC considered but did not formally study GETs for the projects included in the MYRP. In most instances, the nature of the system concerns, such as frequency of contingent events, risk to the system, and cost allows for use of engineering judgment to eliminate many of the alternatives. For instance, FERC Order 881 directs utilities to implement Ambient Adjusted Ratings, for which DEC is working on reaching compliance by the FERC deadline. DEC may consider Dynamic Line Ratings in the future but considers their use as a short-term corrective action to allow time for permanent infrastructure improvements. DLRs are difficult to implement accurately as it is impossible to predict future ambient conditions at all points along a transmission line.

Advanced Power Flow Control devices attempt to force power flows from one transmission path to another. These devices are typically expensive, complex, and delay, but don't eliminate, traditional upgrades. Topology Optimization is still in its infancy and is currently focused on real-time or short-term planning applications. It generally involves radializing network lines, which exposes more customers to outage risk. Their widespread use may impose additional unknown risk to the system by placing it more often in conditions outside those previously studied and well understood by operators.

Duke Energy Carolinas
Response to
Attorney General's Office
Data Request No. 2

Docket No. E-7, Sub 1276

Date of Request: June 6, 2023
Date of Response: June 16, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to AGO Data Request No. 2-3, was provided to me by the following individual(s): Alisa Ewald, Developmental Assignment, and was provided to AGO under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolina

Request:

3. Refer to the transmission projects identified in Maley Direct, Exhibit 2.
   a. Please identify which, if any, of the projects in Exhibit 2 are designed to increase import/export capability with neighboring balancing areas (BAs).
      i. Please provide the costs associated with the projects identified to improve the import/export capability.
   b. Please provide any studies or analyses DEC has conducted to identify specific elements on DEC's transmission system that are binding in terms of the import/export limits for each interchange with neighboring BAs. Please provide a list of the limiting elements for each interchange.
   c. Please provide any analysis Duke has performed to determine how much the import/export constraints could be increased if the limiting elements were upgraded.
      1) Please explain whether any of these interchange limits was a factor contributing to the loss of imports from PJM to DEC during the December 2022 outages.

Response:

a. None of the Capacity & Customer Planning projects in Exhibit 2 are designed to increase import/export capability with neighboring balancing areas (BAs). The projects in Exhibit 2 are those necessary to meet new and existing customer needs, NERC TPL requirements, and generation resources assumed in the Carbon Plan to reliably serve DEC BA load.
i. NA

b. DEC evaluates long-term Transmission Service Requests (TSRs) as they are received. No limits to requested DEC imports or exports have been identified in recent requests.

c. N/A - DEC's transmission planning practice is to initiate transmission upgrades in response to firm Transmission Service Requests but not proactively to increase available transfer capability.
1. No interchange limits or other transmission issues contributed to the loss of imports from PJM to DEC during the December 2022 outages. Curtailment of DEC/DEP imports from PJM were the result of PJM generation failures and associated emergency procedures, not transmission issues. Reference PJM presentation PJM Winter Storm Elliott Overview for OC (https://www.pjm.com/-/media/committees-groups/committees/oc/2023/20230112/item-02---overview-of-winter-storm-elliott-weather-event.ashx) .

STRATEGEN

/A

Caroline Palmer

Manager

As Manager at Strategen, Caroline supports clients in regulatory proceedings, including electric utility cost of service and advanced rate design, avoided cost methodology, and distributed generation interconnection and planning. Caroline has expertise in energy and environmental economics, electric power systems, consumer advocacy, and policy analysis.

Contact

Location
Oakland, California

Email
cpalmer@strategen.com

Phone
+1 (510) 369-5932

Education

MPP
Energy Policy
University of California, Berkeley
2019

BSFS
Science, Technology, and International Affairs
Georgetown University
2013

STRATEGEN.COM

Work Experience

Manager

Strategen / Oakland, CA / 2019 - Present

+ Works with state regulatory commissions, state consumer advocates, and non-profits to advance the public interest in regulatory decision-making around electricity service, pricing, and decarbonization.

Clean Energy Fellow

Metropolitan Area Planning Council / Boston, MA / 2017

+ Provided technical assistance to Massachusetts local governments on renewable energy technology and energy planning.
+ Authored white paper on clean heating and cooling technologies, policies, and opportunities for municipalities

Fulbright Research Fellow

Fulbright Foundation / Athens, Greece / 2015 - 2016

+ Designed and conducted original, independent research on renewable energy policy-making and implementation in the context of Greece's severe economic crisis

Analyst

Meister Consultants Group (now Cadmus) / Boston, MA / 2014 - 2015

+ Performed research and writing for renewable energy policy design, analysis, and implementation.

Caroline Palmer

Manager

STRATEGEN

Domain Expertise

Regulatory Strategy

Energy Economics

Utility Cost of Service

Advanced Rate Design

Net Metering Successor Design

DER Planning & Cost Allocation

Transportation Electrification & Infrastructure

Publications and Speaking Engagements

Utility Transportation Electrification from a Consumer Advocate Perspective. NASUCA Mid-Year Meeting, 2022.

Using Low Carbon Fuel Standard Proceeds from EV Adoption to Improve the Efficiency of Electricity Rates. *Berkeley Public Policy Journal*, 2019.

Integration of renewable energy in Greek energy markets: A case study. 2nd HAEE International Conference, 2017.

Key Projects

For: North Carolina Attorney General's Office

Duke Energy Progress' Rate Design / 2023 - Present

+ Developed revisions to Duke Energy Progress' C&I rate design, TOU period selection, non-residential net energy metering rider, and decoupling proposal to ensure alignment with the needs of the evolving power system

For: Citizens Action Coalition of Indiana

NIPSCO's COSS and Rate Design / 2022 – 2023

+ Developed revisions to Northern Indiana Public Service Company's revenue apportionment and approach for classifying and allocating distribution and production costs
+ Argued for the rejection of proposed residential customer charge increase

For: Kentucky Public Service Commission (KY PSC)

NEM Successor Tariff Analysis and Design / 2021 - Present

+ Evaluated multiple utility proposals for NEM successor tariffs and recalculated avoided energy and capacity cost rates to inform the final approved net metering rates
+ Supported training KY PSC staff on NEM successor proceeding design, cost of service, and DER integration

For: Utah Office of Consumer Services (OCS)

Rocky Mountain Power's COSS and Rate Design / 2020

+ Supported the OCS on analysis and multiple rounds of testimony on the utility's proposed cost of service study, revenue apportionment, and rate design. The Utah PSC accepted several of the recommendations

For: New Hampshire Office of the Consumer Advocate

Liberty & Eversource Utilities' Distribution Rate Case / 2019

+ Evaluated Liberty's Marginal Cost of Service Study and Eversource's Marginal and Embedded COSSs, focusing on the consumer impacts of the utilities' study methodologies
+ Drafted testimony describing the ratepayer implications of the many subjective choices that the companies made when distinguishing customer- and demand-related distribution costs and allocating those among consumer classes

Caroline Palmer

Manager

STRATEGEN

Expert Testimony

On behalf of AARP

Cost of Service and Rate Design

- Case No. PUD 2022-000093. Application of Public Service Company of Oklahoma, an Oklahoma corporation, for an adjustment in its rates and charges and the electric service rules, regulations and conditions of service for electric service in the state of Oklahoma and to approve a formula-based rate proposal (Adoption of Ron Nelson Direct Testimony)
    - Cross-examination on May 22, 2023

On behalf of the Maine Governor's Energy Office

Cost of Service and Rate Design

- Case No. 2022-00152. Request for Approval of a Rate Change - 307 (7/30/23) Pertaining to Central Maine Power Company.
    - Direct Testimony with panelists Ron Nelson and Nikhil Balakumar

On behalf of the Massachusetts Office of the Attorney General

Transportation Electrification, Electric Vehicle Infrastructure, Load Management

- D.P.U. 21-90: Petition of NSTAR Electric Company d/b/a Eversource Energy for approval of its Phase II Electric Vehicle Infrastructure Program and Electric Vehicle Demand Charge Alternative Proposal.
    - Direct Testimony with panelist Ron Nelson
    - Cross-examination on March 22, 2022
- D.P.U. 21-91: Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval of its Phase III Electric Vehicle Market Development Program and Electric Vehicle Demand Charge Alternative Proposal.
    - Direct Testimony with panelist Ron Nelson
    - Cross-examination on March 22, 2022
- D.P.U. 21-92: Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval of its Electric Vehicle Infrastructure Program, Electric Vehicle Demand Charge Alternative Proposal, and Residential Electric Vehicle Time-of-Use Rate Proposal.
    - Direct Testimony with panelist Ron Nelson
    - Cross-examination on March 22, 2022

RAP®

Electric Cost Allocation for a New Era

A Manual

By Jim Lazar, Paul Chernick and William Marcus

Edited by Mark LeBel

JANUARY 2020

Regulatory Assistance Project (RAP)®
50 State Street, Suite 3
Montpelier, VT 05602
USA

Telephone: 802-223-8199
Email: info@raponline.org
raponline.org
linkedin.com/company/the-regulatory-assistance-project
twitter.com/regassistproj

Cover photo: Felix Lipov/Shutterstock.com

Suggested citation

Lazar, J., Chernick, P., Marcus, W., and LeBel, M. (Ed.). (2020, January). *Electric cost allocation for a new era: A manual.* Montpelier, VT: Regulatory Assistance Project.

Contents

Part V: After the Cost of Service Study

Acknowledgments

Editorial assistance was provided by Ruth Hare, Camille Kadoch, Donna Brutkoski and Tim Simard.

The authors wish to express their appreciation to the following people — many of whom are former state utility commissioners — for providing helpful insights into early drafts of this manual:

Ron Binz, Public Policy Consulting
John Colgan, Colgan Consulting
Mike Florio, Gridworks
Jeff Goltz, Cascadia Law Group
Renz Jennings
Douglas Jester, 5 Lakes Energy
Carl Linvill, RAP
David Littell, RAP
Karl Rábago, Pace Energy and Climate Center
Rich Sedano, RAP
John Shenot, RAP
Frederick Weston, RAP
Melissa Whited, Synapse Energy Economics
Tim Woolf, Synapse Energy Economics

The authors also thank Jonathan Wallach of Resource Insight Inc. for his contribution to this effort.

In preparing this manual, the authors drew inspiration from the work and ideas of many others in addition to those discussed within. They include:

Peter Bradford
Eugene Coyle
Phil Jones
Sharon Nelson
Tom Power
George Sterzinger
John Stutz

That said, responsibility for the information and views set out in this work lies entirely with the authors.

About the Authors

Jim Lazar, senior advisor with the Regulatory Assistance Project, is an economist who studied economics and energy at Western Washington University and the University of Washington. He has maintained a consulting practice in utility regulation and pricing and has made more than 100 appearances as an expert witness in rate proceedings in many different jurisdictions. His first utility rate proceeding was in 1974. As a RAP senior advisor, he has advised utility regulators across the United States and in Europe, India, Asia, Africa and South America. He is a former member of the U.S. Department of Energy Electricity Advisory Committee. Mr. Lazar has published more than 20 reference handbooks and topical papers on utility regulation and planning.

Paul Chernick, president of Resource Insight Inc., studied technology and policy at the Massachusetts Institute of Technology. He has advised clients on a wide range of issues, including restructuring policy; estimation of stranded costs; market price forecasts; market valuation of generation resources and divestiture of generation assets; planning and rate-making for central supply, energy efficiency, renewable and distributed resources, and least-cost compliance with environmental regulations; cost allocation and rate design; transmission and distribution planning; and valuation of environmental externalities. Mr. Chernick has testified in more than 300 regulatory and judicial proceedings. He began his career in 1977 with the Massachusetts attorney general's office.

William Marcus, principal of MCPM Economics — a successor company to JBS Energy Inc., where he worked for 32 years — studied economics at Harvard University and the University of Toronto. He began his energy career with the California Energy Commission in 1978. Mr. Marcus has more than 40 years of experience analyzing utility resource plans, costs and rates. He has prepared cost and rate studies for numerous clients and has testified as an expert witness in more than 40 jurisdictions.

Taken together, the three authors have more than 120 years of experience in cost allocation and rate design issues. They have been qualified and testified as expert witnesses before 43 state utility regulatory agencies, eight Canadian provinces and many other local, state and federal regulatory bodies.

About the Editor

Mark LeBel, associate at the Regulatory Assistance Project, has more than a decade of experience working on the overlapping economics and law of energy and environmental policy in the United States. As a member of RAP's U.S. team, he focuses on rate design and regulatory reform, including compensation for distributed energy resources, the evolution of the electricity system and beneficial electrification.

Figures

Tables

Introduction and Overview

The purpose of this manual is to provide a comprehensive reference on electric utility **cost allocation** for a wide range of practitioners, including utilities, intervenors, utility regulators and other policymakers. Cost allocation is one of the major steps in the traditional regulatory process for setting utility rates. In this step, the regulators are primarily determining how to equitably divide a set amount of costs, typically referred to as the **revenue requirement**, among several broadly defined classes of ratepayers. The predominant impact of different cost allocation techniques is which group of customers pays for which costs. In many cases, this is the share of costs paid by residential customers, commercial customers and industrial customers.

In addition, the data and analytical methods used to inform cost allocation are often relevant to the final step of the traditional regulatory process, known as **rate design**. In this final step, the types of charges for each class of ratepayers are determined — which can include a per-month charge; charges per **kilowatt-hour** (kWh), which can vary by season and time of day; and different charges based on measurements of **kilowatt** (kW) **demand** — as well as the price for each type of charge. As a result, cost allocation decisions and analytical techniques can have additional efficiency implications.

Cost allocation has been addressed in several important books and manuals on utility regulation over the past 60 years, but much has changed since the last comprehensive publication on the topic — the 1992 *Electric Utility Cost Allocation Manual* from the **National Association of Regulatory Utility Commissioners** (NARUC). Although these works and historic best practices are foundational, the legacy methods of cost allocation from the 20th century are no more suited to the new realities of the 21st century than the engineering of internal combustion engines is to the design of new electric motors. New electric vehicles (EVs) may look similar on the outside, but the design under the hood is completely different. This handbook both describes the current best practices that have been developed over the past several decades and points toward needed innovations. The authors of this manual believe strongly that charting a new path forward on cost allocation is an important part of creating the fair, efficient and clean electric system of the future.

Charting a new path on cost allocation is an important part of creating the fair, efficient and clean electric system of the future.

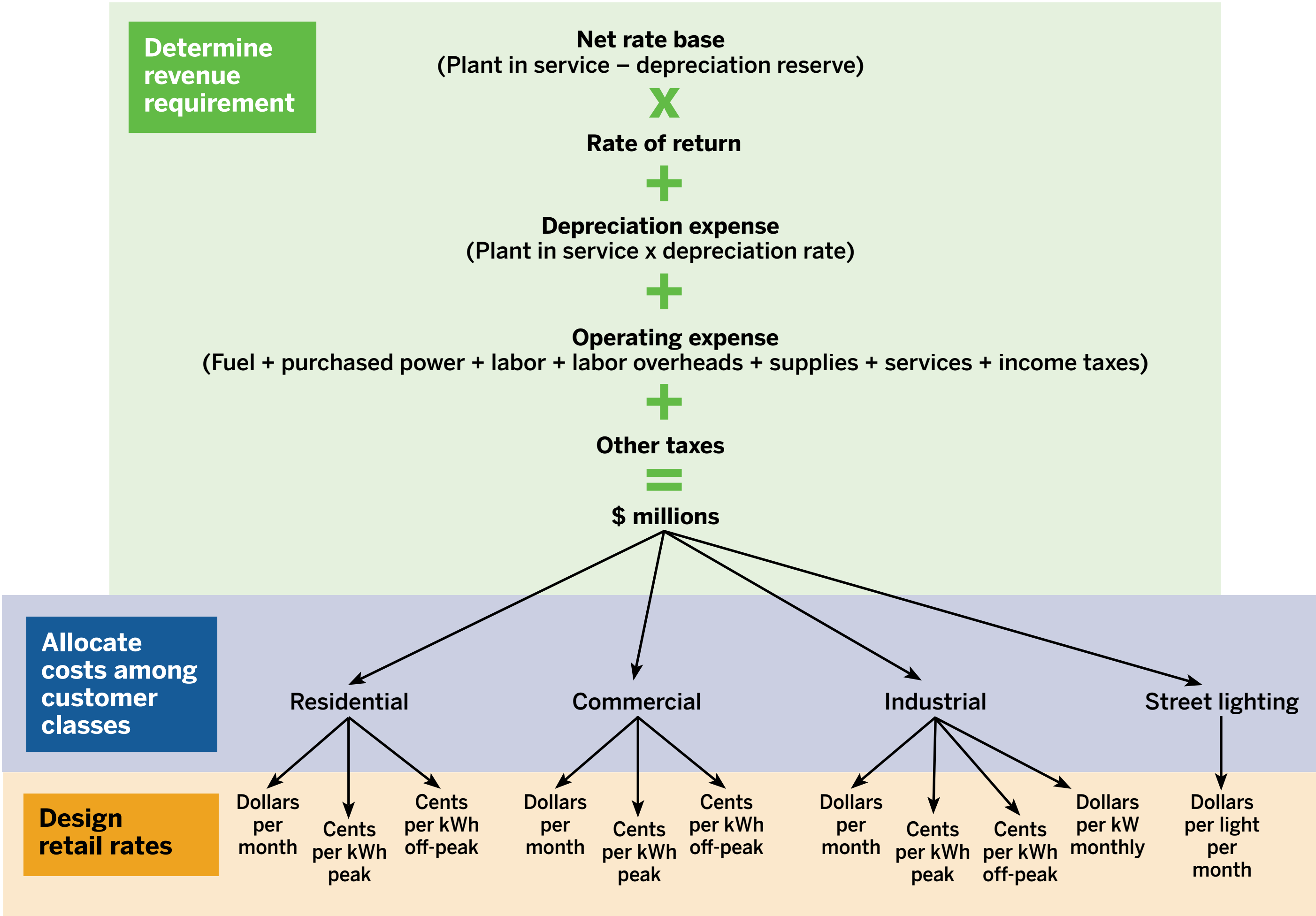
Scope and Context of This Manual

This manual focuses on cost allocation practices for electric utilities in the United States and their implications. Our goal is to serve as both a practical and theoretical guide to the analytical techniques involved in the equitable distribution of electricity costs. This includes background on regulatory processes, purposes of regulation, the development of the electricity system in the United States, current best practices for cost allocation and the direction that cost allocation processes should move. Most of the elements of this manual will be applicable elsewhere in the Americas, as well as in Europe, Asia and other regions.

The rate-making process for **investor-owned utilities** (IOUs) has three steps: (1) determining the annual revenue requirement, (2) allocating the costs of the revenue requirement among the defined rate classes and (3) designing the rates each customer ultimately will pay. Figure 1 on the next page presents a highly simplified version of these steps.

In the cost allocation step, there are two major quantitative frameworks used around the United States: **embedded cost of service studies** and **marginal cost of service studies**. Embedded cost studies typically are based on a single year-long period, using the embedded cost revenue requirement and customer usage patterns in that year to divide up costs.

Figure 1. Simplified rate-making process



Marginal cost of service studies, in contrast, look at how costs are changing over time in response to changes in customer usage.

Regardless of which framework will be used, an enormous amount of data is typically collected first, starting with the costs that make up the revenue requirement, **energy** usage by **customer class** and measurements of demand at various times and often extending to data on **generation** patterns. Furthermore, when the quantitative **cost of service study** is completed, regulators typically don't take the results as the final word, often making adjustments for a wide range of policy considerations after the fact.

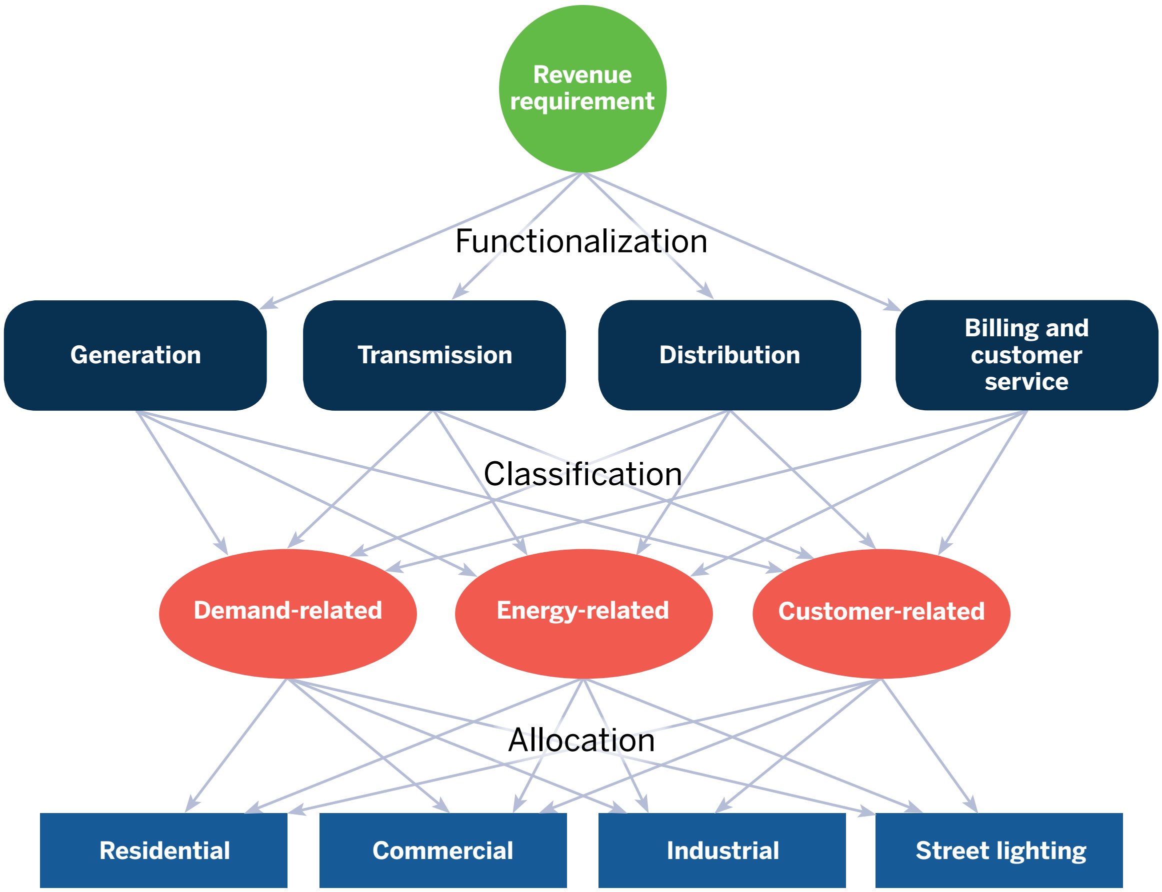
Traditionally, the analysis for an embedded cost of service study is itself divided into three parts: **functionalization**, **classification** and **allocation**. Figure 2 on the next page shows the traditional flowchart for this process.

The analysis for a marginal cost of service study starts with a similar functionalization step, but that is followed by estimation of marginal unit costs for each element of the system, calculation of a **marginal cost revenue requirement** (MCRR) for each class as well as for the system as a whole, and then **reconciliation** with the annual embedded cost revenue requirement.

This cost allocation manual is intended to build upon previous works on the topic and to illuminate several areas where the authors of this manual disagree with the approaches of the previous publications. Important works include:

- *Principles of Public Utility Rates* by James C. Bonbright (first edition, 1961; second edition, 1988).
- *Public Utility Economics* by Paul J. Garfield and Wallace F. Lovejoy (1964).

Figure 2. Traditional embedded cost of service study flowchart



- *The Economics of Regulation: Principles and Institutions* by Alfred E. Kahn (first edition Volume 1, 1970, and Volume 2, 1971; second edition, 1988).
- *The Regulation of Public Utilities* by Charles F. Phillips (1984).
- The 1992 NARUC *Electric Utility Cost Allocation Manual.*

Of course, cost allocation has been touched upon in other works, including RAP's publication *Electricity Regulation in the United States: A Guide* by Jim Lazar (second edition, 2016). However, since the 1990s, there has been neither a comprehensive treatment of cost allocation nor one that addresses the emerging issues of the 21st century. This manual incorporates the elements of these previous works that remain relevant, while adding new cost centers, new operating regimes and new technologies that today's cost analysts must address.

Continuing Evolution of the Electric System

Since the establishment of electric utility regulation in the United States in the early 20th century, the electric system has undergone periods of great change every several decades. Initial provision of electricity service in densely populated areas was followed by widespread rural electrification in the 1930s and 1940s. In the 1950s and 1960s, **vertically integrated utilities**, owning generation, **transmission** and **distribution** simultaneously, were the overwhelmingly dominant form of electricity service across the entire country.

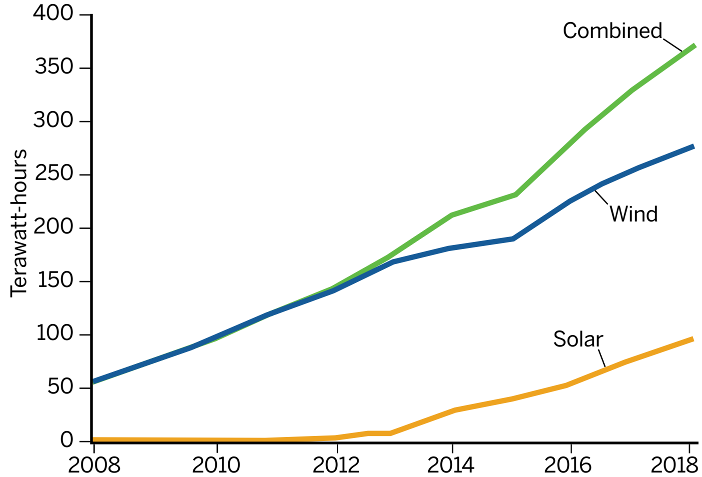
However, the oil crisis in the 1970s sparked a chain reaction in the electric industry. That included a new focus by utilities on **baseload generation** plants, typically using coal or nuclear power. At the same time, the federal government began to open up competition in the electric system with the passage of the **Public Utilities Regulatory Policy Act** (PURPA) of 1978. PURPA dictated that each state utility commission consider a series of standards to reform rate-making practices, including **cost of service**.[1] Nearly every state adopted the recommendation that rates should be based on the cost of service, but neither PURPA nor state regulators were clear about what that should mean. This has led to a fertile legal and policy discussion about the cost of service, how to calculate it and how to use it. PURPA also required that utilities pay for power from **independent power producers** on set terms.

In the 1970s and early 1980s, major increases in oil prices, the completion of expensive capital investments in coal and nuclear generation facilities and general inflation all led to significantly higher electricity prices across the board. These higher prices, in combination with PURPA's requirement for set compensation to independent power producers, led to demands by major consumers to become wholesale purchasers of electricity. This in turn led to the Energy Policy Act of 1992, which enabled the broader restructuring of the electric industry in much of the country around the turn of the 20th century.

The key texts and most of the analytical principles currently used for cost allocation were developed between the 1960s and early 1990s. Since that time, the electric system in the United States has been undergoing another period of dramatic change. That includes a wide range of interrelated advancements in technology, policy and economics:

- Major advances in data collection and analytical capabilities.
- Restructuring of the industry in many parts of the country, including new wholesale electricity markets, new retail markets and new market participants.
- New consumer interests and technologies that can be deployed **behind the meter**, including clean **distributed generation**, **energy efficiency**, **demand response**, storage and other energy management technologies.
- Dramatic shifts in the relative cost of technologies and fuels, including massive declines in the price of **variable renewable resources** like wind and solar and sharp declines in the cost of energy storage technologies.
- The potential for beneficial electrification of end uses that currently run directly on fossil fuels — for example, electric vehicles in place of vehicles with internal combustion engines.

Figure 3. Increase in US wind and solar generation from 2008 to 2018



Data source: U.S. Energy Information Administration. (2019, February). *Electric Power Monthly.* Table 1.1.A. Retrieved from https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_1_01_a

Many, if not all, of these changes have quantifiable elements that can and should be incorporated directly into the regulatory process, including cost allocation. The increased development of renewable energy and the proliferation of more sophisticated meters provide two examples.

Figure 3 illustrates the dramatic increase in wind and solar generation in the United States in the last decade, based on data from the U.S. Energy Information Administration.

Traditional cost allocation techniques classify all utility costs as **energy-related**, **demand-related** or **customer-related**. These categories were always simplifications, but they must be reevaluated given new developments. Some legacy cost allocation methods would have treated wind and solar generation entirely as a demand-related cost simply because they are capital investments without any variable **fuel costs**. However, wind and solar generation does not necessarily provide firm **capacity** at peak times as envisioned by the legacy frameworks, and it displaces the need for fuel supply, so it doesn't fit as a demand-related cost.

1 The PURPA rate-making standards are set forth in 16 U.S.C. § 2621. Congress in 2005 adopted a specific requirement that cost of service studies take time of usage into account; this is set forth in 16 U.S.C. § 2625.

Table 1. Types of meters and percentage of customers with each in 2017

	Residential	Commercial	Industrial
Advanced metering infrastructure	52.2%	50.0%	44.5%
Automated meter reading	29.5%	26.5%	28.0%
Older systems	18.3%	23.5%	27.5%

Data source: U.S. Energy Information Administration. *Annual Electric Power Industry Report, Form EIA-861: 2017* [Data file]. Retrieved from https://www.eia.gov/electricity/data/eia861/

In addition, many utilities now collect much more granular data than was possible in the past, due to the widespread installation of **advanced metering infrastructure** (AMI) in many parts of the country and other advancements in the monitoring of the electric system. As a result, utility analysts often have access to historical hourly usage data for the entire utility system, each distribution **circuit**, each customer class and, increasingly, each customer. Some **automated meter reading** (AMR) systems also allow the collection of hourly data, typically read once per billing cycle. Table 1 shows the recent distribution of meter types across the country, based on data from the U.S. Energy Information Administration. Improved data collection allows for a wide range of new cost allocation techniques.

In addition, meters have been primarily treated as a customer-related cost in older methods because their main purpose was customer billing. However, advanced meters serve a broader range of functions, including demand management, which in turn provides system capacity benefits, and **line loss** reduction, which provides a system energy benefit. This means the benefits of these meters flow beyond individual customers, and logically so should responsibility for the costs.

These are just two examples of how recent technological advances affect appropriate cost allocation. In subsequent chapters, this manual will address each major cost area for electric utilities, the changes that have occurred in how costs are incurred and how assets are used, and the best methods for cost allocation.

Principles and Best Practices

There is general agreement that the overarching goal of cost allocation is equitable division of costs among customers. Unfortunately, that is where the agreement ends and the arguments begin. Two primary conceptual principles help guide the way to the right answers:

1. Cost causation: Why were the costs incurred?
2. Costs follow benefits: Who benefits?

In some cases these two frameworks point to the same answer, but in other cases they conflict. The authors of this manual believe that "costs follow benefits" is usually, but not always, the superior principle. Other helpful questions can be asked to illuminate the details of particularly difficult questions, such as:

- If certain resources were not available, which services would not be provided, and what different resources would be needed to provide those services at least cost?
- If we did not serve this need in this way, how would costs change?

In the end, cost allocation may be more of an art than a science, since fairness and equity are often in the eye of the beholder. In most situations, cost allocation is a zero-sum process where lower costs for any one group of customers lead to higher costs for another group. However, the techniques used in cost allocation have been designed to mediate these disputes between competing sets of interests. Similarly, the data and analysis produced for the cost allocation process can also provide meaningful information to assist in rate design, such as the seasons and hours when costs are highest and lowest, categorized by system component as well as by customer class.

In that spirit, we would like to highlight the following current best practices discussed at more length in the later chapters of this manual. To begin, there are best practices that apply to both embedded and marginal cost of service studies:

- Treat as customer-related only those costs that actually vary with the number of customers, generally known as the **basic customer method**.
- Apportion all shared generation, transmission and distribution assets and the associated operating expenses

on measures of usage, both energy- and demand-based.

- Ensure broad sharing of overhead investments and **administrative and general (A&G) costs**, based on usage metrics.
- Eliminate any distinction between **"fixed" costs** and "variable" costs, as capital investments (including new technology and data acquisition) are increasingly substitutes for fuel and other short-run variable operating costs.
- Where future costs are expected to vary significantly from current costs, make the cost trajectory an important consideration in the apportionment of costs.

Second, there are current best practices specific to embedded cost of service studies:

- Classify and allocate generation capacity costs using a time-differentiated method, such as the **probability-of-dispatch** or **base-intermediate-peak** (BIP) methods, or classify capacity costs between energy and demand using the **equivalent peaker method**.
- Allocate demand-related costs for generation using a broad peak measure, such as the **highest 100 hours** or the **loss-of-energy expectation**.
- Classify and allocate the costs of transmission based on its purpose, with any demand-related costs allocated based on broad peak periods for regional networks and narrower ones for local networks.
- Classify distribution costs using the basic customer method, and divide the vast majority of costs between demand-related and energy-related using an energy-weighted method, such as the **average-and-peak method** that many natural gas utilities use.
- Allocate demand-related distribution costs using appropriately broad peak measures that capture the hours with high usage for the relevant system elements while appropriately accounting for **diversity** in customer usage.
- Ensure that customer connection and service costs appropriately reflect differences between customer classes by using either specific cost studies for each element or a weighted customer approach.
- Functionalize and classify AMI and billing systems according to their multiple benefits across different elements and aspects of the electric system.

Lastly, there are current best practices for marginal cost of service studies:

- Use **long-run marginal costs** for generation that reflect lower greenhouse gas emissions than the present system, and recognize the costs of emissions that do occur as **marginal costs** during those periods.
- Analyze whether demand response, storage or market capacity purchases are cheaper than a traditional peaking **combustion turbine** as the foundation of marginal generation capacity cost.
- Use an expansive definition of marginal costs for transmission and distribution, including automation, controls and other investments in avoiding capacity or increasing reliability, and consider including replacement costs over the relevant timeframe.
- Recognize marginal line losses in each period.
- Functionalize marginal costs in **revenue reconciliation**; use the **equal percentage of marginal cost** technique by function, not in total.

Path Forward and Need for Reform

Our power system is changing, and cost allocation methods must also change to reflect what we are experiencing. Key changes in the power system that have consequences for how we allocate costs include:

- Renewable resources are replacing fossil generation, substituting invested capital in place of variable fuel costs.
- **Peaking resources** are increasingly located near **load** centers, eliminating the need for transmission line investment to meet **peak demand**. Long transmission lines are often needed to bring baseload coal and nuclear resources, and to bring wind and other renewable resources, even if they may have limited peaking value relative to their total value to the power system.
- Storage is a new form of peaking resource — one that can be located almost anywhere and has low variable costs. Storage can help avoid generation, transmission and distribution **capacity-related costs**. The total costs of storage need to be assigned to the proper time period for equitable treatment of customer classes.

- Consumer-sited resources, including solar and storage, are becoming essential components of the modern **grid**. The **distribution system** may also begin to serve as a gathering system for power flowing from locations of local generation to other parts of the utility service territory, the opposite of the historical top-down electric delivery model.
- **Smart grid** systems make it possible to provide better service at lower cost by including targeted energy efficiency and demand response measures to meet loads at targeted times and places and other measures to take advantage of improved data and operational capabilities.

Unfortunately, older techniques, even those resulting from detailed inquiries by cutting-edge regulators in recent decades, may not be sufficiently sophisticated to incorporate new technologies, more granular data and advancements in analytical capabilities. As a result, innovations are needed in the regulatory process to mirror the changes taking place outside of **public utilities commissions**.

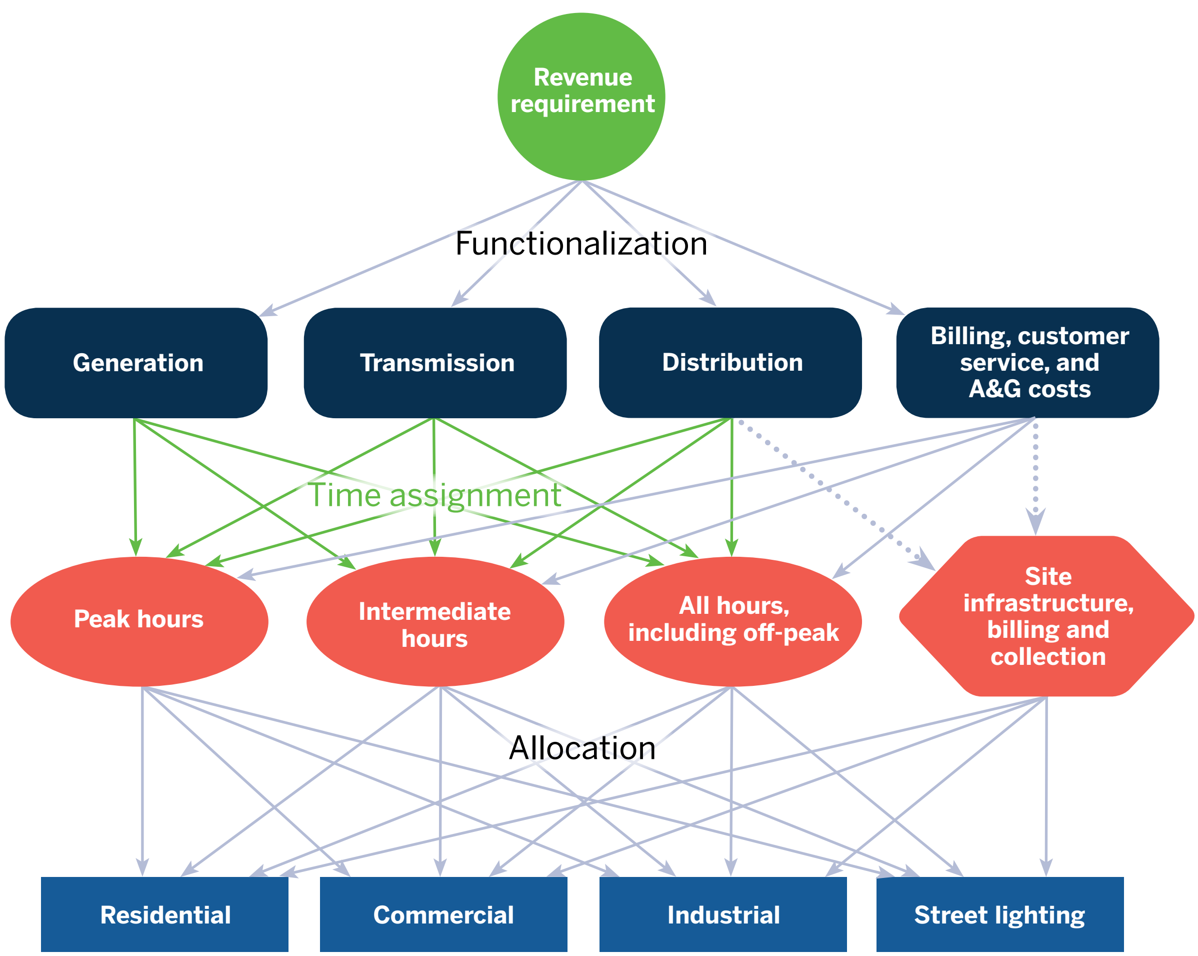
For all cost of service studies, these innovations could include:

- Clear distinction between shared assets and customer-specific assets in the accounting for distribution costs.
- Clearer tracking of distinctions between system costs and overhead investments and expenses at all stages of the rate-making process.
- More accurate definitions of rate classes based on emerging economic and service characteristic distinctions between customers.
- Distinction between loads that can be controlled to draw power primarily at low-cost periods and those that are inflexible.

For embedded cost of service studies, innovative **hourly allocation** techniques could incorporate a number of advances, including:

- Hourly methods for generation: Most generation costs

Figure 4. Modern embedded cost of service study flowchart



should be assigned to the hours in which the relevant facilities are actually used and to all hours across the year, not solely based on measurements in a subset of these hours.

- Hourly methods for transmission: Transmission costs must be examined to determine the purpose and usage patterns, and costs must be assigned to the hours when the transmission services are utilized to serve customer needs.
- All shared distribution costs should be apportioned based on the time periods when customers utilize these facilities. The system is needed to provide service in every hour, and in most cases a significant portion of the distribution system cost should be assigned volumetrically to all hours across the year.
- Billing, customer service and A&G costs that do not vary based on consumption should be functionalized separately.
- **Site infrastructure** to connect customers, billing and collection should be a separate classification category.

Figure 4 shows an example of a modern time-based allocation method in a reformed flowchart.

Innovation in marginal cost of service studies could take the form of more granular hourly marginal cost analysis for the generation, transmission and shared distribution elements of the system. Alternatively, a more conceptual shift to the **total service long-run incremental cost** method developed for the restructuring of the telecommunications industry should be considered. This method estimates the cost of building a new optimally sized system using current technologies and costs. This avoids a number of significant issues with traditional marginal cost of service studies, particularly the problem of significant swings in estimates based on the presence or absence of excess capacity, but it comes with additional data requirements and new uncertainties.

These proposed innovations, regardless of whether they are adopted widely, shed new light into the foundations of cost allocation and may help the reader gain insight into the underlying questions. More generally, we hope that readers find this manual useful as they undertake the complex task of apportioning utility costs among functions, customer classes and types of service and that they join us in finding the best path forward.

Guide to This Manual

After this introduction and summary, this manual is divided into five parts:

- Part I: Chapters 1 through 4 lay out principles of economic regulation of electric utilities, background on the rate-making process, and definitions and descriptions of the electric system in the United States. Readers who are new to rate-making and utility regulation should start here for the basics.[2] Much of this material likely will be familiar to an experienced practitioner but emphasizes key issues relevant to the remainder of the manual.
- Part II: Chapters 5 through 8 cover the important definitions, basic techniques and overarching issues in cost allocation. Some of this material may be familiar to an experienced practitioner but also lays out the issues facing cost allocation.
- Part III: Chapters 9 through 17 delve deeply into the subject of embedded cost of service studies, including discussion of historic techniques, current best practices and key reforms.
- Part IV: Chapters 18 through 26 cover the field of marginal cost of service studies, including historical development, current best practices and key needed reforms.
- Part V: Chapters 27 and 28 cover what happens after the completion of the quantitative studies, including presentation of study results and adjustments, and the relationship between cost allocation and rate design.

The conclusion wraps up with final thoughts.

Each part of this manual ends with a list of works cited. Terms defined in the glossary are set off in boldface type where they first appear in the text.

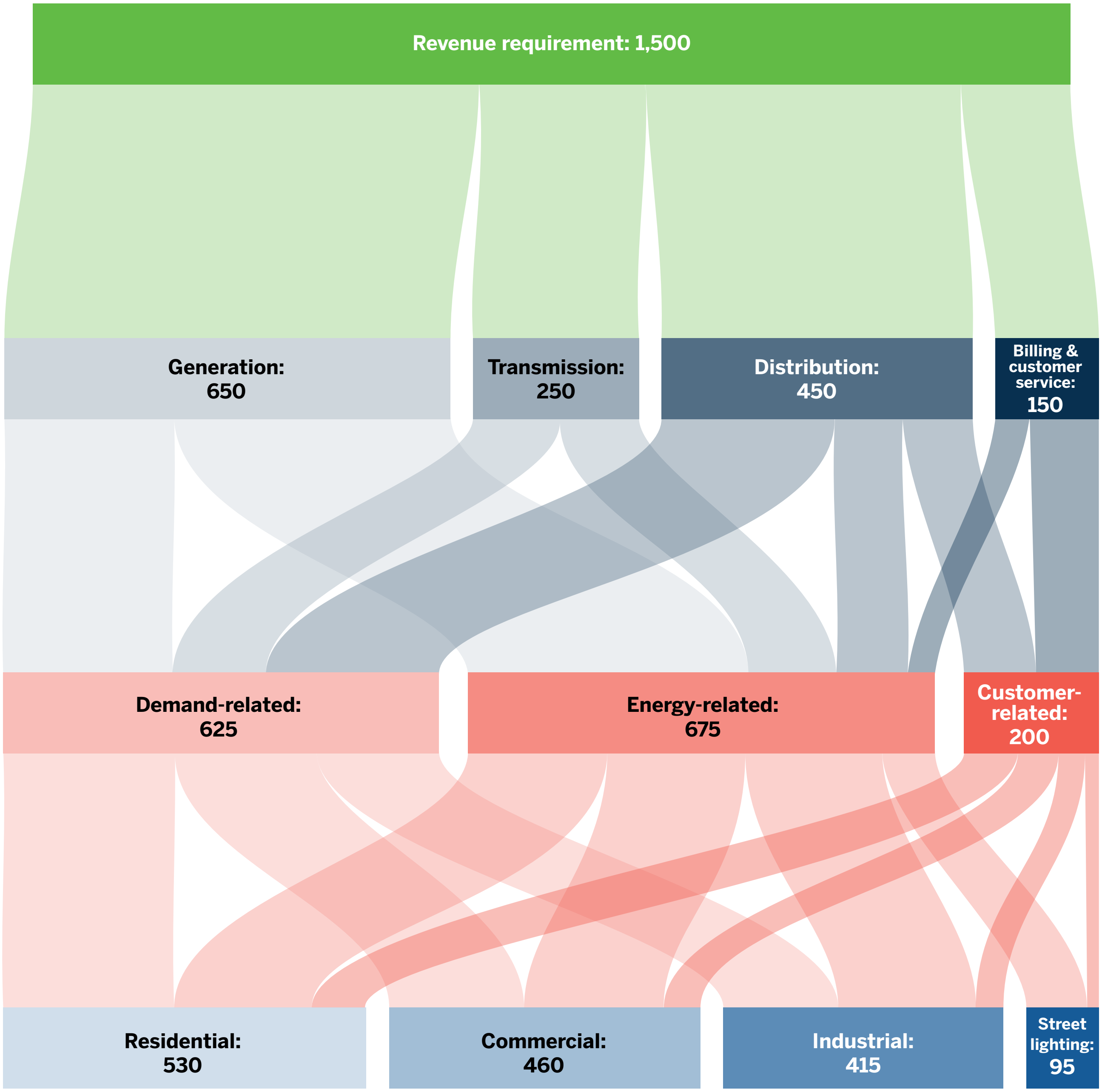
---

2 For a more detailed handbook on the structure and operation of the industry, see Lazar, J. (2016). *Electricity Regulation in the United States: A Guide* (2nd ed.). Montpelier, VT: Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/electricity-regulation-in-the-us-a-guide-2/

Visual display of cost allocation results

Like much of utility regulation, visual display of information in cost allocation tends to be dry and difficult to understand. Much of the analytical information for cost allocation tends to be displayed in large tables that only experts can interpret. Simple flowcharts, such as Figure 2 on Page 16, are also quite common and convey little substantive information. Nevertheless, it should be possible to convey cost allocation results in a meaningful way that a wider audience can understand. One possibility is to convert the traditional flowcharts into Sankey diagrams, where the width of the flows is proportional to the magnitude of the costs. Figure 5 shows this type of diagram for a traditional embedded cost of service study.

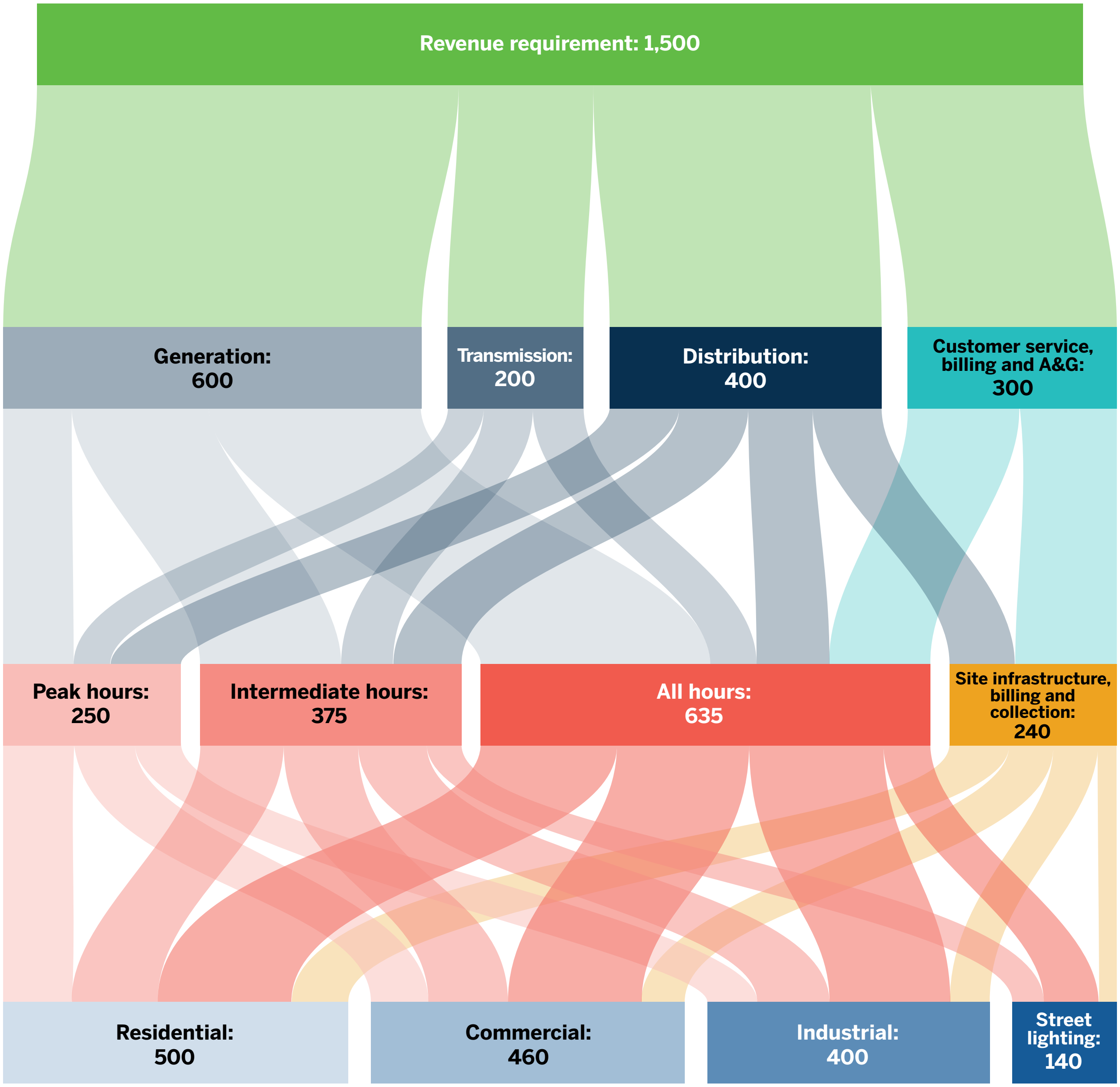
Figure 5. Sankey diagram for traditional embedded cost of service study



A Sankey diagram can display a tremendous amount of information in a way that is reasonably understandable. At the top, it begins with the overall revenue requirement, then splits into three functions. Next, each function splits into the different classifications, which are then allocated by customer class. At each step, the overall costs stay constant, but the relative sizes for each function, classification and customer class are readily apparent. Additionally, the colors in the diagram can be used to indicate additional distinctions. Figure 6 is a Sankey diagram for a more complex reformed embedded cost of service study. Like Figure 5, it shows illustrative results that are feasible with certain allocation techniques. In contrast, the flowcharts in figures 2 and 4 show all the different allocation possibilities with arrows linking different categories.

As the Sankey diagram becomes more complex, it can be less intuitive. Yet it is likely a much more understandable visual representation of the key elements of a cost of service study.

Figure 6. Sankey diagram for modern embedded cost of service study



Part I:

Economic Regulation and the Electric System in the United States

1. Economic Regulation in the U.S.

Economic regulation of privately owned business dates back to the Roman Empire and was a significant feature of government in medieval England, where accommodation prices at inns were regulated because travelers typically had only a single choice when arriving at the end of a day on foot or horseback. In the later medieval period, the English Parliament regulated bakers, brewers, ferrymen, millers, smiths and other artisans and professionals (Phillips, 1984, p. 77). This tradition was brought to the United States in the 19th century, when a series of Supreme Court opinions held that grain elevators, warehouses and canals were monopoly providers of service "affected with a public interest" and that their rates and terms of service could therefore be regulated.[3]

> Property does become clothed with a public interest when used in a manner to make it of public consequence, and affect the community at large. When, therefore, one devotes his property to a use in which the public has an interest, he, in effect, grants to the public an interest in that use, and must submit to be controlled by the public for the common good ...
>
> — U.S. Supreme Court, Munn v. Illinois, 94 U.S. 113, 126 (1877)

1.1 Purposes of Economic Regulation

The primary purpose of economic regulation has always been to prevent the exercise of monopoly power in the pricing of essential public services. Whether applying to a single inn along a stagecoach route or an electric utility serving millions of people, the essence of regulation is to impose on monopolies the pricing discipline that competition imposes on competitive industries and to ensure that consumers pay only a fair, just and reasonable amount for the services they receive and the commodities they consume. Historically, electric utility service is considered a "natural monopoly" where the cost of providing service is minimized by having a single system serving all users. In recent years, competition has been introduced into the power supply function in some areas. The delivery service remains a natural monopoly in all areas, however, and in much of the U.S., power supply is provided at retail by only a single monopoly utility.

Over time, legislative and regulatory bodies have identified subsidiary purposes of regulation, but these all remain subordinate to this primary purpose of preventing the abuse of monopoly power. These subsidiary purposes include:

- Defining and assuring the adequacy of service for customers, including reliability and access to electric service at reasonable prices.
- Setting prices so that the utility has a reasonable opportunity to receive revenue sufficient to cover prudently incurred costs, provide reliable service and allow the utility to access capital.
- Avoiding unnecessary and uneconomic expenditures or protecting customers from the costs of imprudent actions.
- Encouraging or mandating practices deemed important for societal purposes, such as reducing environmental damage and advancing technology.
- Managing intentional shifts in cost responsibility from one customer group to another, such as economic development discounts for industrial customers or assistance for low-income and vulnerable customers.

When monopoly power ceases to be a concern, as when there are many buyers and sellers in a transparent market, the basis for imposing price regulation evaporates. Transportation and telecommunications services used to be regulated in the United States, but as technology changed in a way that

3 Munn v. Illinois, 94 U.S. 113 (1877). The term "affected with a public interest" originated in England around 1670, in two treatises by Sir Matthew Hale, Lord Chief Justice of the King's Bench, De Portibus Maris and De Jure Maris. Munn v. Illinois, at 126-128.

allowed competition, policymakers eliminated the economic regulation, or at least changed the essential features of the regulatory structure. A similar phenomenon has occurred with the introduction of wholesale markets for electricity generation in many parts of the country.

1.2 Basic Features of Economic Regulation

To prevent the exercise of monopoly power, the primary regulatory tool used by governments has been control over the prices the regulated company charges. During the decline of the Roman Empire, emperors issued price edicts for more than 800 articles based on the cost of production (Phillips, 1984, p. 75). Utility regulators today review proposals for rates from utilities and issue orders to determine a just and reasonable rate, typically based on the cost of service. However, price regulation raises the question of the quality and features of the product or service. Inevitably, this means that price regulation must logically extend to other features of the product or service. In the case of electricity, this means utility regulators typically have regulatory authority over the terms of service and often set standards for reliability to ensure a high-quality product for ratepayers.

In the regulation of prices for utility service, the prevailing practice, known as **postage stamp pricing**, is to develop separate sets of prices for a relatively small and easily identifiable number of classes of customers. For electric utilities, one typical class of customers is residential.

> We are asking much of regulation when we ask that it follow the guide of competition. As Americans, we have set up a system that indicates we have little faith in economic planning by the government. Yet, we are asking our regulators to exercise the judgment of thousands of consumers in the evaluation of our efficiency, service and technical progress so that a fair profit can be determined. Fair regulation is now, and always will be, a difficult process. But it is not impossible.
>
> — Ralph M. Besse, American Bar Association annual meeting, August 25, 1953 (Phillips, 1984, p. 151)

James Bonbright, regarded as the dean of utility rate analysts, set out eight principles that are routinely cited today.

For a given utility and its service territory, all customers in this class pay the exact same prices. Postage stamp pricing clearly deviates from strict cost-based pricing but addresses a number of regulatory needs. It keeps the process relatively simple by limiting the number of outputs that need to be produced to one set of rates for each broad customer class. Since rates need to be tied to the cost of service, this logically implies that the cost of service must be determined separately for each rate class, which is one of the key outputs of the cost allocation phase of a **rate case**.

Postage stamp pricing also puts an end to one of the unfair pricing strategies monopolies undertake, known as price discrimination. Price discrimination — that is, strategically charging some customers more than others — helps a monopolist maximize profits but also serves as a way for an unregulated monopolist to punish some customers and reward others. Of course, different pricing can be appropriate for customers that incur different costs.

1.3 Important Treatises on Utility Regulation and Cost Allocation

This handbook recognizes the pathbreaking work done by cost and rate analysts in the past. It is important to review these foundational works, recognize the wisdom that is still current and identify how circumstances have changed to where some of their theories, methodologies and recommendations are no longer current with the industry.

James Bonbright is regarded as the dean of utility rate analysts. His book *Principles of Public Utility Rates*, first published in 1961, addresses all of the elements of the regulatory process as it then stood, with detailed attention to cost allocation and rate design. Bonbright set out eight principles that are routinely cited today (1961, p. 291):

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.

2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. ...
6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use.

Of these, principles 6 and 7 are the most closely related to cost allocation.

Bonbright's chapters on marginal costs (Chapter 17) and fully distributed costs (Chapter 18) are most relevant to this manual's purpose. His analysis of marginal costs carefully distinguishes between **short-run marginal costs** (in which capital assets are not changeable) and long-run marginal costs (in which all costs are variable) and discusses which are most applicable for both cost allocation and rate design. A second edition of this book, edited by Albert Danielsen and David Kamerschen, was published posthumously in 1988.

Paul Garfield and Wallace Lovejoy published their book *Public Utility Economics* in 1964. This text focuses on the economic structure of the industry and the need to have costs and rates measured in terms that elicit rational response by consumers. This text also provides an excellent set of principles for cost allocation and rate design with respect to the shared capacity elements of costs:[4]

1. All service should bear a portion of capacity costs.
2. Capacity charges attributed to each user should reflect the amount of time used, peak characteristics, interruptible characteristics and diversity.
3. Customers with continuous demand should get a bigger share of capacity costs than those with intermittent demand, because the intermittent demand customers have diversity and can share capacity.
4. No class gets a free ride. Every class, including fully **interruptible customers**, must contribute something to the overall system costs in addition to the variable costs directly attributable to its usage.

Alfred Kahn first published *The Economics of Regulation* in two volumes in 1970 and 1971, and a second edition was issued in 1988. Kahn raised the innovative notion of using marginal costs, rather than **embedded costs**, as a foundation of rate-making generally and cost allocation and rate design more specifically. Some states use this approach today. Kahn also served as a regulator, as the chair of both the New York Public Service Commission and the federal Civil Aeronautics Board, which oversaw the deregulation of airlines.

Charles Phillips published *The Regulation of Public Utilities* in 1984, and subsequent editions were released in 1988 and 1993. Phillips wrote in the post-PURPA era, at a time when utility construction of major baseload generating units was winding down. He addressed the desirability of recognizing the difference between baseload and peaking investments as well as the evolution of these cost differentiations into **time-varying rates**. Up to that time, few attempts had been made to prepare time-varying embedded cost studies.

The National Association of Regulatory Utility Commissioners published its *Electric Utility Cost Allocation Manual* in 1992. That handbook provided explicit guidance on some of the different methods that regulators used at that time to apportion rates for both embedded cost and marginal cost frameworks. It was controversial from the outset, due to omission of a very common method of apportioning distribution costs — the basic customer method. However, it is the most recent, comprehensive and directly relevant work on cost allocation prior to this manual.

4 Simplified from principles attributed to Henry Herz, consulting economist, cited in Garfield and Lovejoy (1964, pp. 163-164).

2. Main Elements of Rate-Making

The process of setting rates varies significantly among states and different types of utilities, such as investor-owned utilities regulated by state utility commissions and self-regulated **municipal** and **cooperative utilities**. However, the most basic and essential elements are typically the same. The discussion in this chapter focuses on the methods used for IOUs, with occasional notes on distinctions in other contexts.

There are three distinct elements, or phases, in a rate case, and each phase feeds into the next. The first determines the required level of annual revenue, typically known as the revenue requirement. The second phase, the primary subject of this manual, apportions the revenue requirement among a small number of customer classes, traditionally with additional distinctions made between customer-related costs, demand-related costs and energy-related costs. Finally, the individual prices, formally known as **tariffs** or rates,[5] are designed in order to collect the assigned level of revenue from each class. These elements can be considered by the regulator at the same time or broken into separate proceedings or time schedules. Regardless, the analysis is inevitably sequential. This chapter ends with a brief description of the key features of the procedure used in rate cases.

2.1 Determining the Revenue Requirement

The revenue requirement phase of a conventional rate case consists of determining the allowed **rate base**, allowed **rate of return** and allowed operating expenses for the regulated utility on an annualized basis. In most jurisdictions, the annualized revenue requirement is developed for a "**test year**," which is defined as either a recent year with actual data, which may be adjusted for known changes, or projections for a future year, often the period immediately after the expected conclusion of the rate case. A few elements of the revenue requirement phase have important bearing on the cost allocation study, and we address only these.[6]

Many regulated utilities in the modern United States are one corporation within a broader holding company, which may include other regulated utilities or other types of corporate entities. Early in the revenue requirement process, the utility must identify the subset of costs relevant to the regulated operations that are the subject of a rate case and separate those costs from other operations and entities. This is generally called a jurisdictional allocation study. It is likely that a holding company that has both regulated and unregulated activities has some activities that are of a fundamentally different nature and level of risk from the operations of the regulated utility in question, where sales and revenues can be relatively stable. Jurisdictional allocation is generally beyond the scope of this manual, but many of the principles for apportioning costs among classes may also be relevant for apportioning those costs among multiple states served by a single utility or utility holding company.

Within the subset of costs identified by the regulated utility, the regulator has the discretion to disallow certain costs as imprudent or change key parameters used by the utility to determine the overall revenue requirement. Disallowance of major costs, such as investments in power plants that were not completed or did not perform as expected, have occurred and have led to the bankruptcy of a utility in at least one case.[7] Smaller disallowances or adjustments are more common, such as a reduction in the allowed rate of return the utility proposes, as well as common disallowances for advertising and executive or incentive compensation, which would lower the revenue requirement commensurately.

5 This is an important difference between British English, where "rates" refers to property taxes, and American English, where the term means retail prices.

6 For a more detailed discussion of the determination of the revenue requirement, see Chapter 8 of Lazar (2016).

7 This was the Public Service Company of New Hampshire and the Seabrook nuclear plant (Daniels, 1988).

Performance-based regulation (PBR) may divert from the strict cost accounting approach of the conventional rate case, relying on the performance of the utility to meet goals set by the regulator as a determinant of all or a portion of the revenue requirement.[8]

At the end of this phase, the regulated utility has been assigned a certain level of revenue that it is expected to be able to collect in the **rate year** following the end of the rate case. This annualized revenue requirement is passed along to the next step in the process.

2.2 Cost Allocation

In the second phase of a rate case, the overall revenue requirement is divided up among categories of utility customers, known as classes. These customer classes are usually quite broad and can contain significant variation but are intended to capture cost differentials among different types of customers. Some utilities have many customer classes, but typical classes for each utility include residential customers, small business customers, large commercial and industrial (C&I) customers, irrigation and pumping, and street lighting customers.

At this stage in the process, the utility will use different types of data it has collected to assign costs to each customer class. The types of data available have changed over time, but historically these have included energy usage in specific time periods, different measures of demand, the number of customers in each class and information on generation patterns. In addition, utility costs are categorized using a tracking system known as the Uniform System of Accounts. This system was established by the Federal Power Commission — now the **Federal Energy Regulatory Commission** (FERC) — around 1960, leading to the shorthand of "FERC accounts." Further detail is provided in Appendix A.

These data will be used in a cost of service study that attempts to equitably divide up the revenue requirement among the rate classes. There are two major categories in these studies: an embedded cost of service study (or fully allocated cost of service study), which focuses on the costs the utility intends to recover and other metrics for one year; and a marginal cost of service study, which estimates the responsibility of customer classes for system costs in the future.

An embedded cost of service study itself typically has three major steps:

1. Functionalization of costs as relevant to generation, transmission, distribution and other categories, such as billing and customer service and administrative and general costs.
2. Classification of costs as customer-related, demand-related or energy-related.
3. Allocation among rate classes.

An embedded cost of service study directly splits up the revenue requirement, which is itself calculated on an embedded cost basis.

A marginal cost of service study has a different structure. It begins with a similar functionalization of costs, separately analyzing generation, transmission and distribution. The next step is the estimation of marginal unit costs for different elements of the electric system and customer billing. The estimated marginal costs are then multiplied by the billing determinants for each class. This produces a class marginal cost revenue requirement; when combined with other classes, it's a system MCRR. However, revenue determination solely on this marginal cost basis typically will be greater or less than the allowed revenue requirement, which is normally computed on an embedded cost basis. It is only happenstance if the MCRR is the same as, or even similar to, the revenue requirement calculated on an embedded cost basis. As a consequence, the results of a marginal cost of service study must be reconciled to recover the annual revenue requirement.

Although both embedded and marginal cost studies include precise calculations, most regulators are not strictly bound by the results. Numerous other factors are involved in cost allocation for each rate case, including gradualism of rate changes, policy considerations, such as anticipated changes, and economic conditions in the service territory. The data developed for cost allocation and the analytical techniques used in the cost of service studies can provide helpful information for other purposes, such as rate design. Careful attention

8 For an example of a framework that divorces utility earnings from utility investment, see Lazar (2014). For a broader discussion of performance-based regulation, see Littell et al. (2017).

must be paid, however, to the reason the data were developed, and caution must be taken so that this information is used constructively in an appropriate manner.

The final allocation of costs among the rate classes, as well as the other relevant data and analysis, is passed on to the next step in the process.

2.3 Rate Design

The rate design phase of a proceeding is sometimes separated in time from the previous phases so the parties know the revenue amounts that each class is expected to contribute, or it may be combined into a single proceeding with the other two phases. This manual does not address rate design principles in detail, but they are addressed in two companion publications by RAP: *Smart Rate Design for a Smart Future* (Lazar and Gonzalez, 2015) and *Smart Non-Residential Rate Design* (Linvill, Lazar, Dupuy, Shipley and Brutkoski, 2017). Related issues around compensation for customers with distributed generation are also addressed in RAP's *Designing Distributed Generation Tariffs Well* (Linvill, Shenot and Lazar, 2013).

At the highest level, the principles used for rate design are significantly different from those for cost allocation. Rate design should always focus on forward-looking efficiency, including concepts like long-run marginal costs for the energy system and societal impacts more generally, because rate design will influence consumer behavior, which in turn will influence future costs.

Rate design decisions also include principles around understandability and the ability of customers to manage their bills and respond to the price signals in rates. Of course, equity is also a consideration in the rate design process, but in a significantly different context: Primarily, it's concerned with the distribution of costs among individual customers within a rate class.

There are three basic rate components:

1. **Customer charges**: fees charged every billing period that generally do not vary with respect to any usage characteristics.
2. **Volumetric energy charges**: prices based on metrics of kWh usage during the billing period.
3. **Demand charges**: prices based on metrics of kW or **kilo-volt-ampere** (kVA) power draw during the billing period.

These three basic options allow for a wide range of variations based on season, time of day and type of demand measurement. All types of rates can vary from season to season or month to month, often based on either the cost of service study or energy market conditions.[9] Both demand charges and **energy charges** measure the same thing: electricity consumption over a period of time. Even though demand charges are typically denominated in kWs as a measurement of power draw, virtually all demand charges are actually imposed on consumption within short windows, often the highest 15-, 30- or 60-minute window during the billing period.[10] Because it is based on the maximum within those short windows, a demand charge effectively acts as a one-way ratchet within a billing period. Additional ratchets can be imposed over the course of the year, where the demand charge may be based on the greater of either billing period demand or 90% of the maximum demand within the previous year. In contrast, energy charges are based on consumption throughout a billing period, with no ratchets. Energy charges can vary by time within a billing period, generically known as time-varying rates.[11] Common variants include **time-of-use** (TOU) energy charges, where prices are set separately for a few predetermined time windows within each billing period; and **critical peak pricing**, where significantly higher prices are offered for a short time period announced a day or two in advance in order to maximize customer response to events that stress the system.

Some rate analysts propose rates that rigorously follow the results of a cost allocation study, meaning that customer-related costs must be recovered through customer charges and demand-related costs must be recovered through

9 Rates that vary by season are often referred to as seasonal rates. However, some utilities also define "seasonal" customer classes for customers who have a disproportionate share of their usage during a particular time period. Rates for seasonal customer classes may also be referred to as seasonal rates, which can cause confusion.

10 Note that in these cases kWs is a simplified description of kWhs per hour since it is not truly an instantaneous measurement.

11 Some analysts may describe certain types of demand charges as time-varying rates as well, such as those that are imposed only within certain time windows (e.g., 2 to 6 p.m. on nonholiday weekdays).

demand charges. However, most analysts do not and are careful to note that categorizations like "demand-related" are simplifications at best and, as this manual details, generally reflect an increasingly obsolete framework. Forward-looking efficiency is not a feature of embedded cost of service studies and additionally may require consideration of broader **externalities** that are not necessarily incorporated in the revenue requirement. Similarly, rate design must consider customer bill impacts and the related principles of understandability, acceptability and customer bill management.

2.4 Rate Case Procedure

Although procedures at state utility commissions vary greatly, there are typically several common elements. Most rate cases begin with a proposal from the regulated utility. In the most formal terms, a utility commission is adjudicating the rights, privileges and responsibilities of the regulated utility, although typically without the full formalities and rules of a judicial proceeding. Other interested parties are allowed to become intervenors to participate in discovery, present witnesses, brief the issues for the commission and potentially litigate the result in court. This process often automatically includes an official state consumer advocate. A wide range of stakeholders may join the process, including large industrial consumers, chambers of commerce, low-income advocates, labor, utility investors, energy industries and environmental advocates. These non-utility parties can critique the utility proposal and can propose alternatives to utility cost allocation methods as well as other substantive elements of the rate case. Rate cases can be resolved through a final decision by the utility commission based on the record presented, or some or all aspects of a rate case can be resolved through a settlement among the various parties.

The costs of a rate case for the regulated utility are considered part of the cost of service and ultimately become part of the revenue requirement determined in the rate case. Many states make explicit funding arrangements for the commission itself and any state consumer advocate, often ultimately recovered from ratepayers. In some states and most Canadian provinces, ratepayer funding was historically given to other intervenors who participated productively in the process, a practice that continues in California. However, it is much more common for stakeholders to bear the burden of any litigation costs, which limits the ability of many stakeholders to advance their interests at this level.

3. Basic Components of the Electric System

The electric utility system, for general descriptive purposes and for regulatory and legal purposes, typically is divided into several categories of activities and costs, including generation, transmission, distribution, billing and customer service, and A&G costs. In a vertically integrated utility, a single entity owns and operates all of these, although many other forms of market structure and ownership exist in the United States. Each of these segments includes capital investments and labor and nonlabor operating expenses. Each of these segments is operated and regulated according to different needs and principles.

These distinctions at each level of the power system are important to cost allocation, and the terminology is important to understand. Many of the arguments about proper allocation of costs hinge on the purpose for, and capabilities of, capital investments and the nature of operating expenses. Thus, having a correct understanding of the purpose, limitations and current usage of each major element of the system is important to resolve key cost allocation questions. Figure 7 is a diagram of a traditional electric power system, with one-way power flow from a large central generation facility through the transmission and distribution system to end-use customers (U.S.-Canada Power System Outage Task Force, 2004).

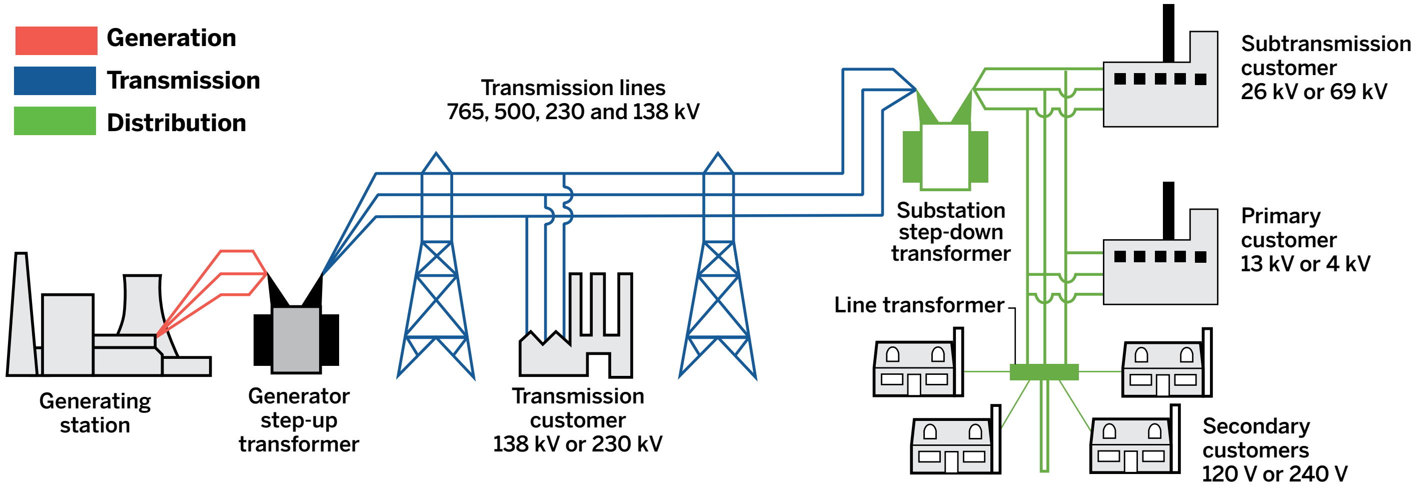
The evolving electric grid will be much different from the grid of the past hundred years. The "smart grid" of the future will look different, operate differently and have different cost centers and potentially different sources of revenues. As a result, it will need different cost allocation methods. Figure 8 on the next page shows a vision of the direction the electric system is evolving, with generation and storage at consumer sites, two-directional power flows, and more sophisticated control equipment for customers and the grid itself (U.S. Department of Energy, 2015).

This manual discusses many of the changes underway in the electric system, but undoubtedly the future will bring further change and new challenges.

3.1 Categories of Costs

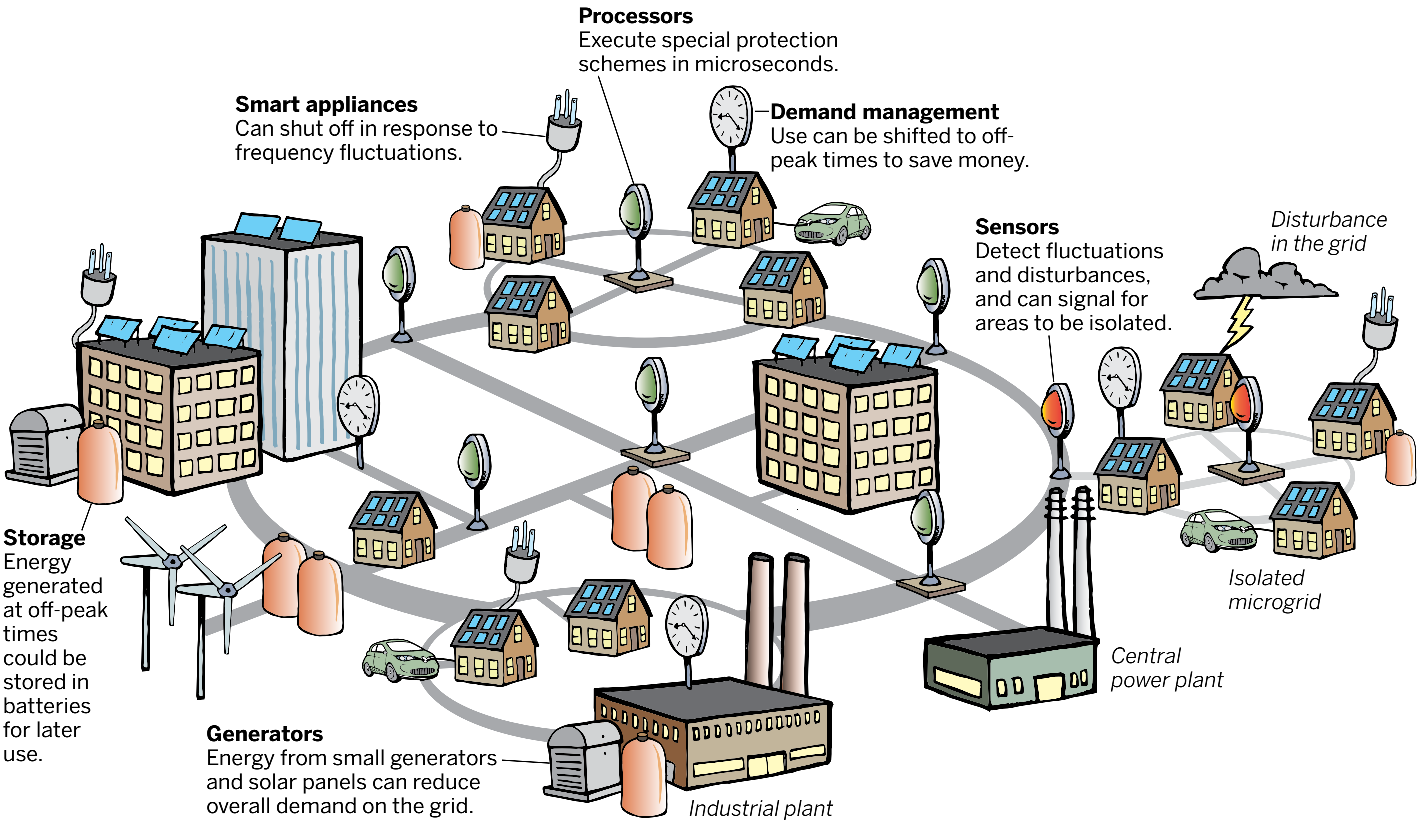
All decisions that a utility makes have consequences for its overall cost of service. Some of those decisions were made decades ago, as the utility made investments — including large power plants and office buildings — based on conditions

Figure 7. Illustrative traditional electric system



Source: Adapted from U.S.-Canada Power System Outage Task Force. (2004). *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*

Figure 8. Illustrative modern electric system



Source: Adapted from U.S. Department of Energy. (2015). *United States Electricity Industry Primer*

or forecasts at that time. Some of the decisions are made every day, as the utility dispatches power plants or replaces worn-out distribution equipment. Many of the decisions that determine the utility's revenue requirement — such as the historical decisions to build particular power plants in particular locations — result from complex processes involving past expectations and many practical complications and trade-offs.

3.1.1 Generation

Electricity generation[12] comes from many different types of technologies that utilize many different types of fuels and resources. Most types of steam-electric units burn fuel, which can be oil, coal, natural gas, biomass or waste products, in a boiler to produce steam to turn a turbine. This turbine then turns an electric generator. Most steam units are older and generally limited in their ability to cycle on and off. This means they can only change generation levels slowly and may require many hours to start up, shut down and restart.

Some noncombustion technologies use a steam turbine to generate electricity. Some geothermal units use steam to drive a turbine, using heat transferred up from underground to boil water. Concentrated solar power, or solar thermal, uses heat from the sun to boil water and spin a turbine. Nuclear generation also uses a steam turbine, where the heat to boil water comes from a chain reaction of uranium fission.

Combustion turbines, which are similar to jet engines, use heated gases from the combustion of either a liquid or gaseous fuel to directly spin a turbine and generate electricity. Simple cycle combustion turbines directly exhaust a significant amount of heat. Combustion turbines can be turned on and off very quickly and require high-quality, relatively clean fuels because of the contact between the combustion gas and the turbine blades.

12 Some sources, including the FERC accounts and the 1992 NARUC *Electric Utility Cost Allocation Manual*, use the term "production" instead of "generation." This manual uses the term "generation" and generally includes exports from storage facilities under this category.

Combined cycle units include combustion turbines but capture the waste heat to boil water, produce steam and spin an extra turbine to generate electricity. As a result, combined cycle units have higher capital costs than combustion turbines but generate more electricity for each unit of fuel burned.

Hydroelectric plants use moving water, either released from reservoirs or running in rivers, to spin turbines and generate electricity. These units vary widely in their seasonal generation patterns, storage capacity and dispatchability. Many, but not all, hydroelectric plants are easily dispatchable to follow load but may be constrained by minimum and maximum allowed river flows below the facility.

There are also a variety of noncombustion renewable resources, including wind power, solar photovoltaic (PV), solar thermal and potentially tidal and current power. In addition, fuel cells can generate electricity from hydrogen by using a chemical reaction. The only byproduct of a fuel cell reaction is water, but different methods of producing hydrogen can have different costs and environmental impacts.

Power supply can come from different types of energy storage facilities as well, although most of these resources also consume electricity. Traditional types of storage, such as pumped hydroelectric storage (where water is moved to higher ground using electricity at times of low prices and released back down to spin turbines at times of high prices) and flywheels have been around for many decades, but battery storage and other new technologies are becoming more prevalent. Different types of storage technologies can have very different capabilities, varying from a few minutes' worth of potentially exportable energy to a few months' worth, which determines the types of system needs that the storage can address. As a result, the allocation of these costs requires careful attention by the cost analyst.

Each of these technologies has a different cost structure, which can depend on the type of fuel used. This is typically divided among: (1) upfront investment costs, also known as capital costs; (2) **operations and maintenance (O&M) costs**, which may depend on the numbers of hours a facility generates ("dispatch O&M costs") or can be incurred regularly on a monthly or annual basis ("nondispatch O&M costs"); and (3) fuel costs. Fuel costs per unit of energy generation depend on the price of the fuel consumed and the efficiency of the unit; this is often defined as an efficiency percentage comparing input fuel potential energy to output electric energy, or as a **heat rate** defined as the **British thermal units** (Btu) of fuel input for every kWh of output electric energy.

Dirtier fuels, such as coal and oil, require expensive and capital-intensive pollution control equipment. Different costs are also incurred in the delivery and handling of each fuel prior to its use, as well as the disposal of any byproducts. For example, both coal ash and nuclear waste require disposal, and there are different controversies and costs associated with each. Noncombustion renewable resources have very low variable costs and relatively high capital costs. Storage resources generally have high investment costs, moderate maintenance costs and low operating costs. The decision around their dispatch is defined by the opportunity cost of choosing the hours to store and discharge, with the goal of picking the hours with the greatest economic benefit.

Some plants, mainly steam, combustion turbine and combined cycle, can be set up to use more than one fuel, primarily either natural gas or oil. Such a dual fuel setup involves a range of costs but allows the plant operator to choose the fuel that is less expensive or respond to other constraints.

Generation facilities are frequently categorized by their intended purpose and other characteristics. This terminology is evolving and does not necessarily reflect a permanent condition. For example, several types of units traditionally have been characterized as baseload because they are intended to run nearly all the time. This includes most steam-electric combustion units, particularly those run on coal. This also includes nuclear units, which run nearly all of the time with the exception of long refueling periods every few years that can last for months. Historically, **baseload units** had higher capital costs, which could be offset by lower fuel costs given their ability to run constantly. However, as fuel price patterns have changed, this is not always the case, particularly when natural gas is cheaper than coal.

Several types of plants are characterized as **peakers** or peaking units because they are flexible and dispatched easily at times of peak demand. Combustion turbines are the prime example of a peaking unit. Historically, these units had lower capital costs per unit of capacity and higher fuel costs per kWh generated. Again, this may no longer be true as fuel prices have changed.

Plants that are neither baseload nor peaking units are often referred to as **intermediate units**. They run a substantial portion of the year but not the whole year or just peak hours. “Midmerit” and “cycling” are commonly used synonyms for these types of generators. Over the last two decades, natural gas combined cycle facilities often filled this role in many parts of the country, but changing fuel costs and environmental regulations have altered the typical operating roles of many types of generation.

Hydroelectric units may effectively be baseload resources or may be storage reservoirs that allow generation to be concentrated in high-value hours. Other noncombustion renewable resources are often characterized as variable or **intermittent resources** because these technologies can generate electricity only in the right conditions — when the sun is shining, the wind is blowing or the currents are moving. However, the addition of storage to these facilities can make these characteristics much less relevant. In addition, the accuracy of forecasts for these resources has improved greatly. These variable renewable resources can also be operated in certain ways to respond to electric system or market conditions, such as through **curtailment**.

3.1.2 Transmission

Transmission systems comprise high-voltage lines, over 100 **kilovolts** (kV), that are generally carried via large towers (although sometimes on poles or buried underground) and the **substations** that interconnect the transmission lines both to one another and between generation resources and customers. Subtransmission lines that interconnect distribution substations, operating between 50 kV and 100 kV, may be functionalized as distribution plant.

Utilities use a variety of transmission voltages. A higher voltage allows more power to be delivered through the same size wires without excessive **losses**, overheating of the **conductor** (wire) or excessive drop in the operating voltage over the length of the line. Higher voltages require taller towers to separate the power lines from the ground and other objects and better insulation on underground cables but are usually less expensive than running multiple conductors at lower voltages where large amounts of power need to be delivered.

Transmission systems can also be either **alternating current** (AC) or **direct current** (DC). Some transmission using DC has been built because it can operate at high voltages over longer distances with lower losses; these lines are known as **high-voltage direct current** (HVDC). However, the vast bulk of the transmission system in the United States is AC.

Transmission serves many overlapping functions, including:

- Connecting inherently remote generation (large hydro, nuclear, mine-mouth coal, wind farms, imports) to load centers.
- Allowing power from a wide range of generators to reach any distribution substation to permit least-cost economic dispatch to reduce fuel costs.
- Providing access to neighboring utilities for **reserve** sharing, economic purchases and economic sales.
- Allowing generation in one area to provide backup in other areas.
- Reducing **energy losses** between generation sources and the distribution system, where transmission capacity is above the minimum required for service.

Each of these purposes carries different implications for cost allocation. Some transmission is needed in all hours, while other transmission is built primarily to meet peak requirements.

Transmission substations connect the generators to the transmission system and the various transmission voltages to one another. They also house equipment for switching and controlling transmission lines. Most substations are centered on large **transformers** to convert power from one voltage to another. The largest customers, such as oil refineries, often have their own substation and take delivery from the grid at transmission voltage.

3.1.3 Distribution

Distribution substations and lines are required for the vast majority of customers who take service at the distribution level. The distribution system receives power primarily from the transmission system through distribution substations, which convert power from higher transmission-level voltages down to distribution-level voltages. Some power may be delivered to the distribution system directly from small generators, such as small hydro plants and distributed generation. Distribution substations are smaller versions of transmission substations.[13] These are often connected by subtransmission lines, which may be functionalized as either transmission or distribution in cost studies. Collectively, the transmission and distribution systems are referred to as T&D or as the delivery system.

From each substation, one or more distribution feeders operating between 2 kV and 34 kV, known as **primary voltage** lines, run as far as a few miles, typically along roadways. These are mostly on wooden utility poles shared with telephone and cable services or in underground conduit. A single pole or underground route may carry multiple circuits. Each feeder may branch off to serve customers on side streets. Although distribution feeders leaving the substations are usually three-phase, like the transmission lines, branches that do not carry much load may be built as single-phase lines with just two wires.

Some customers take power directly at primary voltage (usually 2 kV to 34 kV) and transform it down within their premises to a **secondary voltage** (600 **volts** or less) or use it directly in high-voltage equipment. All residential and most commercial customers take service at secondary voltages, which typically range from 120 V to 480 V. For that purpose, the utility must provide **line transformers**, which are the large cylinders on some utility poles for overhead distribution and the ground-mounted metal boxes near buildings for underground distribution. There is a frequently used shorthand in which customers served at primary voltage are referred to as primary customers and any customer classes distinguished on this basis are described as primary — for example, primary **general service** or primary commercial. Similarly, customers served at secondary voltage can be described as secondary customers, and customer classes distinguished on that basis are referred to as secondary — for example, secondary general service or secondary commercial.

In urban and suburban settings, a typical transformer will serve several residential customers or small businesses, either in one building or several buildings that are relatively close to one another. Typically, an apartment building is served by a larger transformer than would serve single-family dwellings, but the transformer or multitransformer installation could serve dozens or even hundreds of customers. A single large secondary customer is usually served by one or more dedicated transformers, and in exurban and rural areas even a relatively small customer may be so far away from neighbors as to require a dedicated transformer.

Some secondary voltage customers will be served directly by a **service line** from the transformer to their buildings. Other customers farther up the road will be fed from a secondary distribution line from a nearby transformer that is attached to the same poles as the primary feeder but lower down. Secondary voltage lines in older neighborhoods served with overhead wires are often networked among several transformers. For many utilities, underground secondary lines in modern neighborhoods generally are not networked. Underground service is generally more expensive than overhead service but often required by local regulations for aesthetics or reliability reasons.

Figure 9 on the next page illustrates one relatively common arrangement. In this example, each transformer serves two houses directly with service lines, and feeds secondary lines from which service lines run to two or three other houses on the same side of the street and four or five houses across the street. The illustration is for an underground system. The basic layout of an overhead system would be similar. However, since it is easier to string overhead service lines across the street than to dig lines under the street, service lines might run directly from an overhead transformer to one or two houses across the street, and the secondary might just run on the transformers' side of the street, with service lines crossing the street to additional customers. The key factor here for cost allocation purposes is that even secondary voltage lines are often shared among multiple customers and are not a direct cost responsibility of any one of them individually.

13 In some cases, a higher-voltage distribution line (e.g., 13 kV) may power a lower-voltage line (e.g., 4 kV) through a substation.

Figure 9. Underground distribution circuit with radial secondary lines

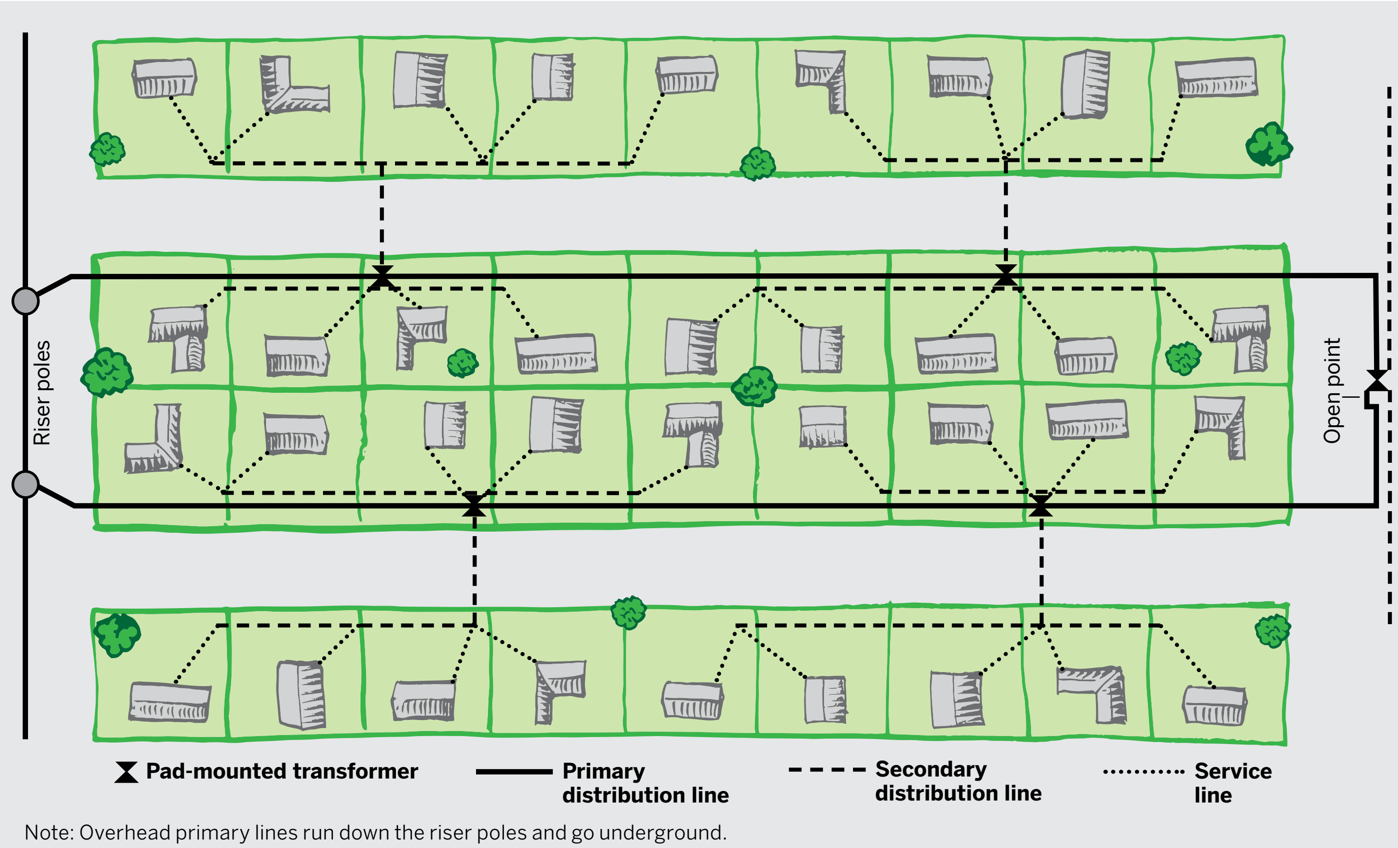


Figure 10 shows a portion of a similar distribution circuit but highlights the difference that in this case the secondary lines are networked, meaning power can flow to the relevant customers over both transformers simultaneously. This allows each transformer to serve as backup for the others in that network and allows for more flexible operation to minimize losses and prevent overloads.

Figure 10. Detail of underground distribution circuit with networked secondary lines

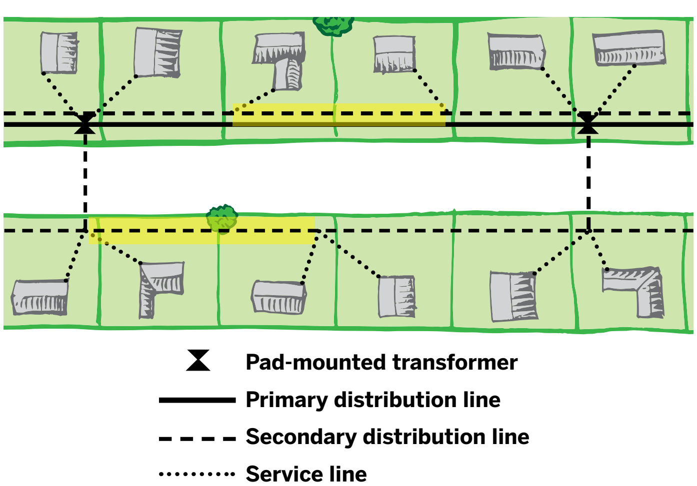


Figure 11 on the next page illustrates a typical overhead distribution pole, showing the primary lines, a transformer, an electric service to one home and secondary lines running in both directions to serve multiple homes.

The final step in the delivery of power from the utility to the customer is the service line, or drop,[14] from the common distribution facilities in the public right of way to the customer's meter. That line may be overhead or underground. Even where the distribution service is overhead, customers may be served by an underground service drop out of concerns for aesthetics or reliability, since underground lines are not vulnerable to damage from wind or trees.

For primary voltage customers, the service drop is a line at the primary voltage, attached to one or more phases of primary feeder. For secondary customers, the service drop may run from the transformer to the customer or from a convenient point along the secondary lines.

14 Since overhead service lines often slope down from their connection on the utility pole to the attachment point on the customer's building, they tend to literally "drop" the service down to the customer.

Figure 11. Secondary distribution pole layout

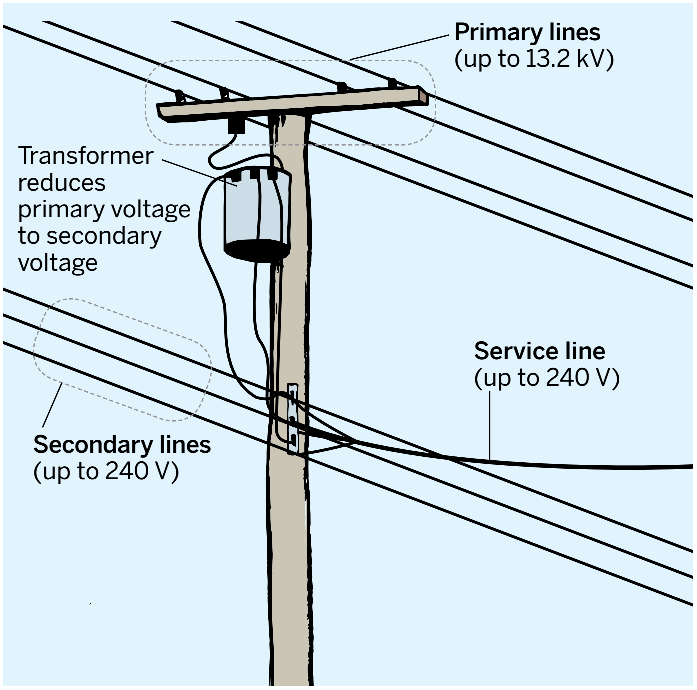
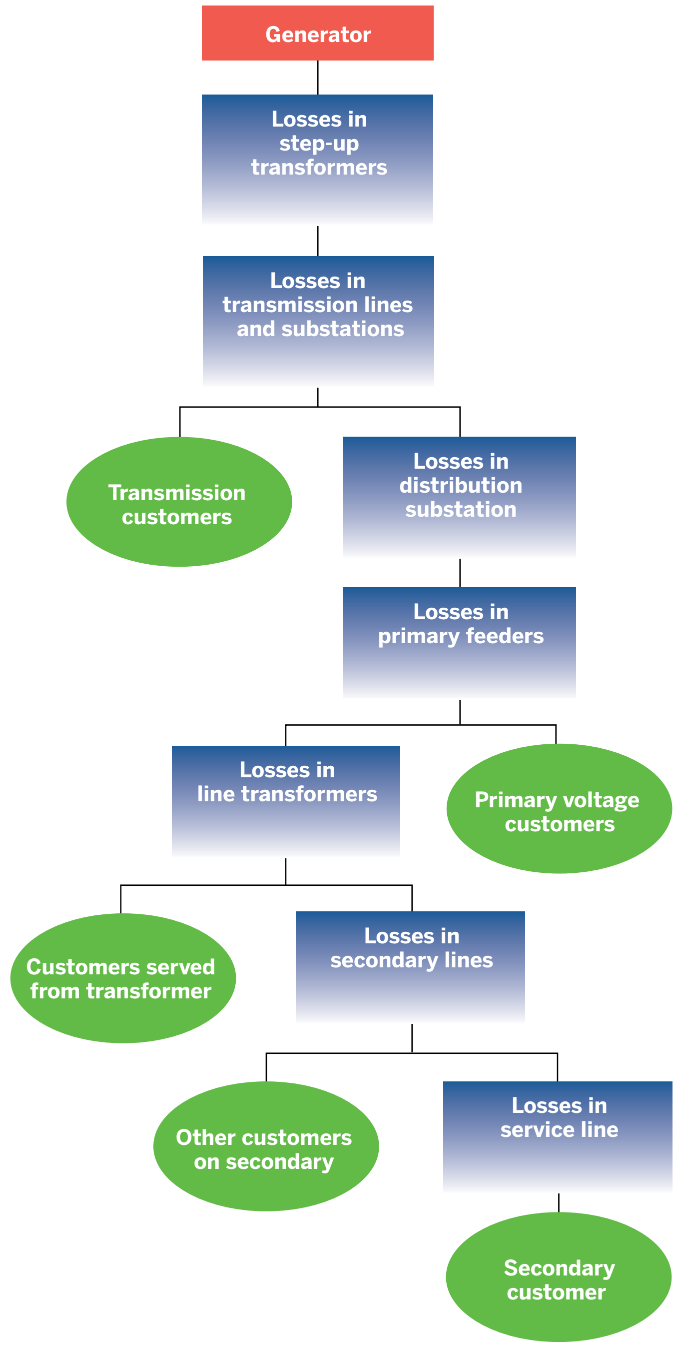


Figure 12. Electric delivery system line losses



3.1.4 Line Losses

For most purposes in a cost allocation study, line losses are not broken out as a separate category of costs. However, the physics of energy flowing over transmission and distribution lines can lead to nontrivial costs. A line loss study is an important input into a cost of service study because it helps determine the differential cost allocations to customers served at different voltages.

A small percentage of power is lost in the form of heat as it flows through each component of the delivery system, as discussed at length in Lazar and Baldwin (2011). The losses in conductors, including transmission and distribution lines, are known as resistive loss. Resistive loss varies with the square of the quantity of power flowing through the wire. Because of this exponential relationship between load and losses, a 1% reduction in load reduces resistive losses by about 2%. The levels of conductor losses from the generators to a customer at secondary voltage (such as a residential customer) are illustrated in Figure 12. Transformers have more complex loss formulae because a certain amount of energy is expended to energize the transformer (core losses) and then all energy flowing through the transformer is subject to resistive losses. Average annual line losses typically are around 7%, but marginal losses can be much higher, more than 20% during peak periods (Lazar and Baldwin, 2011, p. 1).

Reducing a customer's load (or serving that load with an on-site generation or storage resource) reduces the losses in the service drop from the street to the customer, the secondary line (if any) serving that customer, the line transformers, the distribution feeder, the distribution substation, and transmission lines and transmission substations. Lower loads, on-site generation and storage also reduce the generation capacity and reserve requirements, meaning that a 1-kW reduction in load at the customer's premises can avoid nearly 1.5 kWs of generating capacity at a central source (Lazar and Baldwin, 2011, p. 7).

3.1.5 Billing and Customer Service

Traditionally, metering is considered a customer-specific expense for the purpose of billing. Advanced metering infrastructure is used for a much wider array of purposes, however, such as energy management and system planning. This indicates that broader cost allocation techniques should be used. Historically, meter reading was a substantial labor expense, with meter readers visiting each meter every billing cycle to determine usage. However, utilities with either AMI or AMR technology have either eliminated or greatly reduced the labor expenses involved. Customers that opt out of AMI often incur special meter reading costs, if meter readers are needed for a small number of customers.

Most utilities bill customers either monthly or bimonthly for a variety of related practical reasons. If customers were billed less frequently, the bills for some customers would be very large and unmanageable without substantial planning. If billed more frequently, the billing costs would be significantly higher. Billing closer to the time of consumption provides customers with a better understanding of their usage patterns from month to month, which may help them increase efficiency and respond to price signals. There are exceptions, since many water utilities, sewer utilities and even a few electric utilities serving seasonal properties may render bills only once or twice a year.[15]

Related to billing and metering, there are a range of investments and expenses needed to store billing data and issue bills. Historically, billing data was quite simple, and the cost of issuing bills was primarily printing and mailing costs. With AMI, billing data has grown substantially more complex, and additional system and cybersecurity requirements are needed. Conversely, online billing can lower certain costs and provide easier access to customer data.

The expenses of unpaid bills are known as uncollectibles and typically are included as an adjustment in the determination of the revenue requirement as a percentage of expected bills in order to keep the utilities whole. Bills may go unpaid because of customer financial difficulties, departure from the service territory or any number of other factors. In some jurisdictions, deposits are required to protect utilities from unpaid bills. Utilities often use their ability to shut off electric service to a customer to ensure bill payment, and many jurisdictions implement shutoff protections to ensure that customers are not denied access to necessary or life-preserving services.

Customer service spans a whole range of services, from answering simple questions about billing to addressing complex interconnection issues for distributed generation. These expenses may vary greatly by the type of customer. Many utilities have "key accounts" specialists who are highly trained to meet the needs of very large customers. Large customers typically have more complex billing arrangements, such as campus billing, **interruptible rates** and other elements that require more time from engineering, legal and rate staff, as well as higher management. Some utilities lump these customer services together. The better practice is to keep them separate based on how each rate class incurs costs and benefits from the expenses.

Some utilities also characterize various public policy programs, such as energy efficiency programs, as customer service, but this is typically a mistake because these costs are not related to the number of customers. Instead, they relate to the power supply and delivery system capacity and energy benefits the programs provide.

Some states allow utilities to include general marketing and advertising efforts in rates, but others require shareholders to fund any such efforts. More narrowly targeted energy conservation and safety advertising expenses are often recovered from ratepayers as a part of public policy programs.

3.1.6 Public Policy Program Expenditures

States have mandated that utilities make expenditures for various public policy purposes. One of the largest is energy efficiency, but others include pollution control, low-income

15 This is also the case for California customers who opt out of AMI (California Public Utilities Commission, 2014).

customer assistance, renewable resources, storage and hardening of the system to resist storm damage. Each of these cost centers has a place in the cost allocation study, and each must be treated based on the purpose for which the cost is incurred.

3.1.7 Administrative and General Costs

Utilities also have a wide variety of overhead costs, typically called administrative and general costs. They include necessary capital investments, known as general plant, and ongoing expenses, typically called A&G expenses. General plant includes office buildings, vehicles and computer systems. A&G expenses include executive salaries, pensions for retired employees and the expenses due to regulatory proceedings. The common thread is that these costs support all of a utility's functions.

3.2 Types of Utilities

Utilities differ in terms of ownership structure and the types of assets they own. The many types of electric utility organizations have different characteristics that may lead to different cost allocation issues and solutions. Nationwide, publicly owned utilities typically have lower rates. In 2016, the average residential customer served by public power paid 11.55 cents per kWh, compared with 11.62 cents for co-ops and 13.09 cents for customers served by investor-owned utilities, reflecting a mix of service territory characteristics and differing sources of electricity, costs of capital and tax burdens (Zummo, 2018). Some utilities are also vertically integrated, owning generation, transmission and distribution assets simultaneously, while others own just distribution assets.

3.2.1 Ownership Structures

Investor-owned utilities serve about 73% of American homes and businesses and own about 50% of electric distribution circuit miles (National Rural Electric Cooperative Association, 2017). The regulated utilities that directly serve customers may be part of larger holding companies that include other corporate assets, such as regulated utilities in other states, natural gas assets or totally unrelated enterprises. Unlike utilities owned by governments or by the members and customers, IOUs include a return on investment, specifically a return on equity for shareholders, in the calculation of the revenue requirement. This is typically calculated as the net rate base (gross plant net of accumulated **depreciation**) multiplied by the weighted average rate of return, which is composed of the interest rate on debt and the allowed return on equity. In many states, utility commissions regulate only IOUs.

Publicly owned utilities — including municipal utilities, or munis, and public power districts — serve about 15% of American homes and have about 7% of electric distribution circuit miles (National Rural Electric Cooperative Association, 2017). Many of the areas served are urban, and municipal utilities often provide other services as well, such as water, sewer and natural gas. These utilities evolved for a variety of reasons but typically are not subject to state or federal income tax (but typically pay many other types of taxes) and do not include a return on equity in rates. For this reason, their rates tend to be lower than those of most IOUs. The state or local governmental entity that sets up this type of utility also determines the governing structure for the utility, which could be an elected or appointed board. Typically this board will hire a professional manager to oversee the utility. Many municipal utilities also determine their annual revenue requirement on a cash flow basis, which can lead to greater annual variability. In most cases, state public utility commissions have little or no authority over munis and public power districts.

Electric cooperatives are nonprofit membership corporations or special purpose districts that provide service to about 12% of Americans and own about 42% of electric distribution circuit miles (National Rural Electric Cooperative Association, 2017). They also serve more than half of the land area in the U.S. They mostly serve areas that IOUs originally declined to serve because expected sales did not justify the cost, given their shareholders' expectations for rates of return and the required investment. Some cooperatives still serve thinly populated rural areas with few large loads. Others have seen their service territories transformed to booming suburbs or industrial hubs. These entities are also exempt from federal and state income tax and do not need to include a return on equity in the revenue requirement. Unlike municipal utilities, however, cooperatives cannot issue tax-exempt debt. Cooperatives do have flexibility to offer other services to their customers, such as broadband internet, appliance sales and repair, and contract billing and collection. Many cooperatives operate in areas with limited alternatives, and they tend to have good relationships with their member customers. An increasing number of electric cooperatives are building on these assets by entering the solar installation and maintenance field. In most states, cooperatives are entirely self-regulated, with a board being elected by the members. About 16 states regulate cooperatives, often less rigorously than they regulate IOUs (Deller, Hoyt, Hueth and Sundaram-Stukel, 2009, p. 48). This is because any "profits" remain with the member-owned cooperative and members can affect decision-making through board elections.

3.2.2 Vertically Integrated Versus Restructured

Vertically integrated utilities have very different cost structures than utilities in states where the electricity industry has been restructured. Vertically integrated utilities provide complete service to customers, including generation, transmission and distribution service, and their mix of resources and cost elements can be extensive. Generation costs may include utility-owned resources, long-term contract resources, short-term contract resources, storage resources, and spot market purchases and sales. Transmission costs may include resources that are utility-owned; jointly owned with other utilities; owned by transmission companies purchased on a short-term or long-term basis; or purchased through long-term arrangements with an **independent system operator** (ISO), **regional transmission organization** (RTO), federal power marketing agency (e.g., the Bonneville Power Administration in the Northwest and the Tennessee Valley Authority in the Southeast) or other transmission entity.

For regulated utilities in **restructured states**, some of these cost elements will be missing. In most cases, the regulated utility will not own any generation assets. The regulated entity may serve certain functions with respect to power supply, such as the procurement of **default service** (also called standard service offer) for customers who do not choose a non-utility retail electricity supplier. However, these costs should be kept out of the cost of service study and cost allocation process and recovered within default power supply charges or as fees to retail electricity providers. In some restructured states, the regulated utilities still own certain types of transmission as a part of the regulated entity, which is subject to the traditional cost allocation process. In other states, transmission assets have been completely spun off into other entities. In many cases, the regulated utility is allowed to include these transmission costs as an allowed operating expense in determining the revenue requirement.

Depending on the mix of assets the regulated utility owns and the assets and operations of the larger holding company, which could span multiple states and even multiple countries, more complex jurisdictional allocation work may be necessary. The principles for jurisdictional allocation of generation and transmission, as well as billing and customer service, general plant and A&G expenses, are similar to those used for class cost allocation but do not have to be the same. Distribution investment costs generally are assigned to the jurisdiction where the facilities are located. Jurisdictional allocation is typically done as a part of the revenue requirement process and does not flow into the cost allocation process.

3.2.3 Range of Typical Utility Structures

Between the different ownership models and the mix of assets owned, there are dozens of different utility structures across the country. However, certain models are more common in particular areas:

- Nearly all IOUs outside of the restructured states are vertically integrated, owning and operating generation, transmission and distribution systems and billing customers for all of these services. Some municipal and public power entities are also vertically integrated, as well as a handful of large cooperative utilities.
- Generation and transmission (G&T) utilities own and operate power plants and often transmission lines, selling their services to other utilities (especially **distribution utilities**) and sometimes a few large industrial customers. A large portion of cooperative utilities are served by G&T cooperatives, typically owned by the distribution co-ops.

Several states have municipal power joint action agencies that build, buy into or purchase from power plants and may own or co-own transmission facilities. Many IOUs provide these services to municipal and cooperative utilities but are predominantly vertically integrated utilities serving retail customers.

- Flow-through restructured utilities operate distribution systems but do not provide generation services, leaving customers to procure those from competitive providers. Since generation prices are either set by a retail supplier in an agreement with a specific customer or determined by class from the bids of the winning suppliers in utility procurements for default service, generation cost allocation is not normally a cost of service study issue for these utilities.
- Distribution utilities own and operate their distribution systems but purchase generation and transmission services from one or more G&T cooperatives, federal agencies, municipal power agencies, merchant generators or vertically integrated utilities or through an organized market operated by an ISO/RTO. Outside of restructured states, most distribution-only utilities are municipals or cooperatives. The cost allocation issues for these utilities are similar to those for vertically integrated utilities, with the complication that the loads driving the G&T costs may be different from the loads used in setting the charges to the distribution utility.
- Some transmission companies solely own and operate transmission systems, generally under the rules set by an RTO. Their charges may be incorporated into the retail rates of distribution and flow-through utilities. In many cases, these transmission companies are subsidiaries of larger holding companies that own other electricity assets.

4. Past, Present and Future of the U.S. Electric System

Chapter 3 described the basic elements of the electric system in the United States today, but these elements developed out of a 130-year history of twists and turns based on technology, fuels, regulations and even international relations. Understanding the basics of these developments and how and why today's system was formed is relevant to several important cost allocation issues discussed later in this manual. With respect to cost allocation, four primary results of these changes are worth noting:

- A shift from fuel and labor costs to capital costs.
- The transition of new generation to non-utility ownership.
- Significant levels of behind-the-meter **distributed energy resources** (DERs), including rooftop solar.
- Significant increases in the availability, quality and granularity of electric system data.

Figure 13. Pearl Street Station, first commercial power plant in the United States

Source: Wikipedia. *Pearl Street Station*

4.1 Early Developments

Electricity generation and delivery started in the late 19th century with three essentially parallel processes:

- Privately owned companies built power plants and delivery systems in cities and near natural generator locations, starting with small areas close to the plants.
- Industrial plants built their own generation and connected other customers to use excess capacity.
- Municipalities set up their own systems, sometimes starting with the purchase of a small private or industrial facility, to serve the population of the city or town.

Initially, these utilities operated without regulation and competed with other fuels, such as peat, coal and wood, which were locally supplied. Municipalities had internal processes to set prices, but private utilities were able to charge whatever prices they wished. In this initial period, some cities did impose "franchise" terms on them, charging fees and establishing rules allowing them to run their wires and pipes over and under city streets. Multiple utilities emerged in some cities and competed against one another, which led to the building of duplicative networks of wires in many areas. These duplicative networks were aesthetically displeasing and considered by many to be economically wasteful. Relatively quickly, however, the natural monopoly characteristics led to the bankruptcy of many utilities or acquisition by a single dominant firm in each city.

In New York City, the winning utility, founded by Thomas Edison, eventually became the aptly named Consolidated Edison, or ConEd. Figure 13 depicts Edison's first generating station. New York established the first state economic regulation of electric utilities in 1900, and it spread widely from there. In New Orleans, the city remains the regulator of the IOU; its regulatory activity predated the creation of the state commission that regulates all IOUs operating outside of New Orleans.

4.2 Rural Electrification and the Federal Power Act

In the early period, regulatory authority over electric utilities was primarily exercised by states. In 1935, Congress passed the Federal Power Act, which vastly expanded the jurisdiction of the Federal Power Commission (now FERC) to cover interstate electricity transmission and wholesale sales of electricity. However, most economic regulation remained under the jurisdiction of state utility commissions, including authority over retail prices.

By the 1930s, most urban and suburban areas had access to electric service, but most rural areas did not. The Rural Electrification Act passed Congress in 1936, creating the Rural Electrification Administration to finance and assist the extension of service to rural areas through electric cooperatives, the Tennessee Valley Authority, various forms of public power districts and some state-sponsored utilities. The initial financing included significant federal support in the form of grants, technical assistance and very low-interest loans. A handful of states, including New York, North Carolina and Oklahoma, set up their own state power authorities to develop hydro facilities[16] and provide low-cost energy for economic development and other local priorities.

4.3 Vertically Integrated Utilities Dominate

By 1950, 90% of rural America was electrified, and access to electric service became nearly universal across the United States. Nearly all electric service was provided by vertically integrated utilities — which owned or contracted for power plants, transmission and distribution within the same corporate entity — or by municipal entities or cooperatives. The boundaries of service between different utilities became roughly stable in this time period and reveal the unique trends in each utility's development.

Many investor-owned utilities, especially in the Midwest and West, developed service territories that look like octopuses, with major urban areas and industrial loads connected by tentacles following the paths of transmission lines.[17] These utilities made business decisions to extend service to particular geographic areas where they believed the potential sales revenues would justify the cost of investment in transmission or distribution and still cover the additional costs of generation and customer service necessary to serve the load.[18] In each case, the utility expected that the sale of electricity would generate enough revenue to justify this expenditure.

Figure 14 on the next page shows the service territories of the Texas investor-owned utilities, illustrating these patterns (Association of Electric Companies of Texas Inc., 2019). Similar patterns are evident in the service territory maps of Minnesota, Delaware, Ohio, Oregon, Washington and Virginia. IOUs and municipal utilities generally serve densely populated areas, while cooperatives and public power districts, typically created and incentivized under the Rural Electrification Act, serve less dense areas.

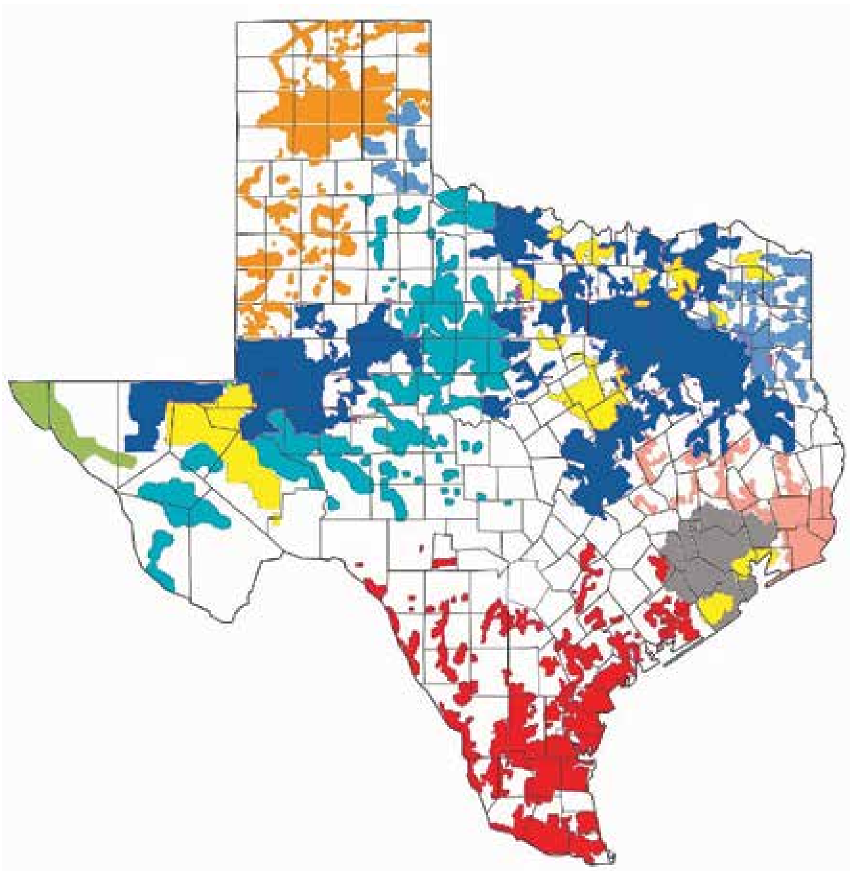
In some states, IOUs do serve some sparsely populated areas. This is often the result of a franchise grant by a municipality or a state mandate for service throughout an identified area to avoid islands where service is unavailable. The cost of this rural service is, to the utility, a price it must pay for access to the more densely populated area for a viable business, although ratepayers typically bear the higher costs of service.

16 Some of these state entities eventually assumed ownership of other types of generation.

17 In some states, such as Massachusetts, most of Maryland, Rhode Island and New Jersey, the IOUs serve large contiguous areas, regardless of density, due to historical and legal conditions in each state. In essence, the utilities incurred an obligation to serve less-developed areas as a price of obtaining authority to serve more densely populated areas.

18 In some cases, the IOU picked up dispersed service territory during the process of acquiring the assets of other power producers or to obtain state or local licenses for generation or transmission facilities.

Figure 14. Investor-owned electric utility service territories in Texas



Source: Association of Electric Companies of Texas Inc. (2019). *Electricity 101*

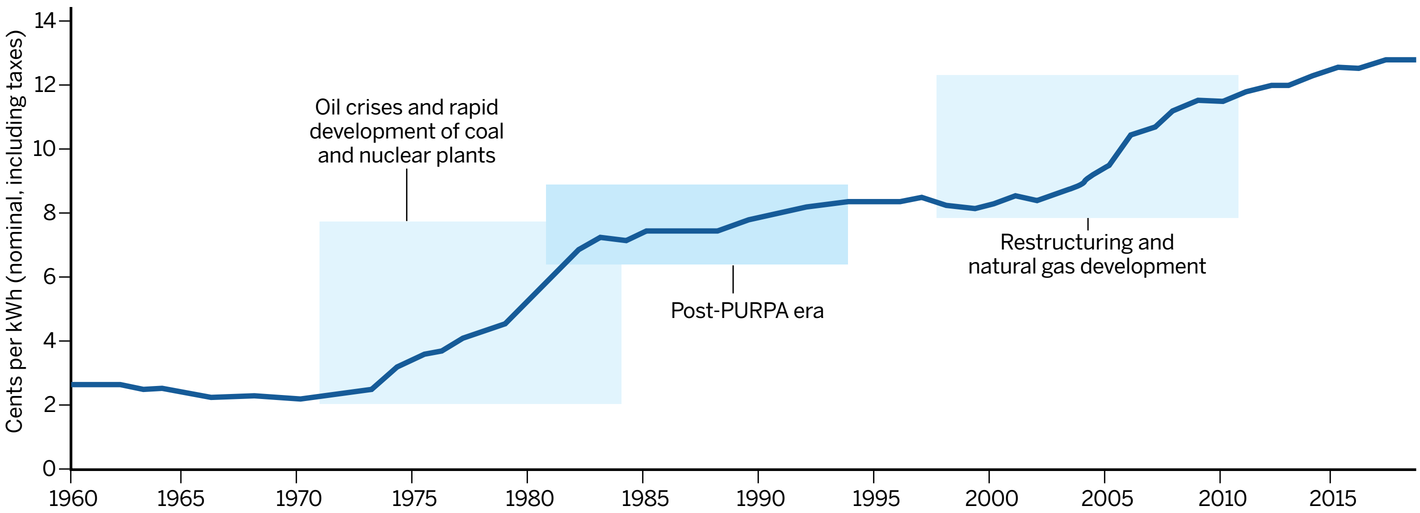
A cost analyst may need to examine these costs carefully to avoid shifting them to specific customer classes and to spread these costs systemwide.

4.4 From the Oil Crisis to Restructuring

From the 1950s to the early 1970s, electric sales skyrocketed due to a wide range of new electric end uses, and prices were relatively stable. However, the cost structure of the utility industry changed drastically after the 1974 oil crisis. Demand fell rapidly, particularly in locations where oil was used to generate electricity, in response to large price increases and fuel shortages. Natural gas prices, which had been partly regulated, were gradually deregulated over the next decade, but natural gas was thought to be in short supply and available only for certain uses. No new baseload power plants running more than 1,500 hours a year could be run on oil or natural gas under the Powerplant and Industrial Fuel Use Act of 1978, which was later repealed. In addition, generation of electricity with natural gas was to be prohibited at existing plants by 1990, with an exception for certain combined heat and power (CHP) facilities (Gordon, 1979). This law accelerated a trend toward the construction of large capital-intensive nuclear and coal power plants across the country in order to get away from the use of oil and natural gas for electricity. The confluence of all these trends, including high oil prices and expensive capital-intensive plants entering the rate base, led to major increases in electricity prices, as depicted in Figure 15 on the next page using U.S. Energy Information Administration data (2019).

Congress also passed PURPA in 1978, which included provisions intended to open up competition in the provision of electricity and to reform state rate-making practices. On the competition side, PURPA required electric utilities to purchase power from independent producers at long-term prices based on **avoided costs**. With regard to state rate-making practices, PURPA also required state commissions

Figure 15. US average retail residential electricity prices through 2018



Data source: U.S. Energy Information Administration. (2019, March). *Monthly Energy Review*

to consider a series of rate-making standards, including cost of service. This standard was widely adopted, but neither PURPA nor the state commissions defined "cost of service."[19] PURPA also requires some method to assure consumer representation in the consideration of rate design, through either a state consumer advocate or intervenor funding.

The widespread end result was low-cost energy generation (particularly after the fall in oil and gas prices in 1985-1986) and excess capacity in the 1980s, meaning the wholesale price of power was often much lower than full retail rates, even the supply portion of those rates. As a result, large industrial power users and municipalities began demanding the right to become wholesale purchasers of electricity. Given the changes in fuel markets, Congress repealed the limits on natural gas usage for electricity in the Natural Gas Utilization Act of 1987.

During the 1980s, major changes occurred in the telecommunications and natural gas industries, often termed deregulation but more accurately described as restructuring. Following these trends and the demands of larger purchasers for lower rates, Congress passed the Energy Policy Act of 1992.[20] This law called for open access to transmission service and paved the way for restructuring of the electric industry, including organized wholesale markets. In several parts of the country, including Texas and the Northeast, Midwest and West Coast, many states followed these trends and passed restructuring acts in the late 1990s, which required formal separation of certain asset classes and, in some cases, total divestment of generation assets. In several parts of the country, following voluntary criteria articulated by FERC in 1996, independent system operators were created to formalize independent control of the electric system and to administer organized wholesale markets for energy supply. FERC also articulated voluntary criteria in 1999 to form regional transmission organizations, which contain many of the same elements as the earlier ISO requirements (Lazar, 2016, pp. 21-23). There are currently six ISOs/RTOs operating solely in the U.S., two operating exclusively in Canada and one that includes areas in both countries:

- California Independent System Operator (CAISO).
- Electric Reliability Council of Texas (ERCOT).
- Midcontinent Independent System Operator (MISO),

19 The relevant provision of PURPA merely states: "Rates charged by any electric utility for providing electric service to each class of electric consumers shall be designed, to the maximum extent practicable, to reflect the costs of providing electric service to such class" (16 U.S.C. § 2621[d][1]). This was clarified by the 2005 amendments to include "permit identification of differences in cost-incurrence, for each such class of electric consumers, attributable to daily and seasonal time of use of service" (16 U.S.C. § 2625[b][1]).

20 Pub. L. 102-486. Retrieved from https://www.govinfo.gov/content/pkg/STATUTE-106/pdf/STATUTE-106-Pg2776.pdf

spanning from North Dakota through Michigan and Indiana and down to Louisiana while also including the Canadian province of Manitoba.

- ISO New England (ISO-NE).
- New York Independent System Operator (NYISO).
- PJM Interconnection, spanning from New Jersey down through part of North Carolina and extending west through West Virginia and Ohio, while also including the Chicago area.
- Southwest Power Pool (SPP), spanning from North Dakota down through Arkansas, Oklahoma and northern Texas.
- Alberta Electric System Operator (AESO).
- Independent Electricity System Operator (IESO) in Ontario.

Organized wholesale markets for energy supply provide for structured competition among owners of power plants while meeting reliability and other constraints. These markets provide a nominal framework for competition but are in actuality much more deliberately constructed than any actual competitive markets that do not have the same reliability obligations. Cost analysts should pay careful attention to whether wholesale market structures and tariffs truly reflect cost causation.

In some states, retail customers were also given the option of choosing a new retail electricity supplier for the energy component of their rates, typically with utility-procured "basic" or default energy service as the more widely used option.[21] FERC regulates ISOs and RTOs, as well as the organized wholesale markets they run. However, each traditional regulated utility retained ownership of the distribution system as a natural monopoly regulated by the state, and states are the primary regulatory entity for retail electricity suppliers.

Several more states were either in the beginning stages of restructuring or contemplating restructuring in the early 2000s when a backlash from events in restructured states halted this trend. Chief among these events was the California energy crisis, where a drought-induced supply shortfall enabled energy traders to manipulate newly formed energy markets. In combination with infrastructure limitations and other features of the new California rules, this led to high wholesale market prices, the bankruptcy of one of the nation's largest utilities and even the recall and removal of California's governor.

4.5 Opening of the 21st Century

The beginning of the 21st century has seen another wave of dramatic change in the electric sector. Restructured areas have seen significant changes in investment patterns. New natural gas combined cycle plants have become a much more important source of generation. Aided by a drop in natural gas prices due to innovations in drilling technology, they have been able to outcompete other types of generation. This has meant significant retirements of other types of generation, starting with older oil and coal units, which have also been affected by new pollution control requirements over the last several decades. More recently, nuclear plants built in the 1960s through 1980s have started to be retired, or their owners have claimed that low energy market prices require additional financial support to enable their continued operation.

In addition, global market developments and federal, state and local policies for renewable generation, as well as energy efficiency and demand response, have led to significant expansions in new resources that have zero pollution and low marginal costs. Many states have adopted **renewable portfolio standards** (RPS) to accelerate the adoption of new renewable technologies, sometimes with requirements for solar or other specific technologies. Storage technology innovation has further increased options for grid flexibility and reliability. New technologies to monitor and manage the electricity grid have also become much more prevalent as a result of continued innovation, cost decreases and policy support.

Some jurisdictions are looking at how to maximize the benefits of customer-sited investments in energy efficiency, energy management and distributed generation. Notable examples are the Reforming the Energy Vision process in

21 Texas is the exception, without any option for utility-provided energy supply service.

New York, E21 in Minnesota and the distribution resources plan proceedings in California. These efforts may even extend to new market structures at the retail level and new platforms for customers and third parties to exchange data and to offer and receive new types of services.

Changes in the electricity system affect many parts of the cost allocation process.

First, a utility cost study performed in 1980 might have placed 70% of the utility revenue requirement in the categories of fuel and purchased power, which are generally considered short-run variable energy-related costs. Since that time, capital has been substituted for fuel, in the form of wind, solar, nuclear and even high-efficiency combined cycle units running on low-cost natural gas. Many variable labor costs for customer service and distribution employees, including meter readers, have been displaced with capital investments in distribution automation and smart grid technologies. As energy storage evolves, even peak hour needs may be met with no variable fuel costs incurred in the hour when service is actually provided. Instead, power may be generated in one period with a variable renewable resource with no fuel cost[22] and saved for a peak hour in a storage system with almost no variable operating costs.

Second, a significant share of electricity generation is now owned by non-utility investors. Some of this shift is driven by federal tax code provisions, some is due to the emergence of specialized companies that build and operate specific types of power generating facilities, and some is due to public policy decisions to limit ownership of generating resources by traditionally regulated utilities. As a result, costs attributable to these sources of generation are primarily the cost of the energy — which is not divided up into capital costs, maintenance costs, etc., as it was when the generation plant was owned and operated by the utility. The 2005 amendments to PURPA, which state that time-differentiated cost studies must be considered, provide an imperative to think carefully about how to assign costs to time periods.

Third, a range of supportive state and federal policies, combined with falling costs, have led to major increases in DERs, notably rooftop solar. Advanced energy storage may be the next great wave on this front, enabling both widespread energy management and backup power resources.

Fourth, today's sophisticated data and analytical capabilities present regulators and analysts alike with a wide range of new choices. Several decades ago, analysts were limited to simple categorizations and shortcuts. This includes the traditional division of costs as customer-related, demand-related or energy-related. Regulators are no longer bound by these limitations and should seek to improve on dated techniques.

22 For example, Xcel Energy has put forward a "steel for fuel" program, which substitutes wind and solar facilities for fuel-burning power plants (Xcel Energy, 2018, p. 5).

Works Cited in Part I

Association of Electric Companies of Texas Inc. (2019). *Electricity 101*. Retrieved from http://www.aect.net/documents/2019/AECT%20Electricity%20101%202019.pdf

Bonbright, J. (1961). *Principles of public utility rates.* New York, NY: Columbia University Press.

California Public Utilities Commission. (2014, December 18). *Decision regarding smartmeter opt-out provisions.* Application No. 11-03-014 et al., Decision No. 14-12-078. Retrieved from http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K904/143904205.PDF

Daniels, L. (1988, January 29). Bankruptcy filed by leading utility in Seabrook plant. *The New York Times.* Retrieved from https://www.nytimes.com/1988/01/29/business/bankruptcy-filed-by-leading-utility-in-seabrook-plant.html

Deller, S., Hoyt, A., Hueth, B., and Sundaram-Stukel, R. (2009). *Research on the economic impact of cooperatives.* Madison: University of Wisconsin Center for Cooperatives. Retrieved from http://reic.uwcc.wisc.edu/sites/all/REIC_FINAL.pdf

Garfield, P., and Lovejoy, W. (1964). *Public utility economics.* Englewood Cliffs, NJ: Prentice Hall.

Gordon, R. (1979). The Powerplant and Industrial Fuel Use Act of 1978 — an economic analysis. *Natural Resources Journal 19*(4). Retrieved from https://digitalrepository.unm.edu/cgi/viewcontent.cgi?referer=&httpsredir=1&article=3074&context=nrj

Kahn, A. (1970 and 1971). *The economics of regulation: Principles and institutions* (vols. 1 and 2). New York, NY: John Wiley & Sons.

Lazar, J. (2014). *Performance-based regulation for EU distribution system operators.* Montpelier, VT: Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/performance-based-regulation-for-eu-distribution-system-operators/

Lazar, J. (2016). *Electricity regulation in the United States: A guide* (2nd ed.). Montpelier, VT: Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/electricity-regulation-in-the-us-a-guide-2/

Lazar, J., and Baldwin, X. (2011). *Valuing the contribution of energy efficiency to avoided marginal line losses and reserve requirements.* Montpelier, VT: Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/valuing-the-contribution-of-energy-efficiency-to-avoided-marginal-line-losses-and-reserve-requirements/

Lazar, J., and Gonzalez, W. (2015). *Smart rate design for a smart future.* Montpelier, VT: Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future/

Linvill, C., Lazar, J., Dupuy, M., Shipley, J., and Brutkoski, D. (2017). *Smart non-residential rate design: Optimizing rates for equity, integration, and DER deployment.* Montpelier, VT: Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/smart-non-residential-rate-design/

Linvill, C., Shenot, J., and Lazar, J. (2013). *Designing distributed generation tariffs well: Fair compensation in a time of transition.* Montpelier, VT: Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/designing-distributed-generation-tariffs-well/

Littell, D., Kadoch, C., Baker, P., Bharvirkar, R., Dupuy, M., Hausauer, B., Linvill, C., Midgen-Ostrander, J., Rosenow, J., Xuan, W., Zinaman, O., and Logan, J. (2017). *Next-generation performance-based regulation: Emphasizing utility performance to unleash power sector innovation* (NREL/TP-6A50-68512). Montpelier, VT and Golden, CO: Regulatory Assistance Project and National Renewable Energy Laboratory. Retrieved from https://www.raponline.org/knowledge-center/next-generation-performance-based-regulation-emphasizing-utility-performance-unleash-power-sector-innovation/

National Association of Regulatory Utility Commissioners. (1992). *Electric utility cost allocation manual.* Washington, DC: Author. Retrieved from https://pubs.naruc.org/pub/53A3986F-2354-D714-51BD-23412BCFEDFD

National Rural Electric Cooperative Association. (2017). *America's electric cooperatives: 2017 fact sheet.* Retrieved from https://www.electric.coop/electric-cooperative-fact-sheet/

Phillips, C. (1984). *The regulation of public utilities* (1st ed.). Arlington, VA: Public Utility Reports.

U.S.-Canada Power System Outage Task Force. (2004). *Final report on the August 14, 2003 blackout in the United States and Canada: Causes and recommendations.* Retrieved from https://www.energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf

U.S. Department of Energy. (2015). *United States electricity industry primer* (DOE/OE-0017). Washington, DC: Author. Retrieved from https://www.energy.gov/sites/prod/files/2015/12/f28/united-states-electricity-industry-primer.pdf

U.S. Energy Information Administration. (2019, March). *Monthly energy review* (DOE/EIA-0035 [2019/3]). Table 9.8. Washington, DC: Author. Retrieved from https://www.eia.gov/totalenergy/data/monthly/index.php

Xcel Energy. (2018, October 2-4). *Leading the energy future* [Presentation at the Wolfe Research Conference]. Retrieved from investors.xcelenergy.com/file/4025308/Index?KeyFile=1500113448

Zummo, P. (2018). *Coast to coast, public power costs less.* Arlington, VA: American Public Power Association. Retrieved from https://www.publicpower.org/periodical/article/coast-coast-public-power-costs-less

Part II:

Overarching Issues and Frameworks for Cost Allocation

5. Key Common Analytical Elements

Several key analytical processes and decisions must be made regardless of the overall framework and specific methods used for cost allocation. These common analytical elements include:

- Cost drivers: What are the key factors that lead different types of costs to be incurred?
- Determining customer classes: How many classes of customers should be categorized separately, and how is each class defined?
- Load research and data collection: What are the key patterns of load, delivery and generation that need to be recorded and analyzed? For any key data that are not tracked comprehensively, is sampling or another approach used?

In any individual rate case, these issues may not be litigated at great length, and many or all parties may rely on past practices and precedent. But the decisions made on these issues historically by each public utility commission can have important consequences in the present, particularly as changes to technology and the regulatory system undermine the basis of past assumptions.

5.1 Cost Drivers

Effective cost allocation and rate design require the identification of central cost causation factors, or cost drivers. Within these processes, it is important to identify relatively simple metrics (e.g., energy use in various periods, demand at various times, numbers of customers of various types) that can be associated with the various customer classes. The cost allocation process, by its nature, approximates cost responsibility and is not a tool of exceedingly precise measurements.

One crucial underlying reality is that customers use electricity at different times, leading to the concept of **load diversity**. Load diversity means the shared portions of the system need to be sized to meet only the **coincident peak** (CP) loads for combined customer usage at each point of the system,[23] rather than the sum of the **customers' noncoincident peak (NCP) loads**.[24] This diversity exists on every point of the system:

- Customers sharing a transformer have diverse loads.
- Loads along a distribution feeder circuit have diversity.
- Multiple circuits on a substation have diversity.
- The substations served by a transmission line have load diversity.
- Individual utilities in an ISO territory or regional transmission interconnection have diversity.

Diversity of load means the actual electricity system is significantly less expensive than a system that would be built to serve the sum of every customer's individual NCP. Holding **peak load** for a customer constant, this also means that a customer with load that varies over time is effectively much cheaper to serve than a customer that uses the same peak amount at every hour. The former customer can share capacity with other customers who use power at other times, but the latter cannot.

Another important reality is that the accounting category to which a cost is assigned does not determine its causation. An expense item may be due to energy use, peak demands or number of customers; the same is true for capital investments. Capital costs and other expenses that do not vary with short-run dispatch changes are referred to as fixed costs by some analysts, and some cost of service studies assume that

23 As explained throughout this section, the critical coincident peak load may be a single peak hour but more typically is some combination of loads over multiple hours.

24 Several other terms are used for individual customers' noncoincident peak demand, including "undiversified maximum customer demand." Unfortunately, both "NCP" and "maximum customer demand" can also be used to refer to various class peaks, particularly when used with modifiers. This manual will use "customer NCP" to refer to individual customer peaks and "class NCP" to refer to aggregated peaks by class, often specifying the level of the system for the relevant class NCP. Class NCP is sometimes referred to as the maximum class peak, maximum diversified demand or other similar terms.

these notionally fixed costs cannot be driven by energy use. As discussed in the text box on pages 78-79, this assumption is incorrect. Utilities make investments and commit to "fixed" expenses for many reasons: to meet peak demands, to reduce fuel costs, to reduce energy losses, to access lower-cost energy resources and to expand the system to attract additional business. As a result, this manual will use the phrase "dispatch O&M costs" to reflect operations and maintenance costs that vary directly with generation output and "nondispatch O&M costs" for O&M costs that are incurred independently of output levels.

5.1.1 Generation

There are several different categories of generation costs, with different lengths of time for the commitment. Depending on the technologies in question, long-term capital costs, nondispatch O&M costs and per-kWh fuel costs are substitutable — that is, a wind generator with a battery storage system involves more capital cost and lower operating cost than a natural gas combustion turbine unit with the same output.

The longest-lived category of generation costs is capital investment in generation facilities, which are often depreciated on a 30-year timeline and can last even longer. Once the investment is made, the depreciation expense typically will not vary over that time. Of course, a generation facility can be permanently shut down (retired), temporarily shut down (mothballed) or repurposed before the depreciation period is over. Different costs and benefits may be incurred for each of these three options. It is also possible for a plant's life to be recalculated at some point, with an appropriate change in the depreciation schedule and the annual depreciation expense.

There can be significant capital investments and nondispatch O&M costs that are incurred on an annual or monthly basis, which may not vary directly with the numbers of hours the facility operates. There are also capital investments that are driven by wear and tear, rather than the passage of time.[25]

The shortest-term variable costs for utilities are mostly fuel costs and the portions of power purchases that vary with energy taken. In addition, some O&M costs are usually considered variable with output: the costs of some consumable materials (especially for pollution control equipment), as well as the costs of replacements (such as lubricants and filters) and overhauls that are required after a specified amount of output, equivalent full-load hours of operation or similar measures.[26]

In many cases, utilities classify costs based on accounting data and administrative convenience, rather than the underlying reasons why the costs were incurred and why any capital investments are still part of the system. For example, utilities may treat some O&M and interim capital additions as variable and energy-related for one set of purposes, such as rate design or evaluation of potential generation resources, but treat the same costs as demand-related for cost allocation purposes for simplicity. Cost of service studies are normally driven primarily by accounting data that do not readily differentiate dispatch O&M costs from nondispatch O&M costs and capital additions.

Similarly, other costs, such as pollution controls and ash handling and disposal at coal plants, include significant long-run investments that were specifically incurred to support the energy generation process and generally should be treated as energy-related. These investments would not be needed or would be less costly either if the plant were run less often or if the fuel were less polluting.

Short-Run Variable Generation Costs

The short-run variable cost of power generation is typically straightforward, primarily entailing a mix of fuel costs, dispatch O&M costs for utility-owned generation and purchased power. As a result, the drivers of these costs are typically fuel prices, market prices for energy and any ongoing contracts the utility has. Utilities can hedge the risk of short-term energy generation costs through a wide range of means, including futures contracts for fuel and power.

The short-run variable costs of some generation facilities, including storage and dispatchable hydro, are very low. Storage facilities require the operation of other resources (which may well have variable costs) to charge them. Dispatch

25 These costs are comparable to tire replacements that are caused by wear and tear closely correlated with miles driven.

26 These costs are comparable to the costs of automotive oil changes and routine services that are the consequence primarily of miles driven.

decisions for storage and dispatchable hydro resources are typically made to maximize the benefits from the limited supply of other time-shiftable generation resources.

Prior to PURPA, most long-term purchased power contracts had separate capacity and energy elements. These were mostly for fuel-dependent power plants. This rate form allowed the owner to obtain capital cost recovery in a predictable payment and the receiving utility to control the output as needed to fit varying loads, paying for short-run variable costs as incurred. Today many power purchase contracts are expressed entirely on a volumetric basis, based on an expected pattern of output. This change in how contracts are priced in the wholesale market does not dictate any particular approach to how costs are allocated in the retail rate-setting process.

Generation Capacity Costs

Beyond these energy needs, most regions of the United States also plan around the amount of shared generation capacity needed, and these processes can drive a significant amount of generation costs. The amount of capacity required by a utility system, typically denominated in **megawatts** (MWs) or gigawatts at the time of the system coincident peak, determines whether the utility should retire existing plants, add new resources or delay planned retirements, or keep the system as it is. All those decisions have costs and benefits. This determination may be made by an ISO/RTO, a holding company or other aggregation of interconnected load.

Although the typical planning procedures used to date by utilities and ISOs have often served their original purposes to measure the least-cost resources available at the utility system level, these procedures often oversimplify important aspects of overall capacity and reliability issues. The key principle is that reliability-related costs are not all "caused" by one hour or a few hours of demand during the year. A system must have some form and level of capacity available at all hours. Loss-of-energy expectation[27] studies generally show that adding capacity at any hour to a system, even **off-peak** hours, has a small but discernible beneficial impact on reliability. Many resources can be justified only if all of the attributes are considered, including contribution to meeting peak demand and contribution to meeting other needs such as fuel cost reduction.

The typical vertically integrated utility calculates the installed capacity requirement by determining what amount of existing and new capacity will provide acceptable reliability, measured by such statistical parameters as the mathematical expected value of the number of hours in which it cannot serve load or of the amount of customer energy it will not be able to serve in a year, due to insufficient available generation. Those expected values are computed from models that simulate the scheduling of generation maintenance and the random timing of forced outages for many potential combinations of outages and load levels. In large portions of North America, the capacity requirement is determined regionally by an ISO/RTO and then allocated to the load-serving entities, transmission control areas or utilities.[28]

Required reserves are usually expressed as the percentage **reserve margin**, which is:

$$(\text{capacity} - \text{peak load}) \div \text{peak load}; \text{ or}$$
$$(\text{capacity} \div \text{peak load}) - 1$$

Capacity may be defined as installed capacity, demonstrated capacity or unforced capacity (installed capacity reduced by the resource's forced outage rate). There may be special provisions to recognize that an installed MW of solar, wind or seasonal hydro capacity is not equivalent to an installed MW of combustion turbine capacity with guaranteed fuel availability or a MW of battery storage capacity located at a distribution substation. Capacity requirements may also be satisfied with curtailable load, energy storage or expected price response to peak pricing. The cost of capacity to meet a very short-term need is very different from the cost of **baseload capacity** that serves customers around the clock

27 Different analysts refer to related measures as loss-of-load hours, loss-of-load expectation, expected unserved energy and loss-of-load probability.

28 Some of the utilities in the ISOs/RTOs are restructured and do not provide generation services, so the cost of service study need not deal with generation costs. However, all the utilities in the SPP and most of those in MISO are vertically integrated, as are some jurisdictions in PJM (West Virginia, Virginia, Kentucky and the PJM pieces of North Carolina, Indiana and Michigan) and ISO-NE (Vermont) and municipal and cooperative utilities in most restructured jurisdictions.

and throughout the year, and the cost analyst must be aware of these differences.

Peak load is generally the utility's maximum hourly output requirement under the worst weather conditions expected in the average year (e.g., the coldest winter day for winter-peaking utilities or the hottest summer day for summer-peaking utilities). In the ISOs/RTOs, the peak load is usually the utility's contribution to the actual or expected ISO/RTO peak load. Although the reserve margin is often stated on the basis of a single peak hour as a matter of measurement convention, the derivation of the reserve margin takes into account far more information than the load in that one hour. The most important parameters in determining the required reserve margin are the following:

- **Load shape**, especially the relationships among the annual and weekly peaks and the number of other hours with loads close to the peaks. The system must have enough reserve capacity to endure generation outages at the high-load hours. The near-peak hours matter because the probability of any given combination of outages coinciding with the peak hour is very low, but if there are hundreds of hours in which that combination of outages would result in a supply shortage, the probability of loss of load would be much larger.
- Maintenance requirements. Utilities attempt to schedule generator maintenance in periods with loads lower than the peak, typically in the autumn and spring, and occasionally in the winter for strongly summer-peaking utilities and in the summer for strongly winter-peaking utilities. Utilities with both modest maintenance requirements and several months with loads reliably well below those in the peak months can schedule all routine maintenance in the off-peak months while leaving enough active capacity to avoid any significant risk of a capacity shortage in those months. But many utilities have large maintenance requirements (especially for coal-fired and nuclear units) and only modest reductions in peak exposure in the shoulder months. After subtracting required maintenance, the effective reserve margin may be very similar throughout the year, increasing the chance that a combination of outages will result in loss of load. As a result, high loads in any month (or perhaps any week) contribute to the need for installed capacity.
- Forced outage rates. All generation units experience some mechanical failures. The higher the frequency of forced outages, the more likely it is that a relatively high-load hour will coincide with outages, eliminating available reserve and resulting in the loss of load.
- Unit sizes. If all of a system's units were very small (say, under 1% of system peak), the random outages could be expected to spread quite evenly through the year. With larger units, outages are much lumpier, and loss of a small number of large units can create operating problems. Hence, systems with larger units tend to need higher reserve margins, all else being equal.
- Other operating constraints. Although hydro resources have the highest overall reliability, they produce power only when water is available to run them. Some hydro resources are required to be operated for flood control, navigation, irrigation, recreation, wildlife or other purposes, and these other constraints may affect the ability of the resource to provide power at full capacity when system peak loads occur.

Some of the factors in this list affect the reliability value of various types of generation, while others highlight the types of load that increase required capacity reserve levels. A large unit with frequent forced outages may contribute little to ongoing system reliability even though it has a significant nameplate capacity. If such a unit has high ongoing costs that could be reduced or eliminated through retirement, continued operation must primarily be justified by its energy benefits. On the demand side, long daily periods of high loads can mean that many weekday hours (and even some weekend hours) in each month will contribute to capacity requirements, proportionately shifting capacity responsibility toward customers with high **load factors**. Table 2 on the next page summarizes cost drivers for power supply capacity.

The value of capacity is partly a function of the type of capacity and the location of that capacity. Although required capacity (measured in MWs) is determined by demand in a subset of hours, along with the characteristics of the power plants, the cost of capacity (measured in dollars per MW-year) is in large part determined by energy requirements.

In the previous millennium, the cheapest form of

Table 2. Cost drivers for power supply

Resource type	Purpose	Investment-related costs	Maintenance costs	Fuel costs
Baseload nuclear, geothermal	Power at all hours	High	High	Low
Coal, intermediate combined cycle	Power at many hours	Medium	Medium	Medium
Peaking	Power in peak hours, plus reserves at all hours	Low	Low	High
Hydro	Power at some or all hours	Very high	Low	Low or none
Wind	Power at some hours	High	Low	None
Solar	Power at some hours	High	Low	None
Storage	Power at peak hours, plus reserves at all hours	High	Low	Low — for purchased kWhs

capacity to serve peak needs was typically considered to be a combustion turbine. These units had low investment costs and low ongoing O&M expenses but were inefficient and typically used more expensive fuels. These characteristics made them perfect to run infrequently during peak times and for other short-term reliability needs. Conversely, it made sense to make major investments in units with high upfront costs but high efficiency and cheap fuel prices and to run these units nearly year-round. These major investments were driven by year-round energy requirements, not peak loads.

Today, in contrast, the least expensive form of capacity to serve extreme peak loads may not be a generating unit at all. For very low-duration loads, demand response, customer response to critical peak pricing or battery storage may be the least-cost resource to serve a very short-duration peak, sometimes described as a needle peak. The ability to curtail an end-use load saves not only the amount of capacity represented by the reduced load but also the marginal line losses and reserves that would be required to reliably sustain that load. Similarly, the ability to dispatch DERs also avoids line losses that would be required to deliver generated capacity to that location.[29]

5.1.2 Transmission

The costs of transmission lines depend on the length of the lines, the terrain they must cover and the amount of power they need to carry at different times, sometimes in either direction. The maximum usage of many transmission lines is not necessarily at system peak hours, and the usage of certain lines can change significantly over time. Carrying more power requires larger conductors, multiple conductors and/or higher voltages, all of which increase costs.

If each load center in a utility's territory had about the amount of generation required to meet its peak load, and the power plants were similar so the utility had no interest in exporting power from one area to another, the transmission system would exist primarily to allow each load center to draw on the others for backup supply when local generation was unavailable. In real utility systems, power plants are often distributed very differently from load, with large centralized plants built to capture economies of scale, often in areas far from major load centers. Generation may be sited remotely away from load for environmental reasons, to facilitate access to fuel and to minimize land costs and land use conflict. Generation plants also tend to vary considerably in fuel cost, efficiency and flexibility; allowing the utility to use the least-cost mix of generation at all load levels may require additional transmission.

By contrast, demand response, energy efficiency and energy storage can be very carefully targeted geographically to provide needed capacity in a specific area without the need for any additional transmission.

Although separating all the causes of the structure of an existing transmission system can be difficult, especially for a

29 The capacity saved can be as high as 1.4 times the load reduced, when marginal line losses and reserves are taken into account. For a detailed discussion of this, see Lazar and Baldwin (2011).

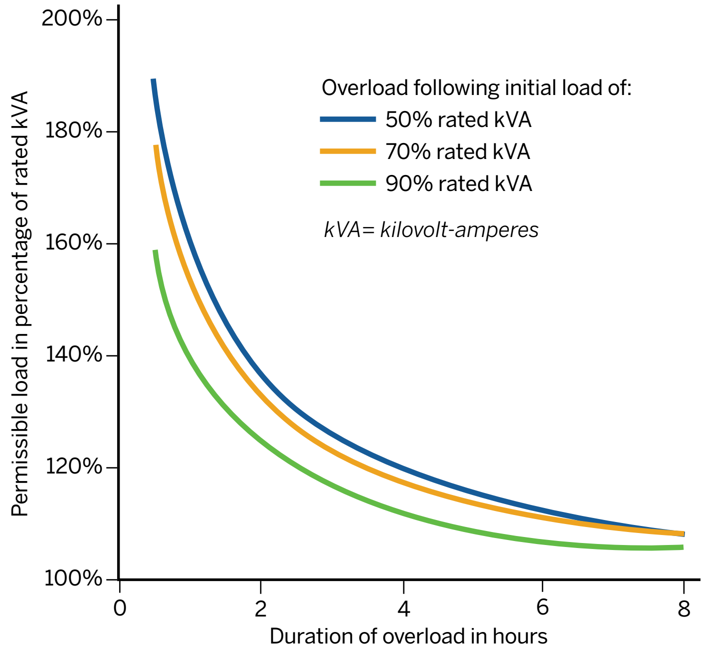
utility whose distribution of load and generation has changed over the decades, decisions about the nature and location of generation facilities can have important effects on the costs of the transmission system.

Energy load over the course of many hours also affects the sizing and cost of transmission. Underground transmission is particularly sensitive to the buildup of heat around the lines, so the duration of peak loads and the extent to which loads decline from the peak period to the off-peak period affects the sizing of underground lines. An underground line may be able to carry twice as much load for a 15-minute peak after a day of low loads as for an eight-hour peak with a high daily load factor. To reduce losses and the buildup of heat from frequent high loads, utilities must install larger cables, or more cables, than they would to meet shorter duration loads.

The capacity of overhead lines is often limited by the sagging caused by thermal expansion of the conductors, which also occurs more readily with summer peak conditions of high air temperatures, light winds and strong sunlight. Overheating and sagging also reduce the operating life of the conductors. A transmission facility normally will have a higher capacity rating for winter than for summer because the heat buildup is ameliorated in cooler weather.

The costs of substations, including the power transformers on which they are centered, are determined by both peak loads and energy use. The capacity of a station transformer is limited by the buildup of heat created by electric energy losses in the equipment. Every time a transformer approaches or exceeds its rated capacity (a common occurrence, since transformers can typically operate well above their rated capacity for short periods), its internal insulation deteriorates and it loses a portion of its useful life.

Figure 16. Permissible overload for varying periods



Source: Bureau of Reclamation. (1991). *Permissible Loading of Oil-Immersed Transformers and Regulators*

Figure 16 illustrates the effect of the length of the peak load, and the load in preceding hours, on the load that a transformer can carry without losing operating life (Bureau of Reclamation, 1991, p. 14). The initial load in Figure 16 is defined as the maximum of the average load in the preceding two hours or 24 hours.[30] A transformer that was loaded to 50% of its rating in the afternoon can endure an overload of 190% for 30 minutes or 160% for an hour. If the afternoon load was 90% of the transformer rating, it could carry only 160% of its rated load for 30 minutes or 140% for an hour.[31]

Similarly, if the transformer's high-load period is currently eight hours in the afternoon and evening, and the preceding load is 50% of rated capacity, afternoon load reductions that cut the high-load period to three hours would increase the permissible load from about 108% of rated capacity to about 127%. Under these circumstances, the transformer can meet higher load without replacement or addition of new transformers.

Short peaks and low off-peak loads allow the transformer to cool between peaks, so it can tolerate a higher peak current. Long overloads and higher load levels increase the rate of aging per overload, and frequent overloads lead to rapid failure of the transformer.

30 This specific example is for self-cooled and water-cooled transformers designed for a 55 degrees Celsius temperature rise; other designs show similar patterns.

31 Utilities recognize that the length of overloads is critical to determining whether a transformer needs to be replaced. For example, Potomac Electric Power Co. (Pepco) in Maryland has established standards for replacing line transformers when the estimated average load over a five-hour period exceeds 160% of the rating of overhead transformers or 100% for pad-mounted transformers (Lefkowitz, 2016, p. 41). The company has not found it necessary to establish comparable policies for shorter periods.

Table 3. Cost drivers for transmission

Connection to (or between)	Purpose	Typical length of line	Investment-related costs	Maintenance costs
Remote baseload generation	Power at all hours	Long	High	Low
Remote wind or solar	Power at some hours	Long	High	Low
Peaking resources	Power in peak hours, plus reserves at all hours	Short	Low	Low
Hydro	Power at some or all hours	Long	High	Low
Neighbor utilities	Reserve sharing; energy trading	Short to long	Vary	Low
Substations networked for reliability	Power at some hours	Short	Medium	Low
Storage and substations	Power at peak hours, plus reserves at all hours	Very short	Very low	Low

In a low load factor system, these high loads will occur less frequently, and the heavy loading will not last as long. If the only high-demand hours were the 12 monthly peak hours, for example, most transformers would be retired for other reasons before they experienced significant damage from overloads. In this situation, larger losses of service life per overload would be acceptable, and the short peak would allow greater overloads for the same loss of service life.

With high load factors, there are many hours of the year when the transformers are at or near full loads. In this case, the transformer must be sized to limit overloads to acceptable levels and frequency of occurrence commensurate with a reasonable projected lifespan for the asset. If the transformer is often near full capacity with frequent overloads, it will fail more rapidly.

Transmission lines serve many purposes, including connecting remote generating plant to urban centers and enabling the optimal economic interchange of power between regions with different load patterns and generation options. Each transmission segment can be separately examined and allocated on a cost-reflective basis. Table 3 provides examples of this.

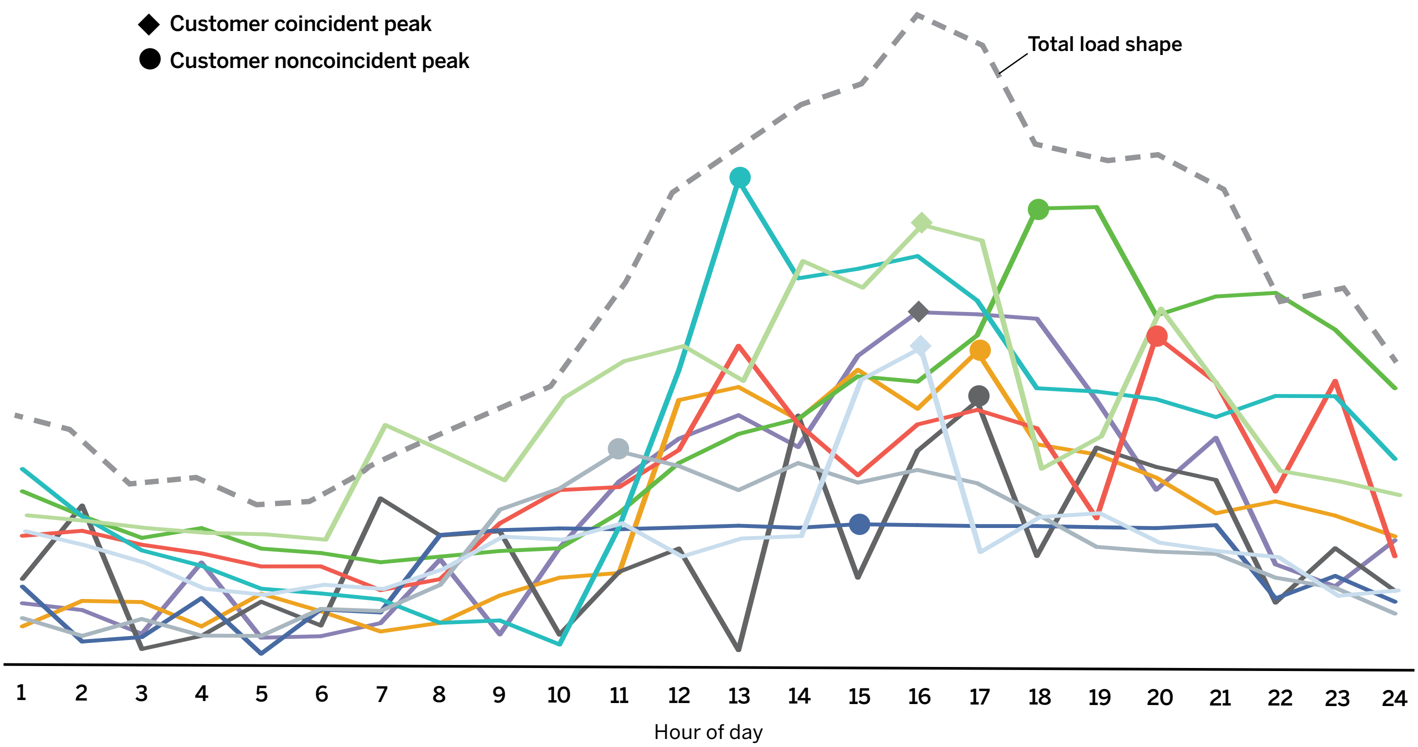
5.1.3 Distribution

The factors driving load-related distribution costs are similar to those for transmission. Different components are built and sized for different reasons; some serve the shared needs of hundreds or thousands of customers, while other components are designed to serve a single customer. Substations and line transformers must be larger — or will wear out more rapidly — if they experience many high-load hours in the year and if daily load factors are high. Underground and overhead feeders are also subject to the effects of heat buildup from long hours of relatively high use.

The allowable load on distribution lines is determined by both thermal limits and allowable voltage drop. Higher loads on a primary feeder may require upgrades (raising the feeder voltage, adding a new feeder, reconductoring to a larger wire size, increasing supply from single-phase to three-phase) to maintain acceptable voltage at the end of the feeder. Small secondary customers can be farther from the line transformers than large customers (allowing the utility to use fewer transformers to serve the same load) and can be served with smaller conductors.

As with station transformers, line transformers can handle moderate overloads for relatively short periods of a few hours but will deteriorate quickly if subjected to extended overload conditions. Therefore, the sizing of transformers takes into consideration not only the maximum capacity required but also the underlying load shape. Figure 17 on the next page shows actual data from a confidential load research sample on a summer peak day for 10 residential customers who share a line transformer. Although no group of 10 customers is identical to any other group of 10 customers, this demonstrates how diversity determines the need for the sizing of system elements. Only three of the 10 customers peak at the

Figure 17. Summer peak day load from 10 residential customers on one line transformer



Source: Confidential load research sample

same time as the 4 p.m. coincident peak for the group, and the coincident peak is only 86% of the sum of the individual peaks on this day. Furthermore, although not shown in this figure, this coincident peak is only 64% of the sum of the annual noncoincident peaks for the individual customers. It is important to note that a group of 10 residential customers is often less diverse than the combined loads from multiple customer classes, which determine the need for substation and generation capacity upstream of the final line transformer.

It is important to note that the load exceeds 50 kVA for only three hours and is below 40 kVA for 18 hours of this summer peak day. Referring back to Figure 16, under these circumstances, a 50-kVA transformer would likely be adequate to serve this load, because the overload is for only a short period. By contrast, the sum of the maximum noncoincident peak loads of the 10 customers is more than 90 kVA.

A large portion of the distribution investment is driven primarily by the need to serve a geographical region. Once a decision is made to build a circuit, the **incremental cost** of connecting additional customers consists mostly of additional line transformers (if the new customer is isolated from others) and secondary distribution lines. This is true even if those investments may serve multiple customers, particularly in urban and suburban areas. These shared facilities are largely justified by the total revenues of the customers served, not the peak load or number of customers. A particular transmission line, substation or feeder to serve an area could be justified by a single very large load, a small number of large customers or a large number of very small customers.

Nearly every electric utility has a line extension policy that sets forth the division of costs incurred to extend service to new customers. Typically, this policy provides for a certain amount of investment by the utility, with any additional investment paid for by the new customers. These provisions are intended to ensure that new customers pay the incremental cost of connecting them to the system without raising rates to other customers. For most utilities, there is no corresponding credit where new service has a cost that is lower than the

Table 4. Cost drivers for distribution

Type	Purpose	Investment-related costs	Maintenance costs
Substations	Power at all hours; capacity for high-load hours	High	Low
Primary circuits	Power at all hours; capacity for high-load hours	High	Low
Line transformers	Power at all hours; capacity for localized high-load hours	Medium	Low
Secondary service lines	Power at all hours; capacity for localized high-load hours	Medium	Low
Meters: Traditional	Measuring usage	Low	Low
Meters: Advanced	Multiple functions	Medium	Low

average embedded cost of service, a circumstance that results in benefits to the utility and other ratepayers.

The final components in the distribution system are meters, typically installed for all residential and general service customers but not for very predictable loads like traffic signals or streetlights. How to classify the cost is a matter of debate. On one hand, a meter is needed because usage levels vary from customer to customer and month to month, a theoretically usage-related cost. But on the other hand, one meter is needed for every metered customer, and meter costs do not typically vary from customer to customer within a class. In addition, **smart meters** entail both higher direct investment costs and back office investments but provide generation, transmission and distribution system benefits by allowing more precise measurement and control of local loads and more accurate assignment of peaking capacity requirements. Lastly, the cost of current transformers and potential transformers necessary to meter large customers should be included as part of their metering costs — an issue common between embedded and marginal cost methods.[32] Table 4 summarizes cost drivers in the distribution system.

5.1.4 Incremental and Complementary Investments

Good economic analysis should distinguish properly between complementary or alternative investments, which substitute for one another, and incremental investments, which add costs to the system.

Customers receive service at different voltages and with different types of equipment. Most of the distinctions among types of equipment represent alternative or complementary methods for providing the same service. For example, various primary distribution feeders operate at 4 kV, 13 kV or 25 kV and may be overhead or underground construction, depending on load density, age of the equipment, local governmental requirements and other considerations. Although the power flowing from generation to a customer served at 25 kV may not flow over any 4-kV feeder, the 4-kV feeders serve the same function as the 25-kV feeders and (in places in which they are adequate) at lower cost.[33] Serving some customers at 4 kV and spreading the feeder costs among all distribution customers does not increase costs allocated to the customers served directly from the 25-kV feeders; converting the 4-kV feeders to a higher voltage would likely increase costs to all distribution customers, including those now served at 25 kV. In this situation, all the feeders should be treated as serving a single function, and all their costs should be allocated in the same manner.

Similarly, most customers served by single-phase primary distribution are served with that configuration because it is cheaper than extending three-phase primary distribution, which they do not require because of the nature of their loads.

32 Current transformers reduce the amperage so a meter can read it. Potential transformers reduce the voltage for meter reading (Flex-Core, n.d.).

33 Conversely, the 4-kV supply to some customers is from transformers fed directly from transmission without using the 25-kV system.

On the other hand, some distinctions in voltage level represent incremental investment:

- Most customers served at distribution voltages cannot take service directly from the transmission system. Even if a transmission line runs right past a supermarket or housing development, the utility must run a feeder from a distribution substation to serve those customers. Distribution in its broadest sense is thus principally an incremental service, rather than an alternative to transmission, needed by and provided to some customers but not all.[34]
- Similarly, most customers who take service at secondary voltage have a primary line running by or to their premises yet cannot take service directly at primary voltage.[35] The line transformers are incremental equipment that would not be necessary if the customers could take service at primary voltage.[36]

These incremental costs should be functionalized so that they are allocated to the loads that cause them to be incurred, while each group of complementary costs (such as various distribution voltages) generally should be treated as a single function and recovered from all customers who use any of the alternative facilities.

In other situations, distinguishing between incremental and complementary costs can be more complicated. Examples include the treatment of transmission equipment at different voltages and the treatment of secondary poles. Many embedded cost of service studies treat subtransmission as an incremental cost separate from transmission and charge more for delivery to customer classes served directly from the subtransmission system or from substations fed by the subtransmission system. For the most part, utilities use lower transmission voltage where it is less expensive than higher voltages, either due to the lower cost of construction relative to the total load that needs to be served by the line or the happenstance that the subtransmission line is already in place. If it is less expensive to serve customers with the lower voltage, it would be inequitable to charge them more for being served at that voltage.

Similarly, distribution poles carrying only secondary lines are less expensive than poles carrying primary lines. If a customer served by a secondary-only pole had to be served at primary voltage instead, the primary pole would be more expensive, and that higher cost would almost certainly be allocated to all distribution customers. Secondary poles (unlike line transformers and most secondary lines) are lower-cost alternatives to some primary poles.[37]

5.2 Determining Customer Classes

In addition to administrative simplicity, the purpose of separating customers into broad classes flows from the idea that different types of customers are responsible for different types of costs, and thus it is fairer and more efficient to charge them separate rates. One set of rates for each customer class, based on separate cost characteristics, is the key feature of postage stamp pricing for electric utilities. As a result, it is very important to determine appropriate customer classes with different cost characteristics at the outset of a cost of service study. The number of classes will vary from utility to utility and may vary depending on the costing methodology being used. In addition to equitable cost allocation, different rate structures are often used for different rate classes. For example, residential customer classes generally do not have demand charges today, but most large industrial classes do. This means that decisions regarding the number and type of customer classes can also have rate design implications,

34 In some cases, a distribution substation and feeder can bring service to customers that would otherwise be served by an extension of the transmission system at higher cost. Identifying and accounting for that limited complementary service is probably not warranted in most embedded cost of service study applications.

35 Another way of looking at this relationship is that secondary customers are those for whom providing service at secondary has a lower total cost than providing service at primary. Sharing utility-owned transformer capacity is less expensive than having each customer build its own transformer. See Chapter 11 for a discussion of primary and secondary distribution and their allocation.

36 Although most networked secondary conductors parallel primary lines and are incremental to the primary system, a limited number of secondary conductors extending beyond the primary lines are complementary, because they avoid the need to extend primary lines.

37 Similarly, a portion of the secondary lines replaces primary lines. If the customers that can be served with secondary poles required primary service, the utility would need to extend the primary lines rather than secondary lines. Hence, a portion of the secondary lines is also complementary to the primary system, rather than additive.

although this is not necessarily permanent.

Most utilities distinguish among residential customers, small commercial customers, large commercial customers, industrial customers and street lighting customers. The commercial and industrial classes often are collectively termed general service rate classes. In many cases, general service customers are categorized by voltage levels. Customers served at primary distribution voltage generally do not use, and should not be allocated, costs of secondary distribution facilities, and customers served at transmission voltage generally do not use, and should not be allocated, costs of distribution facilities. Many utilities also separate general service classes with even greater granularity than using simple voltage criteria.

One area where utility practices can vary significantly is whether there is more than one residential class or, alternatively, multiple residential subclasses. Some utilities separate out residential customers based on a measure of size, such as peak demand or energy use. This can be significant in jurisdictions that categorize farms or large master-metered multifamily buildings as residential in a formal sense. Some jurisdictions also create separate classes based on the usage of specific technologies like electric resistance heating. In some jurisdictions, low-income discount customers are treated as a separate rate class.

The creation of multiple residential classes or subclasses is typically justified on cost grounds. There are inarguably many cost distinctions among different types of residential customers, and simple postage stamp cost allocation and rate structures may not capture many of those distinctions. Regulators and utilities have long analyzed the causes of such differences, which vary widely across the country. Some of the distinctions are based on technology (or, more accurately, as a proxy for the load impacts of certain technologies), such as electric space heating, electric water heating, solar or other distributed generation and even electric vehicles. Other distinctions are based on the characteristics of service. Those with relatively large impacts on cost allocation include:

- Single family versus multifamily.
- Urban (multiple customers per transformer) versus rural (one customer per transformer).
- Overhead service versus underground service.

A word of caution is appropriate here. With respect to technology-driven class characteristics such as electric space heat, water heat, vehicles or solar installations, singling out customers based on technology adoption has serious practical and theoretical downsides. Furthermore, addressing one minor cost distinction is likely not fair or efficient if several other major cost distinctions, such as those listed above, are not addressed. It is wiser to consider multiple customer and service characteristics simultaneously to create technology-neutral subclasses for both cost allocation and rate design purposes.

To begin, electric space heating customers are likely to have different load characteristics from the nonheating customers, with significantly more usage and a different daily load shape in the winter. For a winter-peaking system, this could mean that electric heating customers should be allocated proportionately more costs. Conversely, in a summer-peaking system, electric heating customers should be allocated proportionately fewer overall costs. However, this issue, which is essentially a question of a potential intraclass cross-subsidy between types of residential customers, can also be addressed through changes to rate design. Seasonally differentiated rates, if based appropriately on cost causation, can achieve the same distributional impact as separate rate classes for heating and nonheating customers while bringing additional benefits from the improved efficiency of pricing.

The creation of an electric heating rate class can have other implications. In regions where electric heating customers are disproportionately low-income, this decision also has significant equity implications. There can also be environmental repercussions to this choice. Concerns would arise, for example, if electric heating rates promote use of gas and coal in power plants to replace direct burning of gas on-site for heating, which historically was often more efficient on a total energy basis. Recent developments in efficient electric heating, particularly air and ground source heat pumps, may have switched the valence of these questions. In certain areas, higher-income customers may be disproportionately adopting efficient electric heating. And the new electric technologies may now be significantly cleaner and more efficient than on-site combustion of natural gas, particularly if powered by zero emissions electric resources. A seasonal and time-varying cost study and time-varying rates may enable appropriate cost recovery without need for a separate class.

Several states have considered creating a separate rate class for customers with solar PV systems. Because solar customers may have different usage patterns than other customers, this is reasonable to investigate. However, it is not clear that there is a significant cross-subsidy to address, particularly at low levels of PV adoption. Current rate design practices for solar customers in many jurisdictions — such as net metering using **flat volumetric rates**, monthly netting and crediting at the retail rate — are fairly simple. These rate design practices could be improved significantly over time and integrated with broader rate design reforms. For example, a time-varying cost study would allow the creation of more granular time-varying rates so that solar customers pay an appropriate price for power received during nonsolar hours and are credited with an appropriate price for power delivered to the distribution system during solar hours. This would include changes to netting periods, which would reveal more information about how a solar customer actually uses the electric system.

In terms of rate classes for specific technologies, some utilities separate out customers with electric water heating as a proxy for a flat load shape and the potential for load control. In the future, some utilities may seek to make electric vehicle adoption a separate rate class as a substantially controllable load with distinct usage characteristics. However, these technologies may not need consideration as a separate rate class, particularly given efforts to improve the cost causation basis of rate design more generally. Again, time-varying rates will appropriately charge customers with peak-oriented loads and appropriately benefit customers with loads concentrated in low-cost hours or controlled into those hours.

Some utilities have implemented separate rate classes for single-family and multifamily residential customers. There are many reasons to believe that the cost of serving multifamily buildings is substantially lower than serving single-family homes on average:

- Shared service drops.
- Increased diversity of load for line transformers and secondary distribution lines, enabling more efficient sizing.
- Reduced cost of distribution per customer, since no distribution lines are required between customers in the building.[38]
- Reduced coincidence with both summer and winter peak loads because common walls reduce space conditioning use relative to single-family units of the same square footage, and because lighting and baseload appliances such as refrigerators and water heaters (if electric) are a larger percentage of loads for units with fewer square feet.
- Reduced need for secondary distribution lines in cases where the multifamily building can be served directly from the transformer.
- Reduced summer peak coincidence if space cooling is provided through a separate commercial account for the building, rather than as part of the individual residential accounts.
- Reduced costs of manual meter reading, where still applicable.

There may be countervailing considerations in some service territories, such as if multifamily buildings are served by more expensive underground service and single-family buildings are served with cheaper overhead lines. A similar set of considerations may cause some utilities to disaggregate customers by geography, such as those residing inside and outside city limits.[39] Customers in deeply rural areas tend to be more expensive to serve, since they typically are too far from their neighbors to share transformers, require a long run of primary line along the public way, and generally

38 This distinction is important where some distribution costs are classified as customer-related. In those situations, each multifamily building (rather than each meter) should be treated as one customer, as would a single commercial customer of the same size and load.

39 For example, Seattle City Light, a municipal utility, has two rate schedules for most commercial and industrial classes within the city: one for the highly networked higher-cost underground system in the urban core, and another for the balance of the city, plus separate higher rates for the adjacent cities and towns where it provides service. Compare Schedules MDC, MDD, MDS and MDT at Seattle City Light (n.d.). The city of Austin, Texas, also applies different rates to customers outside the city limits (Austin Energy, 2017). In many places, cities impose franchise fees or municipal taxes that make customer bills inside cities higher than those outside cities, even though the cost data may suggest the opposite is more equitable.

have higher unit costs related to lower load per mile of distribution line.[40]

Analysts may want to employ a simple standard for deciding when to divide a subclass for analytical purposes, based on whether the groups are large enough and distinct enough to form a separate class or subclass. One such guideline might be that, if more than 5% of customers or 5% of sales within a class have distinct cost characteristics, differentiation is worth considering. If fewer than that, although the per-customer cost shifts may be significant, the overall impact on other customers will likely be immaterial. If 2% of the load in a class is paying 20% too much or too little, for example, other customers' bills will change only 0.4%. But if 15% of the load is 20% more or less expensive, the impact on other users rises to 3%. The trajectory of these impacts over time can also be relevant.

Although improved distributional equity from additional rate classes is a laudable goal, and indeed advances the primary goal of cost allocation, there are countervailing considerations that may dictate keeping the number of rate classes on the smaller side. First, there are administrative and substantive concerns around adding rate classes, both in litigation at state regulatory commissions and in real-world implementation. Some potential distinctions among customers may be difficult to implement because they involve subjective and potentially controversial determinations by on-the-ground utility personnel. In creating new distinctions, regulators, utilities and stakeholders must all have confidence that there are true cost differentials between the customer types and that there will be little controversy in the application of the differentials. Some analysts object to customer classes based on adoption of particular end uses, although this may serve as a proxy for significantly different usage profiles. Furthermore, some utilities and parties in a rate case may propose rate classes that effectively allow undue discrimination. If the proper data aren't available to scrutinize such claims, either publicly or for parties in a rate case, then this may allow an end-run around one of the significant motivations for postage stamp pricing: preventing price discrimination.

Lastly, as described above for electric heating and solar PV customers, rate design changes can also address certain cross-subsidies within customer classes in a relatively straightforward manner that also provides additional efficiency benefits. In principle, perfectly designed time- and location-varying pricing for all electric system components and externalities, applied identically to all customers, could eliminate the need for customer classes and cost allocation entirely while providing perfectly efficient price signals. This is unlikely to be the case for the foreseeable future but illustrates the conceptual point that an efficient improvement to rate design may be a strictly preferred option compared with the creation of a new rate class. For example, certain types of customers could be put on technology-neutral time-varying rates on an opt-out or mandatory basis, such as customers with storage, electric vehicles or distributed generation.

5.3 Load Research and Data Collection

Any cost of service study, as well as rate design, load forecasting, system planning and other utility functions, depends heavily on load research data. Cost allocation, in particular, requires reasonably accurate estimates for each class or group distinguished in the analysis, the number of customers, their energy usage (annual, monthly and sometimes more granular time periods), their kW demand at various times and under various conditions, and sometimes more technical measures such as **power factor**. The key principle is that there is diversity among customers in each class, meaning the consumption characteristics for the group are less erratic than those of any individual customer. Load research is the process of estimating that diversity.

At the very least, these data must be available by class across the entire system. For some applications, these data are useful and even essential at a more granular level, such as for each substation, feeder or even customer. Ideally, the cost of service study would be able to draw on information about the hourly energy usage by class, as well as the contribution of each class to the sum of the customer contributions to the maximum loads across the line transformers serving the

40 These factors may be offset by the utility's policy for charging new customers for extending the distribution system, as discussed in Section 11.2

class, the feeders serving the class, the substations serving the class and so on. Modern AMI and advanced distribution monitoring systems, if properly configured, can provide those data. Some utilities now routinely collect interval load data at each level of the system, while others are starting to acquire those capabilities.

The data needed for different cost allocation frameworks and methods can vary greatly, and it is difficult to generalize because of this. But at a high level, embedded cost techniques rely on one year of data or the equivalent forecast for one year. For many inputs, marginal cost techniques often rely on multiple years of data in order to estimate how costs are changing with respect to different factors over time. Different data may be needed for each step of the process, starting from the functionalization of costs down to the creation of **allocation factors**, or allocators, to split up the costs to customer classes.

Where the utility's metering and data collection do not directly provide comprehensive load data for all customers and system components, two options are available. The first and generally preferable option is sampling. Most investor-owned and larger consumer-owned utilities install **interval meters** specifically for load research purposes on a sample of customers in each class that does not have widespread interval metering.[41] The number and distribution of those meters should be determined to provide a representative mix of customer loads within the class (or other subgroups of interest) and to produce estimates of critical values (such as contribution to the monthly system peak load) that reach target levels of statistical significance.[42] These samples are typically a few hundred per class in order to meet the PURPA standard. Second, some smaller utilities borrow "proxy data" from a nearby utility with similar customer characteristics and more robust load research capabilities. Class load data are usually publicly available for regulated utilities. Neither sampled load nor proxy load will provide the precision of comprehensive interval metering, but they can provide reasonable estimates of the contribution of the group to demand at each hour, enabling development of cutting-edge techniques such as time-specific allocation methods.

Different elements of load research data are relevant in the creation of allocation factors for different parts of the system. For example:

- Most residential customers may be served through a transformer shared with other residential, commercial and street lighting customers, so the allocation of transformer costs to each class should ideally be derived from their contribution to the high-load periods of each such transformer.
- Some residential customers are served from feeders that peak in the morning and others from feeders that peak in midday or the evening; some of those feeders may reach their maximum load or stress in the summer and others in the winter. The sum of the class contribution to the various peak hours of the various feeders determines the share of peak-related costs allocated to the class for this portion of the distribution system.
- At the bulk power level, all customers share the generation and transmission system, and the diversity of all usage should be reflected, whether at the highest system hour of the year (a method known as 1 CP, for coincident peak), the highest hour of each month (12 CP) or the highest 200 hours of the year (200 CP), all **on-peak** hours, **midpeak** hours and off-peak hours, or any other criteria relevant for allocation.

Table 5 on the next page shows illustrative load research data for four customer classes. For the purposes of clear examples throughout the manual, we adopt the convention

41 Utilities usually have interval meters on customers over some consumption threshold for billing purposes. Smaller customers may have meters that record only total energy consumption over the billing period (typically a month), or both monthly energy and maximum hourly (or 15-minute) demand, neither of which provides any useful data for allocating time-dependent costs.

42 In 1979, FERC issued regulations to implement PURPA § 133 (16 U.S.C. § 2643), which requires the gathering of information on the cost of service. C.F.R. Title 18, Chapter 1, Subchapter K, Part 290.403(b) established the requirement, since repealed, that "the sampling method and procedures for collecting, processing, and analyzing the sample loads, taken together, shall be designed so as to provide reasonably accurate data consistent with available technology and equipment. An accuracy of plus or minus 10 percent at the 90 percent confidence level shall be used as a target for the measurement of group loads at the time of system and customer group peaks." See Federal Energy Regulatory Commission Order 48 (1979).

Table 5. Illustrative load research data

	Residential	Secondary commercial	Primary industrial	Street lighting	Total	Used for
Energy metrics (MWhs)						
Total	1,000,000	1,000,000	1,000,000	100,000	3,100,000	
Total secondary	1,000,000	1,000,000	N/A	100,000	2,100,000	
Energy by time period						
Summer	600,000	650,000	500,000	30,000	1,780,000	
Winter	400,000	350,000	500,000	70,000	1,320,000	All energy-related costs, including generation, transmission, primary distribution
Daytime	600,000	700,000	500,000	0	1,800,000	
Off-peak	400,000	350,000	500,000	90,000	1,340,000	
Midpeak	550,000	600,000	470,000	9,000	1,629,000	
Critical peak	50,000	50,000	30,000	1,000	131,000	
Customer metrics						
Line transformers used	20,000	10,000	N/A	20,000	50,000	Transformers, services
Customers	100,000	20,000	2,000	50,000	172,000	Billing
Demand metrics (MWs)						
Sum of customer NCP	2,000	1,000	N/A	100	3,100	Input to line transformers
Class NCP: circuit	400	400	250	100	1,150	Primary distribution
Class NCP: substation	300	300	225	100	925	Substations
System 1 CP	250	300	200	0	750	
System monthly 12 CP	225	250	175	10	660	Transmission, generation
System 200 CP	200	240	150	10	600	

of a commercial customer class of all general service customers served at secondary voltage, labeled as "Secondary commercial," and an industrial customer class of all general service customers served at primary voltage, labeled as "Primary industrial."

In this illustration, the sum of individual customer noncoincident peak demands is 3,100 MWs, excluding the primary industrial class that is not shown in the table.[43] However, the coincident peak demand served by the utility becomes more diverse as we move up the system, a phenomenon described in more detail in Section 5.1. As a result, the observed coincident peak demands are lower at more broadly shared portions of the system. At the highest level, this illustrative system has a 750-MW coincident peak demand for the highest single hour, labeled as "System 1 CP." In between, the sum of the class NCPs at the circuit level, labeled as "Class NCP: circuit," is 1,150 MWs, and the sum of the class NCPs at the substation level, labeled as "Class NCP: substation," is 925 MWs. Customers served at primary voltage (primary industrial) have no utility-provided line transformers, and the first level at which their demand is typically relevant is the circuit level.

The street lighting class is important to note with respect to the volatility of results. Because this class has zero daytime usage and a very different (typically completely stable overnight) load profile than other classes, it is highly affected by the choice between noncoincident methods and either coincident or hourly methods. In addition, because streetlights represent many points of delivery but are typically located only in places where other customers are nearby, this class almost never "causes" the installation of a transformer or the creation of a secondary delivery point but also does account for a huge number of the individual points of use

43 In Table 5, the sum of customer NCPs for the primary industrial class is shown as "N/A" because these customers do not use line transformers and thus this demand metric is not generally relevant to this class. For more general purposes, we are assuming that the sum of customer NCPs for the primary industrial class in this illustration is 300 MWs, bringing the overall total to 3,400 MWs.

Table 6. Simple allocation factors derived from illustrative load research data

	Residential	Secondary commercial	Primary industrial	Street lighting	Used for
Energy metrics (MWhs)					
Total	32%	32%	32%	3%	All energy-related costs, including generation, transmission, distribution
Total secondary	48%	48%	N/A	5%	
Energy by time period					
Summer	34%	37%	28%	2%	
Winter	30%	27%	38%	5%	
Daytime	33%	39%	28%	0%	
Off-peak	30%	26%	37%	7%	
Midpeak	34%	37%	29%	1%	
Critical peak	38%	38%	23%	1%	
Customer metrics					
Line transformers used	40%	20%	N/A	40%	Transformers, services
Customers	79%	17%	3%	1%	Billing
Demand metrics (MWs)					
Sum of customer NCP	65%	32%	N/A	3%	Input to line transformers
Class NCP: circuit	35%	35%	22%	9%	Primary distribution (legacy)
Class NCP: substation	32%	32%	24%	11%	Substations
System 1 CP	33%	40%	27%	0%	Transmission, generation
System monthly 12 CP	34%	38%	27%	2%	
System 200 CP	33%	40%	25%	2%	

Note: Class percentages may not add up to 100 because of rounding.

on the system. Put another way, we all like streetlights near our homes and businesses, but nearly all of them go in as a secondary effect of residential or commercial development; a few are along major highways without a nearby residence or business, but these are rare.

The next step is generating allocation factors to be used in the allocation phase of the cost study. For embedded cost studies, these are applied to the total investment and expense by FERC account, while in marginal cost studies they are applied to the calculated unit costs for each type of system component.

Table 6 shows the data above converted to allocation factors. The only implicit assumption is that the circuit-level peak demand for the residential class is one-fourth of the customer NCP demand due to load diversity and that for the commercial class it is one-half, reflecting lower diversity of commercial customer usage across the day compared with residential load. The raw factors are computed simply by dividing each class contribution to each category by the system total, then converting to percentages. For embedded cost of service studies, this manual recommends the use of class hourly energy use as a common allocation factor for all shared system components in generation, transmission and distribution where the system is made up of components essential for service at any hour, but sized for maximum levels of usage, and where the class contribution to that usage varies. The only one of these factors that is not self-explanatory is the midpeak factor, which takes both on-peak and **critical peak** usage into account, reflecting class usage in all higher-cost hours. This is illustrative of the probability-of-dispatch method, in which the likelihood of any resource being dispatched at specified hours is measured. There is no diversity of street lighting usage in this example, but little or no demand imposed at the system peak hours. Customer weighting factors are typically based on the relative cost of meters and billing services for different types of customers, based on complexity.

Table 7. Composite allocation factors derived from illustrative load research data

Method	Components	Residential	Secondary commercial	Primary industrial	Street lighting	Used for
Equivalent peaker	20% system 200 CP/ 80% energy	32%	34%	31%	3%	Generation, transmission
On-peak	50% midpeak/ 50% critical peak	36%	38%	26%	1%	Peaking generation
Average and peak	50% class NCP/ 50% energy	34%	34%	27%	6%	Primary distribution
Minimum system	50% customer/ 50% class NCP: circuit	57%	26%	12%	5%	Circuits (legacy)
Equivalent peaker for transformers	20% delivery points/ 80% customer NCP	60%	30%	0%	11%	Line transformers and secondary service lines

Note: Class percentages may not add up to 100 because of rounding.

In Table 6, we have calculated allocation factors shown as a class percentage of each usage metric. In Part II, we discuss in what circumstances each of these will be appropriate for embedded cost of service studies. In many cases, weighted combinations of these are appropriate. Several commonly used composite allocation factors are shown in Table 7, computed by weighting values in Table 6.

Given the wide diversity of utilities and their load patterns, readers should be careful about overgeneralizing from these illustrative examples. However, some patterns will hold true across the board. For example, the minimum system method will always allocate more costs to classes with large numbers of customers, at least compared with the basic customer method.

6. Basic Frameworks for Cost Allocation

We group cost allocation studies into two primary families. Embedded cost studies look at existing costs making up the existing revenue requirement. Marginal cost studies look at changes in cost that will be driven by changes in customer requirements over a reasonable planning period of perhaps five to 20 years. In the same family as marginal cost studies, total service long-run incremental cost (TSLRIC) studies look at the cost of creating a new system to provide today's needs using today's technologies, optimized to today's needs. Each has a relevant role in determining the optimal allocation of costs, and regulators may want to consider more than one type of study when making allocation decisions for major utilities that affect millions of consumers.

6.1 Embedded Cost of Service Studies

Embedded cost of service studies may be the most common form of utility cost allocation study, often termed "fully allocated cost of service studies." Most state regulators require them, and nearly all self-regulated utilities rely on embedded cost of service studies. The distinctive feature of these studies is that they are focused on the cost of service and usage patterns in a test year, typically either immediately before the filing of the rate case or the future year that begins when new rates are scheduled to take effect. This means there is very little that accounts for changes over time, so it is primarily a static snapshot approach. Embedded cost of service studies are also closely linked to the revenue requirement approved in a rate case, which can be administratively convenient.

Generally speaking, in the traditional model displayed in Figure 18 on the next page, functionalization identifies the purpose served by each cost (or the underlying equipment or activity), classification identifies the general category of factors that drive the need for the cost, and allocation selects the parameter to be used in allocating the cost among classes.[44]

Although they are convenient parts of organizing a cost of service study, functionalization and classification decisions are not necessarily critical to the final class cost allocations. The cost of service study can get to the same final allocation in several ways. For example, consider the reality that a portion of transmission costs is driven by the need to interconnect remote generation to avoid fuel costs. This can be reflected by functionalizing a portion of transmission cost as generation, or by classifying a portion of transmission in the same manner as the remote generation, or it can be recognized by using a systemwide transmission allocator with some energy component. In either case, a portion of costs is allocated based on energy throughput, not solely on design capacity or actual capacity utilization.

6.1.1 Functionalization

In this first step, cost of service studies divide the utility's accounting costs into a handful of top-level functions that mirror the elements of the electric system. At a minimum, this includes three functions:[45]

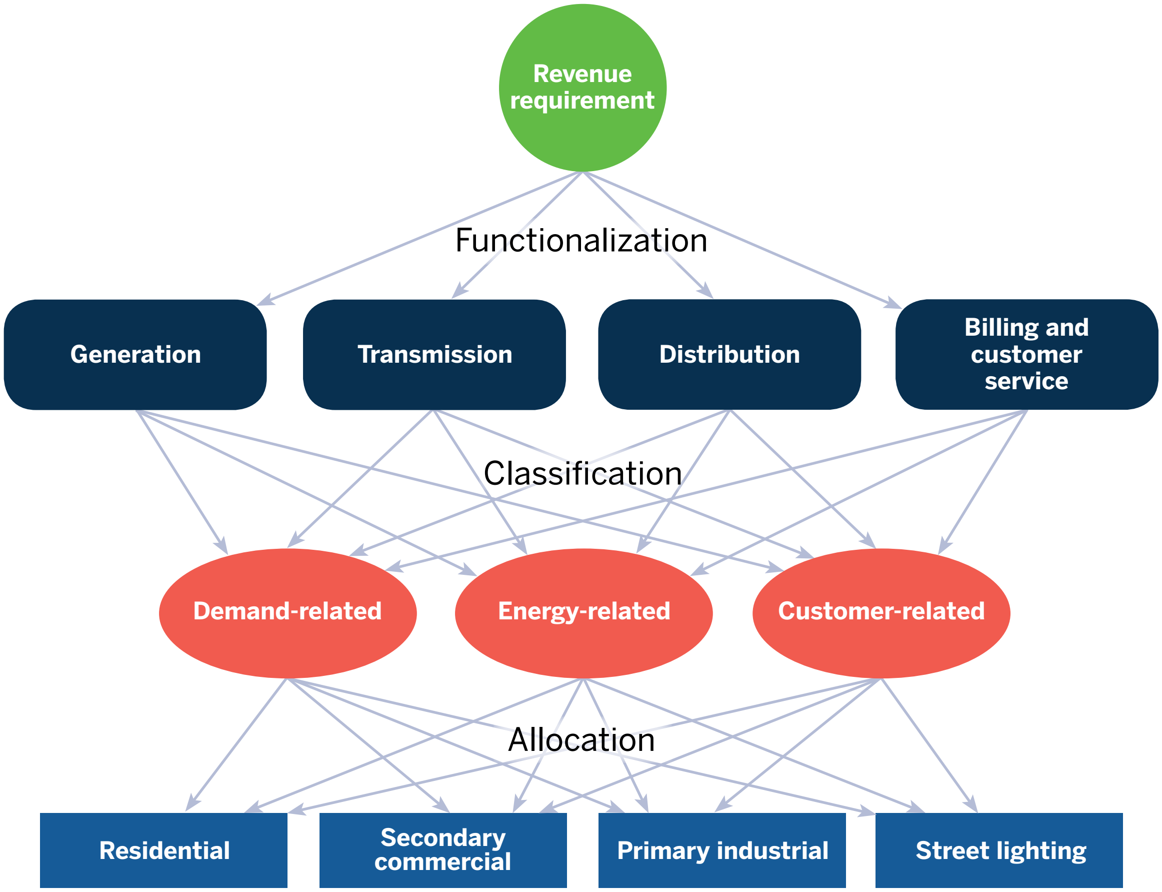
- Generation:[46] the power plants and supporting equipment, such as fuel supply and interconnections, as well as purchased power.
- Transmission: high-voltage lines (which may range from 50 kV to over 300 kV) and the substations connecting

44 The third step is usually called allocation, which is the same as the name of the entire process. This step involves the selection or development of allocation factors. Some analysts refer to this third step as factor allocation to prevent confusion.

45 Some of the costs, such as for energy efficiency programs and advanced meters, may serve multiple functions and must be assigned among those functions or treated as special functional categories.

46 Some sources use the term "production" instead. This manual uses the term "generation" and generally includes exports from storage facilities under this category.

Figure 18. Traditional embedded cost of service study flowchart



those lines, moving bulk power from generation to the distribution system.

- Distribution: lower-voltage primary feeders (in older systems, 4 kV and 8 kV; in newer areas, typically 13 kV to 34 kV) that run for many miles, mostly along roadways, and the distribution substations that step power down to distribution voltages; line transformers that step the primary voltages down to secondary voltages (mostly 120 V and 240 V); and the secondary lines that connect the transformers to some customers' service drops.

Although some utility analysts combine all costs into these three functions, the better practice is to include other functions as well at this stage:

- Billing and customer service: Also known as retail service or erroneously labeled entirely as customer-related costs, these are directly related to connecting customers (service drops, traditional meters) and interacting with them (meter reading, billing, communicating).
- General plant and administrative and general expenses: Overhead investments and expenses that jointly serve multiple functions (e.g., administration, financial, legal services, procurement, public relations, human resources, regulatory, information technology, and office buildings and equipment) can be kept separate at this stage. In some circumstances, these costs could be attributed to certain functions but are not tracked that way in a utility's system of accounts.
- Public policy program costs: In many jurisdictions, these costs are administered and allocated through another process; but if handled in a rate case, energy efficiency and other public policy programs should be tracked separately.

Historically, in most cases functionalization decisions can follow the utility's accounting and are noncontroversial.

The investment that is booked as generation units is usually part of the generation function. But there are exceptions. In some situations, the function of an investment may not match the accounting category. Examples include the following:

- Transmission lines and substations that are dedicated to connecting specific generating plants to the bulk transmission network. These assets are often in the accounting records as transmission but are more properly functionalized as generation.
- Substations that contain switching equipment to connect transmission lines of the same voltage to one another, high-voltage transformers that connect transmission lines of different voltages, and lower-voltage transformers that connect transmission to distribution. These facilities may be carried in the accounting records as entirely transmission or entirely distribution but are properly split between transmission and distribution in the functionalization process.
- Equipment within transmission substations that look like distribution equipment (e.g., poles, line transformers, secondary conductors, lighting). These might be booked in distribution accounts but are functionally part of the transmission substation.

In addition, many cost of service studies subfunctionalize some costs within a function, such as the following:

Generation

- Differentiating baseload generation (which runs whenever it is available or nearly so), intermediate generation (which typically runs several hours daily) and **peaking generation** (which runs only in a few high-load hours and when other generation is unavailable).
- Separating generators by technology to recognize such factors as renewable resources procured to meet energy-based environmental goals, the differing reliability contributions per installed kW of various technologies (e.g., wind, solar, thermal) and the differences in cost structure and output pattern between thermal, wind, solar and hydro resources.

Transmission

- Categorizing lines (and associated substations) by their role in operations, such as networking together the utility's service territory, providing radial supply to scattered distribution substations or importing low-cost baseload energy from distant suppliers.
- Segregating lower-voltage subtransmission facilities (typically under 100 kV) from higher-voltage facilities.
- Treating interconnections differently from the internal transmission network.
- Separating substations from lines.

Distribution

- Separating substations, lines (comprising overhead poles, underground conduit and the wires) and line transformers.
- Segregating costs of system monitoring, control and optimization related to reducing losses, improving **power quality** and integrating distributed renewables and storage.
- Dividing lines into primary and secondary components.
- In some cases, separating underground from overhead lines.

Billing and customer service

- Subfunctionalizing meters, services, meter reading, billing, customer service and other components, each of which may be allocated separately.
- Separating meters by technology — traditional kWh meters, **demand meters**, remotely read meters and advanced meters with hourly load recording and other capabilities — with different costs and different functions (including, for the advanced meters, services to the entire system).

General plant and administrative and general expenses

- Subfunctionalizing by type of cost: pensions and benefits, property insurance, legal, regulatory, administration, buildings, office equipment and so on.

In the future, organizing costs by function probably will still be helpful in organizing thinking about cost causation, but the cost of service study may need to differentiate functions in new ways. For example, distributed generation, storage, energy efficiency, demand response and smart grid technologies can provide services that span generation, transmission and distribution.

6.1.2 Classification

The second step of the process classifies each function or subfunction (i.e., each type of plant and expense) as being caused by one or more categories of factors. In particular, most cost of service studies use the classification categories of demand (meaning some measure of loads in peak hours or other hours that contribute to stressing system reliability or increasing capacity requirements on the generation, transmission or distribution systems), energy and customer number, and some use other categories (e.g., direct assignment, such as of street lighting).

The classification of most costs as demand-, energy- or customer-related dates back many decades. These categories can still be used but need to be interpreted more carefully as the utility system has changed in many ways:

- Utility planning has become more sophisticated.
- Utilities have access to more granular and comprehensive data on load and equipment condition.
- The variety of generation resources has increased to include wind, solar and other renewables with performance characteristics very different from legacy thermal and hydro resources.
- Multiple storage technologies are affecting generation, transmission and distribution costs.
- Legacy hydro, nuclear and fossil resources continue to operate and provide benefits to the utility system, but new similar resources and even continued operation of some existing units may no longer be cost-effective. Until they are retired, all or a portion of costs will remain in the allocation study.
- Demand response programs have increased in scale, role and variety.
- Utility spending on energy efficiency programs has increased.
- Advanced metering technology has added system benefits to a traditionally customer-related asset.

The demand and energy classifications are often treated as totally separate but, as discussed in Chapter 5, the load in many hours contributes to needs that have traditionally been classified to demand, and some hours are more important than others in driving energy costs. With improved information about class loads, and with a range of new technologies, it may be appropriate to move past the traditional energy and demand classifications and create new more granular distinctions, as discussed further in Chapter 17.

Table 8. 1992 NARUC cost allocation manual classification

Cost function	Typical cost classification
Production	Demand-related Energy-related
Transmission	Demand-related Energy-related
Distribution	Demand-related Energy-related Customer-related
Customer service	Customer-related Demand-related

Source: National Association of Regulatory Utility Commissioners. (1992). *Electric Utility Cost Allocation Manual*

Table 8 reproduces a table from the 1992 NARUC *Electric Utility Cost Allocation Manual*, showing how the classification step worked in that period (p. 21).

This was a simplification even at the time, and changes to the industry and in the available data and analytical techniques merit reevaluation and reform. For example, a legacy framework for variable renewable capacity, particularly wind and solar, could treat the investment for utility-owned resources as 100% demand-related, since there are no variable fuel costs. However, power purchase agreements for these same resources are typically priced on a per-kWh basis from independent power producers. This could lead to two different approaches for the same asset depending on the ownership model, an obvious error in analysis that should be avoided by considering the actual products and services being provided. In addition, most of the benefits of wind and solar do not necessarily accrue at peak hours — the underlying justification of a demand-related classification. Similarly, analog meters were only useful for measuring customer usage and billing, but new AMI provides data that can be used for system planning and provides new opportunities for energy management and peak load reduction.

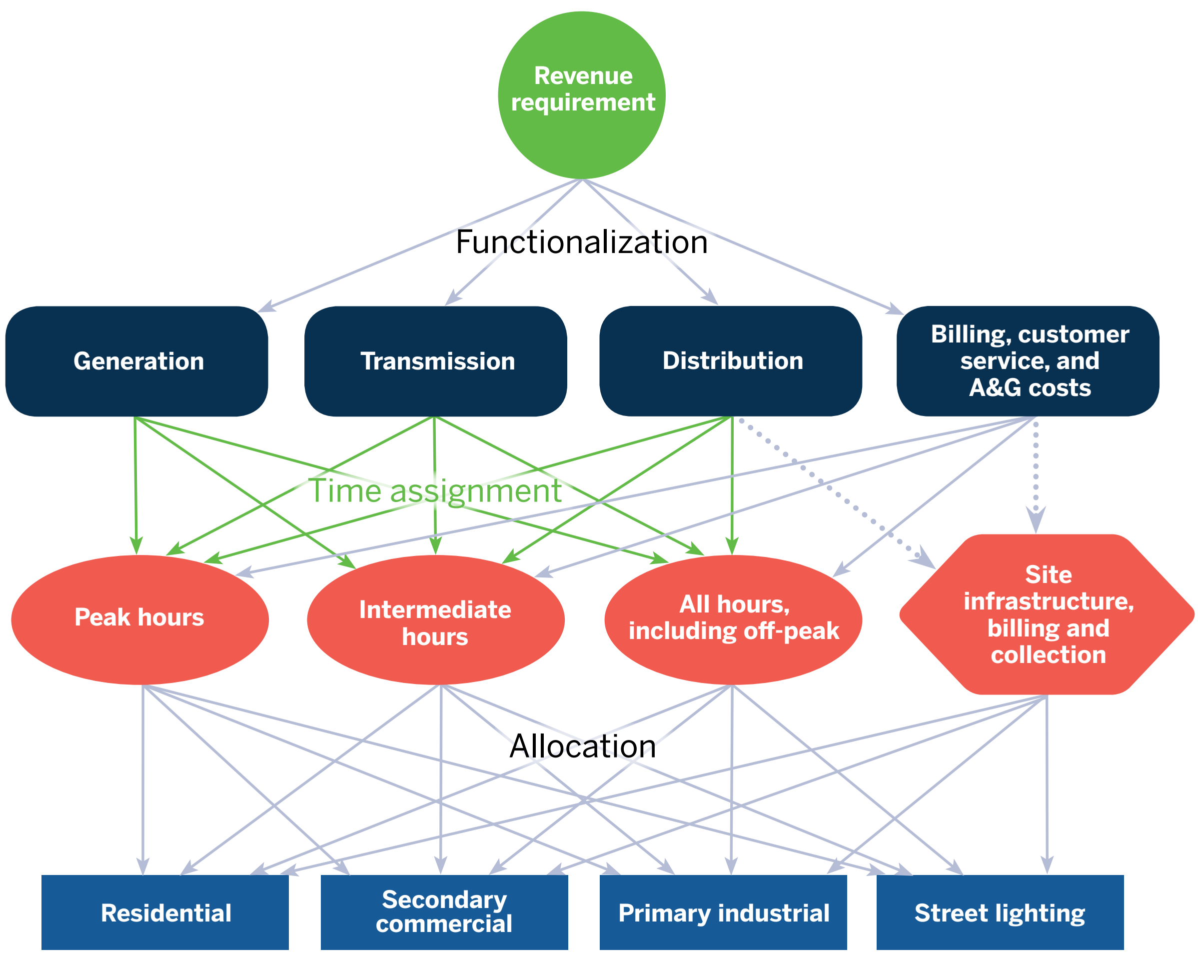
6.1.3 Allocation

The final step of the standard allocation process is the application of an allocation factor, or allocator, to each cost category.[47] An allocator is a percentage breakdown of the selected cost driver among classes. Within each broad type of classification, utilities use multiple allocators for various cost categories. For example, many different measures of "demand" are used to allocate demand-related costs, including various measures of contribution to coincident peaks (a single annual system coincident peak, or 1 CP); the average of several high-load monthly coincident peaks (e.g., 3 CP or 4 CP); the average of all 12 monthly coincident peak contributions (12 CP); the average of class contribution to some number of high-load hours (e.g., 200 CP); or different measurements of class maximum load (class noncoincident peak) at any time during the year. Usage of these peak-based demand allocators is often referred to as the **peak responsibility method**.

Generation allocators are sometimes differentiated among resources, to reflect the usage of different types of capacity and to retain the benefit of legacy resources for historic loads. Customer allocators are often weighted by the average cost of providing the service to customers in the various classes so that the cost of customer relations, for example, may be allocated with a weight of 1 for residential customers, 2 for small commercial, 5 for medium commercial and 20 for industrial.

Other costs, such as A&G expenses, are sometimes allocated on the basis of a labor allocator where the classification and allocation of underlying labor costs for the

Figure 19. Modern embedded cost of service study flowchart



47 Note that "allocation" is the term normally used for the entire process of assigning revenue requirements to classes and is also the term used for the last step of that process.

system is used for a set of other purposes. This is sometimes referred to as an internal allocator because it comes internally from previous calculations in the process. This is in contrast with "external allocators" based on facts and calculations outside of the cost allocation process, such as system peak and energy usage. Lastly, a variety of costs may be allocated based on a revenue allocator, which is based on the division of costs across all the classes.

6.1.4 Potential for Reform

As hourly data become available for all parts of the system, from transmission lines and substations through distribution feeders and line transformers to individual customers, an additional approach to classification and allocation becomes feasible: assigning costs directly to the time periods or operating conditions in which they are **used and useful**. This approach may entirely bypass the traditional classification step, at least between energy and demand.[48] Some relatively recent approaches recognize the complexity of cost drivers and combine classification and allocation into time-varying direct assignment of costs, as explained in Part II.

These time-varying allocation methods are discussed in Chapter 17 and Section 9.2; Figure 19 shows a simplified version.

Table 9 shows a simplified allocation study (very few cost categories and only two customer classes) and a caricature of the effect of using very different approaches. Both are embedded cost studies, but they produce dramatically different results.

The first study uses what might have passed for a reasonable cost allocation method a few decades ago, with all generation capacity and transmission costs allocated

Table 9. Results of two illustrative embedded cost of service study approaches

		Legacy study: Peak responsibility/minimum system			Modern study: Base-peak/basic customer		
Cost category	Revenue requirement	Allocation method	Residential	Commercial and industrial	Allocation method	Residential	Commercial and industrial
Generation							
Baseload	$100,000,000	Peak demand (1 CP)	$60,000,000	$40,000,000	All energy	$50,000,000	$50,000,000
Peaking	$50,000,000	Peak demand (1 CP)	$30,000,000	$20,000,000	On-peak energy	$27,500,000	$22,500,000
Fuel	$100,000,000	All energy	$50,000,000	$50,000,000	All energy	$50,000,000	$50,000,000
Subtotal			$140,000,000	$110,000,000		$127,500,000	$122,500,000
Transmission	$20,000,000	Peak demand (1 CP)	$12,000,000	$8,000,000	75% all energy/ 25% on-peak energy	$10,300,000	$9,800,000
Distribution							
Circuits	$50,000,000	50% peak demand/ 50% customer	$37,500,000	$12,500,000	75% all energy/ 25% on-peak energy	$25,600,000	$24,400,000
Transformers	$20,000,000	Customer	$18,000,000	$2,000,000	75% all energy/ 25% on-peak energy	$10,300,000	$9,800,000
Advanced meters	$10,000,000	Customer	$9,000,000	$1,000,000	50% customer/ 25% all energy/ 25% on-peak energy	$7,100,000	$2,900,000
Subtotal			$64,500,000	$15,500,000		$43,000,000	$37,000,000
Billing and collection	$20,000,000	Customer	$18,000,000	$2,000,000	Customer	$18,000,000	$2,000,000
Total	$370,000,000		$234,500,000	$135,500,000		$198,750,000	$171,250,000
Average per kWh	$0.123		$0.156	$0.09		$0.133	$0.114
Difference						**-15%**	**+26%**

Note: Numbers may not add up to total because of rounding.

48 Some costs associated with providing service under rare combinations of load and operating contingencies may not fit well into this framework.

Table 10. Illustrative allocation factors

Method	Residential	Commercial and industrial
Peak demand (1 CP)	60%	40%
All energy	50%	50%
On-peak energy	55%	45%
Customer	90%	10%
50% peak demand (1 CP)/ 50% customer	75%	25%
75% all energy/ 25% on-peak energy	51.3%	48.8%
50% customer/ 25% all energy/ 25% on-peak energy	71.3%	28.8%

on the highest-hour peak demand and most distribution costs allocated based on customer count. The second uses a simple time-based assignment method, in which all costs are allocated to usage in the hours for which the costs are incurred. This method recognizes that costs have a base level needed to provide service at all hours and incremental costs to provide service at peak hours. It also recognizes the multiple purposes for which advanced meter investments are made. The results are quite striking, with the second study showing a residential class revenue requirement 15% lower than the first. This set of assumptions probably forms the bookends between which most well-developed embedded cost studies would fall.

The first approach presents a legacy method that some industrial and large commercial customer representatives still sometimes propose. The second is a method that residential consumer advocates often champion. This change in method drives a significant change in the result. Both of these are "cost of service" results.

The point of these illustrative examples is not to suggest a specific approach, nor to defend any of the individual allocation methods shown, but to illustrate how different classification and allocation assumptions affect study results. Simply stating that a proposed cost assignment between classes is "based on the cost of service" may ignore the very important judgments that goes into the assumptions of the study. Table 10 shows the illustrative allocators that drive the results in Table 9.

Figure 20 on the next page shows a Sankey diagram for the legacy embedded cost of service study shown in Table 9. In that legacy study, most costs are classified as demand-related, and 60% of demand-related costs get allocated to the residential class. Similarly, a significant amount of costs are classified as customer-related, which are then overwhelmingly allocated to the residential class. This is because the **minimum system method** classifies all metering, billing and line transformers as customer-related, along with a portion of the distribution system.

In contrast, Figure 21 on Page 77 shows a Sankey diagram for the modern study in Table 9. More than half of peak hours costs are allocated to the residential class, but the peak hours classification is much less significant than the demand-related classification in the legacy study. Similarly, the basic customer method classifies only billing and a portion of advanced metering costs as customer-related. These costs are still primarily allocated to the residential class, but the aggregated differential nevertheless comes out significantly lower than in the legacy study. The remainder of advanced metering costs is split between all energy and on-peak energy because the purpose of these investments is to reduce energy costs and peak capacity requirements.

Figure 20. Sankey diagram for legacy embedded cost of service study

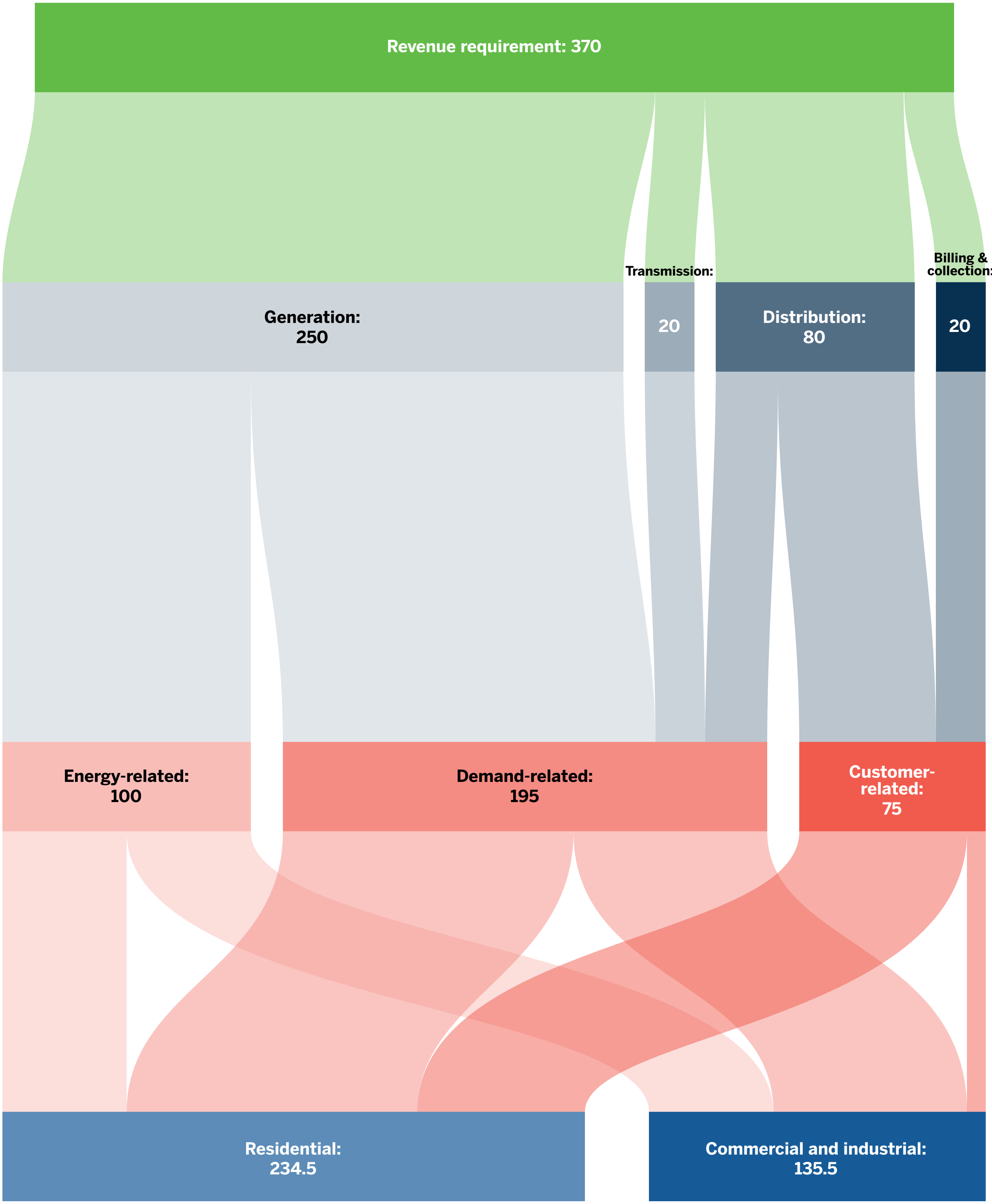
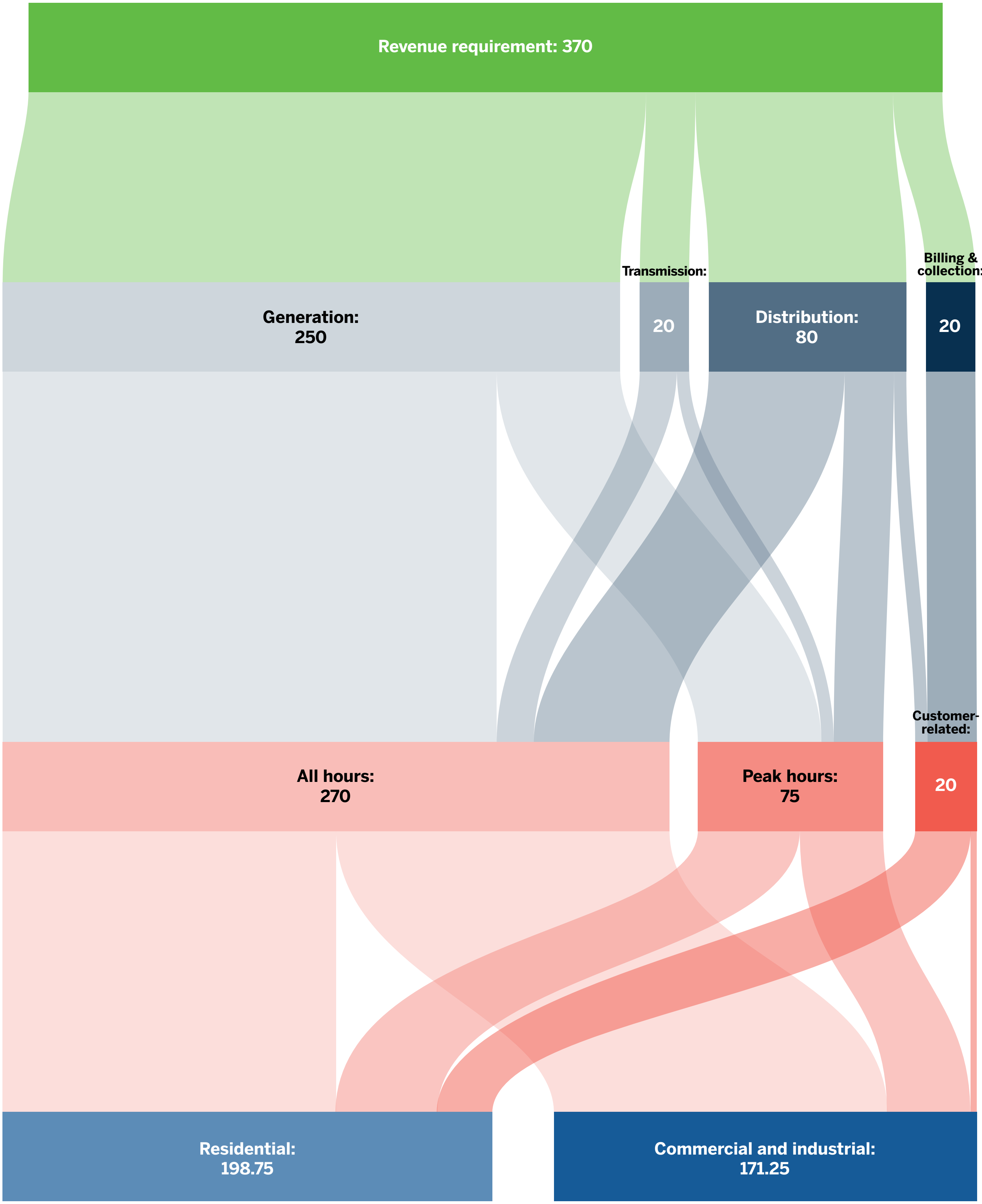


Figure 21. Sankey diagram for modern embedded cost of service study



"Fixed" versus "variable" costs

In the past, some cost allocation studies have relied on a simplified model of cost causation, in which certain costs are labeled as variable and then classified as energy-related and apportioned among classes based on class kWh usage. The remaining costs, labeled as fixed, are classified as demand-related or customer-related and allocated on some measure of peak demand or customer number, respectively.[49] This antiquated approach is based on fundamental misconceptions regarding cost causation. But it still underlies many arguments about cost allocation, perhaps because it typically works to the benefit of customer classes with high load factors and small numbers of customers — which describes most utilities' large industrial classes, data centers and even supermarkets.[50] This technique ignores the reality that modern electric systems trade off capital, labor, contractual obligations, fuel and other expenditures to minimize costs.

One of the problems with using the fixed/variable dichotomy to classify costs is the ambiguity of the concept of a cost being "fixed." Nearly all observers agree that certain generation costs are variable because they are short-term marginal costs that vary directly with usage patterns. These costs include:

- Fuel purchasing and disposal costs.[51]
- Variable operating costs related to consumables (e.g., water, limestone, activated carbon, ammonia) injected to increase output, reduce emissions or provide cooling to the power plant as it produces energy.
- Allowances or offsets that must be purchased to emit various pollutants.
- Purchased power charges that depend on the amount of energy taken by the utility.[52]

Over the decades, nearly every other utility cost has been described as fixed in one context or another: capital, labor, materials and contract services. Most of these costs are fixed for the coming year, in the sense that they are committed (investments made, contracts signed, employees hired) and will not be immediately changed by usage levels (energy, demand or number of customers). However, almost all of these cost accounts are variable over a period of several years, and energy consumption may affect:

- Whether excess generation capacity or other redundant facilities can be retired or mothballed in order to reduce operating and capital expenditures or repurposed to increase the net benefits of the facility.
- Whether additional facilities are needed (increasing capital and operating costs).
- Whether contracts are extended.
- The cost of capacity that is built (e.g., combined cycle versus combustion turbine plants, larger T&D equipment to reduce losses).

As a result, these costs are not fixed over the planning horizon. From an economic perspective more generally, all costs vary in the long run.

Relatedly, nearly all competitive businesses and fee-charging public services recover their fixed costs based on units sold. Customers do not pay an access fee to enter a supermarket.

---

49 In rate design, this approach has been extended to argue that all "fixed" costs must be recovered through **fixed charges**, often meaning customer and demand charges. These approaches promote neither equity nor efficiency.

50 Similarly, the fixed/variable approach is attractive to those who would justify rate designs with lower energy charges and higher customer and demand charges.

51 In previous decades, utilities would even argue that some fuel costs are fixed, on the grounds that having fuel on hand was necessary to allow the plant to function when required, or that a certain amount of fuel was required for startup, before any energy could be generated. These arguments appear to have largely disappeared, although similar issues are raised by the fuel security debate at FERC.

52 Many observers would add another category — expenses whose amount and timing vary with hours of operation, output or unit starts — even though not all cost of service studies separate those costs from other O&M expenses.

Restaurants, theaters and airlines have many costs that can be characterized as fixed (land, buildings, equipment, a large share of labor) and vary their unit prices by time of use but ultimately recover their capital investments and long-term costs from sales of output. RAP has done extensive analysis of utility distribution system investment and the relationship of that investment to the number of customers, peak demands and total kWhs. We found that these costs are roughly linear with respect to each of these metrics (Shirley, 2001).

Some version of the fixed/variable distinction may have been close to reality in the middle of the last century. Most utilities relied primarily on fossil steam plants, using newer, more efficient plants to serve baseloads and older plants to serve intermediate and peak loads. The capital costs of each were not very different. Fuel costs for oil, coal and natural gas were not very different. And because little was required in terms of emissions controls, coal plants were not much more expensive than other fossil-fueled plants.[53] By the 1970s, however, conditions had changed radically. Oil prices rose dramatically, new coal plants were required to reduce air emissions, and new generation technologies arose: nuclear, with high capital and O&M cost but low fuel prices; and combustion turbines, with low capital and O&M costs but high fuel costs. Utilities suddenly had a menu of options among generation technologies, including the potential for trading off short-term fuel costs for long-term capital investments. Today that menu has expanded even more and includes storage, demand response, price-responsive customer load and distributed generation.

As a result, the fixed/variable distinction has lost relevance and adherents over the last several decades. For example, many regulators classify capital investments using methods that recognize the contribution of energy requirements to the need for a wide variety of "fixed" costs for generation, transmission and distribution.[54]

53 In some areas, such as the U.S. Northwest, Manitoba and Québec, utilities had access to ample low-cost hydro facilities and mostly avoided construction of thermal generation.

54 These methods are discussed in chapters 9, 10 and 11.

6.2 Marginal Cost of Service Studies

The fundamental principle of marginal cost pricing is that economic efficiency is served when prices reflect current or future costs — that is, the true value today of the resources that are being used to serve demand — rather than historical embedded costs. Advocates for a marginal cost of service study approach work backward from this pricing concept to suggest that cost allocation should be based around marginal costs as well. Critics of marginal cost methods often point out that this economic theory is appropriate only when other conditions are present, including that all other goods are priced based on marginal costs, that there are no barriers to entry or exit from the market and that capital is fungible.

This is a very broad concept because it abstracts from and does not consider both theoretical and computational issues associated with the development of marginal costs. In contrast to the static snapshot that is typical of embedded cost approaches, marginal cost of service studies account for how costs change over time and which rate class characteristics are responsible for driving changes in cost. Importantly, marginal costs can be measured in the short run or long run. At one extreme, a true short-run marginal cost study will measure only a fraction of the cost of service, the portion that varies from hour to hour with usage assuming no changes in the capital stock. At the other, a total service long-run incremental cost study measures the cost of replacing today's power system with a new, optimally designed and sized system that uses the newest technology. In between is a range of alternatives, many of which have been used in states like Maine, New York, Montana, Oregon and California in determining revenue allocation among classes.

There is a strong theoretical link between optimal rate design and long-run marginal costs. Allocation based on marginal costs works backward from this premise; because pricing should be determined on this basis, cost allocation should as well. In its simplest form, a marginal cost study computes marginal costs for different elements of service, which can be estimated using a number of techniques, including proxies, regressions and other cost data. Table 11 shows illustrative marginal costs for different elements of the electric system.

Different marginal cost of service studies may base their costing on different elements of the system or different combinations. The categories of costs included in each element can also be more or less expansive. The estimated marginal costs are then multiplied by the billing determinants for each class. This produces a class marginal cost revenue requirement and, when combined with other classes, a system MCRR. However, revenue determination solely on this marginal cost basis will typically be greater or less than the allowed revenue requirement, which is normally computed on an embedded cost basis. It is only happenstance if marginal costs and embedded costs produce the same revenue or even similar levels of revenue. As a result, a marginal cost of service study must be adjusted to recover the correct annual amount from the revenue requirement.

Two notable long-run methods are discussed in this section: the long-run marginal cost approaches advocated by Lewis Perl and his colleagues at the consulting firm National Economic Research Associates (NERA) — now NERA Economic Consulting — and the total service long-run incremental cost approach.[55] In the 1980s, during the PURPA hearing era, many states considered and a few adopted the **NERA method** to measuring long-run marginal costs. California, Oregon, Montana and New York are examples of states that began relying on this approach to measuring marginal costs. This methodology generally looked at a 10-year or longer time horizon to measure what costs would change in response to changes in peak demand and energy requirements during different time periods and the number of customers served (National Economic Research Associates, 1977). One essential element of this was to define the cost of generation to meet peak period load growth (peaker units and associated T&D capacity) as much higher than the cost to meet off-peak load growth (increased utilization of existing assets). This approach was influenced by Alfred Kahn's theoretical focus on peak load costs and management (Kahn, 1970), and he himself was associated with NERA for many years.

For generation, one of the theoretical advances that made marginal cost of service studies attractive when they were first developed in the late 1970s was that generation costs were made up of capacity and energy costs, but the embedded plant was not classified to obtain these costs. Marginal energy costs were based on the incremental operating costs of the system (discussed in Chapter 18 in more detail), while capacity costs were the least cost of new capacity (at the time, typically a combustion turbine). The annualization for the capacity costs of all types is not based on the embedded rate of return but on a **real economic carrying charge** (RECC) rate that yields the same present value of revenue requirements when adjusted for inflation.

For transmission and distribution costs in the NERA method, the marginal costs have typically been estimated by determining marginal investment for new capacity over a number of historical and projected years and relating that investment to changes in some type of load or capacity measure in kWs. This relationship can be found either using regression equations (cumulative investment versus cumulative increase in load over the time period) or by simply dividing the number of dollars of investment by the total increase in load over the time period. O&M costs are generally based on some type of average over a number of historical and projected years, although obvious trends or anomalies can be taken into account.

Table 11. Illustrative marginal cost results by element

	Units	Cost per unit
Customer connection	Dollars per year	$80
Secondary distribution	Dollars per kW	$40
Primary distribution	Dollars per kW	$80
Transmission	Dollars per kW	$50
Generation capacity	Dollars per kW	$100
Energy by time period		
On-peak	Dollars per kWh	$0.10
Midpeak	Dollars per kWh	$0.07
Off-peak	Dollars per kWh	$0.05

55 Short-run marginal cost approaches are actually much simpler, primarily varying fuel consumption and purchased power costs, but are applicable only in a limited number of circumstances.

For customer costs, the same type of arguments over classification between distribution demand and customer costs occur as in embedded cost studies. The marginal cost study needs data on the current costs of hooking up new customers by class. The method for annualizing the costs is in dispute (RECC versus a **new-customer-only method** that assigns the costs by new and replacement customers). O&M costs are again typically based on some type of average over historical and projected years.

The time horizon used for the NERA approach has proven controversial because it assumed the utility would install exactly the number of new customer connections and distribution lines required by new customers (i.e., all customer costs are "marginal") but would consider the adequacy of existing generation and transmission (which may be oversized to meet current needs) in determining the need for additional generation and transmission (meaning only some G&T costs are "marginal"). Many utilities have used a 10-year time horizon in this analysis, a period in which many found substantial excess capacity and, therefore, relatively low costs to meet increasing power supply needs. In addition, this methodology, as most often used, treats the cost of increased off-peak usage as only the fuel and variable power costs and losses associated with operating existing resources for additional hours, with no associated investment-related or maintenance-related cost, despite the reliance on expensive investments to produce that power.

The combination of these assumptions meant that many marginal cost of service studies over the last several decades would come to three basic conclusions:

- Power supply and transmission costs to meet off-peak loads were relatively low, due to available excess capacity.
- Power supply and transmission costs to meet peak load growth were higher.
- Distribution costs always grew in lockstep with the number of customers and distribution demands.

The most serious shortcoming of the NERA methodology is that if power supply is surplus due to imperfect forecasting, it assigns a very low cost to power; if it is scarce, the method assigns a very high cost. Neither of those circumstances is *caused* by the action of consumers in any class, but the presence of either can shift costs sharply among consumer classes. Because of this imbalanced result, regulators have adopted modifications to this methodology to equalize the time horizon for different elements of the cost of service. For example, not all customers will require new service drops and meters over a 10-year period — only new customers and those whose existing facilities fail. Some states apportion costs within functional categories, avoiding this problem and addressing markets with partial retail choice.

In contrast to the NERA approach and other marginal cost approaches, which start from the parameters and investments found in the existing system, the total service long-run incremental cost approach looks at a period long enough so that all costs truly are variable. This allows for an estimate of what the system would look like if it were completely constructed using today's technologies and today's costs. Today, new generation is often cheaper than existing resources, while the cost of transmission and distribution continues to rise.

The TSLRIC approach was developed in the context of regulatory reform for telecommunications (International Telecommunication Union, 2009). In the 1990s, as telecommunication technology advanced rapidly, incumbent local exchange companies (better known as phone companies) faced competition from new market entrants that did not have legacy system costs. These new competitors were able to offer service at lower cost than the local phone companies. Regulators did not want to discourage innovation but also did not want existing customers served by the local phone companies to suffer rate increases if select customers left the system.

The TSLRIC approach constructs a hypothetical system with optimal sizing of components, with neither excess capacity nor deficient capacity. It would use the most modern technology. In the context of an electric utility, it would likely rely on wind, solar and storage to a greater extent than most systems today, which would likely lead to lower costs. But it would also incur the cost of today's environmental and land use restrictions, such as the requirement for lower emissions from generation and undergrounding of transmission and distribution lines. These requirements have substantial societal benefits but can also drive up electric system costs.

One advantage of a TSLRIC study over a NERA-style study is that no class is advantaged or disadvantaged by a current surplus or deficiency of power supply or distribution network capacity, since costs for all classes would be based on an optimal mix of resources to serve today's needs. This is one of the most common critiques of the NERA methodology — that it favors any class that is served dominantly by the elements of a system that are in surplus.

6.3 Combining Frameworks

Several jurisdictions require both an embedded and a marginal cost of service study to support cost allocation and rate design. As a result, utilities and other parties may file several studies in the course of a rate proceeding. A regulator may reasonably use multiple cost studies in reaching decisions, using multiple results to define a range of reasonableness. Within that range, the regulator can apply judgment and all of the relevant non-cost concerns to determine the allocation of the revenue requirements among classes. Furthermore, the different types of studies provide different information that can be used at other stages in the rate-making process.

One approach is to use embedded cost methods to determine the allocation of the revenue requirement among customer classes and then a forward-looking cost method of some kind to design rates within classes. This applies the focus of embedded cost studies on equitably sharing the costs among classes while maximizing the efficiency of price signals in the actual rates that individual customers face in making consumption decisions that will affect future costs. The appropriate form of price signals can also be influenced by externalities that are not part of the embedded costs for a regulated utility. For example, many regulatory agencies that allocate costs among classes on embedded costs have reflected higher long-run marginal costs in adopting inclining block or time-of-use rates for customers with high levels of usage (either because large customers are better able to respond to price signals or because the larger customers have more expensive load shapes, such as for space conditioning).

In some situations, regulators will use one costing method to set rates for existing load while using a different method to set rates for new customers or incremental usage. Some jurisdictions have applied this technique for rate design within classes — as the foundation for most "economic development" rate discounts where marginal costs are lower than embedded costs, as well as for inclining block rates where marginal costs are higher than embedded costs. In addition, some jurisdictions have applied this technique across rate classes, allocating new incremental resources to specific rate classes. Depending on the trajectory of costs, this can have two different intended purposes:

- To provide a foundation upon which to impose on fast-growing classes the high costs of growth and to shelter slower-growing classes from these new costs.
- To provide a foundation to give the benefit of low-cost new resources to the growing class.

This approach to differential treatment of incremental resources may be applicable to situations where costs are being driven by disparate growth among customer classes. In the 1980s, for example, commercial loads in the U.S. grew much faster than residential loads, and this technique could be used to assign the cost of expensive new resources to the classes causing those new costs to be incurred.

6.4 Using Cost of Service Study Results

Quantitative cost of service study results should serve only as a guide to the allocation of revenue responsibility among classes, not as the sole determinant. Even the best cost of service study reflects many judgments, assumptions and inputs. Other reasonable judgments, assumptions and inputs would result in different cost allocations. Additionally, loads may be unstable, significantly changing class revenue responsibility between cost studies, particularly for traditional studies that base costs on single peak hours in one or several months. More globally, concepts of equity extend beyond the cost of service study's assignment of responsibility for causing costs or using the services provided by those costs to include relative ability to pay, gradualism in rate changes, differential risks by function and class and other policy considerations.

Chapter 27 addresses the many ways in which the results of cost of service studies can be used to guide regulators.

7. Key Issues for 21st Century Cost Allocation

Many important cost allocation issues for the current era are fundamentally different from those that existed when NARUC published its 1992 *Electric Utility Cost Allocation Manual*. This chapter sets forth the changes the industry has experienced and describes the approaches that may be needed to address those changes in cost allocation studies.

Inevitably, additional costing issues will emerge and require recognition in future cost of service studies. The fundamental considerations are why the costs were incurred and who currently benefits from the costs. Costs are often categorized using engineering and accounting perspectives that are useful for many applications but must not be allowed to obscure the fundamental questions of causation and benefits.

7.1 Changes to Technology and the Electric System

Technological change has affected every element of the electric system since the studies and decisions that informed the 1992 NARUC cost allocation manual. These changes include:

- Improved distribution system monitoring and advanced metering infrastructure, leading to new comprehensive data on the system and customers.
- Evolution of resource options to include significant amounts of variable renewables, new types of storage, energy efficiency and demand response.
- Significant commitments to DERs behind customer meters, including rooftop solar and storage.
- Beneficial electrification of transportation.
- Changes in fuel prices and the resource supply mix that have dramatically changed the operating pattern of various generation resources (addressed in more detail in Section 7.2).

These changes both enable and require new approaches in order to efficiently and equitably allocate costs across customer classes.

7.1.1 Distribution System Monitoring and Advanced Metering Infrastructure

In the past, customer meters were used solely to measure usage and render bills. Today, so-called smart meters are part of a complex web of assets that enable energy efficiency, peak load management and improved system reliability, in addition to the traditional measuring of usage and rendering of bills.

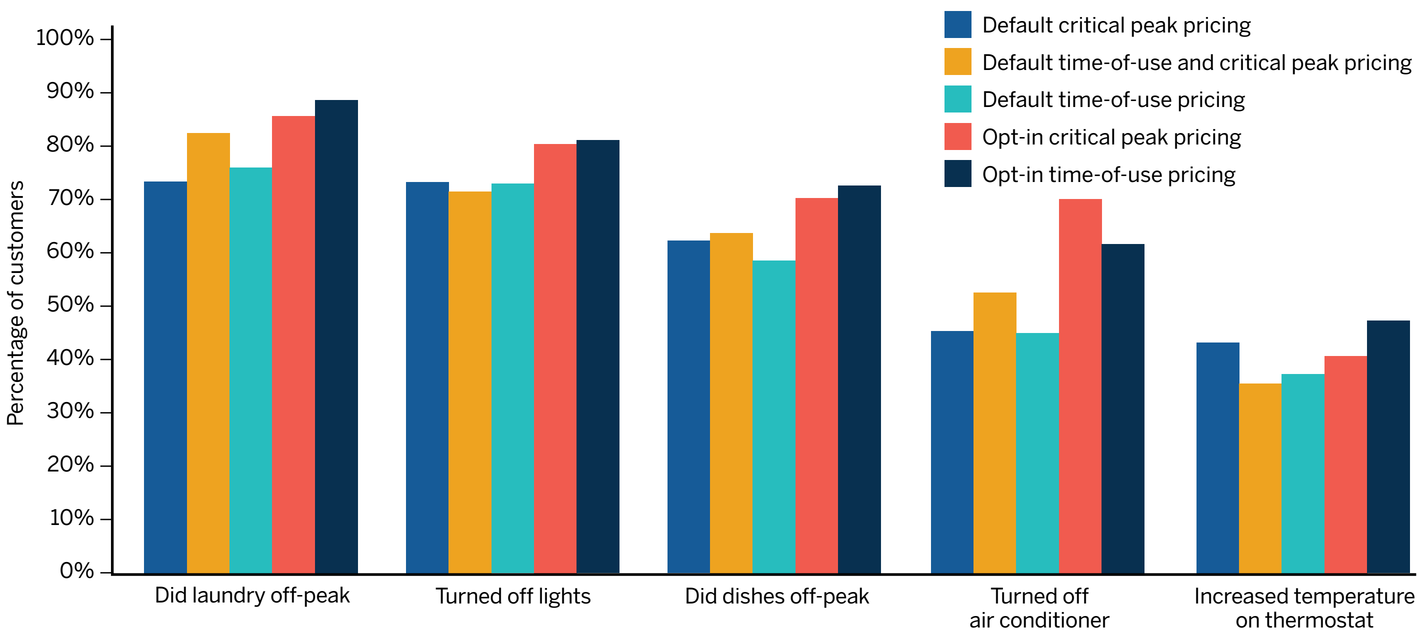
More recently, a number of utilities have used advanced meters to support demand response and other programs. Sacramento Municipal Utility District, for example, ran a pilot program to test the impacts of **dynamic pricing** and smart technology on peak load shaving and energy conservation. Figure 22 on the next page shows how customers in the program took steps to lower their electricity usage during high-load, higher-cost hours (Potter, George and Jimenez, 2014).

Smart meters (along with supporting data acquisition and data management hardware and software) can provide a number of services that improve reliability and reduce costs of generation, transmission and distribution.[56] Analysts have identified a wide range of expected and potential benefits. These include:

- Reduced line losses.
- Voltage control.
- Improved system planning and transformer sizing.
- The ability to implement rate designs that encourage energy efficiency.
- Reduced peak loads.
- Integration of EVs and renewables.

56 The broader concept of "smart grid" includes distribution (and sometimes transmission) automation devices such as automatic reclosers, voltage controls, switchable capacitors and sensors.

Figure 22. Customer behavior in Sacramento Municipal Utility District pricing pilot



Source: Potter, J., George, S., and Jimenez, L. (2014). *SmartPricing Options Final Evaluation*

- Operating savings from, among other things, reduced labor needs and improved outage management.

Lastly, smart meters, distribution sensors and modern computing power provide utilities with large amounts of data that can be used to determine the usage patterns of distribution and transmission equipment in great detail and support direct hourly allocation of costs.

7.1.2 Variable Renewables, Storage, Energy Efficiency and Demand Response

New variable renewable resources, such as wind and solar, are highly capital-intensive, and their contribution to system reliability varies greatly from region to region depending on when their generation occurs relative to peak demand.[57] The emergence of demand response as a service provides an opportunity to meet narrow periods of peak demand with relatively little capital investment by rewarding customers who curtail usage on request.

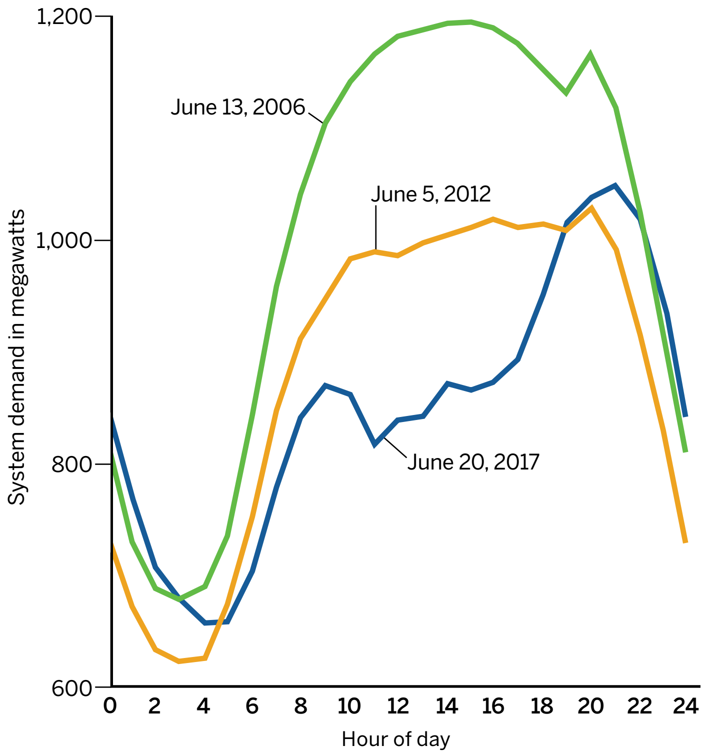
Investments in renewable resources, driven by policy and economic trends, can greatly change patterns in supply and demand that had been roughly constant for decades. Due to significant solar capacity in some regions, such as California and Hawaii, costs (e.g., extra **spinning reserves**, out-of-merit dispatch or quick-start generation) may also be incurred to rapidly ramp up other generation as solar output falls in the late afternoon, particularly if customer load does not drop dramatically from afternoon to evening.[58] Excess solar generation may create ramping costs, while storage resources may reduce ramping costs by both raising load at the beginning of the ramp period and trimming the peak toward the end of the ramp period.

In Hawaii, June load shapes changed as increased levels of distributed solar were added to the system. Figure 23 on the next page illustrates this, using data from the Federal Energy Regulatory Commission (n.d.). In 2006, the **system peak demand** was approximately 1,200 MWs at 1 to 3 p.m. By 2017, with extensive deployment of customer-sited solar, the peak demand was 1,068 MWs at 9 p.m. A cost allocation scheme must be adaptable enough to be relevant as significant changes in the shape and character of utility-served load take place.

57 Growth in solar resources, whether central or distributed, gradually reduces the reliability value of incremental solar capacity in many respects; the same is true for wind resources with respect to the reliability value of incremental wind and the equivalent for (if they become economically competitive) tidal and wave energy. In contrast, these different resources may be complementary to one another in certain respects.

58 The resulting load shape, first identified by Denholm, Margolis and Milford in 2008, is commonly known as a duck curve. See also Lazar (2016).

Figure 23. Evolution of system load in Hawaii on typical June weekday



Data source: Federal Energy Regulatory Commission. *Form No. 714 — Annual Balancing Authority Area and Planning Area Report*

The capacity role and treatment of variable renewable resources, such as wind and solar, vary among jurisdictions and RTOs. The cost of service study should reflect the role of these resources in supply planning, by classifying part of the renewable costs as demand-related and allocating those costs in proportion to class consumption in the hours contributing to capacity requirements. This should recognize that different types of variable renewable resources can be complementary in many respects as long as the temporal patterns, either daily or seasonal, are different. Even solar in slightly different regions can be complementary since they may not be affected in an identical way by cloud cover. For example, as shown in Figure 24 on the next page, a mix of wind resources from West and South Texas plus solar production combine to produce an overall resource shape that corresponds moderately well to the shape of the summer diurnal load (Slusarewicz and Cohan, 2018; Electric Reliability Council of Texas, 2019).

The costs of these resources can be assigned to the hours in which they generate energy, as discussed in Chapter 17. Determining the hours that variable resources provide energy (on either a historical or normalized forecast basis) is generally straightforward.

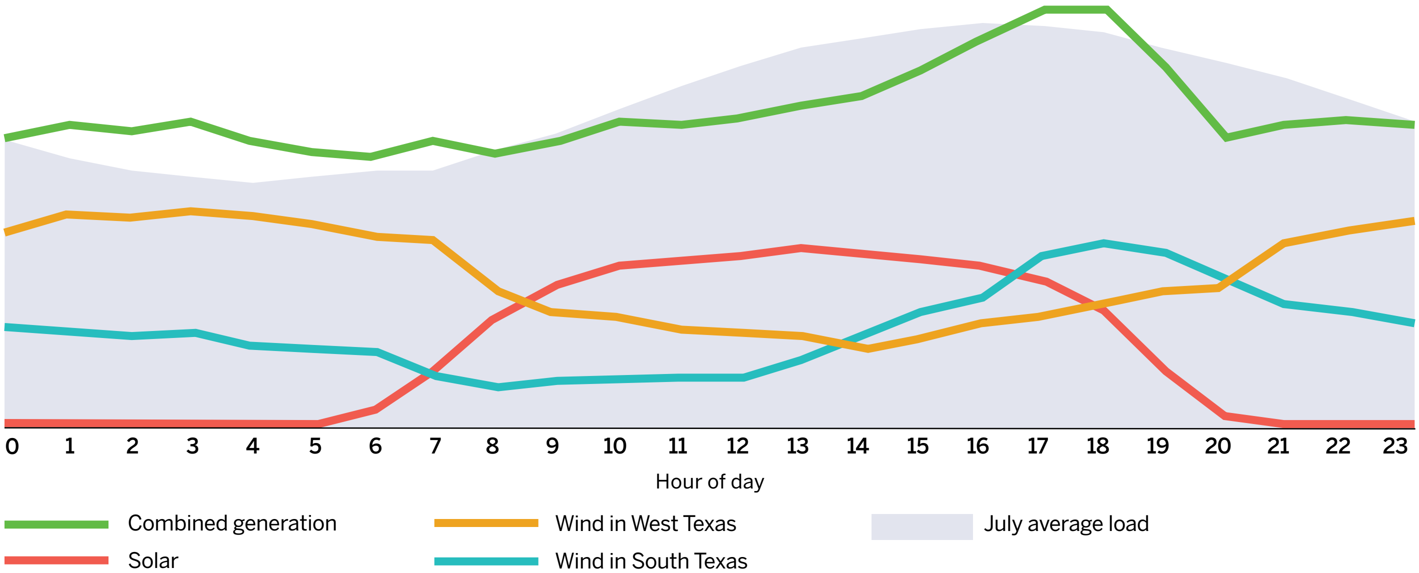
Distributed storage presents other issues and opportunities, as it is a capital-intensive peaking resource with no direct fuel costs, dependent on charging from other resources, and provides a variety of energy, capacity, transmission, distribution and **ancillary services** to the system and sometimes backup supply to host customers. Storage may displace T&D investments, reduce fuel consumption, enable renewable energy integration and provide emergency service at customer sites. Each of these functions has a different place in a modern cost allocation study.

A portfolio of energy efficiency measures reduces energy requirements, generation capacity requirements and stress on T&D equipment, as well as reduces customer billing determinants. As discussed in Section 14.1, energy efficiency expenditures can be classified and allocated in proportion to the benefits they produce. The plans and evaluation reports of the program administrator (the utility or a third party authorized to provide those services) generally provide sufficient data on the load shape and class distribution of load reductions. Since energy efficiency costs are recovered through a variety of mechanisms (rate based or expensed, through base rates or a discrete conservation surcharge or **rider**), the cost allocation should reflect the cost recovery method.

The costs of demand response programs — direct load control, customer load automation (e.g., setback thermostats) and price-responsive load (e.g., critical peak pricing) — should similarly be apportioned to reflect their benefits, so that cost-effective demand response is a net benefit to both participants and nonparticipants.[59] An hourly assignment method, where the costs of demand response are apportioned

59 Under conventional rate designs, participants (and their classes) generally retain a smaller share of the benefits of demand response (other than incentives for program participation, which may include peak-time rebates) than of energy efficiency programs. Depending on the program design, the incentives for the participants may be reflected in cost allocation and rate design through (1) reduced allocation of costs to the participating customers and classes to reflect improved load shape, (2) payment of incentives (including peak-time rebates) and allocation of those and other utility expenditures as costs, or (3) a combination of the two, as long as the benefits are not double-counted. Dynamic peak pricing may encourage demand response without explicit incentives, with the cost allocation to the participants' class reflecting the improved load shape.

Figure 24. Illustrative Texas wind and solar resource compared with load shape



Sources: Adapted from Slusarewicz, J., and Cohan, D. (2018). *Assessing Solar and Wind Complementarity in Texas* [Licensed under http://creativecommons.org/licenses/by/4.0]. Load data from Electric Reliability Council of Texas. (2019). *2018 ERCOT Hourly Load Data*

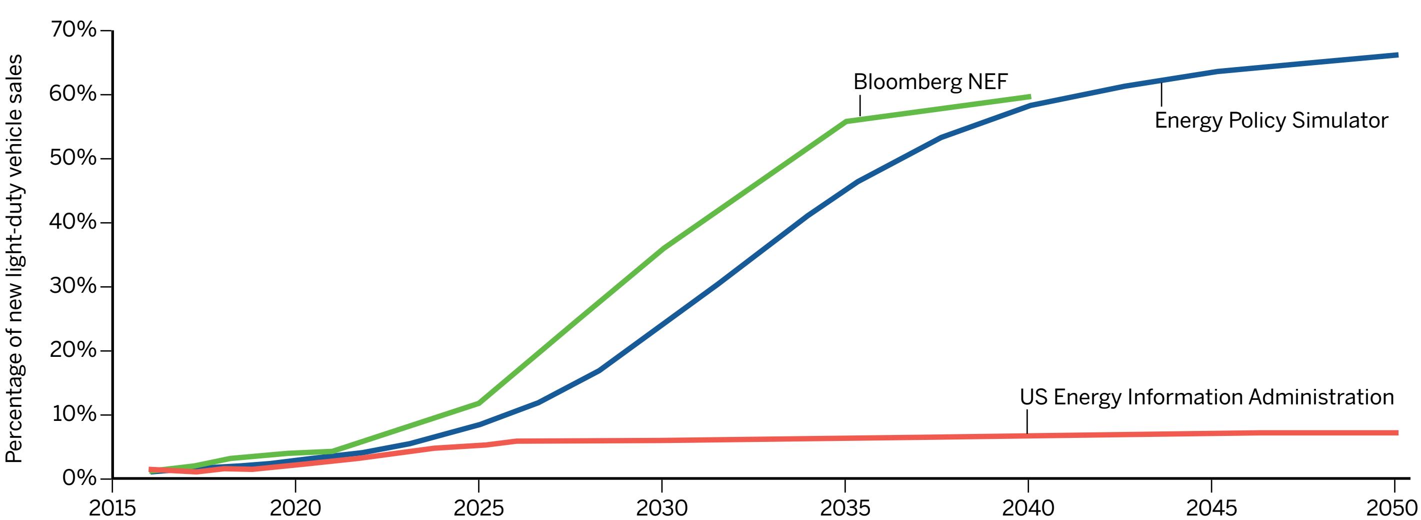
to the hours when it is called upon (to reduce load or provide operating reserves), may help match costs to benefits across classes.

7.1.3 Beneficial Electrification of Transportation

Electric vehicles currently use less than 1% of the nation's electricity, but that is expected to rise sharply in the next two decades. However, the precise rate of expansion is uncertain. Figure 25 shows three alternative projections for sales of electric vehicles (Rissman, 2017).

For cost allocation purposes, there are two interrelated issues: how to treat existing customers who adopt EVs as well as new dedicated EV charging accounts, and how to allocate the costs of new utility EV programs, both for demand management and investments in charging stations.

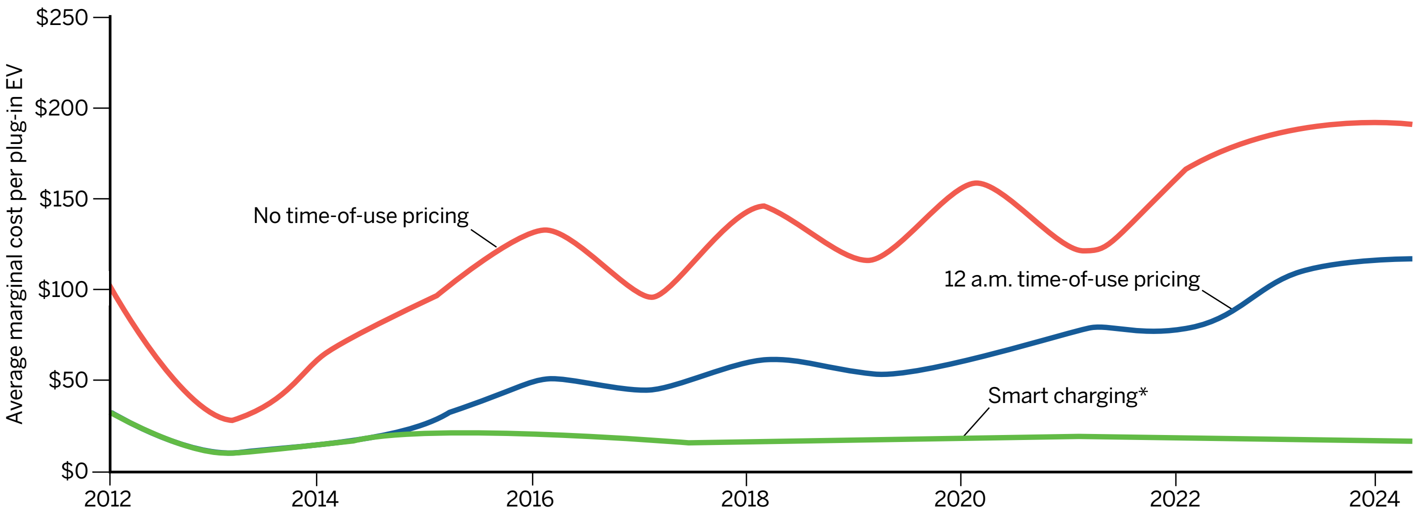
Figure 25. Forecasts of electric vehicle share of sales



Note: Projections of U.S. market share of EVs are from the Energy Policy Simulator 1.3.1 BAU case, the Energy Information Administration *Annual Energy Outlook 2017* "No Clean Power Plan" side case, and the Bloomberg NEF *Electric Vehicle Outlook 2017*.

Source: Rissman, J. (2017). *The Future of Electric Vehicles in the U.S.*

Figure 26. Estimated grid integration costs for electric vehicles



*Not including costs to implement smart charging technology

Source: Sacramento Municipal Utility District, personal communication, July 8, 2019

EVs are first being adopted in light-duty vehicle market segments, which primarily equates to residential adoption. These EVs are charged predominantly at home; there is a general consensus that home charging comprises over 80% on average (U.S. Department of Energy, n.d.). This home EV charging represents a substantial, but not totally unprecedented, amount of new consumption for a residential customer. The annual consumption for an EV represents slightly less than the consumption required for a typical electric water heater (U.S. Department of Energy, n.d.). If uncontrolled, however, this additional consumption could change the load profile significantly for this subset of customers, potentially leading to additional system costs. For example, if EVs begin to charge at home right after the workday ends and the sun is setting, then this could increase system peak and exacerbate ramping issues.

Between rate classes, changes in load profiles can be easily accounted for in future rate cases as long as there is sufficient load research data on the issue. However, there could also be significant changes in customer load profiles within each rate class. As a result, some analysts have suggested that residential customers with EVs should be a separate rate class. As a threshold matter as discussed in Section 5.2, it is an empirical question whether customers with EVs have distinct cost characteristics from other customers in the same rate class and whether EV adoption is high enough within the rate class to have an impact on the other customers. However, assuming for the sake of argument that these thresholds are crossed, there are alternative ways to address the issue. It is not a given that EV charging will increase system peak or otherwise negatively impact other customers. Time-of-use rates and other demand management programs can significantly lessen these impacts. Figure 26 shows estimated grid integration costs for uncontrolled EV charging and two alternative methods for managing EV load (Sacramento Municipal Utility District, personal communication, July 8, 2019).

Many jurisdictions are moving toward widespread TOU rates for residential customers. If these rates are mandatory for residential customers or even just the default for residential customers with EVs, then that would likely eliminate any cross-subsidy issues between residential customers with and without EVs. Similarly, EVs can be easily integrated into other demand management programs, or programs specific to EVs can be examined.

At some point, similar issues may arise for workplace charging for light-duty vehicles, and it will be desirable to concentrate charging into the hours when generation and delivery system capacity is available and unused. For example, it may be desirable to concentrate workplace EV charging during periods when solar generation is prevalent.

As of this writing, many different heavy-duty EVs are beginning to be adopted. Many jurisdictions have started to adopt electric buses, and a wide range of electric trucks are under development, from postal and parcel urban delivery vehicles to long-haul semitrailers. Fleets of these vehicles will have charging requirements measured in MWs, not kWs, and it may be desirable to locate these charging facilities where they can be directly served from the transmission network, avoiding the primary distribution network altogether. In this case, these sites will be more like large industrial high-voltage customers for cost analysis purposes. Making potential customers aware of this option, to access lower-cost power by locating adjacent to transmission capacity, may help guide the evolution of this market segment on an economical pathway.

Lastly, the development of public DC fast charging, thought by many to be a prerequisite to scale up EV adoption dramatically, is posing a range of new public policy issues. DC fast chargers allow for significantly faster recharging than other charging methods, which may be necessary for a variety of EV use cases, including long-distance travel and adoption in areas where residents cannot charge at home. The power rating of DC fast chargers is typically over 50 kWs per charging port and could increase significantly (Nicholas and Hall, 2018). These characteristics mean that DC fast chargers typically cannot be installed for single-family residential customers. However, DC fast chargers can be installed at many commercial and industrial locations with a sufficient service capacity (e.g., a mall) or connected directly as a stand-alone C&I customer with a separate account.

Many jurisdictions have been wrestling with the proper rate class and rate design for stand-alone DC fast charger accounts. This is because these accounts have a load profile without an obvious correspondence to other C&I rate classes. These accounts have typically been placed in rate classes with significant demand charges. However, given the high kW power rating and low utilization rates at this early stage of EV adoption, high demand charges lead to extraordinarily high bills for these fast charging accounts, at least on an average cost per kWh basis. Given the broader public policy need for public DC fast charging, a number of jurisdictions have begun to take steps to lower bills for these accounts, either through outright discounts or alternative rate structures. To date, there are significant tensions in all of the proposed solutions for these DC fast charging accounts. Given the significant site infrastructure needed to connect the uncontrolled power draw from DC fast chargers, the customer NCP demand for these accounts could be a relevant cost driver. RAP's preferred C&I rate design accounts for this by requiring modest customer NCP demand charges for site infrastructure ($1 to $2 per kW) with other elements of the rates established on a time-varying per-kWh basis. Such a rate would provide the right blend of incentives to manage usage for DC fast chargers through storage or other techniques. As a result, reforming rate design for C&I customers could be the optimal solution to this issue, instead of establishing separate rate classes for DC fast charging or providing arbitrary discounts under existing C&I rate designs.

Several states have also begun to implement utility EV programs, and many more states are considering policies in this area. Expenditures by regulated utilities to support electric vehicles are justified on a wide array of grounds:

- Societal benefits: public health and climate benefits, energy independence and reduced noise.
- Electric system benefits to all ratepayers: new load at beneficial off-peak hours and flexible new loads to optimize ramping.
- Benefits to participating customers and EV drivers: increased convenience, lower total driving costs and the potential to attract new customers to retail businesses.

One category of utility EV programs is quite similar to other energy and demand management programs. In the aggregate, uncontrolled EV load could be a significant addition to peak load that drives many system costs. These utility EV programs encourage, or in some cases ensure, that EV charging will take place during off-peak hours to minimize system stress and long-run electric system costs. The justifications for these programs and the principles for allocating the costs are not very different from other energy management and demand response programs, with functionalization, classification and allocation according to the benefits of the program or alternatively to classes in proportion to customer participation.

In contrast, another major category of utility EV programs does raise new questions. Utility expenditures and investments in support of charging infrastructure are taking a wide variety of forms, including rebates, additional allowances for interconnection costs, and direct utility ownership and operation of end-use charging stations. In most of these programs, participants are expected to bear some of the costs of the charging station, either upfront or ongoing, although a few programs may include full utility ownership and responsibility for all ongoing costs. Drivers of EVs are certainly the most direct beneficiaries of these programs, but there are a wide range of potential benefits for other ratepayers and society at large. Depending on the perspective, this could justify a wide range of cost allocation techniques, including:

- Direct assignment to the customer classes receiving free or subsidized equipment.[60]
- Allocation to all classes in proportion to class revenues or energy use to reflect the benefits to each class from increased sales and reduced average costs.
- Direct assignment to EV program accounts or a broader group of identifiable EV customers as program beneficiaries.[61]

These programs are still quite new at the time of publication for this manual, so many of the important issues are only beginning to be investigated. This is further complicated by cross-cutting issues, such as the integration of energy management programs into utility EV infrastructure investments and the impacts of cost allocation decisions on the competitive EV charging market and charging station providers who do not (or cannot) benefit from utility support.

One logical outcome across these issues could be applying fully loaded time-varying rates to identifiable EV accounts, which may provide higher incremental revenue than incremental costs in those hours. This would have the effect of socializing a substantial portion of EV program costs across a broader group of ratepayers. This would be consistent with efforts to jump-start an infant industry. EV charging station program cost responsibility could be more directly concentrated toward EV drivers over time. This could mean specialized ongoing cost recovery mechanisms, including direct assignment of identifiable EV-related costs. However, a jurisdiction that is seeking to accelerate EV adoption would certainly be free to apply short-run marginal cost-based economic development rates to EV charging development while simultaneously socializing EV program costs to all ratepayers.

7.1.4 Distributed Energy Resources

Over the last decade, DERs, particularly rooftop solar, have gained significant traction in many jurisdictions. Many states adopted net metering rules for rooftop solar and other eligible technologies in the 2000s.[62] The federal government also established the investment tax credit for commercial and residential solar systems in 2005, which was thereafter extended and expanded to other solar applications. Starting in the late 2000s, costs for solar panels started to drop quickly. These policies and trends, in addition to a range of additional state policies and incentives, have created a significant new market for rooftop solar. As shown in Figure 27 on the next page, adoption of residential solar accelerated to significant levels in the mid-2010s, with more than 2 GWs of installations annually from 2015 through 2018 (Wood Mackenzie Power & Renewables and Solar Energy Industries Association, 2019, p. 20).

Customer-sited adoption of solar can raise several cost allocation issues. Unlike EVs, distributed solar reduces customer load. At the macro level, for utilities without **decoupling**, this can lead to underrecovery of revenue and necessitate more frequent rate cases. If adoption of distributed solar is captured in the load research data, then cost allocation between rate classes may change over time depending on the cost allocation techniques used.

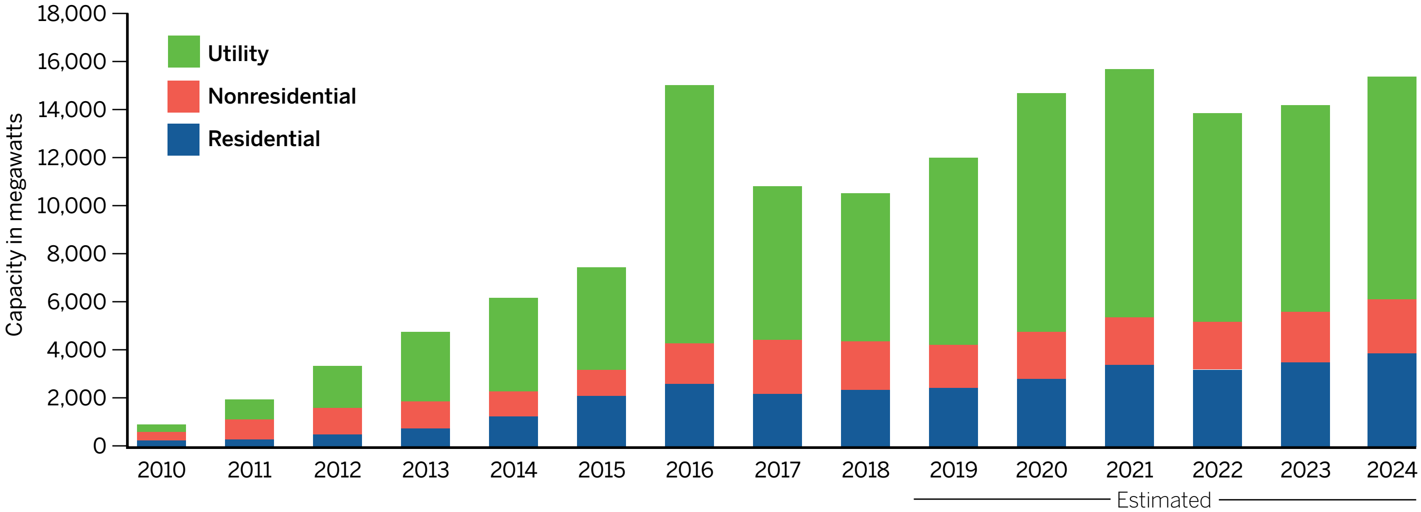
The more difficult issue that jurisdictions around the country have been wrestling with is the possibility of

60 The number of EV program participants in a class, but not the total number of customers in the class, may be relevant to allocation of the costs.

61 There are a number of potential variants on this. Direct recovery of costs from a given customer for installation at that customer's site over time would act as a financing mechanism for that customer. However, specific program costs (e.g., a DC fast charger program) could be recovered through a combination of subsidies from other classes and an ongoing per-kWh basis from the accounts that participated in that program.

62 The 2005 Energy Policy Act added net metering to the PURPA standards that each state was required to consider. Pub. L. No. 109-58 § 1251. Retrieved from https://www.congress.gov/109/plaws/publ58/PLAW-109publ58.pdf

Figure 27. US solar photovoltaic installations



Source: Wood Mackenzie Power & Renewables and Solar Energy Industries Association. (2019, March). *U.S. Solar Market Insight*

intraclass cross-subsidies between customers with solar and those without. Many utilities have proposed special rate designs, changes to net metering rules and separate rate classes for customers with solar. As always, the threshold issue for creating a new rate class is whether customers with solar are having material impacts on the other customers. Some utilities and consumer advocates argue that net metering rules allow customers with solar to pay less than their fair share of system costs. It is important to quantitatively evaluate these concerns before making policy adjustments to address them.

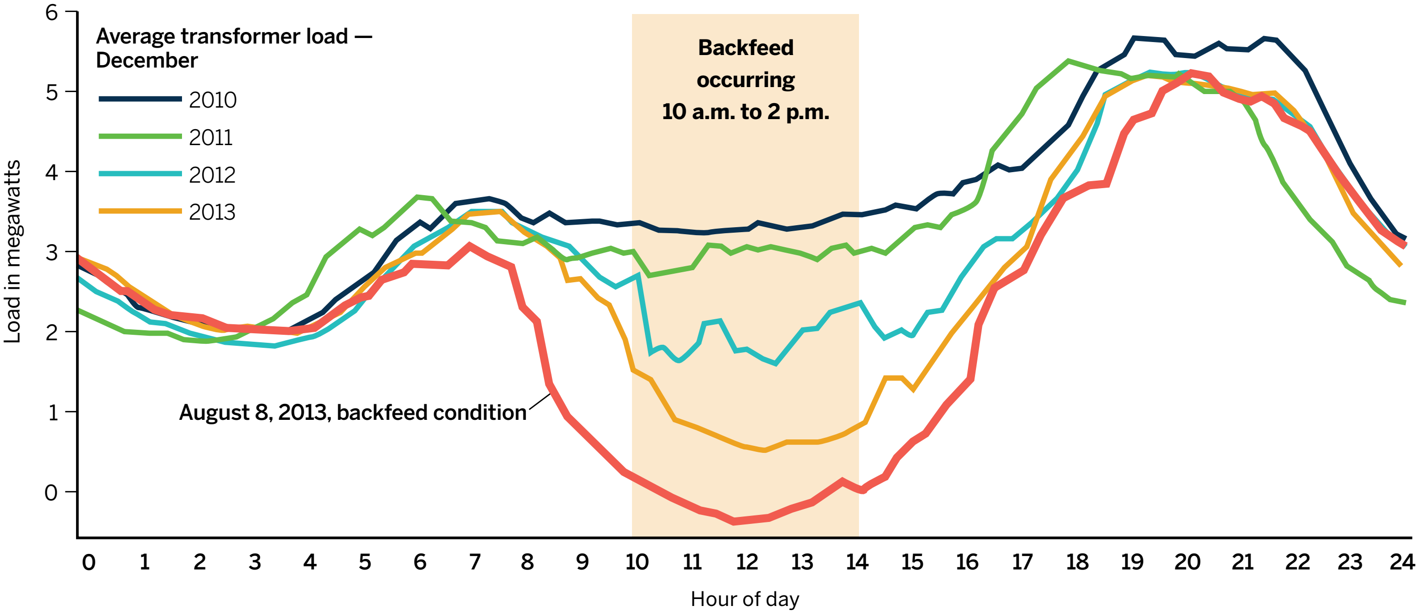
To begin, the levels of distributed solar adoption across the country are quite uneven. While many jurisdictions have significant levels of adoption, particularly those with either strong solar resources (such as California and Hawaii) or supportive state policy environments, many other jurisdictions have low levels of adoption. In jurisdictions with low levels of adoption, the impacts on other customers are necessarily quite small. If only 1% of class load is accounted for by distributed solar, then the worst-case scenario is approximately 1% higher bills for nonparticipating customers, with a strong likelihood of lower impacts given the offsetting benefits of solar generation.[63]

Even in jurisdictions with significant penetration levels of distributed solar, there have been robust debates about the existence of significant cross-subsidies and the proper means to address them. As a general matter, most proposals to establish separate rate classes for distributed solar have been denied so far.[64] Utilities have also proposed higher customer charges and special demand charges for solar customers, which have not been widely adopted. However, a variety of rate design changes have been adopted to better align compensation with value and reduce the potential for unreasonable cross-subsidies. California has begun to address these issues by requiring new residential net metering customers to be placed on TOU rates, a measure that is integrated with a move toward TOU rates for residential customers more generally (California Public Utilities Commission, n.d. and 2016). New York's Value of Distributed Energy Resources proceeding has set up specialized export credit compensation for large distributed energy projects, which include values

63 Net ratepayer impacts from solar policies depend on many factors. In jurisdictions with significant renewable portfolio standard costs or separate solar incentive programs, these costs can be quite different than in jurisdictions where the primary solar compensation policy is net metering. It is important to distinguish whether costs to nonparticipating ratepayers are occurring because of the RPS, dedicated solar incentive programs or net metering policies.

64 The exception to date is Kansas, although separate rate classes for solar customers have been authorized by legislative action in additional states (Trabish, 2017). At the time of this writing, this area of policy is rapidly evolving.

Figure 28. Substation backfeeding during high solar hours



Source: Hawaiian Electric Company. (2014, April 30). *Minimum Day Time Load Calculation and Screening.* Distributed Generation Interconnection Collaborative (DGIC) webinar

for energy, capacity, delivery and environmental externalities (New York Public Service Commission, 2017). Tensions in these debates include differentials between short-term and long-term avoided costs due to distributed generation and how to consider significant societal externalities such as greenhouse gas emissions.

Customer-sited storage is another DER that is expected to grow in importance in the coming decades. Storage can be used to change the load profile for adopting customers and even export energy to the grid if the jurisdiction allows it. Under flat volumetric rates, there is little incentive to manage energy usage with storage and little risk of unusually significant cross-subsidies. However, storage is becoming economically attractive in many jurisdictions to C&I customers that have high demand charges. These demand charges may not be well designed economically, and storage could allow these customers to lower their bills substantially. More generally, well-designed time-varying rates and demand charges can give the proper incentives for energy management through storage, but poorly designed rates will give customers correspondingly poor incentives.

Lastly, higher penetrations of DERs will raise new issues around the allocation of local distribution facilities. As more DERs are added, there will be some systems where primary or transmission voltage customers receive a portion of their power from generating facilities located along distribution circuits. Where this occurs, some provision should be made to treat a portion of the distribution investment as a generation-related cost. Figure 28 shows how some distribution substations may backfeed to the transmission system during solar hours, even if the solar facilities are sited exclusively on the rooftops of secondary voltage customers (Hawaiian Electric Company, 2014).

7.2 Changes to Regulatory Frameworks

As also introduced in Chapter 4, many new regulatory issues have arisen since the 1992 NARUC *Electric Utility Cost Allocation Manual*, and some older issues have become more prominent and widespread. These issues include:

- Restructuring and the emergence of organized wholesale markets and **retail competition**.
- Holding company issues due to widespread mergers and new utility conglomerates.
- Performance-based revenue frameworks.
- Proliferation of **trackers** and riders recovering costs outside of rate cases.
- New types of public policy programs.

- Consideration of differential rates of return in cost allocation studies.
- Recovery of **stranded costs**, assets with changed purposes and exit fees.

7.2.1 Restructuring

A few issues in cost allocation are specific to restructured electric utilities and **distribution system operators**.

Administrative and General Expenses

The most important of these issues may be that A&G costs become a larger share of total costs. As utilities have been restructured, not all have trimmed their management ranks or reduced executive compensation in proportion to the reduction in gross revenues. Regulators may need to use utilities that have never had production as proxies to determine appropriate cost levels to be assigned to distribution services and the apportionment of that cost. Even for **restructured utilities** that do not own generation assets, there are costs of maintaining involvement in regional power planning activities, ISO and RTO involvement and NERC involvement that are more closely related to power supply than the ownership and operation of a distribution system. Memberships in various industry organizations may be power supply-related as well.

Provision of Generation Services

In most states allowing retail competition, the distribution utility also procures and offers, at cost, a **default power supply** service for customers who do not choose an alternative retail electricity supplier.[65] These costs normally will not be included in the cost of service study during a base rate case because they apply only to an optional service and are set through a separate proceeding, generally by competitive bidding to supply individual classes based on their historical load shapes.[66] Any costs incurred by the utility to procure these services should be recovered through the default service, without affecting rate case revenue requirements.

Currently, default service is typically offered on a single residential load profile. We anticipate in the future this will become more granular,[67] at least with respect to time of day and season. This may be done with separate default tariffs for different subclasses of customers, such as multifamily, electric heating or electric vehicle owners. Or it may be done more simply, with a time-varying default service option that applies the same rates to all customers in each period, resulting in different average rates to customers with different usage patterns. A regulator may choose to reconfigure, for retail pricing purposes, these costs on a time-varying basis; if this occurs, the rate analyst must track this change into the cost allocation process.

Some ISOs (for example, ISO-NE, MISO, PJM) apply separate capacity charges and energy charges for power supply delivered to retail providers. Others (such as ERCOT) have eschewed capacity markets, instead concentrating on time differentiation of costs on a volumetric basis and allowing competitive energy prices to rise to levels reflective of scarcity and the value of lost load.[68]

The rate analyst may be in the position of second-guessing the ISO pricing, just as has been the case for natural gas utilities and FERC-approved pipeline charges for decades. If the ISO has treated some costs as capacity-related that can be more economically avoided with storage or demand response within the utility service territory, it may be appropriate to recharacterize these ISO costs as partly capacity-related costs and partly energy-related costs.

Transmission Costs

In addition to billing for generation capacity and energy in most cases, all ISOs/RTOs bill for transmission service. Most assign transmission costs, project by project, to geographic areas, based on the historical ownership of older

---

65 Texas has not had any form of default supply since restructuring; all customers must choose a retail electricity supplier.

66 If the utility procures default service at a single price for multiple classes, the regulator should consider whether to differentiate the rates to reflect differences among the classes.

67 See Hledik and Lazar (2016) for a discussion of future pricing options to enable optimal utilization of DERs to meet system and local capacity requirements.

68 We note that the costs of the Alberta capacity market are spread on a time-differentiated volumetric basis rather than a traditional demand charge; this may be a useful model for U.S. ISOs. For a more robust discussion, see Hogan (2016).

facilities and the loads justifying new facilities. If those charges are billed on a capacity basis, the pricing may exceed the cost of avoidance of some transmission capacity but still be necessary for moving energy at nonpeak hours.[69] In this situation, the analyst may need to consider whether some transmission costs are imprudent and should be excluded from the revenue requirement or, perhaps due to how the assets are used, to split these costs between demand and energy.

There are many circumstances where the analyst must look through ISO pricing to determine an appropriate basis for retail cost allocation. For example, ERCOT charges for transmission primarily on a 4 CP basis for the summer months (June through September). Similar approaches may be used in FERC-regulated transmission agreements among affiliates outside of ISOs. These pricing methods and the resulting allocations are administrative simplifications and do not necessarily reflect cost causation. The ISO cost allocations do not control the retail allocation of transmission costs among customer classes or the manner these costs are reflected in rate design.

7.2.2 Holding Companies

There have been more than 100 mergers of electric utilities since the 1992 NARUC manual. This phenomenon was accelerated in 2005 when Congress repealed the Public Utility Holding Company Act. This has resulted in very different corporate relationships than existed in the 1980s and has created myriad issues to consider in the cost allocation process, from executive compensation to interservice allocation procedures.

Most utility mergers and acquisitions are justified by projections of more efficient management and a corresponding decline in administrative costs. Determining whether these promises have been realized is a revenue requirement issue beyond the scope of this manual. But the apportionment of administrative costs among unregulated and utility functions, and among utilities within the holding company, are often part of cost allocation. The increased complexity of utility holding companies makes this task more difficult.

Many state utility commissions have taken steps to exclude from the revenue requirement any incentives such as higher executive compensation that reward shareholder benefits (such as for a higher stock price) or rewards for good performance in unregulated operations. Determining the portion of executive compensation that is attributable to the utility operations, as contrasted with corporate profit maximization, is not straightforward. This question may be approached by using senior management costs at public agencies (such as state departments of transportation, health and education or universities) as a proxy for the portion of executive compensation that should be allocated to utility service. Large public agencies may have budgets, employee counts and subordinate levels of management comparable to those of utilities.

Different business operations of a modern utility holding company have different risks and rewards. Although management of a distribution utility is complex, the amount of innovation and risk is fundamentally different than in other business units of the holding company. As noted by the U.S. Supreme Court:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property it employs for the convenience of the public equal to that generally being made at the same time and in the same region of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties, but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures.[70]

By the same logic, a utility is entitled to recover the management costs of a company with similar complexity and risk but not necessarily those of a more speculative business operation.

Shareholder service costs — such as the cost of maintaining shareholder data, issuing dividends, issuing new capital stock and annual meeting costs — must be

---

69 The Vermont regulator has regularly identified specific nodes where increased efforts for energy efficiency can reduce the need for transmission or distribution capacity upgrades (Vermont Public Service Board, 2007; Vermont System Planning Committee, n.d.). This may provide a foundation for classification of ISO transmission charges and for functionalizing some of these energy efficiency investments as transmission-related or distribution-related capacity costs.

70 Bluefield Water Works v. Public Service Commission, 262 U.S. 679, 692-93 (1923).

apportioned between the non-utility enterprises and the electric utility. Simple methods such as gross revenue or gross capital may be used; more complex methods looking at the number of employees, the contribution to earnings or other factors may also be appropriate.

Holding company insurance costs are substantial. Some are directly related to the utility service business, some are directly related to non-utility operations, and some are shared expenses. As with administrative costs and shareholder service costs, the most appropriate allocation method may need to rely on proxies of enterprises with simpler structures.

7.2.3 Performance-Based Regulation Issues

Performance-based regulation has emerged as a central theme in utility regulation. Although the genesis of PBR long predates the 1992 NARUC cost allocation manual, new and different approaches are being developed and implemented today. Early PBR mechanisms were simple price caps or discrete adders for specific investments.[71] The relevant issue for this manual is how to treat PBR costs and benefits in the cost allocation process.

The central concept of PBR is greater emphasis on the achievement of public policy objectives — such as lower customer costs, improved fuel cost performance, better reliability, increased reliance on preferred resources or other discrete goals — coupled with lower reliance on investment levels as a determinant of earnings. This tends to increase the operating expenses to cover the incentives while decreasing both investment and operating expenses when the incentives achieve cost savings.

The incentives may be in the form of a higher allowed rate of return based on achieving policy goals or discrete bonuses for achieving specific objectives. Similarly, penalties for underperformance can take a number of forms. The costs to ratepayers of PBR may include the incentives paid to shareholders as well as expenditures undertaken to achieve the PBR goals.[72] Those costs should be allocated to classes in proportion to the benefits they receive, and penalties returned to ratepayers should be allocated in a manner similar to the distribution of the excess costs that prompted the penalties.

One form of PBR is to provide for multiyear rate plans, where the incentive between rate cases is to achieve designated policy goals. Specific rewards for achievement provide higher earnings between proceedings, rather than mere cost control. This may have the effect of extending the period between general rate proceedings, making it more important that cost allocation in rate proceedings be given adequate attention. This is important because the results may be in place for a longer period than with conventional regulation.

7.2.4 Trackers and Riders

The rapid proliferation of tariff riders did not feature in the 1992 NARUC cost allocation manual at all. The earliest of these were **fuel adjustment clauses** adopted in the wake of the oil embargos in the 1970s, but they have now spread to many other categories, including energy efficiency programs, infrastructure spending, nuclear decommissioning and taxes. These riders cause revenue levels to track changes in costs between rate cases in specific categories. Some utilities have 10 or more separate tariff riders, each adjusted between rate cases.

Cost of service studies should be designed for compatibility with the methods that will be used to adjust costs between rate cases. Adjustments between cases may need to be simpler for administrative convenience and may not track cost study results accurately. To maintain consistency, the cost of service study may allocate all costs, with costs to be recovered through riders netted from class revenue requirements as the final step before the design of base rates. Alternatively, allocations of particular cost components from the cost of service study can be applied to the allocation of rider costs (e.g., the residential class might be assigned 34% of any primary distribution upgrades, 30% of purchased renewable energy, and so on).

71 For example, in 1980, the Washington State Legislature approved a 2% incremental rate of return for energy efficiency investments. Two decades later, the Nevada Public Utilities Commission adopted a similar incentive. Both have been allowed to expire.

72 For example, an incentive mechanism to control fuel costs may require capital investments to improve generating units.

Many tariff riders recover only the difference between actually incurred costs and costs estimated in a rate case, which could be reasonably expected to be relatively small. As a result, it often seems relatively fair and administratively efficient to pass these costs on in a simple way. Larger costs may require more detailed methods to track the broader issues laid out in this manual. If general rate cases occur with reasonable frequency, the divergence of riders from the cost of service study between general rate cases probably will be minor.

Many riders are allocated to classes on one of two simple models: a uniform cents-per-kWh surcharge or a uniform percentage surcharge. The uniform cents-per-kWh approach is appropriate for costs associated or correlated with energy usage. The percentage surcharge is rarely appropriate, since it will allocate costs proportionate to all the rate case costs, from meters to substations to (for vertically integrated utilities) baseload generation.

A wide variety of costs are routinely recovered through riders and trackers in many jurisdictions. These costs include the following.

Fuel and purchased power: Historically, most of these costs have been recovered through rate riders on a uniform cents-per-kWh basis across all classes.[73] Various fuels and purchased resources (renewables, combined cycle plants, combustion turbines, storage resources) provide different mixes of services. It may be appropriate to unbundle these costs by time period, so that charges more accurately reflect the hours in which the resource is useful and hence the mix of customer loads that use it. The typical uniform cents-per-kWh fuel adjustment clause may be replaced by a more granular rider, with at least time and seasonal differentiation (Hledik and Lazar, 2016). To the extent feasible, the allocation of costs in the rider should reflect the approach used in the general rate proceeding. If costs associated with purchased power are not separated between base rates and the adjustment mechanism in the same manner as utility-owned generating assets, a double-recovery problem may occur, with base rates recovering hypothetical investment costs to serve load growth, while an adjustment mechanism also recovers these costs.

Decoupling and weather normalization: Many regulators have adopted measures to insulate utility net income from variations in sales volumes. Some of these mechanisms are decoupling adjustments that take all sales variations into account, while others are strictly limited to sales variation due to energy conservation program deployment or weather. Most of these mechanisms adjust costs that are included in the cost allocation study at test-year levels. The allocation method used for these riders between rate cases should reflect the allocation of costs in the general rate cases. For example, customer costs do not vary with sales levels and should not be used in allocating the costs and credits from weather normalization.

Required and approved new projects: Some jurisdictions allow utilities to adjust rates to reflect new investments or operating costs (perhaps limited to specific categories, such as pollution control equipment, storm protection or ISO-approved transmission). The method used to allocate changes in costs between rate cases should be consistent (even if simplified) with the method used to allocate costs in general rate cases.

Inflation and actuarial changes: A few states allow flow-through between rate cases of inflation, attrition, statutory tax rates or other exogenous changes in costs, such as labor contracts or pensions. Where possible, these adjustments should be allocated in a manner similar to that used for the underlying costs.

Flow-through of changes in property taxes: Property taxes affect all elements of service and are generally assessed on the basis of appraised value, which (depending on the jurisdiction) may be very different from the gross and net book values used to set the revenue requirement.

Flow-through of municipal taxes and franchise fees: Some gross revenue taxes and franchise fees are imposed by municipalities and are often directly assigned to customers in that municipality and collected on the same basis they are imposed (e.g., a uniform percentage of gross revenue).

Storm damage: Regulators often allow recovery for storm damage in proceedings separate from general rate cases. In many cases, balancing accounts are created for

73 Some utilities adjust power supply riders by estimated line losses by class.

storm damage recovery; after large storms, the amount to be recovered may be adjusted. Storm damage typically affects primarily distribution and transmission costs. The method used for apportionment of changes in tariff riders for storm damage should generally follow the methods used in rate cases for apportioning the relevant costs (but not the cost for unaffected T&D costs, such as meters in most storms).

Regional transmission charges: Transmission charges imposed by an RTO or ISO are subject to change between rate cases. These changes may flow through to customers through a broader generation-cost tracking mechanism or a separate transmission rider. To the extent feasible, the costs should be classified and allocated using the same approaches used in allocating bulk transmission costs in the cost of service study. Because peaking assets commonly are located inside or near load centers, bulk transmission requirements tend to be driven more by access to low-cost energy resources, such as baseload generation, as discussed in Chapter 10. If some simple allocator is required for transmission costs outside full rate reviews, an energy allocator is likely to be reasonable.

Earnings sharing mechanisms: Some states require utilities to share earnings that exceed some threshold above the allowed rate of return; these are common in conjunction with decoupling mechanisms. Because overall earnings are a broad measure of utility costs compared with revenues, any earnings sharing will likely be spread across all functional areas and should be reflected as a percentage adjustment to overall rates.

7.2.5 Public Policy Discounts and Programs

Regulators and legislatures have dictated that utilities offer a range of public policy programs, mostly falling into two categories: (1) discounts or surcharges for certain categories of customers, such as low-income discounts, economic development discounts for industrial customers and area-specific surcharges; and (2) resource-specific incentives for energy efficiency, storage and renewables (including distributed solar).

These programs result in additional costs or redirected revenue requirements to be recovered through base rates, riders or a combination of the two. These revenue requirements may be included in the allocation of total costs, with base rates set to exclude the revenues expected through the riders, or the base rate revenue requirements and the riders can be allocated separately. In any case, the revenue requirements should be allocated among classes in a manner consistent with causality or benefits, without creating excessive administrative burdens in the updating of riders.

Public policy programs for specific resources or resource types (a renewable portfolio standard or other types of clean energy standard) may be justified on current economic benefits, environmental benefits, reliability improvements or the acceleration of emerging technologies and industries with future potential benefits. The costs of these programs are usually allocated either on the basis of program participation by rate class or in proportion to system benefits as they are expected to accrue across rate classes.

7.2.6 Consideration of Differential Rates of Return

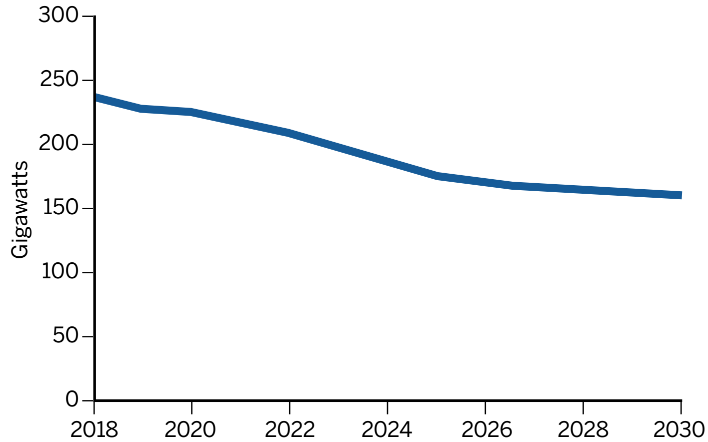
Historically, most cost allocation studies have applied a single rate of return, based on the utility cost of capital, to all capital investment components of the system and to all customer classes. In a more competitive utility environment, this may no longer be appropriate.

Rating agencies and others recognize some utility assets, such as generation, as riskier than other assets, such as distribution. Many utilities have experienced significant disallowances in cost recovery for generation, but the same generally has not been the case with distribution investment. Applying a function-specific rate of return in computing class cost responsibility will assure that this cost follows causation and benefit.

Similarly, some utility customer classes may be viewed as riskier than others. This may be customers with electric space conditioning, whose usage is more temperature-sensitive, creating variability in sales from year to year. Or it may be entire classes of customers whose usage varies with economic conditions, creating what financial analysts call systematic risk that raises the utility cost of capital. Applying a class-specific rate of return in computing class cost responsibility will ensure that low-risk classes do not pay costs more properly attributable to higher-risk classes.

A differential rate of return can be reflected either by assigning different costs of equity and debt to higher- and lower-risk parts of the enterprise, or by assigning a less-leveraged capital structure to the riskier parts of the enterprise and a more leveraged capital structure to the lower-risk parts. Moody's Investor Service applies a higher "business risk" score to generation than to distribution plant. This is then reflected in a higher equity capitalization rate, and thus a higher rate of return requirement, for generation plant (2017, p. 22). This translates into a differential rate of return requirement by customer class because different customer classes use a different mix of generation and distribution assets relative to their total revenue.

Figure 29. Projections for US coal generating capacity



Source: U.S. Energy Information Administration. (2019). *Annual Energy Outlook 2019*

7.2.7 Stranded Costs, Changed Purposes and Exit Fees

Regulators will face several challenging issues as technology evolves in the electric power industry. Among these will be issues of stranded costs and changing purposes of past investments. Stranded costs occur when an asset is retired prior to being fully depreciated or when an asset is sold at a market price that is below the level included in rate base. Stranded costs were quite significant when the telecommunications industry evolved to computer switching and digital transmission after restructuring in the 1990s and 2000s. The issues will be at least as significant regarding the retirement of current coal and nuclear units. But some assets will be redeployed; for example, coal plant sites that formerly operated as baseload resources may be repurposed to support gas-fired peakers. Transmission lines originally built to serve remote baseload power plants may be redeployed to bring variable renewable energy. These changes to asset usage will raise unique cost allocation issues.

Generation

Historically, the largest source of stranded costs in the electric industry has been baseload generating resources. Tens of billions of dollars were invested in nuclear units that were abandoned prior to completion in the early 1980s. Many of the nuclear plants that were completed closed long before they were fully depreciated, due to severe damage (e.g., TMI 2, Crystal River, Trojan, Rancho Seco and San Onofre), large investment requirements or unfavorable economics. Today, innovation is rendering many units uneconomic in a narrow financial sense, excluding externalities of any kind, even when they are still mechanically sound. As shown in Figure 29, the U.S. Energy Information Administration (2019) projects that nearly 100 GWs of coal generation will be retired between 2018 and 2030. Most of this is due to economic obsolescence, but it also reflects changing public policies around air pollution and climate.

Economic obsolescence of coal plants is primarily a result of lower-cost wind, solar and natural gas.[74] Although some policymakers are considering whether these coal plants, or the broader coal industry, need to be supported with financial incentives, there has been widespread support for this coal retirement trend for both cost and environmental reasons. In contrast, many states have been implementing policies to slow or stop nuclear retirements, in part because of the plants' climate benefits. In many cases, regulators have been actively involved in the decision to retire these units through integrated resource planning processes. In some

74 Public Service Company of Colorado decided to retire two coal units at the Comanche generating facility in Pueblo after bids for wind and solar energy were so low that the operating costs of these coal plants were deemed uneconomic (Pyper, 2018).

cases, legislatures have driven the retirements. Although a retirement usually concludes with a regulatory determination of what part of the cost is recoverable, a separate decision must be made on how to reflect the allowed costs in the cost of service methods and rate design of the utility.

Cost allocation analysts are not typically charged with determining the portion of abandoned project costs that electricity consumers or shareholders should bear. However, if these costs are included in rates, analysts are charged with determining how to reflect those costs in utility cost allocation studies and ultimately in rate design. If the plants were allocated in one way when operating and that method changes after termination, then the costs are shifted from one set of customers to another.

In other circumstances, plants have been converted from their original purpose to different purposes. The most common of these are baseload units, originally built to provide year-round service, being converted to peaking or seasonal generation or held in reserve for droughts or other contingencies. The cost allocation framework for the new purpose may be fundamentally different from the historical method based on historical usage.

In all of these cases, the cost of service study must reflect the allowed costs for abandoned or repurposed units. Should the costs be allocated based on the original intended purpose? Or should these costs be allocated based on the last useful purpose for the units? There is no easy answer.

Similar issues arose from the divestment of generation assets during restructuring. In jurisdictions with restructured utilities,[75] millions of retail customers have begun taking generation services from retail electricity providers or public aggregators and no longer pay the regulated utility directly for power supply. In many cases, this was politically achievable only by providing a method to compensate the utility for any stranded costs. This compensation typically was accomplished through a nonbypassable per-kWh charge on all distribution system customers, although in some cases specific exit fees were established so that departing customers made a one-time lump sum payment. Often this was done without reference to how the underlying costs are allocated among classes.

During restructuring proceedings in New England, many of the mid-Atlantic states, Illinois and Texas, regulators used an incremental valuation approach to recover the difference between the embedded costs and market values of generation assets. This included:

1. The net plant for utility-owned generation minus the sales price for those assets. That difference was negative for most hydro and fossil assets and positive for most nuclear assets.[76]
2. Costs of decommissioning for retired plants, especially nuclear units.
3. Payments to terminate or restructure long-term power purchase agreements.
4. Profit or loss from operating any residual utility-owned generation and selling power into the competitive market.[77]
5. Annual differences between payments for continuing power purchase agreements and the value of the power in the capacity and energy markets.[78]

Stranded cost charges are set to recover the sum of categories 4 and 5, the amortization of the balances in categories 1 through 3, any carrying charges for unamortized balances and any over- or undercollections in earlier periods.[79] Categories 4 and 5, and hence the overall surcharge, may be positive or negative. The surcharge continues until the stranded capital costs are recovered (or gains distributed) and all continuing cash flows end. In some jurisdictions,

75 New York, New Jersey, Pennsylvania, Maryland, Delaware, the District of Columbia, Ohio, Illinois, California, Texas and most of New England, as well as some customers in Michigan and Oregon. In Canada, Ontario has restructured similarly.

76 Certain utilities, notably all those in Ohio and some in Pennsylvania, New Jersey and Maryland, were allowed to transfer their generation assets to an affiliate at an estimated market value, rather than imposing a true market test from full divestment.

77 This approach has been applied to generation for which sale has been delayed (e.g., several nuclear units) or is impractical (e.g., ConEd's generation units located at or serving its steam distribution system) and to resources, such as renewables, that the utility is allowed to develop.

78 Long-term wholesale sales agreements may be bought out or treated in the same manner as power purchase agreements.

79 The costs in the first three categories frequently were refinanced through low-risk bonds, in a process called securitization.

restructuring surcharges have continued into 2019, in some cases as a credit.

Lastly, **community choice aggregation** has raised a similar set of issues in California, in part because a choice of energy supplier is not allowed more generally, and the utilities have procured long-term supply resources for a variety of reasons. Locales that form community choice aggregators, primarily counties, are allowed to contract directly with generators for power supply, which may vary from the resource characteristics of the utility's standard supply. In the meantime, market supply costs have declined, especially for renewables, and the migration of customer generation requirements from the utility to the aggregators can result in some stranded power costs, at least according to the utilities. California has selected a complex solution, imposing a power charge indifference adjustment, a type of exit fee with annual updates, on the community choice aggregators to recover the difference between actual utility costs and market prices. Rather than having a single charge for all customers to cover above-market costs, California has created a highly controversial process to set a charge for the customers of the aggregators and the direct marketers. The California experience illustrates the benefits of consistent allocation across customers, as opposed to the development of special rates for special groups of customers.

Any charge for stranded assets or costs should be temporary, only until the specific costs regulators allow are recovered.

Transmission

There is less history with transmission abandoned costs, but many lines are now being repurposed. Originally they were built to connect distant coal or nuclear baseload generating resources to urban load centers. Many of these were classified and allocated in the same manner as the baseload generation, with at least a portion of the cost classified as demand-related and allocated on some measure of peak demand. Today, with new natural gas generation being sited close to load centers and older coal and nuclear baseload units retired, these lines are being repurposed to transport economic energy from distant markets, including opportunity purchases, or to carry power from new wind and solar generating resources.[80] This is a very different use and provides very different economic benefits to consumers.

Some transmission lines are disused due to generation retirement. Although the inclusion of these costs in the rate base of the owning enterprise is a revenue requirement issue, the classification and allocation of any cost allowed by the regulator is a cost allocation issue. Some transmission lines may become economically obsolete due to the deployment of DERs within the service territory, obviating the need for some distant generation and its associated transmission lines. In this situation, the rate analyst is faced with the question of how to classify and allocate the fully or partly stranded costs.

Some lines may be repurposed from providing firm service from baseload resources to providing seasonal economic service without a clear connection to peak demand. In this situation, the costs may still be fully justified as economic and in the public interest, but a change in allocation method may be justified. An hourly assignment method will ensure that these costs are recovered in the hours when the economic energy is flowing.

Distribution

There have been very few regulatory disallowances of any magnitude for distribution plant, in part because the mass accounting methods do not identify specific segments. For example, when a large industrial facility closes, the investment in distribution facilities serving it typically remains in the regulated revenue requirement and continues to be classified and allocated in traditional ways. But technological evolution may result in higher rates of retirement or repurposing.

Some assets will be disused at many hours, due to deployment of DERs. Some CHP facilities will be entirely self-sufficient much of the time, with reliance on grid-supplied energy only during maintenance outages or periods of economical options. Distribution lines originally designed

80 Clear examples of this are found in the desert Southwest, where retirement of coal units in New Mexico, Arizona and Utah that formerly served California utilities is freeing up transmission that is being repurposed for moving variable renewables. State legislation mandated the retirements; economic conditions are driving the repurposing of these facilities.

to provide continuous service may be used only for a limited number of hours. The rate analyst must consider which is appropriate: applying the same methods used before DERs were installed or a different classification and allocation method in light of the changed circumstances.

In some areas of Hawaii, distribution circuits are back-feeding to the transmission system at midday; these lines are now serving a power supply integration function for many hours of each day.

The flow may be bidirectional. Power will flow into the lines from distant generation or storage during hours of darkness and into the grid for redelivery during high solar hours. The cost may be entirely prudent, but the traditional allocation methods may not accurately assign costs to the beneficiaries. An hourly allocation method may be appropriate for these circumstances, with the costs flowing to the consumers actually using the power when it is generated, rather than being apportioned to the generators or to customers not receiving power at certain hours.

Cross-Functional Repurposing

There are myriad examples of utility resources once needed for a particular function being repurposed for an entirely different function. For example, a former power plant site may become a location for a distribution warehouse. The power plant was functionalized as generation and allocated based on demand and energy factors. The distribution warehouse is a component of general plant, and the allocation method may be very different. One challenge for the rate analyst is tracking changes in how assets are being used, to keep the allocation framework consistent with the utilization of the assets.

8. Choosing Appropriate Costing Methods

In general, facilities shared among multiple users, as well as expenses and investments benefiting all ratepayers, should be apportioned based on measures of shared usage. Facilities that are uniquely serving individual customers should be sized to their individual needs, and the costs should be directly associated with those customers. Overhead costs, such as A&G expenses and general plant, are not costs that are subject to a "technically correct" allocation.[81] Pragmatically, these costs can be fairly divided among classes based on a measure of usage or even revenue since there is not necessarily a link between system cost drivers and these costs.

The first task in choosing a cost allocation method is to ascertain the objective of the study: Is it focused on short-run

Many factors influence cost allocation method selection

The appropriate choice of a detailed allocation approach and the most appropriate method may be affected by such factors as:

- Are the utility's loads growing, shrinking or stagnant?
- Does the utility have a mix of different types of supply resources to serve varying load levels?
- Does the utility rely on transmission facilities to deliver power from remote baseload, hydro or renewable energy resources?
- Is generation mostly spread among load centers, or is supply concentrated within certain portions of the service territory?
- Does the utility's supply mix include variable renewable resources, such as wind and solar?
- Does the utility have sufficient load density to support the distribution system with energy sales, or is the load so sparse that other revenues are required to pay for distribution (as is the case for some cooperatives)?
- Are peaking resources located inside the service territory near loads, or are they dependent on transmission from distant sources?
- How do the utility's customers break down into classes and subclasses that have significantly different cost characteristics?
- Does the utility have reasonably reliable hourly load data, by class?
- Does the utility have demand response resources that can help meet extreme peak requirements?
- Does the utility have storage resources that can shift generation or loads among time periods?
- Does the utility's load peak in the winter, in the summer or both?
- Do different customer classes peak at different times of the day or different seasons of the year?

Each of these questions bears on the most appropriate cost allocation approach. A mix of resources requires a method that appropriately treats that variety of resources differently in classification and allocation. Variable resources require a method that assigns their costs to the hours in which they produce benefits. The location of supply resources determines whether the method must apportion transmission costs among multiple purposes.

81 Bonbright described some distribution costs as strictly unallocable: "But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs for the reason just given, while it is also denied a place among the customer costs for the reason stated previously, to which cost function does it then belong? The only defensible answer, in my opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of long-run marginal costs" (1961, p. 348). The same "unallocable" characteristic may apply to other system costs in an evolving industry.

equity considerations or rather on efficiency considerations? Is the system an optimal system or a suboptimal system for today's needs? Most advocates of using embedded cost studies point to the direct link with the revenue requirement and spreading that revenue requirement among multiple customers. Although there is a wide range of embedded cost methods, all of them apportion the existing revenue requirement, and rates based on the results should produce the allowed amount of total revenue.

Within this broad sense of equity, however, the methods selected may result in vastly different results. For example, in one docket, the Washington Utilities and Transportation Commission considered the results of several approaches to embedded cost of service studies, presented by the utility, the commission staff and intervenors. The commission did not rigorously follow any of them but found that the range of these studies defined an appropriate range in which the revenue allocation should be based.

Another goal of cost allocation is long-run efficiency to guide consumer consumption based on where costs are going, not where they are.[82] The use of long-run marginal costs attempts to do this in the cost allocation phase of rate-making, and indeed this was the position that some advocates took in the hearing era after passage of PURPA. Their position was that all costs should be forward-looking to encourage long-run efficiency and that past costs cannot be "saved," so there is no point using them for cost allocation or rate design.

But marginal costs are not the same as current costs making up the revenue requirement, and some method is needed to reconcile (up or down) the results of a marginal cost study with the revenue requirement. The methods to do this include proportionality (adjusting all class revenue requirements by the same percentage) and various methods of focusing on certain aspects of cost in adjusting allowed revenues in consideration of marginal cost. These methods have been highly controversial, as discussed in detail in Part III.

In the short run, it is desirable to optimize the incurrence of variable costs such as fuel, labor and purchased energy. Consideration of short-run marginal costs focuses on exactly this. If systems have excess generating capacity, power costs are low; with deficient capacity (or fuel or water shortages), power costs are high. One problem with establishing cost allocation on the basis of short-run marginal costs is that few costs other than power supply vary significantly in the short run. Although utilities do reduce staffing during a recession and may defer maintenance, these are minor cost savings. Therefore, the costs considered are only a very small fraction of the revenue requirement.

During periods of energy shortage, such as the California energy crisis of 2000-2001, regulators may believe that short-term deviations from traditionally used long-run marginal cost theory are appropriate. In California's case, the commission approved both higher thresholds for energy efficiency investments and very sharply increased tailblock rates.

One issue that has been raised with respect to various short-run and NERA-style marginal cost studies is that they capture only a limited window in time, when utility resources may be imperfectly matched to utility customer needs. This is discussed in detail in Part IV.

A market that has short-run marginal costs that are equal to long-run marginal costs is said to be in equilibrium. When in equilibrium, the cost of producing one more unit of output with existing resources is relatively expensive, because all of the low-cost resources are already fully deployed, resulting in short-run costs that exactly match the cost of building and operating new resources. For electric generation, this might mean running a peaker to provide energy in many hours because available lower-cost units are fully deployed. In this situation, there would be no difference between marginal cost studies using different time horizons.

But electric utilities are almost never in equilibrium, for several reasons:

- Forecast and actual loads, costs, technologies and resource availability change faster than the system can be reconfigured, leaving systems with capacity excess or deficiency and resources that are poorly suited to current needs.
- Utilities maintain reserve margins for reliability, which often results in energy dispatch costs that are lower than

82 Canadian hockey great Wayne Gretzky is widely quoted as having said: "I skate to where the puck is going to be, not where it has been."

the fixed and variable costs of a new efficient generating unit. A system with marginal running costs high enough to justify new construction will tend to have a relatively low reserve margin.

- In other markets, short-run costs can be allowed to rise, with the tightening available supply rationed by pricing, and the short-run cost becomes the price of outbidding other users. For electricity, that approach would lead to blackouts.
- Transmission and distribution do not have short-run marginal costs comparable to the long-run costs of new equipment. Short of allowing overloads until lines and transformers fail, there is no way to bring a T&D system into equilibrium.
- As energy generation transitions from fossil generation with high running costs to zero-carbon resources with low running costs and high capital costs, it will be harder to match short-run and long-run costs.

A state of disequilibrium can severely affect some customer classes if a marginal cost study is based on short- to medium-term costs. If a shortage of power supply exists, it will severely affect large-volume customer classes; if a surplus exists, it will severely affect residential and small commercial customers.

In the following chapters, we address in detail how each type of cost should be considered in different approaches to cost allocation. The methods will be different for every utility because every utility has a different history and a different mix of resources, loads, costs, issues and opportunities. The appropriate method for each utility may be slightly different. It is driven by the mix of customers, the nature of the service territory, the type of resources employed and the underlying history that guided the evolution of the system. No single method is appropriate for every utility, and no single method is likely to produce a noncontroversial result. Many regulators will seek consistent methods to be applied to all utilities in their state, which may require compromise from the most appropriate method for each individual utility. In Chapter 27, we discuss how regulators can use the results of quantitative cost studies to actually determine a fair allocation of costs among classes.

Works Cited in Part II

Austin Energy (2017). *Residential electric rates & line items* [Webpage]. Retrieved from https://austinenergy.com/ae/rates/residential-rates/residential-electric-rates-and-line-items

Bonbright, J. (1961). *Principles of public utility rates.* New York, NY: Columbia University Press.

Bureau of Reclamation. (1991). *Permissible loading of oil-immersed transformers and regulators.* Denver, CO: Author. Retrieved from https://www.usbr.gov/power/data/fist/fist1_5/vol1-5.pdf

California Public Utilities Commission. (n.d.). *Net energy metering (NEM)* [Webpage]. Retrieved from https://www.cpuc.ca.gov/general.aspx?id=3800

California Public Utilities Commission. (2016, January 28). *Decision adopting successor to net energy metering tariff.* Decision No. 16-01-044. Retrieved from http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K181/158181678.pdf

Denholm, P., Margolis, R., and Milford, J. (2008). *Production cost modeling for high levels of photovoltaics penetration* (TP-581-42305). Golden, CO: National Renewable Energy Laboratory. Retrieved from https://www.nrel.gov/docs/fy08osti/42305.pdf

Electric Reliability Council of Texas. (2019). *2018 ERCOT hourly load data* [Data set]. Retrieved from http://www.ercot.com/gridinfo/load/load_hist/

Federal Energy Regulatory Commission. (n.d.). *Form No. 714 — Annual balancing authority area and planning area report* [Webpage]. Retrieved from https://www.ferc.gov/docs-filing/forms/form-714/data.asp

Federal Energy Regulatory Commission. (1979, September 28). *Order 48: Final regulations in Docket RM79-6.* Retrieved from https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14005118

Flex-Core. (n.d.). *Energy metering using potential and current transformers* [Webpage]. Retrieved from https://www.flex-core.com/engineering-resources/application-whitepapers/energy-metering-using-potential-current-transformers/

Hawaiian Electric Company. (2014, April 30). *Minimum day time load calculation and screening.* Distributed Generation Interconnection Collaborative (DGIC) webinar. Retrieved from https://www.energy.gov/sites/prod/files/Hawaiian%20Electric%202014-04-30_minimum-day-time-load-calculation-and-screening.pdf

Hledik, R., and Lazar, J. (2016). *Distribution system pricing with distributed energy resources.* Golden, CO: Lawrence Berkeley National Laboratory. Retrieved from https://www.osti.gov/servlets/purl/1375194

Hogan, M. (2016). *Hitting the mark on missing money: How to ensure reliability at least cost to consumers.* Montpelier, VT: Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/hitting-mark-missing-money-ensure-reliability-least-cost-consumers/

International Telecommunication Union. (2009). *Regulatory accounting guide.* Retrieved from https://www.itu.int/ITU-D/finance/Studies/Regulatory_accounting_guide-final1.1.pdf

Kahn, A. (1970 and 1971). *The economics of regulation: Principles and institutions* (vols. 1 and 2). New York, NY: John Wiley & Sons.

Lazar, J. (2016). *Teaching the "duck" to fly* (2nd ed.). Montpelier, VT: Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/teaching-the-duck-to-fly-second-edition/

Lazar, J., and Baldwin, X. (2011). *Valuing the contribution of energy efficiency to avoided marginal line losses and reserve requirements.* Montpelier, VT: Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/valuing-the-contribution-of-energy-efficiency-to-avoided-marginal-line-losses-and-reserve-requirements/

Lefkowitz, K. (2016, April). Direct testimony on behalf of Potomac Electric Power Co. (Pepco). *Application of Potomac Electric Power Co. for adjustments to its retail rates for the distribution of electric energy* (Vol. 1). Maryland Public Service Commission Case No. 9418. Retrieved from https://www.psc.state.md.us/search-results/?keyword=9418&x.x=34&x.y=18&search=all&search=case

Moody's Investor Service. (2017, June 23). *Rating methodology, regulated electric and gas utilities.*

National Association of Regulatory Utility Commissioners. (1992). *Electric utility cost allocation manual.* Washington, DC: Author. Retrieved from https://pubs.naruc.org/pub/53A3986F-2354-D714-51BD-23412BCFEDFD

National Economic Research Associates. (1977). *A framework for marginal cost-based time-differentiated pricing in the United States.* Palo Alto, CA: Electric Power Research Institute.

New York Public Service Commission. (2017, March 9). *Order on net energy metering transition, Phase One of value of distributed energy resources, and related matters.* Case No. 15-E-0751. Retrieved from http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={5B69628E-2928-44A9-B83E-65CEA7326428}

Nicholas, M., and Hall, D. (2018). *Lessons learned on early electric vehicle fast-charging deployments.* Washington, DC: The International Council on Clean Transportation. Retrieved from https://www.theicct.org/sites/default/files/publications/ZEV_fast_charging_white_paper_final.pdf

Potter, J., George, S., and Jimenez, L. (2014). *SmartPricing options final evaluation*. Sacramento, CA: Sacramento Municipal Utility District. Retrieved from https://www.smartgrid.gov/files/SMUD-CBS_Final_Evaluation_Submitted_DOE_9_9_2014.pdf

Pyper, J. (2018, August 29). Xcel to replace 2 Colorado coal units with renewables and storage. *Greentech Media.* Retrieved from https://www.greentechmedia.com/articles/read/xcel-retire-coal-renewable-energy-storage

Rissman, J. (2017). *The future of electric vehicles in the U.S.* San Francisco, CA: Energy Innovation. Retrieved from https://energyinnovation.org/wp-content/uploads/2017/10/2017-09-13-Future-of-EVs-Research-Note_FINAL.pdf

Seattle City Light. (n.d.). *City Light rates: Tariffs and rules* [Webpage]. Retrieved from https://www.seattle.gov/light/rates/ratedetails.asp

Shirley, W. (2001). *Distribution system cost methodologies for distributed generation* (Vol. 2, Appendices). Montpelier, VT: Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/distribution-system-cost-methodologies-for-distributed-generation-volume-ii-appendices/

Slusarewicz, J., and Cohan, D. (2018). Assessing solar and wind complementarity in Texas. *Renewables: Wind, Water and Solar (5)7.* Retrieved from https://jrenewables.springeropen.com/articles/10.1186/s40807-018-0054-3

Trabish, H. (2017, November 2). In new trend, utilities propose separate rate classes for solar customers without rate increase. *Utility Dive.* Retrieved from https://www.utilitydive.com/news/in-new-trend-utilities-propose-separate-rate-classes-for-solar-customers-w/508393/

U.S. Department of Energy. (n.d.). *Charging at home* [Webpage]. Retrieved from https://www.energy.gov/eere/electricvehicles/charging-home

U.S. Energy Information Administration. (2019). *Annual energy outlook 2019.* Table 9. Washington, DC: Author. Retrieved from https://www.eia.gov/outlooks/aeo/data/browser/#/?id=9-AEO2019&cases=ref2019&sourcekey=0

Vermont Public Service Board. (2007, June 20). *Investigation into least-cost integrated resource planning for Vermont Electric Power Company's transmission system.* Docket No. 7081. Retrieved from https://epuc.vermont.gov/?q=node/104/16200

Vermont System Planning Committee. (n.d.). *Planning for the future of Vermont's electric power grid* [Webpage]. Retrieved from https://www.vermontspc.com/

Wood Mackenzie Power & Renewables and Solar Energy Industries Association. (2019, March). *U.S. solar market insight.* Retrieved from https://www.seia.org/research-resources/solar-market-insight-report-2018-year-review

Part III:

Embedded Cost of Service Studies

9. Generation in Embedded Cost of Service Studies

This chapter addresses the allocation of generation costs, including investment-related costs, operation and maintenance costs and fuel costs. As noted in Section 6.1, equivalent changes in the allocation of a cost category among classes can be achieved by changing functionalization, classification or the choice of allocation factor.[83] That section discusses the relevant issues at a high level, and this chapter delves more deeply into the underlying concepts and analytical techniques.

This chapter is not generally relevant to cost allocation for utilities that have restructured and no longer procure generation resources, as long as the generation prices suppliers offer (directly to customers or to the utility for default service) are differentiated by rate class. High-level cost allocation issues with respect to generation and default service are discussed in Section 7.2.

As discussed in Chapter 3, utilities acquire and maintain different types of generation resources, with distinct operating capabilities, to meet a range of needs including low-cost energy, reliability, **load following** and environmental compliance. Different classification and allocation methods may be necessary to equitably allocate the costs of different types of generation resources. In more recent years, energy efficiency, expanded demand response, distributed generation and energy storage — all of which can be located where load relief is most valuable — have expanded the utility's options to meet load growth or reduce demands on aging assets without building transmission, distribution or central generation facilities.

Fuel costs, purchased power and dispatch O&M costs, such as the short-run variable cost of pollution controls, are typically classified as energy-related. The other categories of generation costs have generally been classified as being driven by some combination of energy (total energy requirements to serve customers, plus losses) and demand (some measure of loads in the hours that contribute to concerns about the adequacy of generation supply to meet loads). Energy use is sometimes broken into TOU periods, so that different types of costs are spread over the hours in which they are used, as discussed further in Section 9.2 and Chapter 17.

When there are multiple cost-based approaches for estimating a classification or allocation factor, a compromise among the results may be appropriate. For example, various measures of reliability risk (emergency purchases, operation of peakers, interruption of load, inadequate operating reserve) may be distributed differently across the months, and the regulator may reasonably select a generation demand allocator averaging across the results of those measures. Similar conditions might apply for varying estimates of the firm-capacity equivalent for wind plants or other inputs.

Some cost of service studies identify other classifications of generation costs, such as ancillary services. These components are generally very small compared with total generation costs, and some ancillary services (automatic generation control, black start capability, uplift) can be difficult to relate to class load characteristics.

9.1 Identifying and Classifying Energy-Related Generation Costs

Many regulators have recognized that energy needs are a significant driver of generation capital investments and nondispatch O&M costs. In modern utility systems, generation facilities are built both to serve demand (i.e., to meet capacity and reliability requirements) and to produce energy economically. The amount of capacity is largely determined by reliability considerations, but the selection of generation technologies and thus the cost of the capacity are

83 As mentioned previously, the third step is usually called allocation, which is the same as the name of the entire process. Some analysts refer to this third step as factor allocation in an attempt to prevent confusion.

largely determined by energy requirements.[84] For variable renewables, particularly wind and solar, the effective capacity (in terms of the reliability contribution) of the generators is much smaller than their nameplate capacity, and the costs are mostly undertaken to provide energy without fuel costs or air emissions. Energy storage systems provide both energy benefits (by shifting energy from low-cost to high-cost hours) and reliability benefits, while demand response is used primarily to increase reliability.

As discussed in the text box on pages 78-79, some older cost of service studies classified a wide range of capital and nondispatch O&M costs as demand-related on the grounds that the costs were in some manner fixed, without regard for cost causation. This approach, known as **straight fixed/variable**, is anachronistic and does not reflect cost causation.[85]

Table 12 shows the capital and O&M costs estimated for new conventional generation units from the 2018 Lazard's *Levelized Cost of Energy Analysis* report.[86] Although the original costs and current plant in service and O&M costs of older units will vary, the general relationships have been consistent.

This section first discusses the insights on this issue from competitive wholesale markets. This is followed by four different classification approaches and two joint classification and allocation approaches, then a discussion of other technologies and issues.

Table 12. Cost components of conventional generation, 2018 midpoint estimates

Technology	Capital cost (per kW)	Fixed operations and maintenance (per kW-year)	Variable operations and maintenance (per MWh)
Combustion turbine	$825	$12.50	$7.40
Combined cycle	$1,000	$5.75	$2.80
Coal	$3,000	$40.00	$2.00
Nuclear	$9,375	$125.00	$0.80

Source: Lazard. (2018). *Lazard's Levelized Cost of Energy Analysis — Version 12.0*

9.1.1 Insights and Approaches From Competitive Wholesale Markets

The ISOs/RTOs that operate energy (and in some cases, capacity) markets — specifically ISO-NE, NYISO, PJM, ERCOT, MISO and the SPP — provide examples of how the recovery of capital investment and nondispatch O&M costs naturally splits between energy and demand. The pricing in these markets can provide both a **competitive proxy** for classifying generation costs and a benchmark to check the reasonableness of other techniques.

ERCOT has no capacity market, and all costs are recovered through time-varying energy charges. Those energy charges are heavily weighted toward a small number of hours, which do not tend to have particularly high loads; the highest-load hours are not the highest-cost hours. Figure 30 on the next page shows the hourly load and Houston Hub prices for 2017 (Electric Reliability Council of Texas, 2018, for load data; ENGIE Resources, n.d., for pricing data).

Prices generally trend upward with load, but the highest-priced hours are spread nearly evenly across load levels.

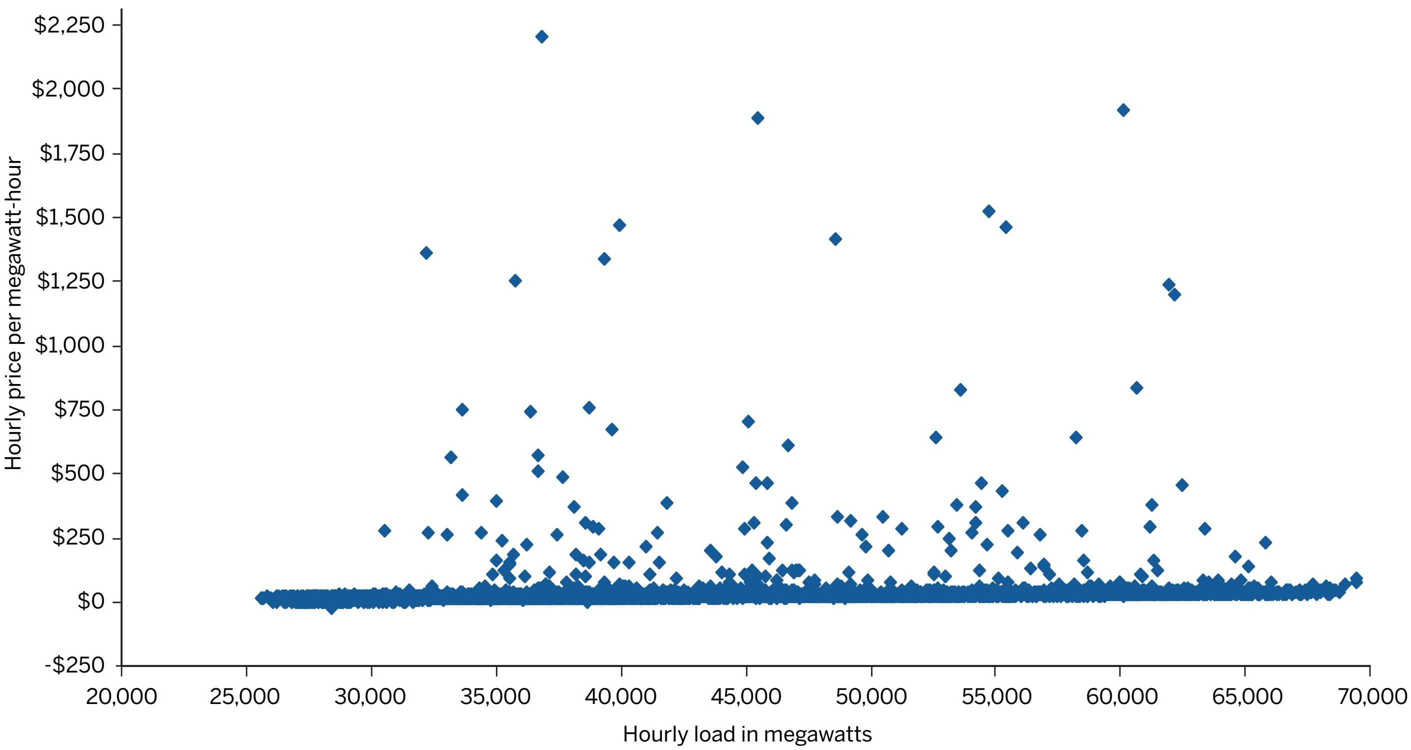
In 2017, the highest-priced 1% of hours (with prices over $160 per MWh) would have provided 18% of the annual net margin for a baseload plant with no variable cost, 53% of the margin for a plant with a variable cost of $20 per MWh (perhaps a combined cycle unit), and 77% of the margin for a plant with a $30-per-MWh variable cost (such as a recently built combustion turbine), assuming ideal dispatch and no

84 "Citing both past operating experience and future resource planning, the Division [the PSC intervention staff] notes that resources with higher energy availability are chosen over those with lower energy availability. Since energy plays a role in the selection of least-cost resources, the Division concludes that some weight needs to be given to energy in planning for new capacity, and the current weight of 25 percent is reasonable. We find the qualitative argument offered by the Division to be … convincing." (Utah Public Service Commission, 1999, p. 82). See also Washington Utilities and Transportation Commission (1993, pp. 8-9).

85 The term "straight fixed/variable" is imported from FERC's rate design method for wholesale gas supply, where utilities, marketers and very large customers contract for capacity in a portfolio of individual pipeline and storage facilities. As is true for many electric wholesale purchased power contracts, these gas contracts require that the buyers pay for investment-related costs regardless of how they use the resources and pay for variable costs in proportion to their usage. This approach is workable at the wholesale level but is not applicable to retail cost allocation, where the utility bundles a portfolio of generation assets for all of its customers.

86 The coal cost in the table is Lazard's low end, since the high-end cost "incorporates 90% carbon capture and compression" (Lazard, 2018, p. 2), which is in use on only one existing utility coal unit, SaskPower's Boundary Dam. The $3,000/kW value is also consistent with the costs of the last three coal plants completed by U.S. regulated utilities (Turk, Virginia City and Rogers/Cliffside 6, all completed in 2012). Actual current costs of various vintages of resources will vary for each utility.

Figure 30. ERCOT load and real-time prices in 2017



Sources: Electric Reliability Council of Texas. (2018). *2017 ERCOT Hourly Load Data*; ENGIE Resources. *Historical Data Reports*

outages. Those 88 hours representing the costliest 1% occurred in every month and almost the whole range of annual loads.

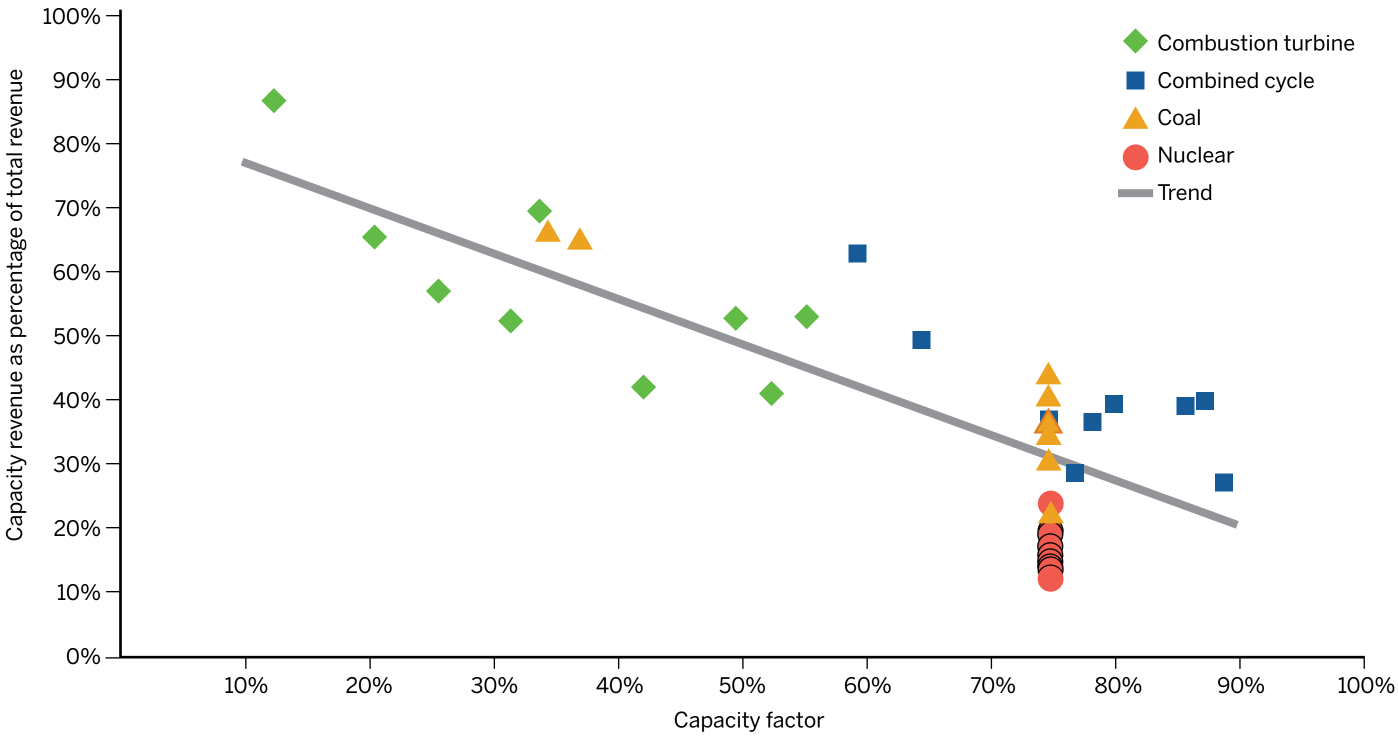
In contrast, the 1% of highest-load hours would have provided 5.1% of the margin for the baseload plant, 2.4% for the intermediate plant and 2% for the combustion turbine. This cost pattern suggests that, at least in some systems, generation costs should be time-differentiated but that load is not a good proxy for the highest-price periods. Classes with the ability to shape load to low-cost periods (with demand response or storage) may be much less expensive to serve than those with inflexible load patterns.

Regardless of how the top hours are chosen, the ERCOT data indicate that most of the long-term power supply costs are not recovered from the few peak hours and thus should not be considered demand-related. For a load shaped like the ERCOT average load, only about 3% of the generation costs were associated with the 1% of highest-load hours, and about 20% were associated with the 1% of highest-price hours.

In New England, the ISO-NE external market monitor estimated that the net revenues available to pay the capital investment and nondispatch O&M costs of a typical recently built gas combined cycle unit would have been about 25% to 60% from the energy market and the remainder from the capacity market, depending on the year (Patton, LeeVanSchaick and Chen, 2017, p. 13). The comparable values for nuclear units were almost all from the energy market (Patton et al., 2017, p. 17).

The PJM independent market monitor reports the capacity revenues and the net energy revenues (i.e., energy revenue in excess of fuel and variable O&M) for a variety of plant types (Monitoring Analytics, 2014, pp. 219-222, 2019, pp. 335-339). These are the revenues available to pay for the capital investment and nondispatch O&M costs and thus represent the market allocation of these costs for the plants. Figure 31 on the next page shows the portion of these costs recovered through capacity payments for four types of new plants (gas-fired combustion turbine and combined cycle units, and hypothetical new coal and nuclear) in each year

Figure 31. Capacity revenue percentage in relation to capacity factor in PJM



Data sources: Monitoring Analytics. (2014 and 2019). *2013 State of the Market Report for PJM, 2018 State of the Market Report for PJM*

2009 through 2017 (Monitoring Analytics, 2014, 2019).[87]

The concept displayed here is that units with a high **capacity factor** tend to make more of their revenue from energy markets instead of from the capacity market. In this set of PJM data, energy revenues cover 14% to 60% of the combustion turbine costs, 38% to 74% of combined cycle costs, 56% to 73% of baseload coal plant costs, about 34% of the costs of economically dispatched coal units, and 77% to 89% of nuclear costs over the nine-year period. The values for 2017 were 39% for modern combustion turbines, 87% for combined cycle units, 65% for coal and 20% for nuclear. Current values for PJM or the relevant load zones could be used as the demand classification percentages for vertically integrated utilities in PJM (e.g., IOUs in Kentucky, Virginia and West Virginia, and municipal and cooperative utilities in several states).

The market monitoring unit of the NYISO provided similar analyses for the various pricing zones of that RTO, as shown in Table 13 (Patton, LeeVanSchaick, Chen and Palavadi Naga, 2018, Table A-14, with additional calculations by the authors). The upstate zones have relatively low capacity prices, while the Hudson Valley and New York City have very high capacity prices, and Long Island has intermediate prices. Both capacity and energy revenues vary among zones within each of these three areas, between load pockets within zones and among combustion turbine types.

Table 13. Energy portion of 2017 net revenue for New York ISO

	Generator type		
Zone	Combustion turbines	Combined cycle	Steam
Upstate	72% to 80%	71% to 79%	42% to 55%
Long Island	52% to 70%	62% to 76%	21% to 57%
Hudson Valley and New York City	31% to 49%	34% to 55%	6% to 29%

Sources: Patton, D., LeeVanSchaick, P., Chen, J., and Palavadi Naga, R. (2018). *2017 State of the Market Report for the New York ISO Markets;* additional calculations by the authors

87 The independent market monitor assumed that a nuclear plant would operate at a 75% capacity factor and made the same assumption for the coal plant through 2015; the capacity factors for the gas-fired plants and for coal in 2016 and 2017 are determined from the economic operation of the units.

9.1.2 Classification Approaches

Many utilities and regulators acknowledge that a large portion of generation investment and nondispatch O&M costs is incurred to serve energy requirements. There are two categories of methods to classifying these costs as energy-related and demand-related. First, average-and-peak is a top-down approach that uses high-level data on system loads and costs. Second, there is a range of bottom-up approaches that examine the drivers for costs on a plant-specific basis:

- Base-peak and related methods.
- Equivalent peaker method.
- **Operational characteristics methods**.

As a general matter, the bottom-up approaches are preferable for classifying generation costs. The average-and-peak approach is well suited for shared distribution system costs, as discussed in Section 11.2.

Average-and-Peak Method

The average-and-peak approach can be applied in classification, when classifying a portion of costs as energy-related and the remainder as demand-related, or in developing a generation capacity allocator that reflects both energy and demand. When using this approach as a classification method, the **system load factor** percentage is classified as energy-related and the remainder as demand-related.[88] When used as an allocation factor, the average-and-peak factor for each class is:[89]

$$\frac{A_C}{A_S} \times SLF + \frac{P_C}{P_S} \times [1\text{-}SLF]$$

Where A = annual average load = energy ÷ 8,760

P = peak load

C = class

S = system

SLF = system load factor = (annual energy) ÷ (peak load × 8,760)

The system load factor, and hence the average-and-peak approach more generally, varies over time independent of the mix of the utility's generation resources and does not respond to changes in that mix unless those changes are accompanied by retail pricing that follows the cost structure.

In addition to changing as loads change, the average-and-peak approach ignores the mix of resources and costs. This approach would produce the same classification of plant for a system that was entirely composed of gas-fired combustion turbines (with low capital costs and high fuel costs) or of coal-fired plants (with high capital costs to produce lower fuel costs).

Thus, while the average-and-peak method for generation costs may sometimes fall in the range of reasonable results, it is neither logical nor consistent.

Base-Peak Methods

Various utilities and other analysts have proposed to subfunctionalize generation resources (in the simplest case, between baseload and peaking plants) and classify each category of generation in a different manner. For example, peakers may be classified 100% as demand-related, while baseload resources are classified 75% to demand and 25% to energy, or some other location- and situation-specific ratio.

More advanced analyses have subfunctionalized generation among base, intermediate and peak categories, known as BIP classification. The base generation might be defined as all nuclear and coal plants, with the intermediate being gas-fired steam and combined cycle plants and the peak units being combustion turbines, storage and demand response. Alternatively, base plants might be any unit that operated at more than a certain capacity factor (for example, 60%), peakers those that ran at less than 5%, and intermediate anything between those 5% and 60% capacity factors. Or, rather than using capacity factor (which can be low due to forced outages, maintenance or economic dispatch), the

88 This method is sometimes called the system load factor approach. It has also been called "average and excess" because a fraction of cost equal to the system load factor is allocated on energy and the excess of costs on a measure of peak loads (Coyle, 1982, pp. 51-52).

89 This average-and-peak allocator should not be confused with the average-and-excess demand allocator described in the 1992 NARUC *Electric Utility Cost Allocation Manual,* which allocates a portion of costs in proportion to average load and the excess in proportion to each class's excess of peak load over its average use. That legacy average-and-excess allocator is essentially just a peak allocator (Meyer, 1981).

generation classes can be defined using operating factor (the ratio of output to equivalent availability). At an extreme, each generation type, or even each unit, can be classified separately.

While the base-peak classification approach and related methods are highly flexible, that is both their greatest strength and a great weakness. The strength is that the method can be modified to accommodate the diversity of generation resources; the weakness is that the method requires a set of decisions about the definition of the generation classes and the classification percentage for each class. The base-peak method is connected to actual utility planning only at the highest conceptual level and provides limited guidance for the nitty-gritty details of traditional classification.

One of the challenges of the base-peak approach relates to the changing usage of generation resources. For example, several units that were built to burn coal in baseload operation have been converted to burn natural gas and thus run mostly on high-load summer days.[90] These units operate as peak or intermediate resources (depending on the definitions used in the particular analysis), but most of the capital costs are attributable to the original baseload design. This problem may be ameliorated by removing those additional costs from the base-peak or BIP computation and directly classifying them as energy-related.

Recent technological changes pose additional challenges and opportunities for expanding the base-peak approach from two generation profiles, or the three profiles of the BIP method, to a full analysis of the use of generation resources. Decades ago, it was reasonably accurate to treat generation resources as being stacked neatly under the load duration curve in order of variable costs. The growing role of variable output renewable resources, additional storage and economic demand response reduces the accuracy of those simple models. Resources like wind and solar do not fit neatly into the BIP categories, providing service in distinct time patterns that may not be related to system loads. At the same time, many utilities have access to much more granular detail on hourly consumption by customer.[91] The BIP method can be expanded to reflect conditions (output by several classes of conventional generation, solar, wind and storage; energy use for storage; usage by class) in as many time periods (or load levels, or bins combining consumption and generation conditions) as desired, even down to an hourly allocation method. Usage and hence costs could thus be assigned directly to the classes using power at the times that each resource provides service.[92]

Equivalent Peaker Method

The equivalent peaker method,[93] discussed at length in the 1992 NARUC *Electric Utility Cost Allocation Manual,* attributes as demand-related the portion of investment in each resource that would have been incurred to secure a peaking resource, such as demand response or a combustion turbine.[94] Peaking resources are usually treated as 100% demand-related, while intermediate and baseload plants are classified as partly energy and partly demand.

If only peak load had been higher (and other needs were already satisfied) in the years in which the utility made the bulk of its generation construction decisions, it would have likely met that increased load by adding peaker capacity.[95] Utilities historically have justified building baseload capacity by relying on these plants' long hours of use and lower fuel

90 Some coal plants that once ran as baseload resources have been taken out of service in low-load months to reduce O&M costs. This includes Nova Scotia Power's Lingan 1 and 2 (Barrett, 2012), Luminant's Monticello and Martin Lake (Henry, 2012) and the Texas Municipal Power Agency's Gibbons Creek (Institute for Energy Economics and Financial Analysis, 2019).

91 Most utilities have long known the hourly generation by unit.

92 Some utilities refer to their classification method as BIP, even though it does not reflect the differences in costs among the various types of generation. For example, the Louisville Gas & Electric and Kentucky Utilities 2018 "BIP" computation classified nondispatch generation costs this way: 34% (the ratio of minimum to peak load) to energy; 36% (the 90% ratio of winter peak to summer peak, minus the 34% energy allocation, or 56%, times the 65% of the peak-period hours that occur in winter) to the winter peak demand; and the remaining 30% to the summer peak demand (Seelye, 2016, Exhibit WSS-11). This approach has no cost basis.

93 In some jurisdictions, this is called the peak credit method.

94 This approach is sketched out in Johnson (1980, pp. 33-35) and described in more detail in Chernick and Meyer (1982, pp. 47-65).

95 To some extent, the peakier load would likely allow for development of more demand response and load management. Estimating the potential and costs for these resources under hypothetical load shapes may be difficult.

costs.[96] This incremental capital cost (often called capitalized energy or "steel for fuel") is attributable to energy requirements, not demand. The investment-related costs of baseload resources above and beyond the cost of peaking units are incurred to serve energy load, not demand. Treating these costs as demand-related overstates the cost of meeting demand and understates the costs incurred to meet energy requirements. This phenomenon has been understood since the 1970s and 1980s:

> [T]he extra costs of a coal plant beyond the cost necessary to build a combustion turbine should all be allocated [on] energy. The rationale for this allocation is that the marginal cost of capacity in the long run is just the lowest-cost technology required to meet peak load, which is typically a combustion turbine. Choosing to invest beyond this level [of combustion turbine capital cost] is justified not on capacity grounds, but on energy grounds. That is, the extra capital cost of a coal plant allows the utility to use a low-cost fuel and avoid higher-cost fuels (Kahn, 1988).

However, there are several additional issues with this concept in the modern electric system. First, the method does not adapt well to wind and solar, where the capital investment is primarily justified by avoiding fuel costs but the installed capital cost per nameplate MW may be little different from the cost of a peaker. An intermediate or baseload plant that is not much more expensive than a contemporaneous peaking resource would be classified as mostly demand-related, while very expensive plants are classified as mostly energy-related. And often, peaker units are used to provide energy when baseload units are not operating or to provide power for off-system sales.[97]

Under the equivalent peaker method, the demand- or reliability-related portion of the cost of each generation unit is estimated as the cost per kW of a peaker (usually a simple-cycle combustion turbine) installed in the same period, times the effective capacity of that unit, adjusted for the equivalent availability of a peaker.[98] The cost of the unit in excess of the equivalent gas turbine capacity is energy-related.

However, the simple version of this calculation typically will overstate the reliability-related portion of plant cost because it assumes a steam plant supports as much firm demand as would the same capacity of (smaller) combustion turbines. Due to higher forced outage rates, lengthy maintenance shutdowns and the size of units, a kilowatt of steam plant capacity typically supports less firm load than a kilowatt of capacity from a small peaker. A system with a peak load of about 6,500 MWs and a 65% load factor could achieve the same level of reliability with 80 units of 100 MWs (8,000 MWs, or a 23% reserve) or 19 units of 600 MWs (11,400 MWs, or a 75% reserve), assuming the units all have a 6% **equivalent forced outage rate** and that the load shape can accommodate all required maintenance off-peak. Increasing the equivalent forced outage rate to 10% would increase the required reserve for the 100-MW units to about 40% and for the 600-MW units to 90%. Even with the 6% equivalent forced outage rate, if the load factor were 96%, the reserve requirement would rise to 30% with 100-MW units and 90% with 600-MW units.

Figure 32 on the next page shows the gross plant per kW for combustion turbines as of 2011, from FERC Form 1 data (Federal Energy Regulatory Commission, n.d.). These values include the original cost of the units, plus capital additions since the plants entered service, minus the cost of any equipment retired. This tabulation includes all non-CHP simple-cycle combustion turbines for which cost data were available.[99] Some of the later combustion turbines in this sample may not be pure peakers, since manufacturers

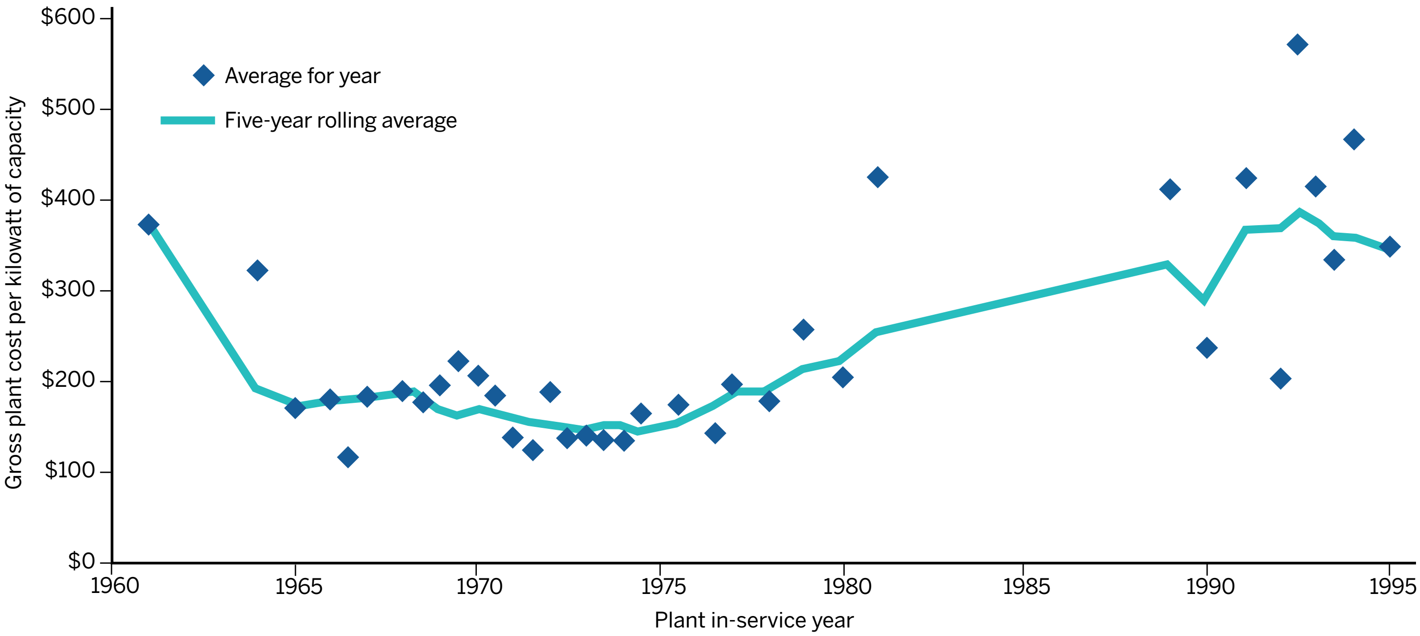
96 Similar reasoning applies to the decision to add renewable resources, substituting investment for fuel costs. See footnote 120.

97 During the 2000-2001 California energy crisis, oil-fired peakers in the Pacific Northwest operated at high monthly capacity factors because they were exempt from both gas supply constraints and California emissions regulations. U.S. Energy Information Administration Form 906 for 2000 and 2001 demonstrates the incremental oil burn in 2000 and 2001, particularly for Puget Sound Energy.

98 In the future, the reference peaking capacity might be an increase in demand response cost or storage peak output capacity, without an increase in energy generating capability. The reference peaker should always be the least-cost option for providing reliability.

99 Municipal and cooperative utilities and non-utility generators (both those under contract with utilities and those operating in the merchant markets) do not file FERC Form 1 reports, so their units are not included in this analysis. The municipal and cooperative utilities typically retain financial and operating records that are compatible with the FERC system of accounts, allowing comparison of the data for a specific utility's nonpeaking resources with national data on contemporaneous peaker costs.

Figure 32. Cost of combustion turbine plant in service in 2011



Data source: Federal Energy Regulatory Commission Form 1 database

developed more expensive and more efficient designs, including steam injection.

For comparison, coal plants built in this period generally cost from several hundred dollars per kW to more than $2,000 per kW; the latest vintage coal plants cost as much as $3,000 per kW. Steam plants fired by gas and oil (and not converted from coal) tend to have a wide range of gross plant costs, from the prices of contemporaneous combustion turbines to perhaps twice those costs. Nuclear plants generally have gross plant costs well above $1,000 per kW, up to $8,000 per kW. Combined cycle plants have usually been 20% to 50% more expensive than contemporaneous combustion turbines.[100]

The capital costs of various types of generating capacity can be compared with the costs of peakers in several ways, including the following:

- Comparing recent or current gross plant costs for other generators with the corresponding cost of peakers, as discussed above.
- Comparing recent or current net plant (gross plant minus accumulated depreciation) costs for nonpeaking generators with the corresponding net plant costs of contemporaneous peakers. This comparison is theoretically the most appropriate basis for classifying generation rate base, which is based on net plant. Unfortunately, net plant is not generally publicly reported by plant or unit, so most cost analysts will have a difficult time implementing this approach. In addition, many utilities have depreciated peakers at a faster rate than steam plants, resulting in lower net plant for a peaker than for a steam plant with the same initial cost, additions and retirements. This results in a higher percentage of the steam plant costs being classified as energy-related based on net plant than gross plant. It is not obvious whether the additional classification to energy is more equitable than the result of the gross plant allocation.
- Comparing the cost of building the actual mix of generation today with the cost of building a peaking-only system today.[101] This approach avoids the problem of

100 These cost ratios are provided to explain the importance of identifying the demand-related portion of generation investment. Any application of the equivalent peaker method should compare the costs of the utility's existing plants to the costs of contemporaneous peakers, using the most comparable estimates of the costs of peakers, reflecting geographical and other differences.

101 The peaking-only system might include combustion turbines, demand response and storage resources.

estimating the cost of building peakers at various times in the past. But many existing plants could not be built today as they currently exist — a new coal plant may require scrubbers, nitrogen oxide reduction, closed-system cooling and other features that the existing coal plant does not have.[102] Other plant types, such as oil- and gas-fired boiler units, no longer make economic sense and would not be built today. Determining the cost of building a new 1970s-style coal plant or a gas-fired steam plant may be much more difficult than determining the cost of peakers in the 1970s. And for some technologies, the costs of new construction do not meaningfully reflect the costs of the plants currently embedded in rates. For example, as expensive as the nuclear units of the 1980s were, the nuclear units currently under construction are much more expensive. Conversely, the costs of wind turbines have fallen dramatically since the 1980s. Comparing today's costs for those resources to the costs of new peakers would probably overstate the energy-related portion of the costs of an old nuclear unit and understate the energy-related portion of the costs of an old wind farm.

Whether the comparison uses gross plant in service, net plant in service or hypothetical new construction, the data sources should be as consistent as possible. It would not be appropriate to compare the current book value of an actual plant with the cost of a hypothetical plant in today's dollars (Nova Scotia Utility and Review Board, 1995, p. 18).

Table 14 shows the equivalent peaker method analysis that Northern States Power Co.-Minnesota (a subsidiary of Xcel Energy) used in its 2013 rate case filing (Peppin, 2013, Schedule 2, p. 4).[103] The capacity portion for each plant type is the ratio of the peaking cost ($770 per kW) to the plant type cost. For example, the peaking cost is 20.9% of the cost of the nuclear plant, so 20.9% of the nuclear investment is treated as capacity-related. The company uses its estimates of the replacement costs of each type of generation and applies the results to each capital cost component (gross plant, accumulated depreciation, deferred taxes, etc.).

Table 14. Equivalent peaker method analysis using replacement cost estimates

Resource type	Cost per kW	Capacity-related share of cost	Energy-related share of cost
Peaking	$770	100%	0%
Nuclear	$3,689	20.9%	79.1%
Fossil*	$1,976	39.0%	61.0%
Combined cycle	$1,020	75.4%	24.6%
Hydro	$4,519	17.0%	83.0%

*The "fossil" resource type appears to be coal- or gas-fired steam.

Source: Peppin, M. (2013, November 4). Direct testimony on behalf of Northern States Power Co.-Minnesota. Minnesota Public Utilities Commission Docket No. E002/GR-13-868

This is not a very realistic comparison, for reasons discussed above. Many of the plants could not be built today, and some have complicated histories of retrofits and repowering. The nuclear replacement cost appears to be particularly optimistic compared with the cost of nuclear power plants under construction today.

Table 15 on the next page shows an alternative analysis based on the Xcel Energy Minnesota subsidiary's actual investments in each plant type at the end of 2017, from Page 402 of its FERC Form 1 report (Federal Energy Regulatory Commission, n.d.).

The results of the two analyses are generally consistent, except for the classification of the combined cycle resources. These plants are of more recent vintage than the others; a fairer comparison, using peaker costs contemporaneous with the in-service dates of each of the other resources, probably would result in a lower energy classification of the combined cycle resources and higher energy classification for the coal and nuclear units.

The equivalent peaker method does have limitations. Perhaps most importantly, it requires cost comparisons of individual generation units with peakers of the same vintage. Utilities installed combustion turbines as far back as the early 1950s, but the technology was widely installed only in the late 1960s. The oldest remaining combustion turbine owned

102 Many hydroelectric projects could not be licensed if they were proposed today.

103 The company calls this a plant stratification analysis.

Table 15. Equivalent peaker method analysis using 2017 gross plant in service

Resource type	Capacity (MWs)	Plant in service: Cost	Plant in service: Cost per kW	Excess over combustion turbine: Cost	Excess over combustion turbine: Cost per kW	Energy-related share of cost
Combustion turbine	1,114	$291,000,000	$261	N/A	N/A	0%
Nuclear	1,657	$3,448,000,000	$2,081	$3,016,000,000	$1,820	87%
Coal	2,390	$2,156,000,000	$902	$1,532,000,000	$641	71%
Combined cycle	1,266	$939,000,000	$742	$609,000,000	$481	65%
All resources	6,427	$6,834,000,000	$1,063	$5,157,000,000	$802	75%

Data source: Federal Energy Regulatory Commission Form 1 database records for Northern States Power Co.-Minnesota

by a utility filing cost data (Madison Gas and Electric's Nine Springs) entered service in 1964. The paucity of earlier data complicates the use of the equivalent peaker method for classifying the costs of older plants. This problem is gradually fading away, as all pre-1970 nuclear is gone and much of the pre-1970 fossil-fueled steam capacity has been retired or is nearing retirement, but the issue remains for classifying hydro plant costs and the few remaining old fossil fuel plants (U.S. Energy Information Administration, 1992).

One solution to the problem of classifying the investment in very old, little-used steam plants is to treat that cost as entirely demand-related. Since these units often represent a very small portion of generation rate base, this solution may be reasonable.

A full equivalent peaker analysis would compare the product of the actual depreciation charges for the nonpeaking plants with the product of the peaker depreciation rate and the peaker-equivalent gross investment for the same reliability contribution. Since the classification of rate base usually ignores the higher accumulated depreciation of peakers compared with the accumulated depreciation for other generation resources of the same vintage (which tends to overstate the demand-related portion of generation rate base), it is also generally symmetrical to classify generation depreciation expense as proportional to the demand-related portion of gross plant (which will tend to understate the demand-related portion). If classification of one of these cost components is refined to reflect the difference in depreciation rates, the other cost component should be similarly adjusted.

As is true for plant in service, the nonfuel O&M costs of steam plants are generally much higher than the nonfuel O&M costs of combustion turbines. Typical O&M costs per kW-year are $1 to $10 for combustion turbines, $10 to $15 for combined cycle plants, $10 to $20 for oil- and gas-fired steam plants, $40 to $80 for coal plants and more than $100 for nuclear plants. Table 16 shows how the capacity-related O&M for conventional generation might be classified between energy and demand, using the utility's actual nonfuel O&M

Table 16. Equivalent peaker method classification of nonfuel operations and maintenance costs

Resource type	Capacity (MWs)	Nonfuel operations and maintenance: Cost	Nonfuel operations and maintenance: Cost per kW-year	Excess over combustion turbine: Cost	Excess over combustion turbine: Cost per kW-year	Energy-related share of cost
Combustion turbine	1,114	$4,170,000	$3.74	N/A	N/A	0%
Nuclear	1,657	$215,880,000	$130.28	$209,680,000	$126.54	97%
Coal	2,390	$33,490,000	$14.01	$24,550,000	$10.27	73%
Combined cycle	1,266	$16,380,000	$12.94	$11,650,000	$9.20	71%

Data source: Federal Energy Regulatory Commission Form 1 database records for Northern States Power Co.-Minnesota costs; the data are 2017 numbers from FERC Form 1, Page 402, for Northern States Power Co.-Minnesota (Federal Energy Regulatory Commission, n.d.).

Table 16 does not include the company's wind resources, which average about $30 per kW-year in O&M, since MISO credits wind with unforced capacity value at only about 15% of rated capacity, or about 17% of the value of an installed MW of typical conventional generation. The demand-related portion of the wind capacity is thus less than $1 per kW-year, and the wind O&M is almost all energy-related.[104]

Operational Characteristics Methods

The operational characteristics methods classify generation resources (units, resource types, purchases) based on their capacity factors or operating factors. Newfoundland Hydro classifies as energy-related a portion of the cost of each oil-fueled steam plant equal to the plant's capacity factor (Parmesano, Rankin, Nieto and Irastorza, 2004, p. 22). At first blush, this approach appears to roughly follow the use of the resource, with plants that are used rarely being treated as primarily demand-related and those used in most hours classified as predominantly energy-related. Unfortunately, the use of capacity factor effectively classifies more of the cost to demand as the reliability of the resource declines.

A better approach would be to use the resource's operating factor, which is the ratio of its output to its equivalent availability (that is, its potential output, if it were used whenever available). This approach would classify any resource that is dispatched whenever it is available (e.g., nuclear, wind and solar) as essentially 100% energy-related. That may be seen as an overstatement, since those resources generally provide some demand-related benefits and are sometimes built to increase generation reliability, as well as to produce energy with little or no fuel cost.

9.1.3 Joint Classification and Allocation Methods

Although most cost of service studies classify capital investments and capacity-related O&M as either demand-related or energy-related, classify power and short-term variable costs as energy-related, and then allocate energy-related and demand-related costs in separate steps, two approaches accomplish both at once. These are the probability-of-dispatch (POD) and **decomposition** approaches.

Probability of Dispatch

The POD approach is the better of the two.[105] Methods using this approach are generically referred to as probability of dispatch, even for versions that do not explicitly incorporate probability computations.[106] A simplified illustrative example of power plant dispatch is shown in Figure 33 on the next page, under the utility load duration curve. The example uses only four types of generation: nuclear, coal, gas combined cycle and a peaking resource consisting of a mix of demand response, storage and combustion turbines. An actual POD analysis might break the generation data down to the plant or even unit level and may need to include load management and demand response as resources. This simplified example also does not illustrate maintenance, forced outages or ramping constraints.

Off-system sales and purchases can be added or subtracted from the load duration curve when they occur, or they can be subtracted or added to the generation available in each hour or period. Similar adjustments may be needed to reflect the charging of storage and operation of behind-the-meter generation.

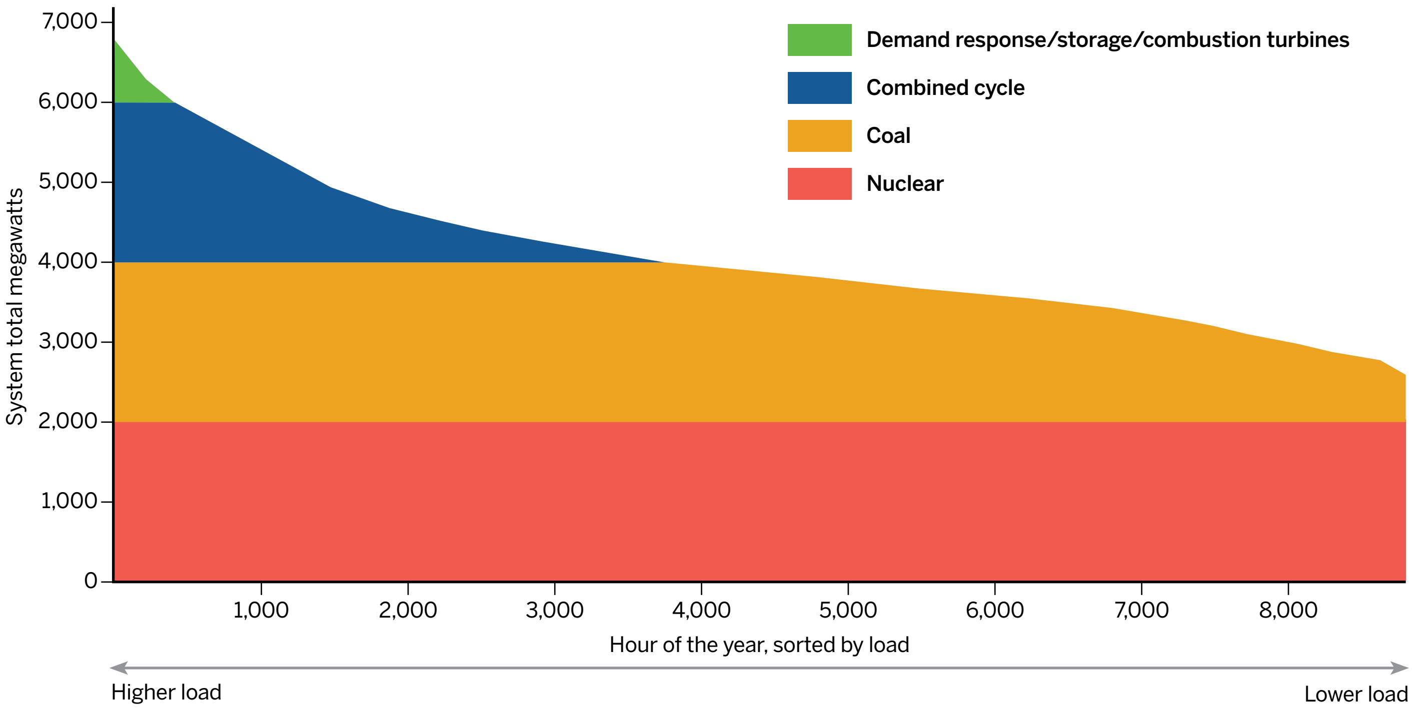
Figure 34 shows the composition of demand in each hour for the same illustrative system, divided among three customer classes. In this example, the residential class peak load occurs when load is high but not near the system peak.

104 The nonfuel O&M costs per kW for Northern States Power's two small waste-burning plants and its small run-of-river hydro plant are even higher than the nuclear O&M and hence are effectively entirely energy-related, even if the hydro plant provides firm capacity.

105 The Massachusetts Department of Public Utilities explained its preference for this method as follows: "The modified peaker POD results in a fair allocation of embedded capacity costs because this method recognizes the factors that cause the utility to incur power plant capital costs and because this method allocates to the beneficiaries of fuel savings the capitalized energy costs that produce those savings" (1989, p. 113).

106 For an example of the POD method, see La Capra (1992).

Figure 33. Simplified generation dispatch duration illustrative example



This situation might arise for a winter-peaking residential class in a summer-peaking system, or an evening-peaking residential class in a midday-peaking system.

Note that the three customer classes need not peak at the same time. On a high-load summer day, the primary industrial class might peak in the morning, the secondary commercial class at 1 p.m., and the residential class in the evening. Large commercial buildings typically experience their peak load in the summer, since large buildings require cooling in most climates. If a large percentage of home

Figure 34. Illustrative customer class load in each hour

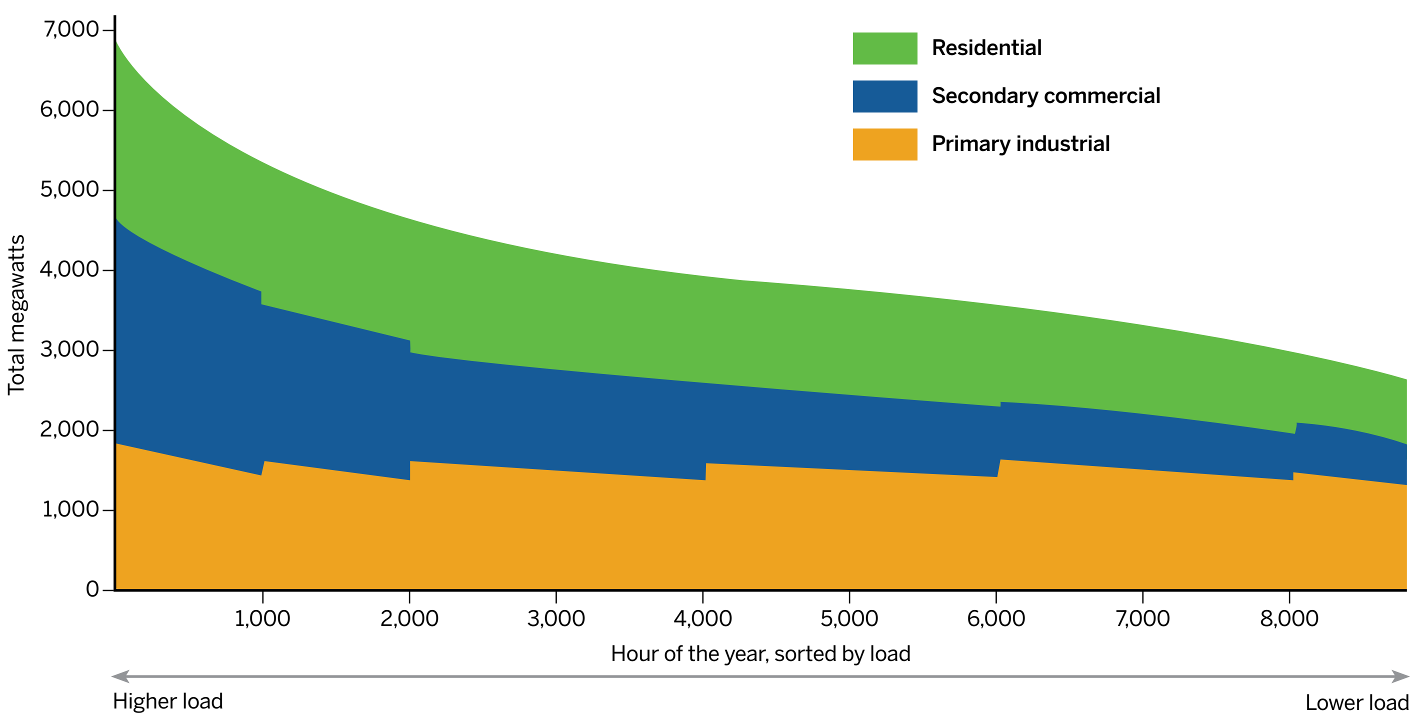


Table 17. Class share of each generation type under probability-of-dispatch allocation

Customer class	Generation source: Nuclear	Coal	Combined cycle	Peaking resources
Residential	34%	34%	32%	31%
Secondary commercial	28%	29%	39%	42%
Primary industrial	38%	37%	29%	27%

heating is electric, the residential class is likely to experience its highest load in the winter, even in places like Florida. The industrial class loads may peak in a variety of seasons, driven by vacation and maintenance schedules, variation in inputs (e.g., agricultural products) and demand, and other factors. The system peak may occur at a time different from all of the customer class NCP demands.

Table 17 shows how the costs of each generation resource would be allocated to the classes in the illustrative example in Figure 34. In the lowest-load hours, when nuclear is serving 80% of the energy load, the industrial class uses half the system energy and hence half the nuclear output; in the highest-load hours, when nuclear is serving about 29% of the load, the industrial class uses about 27% of the system energy. Averaged over the year, the industrial class uses 38% of the nuclear output. In the hours that the combustion turbines are running, the industrial class uses only 27% of the peaking resources' output, since the residential and commercial classes dominate loads in that period.

The commercial class is responsible for the largest share of the summer peak and hence of the combustion turbine costs but the smallest part of the low-load hours and hence the lowest share of the nuclear and coal costs. Every class pays for a share of each type of generation.[107]

The POD method has been applied with a wide range of detail. The generation "dispatch" over the year may represent historical or forecast operation, equivalent availability or capacity factor, seasonal variation (due to maintenance outages, hydro output, natural gas price, off-system purchases and sales), actual hourly output (reflecting planned and random outages and unit ramping constraints) and other variants. The POD method is thus one approach to hourly allocation. Ideally, dispatch and class loads should use the available data to match costs with usage as realistically as possible.

The POD approach has some limitations. Most importantly, it does not consider the reason that investments were incurred, only the way they are currently used. The costs of an expensive coal plant no longer needed for baseload service and converted to burn natural gas and operating at a 10% capacity factor to meet peak loads might be allocated in exactly the same way as the costs of a much less expensive combustion turbine operating at 10% capacity factor.[108] The excess costs of the converted coal plant are due to its historical role of providing large amounts of energy at then-attractive fuel costs; those costs were not incurred for the 10% of hours with highest demand. The same considerations arise for other steam plants that operate at much lower capacity factors than they were planned for and justified by. Some hydro plants have also changed operating patterns from their original use, either running for more hours to maintain downstream flow or for fewer hours due to reduced water supply. Peaking capacity is used to provide a range of ancillary services at many load levels, including upward ramping services (when load surges during the day or wind and solar output falls) and operating reserves (especially to back up large generation and transmission facilities). Reflecting these considerations may require modification of the inputs to the POD analysis, which considers only current use, not historical causation.

Second, the POD method spreads the cost of each resource equally to all hours or energy output, assigning the same cost of a totally baseload plant (with a 100% capacity factor) to the lowest-load off-peak hour as to the system peak hour. That approach comports with some concepts of equity and cost responsibility: The cost of each resource is allocated

107 If this example had included a street lighting class, that class might not have been allocated any combustion turbine costs if the lights would not be on in the summer peak hours. In a more realistic example, including outages of the baseload plants, the combustion turbines probably would operate in some hours with street lighting loads and the lighting class would be allocated some combustion turbine costs.

108 In the simpler forms of POD, the costs of both plants would be spread over the top 10% of hours. In more sophisticated approaches that map generation to actual operating hours, the steam plant would generate in many hours with load lower than the top 10%, while missing some of the top 10%, due to limits on load following.

proportionately to the classes that use it. On the other hand, it can be argued that the hours with higher marginal energy costs contribute more of the rationale for investing in that resource and that, in a sense, each kWh of usage at high-load times should bear more of the resource's investment-related costs than should each kWh in the off-peak hours. This concern can be addressed by weighting the energy over the hours, such as in proportion to some measure of hourly market price.

Third, it is important that the load and dispatch data be representative of the cost causation or resource usage in the years for which the cost allocation will be in place. For example, a baseload plant may have operated at only 40% capacity factor in the most recent year because of major maintenance or availability of economic energy imports. Or load and dispatch in the last 12 months of data may be atypical because of an extremely cold winter and mild summer. The POD allocation should be based on weather-normalized dispatch and load, just as the rate case costs allowed by the regulator and included in the cost of service study should reflect weather-normalized load.

Decomposition

Class obligations for generation costs have occasionally been addressed by dividing the generation resource into separate generation systems serving hypothetical loads for portions of the utility's customers, such as just the residential customers, just the commercial customers and just the industrial customers. For example, industrial customers in Nova Scotia have argued that their high-load-factor demands could be served by the capacity and energy of some set of baseload plants, where those costs are lower than the average generation cost per kWh (Drazen and Mikkelsen, 2013, pp. 11-16). The industrial advocates for this approach assume that the flat industrial load would be served exclusively by baseload plants and that all other costs should be allocated to other classes.[109] A similar approach might inappropriately be suggested to justify allocating the highest-cost resources to customers with behind-the-meter solar generation and lower-cost resources to nonsolar customers whose load does not dip in midday. The method might also be used to test whether classes are paying for enough capacity to cover their energy and reliability requirements.

In the context of resources stacked under a load duration curve, such as that shown in Figure 33 on Page 119, the decomposition approach allocates the resource mix horizontally, rather than the vertical allocation used in the POD method. Figure 35 on the next page illustrates the decomposition approach.

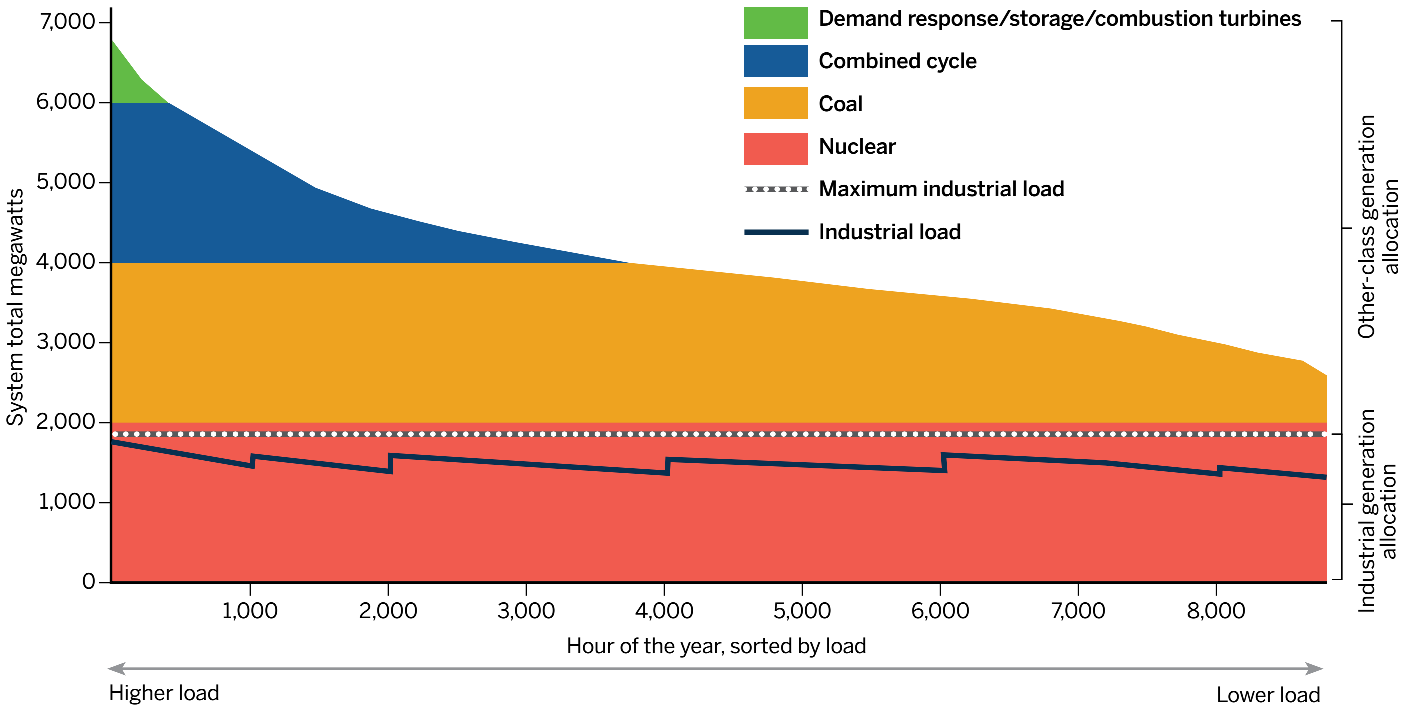
In essence, the decomposition method treats the utility as if it were multiple separate utilities. In the case of Figure 35, the utility system is decomposed into an all-nuclear system with enough capacity to meet the industrial peak load, and a utility with a little nuclear and all the other resources to serve all other load. Whether the industrial customers would support this allocation would usually depend on the cost of the nuclear resources compared with the system average.

The decomposition approach conflicts with reality in many ways, including:

1. The reserve requirements for the decomposed systems would be driven by their noncoincident class peaks or high loads (if they are assumed to be fully free-standing), requiring additional hypothetical capacity for utilities that are not already extensively overbuilt. If the decomposition assumes that the multiple class-specific systems would operate in a power pool, contribution to the system peaks would drive capacity requirements.
2. A system with a high load factor and relatively few large units would require a very high reserve margin (as discussed in Subsection 5.1.1) to cover fixed outages and even maintenance outages. The reserve units would operate in many hours (since the system load would always be near the allocated baseload capacity).
3. A baseload-only system would require a large amount of backup supply energy, either from hypothetical units or as purchases from the other classes.
4. The decomposition approach is usually designed to assign the lowest-cost resources to the industrial class,

109 A decomposition method that accounts for all relevant factors may not show an advantage for industrial customers. In Alberta, a related method to the decomposition method was presented to demonstrate that baseload power for industrial customers would be considerably more expensive than the demand-based cost allocation of the existing system for the industrial class (Marcus, 1987).

Figure 35. Illustration of decomposition approach to allocating resource mix



shifting all the costs of mistakes and market changes onto the other classes. That includes excess capacity (even excess baseload and capacity made excess by decline in industrial loads), the costs of fuel conversion and the high costs of plants built as baseload but currently operated as peakers.

5. It is not clear how variable renewables and other unconventional resources would be incorporated into the decomposed utility systems.

It is possible (if not certain) that the decomposition approach could be expanded and revised to create a viable classification and allocation method, but at this point no such model has been developed.

9.1.4 Other Technologies and Issues

Several types of generation costs do not fit neatly into the classification methods discussed in the previous sections. Some of those costs, such as hydro resources and purchased power, have been part of utility cost structures since before the development of formal cost of service studies. Others, such as excess capacity and uneconomic investments, became prominent in recent decades. More recently, utilities have needed to deal with allocating nonhydro renewable costs; a few utilities already have significant costs for nonhydro storage (mostly batteries) and most will need to deal with those costs in the future. As technologies change, new cost allocation challenges will arise — for new resources, repurposed existing assets and newly obsolete resources.

Fuel Switching and Pollution Control Costs

Many fuel conversion investments have been undertaken to reduce fuel costs or increase the reliability of fuel supply for high-capacity-factor power plants. This category includes:

- Conversion of oil-fired steam plants to burn coal in the 1970s and 1980s (most of which have since been retired).
- Conversion of gas-fired plants to burn oil in the 1970s, when the supply of gas was limited.
- Conversion of oil-fired plants to co-firing or dual firing with gas since the 1990s to achieve environmental compliance and reduce fuel costs.
- Conversion of coal-fired plants to partial or full operation on gas to achieve environmental compliance.
- Conversion of coal-fired plants to partial or full

operation on biomass to achieve environmental compliance and RPS credit.[110]

- Conversion of coal-fired plants to partial or full operation on petroleum coke, tire-derived fuel or other waste to reduce fuel costs.

These investments and resulting longer-term operating costs may reasonably be classified as 100% energy-related.

Most pollution control retrofit costs are incurred to comply with regulatory requirements to reduce the environmental effects of fossil-fueled plants and to allow them to continue burning low-cost fuel at high capacity factors. Peaking units that are needed only in a few high-load hours annually can afford to burn expensive clean fuels and are often allowed to have higher emissions rates since they operate so little. Hence, the need for the pollution control is driven primarily by the energy-serving function of the nonpeaking fossil plants. These environmental costs are most often related to emissions standards for air pollutants, but some substantial costs are driven by the need to protect water quality and aquatic life and to meet other health and environmental standards. As a result, the identifiable capital investment and nondispatch O&M costs of pollution controls may reasonably be classified as 100% energy-related or allocated in proportion to class usage of energy during the times that the plant is operated, to recognize the causes of the environmental retrofits.[111]

Excess Capacity and Excess Costs

Utilities sometimes add generation that is not needed to maintain adequate reliability. Some of that excess capacity may result from the lumpiness of generation additions or declining load, with no clear connection to the classification of the additional costs. Other times the excess is the result of the long lead times for certain baseload generation (especially nuclear, but also some coal and hydro facilities), which can result in a plant being completed after the need for its capacity has vanished and the value of its energy output has decreased dramatically. One or both of those outcomes befell many of the nuclear plants and some coal plants in the late 1970s and 1980s. The long lead times are generally the result of choices to build plants to produce large amounts of energy at low variable costs; in those cases, there is a reasonable presumption that the costs of the excess capacity are due to anticipated or actual energy requirements.[112]

Excess capacity can be priced at the costs of contemporaneous peaking capacity and allocated among classes in proportion to the differences between projected class contribution to peak loads (at the time commitments were undertaken) and actual current class loads. Excess capitalized energy costs (net of equivalent peaking capacity costs and any fuel savings) similarly can be allocated in proportion to the differences between class projected energy requirements and their actual energy requirements.

Table 18 on the next page provides an illustration of the allocation of excess capacity among classes to reflect responsibility for the excess. In this illustration, the actual load in the rate case test year is 600 MWs lower than the load forecast at the time the utility committed to the excess capacity. Because of other adjustments in supply planning, the utility has about 480 MWs of excess capacity, which would support about 400 MWs more load than the actual need. That 400-MW excess is allocated among the classes in proportion to their shortfalls in load.[113]

This adjusted peak load could be used in allocating peaking resources or the peaking-equivalent portion of all generation resource costs. A similar approach could be applied to allocate the additional costs of having a baseload-heavy resources mix resulting from actual energy use being lower than the forecast usage.

Another source of excess capacity is the addition of clean resources to allow the reduced use of dirty older generation, which thus allows the utility to meet environmental

110 In principle, biomass conversion might also reduce fuel costs, although that is not necessarily the case.

111 Nova Scotia Power uses this adjustment to the average-and-peak approach (Nova Scotia Power, 2013a, p. 37).

112 Accounting for a suboptimal system resource mix (and other inefficiencies) is also discussed in detail in Chapter 18.

113 Any load shortfall due to increased utility efficiency efforts since the commitment to build the capacity should generally be excluded from the shortfall.

Table 18. Allocation of 400 MWs excess capacity to reflect load risk

	Forecast load (MWs)	Actual load (MWs)	Load differential	Share of load shortfall	Allocated excess (MWs)	Load for allocation (MWs)
Residential	1,400	1,500	+100	0%	0	1,500
Secondary commercial	2,300	2,000	-300	43%	171	2,171
Primary industrial	2,700	2,300	-400	57%	229	2,529
Total	6,400	5,800	+600	100%	400	6,200

requirements, reduce fuel costs or meet portfolio standards.[114] Even though these new clean resources may raise the reliability of generation supply (usually above an existing adequate level), their costs were incurred as a result of energy loads; in these cases, the excess capacity should be recognized as energy-related.[115]

Aside from excess capacity, changing economic, technological and regulatory conditions can result in a facility providing a service different from its original purpose. For example, a previously baseload generation plant may run on only a few days annually or may house a distribution service center. The plant may still have unrecovered capital costs, environmental cleanup obligations or other burdens. If the full cost of the repurposed facility exceeds its value in its new use, the excess costs should be allocated based on its former use as a baseload generating plant.[116]

Finally, the amortization of a canceled generation plant is attributable to the reason the utility spent the money on the plant, long before the plant's costs and benefits were clear. Many nuclear plants were canceled after the utility spent more on the plant than the entire original expected cost, most recently the Summer plant in South Carolina. A number of coal plants were also canceled after the commitment of substantial funds.

Hydroelectric Generation

The classification of hydroelectric generation presents some issues that differ from those of thermal generation.[117] First, many large generation facilities installed prior to 1960 are still in operation, so their costs are difficult to classify using the equivalent peaker method. Most of them could not be built today, given environmental siting constraints, so comparing new construction costs with new peaker costs may not be practical. Second, each conventional hydro facility consists of turbines and dams (and other civil works), which have different and varying effects on the energy and

114 MidAmerican Energy, for example, will have added over 6,000 MWs of wind in the period 2004-2020 to reduce fuel costs to its retail customers but has kept most of its fossil generation in operation (Hammer, 2018). This could result in a MISO-recognized reserve margin of 26% in unforced capacity terms in certain areas (Hammer, 2018, Table 3). This is nearly three times the typical MISO-required unforced capacity reserve around 8% (Midcontinent Independent System Operator, 2018, p. 23).

115 Texas and Iowa established their initial renewable portfolio standards in terms of installed capacity, rather than the more common energy percentage requirement, and several jurisdictions have established targets for specific renewables (e.g., solar, offshore wind). See Texas Utilities Code § 39.904 and Iowa Code Ch. 476 §§ 41-44. The motivations for these targets, however they are formulated, have been primarily related to reducing fuel costs and emissions. Both Texas and Iowa have exceeded their requirements and continue to add renewables to reduce fuel and other energy costs.

116 Excess costs can also be associated with underutilized or repurposed facilities. For example, a retired steam power plant may be used to warehouse distribution equipment; the generator may be operated as a synchronous condenser to support the transmission system; or a portion of the plant site may remain in service to house a combustion turbine, a transmission switching station or a control center. Sometimes this is intentionally done to avoid (or evade) a rate base disallowance for a unit retired prior to being fully depreciated. Most of those costs continue to be attributable to the original purpose of the steam plant and hence to energy and demand. Similarly, the utility may face cleanup costs for a former coal gasification site or any site contaminated by hazardous materials (e.g., heavy metals, waste lubricating oil or PCB-contaminated transformer oil). Regardless of how that site is used today or was most recently used, the cleanup costs are attributable to the activity that generated the contamination, not the current use.

117 The treatment of pumped storage, where water is pumped uphill off-peak and released to produce electricity during peak periods, is addressed with other storage technologies in Subsection 9.1.4.

demand values of the facility. Adding a turbine may increase the facility's capacity at peak load times without increasing energy output, since total energy output is limited by the amount of water flowing in the river. At another hydro facility, adding an additional turbine will not increase the output in periods of peak need (usually summer and winter) because there is not enough water to run the additional turbine, but it may increase energy output in the spring flood; this energy has value, even if it does not contribute to meeting peak load. Adding additional water storage (such as in an upstream reservoir to hold water from the spring flood) may allow the plant to operate longer hours each day but may not increase the contribution in peak hours. Increasing the height of a dam may increase capacity by raising the hydraulic head and also increase energy output because of both the greater head and the increased storage volume.

Hydro is distinct in that the fuel supply (water) is limited, and although the units usually can be dispatched to cover higher-cost hours, doing so precludes using the units at lower-cost hours. Utilities have often recognized this dual function of hydro investments by classifying hydro plant costs to both energy and capacity. For example:

- BC Hydro in British Columbia classifies hydro generation as 45% energy-related (BC Hydro, 2014, p. 9).
- Newfoundland and Labrador Hydro has proposed classification of 80% energy for a new hydro project (Newfoundland and Labrador Hydro, 2018, p. 6).
- Manitoba Hydro has long classified its generation as 100% energy-related, but this was modified in 2016 to an average-and-peak classification approach with a broad peak demand allocation measure (Manitoba Public Utility Board, 2016, pp. 47-53).

Other utilities, including Idaho Power, Hydro-Québec, and Newfoundland and Labrador Hydro, use the average-and-peak approach for legacy hydro.

In selecting classification and allocation methods it is important to recognize the usage of each type of hydro resource. Some are run-of-river, with each hour's output determined by the amount of water flowing through the system. Other hydro resources have limited flexibility in dispatch due to environmental constraints. Both of these categories of hydro resources should be treated as variable, similar to wind and solar.

Other categories of hydro resources have some storage capacity, allowing the operator to optimize dispatch over a day, a week or even a year.[118] These resources are generally operated under a reliability-constrained economic dispatch regime, but since the variable cost is zero or minimal, they are dispatched to maximize the value of their limited energy supply rather than in merit dispatch order. For example, a hydro resource may be able to generate 100 MWhs in the hour ending at 2 a.m. at no cost, but the dispatcher is likely to prefer to keep the water in the reservoirs to be used for operating reserves, load following and avoidance of fuel costs in higher-cost hours later in the day.

The difference between the dispatch of hydro and thermal resources requires some adaptation in classification and allocation approaches. In some applications of the BIP classification approach, for example, resources are stacked under the load duration curve starting with the resources with the lowest variable costs. In a system with a significant hydro contribution, the method must be modified to reflect the value (not cost) in time periods (ideally hours) in which hydro energy is actually provided, whether that is due to run-of-river, minimum flow or economic dispatch.

It may be appropriate to recognize that some hydro resources are justified primarily by avoiding fuel costs in high-load hours, resulting in allocation of the investment-related hydro costs in proportion to some measure of hourly market or marginal energy costs.[119]

118 Many of these resources will also operate with little or no flexibility in the spring flood, with minimum flow constraints (which may change by season) and with requirements for flow variation for streambed maintenance, recreational activities, flood control and other factors.

119 Many hydro resources bear the costs of providing services unrelated to electric generation, such as flood control, recreation, water supply and environmental protection. Other resources, especially those built in recent decades, may also bear the costs of endangered species protection, conservation easements, access to open space, aesthetic screening around a plant or payments in lieu of taxes. If the non-energy benefits are conditions of a license or permit, those are simply the costs of building or running the plant.

Renewable Energy

Renewable energy, generated from wind, solar, biomass, hydro, geothermal and other technologies, is becoming a larger part of the electric supply mix and hence the cost allocation challenge. Renewable resources may have very different cost characteristics than conventional resources, and the decision to invest in them may be driven by policy that may not consider peak demand at all.

As discussed in Subsection 7.1.2, renewable energy may be added — even though the utility does not need the capacity at peak hours — to reduce fuel costs, comply with portfolio requirements (which often require that a specified percentage of energy consumption is supplied by renewable generation) or meet environmental targets, particularly reducing the atmospheric effects of fossil energy generation. This substitution of capital investment for fuel is widely accepted as an important approach in 21st century utility planning, as shown in examples from Colorado, Iowa and Indiana.[120]

In the classification of costs between capacity and energy, renewable costs that are driven by energy consumption, either directly or indirectly, should be classified as energy-related. For renewable resources that provide some demand-related benefits, the costs can be classified between demand and energy based on the equivalent peaker, average-and-peak or other methods, as long as the demand-related portion is discounted to reflect the effective load-carrying capacity of the renewable resource. Variable renewable resources fit well in a time-based allocation (such as a detailed POD allocation) because their costs can be allocated directly to the hours in which they provide energy to the system.

Purchased Power

Many power purchase agreements with utilities or non-utility generators (especially fossil-fueled generation) have been structured with two types of charges: predetermined monthly charges the utility must pay regardless of how much energy it takes from the power producer, as long as the supplier meets contracted requirements for availability; and variable charges per MWh that the buyer pays for the energy it takes. The charges may reflect the projected cost of a single unit or plant (traditionally fossil fueled, increasingly renewable) at the time the contract was signed, or the actual cost of service for a unit or a portfolio of resources.

Another large set of power purchase agreements — including PURPA contracts, some dating back to the 1980s, and most 21st century renewable projects — pay the provider a rate per kWh delivered (perhaps with different rates by time of delivery). This cost structure fits well into an hourly allocation framework, although it is also possible to extract a demand component of the resource's value for inclusion in a traditional demand/energy framework.

Many utilities classify the monthly guaranteed portion of payments to independent power producers as demand-related, using the archaic perspective that any generation cost that is committed for the rate year should be considered fixed and therefore demand-related, thus leading to great controversy in choosing the appropriate basis for allocation of demand-related costs. In reality, the utility may have agreed to the payment structure because of the low-cost energy provided by the deal, with that financial commitment having value to the resource owner in obtaining financing.

Others classify purchased power to mimic the classification of generation plant, as if the purchase were the equivalent of plant capital, without fuel.[121] This treatment is similarly inconsistent with cost causation. Many power purchase agreements are structured to recover the costs of a baseload or intermediate resource, such as by charging a relatively high nonbypassable capacity charge and a low energy charge based on the usage of the resource. These contracts are typically not the lowest-cost way to meet peak loads. The only rational reason to enter into these contracts

120 Xcel Energy touted its renewable energy investments as "steel for fuel," in which "capital recovery costs [are] offset by lower fuel and O&M costs" and wind "displaces coal and natural gas fuel," resulting in "significant customer savings" (2018). MidAmerican Energy justified its aggressive wind generation plan on eliminating exposure to fossil fuel costs (Hammer, 2018). Northern Indiana Public Service Co. found that replacing its coal plants' fuel and operating costs with wind and solar would reduce customer costs, uncertainty and risk (2018, p. 6).

121 The contract may require the purchaser to take all of the available energy, so even a rate denominated in MWhs can be thought of as investment-related and thus similar to generation plant costs. In reality, the purchase contract replaces both the investment-related and variable costs of a comparable resource built by the purchasing utility.

would be to access lower-priced energy and higher efficiency. The classification process should look beyond the contract pricing terms to ascertain the true cost causation factors and where the benefits accrue.

Within the centrally dispatched power pools (such as the New England, New York, California and Midcontinent ISOs), utilities and other load-serving entities purchase energy on an hourly basis to meet their loads. The transactions are priced at the marginal costs of the supply bids to the system operator and cover some investment-related costs for most generators. The cost of those purchases should be classified as energy and allocated to loads on a time-differentiated basis.[122]

Costs for purchased power can be classified in most of the same ways that the costs of utility-owned generation are classified, including the probability-of-dispatch, equivalent peaker and average-and-peak methods and many others. In many cases, the purchase will be from a specific plant whose investment and nondispatch O&M costs can be allocated in the same manner as the costs of similar resources the utility owns. In other cases, such as system power, the classification and allocation of power purchase costs will need to be based on the cost characteristics of the purchase.[123] Where possible, the most straightforward classification approach would be to treat as energy-related the excess of the purchase costs over the capacity costs of a contemporaneous gas turbine peaking plant.

Energy Storage

Energy storage takes many forms, including:

- Water held in conventional hydro reservoirs.
- Pumped storage hydro facilities.
- A variety of battery technologies, which may be co-located with generation, transmission or distribution facilities or be behind the customer's meter.
- A host of other electricity storage technologies, including compressed air, flywheels and gravity (moving weights upward to store energy, using the potential energy to drive a generator as needed).
- Thermal storage as molten salt in solar thermal plants, ice or hot water at customer premises.

Batteries will be an increasingly important part of utility systems, and therefore of cost allocation studies, because of their flexibility and the rapid and continuing decline in their costs. Batteries can be installed (1) at the location of generation to stabilize or optimize output to the transmission system; (2) at substations to avoid transmission and distribution costs; or (3) throughout the system, on the utility or customer side of the meter to avoid transmission and distribution costs and to provide customer emergency power.

Batteries can provide a range of services, including contributing to bulk supply reliability, ancillary services (load following, reserves and automatic generator control), energy arbitrage, transmission load relief, distribution load relief and customer emergency supply. To the extent that the allocation study can reflect these various services, it should classify the costs of the batteries in proportion to their value. That classification may be based on the frequency with which the storage is used for each purpose, on the anticipated mix of benefits that justified the installation, or on the incremental cost incurred to achieve the additional purpose.[124] Batteries may be very valuable for providing second-contingency support to the transmission system (avoiding the installation of redundant equipment), even if they may never actually be dispatched for that purpose. Where utilities purchase some attributes of behind-the meter batteries, such as ancillary services, the services they purchase should drive the cost allocation.

Storage operates as both a load and a supply resource and thus may operate at very different times than conventional generation. As a result, storage fits well into hourly allocation

122 Some utilities in these pools own generation, which is sold into the regional market. The revenue from those sales can be credited against the costs of the generator before those costs are allocated to classes.

123 Since costs for purchased power may be recovered through both base rates and a power cost recovery mechanism, and the allocation of these costs may be reflected in both base rates and the power-cost mechanism, some care should be taken to ensure that the allocation is applied only once, just as the costs are recovered only once. For example, the costs for purchased power may be included in the cost of service study, with the anticipated purchased-power revenues from each class subtracted from the allocated costs. Alternatively, the purchase costs may be excluded from the base rate cost of service study and allocated separately on an appropriate basis in the fuel and purchased power cost recovery mechanism.

124 Renewable incentives and tax policy may encourage co-location of storage with centralized renewable generation. Moving the storage to support transmission, distribution or customer resilience would typically increase both the value and the cost of the resource; those incremental costs should be classified as due to the incremental service.

schemes. Storage usually delivers power into the grid at high-cost hours, so assigning the capital and operating costs, including the costs of charging storage, to those hours usually will result in an equitable tracking of costs to benefits.

But storage also provides some services while it is charging, including operating reserves. A 200-MW pumped storage unit can typically transition from being a 200-MW pumping load to a 200-MW supply within minutes, providing 400 MWs of net operating reserves at no incremental cost during low-cost hours, allowing avoidance of fuel costs for load-following resources. Storage may also provide other ancillary services while charging. If the cost of service study is sophisticated enough to classify and allocate ancillary services separately from demand and energy, some of the storage costs can be classified to ancillary service, reflecting the increased reserves available during charging.

In addition, some utility systems experience high ramp rates in net load at times that variable renewable generation is declining and load is rising, such as an evening-peaking utility with a large amount of solar generation in the midday period. To be able to ramp up output from other generation quickly enough to offset the drop in renewable output and meet the rising load, the system may require the construction of additional resources and the uneconomic operation of thermal generators at low-load times to ensure they are available when the ramping need arises. Storage-charging load in the period of minimum net load (which is also likely to be a period of low or even negative short-run marginal costs) raises the minimum load and reduces the ramp rate. These benefits flow to the loads during the ramping period, not just during the discharge period, so some of the costs of storage should be allocated to those loads.

System Control and Dispatch

The costs of scheduling, committing and dispatching generation units, recorded in FERC Account 556, are fixed in the short term but vary with the generation mix, load shapes and variability and other considerations. Costs of forecasting load and supply and optimizing dispatch may vary depending on the amount of weather-related load, the existence of large loads and large generators that may suddenly trip off line, the extent of integration with other utilities, the length of time required for major plants to start up and the amount of variable renewable generation. Some dispatch costs would be required, even if the utility only needed to dispatch generation on a few peak hours, while others are required for multiday planning, 24-hour operation and other energy-related factors.

These costs might most reasonably be classified as partly demand-related and partly energy-related. Reasonable approaches would include classification of dispatch costs in proportion to the classification of long-term generation costs, using the average-and-peak method or a 50/50 split between energy and demand.

9.1.5 Summary of Generation Classification Options

Table 19 on the next page summarizes some attributes of the generation classification options described above. These descriptions are highly simplified and should be read in context of the discussion prior, including the discussion of special situations in Subsection 9.1.4.

9.2 Allocating Energy-Related Generation Costs

Energy-classified generation costs are often allocated to all classes in proportion to total annual class energy consumption. Alternatively, energy-related costs can be calculated by time period and allocated to classes in proportion to their usage in each time period. Assigning costs to time periods is usually straightforward for fuel and dispatch O&M.[125] For systems with high penetration of variable renewables, such as wind and solar, then TOU or BIP allocation of energy-related costs is the most equitable.

The energy-related capital investment and nondispatch O&M costs can be allocated to classes in proportion to

125 One possible complication with time differentiation is that some steam plants must be operated in low-load hours, when they are not really needed, so that they will be available when needed in higher-load hours. The costs of fuel and reagents used in low-load hours may be required to serve high-load hours, but the plants may also be supplying energy in the low-load hours; sorting out generation and fuel use among periods within a week or day can be very complicated.

Table 19. Attributes of generation classification options

Method	Data and computational intensity	Accuracy of cost causality	Allows joint classification/allocation	Applicability
Straight fixed/variable	Very low	Very low	No	Peaker-only systems
Competitive proxy	Low	Medium	No	In or near regional transmission organizations that perform revenue computations
Average and peak	Low	Low	No	Hydro systems
Simple base-intermediate-peak	Low to medium	Medium	No	Simple systems: limited hydro, solar, wind, storage
Complex base-intermediate-peak	High	High	Yes	Broad
Equivalent peaker (peak credit)	Low	High	No	Broad
Operational characteristics (capacity value, capacity factor, operating factor)	Generally low	Low to medium	No	Limited
Probability of dispatch	Medium to high	Highest	Yes	Broad
Decomposition	Very high	Low	Yes	Rarely

energy or assigned among time periods in proportion to the fuel and dispatch O&M. Table 20 provides an illustration of the development of energy-classified costs per MWh (both dispatch- and investment-related) over three time periods.

Table 21 on the next page shows an illustrative example applying these costs per MWh to usage for three customer classes by time period to allocate costs.

The comparable computation for most utilities could use many more periods (perhaps even hourly data), include all resource types and compute usage by generation unit, rather than category.

Manitoba Hydro, which has an almost all-hydro system, assigns energy-classified capital investment costs among four seasons and three time periods (for a total of 12 periods) in proportion to the MISO market prices for exports in those periods, reflecting the reality that there are hours in which

Table 20. Illustrative example of energy-classified cost per MWh by time of use

			Period (and annual hours)			
	Energy-related cost per MWh	Capacity (MWs)	Peak (50)	Midpeak (2,000)	Off-peak (6,710)	Total
Resource type						
Nuclear	$30	500	$750,000	$28,500,000	$90,585,000	$119,835,000
Coal	$40	1,500	$3,000,000	$84,000,000	$161,040,000	$248,040,000
Combined cycle	$35	1,000	$1,750,000	$35,000,000	$0	$36,750,000
Peaking	$100	300	$1,500,000	$12,000,000	$0	$13,500,000
Demand response	$250	100	$1,250,000	$0	$0	$1,250,000
Subtotal of all resources			$8,250,000	$159,500,000	$251,625,000	$419,375,000
Consumption (MWhs)			170,000	4,170,000	7,045,500	11,385,500
Cost per MWh			$48.53	$38.25	$35.71	$36.83

Note: Numbers may not add up to total because of rounding. The illustration assumes that all resources are fully utilized in the peak period, with reductions in capacity factor between periods by 5 percentage points for nuclear, 30 points for coal, 50 points for combined cycle and 80 for peaking.

Table 21. Illustrative example of time-of-use allocation of energy-classified costs

	Period (and annual hours)			
	Peak (50)	Midpeak (2,000)	Off-peak (6,710)	Total
Consumption (MWhs)	170,000	4,170,000	7,045,500	11,385,500
Cost per MWh	$48.53	$38.25	$35.71	$36.83
Class				
Residential				
Consumption (MWhs)	69,250	2,080,000	2,818,200	4,967,450
Allocated costs	$3,360,662	$79,558,753	$100,650,000	$183,569,415
Commercial				
Consumption (MWhs)	85,000	1,460,000	2,113,650	3,658,650
Allocated costs	$4,125,000	$55,844,125	$75,487,500	$135,456,625
Industrial				
Consumption (MWhs)	15,750	630,000	2,113,650	2,759,400
Allocated costs	$764,338	$24,097,122	$75,487,500	$100,348,961

Note: Numbers may not add up to total because of rounding.

transmission constraints preclude additional exports. That approach recognizes that using energy in some time periods is more expensive for Manitoba Hydro (in terms of lost export revenues) than consumption in other time periods.

9.3 Allocating Demand-Related Generation Costs

As discussed in Subsection 9.1.3, some classification methodologies, such as probability of dispatch and more granular hourly variants, simultaneously develop cost by period and the associated allocation factors driven by use by period. This section describes methods for developing allocation factors for demand-related costs developed by legacy demand/energy classification methods.

Typically, utilities allocate demand-related generation based on some form of class contribution to system peak loads, referred to as coincident peak. The loads that determine how much capacity a utility requires may be concentrated in a few hours a year, a few hours in each month, the highest 50 or 100 hours in the year, or some other measure of the loads stressing system reliability.

Frequently used demand allocators include:

- The class contributions to the annual system coincident peak (1 CP).
- The class contributions to three or four seasonal peaks (3 CP or 4 CP).
- The average of the class contributions to multiple high-load hours, such as:
  - The 12 monthly peaks (12 CP).
  - All hours with loads greater than a threshold, such as 80% to 95% of annual peak.
  - **Peak capacity allocation factor** (PCAF), a technique developed in California that weights high-usage hours based on how close each hour is to the peak hour.
  - Hours with some expectation for loss of energy.
  - Hours in which the system is stressed (e.g., operating reserves are below target levels).

As discussed in Chapter 5, generation capacity requirements have always been driven by more than a few hourly loads. Moreover, with peak loads being offset by solar generation and expanding demand response available to serve the highest-load or highest-cost hours, capacity requirements are driven by an even broader group of hours, which should be reflected in the development of the demand allocation factors. Broader allocation factors also have the virtue of limiting the instability resulting from the use of a limited number of peak hours. For example, ERCOT experienced an annual peak in 2017 at approximately

69,500 MWs on July 28 at 5 p.m. However, there were 13 other hours within 2% of that annual peak in 2017, in the hours ending at 3 p.m. to 7 p.m. (Electric Reliability Council of Texas, 2018, and calculations by the authors). Changes in temperature or cloud cover could shift the peak load to any of those hours. The peak timing in the load data can be very important in determining the allocators. The residential class typically will have a greater share of a peak load occurring at 7 p.m. than one occurring at 3 p.m. or 4 p.m.[126]

Utilities have sometimes allocated generation demand costs on the class NCP at the system level.[127] This approach may have been roughly appropriate for some utilities serving distinct classes with peak demands in different seasons, such as winter-peaking ski resorts and summer-peaking irrigation pumping, with both seasons contributing to the need for generation capacity. The class NCP would not recognize whatever load the ski resorts' summer operations contribute to the pumping-dominated peaks and would allocate demand costs to other classes based on their summer or winter peaks — but not their contributions to either of the seasons' high-load hours. Since reliability computations and the need for generation capacity are driven by combined system load, some measure of the combined loads on the system is relevant. With the hourly data collection technologies now available, this class NCP approximation is no longer necessary.

Traditionally, without access to the kind of sophisticated hourly data we can obtain today, utilities have tended to allocate demand costs on a single annual coincident peak, the average of the four monthly peaks in the high-load summer season, the average of some number of summer and winter monthly peaks, a defined number of peak hours when peaking resources are expected to operate, or the average of the 12 monthly peaks.[128] The number of months included in the computations of the demand allocator often reflects the following factors:

- The number of months in which the system may experience its annual peak load.
- Whether high loads occur in both summer and the winter.
- Whether requirements for maintenance outages reduce available capacity in off-peak months enough that available reserves in those months are comparable to the reserves in the peak months.

A more comprehensive approach to these factors would develop the demand allocator from all the hours identified in a loss-of-energy expectation study, after accounting for maintenance scheduling. Depending on the system, that may be several hours or several hundred hours. If data are not available for a comprehensive loss-of-energy expectation analysis, a demand allocator based on all hours within a specified percentage of the peak (e.g., 80% to 95%) or based on a significant number of the highest hours in the year (e.g., 100) is preferable to a coincident peak analysis. In sum, averaging or weighting a small number of coincident peaks incorrectly assumes that the need for capacity is a simple function of the amount of the system monthly peak, even though capacity requirements are driven by many hours,

126 The range of loads in these 14 hours was only about 1,400 MWs, roughly the size of one large nuclear unit or two large coal units. The differences in loads over those hours are of little significance in terms of reliability.

127 In some jurisdictions, the class NCP is referred to as the maximum class peak, maximum diversified demand or something similar, and "NCP" is used to designate the sum of the individual customer noncoincident peaks within each class. We refer to class NCP and customer NCP in this manual to distinguish between the two methods.

128 FERC has a set of guidelines for determining whether wholesale demand-classified costs should be allocated on 3 CPs or 12 CPs (for example, see Federal Energy Regulatory Commission, 2008, pp. 30-35). FERC's approach does not contemplate that any other number of months (such as four or eight) might be responsible for the need for capacity.

Table 22. Attributes of generation demand allocation options

Method	Data and computational intensity	Accuracy of cost causality	Allows joint classification/ allocation	Applicability
1 CP	Very low	Very low	No	Rare
3 CP; 4 CP	Low	Low	No	One-season peak; needle peaks
12 CP	Low	Low to medium	No	Multiple seasonal peaks; extensive maintenance requirements; class load shapes near peak similar
Multiple hours near peak (e.g., top 100 hours)	Low to medium	Medium	No	Broad, but loss-of-energy expectation gives more robust results if data exist to calculate them
Loss-of-energy expectation	High	High	No	Broad
Complex base-intermediate-peak	High	High	Yes	Broad
Probability of dispatch	Medium to high	High	Yes	Broad

depending on load; the amount of generation capacity that is available, not just installed; and the scheduling of maintenance outages.

Table 22 summarizes some characteristics of the allocation methods described in this section, along with the POD method described in Subsection 9.1.3 and the more complex variants of the BIP method from Subsection 9.1.2.

9.4 Summary of Generation Allocation Methods and Illustrative Examples

As demonstrated in many ways in the previous sections, it is appropriate to classify some of the long-term investment and O&M costs to energy usage rather than to demand. Table 23 presents a simplified view of appropriate classification results by plant type.

As variable renewable capacity (mostly wind and solar) on a system increases, the role for baseload capacity decreases. At some point, in hours with low load and high renewable output, traditional baseload resources will run only if they cannot shut down and restart on a timely basis.

Cost of service studies can also combine features of the various classification approaches, such as classifying peakers as 100% demand-related; classifying fuel conversion costs, environmental costs and generation without firm transmission as 100% energy-related; and applying the average-and-peak

Table 23. Summary of conceptual generation classification by technology

Resource type	Function	Classification
Nuclear, some hydro and best coal	Baseload	Primarily energy
Modern combined cycle, best gas-fired steam and mediocre coal	Intermediate	Energy and demand
Combustion turbines, mediocre fossil-fueled steam and combined cycle	Peaking and operating reserves	Primarily demand or on-peak energy
Storage and flexible hydro	Peaking and energy shifting	Demand or on-peak energy
Wind and solar	Energy and some capacity	Primarily energy

Note: “Best” refers to resources with the lowest variable costs, “mediocre” to those with higher variable costs. Resources that are worse than mediocre are likely candidates for retirement. “Intermediate” refers to generation that is neither baseload nor peaking.

Table 24. Summary of generation allocation approaches

Resource type	Classification and allocation methods: Legacy	Modern	Evolving
Nuclear	CLASSIFICATION: Average and peak ENERGY ALLOCATOR: All energy DEMAND ALLOCATOR: 12 CP	CLASSIFICATION: Equivalent peaker ENERGY ALLOCATOR: All energy DEMAND ALLOCATOR: Loss-of-energy expectation	All hours
Baseload coal	CLASSIFICATION: Average and peak ENERGY ALLOCATOR: All energy DEMAND ALLOCATOR: 12 CP	Probability of dispatch	Hours dispatched
Combined cycle	CLASSIFICATION: Average and peak ENERGY ALLOCATOR: All energy DEMAND ALLOCATOR: 12 CP	Probability of dispatch	Hours dispatched or used for reserve
Gas-fired steam	CLASSIFICATION: Average and peak ENERGY ALLOCATOR: On-peak energy DEMAND ALLOCATOR: 4 CP*	Probability of dispatch	Hours dispatched or used for reserve
Peaker	CLASSIFICATION: 100% demand DEMAND ALLOCATOR: 4 CP or 12 CP	Probability of dispatch	Hours dispatched or used for reserve
Hydro	CLASSIFICATION: Average and peak ENERGY ALLOCATOR: All energy DEMAND ALLOCATOR: 12 CP*	Probability of dispatch	Hours dispatched or used for reserve
Wind	CLASSIFICATION: 100% energy ENERGY ALLOCATOR: All energy	CLASSIFICATION: Equivalent peaker ENERGY ALLOCATOR: All energy DEMAND ALLOCATOR: Loss-of-energy expectation	Hours of output
Solar	CLASSIFICATION: Average and peak ENERGY ALLOCATOR: On-peak energy DEMAND ALLOCATOR: 4 CP	CLASSIFICATION: Equivalent peaker ENERGY ALLOCATOR: All energy DEMAND ALLOCATOR: Loss-of-energy expectation	Hours of output
Storage	CLASSIFICATION: Average and peak ENERGY ALLOCATOR: All energy DEMAND ALLOCATOR: 12 CP	Probability of dispatch	Hours dispatched, used for reserve or reducing ramp rate
Demand response	CLASSIFICATION: 100% demand DEMAND ALLOCATOR: 3 CP to 12 CP**	CLASSIFICATION: 100% demand DEMAND ALLOCATOR: 3 CP to 12 CP**	Hours dispatched or used for reserve

* Depends on use of resource
** Depends on program type and technology

approach to the remaining costs. A hybrid approach is only as equitable as the component techniques but may be useful where particular classification decisions can be made before the application of a generic approach to the residual costs.

Table 24 summarizes examples of allocation factors that might be applied to the capital and nondispatch O&M costs for various types of generation resources, whether utility-owned or purchased.[129] This summary is, by its very nature, highly simplified, ignoring many of the complexities discussed in sections 9.1, 9.2 and 9.3.

129 The probability-of- dispatch and hourly approaches can also be applied to the short-run variable costs of the resources.

For simplicity, we show an illustration only for generation investment-related costs. Table 25 shows the amount of investment in each category, which we will then divide using multiple allocation methods.

Table 26 shows two currently used methods: a legacy 1 CP system measure and a more modern method, equivalent peaker, where 80% of baseload costs are considered to be energy-related. The illustrative load data and allocation factors are from tables 5 through 7 in Chapter 5.

Table 27 shows the calculation of an hourly allocation model, where baseload costs are apportioned to all hours, peaking and intermediate costs to midpeak hours, and storage only to the 2% of usage at the most extreme hours.

Table 25. Illustrative annual generation data

	Net generation (MWhs)	Annual nonfuel revenue requirement	Annual nonfuel cost per MWh
Baseload	1,860,000	$74,400,000	$40
Peaker	534,000	$42,720,000	$80
Solar	1,056,000	$31,680,000	$30
Storage	62,000	$6,200,000	$100
Total	3,512,000	$155,000,000	$44

	Disposition of net generation
Storage input and delivery losses	412,000
Sales to customers	3,100,000

Note: Numbers may not add up to total because of rounding.

Table 26. Allocation of generation capacity costs by traditional methods

	Residential	Secondary commercial	Primary industrial	Street lighting	Total
1 CP (legacy)	$51,667,000	$62,000,000	$41,333,000	$0	$155,000,000
Equivalent peaker	$50,333,000	$52,400,000	$47,750,000	$4,517,000	$155,000,000

Note: Numbers may not add up to total because of rounding.

Table 27. Modern hourly allocation of generation capacity costs

	Residential	Secondary commercial	Primary industrial	Street lighting	Total
Baseload (all hours)	$24,000,000	$24,000,000	$24,000,000	$2,400,000	$74,400,000
Peaker (midpeak)	$14,424,000	$15,735,000	$12,326,000	$236,000	$42,720,000
Solar (daytime)	$10,560,000	$12,320,000	$8,800,000	$0	$31,680,000
Storage (critical peak)	$2,366,000	$2,366,000	$1,420,000	$47,000	$6,200,000
Total hourly allocation	$51,350,000	$54,421,000	$46,545,000	$2,683,000	$155,000,000
Composite hourly factor	33%	35%	30%	2%	100%

Note: Numbers may not add up to total because of rounding.

10. Transmission in Embedded Cost of Service Studies

As discussed in Chapter 3, investments in transmission lines and substations are needed and valuable for a wide assortment of purposes, including integrating inherently remote generation, allowing economic dispatch of generation over large areas and providing backup reliability. Any particular transmission line and the substations to which it is connected may perform multiple functions under varying load and generation conditions. Because the purposes for constructing transmission and the use of the facilities vary so widely, the allocation methods used may need to distinguish among several categories of transmission.

The generation-related portions of transmission equipment — including switching stations, substations and transmission lines required to tie generators into the general transmission network and reinforcements of the transmission system required by remote generation locations and by economic dispatch — are often functionalized as generation.

In regions with FERC-regulated ISOs or RTOs, state regulators may not have authority to determine the amount of bulk transmission cost a local distribution utility must pay. The states may choose to allocate costs among classes in a manner similar to that FERC uses to allocate costs among utilities and other parties. States also retain the authority to allocate that cost using a different method than FERC uses for wholesale market allocation.

10.1 Subfunctionalizing Transmission

As noted in Chapter 3, transmission of different voltage levels often serves similar functions. Nonetheless, some utilities have subfunctionalized transmission between **extra-high-voltage** (EHV) facilities (perhaps over 100 kV) and subtransmission (at lower voltages), sometimes called network transmission as it connects the different substations inside the utility service territory. Subtransmission that FERC does not claim authority over (based on voltage, configuration, direction of power flow and other factors) is regulated by the state or consumer-owned utility governing body.

If those subfunctions were classified and allocated in the same manner, the division of the facilities by voltages would not matter. Unfortunately, some cost of service studies allocate only the EHV facilities to certain customers directly served from these facilities, with customers served at subtransmission or distribution voltages being charged for both the EHV system and the subtransmission. For example, in 2013, Nova Scotia Power proposed to functionalize 23% of transmission costs to subtransmission and excuse from those costs the largest industrial customers, served at 138 kV (Nova Scotia Power, 2013b). Similarly, Manitoba Hydro functionalizes its 66-kV and 33-kV transmission lines as subtransmission, which is allocated to all classes except for the industrial customers served at voltages above 66 kV (Manitoba Public Utility Board, 2016).

This approach is inequitable and fails to reflect cost causality. The various voltages of transmission serve complementary functions. In general, customers and distribution substations that are served from subtransmission would be more expensive to serve from EHV transmission. Subtransmission is a lower-cost alternative to EHV where the higher capacity of the EHV facilities is not required.

For some systems, the subtransmission and EHV systems may seem to be serving different functions since the EHV lines may be more often networked or looped, while the subtransmission lines are often radial. This pattern is due to the higher load-carrying capacity of the EHV lines, which results in their being used in high-load backbone configurations. These lines are usually networked for greater reliability, not due to some inherent difference in the capabilities of the technologies. Higher-voltage lines can be used in radial applications, and subtransmission can be networked or looped in some situations.

Figure 36 is a section of a California transmission map, showing EHV lines as solid lines (220 to 287 kV) and large dashed lines (110 to 161 kV) and subtransmission as small dashed lines (California Energy Commission, 2014). This excerpt shows some features that are consistent with the proposition that higher-voltage transmission is networked while subtransmission is radial:

- A large backbone transmission line running north-south.
- A looped network of 110- to 161-kV lines coming off the backbone line into the Oakland area.
- Radial subtransmission lines that dead-end at distribution substations in Berkeley and parts of Oakland.

But Figure 36 also illustrates situations contradicting these stereotypes:

- Networked subtransmission lines in the San Leandro-San Lorenzo area.
- Radial 220- to 287-kV lines that dead-end at such substations as Rossmoor and Castro Valley.

Figure 36. Transmission east of San Francisco Bay

Source: California Energy Commission. (2014). *California Transmission Lines – Substations Enlargement Maps*

Thus, the idea that the EHV system is a network and the subtransmission system is a purely radial system served off the EHV network is a gross simplification. If loads to near San Lorenzo were higher, for example, the local utility might have upgraded the subtransmission network to higher voltages.

As a result, the separation of subtransmission is often inappropriate in principle and impractical in application, leading to the conclusion that all voltages of transmission should be allocated consistently as a single function.

However, if a state determines that subtransmission costs are to be allocated to the classes that use the subtransmission system, ignoring the complementary nature of high- and low-voltage transmission, the allocator should approximate the extent to which each class uses the subtransmission system and not be designed simply as a benefit to high-voltage industrial customers.

Not all distribution loads are served from subtransmission. If industrial customers served directly off the EHV system are excused from being allocated a share of the subtransmission, so should the portion of distribution load served by substations that are fed from EHV transmission. Although segregating EHV facilities is typically performed in a manner that benefits a small number of EHV industrial customers, a full subfunctionalization of transmission for all classes would sometimes reduce the allocation to classes served at distribution, at the expense of the classes served directly from the subtransmission system.

A separate subtransmission allocator should approximate the following:

- An EHV industrial class that takes all its power from the EHV system would be allocated no subtransmission costs.
- A subtransmission industrial class that takes all its power from the subtransmission system would be allocated subtransmission costs in proportion to its entire load.
- A general transmission class would be allocated subtransmission costs in proportion to the fraction of its load served from subtransmission.
- The distribution classes would be allocated subtransmission costs in proportion to the fraction of their load served from substations on the subtransmission lines.

Most large utilities appear to serve a significant fraction of distribution load from the EHV system. The utility FERC Form 1 reports indicate that at least 26% of Southern California Edison's distribution substation capacity (the substations with low-side transformers below 30 kV) is served from the EHV system; for Northern Indiana Public Service, the portion is at least 49% (Federal Energy Regulatory Commission, n.d.).[130]

10.2 Classification

The classification of transmission costs raises many of the same issues as the classification of generation costs and can often be dealt with in similar ways. As for generation, some approaches for transmission avoid the need for classification by assigning specific transmission facilities to the loads occurring in the hours in which these lines serve customers with improved reliability, lower variable costs or other benefits.

Some assets that are carried on the books as transmission may actually be related to interconnecting or integrating generation (step-up transformers and generation ties for many utilities; more extensive facilities for utilities with extremely remote generators). Those facilities can either be functionalized as generation-related and classified along with the generation resource or functionalized as transmission and classified in the same manner as the investment-related costs of the associated generation. Facilities connecting peakers should be treated as demand-related, while those connecting the baseload generation, especially remote generation, should be primarily treated as energy-related since the facilities were built primarily to provide energy benefits. For example, Manitoba Hydro classifies as entirely energy-related the high-voltage direct current system that brings its northern hydro generation to the southern load centers and export points, as well as its transmission interties, which allow for economic energy exports and for off-peak energy imports to firm up hydro supplies in drought conditions.[131]

In addition to the substations that step up the generator output to transmission voltages and the lines that connect the generator to the broader transmission network, many utilities have transmission facilities that are integrated with the transmission network but are driven largely by the need to move large amounts of power from remote generators. Those transmission facilities may be identifiable because they were originally required to reinforce the transmission system when major baseload (or remote hydro or wind) resources were added or because they connect areas that have surplus generation to areas with generation shortages. For example, a utility may have 60% of its load in a central metropolitan area but 80% of its baseload resources far to the east or north, with multiple major transmission lines connecting the resource-rich east with the load in the center.[132]

---

130 Some distribution substation transformers are at substations serving multiple transmission voltages. The FERC Form 1 reports provide only the total transformer capacity at the substation, without differentiating among the EHV-subtransmission, EHV-distribution and EHV-EHV capacity. The percentages of distribution capacity served from the EHV system, listed above, do not include any of this multivoltage capacity.

131 The northern AC gathering system that brings the hydro to the HVDC converters is also classified as energy-related.

132 Examples of this phenomenon include Nova Scotia Power's concentration of coal in the eastern end of the province; BC Hydro's, Manitoba Hydro's and Hydro-Quebec's northern generation; PacifiCorp's Rocky Mountain Power division (with load concentrated around Salt Lake City and generation in Colorado, Wyoming, Arizona and Montana); Arizona Public Service Co. with load in Phoenix and generation in the Four Corners and Palo Verde areas; Puget Sound Energy and the Colstrip transmission system from Montana; the California utilities and the AC and DC interties to the Pacific Northwest and lines to the Southwest; and Texas' concentration of wind generation in the Panhandle, serving load throughout ERCOT. This pattern is also emerging for California's imports of solar energy from Nevada and Arizona, Minnesota's imports of wind power from North Dakota and hydro energy from Manitoba, and the transfers of large amounts of wind power from generation in the western parts of Kansas and Oklahoma to load centers in the eastern parts of those states.

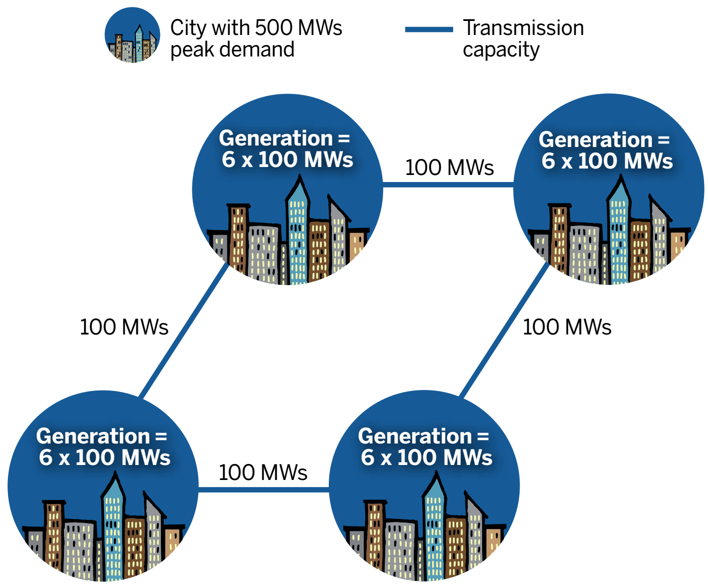
Utility transmission system design typically lowers energy costs in at least three ways. First, a large portion of many transmission systems is required to move power from the remote generators to the load centers and for export. If generation were located nearer the load centers, the long, expensive transmission lines would not be required, and transmission losses would be smaller. These transmission costs were incurred as part of the trade-off against the higher operating costs of plants that could be located nearer the load centers — in other words, as a trade-off against energy-related costs. This category includes transmission built to allow the addition of remote wind resources, which are often the least-cost energy resources even where the utility already has sufficient capacity and energy supply. In other cases, the remote wind resources may be more expensive than conventional resources, new or existing, but less expensive than local renewables (e.g., solar, wind turbines in areas with lower wind speed, higher land costs and more complex siting problems) that would otherwise need to be built to comply with energy-related renewable energy standards.

Second, transmission systems are more expensive because they are designed to allow for large transfers of energy between neighboring utilities. Third, transmission systems are designed to minimize energy losses and to function over extended hours of high loading. Were the system designed only to meet peak demands, a less costly system would suffice; in some cases, entire lines or circuits would not be required, voltage levels could be lower, and fewer or smaller substations would be needed.

Figure 37 shows a simple illustrative system with relatively small units of a single generation resource co-located with each load center. Since all the generators are the same, economic dispatch does not require shipping power from one load center to another, so transmission is limited to the amount needed to allow reserve capacity in one center to back up multiple outages in another center. In this simple illustration, the transmission costs would truly be demand-related.

Figure 38 on the next page illustrates a more complex system, with baseload coal concentrated in one area, combined cycle generation in another and combustion turbines in a third. Additional transmission corridors and substations are required to connect remote generation (wind from one direction and hydro from another), and the transmission lines between the load centers need to be beefed up to support backup of the larger units and the economic dispatch of the lowest-cost available generation to meet load. In this more complex system, the incremental costs of transmission (compared with the simple system in Figure 37) should be classified as energy-related.

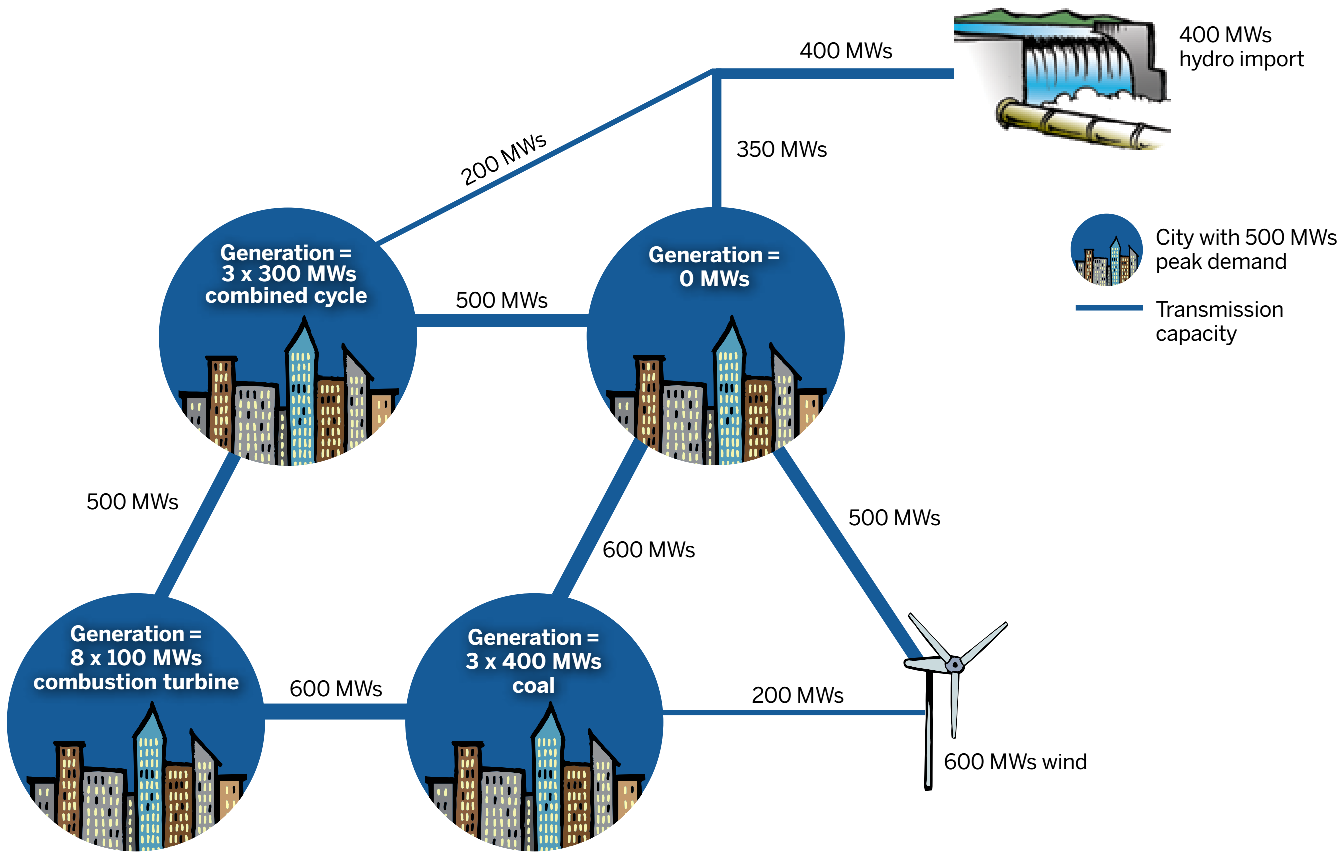
Figure 37. Transmission system with uniformly distributed demand and generation



It may be possible to identify and classify the costs of the individual lines or classify total costs in proportion to circuit-miles of each voltage serving various energy functions. If all else fails, a more judgment-based classification method, such as average and peak, may be the best feasible option.

PacifiCorp's Rocky Mountain Power subsidiary in Utah classifies transmission as 75% demand-related and 25% energy-related (Steward, 2014, p. 7). This classification recognizes that, although peak loads are a major driver of transmission costs, a significant portion of transmission costs is incurred to reduce energy costs. Since PacifiCorp has a large amount of transmission connecting remote coal plants in Wyoming, Arizona and Colorado to its load centers and connecting its Northwestern hydro assets to its load centers, an even higher energy classification may be

Figure 38. Transmission system with remote and centralized generation



appropriate. PacifiCorp's highest-voltage lines (500 kV, 345 kV and 230 kV) primarily connect its load with remote baseload generation and would not be needed except to access low-cost energy. Those lines account for more than half of PacifiCorp's transmission investment. Hence, more than half of PacifiCorp's transmission revenue requirement is likely to be attributable to energy.

Similarly, Nova Scotia Power has much of its generation (coal plants, storage hydro and an HVDC import of hydropower from Newfoundland) in the eastern end of the province, but most of its load is about 250 miles to the west. To reflect the large contribution of remote generation to its transmission cost, the company uses an average-and-peak (system load factor) approach that effectively classifies about 62% to energy and 38% to demand (Nova Scotia Utility and Review Board, 2014, pp. 22-23).

Washington state has explicitly rejected a single hour of peak as a determinant and ruled that transmission costs should be classified to both energy and demand (Washington Utilities and Transportation Commission, 1981, p. 23). Appropriate classification percentages will vary among utilities and transmission owners.

10.3 Allocation Factors

Historically, most cost of service studies have computed transmission allocation factors from some combination of monthly peak demands from 1 CP to 12 CP.

Some utilities have recognized that transmission investments are justified by loads in more than one hour in a month. For example, Manitoba Hydro has used a transmission allocator computed from class contribution to the highest 50 hours in the winter, Manitoba Hydro's peak period, and the highest 50 hours in the summer, the period of Manitoba Hydro's maximum exports, which also drive intraprovincial transmission construction (Manitoba Hydro, 2015, Appendix 3.1, p. 9).

The hours of maximum transmission loads may be different from the hours of maximum generation stress. For example, the power lines from remote baseload units to the load centers may be most heavily loaded at moderate demand levels. At high load levels, more of the low-cost remote generation may be used by load closer to the generator, while higher-cost generation in and near the load centers increases, reducing the long-distance transmission line loading. In addition, generator maintenance does not necessarily smooth out transmission reliability risk across months in the same way that it spreads generation shortage risk. If transmission loads peak in winter, when carrying capacity is higher, then transmission peaks may not match even the maximum transmission stress period.

In its Order 1000, establishing regional transmission planning and cost allocation principles, FERC includes the following cost allocation principles, which recognize that transmission is justified by multiple drivers and that different allocation approaches may be justified for different types of transmission facilities:

> (1) The cost of transmission facilities must be allocated to those … that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits. In determining the beneficiaries of transmission facilities, a regional transmission planning process may consider benefits including, but not limited to, the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting public policy requirements established by state or federal laws or regulations that may drive transmission needs. …
>
> (5) The cost allocation method and data requirements for determining benefits and identifying beneficiaries for a transmission facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility.
>
> (6) A transmission planning region may choose to use a different cost allocation method for different types of transmission facilities in the regional plan, such as transmission facilities needed for reliability, congestion relief or to achieve public policy requirements established by state or federal laws or regulations (Federal Energy Regulatory Commission, 2011, ¶ 586).

The FERC guidance clearly anticipates differential treatment of transmission facilities built for different purposes. Aligning costs with benefits may require allocation of transmission costs to most or all hours in which a transmission facility provides service.[133]

Demand-related transmission costs may be allocated to hours in proportion to the usage of the lines or to the high-load hours in which transmission capacity may be tight following a contingency (the failure of some part of the system) or two. The high-load hours may be chosen as a more or less arbitrary number of the highest hours, as in Manitoba, or as the hours in which loads on a particular line or substation are high enough that the worst-case planning contingency (such as the loss of two lines) would leave the transmission system with no more reserve than it has on the system peak with no contingencies.[134]

10.4 Summary of Transmission Allocation Methods and Illustrative Examples

The discussion above has indicated why transmission investments must be carefully scrutinized in the cost allocation process. Different transmission facilities provide different services and are thus appropriately allocated by different allocation methods. Table 28 on the next page lists some types of transmission facilities and identifies appropriate methods for each.

Transmission is a very difficult challenge for the cost analyst because each transmission segment may have a

133 Attributing transmission to hours is more complicated than assigning generation costs by hours, because of the flow of electricity in a network. Once a transmission line is in service, power will flow over it any time there is a voltage differential between the ends of the line, whether or not the line was in any way needed to meet load in that hour.

134 The latter definition would require load flow modeling for each transmission line or a representative sample; the practicality of this approach will depend on the extent of transmission modeling undertaken for system planning.

Table 28. Summary of transmission classification and allocation approaches

Element	Example methods	Comments	Hourly allocation
Bulk transmission	CLASSIFICATION: To energy* — costs to allow centralized generation and economic dispatch; cost due to heating ENERGY ALLOCATOR: All energy DEMAND ALLOCATOR: Highest 100 hours	• Typically above 150 kV • Mostly bidirectional • Operates in all hours	Allocate in proportion to usage or hours needed
Integration of remote generation	CLASSIFICATION: To energy* — costs to connect remote energy resources ENERGY ALLOCATOR: All energy DEMAND ALLOCATOR: Highest 100 hours	Treat same as connected remote resources	Allocate in same manner as remote resources
Economy interconnections	CLASSIFICATION: Energy and demand	Depends on purpose and use of connection	• Allocate reliability value as equivalent peaker • Allocate energy value in proportion to use
Local network	CLASSIFICATION: To energy* — cost due to heating ENERGY ALLOCATOR: On-peak energy DEMAND ALLOCATOR: 4 CP to 12 CP	• Typically below 150 kV • Mostly radial	Allocate in proportion to usage or hours needed
Transmission substations	As lines**	May also have distribution functions	As lines**

* "To energy" = portion classified as energy-related
** "As lines" = in proportion to the classification or allocation of the lines served by each substation

different history and purpose and that purpose may have changed over time. For example, a line originally built to connect a baseload generating unit that has since been retired is repurposed to facilitate economic energy interchange with nearby utilities. In Table 29, we use only three methods, which may or may not be relevant to particular types of transmission costs, including purchased transmission service from another utility, a transmission-owning entity or an ISO. The illustrative data for the 1 CP and equivalent peaker methods are from tables 5 through 7 in Chapter 5, and the hourly allocation factor is derived in Table 27 in Chapter 9.

Table 29. Illustrative allocation of transmission costs by different methods

	Residential	Secondary commercial	Primary industrial	Street lighting	Total
1 CP (legacy)	$16,667,000	$20,000,000	$13,333,000	$0	$50,000,000
Equivalent peaker	$16,237,000	$16,903,000	$15,403,000	$1,457,000	$50,000,000
Hourly	$16,565,000	$17,555,000	$15,015,000	$866,000	$50,000,000

Note: Numbers may not add up to total because of rounding.

11. Distribution in Embedded Cost of Service Studies

Distribution costs are all incurred to deliver energy to customers and are primarily investment-related costs that do not vary in response to load in the short term. Different rate analysts approach these costs in very different ways. These costs are often divided into two categories.

1. Shared distribution, which typically includes at least:
   - Distribution substations, both those that step power down from transmission voltages to distribution voltages and those that step it down from a higher distribution voltage (such as 25 kV) to a lower voltage (such as 12 kV).
   - Primary feeders, which run from the substations to other substations and to customer premises, including the conductors, supports (poles and underground conduit) and various control and monitoring equipment.
   - Most line transformers, which step the primary voltage down to secondary voltages (under 600 V, and mostly in the 120 V and 240 V ranges) for use by customers.
   - A large portion of the secondary distribution lines, which run from the line transformers to customer service lines or drops.
   - The supervisory control and data acquisition equipment that monitors the system operation and records system data. This is a network of sensors, communication devices, computers, software and typically a central control center.
2. Customer-specific costs, which include:
   - Service drops connecting a customer (or multiple customers in a building) to the common distribution system (a primary line, a line transformer or a secondary line or network).
   - Meters, which measure each customer's energy use by month, TOU period or hour and sometimes by maximum demand in the month.[135] Advanced meters can also provide other capabilities, including measurement of voltage, remote sensing of outages, and remote connection and disconnection.[136]
   - Street lighting and signal equipment, which usually can be directly assigned to the corresponding rate classes.
   - In some systems with low customer spatial density, a significant portion of primary lines and transformers serving only one customer.

11.1 Subfunctionalizing Distribution Costs

One important issue in cost allocation is the determination of the portion of distribution cost that is related to primary service (the costs of which are allocated to all customers, except those served at transmission voltage) as opposed to secondary service (the costs of which are borne solely by the secondary voltage customers — residential, some C&I customers, street lighting, etc.).

Some plant accounts and associated expenses are easily subfunctionalized. Substations (which are all primary equipment) have their own FERC accounts (plant accounts 360 to 362, expense accounts 582 and 592). In addition, distribution substations take power from transmission lines and feed it into the distribution system at primary voltage. All distribution substations deliver only primary power and therefore should be subfunctionalized as 100% primary.

135 The Uniform System of Accounts treats meters as distribution plant and the costs of keeping the meters operable as distribution expenses, even though all other metering and billing costs are treated as customer accounts or A&G plant or expenses. Traditional meters that tally only customer usage are not really necessary for the operation of the distribution system, only for the billing function. As a result, references to meters in this chapter are quite limited, and the costs of meters are discussed with meter reading and billing in the next chapter.

136 These capabilities require additional supporting technology, some of which is also required to provide remote meter reading. These costs should be spread among a variety of functions, including distribution and retail services, as discussed in Section 11.5.

However, many other types of distribution investments pose more difficult questions. The FERC accounts do not differentiate lines, poles or conduit between primary and secondary equipment, and many utilities do not keep records of distribution plant cost by voltage level. This means any subfunctionalization requires some sort of special analysis, such as the review of the cost makeup of distribution in areas constituting a representative sample of the system.

Traditionally, most cost of service studies have functionalized a portion of distribution poles as secondary plant, to be allocated only to classes taking service at secondary voltage. This approach is based on misconceptions regarding the joint and complementary nature of various types of poles. Although distribution poles come in all sorts of sizes and configurations, the important distinction for functionalization is what sorts of lines the poles carry: only primary, both primary and secondary or only secondary. The proper functionalization of the first category — poles that carry only primary lines — is not controversial; they are required for all distribution load, the sum of load served at primary and the load for which power is subsequently stepped down to secondary.[137]

For the second category — poles carrying both primary and secondary lines — some cost of service studies have treated a portion of the pole cost as being due to all distribution load and the remainder as being due to secondary loads, to be allocated only to classes served at secondary voltage. There is no cost basis for allocating any appreciable portion of these joint poles to secondary. The incremental pole cost for adding secondary lines to a pole carrying primary is generally negligible. The height of the pole is determined by the voltage of the primary circuits it carries, the number of primary phases and circuits and the local topography. Much of the equipment on the poles (cross arms, insulators, switches and other monitoring and control equipment) is used only for the primary lines. The required strength of the pole (determined by the diameter and material) is determined by the weight of the lines and equipment and by the leverage exerted by that weight (which increases with the height of the equipment and the breadth of the cross arms, again due to primary lines).[138] Equipment used in holding secondary lines has a very low cost compared with those used for primary lines. If the poles currently used for both secondary and primary lines had been designed without secondary lines, the reduction in costs would be very small. Thus, the costs of the joint poles are essentially all due to primary distribution.

Although nearly all poles carry primary lines, a utility sometimes will use a pole just to carry secondary lines, such as to reach from the last transformer on a street to the last house, or to carry a secondary line across a wide road to serve a few customers on the far side. Secondary-only poles are usually shorter and skinnier and thus less expensive than primary poles and do not require cross arms and other primary equipment. Some cost of service studies functionalize a portion of pole costs to secondary, based on the population of secondary-only poles (either from an actual inventory or an estimate) or of short poles (less than 35 feet, for example), on the theory that these short poles must carry secondary.

The assumption that all short poles carry secondary is not correct; some utility poles carry no conductor but rather are stubs used to counterbalance the stresses on heavily loaded (mostly primary) poles, as illustrated in Figure 39 on the next page. Depending on the nature of the distribution system and the utility's design standards, the number of stub poles may rival the number of secondary-only poles.

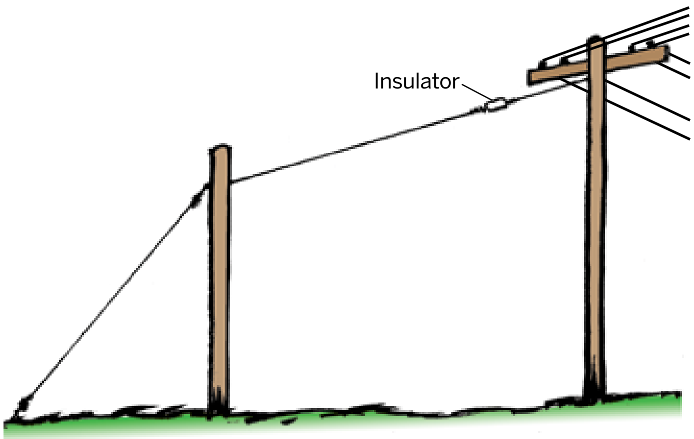
Where only secondary lines are needed, the utility typically saves on pole costs due to the customer taking secondary service, rather than requiring primary voltage service and a bigger pole. Some kind of pole would be needed in that location regardless of the voltage level of service. Hence, the primary customers are better off paying for their share of the secondary poles than if the customers using those poles were to require primary service. It does not seem fair to penalize customers served at secondary for the fact that the utility is able to serve some of them using a type of pole that is less expensive than the poles required for primary service.

As a result, the vast majority of pole costs (other than for

137 The class loads should be measured at primary voltage, including losses, which will be higher for power metered at secondary.

138 There is one situation in which secondary distribution can add to the cost of poles. A very large pole-mounted transformer (perhaps over 75 kVA) may require a stronger pole, which would be a secondary distribution cost. A highly detailed analysis of pole subfunctionalization might thus result in a portion of the cost of those few poles being treated as an extra cost of secondary service, offset to some extent by the savings from some poles being designed to carry only secondary lines.

Figure 39. Stub pole used to guy a primary pole



dedicated poles directly assigned to street lighting or similar services) generally should be treated as serving all distribution customers.[139] For many cost of service studies, that would result in the costs being subfunctionalized as primary distribution, which is then allocated to classes in proportion to their contribution to demand at the primary voltage level.

Line transformers dominate two FERC accounts (plant account 368 and expense account 595), but those accounts also include the costs of capacitors and voltage regulators. These three types of equipment should be subfunctionalized in three different manners:

- Secondary line transformers (which compose the bulk of these accounts) are needed only for customers served at secondary voltage and thus can be subfunctionalized as 100% secondary.
- Voltage regulators are devices on the primary system that adjust voltage levels along the feeder to keep delivered voltage within the design range. The number and capacity of voltage regulators is determined by the distribution of load along the feeder, regardless of whether that load is served at primary or secondary. The regulator costs should be subfunctionalized as primary distribution and classified in the same manner as substations and primary conductors.
- Capacitors improve the power factor on distribution lines at primary voltage, thus reducing line losses (reducing generation, transmission and distribution costs), reducing voltage drop (avoiding the need for larger and additional primary conductors) and increasing primary distribution line capacity. Capacitors can be functionalized as some mix of generation, transmission and primary distribution; in any case they should be functionalized separately from line transformers.

Overhead and underground conductors as well as conduit must be subfunctionalized between primary and secondary using special studies of the composition of the utility's distribution system, since secondary conductors are mostly incremental to primary lines. Estimates of the percentage of these investments that are secondary equipment typically range from 20% to 40%.

Within the primary conductor category, utilities use three-phase feeders for areas with high loads and single-phase (or occasionally two-phase) feeders in areas with lower loads. The additional phases (and hence additional conductors) are due to load levels and the use of equipment that specifically requires three-phase supply (such as some large motors), which is one reason that primary distribution is overwhelmingly load-related and should be so treated in classification.

Some utilities subfunctionalize single- and three-phase conductors, treating the single-phase lines as incremental to the three-phase lines (see, for example, Peppin, 2013, pp. 25-26). Classes that use a lot of single-phase lines are allocated both the average cost of the three-phase lines and the average cost of the single-phase lines. This treatment of single-phase service as being more expensive than three-phase service gets it backward. If load of a single-phase customer or area changed in a manner that required three-phase service, the utility's costs would increase; if anything, classes disproportionally served with single-phase primary should be assigned lower costs than those requiring three-phase service. The classification of primary conductor as load-related will allocate more of the three-phase costs to the classes whose loads require that equipment.

139 As noted above, some utilities may be able to attribute some upgrades in pole class to line transformers; that increment is appropriately functionalized to secondary service. On the other hand, the secondary classes may be due a small credit to reflect the fact that they allow the use of some less expensive poles.

11.2 Distribution Classification

Newly evolving methods can fairly allocate a substantial portion of distribution costs on an energy basis.

The classification of distribution infrastructure has been one of the most controversial elements of utility cost allocation for more than a half-century. Bonbright devoted an entire section to a discussion of why none of the methods then commonly used was defensible (1961, pp. 347-368). In any case, traditional methods have divided up distribution costs as either demand-related or customer-related, but newly evolving methods can fairly allocate a substantial portion of these costs on an energy basis.

Distribution equipment can be usefully divided into three groups:

- Shared distribution plant, in which each item serves multiple customers, including substations and almost all spans of primary lines.
- Customer-related distribution plant that serves only one customer, particularly traditional meters used solely for billing.
- A group of equipment that may serve one customer in some cases or many customers in others, including transformers, secondary lines and service drops.

The basic customer method for classification counts only customer-specific plant as customer-related and the entire shared distribution network as demand- or energy-related. For relatively dense service territories, in cities and suburbs, this would be only the traditional meter and a portion of service drop costs.[140] For very thinly settled territories, particularly rural cooperatives, customer-specific plant may include some portion of transformer costs and the percentage of the primary system that consists of line extensions to individual customers. Many jurisdictions have mandated or accepted the basic customer classification approach, sometimes including a portion of transformers in the customer cost. These jurisdictions include Arkansas,[141] California,[142] Colorado,[143] Illinois,[144] Iowa,[145] Massachusetts,[146] Texas[147] and Washington.[148]

The basic customer method for classification is by far the most equitable solution for the vast majority of utilities.

---

140 Alternatively, all service drops may be treated as customer-related and the sharing of service drops can be reflected in the allocation factor. As discussed in Section 5.2, treating multifamily housing as a separate class facilitates crediting those customers with the savings from shared service drops, among other factors.

141 The Arkansas Public Service Commission found that "accounts 364-368 should be allocated to the customer classes using a 100% demand methodology and ... that [large industrial consumer parties] do not provide sufficient evidence to warrant a determination that these accounts reflect a customer component necessary for allocation purposes" (2013, p. 126).

142 California classifies all lines (accounts 364 through 367) as demand-related for the calculation of marginal costs, while classifying transformers (Account 368) as customer-related with different costs per customer for each customer class, reflecting the demands of the various classes.

143 In 2018, the state utility commission affirmed a decision by an administrative law judge that rejected the **zero-intercept approach** and classified FERC accounts 364 through 368 as 100% demand-related (Colorado Public Utilities Commission, 2018, p. 16).

144 "As it has in the past, ... the [Illinois Commerce] Commission rejects the minimum distribution or zero-intercept approach for purposes of allocating distribution costs between the customer and demand functions in this case. In our view, the coincident peak method is consistent with the fact that distribution systems are designed primarily to serve electric demand. The Commission believes that attempts to separate the costs of connecting customers to the electric distribution system from the costs of serving their demand remain problematic" (Illinois Commerce Commission, 2008, p. 208).

145 According to 199 Iowa Administrative Code 20.10(2)e, "customer cost component estimates or allocations shall include only costs of the distribution system from and including transformers, meters and associated customer service expenses." This means that all of accounts 364 through 367 are demand-related. Under this provision, the Iowa Utilities Board classifies the cost of 10 kVA per transformer as customer-related but reduces the cost that is assigned to residential and small commercial customers to reflect the sharing of transformers by multiple customers.

146 "Plant items classified as customer costs included only meters, a portion of services, street lighting plant, and a portion of labor-related general plant" (La Capra, 1992, p. 15). See also Gorman, 2018, pp. 13-15.

147 Texas has explicitly adopted the basic customer approach for the purposes of rate design: "Specifically, the customer charge shall be comprised of costs that vary by customer such as metering, billing and customer service" (Public Utility Commission of Texas, 2000, pp. 5-6). But it has followed this rule in practice for cost allocation as well.

148 "The Commission finds that the Basic Customer method represents a reasonable approach. This method should be used to analyze distribution costs, regardless of the presence or absence of a decoupling mechanism. We agree with Commission Staff that proponents of the Minimum System approach have once again failed to answer criticisms that have led us to reject this approach in the past. We direct the parties not to propose the Minimum System approach in the future unless technological changes in the utility industry emerge, justifying revised proposals" (Washington Utilities and Transportation Commission, 1993, p. 11).

For certain rural utilities, this may be reasonable under the conceptual view that the size of distribution components (e.g., the diameter of conductors or the capacity of transformers) is load-related, but the number and length of some types of equipment is customer-related. In some rural service territories, the basic customer cost may require nearly a mile of distribution line along the public way as essentially an extended service drop.

However, more general attempts by utilities to include a far greater portion of shared distribution system costs as customer-related are frequently unfair and wholly unjustified. These methods include straight fixed/variable approaches where all distribution costs are treated as customer-related (analogous to the misuse of the concept of fixed costs in classifying generation discussed in Section 9.1) and the more nuanced minimum system and zero-intercept approaches included in the 1992 NARUC cost allocation manual.

The minimum system method attempts to calculate the cost (in constant dollars) if the utility's installed units (transformers, poles, feet of conductors, etc.) were each the minimum-sized unit of that type of equipment that would ever be used on the system. The analysis asks: How much would it have cost to install the same number of units (poles, feet of conductors, transformers) but with the size of the units installed limited to the current minimum unit normally installed? This minimum system cost is then designated as customer-related, and the remaining system cost is designated as demand-related. The ratio of the costs of the minimum system to the actual system (in the same year's dollars) produces a percentage of plant that is claimed to be customer-related.

This minimum system analysis does not provide a reliable basis for classifying distribution investment and vastly overstates the portion of distribution that is customer-related. Specifically, it is unrealistic to suppose that the mileage of the shared distribution system and the number of physical units are customer-related and that only the size of the components is demand-related, for at least eight reasons.

1. Much of the cost of a distribution system is required to cover an area and is not sensitive to either load or customer number. The distribution system is built to cover an area because the total load that the utility expects to serve will justify the expansion into that area. Serving many customers in one multifamily building is no more expensive than serving one commercial customer of the same size, other than metering. The shared distribution cost of serving a geographical area for a given load is roughly the same whether that load is from concentrated commercial or dispersed residential customers along a circuit of equivalent length and hence does not vary with customer number.[149] Bonbright found that there is "a very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by the system." He concluded that "the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems … clearly indefensible. [Cost analysts are] under impelling pressure to fudge their cost apportionments by using the category of customer costs as a dumping ground" (1961, p. 348).
2. The minimum system approach erroneously assumes that the minimum system would consist of the same number of units (e.g., number of poles, feet of conductors) as the actual system. In reality, load levels help determine the number of units as well as their size. Utilities build an additional feeder along the route of an existing feeder (or even on the same poles); loop a second feeder to the end of an existing line to pick up some load from the existing line; build an additional feeder in parallel with an existing feeder to pick up the load of some of its branches; and upgrade feeders from single-phase to three-phase. As secondary load grows, the utility typically will add transformers, splitting smaller customers among the existing and new transformers.[150] Some other feeder construction is designed to improve reliability (e.g., to interconnect feeders with automatic switching to reduce the number of customers affected by outages and outage duration).

149 As noted above, for some rural utilities, particularly cooperatives that extend distribution without requiring that the extension be profitable, a portion of the distribution system may effectively be customer-specific.

150 Adding transformers also reduces the length of the secondary lines from the transformers to the customers, reducing losses, voltage drop or the required gauge of the secondary lines.

3. Load can determine the type of equipment installed as well. When load increases, electric distribution systems are often relocated from overhead to underground (which is more expensive) because the weight of lines required to meet load makes overhead service infeasible. Voltages may also be increased to carry more load, requiring early replacement of some equipment with more expensive equipment (e.g., new transformers, increased insulation, higher poles to accommodate higher voltage or additional circuits). Thus, a portion of the extra costs of moving equipment underground or of newer equipment may be driven in part by load.
4. The "minimum system" would still meet a large portion of the average residential customer's demand requirements. Using a minimum system approach requires reducing the demand measure for each class or otherwise crediting the classes with many customers for the load-carrying capability of the minimum system (Sterzinger, 1981, pp. 30-32).
5. Minimum system analyses tend to use the current minimum-sized unit typically installed, not the minimum size ever installed or available. The current minimum unit is sized to carry expected demand for a large percentage of customers or situations. As demand has risen over time, so has the minimum size of equipment installed. In fact, utilities usually stop stocking some less expensive small equipment because rising demand results in very rare use of the small equipment and the cost of maintaining stock is no longer warranted.[151] However, the transformer industry could produce truly minimum-sized utility transformers, the size of those used for cellular telephone chargers, if there were a demand for these.
6. Adding customers without adding peak demand or serving new areas does not require any additional poles or conductors. For example, dividing an existing home into two dwelling units increases the customer count but likely adds nothing in utility investment other than a second meter. Converting an office building from one large tenant to a dozen small offices similarly increases customer number without increasing shared distribution costs. And the shared distribution investment on a block with four large customers is essentially the same as for a block with 20 small customers with the same load characteristics. If an additional service is added into an existing street with electrical service, there is usually no need to add poles, and it would not be reasonable to assume any pole savings if the number of customers had been half the actual number.
7. Most utilities limit the investment they will make for low projected sales levels, as we also discuss in Section 15.2, where we address the relationship between the utility line extension policy and the utility cost allocation methodology. The prospect of adding revenues from a few commercial customers may induce the utility to spend much more on extending the distribution system than it would invest for dozens of residential customers.
8. Not all of the distribution system is embedded in rates, since some customers pay for the extension of the system with **contributions in aid of construction**, as discussed in Section 15.2. Factoring in the entire length of the system, including the part paid for with these contributions, overstates the customer component of ratepayer-funded lines.

Thus, the frequent assumption that the number of feet of conductors and the number of secondary service lines is related to customer number is unrealistic. A piece of equipment (e.g., conductor, pole, service drop or meter) should be considered customer-related only if the removal of one customer eliminates the need for the unit. The number of meters and, in most cases, service drops is customer-related, while feet of conductors and number of poles are almost entirely load-related. Reducing the number of customers, without reducing area load, will only rarely affect the length of lines or the number of poles or transformers. For example, removing one customer will avoid

151 For example, in many cases, utilities that make an allocation based on a minimum system use 10-kVA transformers, even though they installed 3-kVA or 5-kVA transformers in the past. Some utilities also have used conductor sizes and costs significantly higher than the actual minimum conductor size and cost on their systems.

overhead distribution equipment only under several unusual circumstances.[152] These circumstances represent a very small part of the shared distribution cost for the typical urban or suburban utility, particularly since many of the most remote customers for these utilities might be charged a contribution in aid of construction. These circumstances may be more prevalent for rural utilities, principally cooperatives.

The related zero-intercept method attempts to extrapolate from the cost of actual equipment (including actual minimum-sized equipment) to the cost of hypothetical equipment that carries zero load. The zero-intercept method usually involves statistical regression analysis to decompose the costs of distribution equipment into customer-related costs and costs that vary with load or size of the equipment, although some utilities use labor installation costs with no equipment. The idea is that this procedure identifies the amount of equipment required to connect existing customers that is not load-related (a zero-kVA transformer, a zero-**ampere** conductor or a pole that is zero feet high). The zero-intercept regression analysis is so abstract that it can produce a wide range of results, which vary depending on arcane statistical methods and the choice of types of equipment to include or exclude from an equation. As a result, the zero-intercept method is even less realistic than the minimum system method.

The best practice is to determine customer-related costs using the basic customer method, then use more advanced techniques to split the remainder of shared distribution system costs as energy-related and demand-related. Energy use, especially in high-load hours and in off-peak hours on high-load days, affects distribution investment and outage costs in the following ways:

- The fundamental reason for building distribution systems is to deliver energy to customers, not simply to connect them to the grid.
- The number and extent of overloads determines the life of the insulation on lines and in transformers (in both substations and line transformers) and hence the life of the equipment. A transformer that is very heavily loaded for a couple of hours a year and lightly loaded in other hours may last 40 years or more until the enclosure rusts away. A similar transformer subjected to the same annual peaks, but also to many smaller overloads in each year, may burn out in 20 years.
- All energy in high-load hours, and even all hours on high-load days, adds to heat buildup and results in sagging overhead lines, which often defines the thermal limit on lines; aging of insulation in underground lines and transformers; and a reduction the ability of lines and transformers to survive brief load spikes on the same day.
- Line losses depend on load in every hour (marginal line losses due to another kWh of load greatly exceed the average loss percentage in that hour, and losses at peak loads dramatically exceed average losses).[153] To the extent that a utility converts a distribution line from single-phase to three-phase, selects a larger conductor or increases primary voltage to reduce losses, the costs are primarily energy-related.
- Customers with a remote need for power only a few hours per year, such as construction sites or temporary businesses like Christmas tree lots, will often find non-utility solutions to be more economical. But when those same types of loads are located along existing distribution lines, they typically connect to utility service if the utility's **connection charges** are reasonable.

A portion of distribution costs can thus be classified to energy, or the demand allocation factor can be modified to reflect energy effects.

The average-and-peak method, discussed in Section 9.1 in the context of generation classification, is commonly used by natural gas utilities to classify distribution mains and other shared distribution plant.[154] This approach recognizes that a portion of shared distribution would be needed even if all

152 These circumstances are: (1) if the customer would have been the farthest one from the transformer along a span of secondary conductor that is not a service drop; (2) if the customer is the only one served off the last pole at the end of a radial primary feeder, a pole and a span of secondary, or a span of primary and a transformer; and (3) if several poles are required solely for that customer.

153 For a detailed analysis of the measurement and valuation of marginal line losses, see Lazar and Baldwin (2011).

154 See *Gas Distribution Rate Design Manual* from the National Association of Regulatory Utility Commissioners (1989, pp. 27-28) as well as more recent orders from the Minnesota Public Utilities Commission describing the range of states that use basic customer and average-and-peak methods for natural gas cost allocation (2016, pp. 53-54) and the Michigan Public Service Commission affirming the usage of the average-and-peak method (2017, pp. 113-114).

customers used power at a 100% load factor, while other costs are incurred to upsize the system to meet local peak demands. The same approach may have a place in electric distribution system classification and allocation, with something over half the basic infrastructure (poles, conductors, conduit and transformers) classified to energy to reflect the importance of energy use in justifying system coverage and the remainder to demand to reflect the higher cost of sizing equipment to serve a load that isn't uniform.

Nearly every electric utility has a line extension policy that dictates the circumstances under which the utility or a new customer must pay for an extension of service. Most of these provide only a very small investment by the utility in shared facilities such as circuits, if expected customer usage is very small, but much larger utility investment for large added load. Various utilities compute the allowance for line extensions in different ways, which are usually a variant of one of the following approaches:

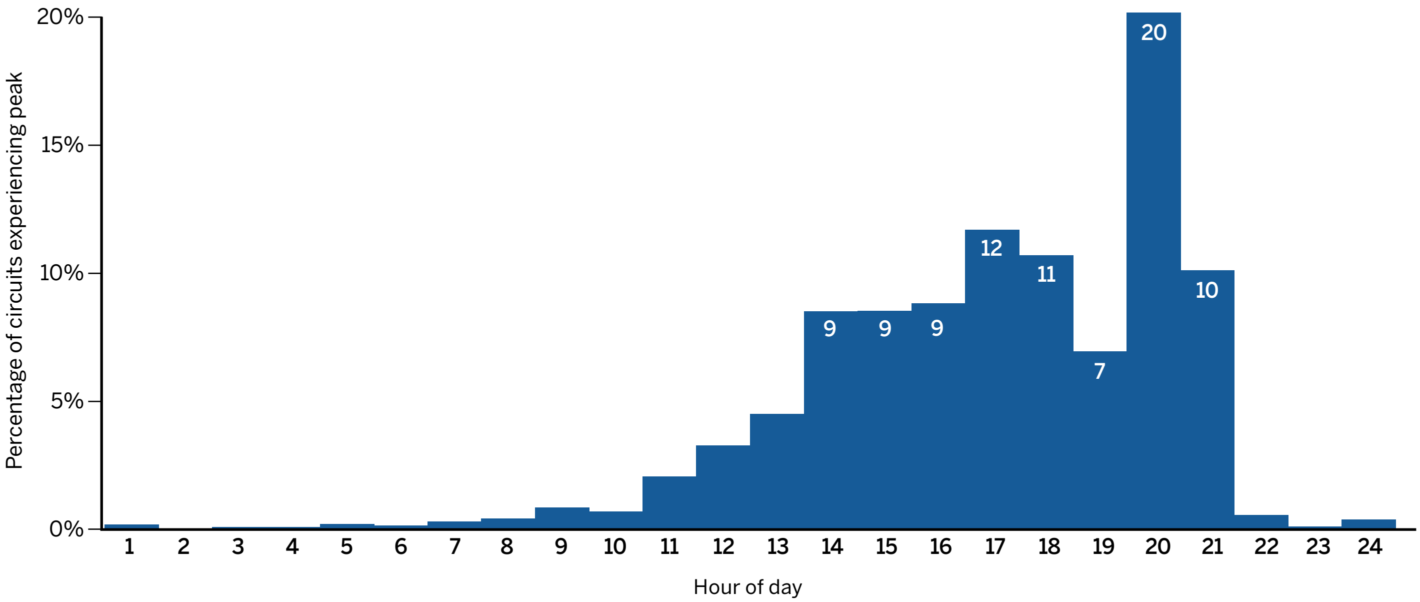
- The credit equals a multiple of revenue. For example, Otter Tail Power Co. in Minnesota will invest up to three times the expected annual revenue, with the customer bearing any excess (Otter Tail Power Co., 2017, Section 5.04). Xcel Energy's Minnesota subsidiary uses 3.5 times expected annual revenue for nonresidential customers (Northern States Power Co.-Minnesota, 2010, Sheet 6-23). Other utilities base their credits on expected nonfuel revenue or the distribution portion of the tariff; on different periods of revenue; and on either simple total revenue or present value of revenue.[155] These are clearly usage-related allowances that, in turn, determine how much cost for distribution circuits is reflected in the utility revenue requirement. Applying this logic, all shared distribution plant should thus be classified as usage-related, and none of the shared distribution system should be customer-related.
- The credit is the actual extension cost, capped at a fixed value. For example, Minnesota Power pays up to $850 for the cost of extending lines, charges $12 per foot for costs over $850 and charges actual costs for extensions over 1,000 feet (Minnesota Power, 2013, p. 6). Xcel Energy's Colorado subsidiary gives on-site construction allowances of $1,659 for residential customers, $2,486 for small commercial, $735 per kW for other secondary nonresidential and $680 per kW for primary customers (Public Service Company of Colorado, 2018, Sheet R226). The company describes these allowances as "based on two and three-quarters (2.75) times estimated annual non-fuel revenue" — a simplified version of the revenue approach.[156]
- The credit is determined by distance. Xcel Energy's Minnesota subsidiary includes the first 100 feet of line extension for a residential customer into rate base, with the customer bearing the cost for any excess length (Northern States Power Co.-Minnesota, 2010, Sheet 6-23). Green Mountain Power applies a credit equal to the cost of 100 feet of overhead service drop but no costs for poles or other equipment (Green Mountain Power, 2016, Sheet 148). The portion of the line extensions paid by the utility might be thought of as customer-related, with some caveats. First, the amount of the distribution system that was built out under this provision is almost certainly much less than 100 feet times the number of residential customers. Second, these allowances are often determined as a function of expected revenue, as in the Xcel Colorado example, and thus are usage-related.

If the line extension investment is tied to revenue (and most revenue is associated with usage-related costs, such as fuel, purchased power, generation, transmission and substations), then the resulting investment should be classified and allocated on a usage basis. The cost of service study should ensure that the costs customers prepay are netted out (including not just the costs but the footage of lines or excess costs of poles and transformers if a minimum system method is used) before classifying any distribution costs as customer-related.

155 California sets electric line extension allowances at expected net distribution revenue divided by a cost of service factor of roughly 16% (California Public Utilities Commission, 2007, pp. 8-9).

156 The company also has the option of applying the 2.75 multiple directly (Public Service Company of Colorado, 2018, Sheet R212).

Figure 40. San Diego Gas & Electric circuit peaks



Source: Fang, C. (2017, January 20). Direct testimony on behalf of San Diego Gas & Electric. California Public Utilities Commission Application No. 17-01-020

11.3 Distribution Demand Allocators

In any traditional study, a significant portion of distribution plant is classified as demand-related. A newer hourly allocation method may omit this step, assigning distribution costs to all hours when the asset (or a portion of the cost of the asset) is required for service.

For demand-related costs, class NCP is commonly, but often inappropriately, used for allocation. This allocator would be appropriate if each component overwhelmingly served a single class, if the equipment peaks occurred roughly at the time of the class peak, and if the sizing of distribution equipment were due solely to load in a single hour. But to the contrary, most substations and many feeders serve several tariffs, in different classes, and many tariff codes.[157]

11.3.1 Primary Distribution Allocators

Customers in a single class, in different areas and served by different substations and feeders, may experience peak loads at different times. Figure 40 shows the hours when each of San Diego Gas & Electric's distribution circuits experienced peak loads (Fang, 2017, p. 21). The peaks are clustered between the early afternoon (on circuits that are mostly commercial) and the early evening (mostly residential), while other circuits experience their peaks at a wide variety of hours.

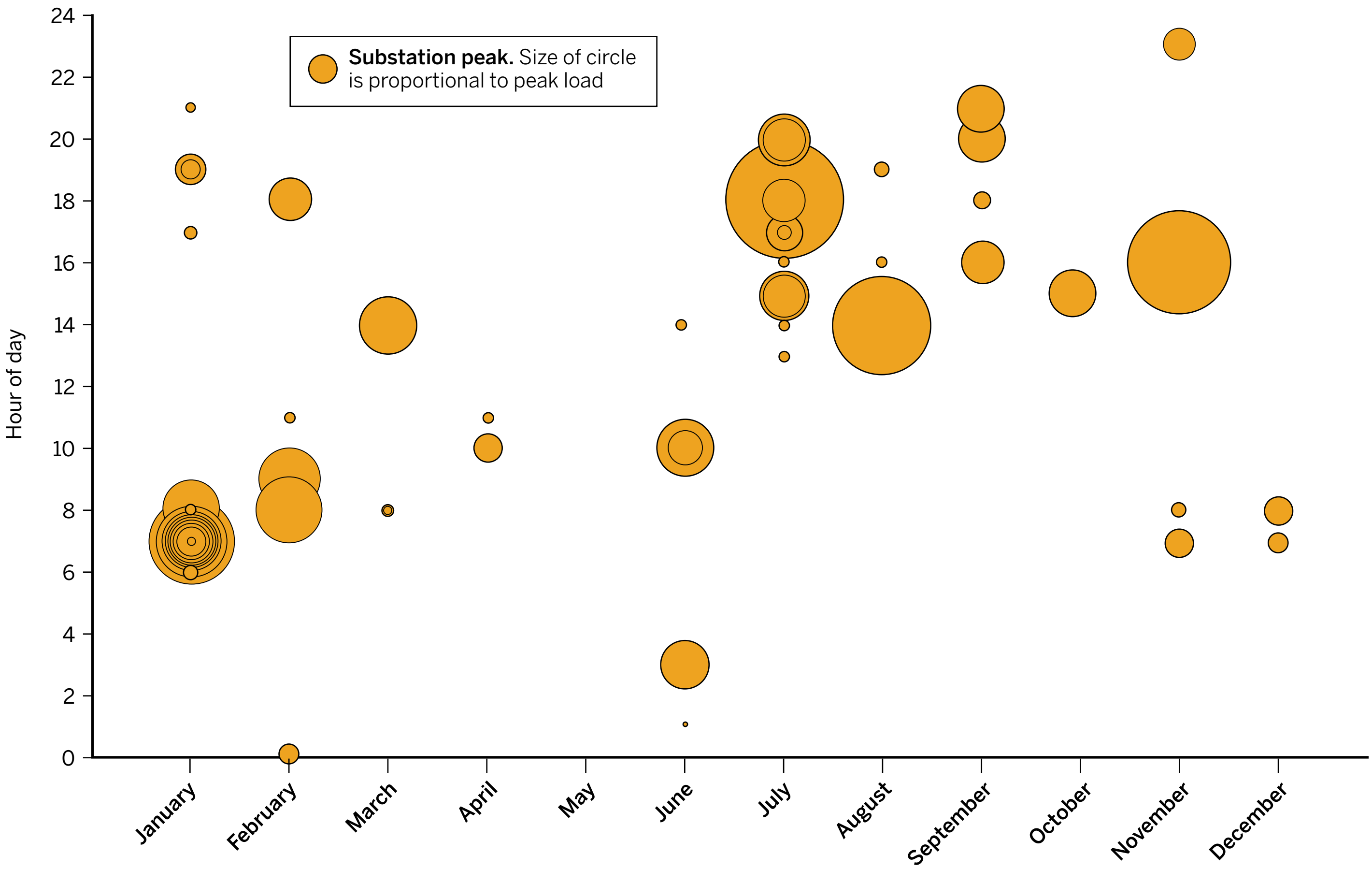
Figure 41 on the next page shows the distribution of substation peaks for Delmarva Power & Light over a period of one year (Delmarva Power & Light, 2016). The area of each bubble is proportional to the peak load on the station. Clearly, no one peak hour (or even a combination of monthly peaks) is representative of the class contribution to substation peaks.

The peaks for substations, lines and other distribution equipment do not necessarily align with the class NCPs. Indeed, even if all the major classes are summer peaking, some of the substations and feeders may be winter peaking, and vice versa. Even within a season, substation and feeder peaks will be distributed to many hours and days.

Although load levels drive distribution costs, the maximum load on each piece of equipment is not the only important load. As explained in Subsection 5.1.3, increased

157 Some utilities design their substations so that each feeder is fed by a single transformer, rather than all the feeders being served by all the transformers at the substation. In those cases, the relevant loads (for timing and class mix) are at the transformer level, rather than the entire substation.

Figure 41. Month and hour of Delmarva Power & Light substation peaks in 2014



Source: Delmarva Power & Light. (2016, August 15). Response to the Office of the People's Counsel data request 5-11, Attachment D. Maryland Public Service Commission Case No. 9424

energy use, especially at high-load hours and prior to those hours, can also affect the sizing and service life of transformers and underground lines, which is thus driven by the energy use on the equipment in high-load periods, not just the maximum demand hour. The peak hourly capacity of a line or transformer depends on how hot the equipment is prior to the peak load, which depends in turn on the load factor in the days leading up to the peak and how many high-load hours occur prior to the peak. More frequent events of load approaching the equipment capacity, longer peaks and hotter equipment going into the peak period all contribute to faster insulation deterioration and cumulative line sag, increasing the probability of failure and accelerating aging.

Ideally, the allocators for each distribution plant type should reflect the contribution of each class to the hours when load on the substation, feeder or transformer contributes to the potential for overloads. That allocation could be constructed by assigning costs to hours or by constructing a special demand allocator for each category of distribution equipment. If a detailed allocation is too complex, the allocators for costs should still reflect the underlying reality that distribution costs are driven by load in many hours.

The resulting allocator should reflect the variety of seasons and times at which the load on this type of equipment experiences peaks. In addition, the allocator should reflect the near-peak and prepeak loads that contribute to overheating and aging of equipment. Selecting the important hours for distribution loads and the weight to be given to the prepeak loads may require some judgments. Class NCP allocators do not serve this function.

Rocky Mountain Power allocates primary distribution on monthly coincident distribution peak, weighted by the percentage of substations peaking in each month (Steward, 2014, p. 7). Under this weighting scheme, for example:

- A small substation has as much effect on a month's weighting factor as a large substation. The month with the largest number of large substations seriously overloaded could be the highest-cost month yet may not receive the highest weight since each substation is weighted equally.
- The month's contribution to distribution demand costs is assumed to occur entirely at the hour of the monthly distribution peak, even though most of the substation capacity that peaks in the month may have peaked in a variety of different hours.
- A month would receive a weight of 100% whether each substation's maximum load was only 1 kVA more than its maximum in every other month or four times its maximum in every other month.

This approach could be improved by reflecting the capacity of the substations, the actual timing of the peak hours and the number of near-peak hours of each substation in each month. The hourly loads might be weighted by the square or some other power of load or by using a peak capacity allocation factor for the substation, to reflect the fact that the contribution to line losses and equipment life falls rapidly as load falls below peak.

Many utilities will need to develop additional information on system loads for cost allocation, as well as for planning, operational and rate design purposes. Specifically, utilities should aim to understand when each feeder and substation reaches its maximum loads and the mix of rate classes on each feeder and distribution substation.

In the absence of detailed data on the loads on line transformers, feeders and substations, utilities will be limited to cruder aggregate load data. For primary equipment, the best available proxy may be the class energy usage in the expected high-load period for the equipment, the class contribution to coincident peak or possibly class NCP, but only if that NCP is computed with respect to the peak load of the customers sharing the equipment. Although most substations and feeders serving industrial and commercial customers will also serve some residential customers, and most residential substations and feeders will have some commercial load, some percentage of distribution facilities serve a single class.

The NCP approximation is not a reasonable approximation for finer disaggregation of class loads. For example, there are many residential areas that contain a mix of single-family and multifamily housing and homes with and without electric space heating, electric water heating and solar panels. The primary distribution plant in those areas must be sized for the combined load in coincident peak periods, which may be the late afternoon summer cooling peak, the evening winter heating and lighting peak or some other time — but it will be the same time for all the customers in the area.[158]

Many utilities have multiple tariffs or tariff codes for residential customers (e.g., heating, water heating, all-electric and solar; single-family, multifamily and public housing; low-income and standard), for commercial customers (small, medium and large; primary and secondary voltage; schools, dormitories, churches and other customer types) and for various types of industrial customers, in addition to street lighting and other services. In most cases, those subclasses will be mixed together, resulting in customers with gas and electric space heat, gas and electric water heat, and with and without solar in the same block, along with street lights. The substation and feeder will be sized for the combined load, not for the combined peak load of just the electric heat customers or the combined peak of the customers with solar panels[159] or the street lighting peak.

Unless there is strong geographical differentiation of the subclasses, any NCP allocator should be computed for the

158 Distribution conductors and transformers have greater capacity in winter (when heat is removed quickly) than in summer; even if winter peak loads are higher, the sizing of some facilities may be driven by summer loads.

159 The division of the residential class into subclasses for calculation of the class NCP has been an issue in several recent Texas cases. In Docket No. 43695, at the recommendation of the Office of Public Utility Counsel, the Public Utility Commission of Texas reversed its former method for Southwestern Public Service to use the NCP for a single residential class (instead of separate subclasses for residential customers with and without electric heat), which reduced the costs allocated to residential customers as a whole (Public Utility Commission of Texas, 2015, pp. 12-13 and findings of fact 277A, 277B and 339A). The issue was also raised in dockets 44941 and 46831 involving El Paso Electric Co. El Paso Electric proposed separate NCP allocations for residential customers with and without solar generation, which the Office of Public Utility Counsel and solar generator representatives opposed. Both of these cases were settled and did not create a precedent.

combined load of the customer classes, with the customer class NCP assigned to rate tariffs in proportion to their estimated contribution to the customer class peak.

11.3.2 Relationship Between Line Losses and Conductor Capacity

In some situations, conductor size is determined by the economics of line losses rather than by thermal overloads or voltage drop. Even at load levels that do not threaten reliability, larger conductors may cost-effectively reduce line losses, especially in new construction.[160] The incremental cost of larger capacity can be entirely justified by loss reduction (which is mostly an energy-related benefit), with higher load-carrying capability as a free additional benefit.

11.3.3 Secondary Distribution Allocators

Each piece of secondary distribution equipment generally serves a smaller number of customers than a single piece of primary distribution equipment. On a radial system, a line transformer may serve a single customer (a large commercial customer or an isolated rural residence) or 100 apartments; a secondary line may serve a few customers or a dozen, depending on the density of load and construction. Older urban neighborhoods often have secondary lines that are connected to several transformers, and some older large cities such as Baltimore have full secondary networks in city centers.[161] In contrast, a primary distribution feeder may serve thousands of customers, and a substation can serve several feeders.

Thus, loads on secondary equipment are less diversified than loads on primary equipment. Hence, cost of service studies frequently allocate secondary equipment on load measures that reflect customer loads diversified for the number of customers on each component. Utilities often use assumed diversity factors to determine the capacity required for secondary lines and transformers, for various numbers of customers. Figure 42 on the next page provides an example of the diversity curve from El Paso Electric Co. (2015, p. 24).

Even identical houses with identical equipment may routinely peak at different times, depending on household composition, work and school schedules and building orientation. The actual peak load for any particular house may occur not at typical peak conditions but because of events not correlated with loads in other houses. For example, one house may experience its maximum load when the family returns from vacation to a hot house in the summer or a very cold one in the winter, even if neither temperatures nor time of day would otherwise be consistent with an annual maximum load. The house next door may experience its maximum load after a water leak or interior painting, when the windows are open and fans, dehumidifiers and the heating or cooling system are all in use.

Accounting for diversity among different types of residential customers, the load coincidence factors would be even lower. A single transformer may serve some homes with electric heat, peaking in the winter, and some with fossil fuel heat, peaking in the summer.

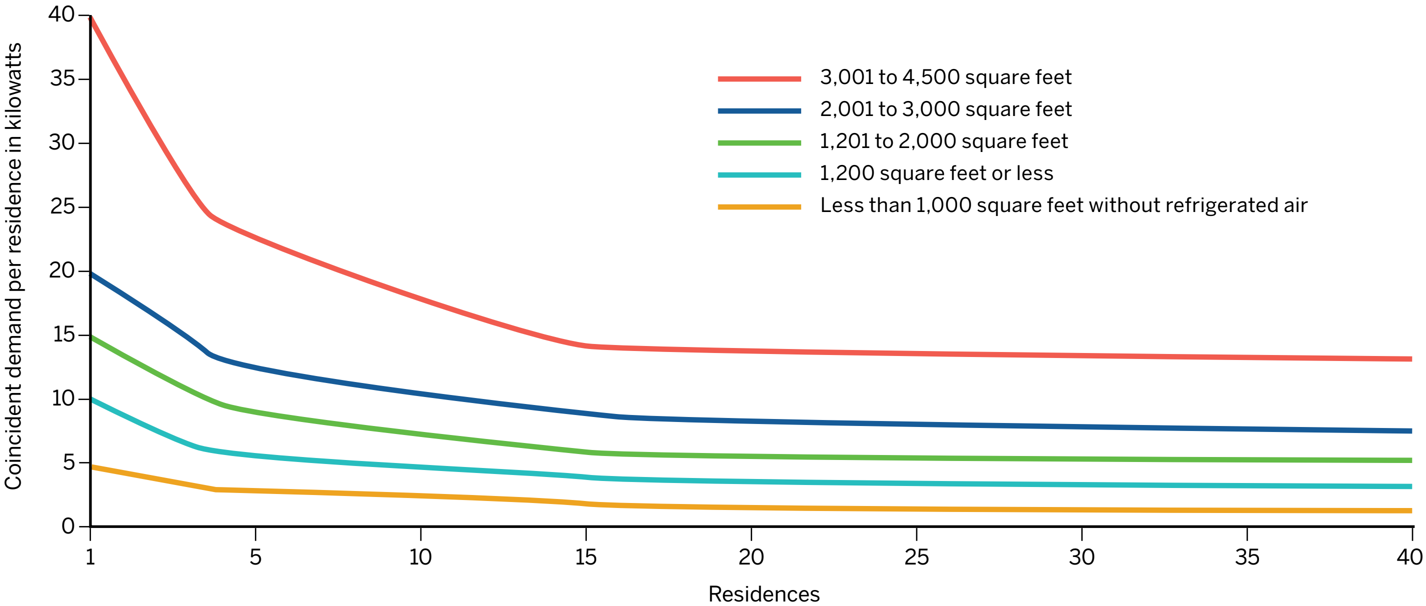
The average transformer serving residential customers may serve a dozen customers, depending on the density of the service territory and the average customer NCP, which for the example in Figure 42 suggests that the customers' average contribution to the transformer peak load would be about 40% of the customers' undiversified load. Thus, the residential allocator for transformer demand would be the class NCP times 40%. Larger commercial customers generally have very little diversity at the transformer level, since each transformer (or bank of transformers) typically serves only one or a few customers.

The same factors (household composition, work and

160 The same is true for increased distribution voltage. Seattle City Light upgraded its residential distribution system from 4 kV to 26 kV in the early 1980s based on analysis done in the Energy 1990 study, prepared in 1976, which focused on avoiding new baseload generation. The line losses justified the expenditure, but the result was also a dramatic increase in distribution system circuit capacity. The Energy 1990 study was discussed in detail in a meeting of the City Council Utilities Committee (Seattle Municipal Archives, 1977).

161 In high-load areas, such as city centers, utilities often operate secondary distribution networks, in which multiple primary feeders serve multiple transformers, which then feed a network of interconnected secondary lines that feed all the customers on the network (See Behnke et al., 2005, p. 11, Figure 8). In secondary networks, the number of transformers and the investment in secondary lines are driven by the aggregate load of the entire network or large parts of the network. The loss of any one feeder and one transformer, or any one run of secondary line, will not disconnect any customer. The existence of the network, the number of transformers and the number and length of primary and secondary lines are entirely load-related. Similar arrangements, called spot networks, are used to serve individual large customers with high reliability requirements. A single spot network customer may thus have multiple transformers, providing redundant capacity.

Figure 42. Typical utility estimates of diversity in residential loads



Source: El Paso Electric Co. (2015, October 29). *El Paso Electric Company's Response to Office of Public Utility Counsel's Fifth Request for Information.* Public Utility Commission of Texas Docket No. 44941

school schedules, unit-specific events) apply in multifamily housing as well as in single-family housing. But the effects of orientation are probably even stronger in multifamily housing than in single-family homes. For example, units on the east side of a building are likely to have summer peak loads in the morning, while those on the west side are likely to experience maximum loads in the evening and those on the south in the middle of the day.

Importantly, Figure 42 represents the diversity of similar neighboring single-family houses. Diversity is likely to be still higher for other applications, such as different types and vintages of neighboring homes, or the great variety of customers who may be served from the shared transformers and lines of a secondary network.

Until 2001, the major U.S. electric utilities were required to provide the number and capacity of transformers in service on their FERC Form 1 reports. Assuming an average of one transformer per commercial and industrial customer, these reports typically suggest a ratio ranging from 3 to more than 20 residential customers per transformer, with the lower ratios for the most rural IOUs and the highest for utilities with dense urban service territories and many multifamily consumers.[162] Only about a dozen electric co-ops filed a FERC Form 1 with the transformer data in 2001, and their ratios vary from about 1 transformer per residential customer for a few very rural co-ops to about 8 residential customers per transformer for Chugach Electric, which serves part of Anchorage as well as rural areas.

Utilities can often provide detailed current data from their geographic information systems. Table 30 on the next page shows Puget Sound Energy's summary of the number of transformers serving a single residential customer and the number serving multiple customers (Levin, 2017, pp. 8-9). More than 95% of customers are served by shared transformers, and those transformers serve an average of 5.3 customers. Using the method described in the previous paragraph, an estimated average of 4.9 Puget Sound Energy residential customers would share a transformer, which is close to the actual average of 4.5 customers per transformer shown in Table 30 (Levin, 2017, and additional calculations by the authors).

The customers who have their own transformer may be too far from their neighbors to share a transformer, or local load growth may have required that the utility add a transformer. In many cases, residential customers with

162 Ratios computed using Form 1, p. 429, transformer data (Federal Energy Regulatory Commission, n.d.) and 2001 numbers from utilities' federal Form 861 (U.S. Energy Information Administration, n.d.-a, file 2).

Table 30. Residential shared transformer example

	With multiple residences per transformer	With single residence per transformer	Total
Number of transformers	197,503	47,699	245,202
Number of customers	1,054,296	47,699	1,101,995
Customers per transformer	5.3	1	4.5

Sources: Levin, A. (2017, June 30). Prefiled response testimony on behalf of NW Energy Coalition, Renewable Northwest and Natural Resources Defense Council. Washington Utilities and Transportation Commission Docket No. UE-170033; additional calculations by the authors

individual transformers may need to pay to obtain service that is more expensive than their line extension allowances (see Section 11.2 or Section 15.2).

Small customers will have similar, but lower, diversity on secondary conductors, which generally serve multiple customers but not as many as a transformer. A transformer that serves a dozen customers may serve two of them directly without secondary lines, four customers from one stretch of secondary line and six from another stretch of secondary line running in the opposite direction or across the street.

Where no detailed data are available on the number of customers per transformer in each class, a reasonable approximation might be to allocate transformer demand costs on a simple average of class NCP and customer NCP for residential and small commercial customers and just customer NCP for larger nonresidential customers.

11.3.4 Distribution Operations and Maintenance Allocators

Distribution O&M accounts associated with a single type of equipment (FERC accounts 582, 591 and 592 for substations and Account 595 for transformers) should be classified and allocated in the same manner as associated equipment. Other accounts serve both primary and secondary lines and service drops (accounts 583, 584, 593 and 594) or include services to a range of equipment (accounts 580 and 590). These costs normally should be classified and allocated in proportion to the plant in service, for the plant accounts they support, subfunctionalized as appropriate. For example, typical utility tree-trimming activities are almost entirely related to primary overhead lines, with very little cost driven by secondary distribution and no costs for protecting service lines (see, for example, Entergy Corp., n.d.).

11.3.5 Multifamily Housing and Distribution Allocation

One common error in distribution cost allocation is treating the residential class as if all customers were in single-family structures, with one service drop per customer and a relatively small number of customers on each transformer.[163] For multifamily customers, one or a few transformers may serve 100 or more customers through a single service line.[164] Treating multifamily customers as if they were single-family customers would overstate their contribution to distribution costs, particularly line transformers and secondary service lines.[165]

This problem can be resolved in either of two ways. The broadest solution is to separate residential customers into two allocation classes: single-family residential and multifamily residential, as we discuss in Section 5.2.[166] Alternatively, the allocation of transformer and service costs to a combined residential class (as well as residential rate design) should take into account the percentage of customers who are in multifamily buildings, and only components that are not shared should be considered customer-related.

163 One large service drop is much less expensive than the multiple drops needed to serve the same number of customers in single-customer buildings. Small commercial customers may also share service drops, although probably to a more limited extent than residential customers.

164 Similarly, if the cost of service study includes any classification of shared distribution plant as customer-related (such as from a minimum system), each multifamily building should be treated as a single location, rather than a large number of dispersed customers. For utilities without remote meter reading, the labor cost for that activity per multifamily customer will be lower than for single-family customers.

165 Allocating transformer costs on demand eliminates the bias for that cost category.

166 If any sort of NCP allocator is used in the cost of service study, the multifamily class load generally should be combined with the load of the type of customers that tend to surround the multifamily buildings in the particular service territory, which may be single-family residential or medium commercial customers.

11.3.6 Direct Assignment of Distribution Plant

Direct cost assignment may be appropriate for equipment required for particular customers, not shared with other classes, and not double-counted in class allocation of common costs. Examples include distribution-style poles that support streetlights and are not used by any other class; the same may be true for spans of conductor to those poles. Short tap lines from a main primary voltage line to serve a single primary voltage customer's premises may be another example, as they are analogous to a secondary distribution service drop.

Beyond some limited situations, it is not practical or useful to determine which distribution equipment (such as lines and poles) was built for only one class or currently serves only one class and to ensure that the class is properly credited for not using the other distribution equipment jointly used by other classes in those locations.

11.4 Allocation Factors for Service Drops

The cost of a service drop clearly varies with a number of factors that vary by class: customer load (which affects the capacity of the service line), the distance from the distribution line to the customer, underground versus overhead service, the number of customers sharing a service (or the number of services required by a single customer) and whether customers require three-phase service.

Some utilities, including Baltimore Gas & Electric, attempt to track service line costs by class over time (Chernick, 2010, p. 7). This approach is ideal but complicated. Although assigning the costs of new and replacement service lines just requires careful cost accounting, determining the costs of services that are retired and tracking changes in the class or classes in a building (which may change over time from manufacturing to office space to mixed residential and retail) is much more complex. Other utilities allocate service lines on the sum of customer maximum demands in each class. This has the advantage of reflecting the fact that larger customers require larger (and often longer) service lines, without requiring a detailed analysis of the specific lines in use for each class.

Many utilities have performed bottom-up analyses, selecting a typical customer or an arguably representative sample of customers in each class, pricing out those customers' service lines and extrapolating to the class. Since the costs are estimated in today's dollars, the result of these studies is the ratio of each class's cost of services to the total cost, or a set of weights for service costs per customer. Either approach should reflect the sharing of services in multifamily buildings.

11.5 Classification and Allocation for Advanced Metering and Smart Grid Costs

Traditional meters are often discussed as part of the distribution system but are primarily used for billing purposes.[167] These meters typically record energy and, for some classes, customer NCP demand for periodic manual or remote reading and generally are classified as customer-related. Meter costs are then typically allocated on a basis that reflects the higher costs of meters for customers who take power at higher voltage or three phases, for demand-recording meters, for TOU meters and for hourly-recording energy meters. The weights may be developed from the current costs of installing the various types of meters, but as technology changes, those costs may not be representative of the costs of equipment in rates.

In many parts of the country, this traditional metering has been replaced with advanced metering infrastructure. AMI investments were funded in many cases by the American Recovery and Reinvestment Act of 2009, the economic stimulus passed during the Great Recession, but in other cases ratepayers are paying for them in full in the traditional method. In many jurisdictions, AMI has been accompanied by other complementary "smart grid"

167 Some customers who are small or have extremely consistent load patterns are not metered; instead, their bills are estimated based on known load parameters. The largest group of these customers is street lighting customers, but some utilities allow unmetered loads for various small loads that can be easily estimated or nearly flat loads with very high load factors (such as traffic signals). An example of an unmetered customer from the past was a phone booth. Unmetered customers should not be allocated costs of traditional metering and meter reading.

Table 31. Smart grid cost classification

	Legacy approach			
Smart grid element	Equivalent cost	FERC account	Classification	Smart grid classification
Smart meters	Meters	370	Customer	Demand, energy and customer
Distribution control devices	Station equipment and devices	362, 365, 367	Demand	Demand and energy
Data collection system	Meter readers	902	Customer	Demand, energy and customer
Meter data management system	Customer accounting and general plant	903, 905, 391	Customer and overhead	Demand, energy and customer

investments. On the whole, these investments include:

- Smart meters, which are usually defined to include the ability to record and remotely report granular load data, measure voltage and power factor, and allow for remote connection and disconnection of the customer.
- Distribution system improvements, such as equipment to remotely monitor power flow on feeders and substations, open and close switches and breakers and otherwise control the distribution system.
- Voltage control equipment on substations to allow modulation of input voltage in response to measured voltage at the end of each feeder.
- Power factor control equipment to respond to signals from the meters.
- Data collection networks for the meters and line monitors.
- Advanced data processing hardware and software to handle the additional flood of data.
- Supporting overhead costs to make the new system work.

The potential benefits of the smart grid, depending on how it is designed and used, include reduced costs for generation, transmission, distribution and customer service, as described in Subsection 7.1.1. A smart meter is much more than a device to measure customer usage to assure an accurate bill — it is the foundation of a system that may provide some or all of the following:

- Benefits at every level of system capacity, by enabling peak load management since the communication system can be used to control compatible end uses, and because customer response to calls for load reduction can be measured and rewarded.
- Distribution line loss savings from improved power factor and phase balancing.
- Reduced energy costs due to load shifting.
- Reliability benefits, saving time and money on service restoration after outages, since the utility can determine which meters do not have power and can determine whether a customer's loss of service is due to a problem inside the premises or on the distribution system.
- Allowing utilities to determine maximum loads on individual transformers.
- Retail service benefits, by reducing meter reading costs compared with manual meter reads and even automated meter reading and by reducing the cost of disconnecting and reconnecting customers.[168]

The installations have also been very expensive, running into the hundreds of millions of dollars for some utilities, and the cost-effectiveness of the AMI projects has been a matter of dispute in many jurisdictions. Since these new systems are much more expensive than the older metering systems and are largely justified by services other than billing, their costs must be allocated over a wider range of activities, either by functionalizing part of the costs to generation, distribution and so on or reflecting those functions in classification or the allocation factor.

Special attention must be given to matching costs and benefits associated with smart grid deployment. The expected benefits spread across the entire spectrum of utility costs, from lower labor costs for meter reading to lower energy

168 The data systems can also be configured to provide systemwide Wi-Fi internet access, although they usually are not. See Burbank Water and Power (n.d.).

Table 32. Summary of distribution allocation approaches

Element	Method	Comments	Hourly allocation
Substations	FUNCTIONALIZATION: Entirely primary CLASSIFICATION: Demand and energy ALLOCATOR: Loads on substations in hours at or near peaks	Reflect effect of energy near peak and preceding peak on sizing and aging	Allocate by substation cost or capacity, then to hours that stress that substation with peak and heating
Poles	FUNCTIONALIZATION: Entirely primary CLASSIFICATION: Demand and energy* ENERGY ALLOCATOR: Energy or revenue DEMAND ALLOCATOR: Loads in hours at or near peaks	Pole costs driven by revenue expectation	As primary lines
Primary conductors	FUNCTIONALIZATION: Entirely primary CLASSIFICATION: Demand and energy* ENERGY ALLOCATOR: Energy or revenue DEMAND ALLOCATOR: Loads in hours at or near peaks	• Distribution network is installed due to revenue potential • Sizing determined by loads in and near peak hours	• Cost associated with revenue-driven line extension to all hours • Cost associated with peak loads and overloads on distribution of line peaks and high-load hours
Line transformers	FUNCTIONALIZATION: Entirely secondary CLASSIFICATION: Demand and energy* ENERGY ALLOCATOR: Secondary energy DEMAND ALLOCATOR: Diversified secondary loads in peak and near-peak hours	Reflect diversity	Distribution of transformer peaks and high-load hours
Secondary conductors	FUNCTIONALIZATION: Entirely secondary CLASSIFICATION: Demand and energy* ENERGY ALLOCATOR: Energy or revenue DEMAND ALLOCATOR: Loads in hours at or near peaks	Energy is more important for underground than overhead	Distribution of line peaks and high-load hours
Meters	FUNCTIONALIZATION: Advanced metering infrastructure to generation, transmission and distribution, as well as metering ALLOCATOR FOR CUSTOMER-RELATED COSTS: Weighted customer	Allocation of generation, transmission and distribution components depends on use of advanced metering infrastructure	N/A

* Except some to customer, where a significant portion of plant serves only one customer

costs due to load shifting and line loss reduction. Legacy methods for allocating metering costs as primarily customer-related would place the vast majority of these costs onto the residential rate class, but many of the benefits are typically shared across all rate classes. In other words, the legacy method would give commercial and industrial rate classes substantial benefits but none of the costs.

Table 31 identifies some of the key elements of smart grid cost and how these would be appropriately treated in an embedded cost of service study. These approaches match smart grid cost savings to the enabling expenditures.

11.6 Summary of Distribution Classification and Allocation Methods and Illustrative Examples

The preceding discussion identifies a variety of methods used to functionalize, classify and allocate distribution plant. Table 32 summarizes the application of some of those methods, including the hourly allocations that may be applicable for modern distribution systems with:

- A mix of centralized and distributed resources, conventional and renewable, as well as storage.
- The ability to measure hourly usage on the substations and feeders.
- The ability to estimate hourly load patterns on transformers and secondary lines.

Table 33. Illustrative allocation of distribution substation costs by different methods

	Residential	Secondary commercial	Primary industrial	Street lighting	Total
Class NCP: substation (legacy)	$9,730,000	$9,730,000	$7,297,000	$3,243,000	$30,000,000
Average and peak	$10,056,000	$10,056,000	$8,100,000	$1,788,000	$30,000,000
Hourly	$9,939,000	$10,533,000	$9,009,000	$519,000	$30,000,000

Note: Numbers may not add up to total because of rounding.

Where the available data or analytical resources will not support more sophisticated analyses of distribution cost causation, the following simple rules of thumb may be helpful.

- The only costs that should be classified as customer-related are those specific to individual customers:
  - Basic metering costs, not including the additional costs of advanced meters incurred for system benefits.
  - Service lines, adjusting for shared services in buildings with multiple tenants.
  - For very rural systems, where most transformers and large stretches of primary line serve only a single customer (and those costs are not recovered from contributions in aid of construction), a portion of transformer and primary costs.
- Other costs should be classified as a mix of energy and demand, such as using the average-and-peak allocator.
- The peak demand allocation factor should reflect the distribution of hours in which various portions of distribution system equipment experience peak or heavy loads. If the utility has data only on the time of substation peaks, the load-weighted peaks can be used to distribute the demand-related distribution costs to hours and hence to classes.

11.6.1 Illustrative Methods and Results

The following discussion and tables show illustrative methods and results for several of the key distribution accounts, focused only on the capital costs. The same principles should be applied to O&M costs and depreciation expense. These examples use inputs from tables 5, 6, 7 and 27.

Substations

Table 33 shows three methods for allocating costs of distribution substations. The first of these is a legacy method, relying solely on the class NCP at the substation level.[169] The second is an average-and-peak method, a weighted average between class NCP and energy usage. The third uses the hourly composite allocator, which includes higher costs for hours in which substations are highly loaded.

Primary Circuits

Distribution circuits are built where there is an expectation of significant electricity usage and must be sized to meet peak demands, including the peak hour and other high-load hours that contribute to heating of the relevant elements of the system. Table 34 on the next page illustrates the effect of four alternative methods. The first, based on the class NCP at the circuit level, again produces unreasonable results for the street lighting class. The second, the legacy minimum system method, is not recommended, as discussed above. The third and fourth use a simple (average-and-peak) and more sophisticated (hourly) approach to assigning costs based on how much each class uses the lines and how that usage correlates with high-load hours.

Transformers

Line transformers are needed to serve all secondary voltage customers, typically all residential, small general

169 The street lighting class NCP occurs in the night, and street lighting is a small portion of load on any substation, so the street lighting class NCP load rarely contributes to the sizing of summer-peaking substations. The NCP method treats off-peak class loads as being as important as those that are on-peak. This is particularly inequitable for street lighting, which is nearly always a load caused by the presence of other customers who collectively justify the construction of a circuit.

Table 34. Illustrative allocation of primary distribution circuit costs by different methods

	Residential	Secondary commercial	Primary industrial	Street lighting	Total
Class NCP: circuit (legacy)	$69,565,000	$69,565,000	$43,478,000	$17,391,000	$200,000,000
Minimum system (legacy)	$113,783,000	$51,783,000	$24,739,000	$9,696,000	$200,000,000
Average and peak	$67,041,000	$67,041,000	$53,997,000	$11,921,000	$200,000,000
Hourly	$66,258,000	$70,221,000	$60,059,000	$3,462,000	$200,000,000

Note: Numbers may not add up to total because of rounding.

service and street lighting customers and often other customer classes as well. We present four methods in Table 35: two archaic and two more reflective of dynamic systems and more granular data. All of these apportion no cost to the primary voltage class, which does not use distribution transformers supplied by the utility.

The first method is to apportion transformers in proportion to the class sum of customer noncoincident peaks. This method is not recommended because it fails to recognize that there is great diversity between customers at the transformer level; as noted in Subsection 11.3.3, each transformer in an urban or suburban system may serve anywhere from five to more than 50 customers. The second is the minimum system method, also not recommended because it fails to recognize the drivers of circuit construction, as discussed in Section 11.2. The third is the weighted transformers allocation factor we derive in Section 5.3 (Table 7), weighting the number of transformers by class at 20% and the class sum of customer NCP (recognizing that the diversity is not perfect) at 80%. The last is an hourly energy method but excluding the primary voltage class of customers.

Customer-Related Costs

The final illustration shows two techniques for the apportionment of customer-related costs, based on a traditional customer count and a weighted customer count. Even for simple meters used solely for billing purposes, larger customers require different and more expensive meters. There are fewer of them per customer class, but the billing system programming costs do not vary by number of customers. In addition, a weighted customer account is also relevant to customer service, discussed in the next chapter, because the larger use customers typically have access to superior customer service through "key accounts" specialists who are trained for their needs.

Table 35. Illustrative allocation of distribution line transformer costs by different methods

	Residential	Secondary commercial	Primary industrial	Street lighting	Total
Customer NCP (legacy)	$32,258,000	$16,129,000	$0	$1,613,000	$50,000,000
Minimum system (legacy)	$32,461,000	$14,773,000	$0	$2,766,000	$50,000,000
Weighted transformers factor	$29,806,000	$14,903,000	$0	$5,290,000	$50,000,000
Hourly	$23,810,000	$23,810,000	$0	$2,381,000	$50,000,000

Note: Numbers may not add up to total because of rounding.

Table 36. Illustrative allocation of customer-related costs by different methods

	Residential	Secondary commercial	Primary industrial	Street lighting	Total
Unweighted					
Customer count	100,000	20,000	2,000	50,000	172,000
Customer factor	58%	12%	1%	29%	100%
Customer costs	$58,140,000	$11,628,000	$1,163,000	$29,070,000	$100,000,000
Weighted					
Weighting factor	1	3	20	0.05	
Customer count	100,000	60,000	40,000	2,500	202,500
Customer factor	49%	30%	20%	1%	100%
Customer costs	$49,383,000	$29,630,000	$19,753,000	$1,235,000	$100,000,000

Note: Numbers may not add up to total because of rounding.

Table 36 first shows a traditional calculation based on the actual number of customers. Then it shows an illustrative customer weighting and a simple allocation of customer-related costs based on that weighting. Each street light is treated as a tiny fraction of one customer; although there are tens of thousands of individual lights, the bills typically include hundreds or thousands of individual lights, billed to a city, homeowners association or other responsible party.[170]

170 In some locales, street lighting is treated as a franchise obligation of the utility and is not billed. In this situation, there are no customer service or billing and collection expenses.

12. Billing and Customer Service in Embedded Cost of Service Studies

Many utilities classify billing and customer service costs, often termed retail service costs, as almost entirely customer-related and allocate these costs across classes based on the number of customers. This chapter describes how these costs can be allocated in a more granular and detailed way.

12.1 Billing and Meter Reading

Most utilities bill customers either monthly or bimonthly. The reason for this is relatively simple: If billed less frequently, the bills would be very large and unmanageable for some consumers; if billed more frequently, the billing costs would be an unacceptable part of the total cost. As noted in Subsection 3.1.5, billing closer to the time of consumption provides customers with a better understanding of their usage patterns from month to month, which may assist them in increasing efficiency. There are exceptions: Many water, sewer and even electric utilities serving seasonal properties may render bills only once or twice a year.[171]

It is important to recognize these cost drivers in the classification of billing costs. From a cost causation perspective, the reason for frequent billing is that usage drives the size of the bill. We receive annual bills for magazine subscriptions because the quantity we will use (one per week or month) is very small and predictable. In some states, rules of the regulatory commission require billing on a specified interval. For example, in Washington state, the rules require billing not less than bimonthly (Washington Administrative Code Title 480, Chapter 100, § 178[1][a]). In this situation, billing frequency in excess of that required by law or regulation is driven by consumption. The portion of the costs of reading meters and billing more frequently should be classified and allocated according to appropriate measures of usage, rather than customer count.

Manual reading of the meters of large customers typically takes longer than for small customers, both because of travel distance among larger customers and the complexity of metering typical of large customers (TOU or demand-metered). In some cases, small customer meters are read manually but large customers are remotely metered; the additional costs of the equipment for that remote metering should be assigned to the classes that use remote metering. As noted in Section 11.5, unmetered customers such as streetlights should not be allocated meter reading costs.

For utilities with AMI, any meter reading costs arising from customers opting out of AMI should be recovered either from the opt-out customers or functionalized, classified and allocated in proportion to the AMI costs, because opt-outs are part of the cost of obtaining the benefits of AMI.

The costs of billing, payment processing and collections for special services (e.g., line extensions and relocations) can end up in Account 903 for some utilities. These are overhead costs, not customer costs, and should be either classified or allocated as an overhead expense.[172]

Some utilities provide on-bill financing for energy efficiency, renewable energy or demand response investments that the utility (or a third party) makes at the customer premises. Where this occurs, a portion of the billing cost should be assigned to the nonservice cost element.

12.2 Uncollectible Accounts Expenses

Uncollectible accounts expenses are the expenses from customers who have not paid their bills, due to financial

171 This is also the case for California customers who opt out of AMI (California Public Utilities Commission, 2014).

172 The same is true for any uncollectible charges for special services. If there is direct assignment of uncollectibles, charges related to non-energy billings or claims should be segregated from the remainder of Account 904 and directly assigned as overhead expenses.

distress, bankruptcy or departure from the service territory.[173] Some analyses erroneously allocate the costs of former customers to the classes of current customers on a per-customer basis or by direct assignment. However, these costs are not caused by any current customer in any particular class.[174] Although certain accounts have unpaid electric bills, those accounts are former customers who are no longer members of any class.

Uncollectible accounts are related to class revenue in two ways. First, the higher the bills of a particular class, the more revenue is at risk of becoming uncollectible. Second, if the customer had shut down or left before rates were set, most of the costs reflected in the uncollectible bills would have been allocated to the remaining customers, in all classes. Hence, uncollectible revenues should be classified as revenue-related and allocated in proportion to revenues, not customer number.[175]

The treatment of four elements should be coordinated in the cost of service study:

- Uncollectible accounts expenses.
- Late payment revenues if charged to all classes (sometimes called forfeited discounts, often recorded in FERC Account 450 in the Uniform System of Accounts).
- Customer deposits, which protect utilities against uncollectibles and which offset rate base for most utilities in North America.
- Interest paid to customers on customer deposits.

If uncollectible accounts expenses are assigned as an overhead expense based on revenue, then all of these four items should be allocated based on revenue.

On the other hand, if uncollectible accounts expenses are directly assigned to the originating class or using a customer allocator, then late payment revenues and customer deposits should be assigned in the same manner.

Although an allocation based on revenue is more appropriate, the consistent allocation of these four items by either revenue or direct assignment may not have a large effect on the cost of service study, because direct-assigned late payment revenues and deposits partly offset direct-assigned uncollectible accounts expenses.

The worst cost allocation outcome is inconsistency: assigning uncollectible accounts expenses largely to residential customers using direct assignment or a per-customer allocation while using a broad allocation method for late payment charges and customer deposits, even though both of these items are also largely paid by residential customers.

12.3 Customer Service and Assistance

Utilities frequently classify customer service and information expenses as customer-related and allocate them in proportion to customer number. This approach is not reasonable, because these expenses are more likely to vary with class energy consumption and revenues.

In general, larger customers have more complicated installations, metering and billing and warrant more time and attention from a utility. A utility customer service staff does not spend as much time and attention on each residential customer as on each large commercial or industrial customer, considering the fact that the larger customers may have bills 100 or 1,000 times that of the average residential customer. Indeed, most utilities have key accounts specialists — highly trained customer service personnel who concentrate on the needs of the largest customers. Large customers may also have more complex billing arrangements, multiple delivery points, demand charges, campus billing, interruptible rates and credits, transformer ownership credits and additional complications that require more time from engineering, legal and rate staff, supervisors and higher management, so the billing costs should be weighted proportionately to the customer classes with complex arrangements.

The alternative to a simple customer allocator for customer service costs may be to use a weighted customer

173 For most utilities, the residential class produces most of the uncollectible accounts expenses, in part because large customers are more often required to post deposits or demonstrate good financial standing. However, when large customers' bills are uncollectible, often due to bankruptcy, the amounts can be very large.

174 Texas has one of the strongest precedents on this issue for utilities not in ERCOT and therefore not subject to competition. See Public Utility Commission of Texas (2018, p. 47, findings of fact 303-305).

175 Texas and California have treated these costs as overhead costs, allocated by revenue to all customer classes.

allocator — in which larger customers are assigned a multiple of the costs assigned to smaller customers — or a combination of customer number and class revenue. The retail allocators should be derived from the relative cost or effort required per customer for each class.

Most utilities can segregate costs for key accounts and identify the customer classes for which these services are provided. Although these costs should be recorded in customer service costs (accounts 907 to 910), they can appear in other accounts. Wherever they appear, they should be assigned to the classes that use them. The costs should be assigned mostly to the largest commercial and industrial customers who receive the services, perhaps with a small amount allocated to classes with smaller nonresidential customers.[176]

Account 908, which FERC identifies as customer assistance expenses, contains general advice and education on electrical safety and energy conservation. Account 909 involves informational advertising. Those activities are generally not extensive (or expensive), and allocation is not usually controversial. But many utilities also book to this account energy efficiency expenditures, which can represent a few percent of consumer bills. If there are significant costs in this account, they are likely to be dominated by energy efficiency programs, which should be allocated as described in Section 14.1.

12.4 Sales and Marketing

Sales and marketing costs are often erroneously allocated by the number of customers rather than the purpose of sales and marketing expenses: to increase electric loads (e.g., by economic development or load retention). Since the purpose of these costs is to increase contributions to margin from new or existing customers, thereby reducing the need for future rate increases, the costs should be allocated by base rate revenue or another broad allocation factor such as rate base.

Some sales and marketing funds are used to promote important public policy programs (such as energy efficiency or electric vehicles, discussed further in sections 14.1 and 7.1.3, respectively). Other sales and marketing efforts, however, may promote programs that ratepayers arguably should not fund at all (e.g., promotion of inefficient electric resistance heating by a utility that is almost entirely fossil fuel-based, through sponsorships and advertising) and should be examined closely in revenue requirements cases.

176 A few large customers billed on multiple small or medium commercial tariffs may receive key-customer services, such as franchisees, government agencies and small accounts attached to large ones.

13. Administrative and General Costs in Embedded Cost of Service Studies

Utilities have very significant administrative overhead costs, including general plant (office buildings, vehicles, computer systems), labor costs (executive compensation, employee benefits) and the cost of outside services. Some cost of service studies functionalize a portion of each category of general plant and overhead costs to each of the first four functions. Other cost of service studies treat overhead as a function and allocate those costs to classes in proportion to the costs allocated to other functions, or on such drivers as the labor cost incurred by each of the other functions.[177] In this regard, the structure of the cost of service does not constrain or distort the allocation of overhead costs.

Overheads are costs that cannot be directly assigned to particular functions. The overhead category includes the capital costs and depreciation expenses recorded as general plant in accounts 389 to 399 (which includes office buildings and warehouses), property taxes in Account 408, employment taxes in Account 408.2 and the O&M expenses recorded as administrative and general in accounts 920 to 935.

13.1 Operations and Maintenance Costs in Overhead Accounts

Some costs included as A&G expenses may be more accurately treated as O&M for specific functions. Utilities do not all interpret the FERC Uniform System of Accounts in the same way. For example, a utility may include some or all of its expenses for procuring electricity and fuel in Account 920 (administrative salaries) and Account 921 (office expenses). These costs should be treated as energy-related, either by being refunctionalized to fuel costs and Account 557 (other power supply expenses) or allocated in proportion to those costs or on energy. Similarly, some utilities include all or a portion of the major accounts expenses (discussed in Section 12.3) in accounts 920 and 921. These should be reclassified to customer service and assigned to the classes with the large customers who receive these services.

13.2 Labor-Related Overhead Costs

Some of the A&G accounts in the standard utility accounting systems serve a single function and are driven by a single factor. For example, employment taxes, pension expenses and other employee benefits vary with the number of employees and salaries and are generally functionalized in proportion to the labor in each function or are allocated using the special labor allocation factor calculated earlier in the process, based on how the labor costs in each function were previously allocated among the classes. If a labor allocator is not available, nonfuel O&M is often used as a reasonable proxy for labor.[178]

If the administrative overheads are available disaggregated by department or function, the human resources or personnel office should also be functionalized or allocated in proportion to labor. For administrative labor and other costs that cannot be directly functionalized, see Section 13.5.

13.3 Plant-Related Overhead

Accounts 924 (property insurance) and 925 (injuries and damages) are clearly plant-related and are generally functionalized or allocated in proportion to plant, with the exception of workers' compensation expenses in Account 925,

177 In setting wholesale transmission rates, FERC allocates A&G and general plant costs among jurisdictions by labor, with the exception of property insurance Account 924 (by plant) and regulatory commission expenses (directly assigned). As described in sections 5.2 and 5.3, this treatment is overgeneralized.

178 If nonfuel O&M is used instead of labor, transmission wheeling expenses, uncollectible accounts expenses and regulatory amortizations to operation and maintenance accounts should also be excluded, since these costs do not require supervision and administrative cost.

which are labor-related.[179] The same is true for property taxes that are based on the assessed value of each utility facility.[180] Typically, an allocator based on net plant (or net plant less deferred taxes) is used, but the allocation should reflect the method by which taxes are assessed in each state.

13.4 Regulatory Commission Expenses

The benefits to customers of the regulatory oversight funded through FERC Account 928 will normally be distributed more in proportion to the classes' total bills, including both investment-related costs and operating expenses, rather than to the number of customers in the classes. In terms of cost causation, the regulatory assessment covers expenditures on many types of proceedings, including (depending on the jurisdiction) rate cases, resource planning, project certification, review of investments, power purchase contracts and fuel expenses. Demand and energy use are the major contributors to the size of the assessment and the cost of its regulatory efforts. Depending on the jurisdiction and the distribution of the regulator's efforts, the most equitable allocator may be class revenues or energy consumption.[181]

13.5 Administrative and Executive Overhead

Many of the standard A&G accounts serve multiple functions. Administrative salaries pay employees in human resources, financing, public relations, regulatory affairs, the legal department, purchasing and senior management. Some of their work is driven by employee numbers (e.g., human resources), others by capital investment (finance) and most by a mix of labor, fuel procurement, nonfuel expenses and capital investments, including dealing with disputes with suppliers, customers, regulators and other parties. Outside purchased services may include consultants on new power plants, fuel and equipment procurement, power transactions, environmental compliance, worker safety and many other activities.

These costs are driven by the utility's entire operation, including labor, other O&M and plant investment. If these corporate overheads can be differentiated in sufficient detail (sections 13.1, 13.2 and 13.3), they can be functionalized or allocated to specific cost categories. Otherwise, these costs can be allocated in proportion to class revenue (or the total of other cost allocations).

Utilities agree to franchise payments (in Account 927) to gain access to customers and the associated revenues; thus franchise payments should be allocated in proportion to total revenues or other allocated costs.

13.6 Advertising and Donations

Some utilities assign Account 930.1 (general advertising) or certain donations as customer-related. This treatment is erroneous. General advertising is not trying to inform customers of anything they need to know about their regulated utility service (the purpose of Account 909) or sell them anything (Account 913). Rather Account 930.1 includes "cost of advertising activities on a local or national basis of a good will or institutional nature, which is primarily designed to improve the image of the utility or the industry" (18 C.F.R. § 367.901[d]). If allowed in rates at all, these costs are clearly overheads, even if the expenditures are largely intended to affect the opinions of residential customers (or voters). To the extent that some donations are allowed in rates (as in Texas), they also are image-building and charitable overhead and, as such, should not be assigned by the number of customers.

179 As a refinement, a study could be done to determine workers' compensation costs by functions. Customer service representatives (largely customer-related in Account 903) are likely to have lower workers' compensation costs than power plant operators or power line workers.

180 For publicly owned utilities, the equivalent may be payments in lieu of taxes.

181 Many utilities allocate these costs by base rate revenues; a more appropriate allocator would be total revenues given that fuel and other costs collected in riders are also regulated and planning and certification activities related to the rider costs constitute a significant portion of the burden on regulators.

14. Other Resources and Public Policy Programs in Embedded Cost of Service Studies

14.1 Energy Efficiency Programs

Energy efficiency costs have three effects on the revenue requirement that will be recovered through rates. First, energy efficiency shrinks the size of the pie of non-energy efficiency costs that have to be split up, because the utility will need less generation, transmission and distribution in the long run, and utilities that own generation may be able to earn some export revenues to offset other costs. Since utilities generally undertake energy efficiency only if it is less expensive than the avoided costs (sometimes measured as short run, sometimes as long run, and including or excluding environmental costs), energy efficiency tends to reduce total costs, at least in the long term.

Energy efficiency programs typically reduce generation, transmission and distribution costs, and hence also some of the associated overheads, but not most retail service costs, such as metering and billing.[182] In restructured utilities, energy efficiency load reductions tend to reduce the prices that all customers pay for generation services, as well as avoiding transmission and distribution investments. These benefits typically are dominated by energy savings, with a portion being demand-related. Some utilities collect energy efficiency costs from all customers, on an equal cents-per-kWh basis or using an energy/demand allocator. Where this is done, the allocation of program costs should generally follow the framework for revenue collection.

Second, a program that reduces the loads of one class shrinks its share of the cost pie, increasing other classes' shares of the pie. For the participating class, the reduction in both the size of the pie and the class's share of the pie reduces customers' cost allocation. For each class participating in each program, the program reduces the bills of participants and the costs allocated to the class. Thus, some utilities have assigned the costs of each energy efficiency program to the participating classes. But for some other class, the increase in its share of the costs may be either larger or smaller than the effect on the size of the total pie, so its cost allocation may either rise or fall due to the energy efficiency.

Thus, cost-effective energy efficiency, with the costs allocated to classes based on the class share of the system benefits, can result in nonparticipating classes paying more than they would without energy efficiency. Conversely, assigning the costs directly to the participating class or classes can result in the participants paying more for energy efficiency programs than they benefit from the shrinking of the revenue requirements and of their share, leaving them worse off. These are extreme situations. With highly cost-effective programs and broad participation, all classes are very likely to benefit from energy efficiency, no matter how the costs are allocated. But the net benefits can be inequitably allocated.

The cost effects of energy efficiency differ between the short term and the long term. The costs of energy efficiency investment are often incurred in the year of program implementation, while the benefits stretch on for many years. In 2018, the customers will be paying roughly the costs of the 2018 program, while nonparticipating customers in 2018 are primarily receiving the benefits of energy efficiency investment that occurred in the past. This could be another source of misalignment between cost recovery and benefits, particularly if there are changes over time in the cost recovery method or the relative benefits to each customer class.

Energy efficiency costs are typically caused by the opportunity to reduce total costs to consumers. For most costs, revenue requirements would be lower if customers did less to require the utility to incur those costs. Customers

182 Energy efficiency programs targeted to low-income customers can reduce collection costs, uncollectibles and other burdens on the utility and other customers.

whose load growth requires upgrades to their service drops and transformers, extension of three-phase primary distribution and retention of more hydro energy that could have been exported would increase costs to the system. The same is true for customers who want their service drops underground for aesthetic reasons. Other customers should not bear those costs, so the costs are assigned or allocated to the participating class and billed (more or less) to the customer demanding the service. If customers do not want to pay the costs, they should not increase their load or request more expensive services.

The allocation of energy efficiency costs should reflect both the system benefits and the benefits to the participating classes, while avoiding making any class worse off.

Unlike other costs, energy efficiency costs produce benefits for the participating class and entire system. Utilities do not want to discourage participation in energy efficiency efforts, and they recognize there are benefits beyond the participant. In principle, the cost of service study might allocate all energy efficiency costs to the participating rate classes, offset by all the system benefits of energy efficiency. In practice, it would be difficult. The cost savings in 2020, for example, will result from expenditures made in earlier energy efficiency programs, and relatively little savings will be realized for nonparticipants in 2020 from the activities underway in that year. Determining the load reductions in 2020 from those prior years' programs, the cost savings from the load reductions and the class responsibility for those savings would be quite complex.

The allocation of energy efficiency costs should reflect both the system benefits from energy efficiency and the benefits to the participating classes, while avoiding making any class worse off. If a utility has high avoided costs and low embedded costs, the first solution may result in a class being charged for all the costs of the energy efficiency it undertakes, even though most of the benefit flows to other classes, leaving the participant class worse off than if it had not participated. That outcome would not be equitable and would not encourage the class to engage in further efficiency. If a utility has relatively low avoided costs and high embedded costs, the second option may result in the participating class's revenue requirements falling by more than the total net benefit of the energy efficiency program, leaving other classes with higher bills. That outcome would also be inequitable and may inspire each class to oppose energy efficiency proposals for the other classes.

The allocation of energy efficiency program costs should avoid both of these extremes, which may lead to the use of a split between energy-related and demand-related, direct assignment to participating classes or a combination of the two approaches (such as 50% of the costs being directly assigned and the rest allocated based on energy usage).

To avoid these problems, the utility could estimate the effects of recent or planned energy efficiency on revenue requirements for each class, for alternative allocations. This analysis would include the long-term annual revenue requirements for three cases:

1. Actual or planned energy efficiency spending and load reductions, with energy efficiency costs assigned to the participating classes and system revenue requirements allocated roughly as they would flow through the cost of service study.
2. Actual or planned energy efficiency spending and load reductions, with energy efficiency costs allocated in proportion to avoided costs (using weighted energy or other allocators reflecting the composition of avoided costs) or total revenues, and system revenue requirements allocated roughly as they would flow through the cost of service study.
3. No energy efficiency, resulting in higher loads, higher energy costs, lower export revenues and higher T&D costs.

The difference between case 1 and case 3 would show the effect on rate classes of assigning energy efficiency costs by class, and the difference between case 2 and case 3 would show the effect on rate classes of allocating energy efficiency costs in proportion to the system benefits. Based on that analysis, the cost of service study should use an allocation approach that is fair to all classes, avoiding a situation in which one class is paying for its own energy efficiency efforts that are disproportionately benefiting other classes or, conversely, paying for energy efficiency for other classes and receiving little of the benefit.

14.2 Demand Response Program and Equipment Costs

Demand response programs may avoid generation, transmission and distribution investments depending on the specifics of the program and may avoid high purchased power and transmission costs incurred for peak periods or contingencies. The costs of marketing the programs, and even payments to participants, may appear in a customer service account, such as Account 908. Despite their location in this account, the costs are not customer-related. They are resource costs that benefit all customers.

Utility demand response programs are designed to avoid capacity and energy costs and line losses for short-duration loads during times of system stress. The program costs may include investments and expenses at utility offices (computers, software and labor), installations on the distribution system (sensors and communication equipment) and installations on customer premises (controls). These costs are incurred to avoid peak capacity (and sometimes associated energy) costs on the generation system and sometimes on the transmission and distribution systems as well.

The demand response costs should be functionalized across all affected functions and allocated based on metrics of peak usage that relate to the period for which they are incurred — the hours contributing to highest stress. Where demand response provides benefits outside the highest-stress hours, such as by providing operating reserves (which reduce the need to run uneconomic fossil-fueled generation), a portion of the demand response costs should be allocated to the hours when demand response provides those benefits.

Some investments provide not only demand response but also load shifting or energy efficiency. Examples include controls for water heaters, space cooling and space heating and swimming pool pumps. These programs can reduce energy costs, including increasing load in periods with excess renewables that would otherwise be curtailed. Allocation of these costs should reflect the mix of benefits, including peak reductions, reduced reserve costs and reduced energy costs.

For programs that are operated only infrequently under conditions of bulk generation shortage (e.g., industrial interruptible load), the loads that were curtailed should be added back to the relevant class loads, and the costs of the programs — both outreach and incentive payments — should be treated as purchased power and allocated either to generation demand or to the specific hours when the program could be called.[183] Some utilities remove interruptible demand from the associated class load before allocating costs and allocate the costs of the program back to the participating class; that approach can be reasonable, as long as the interruptibility provides benefits equivalent to the utility functions for which the class allocation is reduced.[184] In no case should a cost of service study both reduce the participant class loads for demand response and allocate the costs to all classes; that would double count the benefit to the participating class.

Other programs with more frequent operations or wider benefits than emergency bulk generation should be assigned more broadly to generation, transmission and distribution based on program design. For example, if a demand response or storage program is developed simultaneously to improve the reliability and efficiency of the distribution system (i.e., a targeted nonwires alternative investment program) and to provide bulk power benefits, the costs could be assigned partly to each function as discussed above.[185]

In certain cases, utilities may directly own demand

183 It is generally inappropriate to pay customers to participate in a demand response program, subtract demand response capacity from the loads used for deriving allocation factors and also allocate the costs of the program to nonparticipating classes. Paying the participants and reducing their class loads pays twice for the same resource. The participants should be paid, of course, but all load should pay for the service that the program provides.

184 Many legacy interruptible rates require long lead times, allow only a limited number of annual interruptions, limit the length of each interruption and allow customers to ride through an interruption for a modest penalty. These rates may reduce the cost of serving the interruptible customers but do not fully replace equivalent amounts of generation and transmission.

185 Although a program theoretically could be designed only to have targeted distribution benefits without bulk power benefits, that may not be the most cost-effective program design.

response or load management equipment at customer premises to enable utility or consumer control of space conditioning, water heating, irrigation pumping and other loads. This type of investment's primary purpose is to enable peak load management, but it may also provide ancillary services and shifting of energy between periods. Although located within the distribution system, it is functionally different from most other distribution system plant in that it directly offsets the need for generation and transmission expenditures. For this reason, these costs should be classified and allocated differently from other distribution plant.

14.3 Treatment of Discounts and Subsidies

The decision to reduce the revenue responsibility of some customers increases the revenue responsibility of other customers. There are a variety of reasons for legislatures and regulators to provide discounts. Some are cost-based (such as for off-peak or interruptible service), in which case other customers are not truly providing a subsidy. Other discounts are truly subsidies, most commonly for low-income residential customers (unless justified by a substantially different load profile) and for financially distressed businesses — especially agricultural irrigation[186] and businesses that are major employers.

A common example is the difference between the revenues that low-income consumers would have paid under the standard residential tariff (or a tariff designed to recover the costs appropriately allocated to a low-income class) and what they actually pay under discounted low-income tariffs.[187] Where those subsidies exist, the cost of service study must address how to recover the subsidies through adding to the revenue responsibility of other customers. The decision as to whether the subsidy should be recovered from the class whose members receive the discount or from all customers is a matter of public policy, which is sometimes settled by the legislature[188] and other times left to the regulator's judgment. If the subsidy is recovered within the discounted class, the discount does not affect cost allocation to the class because the costs remain within the class and the subsidy shows up in the form of reduced revenues (and may thus result in higher rates for the remainder of the residential class). But if the subsidy is to be redistributed to other classes, it is appropriate for inclusion in the cost of service study as a cost or revenue adjustment to be apportioned across classes.[189]

As a practical matter, recovering a subsidy from the nondiscounted customers in the class receiving the discount may just push more of those customers into distress. Hence, the most reasonable manner of recovering a subsidy will vary: If the residential class is mostly affluent, with small pockets of poverty, dealing with a low-income discount entirely through rate design in the residential class may be appropriate. But if most of the residential class is in a tenuous financial condition, but the commercial and industrial classes in the territory are thriving, spreading the subsidy costs over all classes may be most appropriate, with a net credit to the residential class and charges to other classes, perhaps on an energy basis.

---

186 For example, Nevada has a requirement that certain irrigators receive low rates: "IS-2 is a subsidized rate that NV Energy charges eligible agricultural customers who agree to interruptible irrigation pump service during certain situations. This service is applicable to electricity used solely to pump water to irrigate land for agricultural purposes. Agricultural purposes include growing crops, raising livestock or for other agricultural uses which involve production for sale, and which do not change the form of the agricultural product pursuant to NRS 587.290" (NV Energy, n.d.).

187 Low-income subsidies may be motivated by a combination of social concerns (such as reducing the burdens on needy customers and avoiding health-related problems of customers unable to heat or cool their homes), utility practicality (reducing bad debt and collection expenses) and cost causation. Low-income consumers are typically low-use customers and may tend to have less temperature-sensitive load that drives utility system peaks. Depending on the composition of the low-income population, they may also be at home in a different pattern than higher-income customers. A time-differentiated cost study may illuminate these differences.

188 For example, California Public Utilities Code § 327(a)(7) requires that the low-income electric rate for its IOUs be allocated by equal cents per kWh to all customers except recipients of the low-income rate and street lighting customers.

189 For example, a pro forma adjustment to revenue for each class (positive to the residential class; negative to other classes) would spread the subsidy across all the classes that the regulator concludes should contribute to this service.

15. Revenues and Offsets in Embedded Cost of Service Studies

15.1 Off-System Sales Revenues

Some retail cost of service studies treat wholesale sales as a separate class and allocate costs to the off-system customers. The cost of service study does not necessarily lead to any change in the off-system customers' charges (which are typically set by contracts, markets or FERC) but does help the regulator determine what share of the revenue requirement not recovered by FERC-regulated sales should be borne by each retail class. Alternatively, many utilities allocate all their costs to the retail classes and credit the export revenues back to the retail classes.[190]

In the latter approach, utilities sometimes allocate wholesale revenues to classes in proportion to their allocation of generation costs. Under this type of allocator, the greater the rate class's demand and usage, the greater its share of the off-system sales revenue. The problem with this approach is that some classes (e.g., industrials) use most of the generation capacity allocated to them throughout the year, while other classes typically pay for capacity they use in their peak season but which is available for sale in other seasons. Off-system sales revenues depend not only on the retail customers' financial support of the resources (including generating capacity) from which off-system sales are made but also on the extent to which class load shapes leave resources available to make those sales.

A more appropriate allocator would reward a class for having lower demand and usage, perhaps on a monthly basis, thereby leaving generation (and transmission) capacity available to support the off-system sales. In other words, the revenue from off-system sales should reflect classes' contribution to the availability of capacity to make the sales.[191]

15.2 Customer Advances and Contributions in Aid of Construction

As discussed in Section 11.2, most utilities charge new customers or new major loads for expansion of the delivery system, at least in some circumstances. Utilities frequently require customer advances for construction costs when they are asked to build a facility to accommodate subsequent load growth (e.g., to connect a subdivision or commercial development before some or perhaps any of the units are built and sold). The utility requires the advance to transfer to the developer the risk that the load will never materialize, or that load will grow more slowly than expected. As the load materializes, the advances are refunded to the developer. Those advances provide capital to the utility and generally are treated as a reduction of rate base; that cost reduction should be directly assigned to the customer classes for whom the advances were made.

Contributions in aid of construction are similar to customer advances but are applied in situations in which the utility does not expect the incremental net revenues from the load to cover the entire cost of the expansion. The contributions are thus a permanent payment to the utility, offsetting part of the capital cost. Contributions in aid of construction should be treated similarly to customer advances, allocated as

190 The same approach is possible with retail customers whose rates are fixed under multiyear contracts. Off-system sales revenues may vary considerably, based on market conditions, and are therefore often included in a fuel adjustment clause or similar rider between rate cases, while the base allocation is typically established in a general rate case.

191 MidAmerican Energy in Iowa proposed an hourly cost allocation method for capacity and energy in a recent case but also argued that if the Iowa Utilities Board were to use its traditional "average and excess demand" method instead, off-system sales margins should be allocated by excess demand, not by energy. "MidAmerican believes it is more appropriate to allocate wholesale margins (revenues less fuel costs) based on the excess demand component of the [average and excess] allocator, as it is from excess generation capacity that wholesale sales can be made" (Rea, 2013, p. 19).

rate base reductions for the class for which the contributions were made. Where that is not possible, they should be applied as realistically as possible to offset the rate base for the types of facilities for which the contributions were collected.

As noted in Section 12.2, customer deposits that offset rate base should be allocated consistently with uncollectible accounts expenses and late payment revenues.

15.3 Other Revenues and Miscellaneous Offsets

The treatment of other operating revenues affects customer class allocation. Some cost of service studies allocate all these revenues proportionally to a broad-based factor such as base rate revenue. Others do a more granular analysis. The granular analysis is preferable analytically because it is closer to the basis for the revenues.[192] There are several types of other operating revenue. Three of the largest are:

- Late payment revenues.
- Revenues for auxiliary tariffed services.
- Rents and pole attachment revenues.

As discussed in Section 12.2 earlier, late payment revenues need to be treated consistently with uncollectible accounts expenses and customer deposits.

Auxiliary tariffed service revenues result from directly charging customers for certain actions that customers take. The large majority of tariffed revenues result from items such as service establishment charges, charges for reconnection after disconnection, field collection charges and returned check charges. These revenues should not be allocated broadly because the revenues are predominantly paid by residential customers and the costs that these revenues reimburse are predominantly in customer-related accounts that are largely assigned to residential customers (accounts 586, 587, 901 to 903 and 905). These revenues should be directly assigned to the customer class that pays them or (if that is not possible) allocated in proportion to customer accounts expenses excluding uncollectibles.

Tariffed service charges for costs associated with opting out of AMI should be allocated in the same way as the costs of AMI opt-outs (as discussed in Section 12.1).

Rents should be allocated to the function causing the rents (distribution lines, office buildings, etc.). In particular, pole attachment revenues from cable and telecommunications companies should be allocated in proportion to poles.

192 For example, assigning revenues from service establishment charges based on total base rate revenue would result in large customers, who rarely move, receiving revenue as if they had moved many times in a single year.

16. Differential Treatment of New Resources and New Loads

In some situations, regulators have treated new resources or new loads using considerations that do not fit neatly into the embedded cost of service study framework. In particular, equity may sometimes be improved by reflecting the history and projections of class loads. However, there are risks in adopting such an approach, particularly within customer classes. Regulators should be careful to ensure adoption of such techniques is not arbitrary or discriminatory and is grounded in solid reasoning.

These differential treatment techniques are sometimes referred to as incremental cost of service studies[193] and can be conceptualized as either applying two different embedded cost techniques or combining an embedded cost technique with a marginal cost technique. In either case, the defining characteristic of these methods is the recognition that the costs associated with load growth in the recent past or the relatively near future, which typically might be several years, are being driven by a specific class or subclass of customers.

Incremental cost considerations are sometimes used to address a special circumstance that justifies differential treatment for particular classes or subclasses of customers within the context of an embedded cost study. Examples include:

- Allocating legacy low-cost generation resources to classes in proportion to their contribution to loads in a past year (perhaps the last year in which those resources were adequate to serve load), with the higher incremental costs of newer generation allocated to classes in proportion to their load growth since that base year.
- Setting the revenue requirements for selected classes or subclasses at levels below the general cost allocation but higher than near-term incremental costs; for example, in determining how to apportion the cost burden of economic development programs or low-income assistance programs.
- Developing desired end uses that may require preferential rates in the short term (e.g., electric vehicles or docked ships that would otherwise be burning oil) to provide a societal benefit or stimulate a desirable market.

In most cases, the differential treatment is intended to protect customers in the other classes from higher costs of new resources or from bearing a larger share of legacy costs.

16.1 Identifying a Role for Differential Treatment

A study with differential treatment typically looks at the costs the system will incur within a relatively short time horizon to serve new load or retain existing load. The costs that may differ between the legacy loads and resources and incremental loads and resources include the variable costs of existing generation resources and the costs of new supply resources, transmission projects and distribution upgrades.[194] In each case, inequities or inefficiencies arise because costs do not scale proportionally to the drivers, such as load. If the utility has committed generation resources, with low variable costs, in excess of its requirements and has overbuilt most of its transmission and distribution circuits, incremental costs will tend to be below average costs.[195] In contrast, in a period of tight supply, the near-term costs of running expensive generation and adding generation, transmission and distribution resources may be higher than embedded costs.

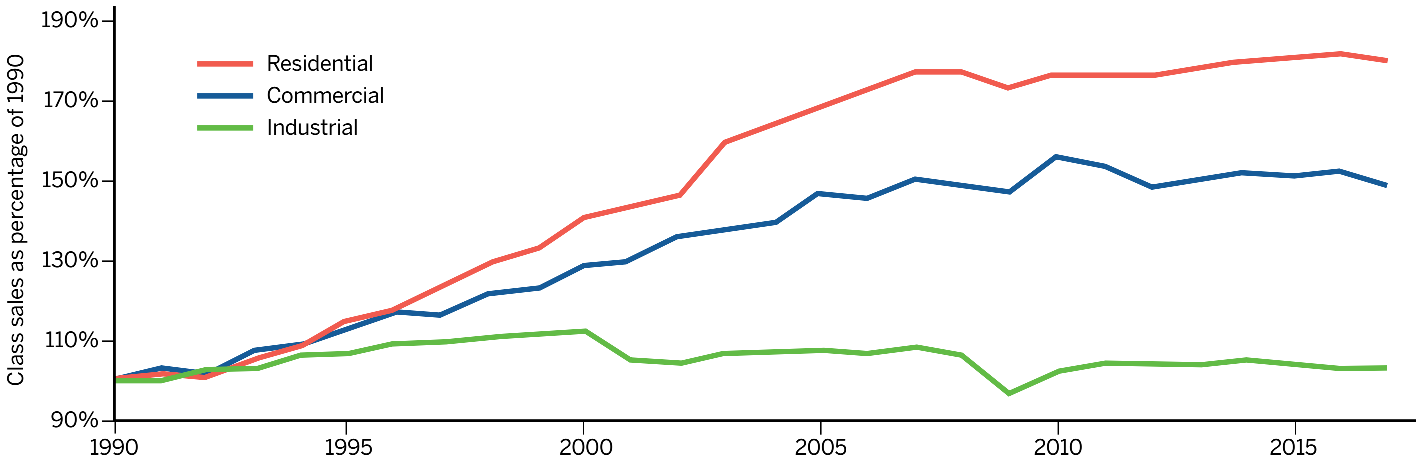
---

193 The term "incremental cost of service study" in this case is not used in the same sense as a marginal cost of service study, where the marginal impact of load patterns is measured.

194 In principle, there could be similar differences in the costs of some customer service elements, such as between an existing billing system that would be adequate indefinitely for the existing accounts and an expensive new system that would be required if the utility adds accounts.

195 Surplus capacity does not always imply that incremental costs are below average costs. If the utility can save money by selling surplus generation resources or shutting them down, the incremental cost of retaining or increasing load may be as high as the embedded costs or nearly so.

Figure 43. US load growth by customer class since 1990



Data source: U.S. Energy Information Administration. *Form EIA-861M Sales and Revenue: 1990-Current*

In some cases, growth has profound impacts on system costs, and special consideration of differential growth rates may be important to the regulator. Load growth at certain hours may be beneficial, while load growth at other hours may be problematic, requiring new resources. Those facilities may be more expensive than the existing equivalents due to any of the following:

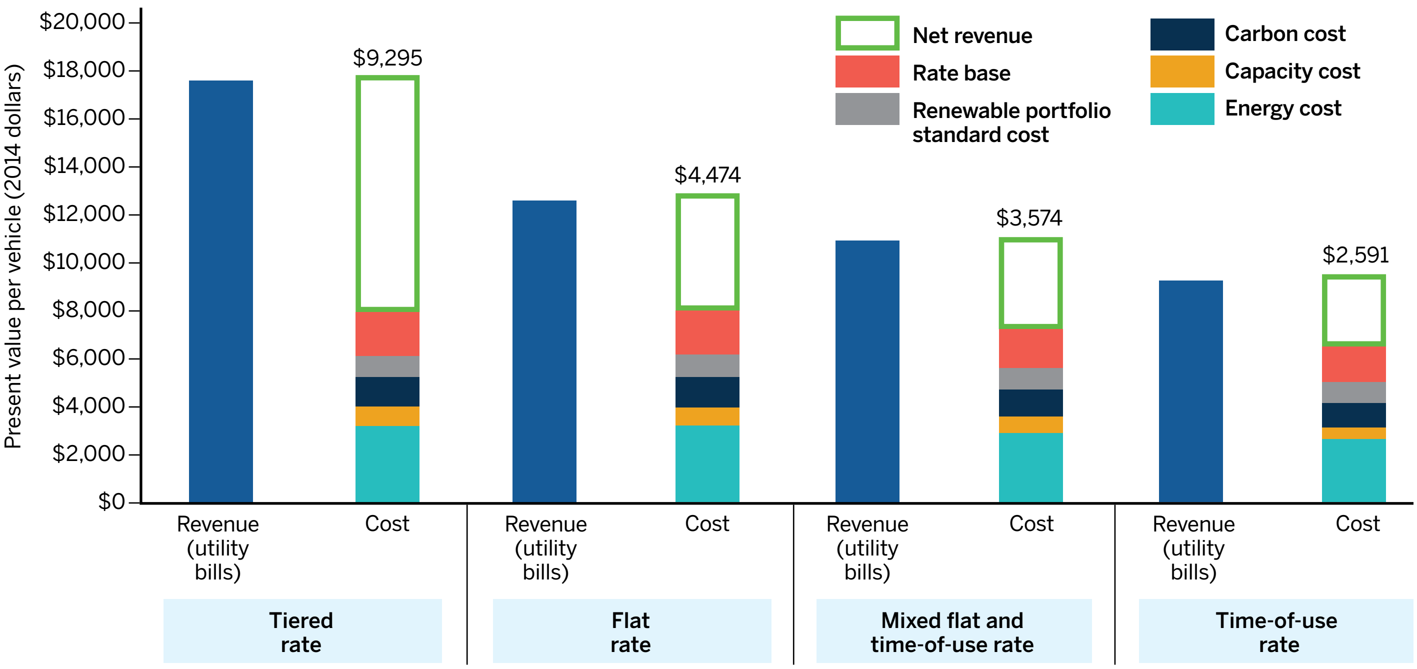
- Inflation: Equipment built 20 years ago will usually be less expensive than the same equipment installed today; buying new sites for generation or substations may be many times the embedded costs of sites purchased in the 1950s.
- Location: Existing generation may be located near load centers, while new generation may be required to locate much farther away; the existing distribution system may be relatively dense, while the new loads require long line extensions.
- Regulatory standards: The utility may be required to locate new lines underground;[196] environmental standards for routing, construction and emissions are often more restrictive for new resources than existing ones.
- Exhaustion of favorable opportunities: A utility may have relied historically on low-cost hydro, while its new resources may be much more expensive; ideal sites for wind power tend to be the first ones developed, while less favorable sites are generally developed later.
- The particular needs of the growing loads, such as higher reliability or power quality, or three-phase service in areas with mostly single-phase service.

Most traditional embedded and marginal cost studies do not take differential growth into account. U.S. residential loads grew about 50% from 1990 to the 2008 recession and not at all since; commercial loads grew about 80% up to the recession and slightly since; and total industrial electricity consumption grew slowly to about 2000 and has declined slowly since, as shown in Figure 43 (U.S. Energy Information Administration, n.d.-b). Load growth patterns for individual utilities may be much more disparate, both among customer classes and between clearly distinguishable subclasses (such as urban and rural, small markets and big-box stores, or farms and mines).

Where incremental costs are much higher than embedded costs, the difference may be assigned to classes in proportion to their growth. If it is a subset of a class that is growing quickly, there may be a rationale for adopting separate tariffs or riders for new customers within that class or for an identifiable subgroup contributing to higher costs (e.g., large vacation homes or data centers). The correct answer in some cases is the creation of a new customer class with separate load and cost characteristics. Beyond cost allocation, the incremental costs may be reflected in rate design and connection fees. For

196 Undergrounding may also be required by the difficulty in finding room for overhead transmission through built-up areas.

Figure 44. Estimated revenue and cost from serving additional electric vehicle load



Source: Energy and Environmental Economics. (2014). *California Transportation Electrification Assessment — Phase 2: Grid Impacts*

example, higher costs may also be allocated to the entire class but collected through a rate element (e.g., consumption over twice the monthly average) that aligns well with the customers causing the additional costs.

In some situations, load growth can reduce system average costs, at least temporarily, by spreading embedded costs over more units of sales. Regulators sometimes reduce rates to a special class or particular customers who will demonstrably generate more revenue with the lower rates, such as with economic development and load retention rates. At the present time, this may apply to beneficial electrification of transportation. Figure 44 shows a calculation of how additional electric vehicle load would generate additional net revenue, thus creating opportunity to benefit new EV users and existing consumers (Energy and Environmental Economics, 2014).

Some generation resources, such as federal hydropower entitlements, are made available to utilities by statute to serve particular loads, such as residential customers. Many regulators allocate those benefits to the classes whose entitlement to the power makes it available to the utility.[197]

16.2 Illustrative and Actual Examples of Differential Treatment

Table 37 on the next page shows an illustrative incremental cost study. In this simplified example, costs are rising; many are directly related to growth, but some are not. Costs relating to growth are assigned to the classes in proportion to their growth. Costs not related to growth are assigned based on each class share of current usage. The result, where both classes start at the same usage level but one grows four times as quickly as the other, is that the growth-related costs are assigned to the growing class, increasing its revenue responsibility if its costs are greater than current rates or decreasing its responsibility if its costs are lower than current rates.

In this illustration, both classes had equal rates in the previous rate proceeding. But costs have risen for both nongrowth categories (inflation) and growth categories (new resources and new distribution capacity). After application of an incremental cost study, the slow-growing class is assigned a rate averaging

197 Those benefits are often reflected in rate design by development of a lower first energy block to ensure that each eligible customer gets an appropriate share of the benefit.

14 cents per kWh, while the fast-growing class is assigned an average of 17 cents per kWh. In the opposite situation, where incremental costs are lower than average costs, the growing class might be assigned lower costs.

Table 37. Illustrative cost study with differential treatment of new resources

	Total	Residential	Commercial and industrial
Revenues at previous usage	$200,000,000	$100,000,000	$100,000,000
Previous usage (MWhs)	2,000,000	1,000,000	1,000,000
Current rates per kWh	$0.10	$0.10	$0.10
Usage			
In current rate period (MWhs)	2,250,000	1,050,000	1,200,000
Growth from previous (MWhs)	250,000	50,000	200,000
Class share of growth		20%	80%
Class share of current		46.7%	53.3%
Growth-related costs	$100,000,000	$20,000,000	$80,000,000
Nongrowth costs	$50,000,000	$23,335,000	$26,667,000
All increased costs	$150,000,000	$43,335,000	$106,667,000
Total revenue requirement	$350,000,000	$143,335,000	$206,667,000
Usage in current rate period (MWhs)		1,050,000	1,200,000
New rates per kWh		$0.14	$0.17

Note: Numbers may not add up to total because of rounding.

16.2.1 Real-World Examples

This section describes specific applications of differential treatment in cost allocation to illustrate the range of concepts.

Seattle City Light 1980 Cost Allocation

In 1980, Seattle City Light, a municipal utility, was experiencing rapid growth in commercial loads with stagnant to declining industrial loads. It recognized that continued growth would require it to commit to new nuclear or coal plants with incremental power costs much higher than the embedded hydro resources. Average rates were about 2 cents per kWh, while just the expected cost of new generation resources was about five times that level.

Even without the new resources, Seattle City Light required a rate increase and developed an interclass cost allocation method along the following lines:[198]

- Starting with historical-year sales by class and prior year revenues by class.
- Assigning the costs related to growth in proportion to the sales to each class, using forecast sales and expected long-term resource acquisition costs.
- Apportioning the residual revenue requirement increase on a uniform basis to all customer classes.

This approach resulted in an average increase in residential rates, an above-average rate increase to commercial customers and a below-average rate increase to industrial customers. It achieved the stated equity goal of charging more to the fastest-growing customer class — that is, the class that was driving the lion's share of the incremental costs.

Vermont Hydro Allocation

The state of Vermont receives an allocation of low-cost power from the Niagara and St. Lawrence hydroelectric facilities owned by the New York Power Authority, pursuant to a requirement in statute that allowed construction of the plants, to provide power to Vermont.[199] The Burlington Electric Department allocates this power to the residential customer class.[200] Other classes do not benefit from this resource. This is a method of ensuring that limited low-cost

198 One of the authors of this manual, Jim Lazar, participated in this proceeding on behalf of an intervenor.

199 "In order to assure that at least 50 per centum of the project power shall be available for sale and distribution primarily for the benefit of the people as consumers, particularly domestic and rural consumers, to whom such power shall be made available at the lowest rates reasonably possible" (Niagara Redevelopment Act, Pub. L. No.85-159, 16 U.S.C. § 836[b][1]). NYPA was required to provide a portion of the power to public bodies and co-ops in neighboring states (16 U.S.C. § 836[b][1]). Thus, the resources were made available to the Burlington Electric Department for the purpose of benefiting residential customers.

200 The Burlington Electric Department also uses that allocation to create an inclining block rate design consisting of a customer charge to cover billing, collection and other customer-specific costs; an initial block priced at the New York Power Authority cost plus average T&D costs; and a tail block that pays for other generation resources plus average T&D costs. See Burlington Electric Department (2019).

resources are equitably allocated to the customers for whom the New York Power Authority provides the power and that all customers share the cost of incremental resources needed to serve demand in excess of incremental usage.[201]

Northwest Power Act — New Large Single Loads

The Pacific Northwest Electric Power Planning and Conservation Act of 1980 provided, among other things, for division of the economic benefits of the federal Columbia River power system among various customer groups and rate pools (Pub. L. No. 96-501; 16 U.S.C. § 839 et seq.). The act set forth a specific mechanism for the Bonneville Power Administration to charge a price based on new resources to "new large single loads" (discrete load increments of 10 average MWs or 87,600 MWhs per year, such as might be experienced if a new oil refinery were built). This provision was intended to protect existing consumers from rate increases that could result from new very large loads attracted by the low average generation costs in the region, in a period in which new resources were very expensive. Table 38 shows average rates for Bonneville Power Administration by category for recent years, including a higher rate for new resources (Bonneville Power Administration, n.d.).[202]

Table 38. Bonneville Power Administration rate summary, October 2017 to September 2019

Rate category	Average rates per MWh
Priority firm public utility average	$36.96
Priority firm public utility Tier 1	$35.57
Priority firm – IOU residential load	$61.86
Industrial power	$43.51
New resources	$78.95

Source: Bonneville Power Administration. *Current Power Rates*

Nova Scotia Power Load Retention and Economic Development Rates

In 2011, falling global demand for paper resulted in the bankruptcy and shutdown of two paper mills that were Nova Scotia Power's largest customers, which accounted for about 20% of its sales and 12% of its revenues. The mills had been major employers, both directly and as purchasers of wood harvested from forests in the province. A buyer emerged for the larger of those facilities, contingent on a variety of supportive policies from the provincial and federal governments, including favorable tax treatment and rates.

Nova Scotia Power proposed and the Nova Scotia Utility and Review Board approved (with modifications) a load retention rate that would charge the mill hourly marginal fuel and purchased power costs (including opportunity costs from lost exports), plus administrative charges and mill rates to cover variable O&M, variable capital expenditures and a contribution to capital investments and long-term O&M. The load would be entirely interruptible, and the utility committed to excluding the mill's load from its planning and commitment decisions (Nova Scotia Utility and Review Board, 2012).

The determination of Nova Scotia Power's hourly marginal costs proved to be more difficult than expected.[203] Nonetheless, the rate design succeeded in attracting the investment necessary to restart and retain the mill as an employer while producing some contribution to Nova Scotia Power's embedded costs. The load retention tariff expires in 2020, at which time the mill may switch to a firm rate or negotiate a new load retention tariff.[204]

Chelan County Public Utility District Bitcoin Rate

The creation of bitcoin cryptocurrency units requires energy-intensive mathematical computations called mining. To limit the cost of their operations, bitcoin "miners" have sought locations with low-priced electricity. Those operations

201 This same concept has been the foundation of inclining block rates in Washington state and Indonesia.

202 The average rates subsume a variety of fixed and variable charges.

203 Nova Scotia Power was not part of an energy market and had limited connections to its only neighboring utility (NB Power, which is also not part of an energy market), and its marginal generation resources are coal plants with long commitment horizons (Rudkevich, Hornby and Luckow, 2014).

204 The Nova Scotia Power system will operate differently after 2020, when it is expected to have access to large amounts of Newfoundland hydro energy and operate under stricter carbon emissions standards. Any new load retention tariff would need to reflect those changes.

typically require very large amounts of power but have few on-site employees and little local economic benefit. One of these locations is Chelan County in Washington state, where the local public utility district owns two very large dams on the Columbia River and has industrial rates about one-fourth of the national average.[205]

Chelan County Public Utility District's existing low-cost resource is fully obligated to a combination of local retail use and long-term contract sales. The contract sales prices are above the average retail rates, bringing significant revenue to fund public infrastructure in the county, including a world-class parks network. When the district received applications for service from bitcoin miners, it decided that this high-density load growth would not be in the public interest, declared a moratorium on new connections and developed a tariff designed to ensure that any growth of this type of load would not adversely affect other consumers or the local economy (Chelan County Public Utility District, 2018). This tariff is geographically differentiated, to recognize areas where transmission and distribution capacity are available, and includes:

- Payment in a one-time charge of transmission and distribution system costs to serve large new loads.
- A price for electricity, tied to (generally higher) regional wholesale market prices, not Chelan County Public Utility District system costs.
- Severe penalties for excess usage that could threaten system reliability.

205 The Chelan County Public Utility District rate for primary industrial customers up to 5 MWs with an 80% load factor is 1.91 cents per kWh (Chelan County Public Utility District, n.d.). The average U.S. industrial price was 6.88 cents per kWh in 2017 (U.S. Energy Information Administration, 2018, Table 5.c).

17. Future of Embedded Cost Allocation

Change is inevitable as the electric industry adapts to new technology. Part III of this manual, on embedded cost of service studies, has attempted to address many common situations the cost analyst will face in determining an equitable allocation of costs among customer classes. But new technologies and changing loads will dictate new issues and perhaps new methods.

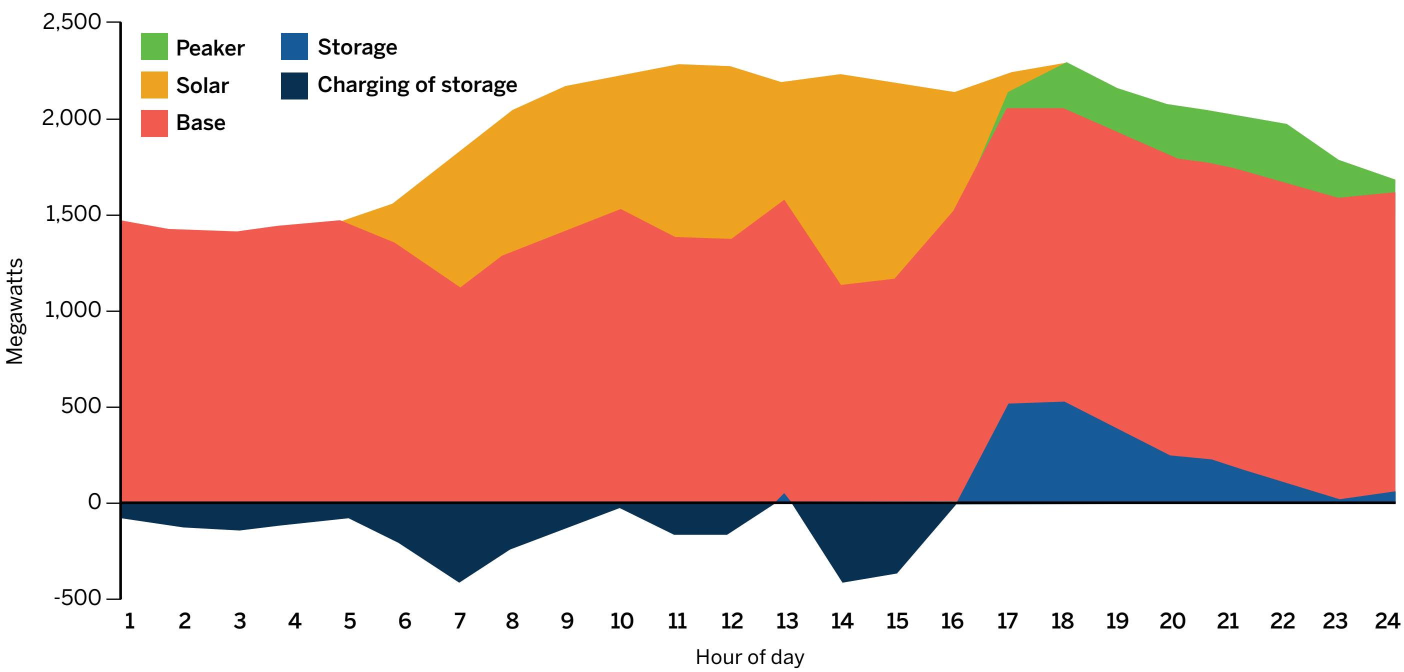
Historically, power has flowed from central generators, through transmission, to primary distribution and then secondary distribution. Customers served at the transmission level have not paid for distribution, and those served at primary have not paid for line transformers or secondary lines. This situation is beginning to change. In some places, the development of distributed solar capacity already causes power to flow from secondary to primary and even onto the transmission system. At some point, all customers may receive service through all levels of the delivery system, requiring a substantial rethinking of the allocation of distribution costs.

In addition to the increased complexity of system operations, utilities have more data about system operations and customer loads than they had a few decades ago. As the costs of electronics decline, more data will become available to more utilities. Thus, methods that were the best available in the 1980s can now (or soon) be superseded by more accurate and realistic allocations. Computations that would have been unwieldy on the computers of the 1980s are trivial today.

For example, as utilities acquire data on the hourly load of each class, many costs can be allocated on an hourly basis, rather than on such summary values as annual energy use and contribution to a few peak load hours. The costs of baseload generation resources (nuclear, biomass, geothermal) may be assigned to all hours; costs of wind and solar resources to the hours they provide service; storage to the hours in which it exports energy and provides other benefits;[206] and demand response costs to the hours these resources are deployed or the hours in which they reduce costs by supplying operating reserves. In a sense, this is an evolution and refinement of the base-intermediate-peak traditional method, described in Section 9.1.

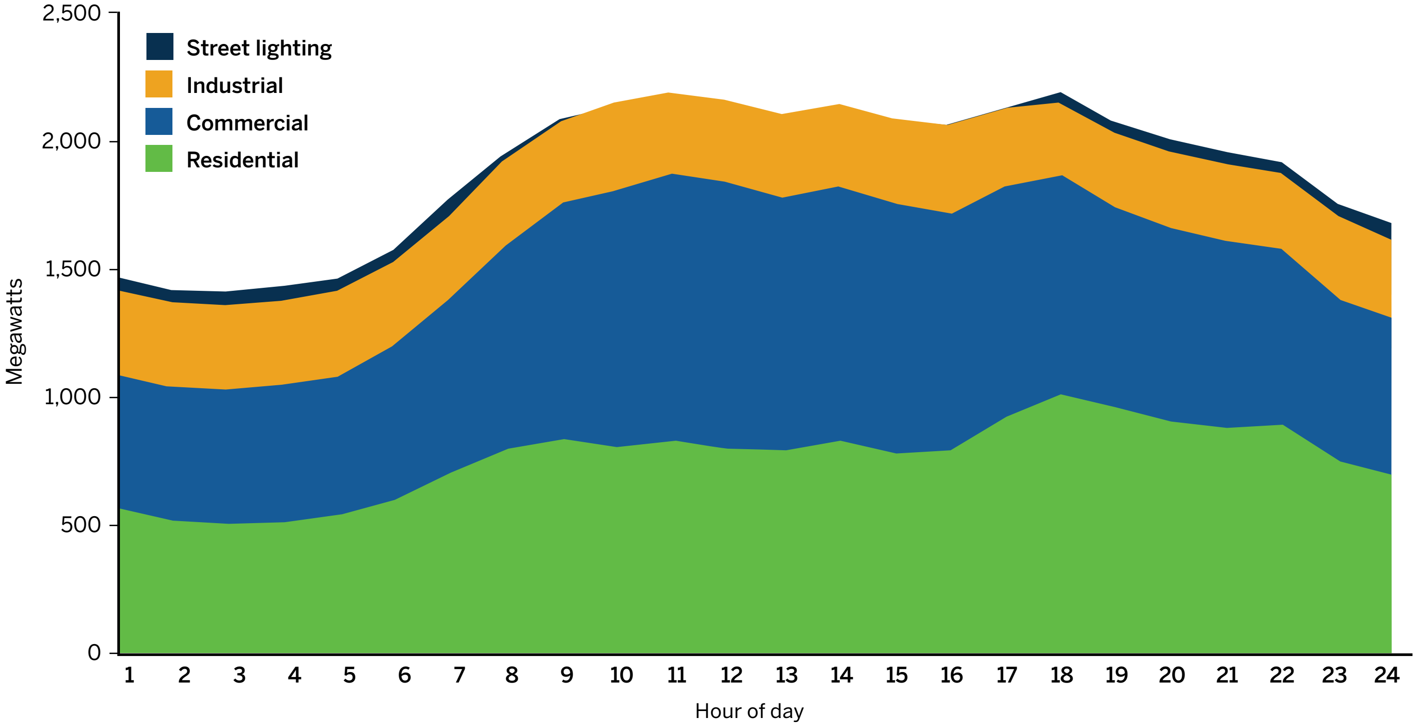
To illustrate this approach, Figure 45 provides a day's

Figure 45. Daily dispatch for illustrative hourly allocation example



206 Among other things, charging storage in hours with low net loads will raise minimum load levels and reduce ramp rates, benefiting the hours in which net load rises rapidly.

Figure 46. Class loads for illustrative hourly allocation example



worth of hourly dispatch of four resources: a baseload resource (perhaps nuclear), solar, a peaker (perhaps a combustion turbine) and storage (both as charging load below the axis and generation above the line). In this example, the storage charges from excess base capacity in the early morning and then from solar, and discharges in the evening to replace the waning solar. The actual application of hourly allocation would include 8,760 hours from an actual or typical year, with a wide range of load levels, availability of the base resource and solar output patterns.

Figure 46 provides hourly energy requirements by class (including losses) for the same day as in Figure 45.

Table 39 on the next page provides two types of data from Figure 45 and Figure 46: each class's share of the load in each hour, and the portion of each resource's daily generation that occurs in the hour.

The generation cost allocation for a class would be:

$$\sum_{r,h} L_h \times S_{r,h} \times C_r$$

Where L_h = class share of load in hour *h*

$S_{r,h}$ = share of resource *r* output that occurred in hour *h*

C_r = cost of resource (in this example, for the day)

Table 40 shows the result of this computation for the data in Table 39. The lighting class, for example, would pay for 1.8% of the base resource, 2.2% of the peakers and just 0.6% of the solar. Table 40 also shows each class's share of total load, for reference.

Table 39. Hourly class load share and resource output

	Class share of load				Resource output: Percentage occurring by hour			
Hour	**Residential**	**Commercial**	**Industrial**	**Street lighting**	**Base**	**Peaking**	**Solar**	**Storage**
1	39.0%	35.3%	22.5%	3.2%	4%	0%	0%	0%
2	37.0%	36.2%	23.5%	3.3%	4%	0%	0%	0%
3	36.4%	36.7%	23.5%	3.4%	4%	0%	0%	0%
4	36.7%	37.0%	23.1%	3.3%	4%	0%	0%	0%
5	37.5%	36.6%	22.7%	3.2%	4%	0%	0%	0%
6	38.4%	37.2%	21.4%	3.0%	4%	0%	3%	0%
7	39.7%	37.1%	20.6%	2.6%	4%	0%	8%	0%
8	39.8%	39.2%	19.5%	1.6%	4%	0%	9%	0%
9	38.8%	42.6%	18.4%	0.2%	4%	0%	9%	0%
10	36.7%	44.8%	18.2%	0.2%	4%	0%	8%	0%
11	36.6%	45.1%	18.1%	0.2%	4%	0%	11%	0%
12	35.9%	45.8%	18.1%	0.2%	4%	0%	10%	0%
13	36.7%	44.8%	18.3%	0.2%	4%	0%	7%	1%
14	37.5%	44.0%	18.2%	0.2%	4%	0%	13%	0%
15	36.3%	44.7%	18.8%	0.2%	4%	0%	12%	0%
16	37.4%	43.5%	18.8%	0.2%	4%	0%	7%	0%
17	41.5%	40.6%	17.4%	0.4%	4%	5%	1%	25%
18	44.7%	37.3%	16.1%	2.0%	4%	13%	0%	25%
19	45.2%	35.8%	16.8%	2.2%	4%	13%	0%	18%
20	44.2%	36.1%	17.4%	2.3%	4%	15%	0%	12%
21	44.4%	35.4%	17.8%	2.3%	4%	15%	0%	10%
22	45.9%	33.8%	17.9%	2.4%	4%	19%	0%	5%
23	42.8%	35.1%	19.4%	2.6%	4%	12%	0%	1%
24	41.6%	35.5%	20.1%	2.8%	4%	6%	0%	3%
All hours	39.7%	39.6%	19.1%	1.6%	100%	100%	100%	100%

Note: Percentages may not add up to 100 because of rounding.

Table 40. Class shares of resource cost responsibilities and load

	Residential	Secondary commercial	Primary industrial	Street lighting
Resource type				
Base	39.6%	39.2%	19.4%	1.8%
Peaker	44.3%	35.8%	17.7%	2.2%
Solar	37.5%	43.1%	18.7%	0.6%
Storage	43.8%	37.4%	17.2%	1.7%
Class share of total load	39.7%	39.6%	19.1%	1.6%

Works Cited in Part III

Arkansas Public Service Commission. (2013, December 30). Docket No. 13-028-U, Order No. 21 in general rate case for Entergy Arkansas. Retrieved from http://www.apscservices.info/pdf/13/13-028-U_431_1.pdf

Barrett, L. (2012, March 29). Nova Scotia-located coal plants next to go. *Australia's Mining Monthly.* Retrieved from https://www.miningmonthly.com/archive/news/1300953/nova-scotia-located-coal-plants

BC Hydro. (2014, June 19). *2015 rate design application (RDA): Cost of service (COS) methodology review* [Presentation]. Retrieved from http://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/cos-methodology-review-workshop-presentation.PDF

Behnke, M., Erdman, W., Horgan, S., Dawson, D., Feero, W., Soudi, F., et al. (2005). *Secondary network distribution systems background and issues related to the interconnection of distributed resources* (NREL/TP-560-38079). Golden, CO: National Renewable Energy Laboratory. Retrieved from https://www.nrel.gov/docs/fy05osti/38079.pdf

Bonbright, J. (1961). *Principles of public utility rates.* New York, NY: Columbia University Press.

Bonneville Power Administration. (n.d.). *Current power rates* [Webpage]. Retrieved from https://www.bpa.gov/Finance/RateInformation/Pages/Current-Power-Rates.aspx

Burbank Water and Power. (n.d.). *BWP free WiFi* [Webpage]. Retrieved from https://www.burbankwaterandpower.com/bwp-free-wifi

Burlington Electric Department. (2019, February 1). *Rates & fees* [Webpage]. Retrieved from https://www.burlingtonelectric.com/rates-fees

California Energy Commission. (2014, May 21). *California transmission lines – substations enlargement maps.* Retrieved from https://ww2.energy.ca.gov/maps/infrastructure/3part_enlargements.html

California Public Utilities Commission. (2007, July 12). *Opinion addressing electric and gas residential line extension allowance calculation methodology.* Application No. 05-09-019 et al., Decision No. 07-07-019. Retrieved from http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/70109.PDF

California Public Utilities Commission. (2014, December 18). *Decision regarding smartmeter opt-out provisions.* Application No. 11-03-014 et al., Decision No. 14-12-078. Retrieved from http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K904/143904205.PDF

Chelan County Public Utility District. (n.d.). *Rates and policies* [Webpage]. Retrieved from https://www.chelanpud.org/my-pud-services/rates-and-policies

Chelan County Public Utility District. (2018, November 5). *Cryptocurrency rate: Board preview of Nov. 7 public information meeting* [Presentation]. Retrieved from https://www.chelanpud.org/docs/default-source/default-document-library/nov-5-board-preview-of-nov-7-info-meeting.pdf

Chernick, P. (2010, August 20). Rebuttal testimony on behalf of the Office of the People's Counsel. Maryland Public Service Commission Case No. 9230.

Chernick, P., and Meyer, M. (1982). Capacity/energy classifications and allocations for generation and transmission plant. *Award Papers in Public Utility Economics and Regulation*. East Lansing, MI: Michigan State University, Institute for Public Utilities.

Colorado Public Utilities Commission. (2018, June 15). Proceeding No. 17AL-0477E, Decision No. C18-0445 in rate case for Black Hills/Colorado Electric Utility Co. Retrieved from https://www.dora.state.co.us/pls/efi/EFI_Search_UI.Show_Decision?p_session_id=&p_dec=25270

Coyle, E. (1982, June 24). Average and excess demand once again. *Public Utilities Fortnightly.*

Delmarva Power & Light. (2016, August 15). Response to the Office of the People's Counsel data request 5-11, Attachment D. Maryland Public Service Commission Case No. 9424.

Drazen, M. and Mikkelsen, R. (2013, December 2). Rebuttal evidence on behalf of the Industrial Group. Nova Scotia Utility and Review Board NSPI-P-892/Matter No. M05473, Exhibit N-28. Retrieved from https://uarb.novascotia.ca/fmi/webd/UARB15

Electric Reliability Council of Texas. (2018). *2017 ERCOT hourly load data* [Data set]. Retrieved from http://www.ercot.com/gridinfo/load/load_hist/

El Paso Electric Co. (2015, October 29). *El Paso Electric Company's response to Office of Public Utility Counsel's fifth request for information*. Public Utility Commission of Texas Docket No. 44941. Retrieved from http://interchange.puc.texas.gov/Search/Documents?controlNumber=44941&itemNumber=215

Energy and Environmental Economics. (2014). *California transportation electrification assessment — Phase 2: Grid impacts*. San Francisco, CA: Author. Retrieved from http://www.caletc.com/wp-content/uploads/2016/08/CalETC_TEA_Phase_2_Final_10-23-14.pdf

ENGIE Resources (n.d.). *Historical data reports* [Webpage]. Retrieved from https://www.engieresources.com/historical-data

Entergy Corp. (n.d.). *How we trim trees* [Webpage]. Retrieved from https://www.entergy.com/tree_trimming_how/

Fang, C. (2017, January 20). Direct testimony on behalf of San Diego Gas & Electric. California Public Utilities Commission Application No. 17-01-020. Retrieved from https://www.sdge.com/regulatory-filing/20491/application-sdge-authority-implement-priority-review-and-standard-review

Federal Energy Regulatory Commission. (n.d.). *Form 1 — electric utility annual report* [Database]. Retrieved from https://www.ferc.gov/docs-filing/forms/form-1/data.asp

Federal Energy Regulatory Commission. (2008, April 21). *Opinion and order on initial decision*. 123 FERC ¶ 61,047. Docket No. EL05-19-002, Opinion No. 501. Retrieved from https://www.ferc.gov/whats-new/comm-meet/2008/041708/E-7.pdf

Federal Energy Regulatory Commission. (2011, July 21). *Transmission planning and cost allocation by transmission owning and operating public utilities.* 136 FERC ¶ 61,051. Docket No. RM10-23-000, Order No. 1000. Retrieved from https://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf

Gorman, H. (2018, November 15). Testimony on behalf of National Grid. Massachusetts Department of Public Utilities Docket No. 18-150. Retrieved from https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/10043215

Green Mountain Power. (2016, April 1). *Electric service extensions and relocations*. Retrieved from http://greenmountainpower.com/wp-content/uploads/2017/01/Line-Extension-Rules-Regulations-4.1.16.pdf

Hammer, N. (2018, May 30). Direct testimony on behalf of MidAmerican Energy Co. Iowa Utilities Board Docket No. RPU-2018-0003. Retrieved from https://efs.iowa.gov/efs/ShowDocketSummary.do?docketNumber=RPU-2018-0003

Henry, T. (2012, October 31). *Luminant coal units get permission to mothball this winter*. National Public Radio. Retrieved from https://stateimpact.npr.org/texas/2012/10/31/luminant-coal-units-get-go-ahead-to-mothball-this-winter/

Illinois Commerce Commission. (2008, September 10). Docket No. 07-0566, order in rate case for Commonwealth Edison Co. Retrieved from https://www.icc.illinois.gov/docket/files.aspx?no=07-0566&docId=128596

Institute for Energy Economics and Financial Analysis. (2019, March 4). *Owners say Gibbons Creek coal plant in Texas will remain in mothball status*. Retrieved from http://ieefa.org/owners-say-gibbons-creek-coal-plant-in-texas-will-remain-in-mothball-status/

Johnson, B. (1980, December 4). Cost allocations: Limits, problems and alternatives. *Public Utilities Fortnightly*.

Kahn, E. (1988). *Electric utility planning and regulation.* Washington, DC: American Council for an Energy-Efficient Economy.

La Capra, R. (1992). Direct testimony on behalf of Boston Edison. Massachusetts Department of Public Utilities Docket No. 92-92.

Lazar, J., and Baldwin, X. (2011). *Valuing the contribution of energy efficiency to avoided marginal line losses and reserve requirements*. Montpelier, VT: Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/valuing-the-contribution-of-energy-efficiency-to-avoided-marginal-line-losses-and-reserve-requirements/

Lazard. (2018). *Lazard's levelized cost of energy analysis — Version 12.0*. Retrieved from https://www.lazard.com/media/450784/lazards-levelized-cost-of-energy-version-120-vfinal.pdf

Levin, A. (2017, June 30). Prefiled response testimony on behalf of NW Energy Coalition, Renewable Northwest and Natural Resources Defense Council in rate case for Puget Sound Energy. Washington Utilities and Transportation Commission Docket No. UE-170033. Retrieved from https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/GetDocument.ashx?docID=2309&year=2017&docketNumber=170033

Manitoba Hydro. (2015). *Cost of service methodology review*. Retrieved from https://www.hydro.mb.ca/regulatory_affairs/pdf/electric/cost_of_service_study_submission/appendix_3_1_pcoss14.pdf

Manitoba Public Utility Board (2016, December 20). *Order in respect of a review of Manitoba Hydro's cost of service study methodology*. Order No. 164/16. Retrieved from http://www.pubmanitoba.ca/v1/pdf/16hydro/164-16.pdf

Marcus, W. (1987). Testimony on behalf of Alberta Federation of Rural Electrification Associations and Alberta Association of Municipal Districts and Counties. Alberta Public Utilities Board 1987 Electric Energy Marketing Agency adjustment.

Massachusetts Department of Public Utilities. (1989). Docket No. 88-250, order in rate case for Western Massachusetts Electric Co.

Meyer, M. (1981, December 17). Clarifying NARUC demand allocation methods. *Public Utilities Fortnightly*.

Michigan Public Service Commission. (2017, July 31). Case No. U-18124, order in natural gas rate case for Consumers Energy Co. Retrieved from https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000001UUAgAAO

Midcontinent Independent System Operator. (2018). *Planning year 2019-2020 loss of load expectation study report*. Carmel, IN: Author. Retrieved from https://cdn.misoenergy.org/2019%20LOLE%20Study%20Report285051.pdf

Minnesota Power. (2013, May 28). *Minnesota Power construction guide: Home edition*. Retrieved from https://mnpower.com/Content/Documents/CustomerService/ConstructionCenter/residential-construction-guide-with-toc.pdf

Minnesota Public Utilities Commission. (2016, June 3). Docket No. G-008/GR-15-424, order in natural gas rate case for CenterPoint Energy. Retrieved from https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={92AB0946-4F77-4A70-BF38-7D36F88AC979}&documentTitle=20166-121975-01

Monitoring Analytics. (2014). *2013 state of the market report for PJM*. Eagleville, PA: Author. Retrieved from http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2013.shtml

Monitoring Analytics. (2019). *2018 state of the market report for PJM*. Eagleville, PA: Author. Retrieved from http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018.shtml

National Association of Regulatory Utility Commissioners. (1989). *Gas distribution rate design manual*. Washington, DC: Author. Retrieved from http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B04381803-1D3A-4CD7-BBE3-64EDB16835C0%7D

National Association of Regulatory Utility Commissioners. (1992). *Electric utility cost allocation manual*. Washington, DC: Author. Retrieved from https://pubs.naruc.org/pub/53A3986F-2354-D714-51BD-23412BCFEDFD

Newfoundland and Labrador Hydro (2018). *2018 cost of service methodology review report*. Retrieved from http://www.pub.nf.ca/applications/NLH2018CostofService/application/Application%20-%20Cost%20of%20Service%20Methodology%20-%202018-11-15.PDF

Northern Indiana Public Service Co. (2018). *2018 integrated resource plan executive summary*. Retrieved from https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/irp-executive-summary.pdf

Northern States Power Co.-Minnesota. (2010, November 3). *General rules and regulations.* Retrieved from https://www.xcelenergy.com/staticfiles/xe/PDF/Regulatory/Me_Section_6.pdf

Nova Scotia Power. (2013a, June 28). *2013 Nova Scotia Power cost of service study.* Nova Scotia Utility and Review Board Matter No. M05473, Exhibit N-1. Retrieved from https://uarb.novascotia.ca/fmi/webd/UARB15

Nova Scotia Power. (2013b, September 12). *2013 Nova Scotia Power cost of service study: Attachment 1 in response to IR-15.* Nova Scotia Utility and Review Board Matter No. M05473, Exhibit N-3(i). Retrieved from https://uarb.novascotia.ca/fmi/webd/UARB15

Nova Scotia Utility and Review Board. (1995, September 22). Docket No. NSPI864, order in generic hearing respecting cost of service and rate design for Nova Scotia Power.

Nova Scotia Utility and Review Board. (2012, August 20). Matter No. M04862, decision approving with conditions a load retention rate mechanism. Retrieved from https://uarb.novascotia.ca/fmi/webd/UARB15

Nova Scotia Utility and Review Board. (2014, March 11). Matter No. M05473, decision approving amended 2013 Nova Scotia Power cost of service study. Retrieved from https://uarb.novascotia.ca/fmi/webd/UARB15

NV Energy. (n.d.). *IS-2 interruptible irrigation service* [Webpage]. Retrieved from https://www.nvenergy.com/account-services/energy-pricing-plans/is-2

Otter Tail Power Co. (2017, July 21). *Tariff schedules applicable to electric service of Otter Tail Power Company*. Retrieved from https://www.otpco.com/media/1300/mn_indexandgeneralrulesandregulations.pdf

Parmesano, H., Rankin, W., Nieto, A., and Irastorza, V. (2004). *Classification and allocation methods for generation and transmission in cost-of-service studies.* Los Angeles, CA: National Economic Research Associates. Retrieved from https://www.nera.com/content/dam/nera/publications/archive1/final%20report%20to%20PUB-MH-NERA-20040401-1.pdf

Patton, D., LeeVanSchaick, P., and Chen, J. (2017). *2016 assessment of the ISO New England electricity markets.* Fairfax, VA: Potomac Economics. Retrieved from https://www.iso-ne.com/static-assets/documents/2017/08/iso-ne-2016-som-report-full-report-final.pdf

Patton, D., LeeVanSchaick, P., Chen, J., and Palavadi Naga, R. (2018). *2017 state of the market report for the New York ISO markets*. Fairfax, VA: Potomac Economics. Retrieved from https://www.potomaceconomics.com/wp-content/uploads/2018/06/NYISO-2017-SOM-Report-5-07-2018_final.pdf

Peppin, M. (2013, November 4). Direct testimony on behalf of Northern States Power Co.-Minnesota. Minnesota Public Utilities Commission Docket No. E002/GR-13-868, Document No. 20311-93284-02. Retrieved from https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={21D30B7C-A614-4649-AEE7-CDA29BD1192B}&documentTitle=201311-93284-02

Public Service Company of Colorado. (2018, December 3). *Rules and regulations: Electric service distribution extension policy.* Retrieved from https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/18AL-0852E-AL-1785-E-Distribution-Extension-Policy-Tariffs-FINAL.pdf

Public Utility Commission of Texas. (2000, November 22). *Interim order establishing generic customer classification and rate design*. Docket No. 22344, Order No. 40. Retrieved from http://interchange.puc.texas.gov/Search/Documents?controlNumber=22344&itemNumber=655

Public Utility Commission of Texas. (2015, December 18). Docket No. 43695, order in rate case for Southwestern Public Service Co. Retrieved from http://interchange.puc.texas.gov/Documents/43695_1018_876737.PDF

Public Utility Commission of Texas. (2018, March 19). Docket No. 46449, order on rehearing in rate case for Southwestern Electric Power Co. Retrieved from http://interchange.puc.texas.gov/Documents/46449_825_973078.PDF

Rea, C. (2013, May 17). Testimony on behalf of MidAmerican Energy Co. Iowa Utilities Board Docket No. RPU-2013-0004. Retrieved from https://efs.iowa.gov/cs/groups/external/documents/docket/mdaw/mtgy/~edisp/182629.pdf

Rudkevich, A., Hornby, R., and Luckow, P. (2014, February 28). *Audit of Port Hawkesbury paper load retention tariff.* Synapse Energy Economics and Newton Energy Group. Nova Scotia Utility and Review Board Matter No. M05803, Exhibit N-4. Retrieved from https://uarb.novascotia.ca/fmi/webd/UARB15

Seattle Municipal Archives. (1977, September 27). *Utilities Committee meeting* (Record Series 4601-03, Event ID 6544) [Audio recording]. Retrieved from https://www.seattle.gov/cityarchives/exhibits-and-education/seattle-voices/energy-conservation

Seelye, W. (2016, November 23). Direct testimony on behalf of Kentucky Utilities Co. Kentucky Public Service Commission Case No. 2016-00370. Retrieved from https://psc.ky.gov/pscecf/2016-00370/derek.rahn%40lge-ku.com/11232016073202/10_-_KU_Testimony_and_Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf

Sterzinger, G. (1981, July 2). The customer charge and problems of double allocation of costs. *Public Utilities Fortnightly.*

Steward, J. (2014). Direct testimony on behalf of Rocky Mountain Power. Utah Public Service Commission Docket No. 13-035-184. Retrieved from https://pscdocs.utah.gov/electric/13docs/13035184/249702 ExJJJDirTestSteward1-3-2014.pdf

U.S. Energy Information Administration. (n.d.-a). *Annual electric power industry report, Form EIA-861: 2001* [Data file]. Retrieved from https://www.eia.gov/electricity/data/eia861

U.S. Energy Information Administration. (n.d.-b). *Form EIA-861M sales and revenue: 1990-current* [Data file]. Retrieved from https://www.eia.gov/electricity/data/eia861m/

U.S. Energy Information Administration. (1992). *Form EIA-860A: 1990* [Data file]. Retrieved from https://www.eia.gov/electricity/data/eia860/

U.S. Energy Information Administration. (2018, October 12). *Electric sales, revenue, and average price.* Retrieved from https://www.eia.gov/electricity/sales_revenue_price/

Utah Public Service Commission. (1999, March 4). Docket No. 97-035-01, report and order in investigation into the reasonableness of rates and charges of PacifiCorp. Retrieved from www.utilityregulation.com/content/orders/99UT9703501r.pdf

Washington Utilities and Transportation Commission. (1981). Cause U-81-41, sixth supplemental order in rate case for Puget Sound Power and Light Co.

Washington Utilities and Transportation Commission. (1993, August 16). Docket No. UE-920499, ninth supplemental order on rate design issues.

Xcel Energy. (2018, October 2-4). *Leading the energy future* [Presentation at the Wolfe Research Conference]. Retrieved from investors.xcelenergy.com/file/4025308/Index?KeyFile=1500113448

Part IV:

Marginal Cost of Service Studies

18. Theory of Marginal Cost Allocation and Pricing

The fundamental principle of marginal cost pricing is that economic efficiency is served when prices reflect current or future costs — that is, the true value of the resources being used to serve customers' loads — rather than historical embedded costs. This is a strong underpinning that most analysts agree on, but there are serious theoretical and computational complications associated with the development of marginal costs.

Economic efficiency is served when prices reflect the true value of the resources being used to serve customers' loads.

Marginal cost studies start from a similar functionalization as embedded cost studies: generation, transmission, distribution. However, the data used are not at all the same as those used in an embedded cost of service study. The typical marginal cost of service study requires detailed hourly data on loads by customer class, marginal energy costs and measures of system reliability (loss-of-energy expectation, peak capacity allocation factor, probability of peak, etc.), as well as multiyear data on loads and investments for the transmission and distribution system.

As will be discussed below with specific examples and applications, the time horizon of marginal cost studies and even of individual components within studies can vary. Marginal costs can be measured in:

- The short run, as with energy costs measured for one to three years, and all capital assets kept constant.
- Intermediate periods ranging from six years (the length of two typical general rate cases for many utilities) to 15 years (often used for analysis of T&D capital investments).
- The long term, such as with **long-run incremental costs** for the entire generation function; long-run generation capacity costs based on equilibrium conditions; and the rental of customer equipment in some marginal customer cost studies. The longest possible analysis would be a total service long-run incremental cost study where an optimal system is costed out.

At one extreme, a true short-run marginal cost study will measure only a tiny fraction of the cost of service that varies from hour to hour with usage and holds all other aspects of the system constant. At the other extreme, a TSLRIC study measures the cost of replacing today's power system with a new optimally designed and sized system that uses the newest technology. In between is a range of alternatives, many of which have been used in states like Maine, New York, Montana, Oregon and California to determine revenue allocation among classes. The major conceptual issue in these studies is using very short-run metrics for energy cost and longer-term metrics for capital costs (generation, transmission and distribution capacity and customer connection costs). Many studies use these mixed time horizons, but this is an error that should be avoided.

Marginal cost pricing generally is not connected to the utility's revenue requirement, except to some extent in restructured generation markets (where the costs are not subject to traditional cost of service regulation). The calculated marginal costs may be greater or less than the allowed revenue requirement, which is normally computed on an accounting or embedded cost basis. It is only happenstance if marginal costs and embedded costs produce the same revenue.

There is also no necessary connection between marginal cost pricing and cost allocation. To summarize the material discussed in more depth below, in its simplest hypothetical form, a marginal cost study computes marginal costs for different elements of service, and these are multiplied by the determinants for each class. This produces a class marginal cost revenue requirement and, when combined with other classes, a system MCRR. This is then reconciled with the allowed revenue requirement to determine revenue allocation by class. This part of this manual provides some examples of marginal cost studies and the revenue allocation resulting from them.

A second important concept related to marginal cost pricing comes from the theory of general equilibrium: If costs are in equilibrium, short-run marginal costs equal long-run marginal costs. That is, to get one more unit from existing resources would require operating resources with high variable costs, at a cost equal to the cost of both building and operating newer, cheaper resources. However, it is hard to apply this theory in practice because developing and quantifying a system in equilibrium is extremely difficult. Until recently, assets tended to be developed in large sizes relative to the utility's overall system needs, rendering equilibrium conditions unlikely. Equilibrium is also impossible in the real world, for three main reasons. First, loads and fuel prices can never be forecast exactly (and often cannot be forecast even closely). Technology also changes, and the use of specific resources ends up changing. Finally, long lead times to construct various resources (particularly large power plants and transmission lines) can exacerbate the consequences of forecasting errors.

As a result, the marginal cost methods used today, such as those developed by National Economic Research Associates (now NERA Economic Consulting) — discussed in considerably more detail throughout Part IV — do not reflect equilibrium conditions. Moreover, with the current configuration of the electric system and changes over time, the trend has been toward overbuilding, so generation marginal cost ends up systematically below average cost, with ramifications for class allocation. In addition, as previously implemented in many jurisdictions, the definitions of marginal cost have mixed short-term and long-term elements in ways that are theoretically inconsistent.

18.1 Development of Marginal Cost of Service Studies

The most common method used in jurisdictions relying on marginal costs for allocation purposes was developed by Alfred Kahn and colleagues at NERA in the late 1970s.[207]

The Kahn/NERA method (referred to as the NERA method in this manual because that is the term most analysts and practitioners use) is the predominant method that current marginal cost analysts use. Some entities, such as Oregon, use a long-run marginal cost method for generation, and other states and analysts have proposed changes to specific components of the NERA method. Nevertheless, the NERA method, whatever its benefits and detriments, is the starting point for most current marginal cost of service study analysis, and marginal cost of service study analysts have identified fewer alternative methods than have embedded cost of service study analysts.

Another practical consideration in analyzing marginal cost methods is that very few states are marginal cost jurisdictions. In particular, California, Nevada and Oregon calculate marginal costs for generation and other functions; Maine and New York have deregulated generation but use marginal costs for distribution. Thus, many examples in the remaining discussion come from a relatively small number of jurisdictions.

The NERA methodology uses:

- Long-term customer costs based on the cost of renting new customer connection equipment using the current technology.
- Intermediate-term transmission and shared distribution costs based on an analysis of additions made to serve new capacity but not to increase reliability or replace existing capacity to continue to serve load, measured over 10 to 15 years.
- Generation capacity costs that tend toward a longer term based on new construction.[208]
- Usually relatively short-term marginal energy costs (one to six years).

207 National Economic Research Associates developed a series of papers on the topic. The most critical for this manual are *A Framework for Marginal Cost-Based Time-Differentiated Pricing in the United States* (1977a) and *How to Quantify Marginal Costs* (1977b).

208 Some utilities and consumer advocates have used shorter-term generation capacity costs. Consumer advocates often chose shorter-term generation costs when revenue allocation was done by function rather than in total. See Section 19.3.

One of the key concepts developed through this work was the real economic carrying charge. A RECC takes the revenue requirements or costs of a resource and reshapes them to reflect a stream of costs that increases with inflation and has the same present value as the revenue requirements. Inputs to a RECC are the same as those used for utility revenue requirements. They include the capital structure and cost of capital, a discount rate, income tax parameters (rates, depreciation and whether specific tax differences are normalized or flowed through), book depreciable life and costs of property taxes and insurance. The RECC is not unique to this method but can be used in conjunction with other methods, such as long-run incremental cost of generation (see Section 19.1) or total service long-run incremental cost (Section 25.1).

Analytically, the RECC also reflects the value associated with deferring a project from one year to the next and can be used to place projects with different useful lives on a common footing. The RECC is lower than the utility's nominal levelized cost of capital for a given type of plant and lower than the early year revenue requirements calculated traditionally for such a plant. A further discussion of the RECC, with a specific example, is in Appendix B.

The mismatch of long-run and short-run marginal costs among cost components is particularly problematic in the NERA method. If system costs are allocated using the total measurement of generation costs based on relatively low shorter-run costs for energy and generation (that do not consider the value of capital substituting for energy over time) and much longer-term costs for the distribution and customer functions, the study will mathematically give too much weight to distribution costs in a marginal cost study, to the detriment of small customers. Analysts have used a number of methods to ameliorate or counteract this mismatch. These methods are briefly identified here but discussed in more detail in the sections noted.

- Developing a longer time horizon for generation costs (see Chapter 19 and Section 25.1). Various methods include:
  - Extending the time horizon for marginal energy costs and including carbon dioxide reductions and renewable costs as adders to short-run marginal energy costs.
  - Using long-run incremental costs, including full costs of new construction of generation.
  - Applying the new paradigm of long-run incremental cost analysis, at least for generation, explicitly to include the energy transition to renewables for generation and storage and demand response for capacity.
- Using short-run customer costs based on the direct costs of hooking up new customers as a better match with short-run energy costs (see Chapter 21).
- Ignoring joint and common costs, reducing long-run A&G costs that are assigned to functions other than energy (see Chapter 22).
- Reconciling on a functionalized basis (generation, transmission and distribution by the marginal costs of those functions) instead of on a total cost basis (see Chapter 24).

Another important issue NERA addressed was the method used to reconcile marginal costs to the system revenue requirement. The calculated marginal costs may be greater or less than the allowed revenue requirement, which is normally computed on an accounting or embedded cost basis. Thus, methods such as the equal percent of marginal cost approach are sometimes used for reconciliation, but some analysts prefer to use the **inverse elasticity rule**, where elastic components of usage are priced at the measured marginal cost, while inelastic components of usage are priced higher or lower than marginal cost to absorb the difference between embedded and marginal costs. This issue is discussed further in Chapter 24.

In the NERA method, the functionalization and then classification of system costs as energy-related, demand-related and customer-related is performed, just as in a traditional embedded cost of service study. The marginal cost of each of these elements is then estimated using a wide variety of techniques. These marginal costs are then multiplied by the billing determinants for each class to obtain the marginal cost by class, commonly referred to as the marginal cost revenue requirement. The MCRR is then reconciled to embedded costs and allocated across the classes. Each set of billing determinants used in the calculation is developed on a class

Table 41. Illustrative example of allocating marginal distribution demand costs by two methods

	Residential	Small commercial	Medium commercial	Large commercial and industrial
Class coincident peak-based allocation				
Marginal cost per kW	$100	$100	$100	$98*
Probability of circuit peak (MWs)	5,900	1,000	3,800	1,500
Marginal cost revenue requirement for distribution demand	$590,000,000	$100,000,000	$380,000,000	$147,000,000
Share of costs	48%	8%	31%	12%
Customer noncoincident peak demand allocation with diversity				
Marginal cost per kW	$100	$100	$100	$98*
Noncoincident peak demand (MWs)	23,878	3,131	7,482	3,561
Effective demand factor	36%	37%	65%	76%
Noncoincident peak demand multiplied by effective demand (MWs, rounded)	8,600	1,150	4,850	2,700
Marginal cost revenue requirement for distribution demand	$860,000,000	$115,000,000	$485,000,000	$264,600,000
Share of costs	50%	7%	28%	16%

*Lower marginal cost of large commercial/industrial reflects lower line losses on primary distribution loads.
Note: Percentages may not add up to 100 because of rounding.

Sources: Southern California Edison. (2017). *Errata to Phase 2 of 2018 General Rate Case: Marginal Cost and Sales Forecast Proposals; 2018 General Rate Case Phase 2 Workpapers*; additional calculations by the authors

basis and, except for the customer-related costs, is divided into time periods and provided for the year as a whole.

For the energy-related costs, the allocation is relatively straightforward, multiplying energy use in each time period by the energy cost in each time period. For the generation capacity costs related to reliability at peak, the allocation typically has not been done using the coincident peak methods most commonly used in embedded cost analysis (and discussed in Section 9.3). Instead, marginal costs are typically allocated over a larger number of hours. This allocation has been done using (1) loss-of-energy expectation, (2) an allocation factor spread equally over the top few hours (100 to 300)[209] or (3) peak capacity allocation factors, effectively a hybrid between the two other methods.[210]

For transmission and distribution costs, the methodology is not as settled, even among marginal cost jurisdictions. Allocation has been either coincident peak-based (related to the probability of peaks on distribution elements) or noncoincident demand-based, with adjustments for diversity between the load at the customer and load at the circuit or substation transformer (which can be developed through statistical analysis). Table 41 illustrates how the two methods can produce

209 This method was developed in California after restructuring in the late 1990s for use in allocating certain transition costs, because generation was expected to be competitive and loss-of-load probability was expected not to exist in a competitive market. San Diego Gas & Electric used the top 100 hours method for allocation of generation costs until 2012 (Saxe, 2012, Chapter 3, pp. 4-5). The company ultimately switched to loss-of-load expectation in 2014 (Barker, 2014). The top 100 hours are still used for allocation of the remaining transition costs of all the major California utilities.

210 Pacific Gas & Electric uses these. Every hour in excess of 80% of the peak is assigned a contribution to peak based on the load minus 80% of the peak. The mathematics mean that the peak hour has an allocation that is 20 times the allocation of an hour that is 81% of the peak and twice the allocation of an hour that is 90% of the peak. In past cases, the company used the gross load curve for both generation and distribution; in 2016, it switched for generation to the load curve net of wind and solar generation while using gross load for distribution. See Pacific Gas & Electric (2016), chapters 9 and 10.

substantially different outcomes (Southern California Edison, 2017a, 2017b, pp. 59-61 and Appendix B, with additional calculations by the authors).[211] Data from Southern California Edison were used because the company currently employs a hybrid of both methods.

Similar to its use of PCAF for generation allocation, Pacific Gas & Electric (PG&E) uses a PCAF method at the local level (each of its 17 divisions) for distribution costs (Pacific Gas & Electric, 2016, Chapter 10). Nevada uses an hourly allocation method based on probability of peak using the system peak demand from which its costs were calculated (Bohrman, 2013, pp. 3-8).

Analysts must be extremely careful when calculating the MCRR, particularly associated with T&D demand. The reason is that not all kWs are the same. Many utilities use one type of kW when developing a marginal cost per kW of demand or capacity (e.g., a kW of substation capacity, where there are 25,000 MWs of such capacity on a utility system) and then multiply the marginal costs by a kW that measures a different type of demand (for example, system peak demand where there are only 15,000 kWs of demand). In particular, when the marginal cost is measured based on a larger number of kWs than the kWs on which the cost is allocated, the result is to assign too few costs as demand-related; this overweights the customer costs in a distribution cost calculation. Additionally, controversy can arrive in measuring the kWs of demand for cost allocation. Although there is no hard and fast rule, two examples in Appendix C illustrate the concerns.

18.2 Marginal Costs in an Oversized System

T&D systems have tended to be oversized because equipment (transformers, wires, etc.) comes in fixed sizes. Moreover, oversizing could theoretically be cheaper in the long run than having to return to the same site to change out equipment, particularly when underground lines have been installed. Although it may be economically preferable in some circumstances, this oversizing tends to reduce intermediate-term marginal T&D costs below full long-run marginal costs or embedded costs.

Increased marginal costs for T&D do not necessarily result from high utility rates of return and strong financial incentives for rate base growth, as noted in almost every utility presentation and analyst report, because intermediate-term marginal cost methods usually have not included system replacements, as discussed in Chapter 20 and Appendix D. System replacements and incremental investments to improve safety and reliability (but not to serve new demand) are a large component of new T&D construction by utilities.

Generation is even more complex. Not only was it uneconomic in the past to build generation in small increments, but there were significant benefits of capital substitution (spending money on capital to reduce the use of expensive fuel) that created excess expensive capacity. In the past, when vertically integrated utilities built coal and nuclear plants, they would conduct planning exercises that provided a justification for those projects based on extremely long-term estimates of future fuel costs and future dispatch. As a result, large portions of the investment-related costs of these plants were justified based on savings of costly fuel and purchased power relative to building peaking generation. The forecast relatively high loads and high fuel prices did not always materialize, and long lead times of large projects meant they could not be economically changed or canceled in cases where the forecasts turned out to be wrong. The disconnect between generation construction and short-run marginal costs also resulted in stranded costs when restructuring took place.

A similar phenomenon occurred more recently as investments were made in expensive environmental retrofits of coal plants instead of retiring the units. Some of these investments ended up being uneconomic given lower than expected prices for natural gas and renewables, not to mention the prospect of greenhouse gas regulation.

For a number of utilities, a short-run marginal cost — assuming the existence of these future plants with high capital cost and low-cost fuel — was used to evaluate energy efficiency, renewables and CHP and to design rates. This methodology effectively gives preference to utility resources while depressing the avoided cost paid to independent power producers, finding less energy efficiency to be cost-effective,

211 Loads are rounded off to the nearest 50 MWs in the table, leaving out small classes and granular detail for ease of exposition.

and lowering incentives for customer-side response through rate design. Examples include Duke Power and Carolina Power and Light Co. from 1982 to 1985, which assumed that future coal and nuclear plants would be built when evaluating PURPA projects (Marcus, 1984, pp. 10-23). Another example is the calculations by Ontario Hydro for evaluation of energy efficiency and private power prior to and during the 1990-1993 demand/supply plan hearings at the Environmental Assessment Board (Marcus, 1988, pp. 14-16). A third, from 1990-1991 hearings, is Manitoba Hydro's analysis of energy efficiency using differential revenue requirement analyses assuming that the Conawapa hydro project would be constructed (Goodman and Marcus, 1990, pp. 132-133, F34-F45). Appendix E provides a mathematical discussion of this issue.[212]

Then, when excess capacity appeared, short-run marginal energy costs declined. The need for generation capacity also declined, although the extent to which that decline was recognized in short-run marginal cost methods varied across jurisdictions (see Section 19.3).

18.3 Impact of New Technology on Marginal Cost Analysis

Excess capacity can be the result of other cost transitions made for a combination of economic and environmental reasons — in particular, the transition to renewables and other related technologies (storage) that are not fuel-intensive.

18.3.1 Renewable Energy

Low-cost wind and solar resources are being installed to provide economic and environmental benefits and reduce fuel use even where capacity is not needed and in some cases are causing the retirements of older plants.[213] In some instances, the total cost of new renewable generation can be less than the fuel and O&M costs of generation that it displaces.

These resources have already been reducing short-term market prices in virtually all ISOs/RTOs. Short-run energy market prices are even sometimes negative in off-peak hours, due to generation that cannot shut down and restart for the next peak period and the renewable energy tax credits that make operating some resources profitable even if they need to pay for the market to absorb their energy output.

The renewable transition makes the traditional marginal cost methodology less relevant. Capacity costs and short-run marginal energy costs are low, while embedded costs remain high. Essentially a short-run marginal cost method sends price signals that energy is cheap because the fossil-fueled component of energy is being used less frequently and is becoming less costly when it is used, while generation capacity costs are also low unless artificially increased.

However, while short-run marginal costs are decreasing, embedded system generation costs are remaining at current levels or increasing because additional capacity is being brought on in advance of need. Other effects on utility generation revenue requirements arise because: (1) some renewables acquired relatively early may be relatively expensive compared with newer renewables in the face of declining cost curves; (2) the growth of renewables may be dampening growth in natural gas prices, which makes renewable energy look less cost-effective than it really is; and (3) in some cases, accelerated recovery of costs reflecting the early retirement of fossil-fueled and nuclear generation may raise embedded costs.

18.3.2 Other New Technologies

Smart grid resources can also reduce the marginal cost of distribution capacity by extending the ability to optimize the use of existing capacity. This may increase excess capacity in the short term while reducing long-run costs by substituting controls for wires and fuel. Sections 7.1 and 11.5 discuss in detail the technological characteristics of smart grid functions — including integrated volt/VAR (**volt-ampere reactive**) controls, automated switching and balancing of loads across circuits and enablement of demand response programs — and of storage and demand response resources.

In the near term, large-scale battery storage on the utility grid can be an economic substitute for peaking and relatively

212 Although not strictly a marginal cost issue, divergence between short-run and long-run marginal cost can be one reason for stranded costs (which tend to have been measured against an estimate of short-run cost over time).

213 An explicit example is Xcel Energy's program of substituting "steel for fuel" by replacing coal and gas with wind and solar generation (Xcel Energy, 2018).

inefficient intermediate gas-fired generation — including generation now receiving reliability-must-run (RMR) contracts in transmission rates — while reducing the cost of ramping to meet daily peak loads (Maloney, 2018; see also California Public Utilities Commission, 2018). This could reduce both marginal energy costs and marginal capacity costs if it proves ultimately to be cheaper than a combustion turbine. In the longer term of a decarbonized system with large amounts of intermittent resources, batteries are likely to need to operate for more hours.

The technology-based economic transition to a smarter grid and a greater role for intermittent and storage resources will change the marginal cost paradigm.

If installed elsewhere on the system, particularly on the distribution system, storage batteries can not only provide support for generation and transmission but remedy distribution overloads or mitigate outages on less reliable radial distribution lines, especially where other smart grid functions are not feasible. The effect would be to reduce marginal capacity costs — although some portion of the cost of the storage should be included as a distribution capacity resource. Behind the meter, storage can provide demand response for the utility as well as significant benefits to customers.

Demand response (e.g., air conditioner cycling, interruptible customers) typically has been used as an emergency capacity resource to avoid bulk generation outages. But it could also be used (when coupled with smart appliances) to mitigate transmission and distribution overloads when the customer is at an appropriate voltage level, reducing future marginal costs.

18.4 Summary

The key issues associated with marginal cost analysis on a generic basis are:

- Mixed time horizons. Marginal cost methods often mix short-run, intermediate-term and long-run marginal costs in an inconsistent manner that has tended to have inequitable results over the last 30 years.
- Obsolete technique given changing resource options. Whether short-run or long-run, marginal energy and generation capacity cost allocation methods essentially have been designed for fossil-fueled systems, using economic dispatch. Renewable resources, storage and other resources tend to depress the short-run prices of fossil-fueled energy and existing fossil-fueled capacity.
- Treatment of renewables. With the substitution of renewables (relatively high capital costs but almost zero variable costs) for fossil fuel, short-run marginal energy costs are significantly below the cost of new generation, with significant implications for cost allocation. As an example, a wind plant that runs at 40% to 50% capacity factor (in the Southern Plains) depresses short-run marginal energy cost and may have no impact on capacity costs.
- Availability of storage. Storage is likely to have a lower cost of capacity than fossil-fueled capacity for at least some applications. It also provides more services than conventional peaking capacity depending on where it is sited — for example, it can provide some ancillary services (e.g., fast ramping service) and help with variable renewable energy integration. However, it may have the counterintuitive impact of depressing short-run marginal costs.

In essence, the technology-based economic transition to a smarter grid and a greater role for intermittent and storage resources will ultimately change the marginal cost paradigm from that used for the last four decades while blurring the traditional distinctions among generation, transmission and distribution costs. The short-run marginal cost paradigm based primarily on variable costs of fossil-fueled generation is becoming less central to the fundamental economics of electricity service for which regulation must account. That change has not been fully analyzed within the structure of marginal cost rate-making, but a pathway for such analysis will be discussed in Chapter 25.

19. Generation in Marginal Cost of Service Studies

The theory of marginal generation costs starts from the position that electric generation is a joint product, producing energy as well as capacity or reliability. When marginal cost methods were introduced in the 1970s, they constituted a significant advance over the previously used embedded cost theory that assumed that generation capital investment and nondispatch O&M costs are all demand-related and only short-term variable costs are energy-related. The marginal cost paradigm recognizes in some way, albeit imperfectly, that with a variety of generating plant technologies, capital can be substituted for energy and that all capital is not related to the need to serve peak demand.

19.1 Long-Run Marginal Cost of Generation

The first key question regarding marginal generation costs is the balance between short-run and long-run marginal costs. There are two options for explicitly calculating long-run marginal costs. Both are based on the cost of building and operating new resources.

The first option is the use of long-run marginal costs (referred to as long-run incremental costs by the entities that developed these methods) to allocate generation costs based on plant types. This method was developed in the Pacific Northwest, where large portions of the systems were energy-constrained. Hydro systems have very flexible capacity but depend on water for energy generation, and the supply of water is both limited under adverse conditions and not controllable. Under this method, the cost of new baseload generation in a resource plan was calculated as the total marginal generation cost. The cost of peaking generation (usually a combustion turbine) was determined to be the peak cost, and the remaining costs were energy-related.[214] In the past, the baseload generation cost was often a coal plant. This method has recently been modified in Oregon to use a combustion turbine for peak generation and a mix of combined cycle gas generation and wind generation for the nonpeak alternative (Paice, 2013, pp. 7-8).

The second long-run marginal cost option has been used by the California Public Utilities Commission for purposes other than cost allocation and rate design. Energy and Environmental Economics Inc. (E3) developed a relatively sophisticated hourly long-run incremental cost model.[215] The California commission has used the E3 model to evaluate energy efficiency, demand response and distributed generation for a number of years, although it has not yet used it for rate design. The generation components of this method have an evaluation period of up to 30 years. The model is designed to assume the short-run avoided cost until the year when capacity is projected to be needed and the full cost of a combined cycle generator if the long-run base total fossil-fueled generation cost is in equilibrium. The effect of this, in the past three decades, would have been to understate generation marginal costs compared with those that would exist under an equilibrium market. However, if the year of capacity need is set to the current year, which has been done in some recent analyses, the model becomes a full long-run marginal cost model, alleviating this problem.

E3 divides the costs into energy and capacity, with the costs of a simple-cycle combustion turbine (net of profits received for energy and ancillary services) treated as capacity-related and all remaining combined cycle costs as energy-related. The E3 model then shapes the energy costs into an

214 This method is similar to the equivalent peaker method (discussed in Section 9.1), except that it includes both capacity and energy.

215 The description of this method is taken from Horii, Price, Cutter, Ming and Chawla, 2016.

hourly load shape using information on load shapes over time (including changes resulting from renewable resource additions) and adds a projection of line losses, carbon dioxide costs and ancillary services to obtain a market price. To obtain the full marginal or avoided energy cost — to the extent that renewable resources (net of their resource-specific capacity credits) cost more than the energy-related cost of a combined cycle unit — the resulting extra costs of meeting the renewable portfolio standard over the 20-year period are added to the market-based costs.

19.2 Short-Run Marginal Energy Costs

Short-run marginal energy costs normally are calculated from a production cost or similar model on a time-differentiated (or even hourly) basis. These calculations are made over a relatively short period (typically one to six years out, depending on the utility). Marginal energy costs in the West — whether simulated directly or simulated through a market pricing version of a production cost model — typically have been dependent on the cost of gas and the overall efficiency of the system (i.e., the percentage of time gas was the incremental fuel, the type of gas plants used and the amount of baseload or intermittent generation available). This changes in very wet months, when hydro may be the marginal resource, or increasingly at midday on light-load days, when solar becomes a market driver. In Texas and the Plains states, wind is increasingly a market-driving resource. For utilities in the Midwest, South and East, the incremental fuel is typically a mix of gas-fired generation during peak and midpeak periods with coal-fired generation off-peak in some locations. Some utilities face much higher marginal costs or market prices in extreme winter weather because of gas price spikes, limits on gas availability, high peak loads and unreliability of service due to freezing of coal piles and some mechanical parts of power plants and gas wells.

In California and Nevada, utilities typically have modeled and averaged marginal energy costs over one or three years, corresponding to the length of time between rate cases, but PG&E uses six years. These very short-run energy analyses, particularly when coupled with long-run generation capacity cost analyses, tend to overstate the balance of costs for customer classes with lower load factors and understate them for customer classes with higher load factors. The cost of a combustion turbine, which is allocated heavily based on peak conditions, becomes a larger portion of marginal generation costs if short-run energy costs are lower than if higher longer-run costs are used.

It is of key importance that reasonable natural gas price forecasts are used, particularly if looking out beyond a very short time horizon. In much of the country, the modeling outputs are very sensitive to this input factor, and key results can vary greatly depending on the natural gas forecast. The E3 long-run incremental cost forecast uses short-term forecasts from futures and a longer-term mix of forecasts from the U.S. Energy Information Administration and the California Energy Commission's *Integrated Electric Policy Report* (Horii et al., 2016, pp. 5-8). Utilities tend to use their own forecasts, but in California those forecasts are updated after intervenor testimony is filed.

Greenhouse gas emissions are an important marginal cost, but there is not a consensus method to address it. Carbon cost is, in theory, internalized by California's cap-and-trade system, although it becomes difficult to properly model the dispatch in the Western United States when only California resources and California imports carry carbon values. The **Regional Greenhouse Gas Initiative** market performs a similar function in the Northeastern United States. In all jurisdictions where carbon prices are included, carbon prices must be forecast if longer-term marginal cost methods are used. Prices need to be forecast over the full study duration where markets do not exist for these products. Even in California and the Regional Greenhouse Gas Initiative states, market-determined allowance prices extend out for only a three-year period. However, in places where carbon is not explicitly valued, a marginal cost method should include current or future carbon values associated with fossil-fueled generation to provide forward-looking price signals. In jurisdictions covered by electric sector cap-and-trade programs, there are still questions about whether the marginal cost from the program is sufficient or whether another measure, such as the social cost of carbon or marginal cost of long-term greenhouse gas reductions, is more accurate.

The addition of renewable resources to utility portfolios, especially if added in advance of the need for capacity, depresses marginal energy costs by adding energy with zero fuel costs (or even negative costs in the case of wind energy with the production tax credit). The result is to reduce marginal costs in two ways. It reduces the heat rates of gas-fired generators on the margin. It also decreases the number of hours when a gas-fired resource is on the margin in some places where cheaper coal or surplus hydro (the Pacific Northwest or Canada) can be a marginal source of energy or when renewables are curtailed. In other words, the short-run model reduces energy costs relative to capacity costs when new renewable resources are constructed.

It can be argued that costs of compliance with an RPS are short-run marginal costs, in the sense that if load changes on a permanent basis, a portion of that load must be met with renewable resources. The capital and operating costs of those resources (possibly net of the fixed costs of an equivalent amount of peaking capacity) would replace the market prices and fuel costs from existing generation used to calculate marginal costs.[216] The Nevada utilities first developed calculations using the RPS as an adder to conventional resources in Sierra Pacific Power Co.'s 2010 rate case (Pollard, 2010).[217] The RPS adder was then adopted by California consumer groups (Marcus, 2010b, p. 45) and by Southern California Edison (2014, pp. 31-32). It is also included in the E3 long-run marginal cost model (Horii et al., pp. 36-38). Note that, mathematically, in the Western states that use marginal cost analysis, the RPS adder increases if short-run market energy prices decline (e.g., due to an update that reduces gas prices).

Before deregulation, there was a debate over whether short-run marginal energy costs should be the instantaneous cost in the given hour as envisioned in the original NERA method or should reflect other factors such as unit commitment. Often the actual unit that varies with short-term variation in loads is a flexible resource, not necessarily the least-cost resource, and the dispatch of hydro can change with changes in load. In California, the utilities commission adopted a method that computed marginal costs as the change in total costs for a large utility between a symmetrical increment of several hundred MWs above and several hundred MWs below current loads in each hour. This resulted in a more expansive definition of short-run marginal costs that included not just the incremental costs of a plant running in a given hour but the differences in how many power plants were committed if the load were different — thus causing changes in costs of startups and plants running at minimum load to be available the next day. These unit commitment costs generally increase the marginal costs experienced during peak hours above hourly marginal costs. In current wholesale markets, unit commitment costs tend to be reflected in day-ahead prices because bidders who need to commit a resource must include that cost in their bids.

Several ancillary services defined by FERC and ISOs/RTOs are purchased on an hourly basis. These include spinning reserves, nonspinning reserves available in a time frame of about 10 minutes, in some cases replacement reserves (plants that could fill another reserve type on a contingency basis if that reserve was used in real time) and frequency regulation (both upward and downward) on a minute-to-minute basis. Additionally, there are services that are not officially called ancillary services but that are related. These include the need to assure that enough generation is committed to meet energy requirements (residual unit commitment, acquired daily) and energy that can be dispatched to ramp upward or downward within a bid period to meet changes in demand and changes in variable (typically renewable) resource output that can be forecast hourly or subhourly (e.g., solar). Finally, there are out-of-market real-time costs necessary to maintain system reliability if generation is not available or if transmission contingencies occur. These costs are "uplift" (charged to system loads) by ISOs/RTOs. That said, uplift costs can be

216 As an analogy, in most jurisdictions with retail choice, RPS requirements typically are implemented in a way that is a short-run cost. As a percentage requirement based on load served or retail kWh sales, it automatically varies based on kWhs in a predictable way. Therefore, treating RPS requirements similarly in jurisdictions where generation is regulated is appropriate.

217 Those calculations established the principle, even though they were flawed because they included energy efficiency resources that were cheaper than market prices that could meet Nevada RPS requirements and because the energy efficiency costs did not consider a time value of money (Marcus, 2010c, pp. 7-8).

incurred unnecessarily if ISOs/RTOs fail to optimize existing markets to provide necessary reserves and other ancillary services to provide necessary grid support.

Although some utilities and industrial customers suggest these costs are really capacity costs and thus should be subsumed in the marginal cost of capacity, they are paid for in each hour along with market energy costs, so that, regardless of the semantics, they should be allocated on an hourly basis. The costs are not large in normally functioning markets. For purposes of evaluation of energy efficiency in California, E3 uses a figure of 0.7% of marginal energy costs for ancillary services (Horii et al., pp. 25-26),[218] a decrease from 1% several years ago. A more detailed study of California ISO ancillary services costs for the 12 months ending April 2010 ended up with 0.8% of marginal energy cost, with amounts ranging from 1.17% summer on-peak to 0.61% winter midpeak (Marcus, 2010b, p. 45). Although not large, the costs are real and should be included in a short-run energy costing methodology.

Costs paid on an hourly basis for intrahour ramping may also be incurred. This is particularly an issue in the Western U.S. The drop-off of solar energy as the sun sets plus increasing of loads toward an evening peak can cause a doubling of loads served by other resources (i.e., net loads, excluding wind and solar generation) on some low-load days in the spring and fall. This causes the need to rapidly ramp up conventional generation, such as natural gas and hydro, and opens up an important new role for storage. Any energy costs of ramp should be assigned as a marginal cost to those hours.

19.3 Short-Run Marginal Generation Capacity Costs

Under the short-run marginal cost method, the theory, as originally developed in the late 1970s, is that the value of generation capacity is capped at the least cost of acquiring generation for reliability. If all that was needed was capacity, a cheap resource to provide capacity (such as a peaking plant) could be built. Any more expensive generation would have been built specifically to reduce total system costs (fuel plus capacity). Under this method, the cost of the peaker is multiplied by the real economic carrying charge, and O&M and A&G costs are added to it.

A number of technologies could be the least-cost generating capacity option, including:

- Conventional peaking generation, demand response or economic curtailment.
- Midrange generation net of fuel or market price savings.
- Short-term or intermediate-term power purchases.
- Results of RTO capacity market auctions or market prices for capacity procured for resource adequacy (if applicable).
- Centralized or distributed storage net of fuel or market price savings.

In equilibrium, without cheaper short-term options, the cost of a peaker would theoretically equal the shortage value customers experience from generation outages. That is the reason marginal generation costs have typically used a peaker, because they effectively assume equilibrium exists. The California and Nevada utilities other than PG&E use the full cost of a combustion turbine as the basis for marginal capacity costs. PG&E, the California Public Utilities Commission advocacy staff and other consumer intervenors recognize that the short-run marginal cost can be less than a peaker. Lower costs should occur if capacity is either unneeded or so economic that energy savings from construction of baseload generation exceeds the cost of the plant, or if cheaper options than a combustion turbine peaker are available. Theoretically, the marginal generation capacity cost can also be higher for short periods when there are shortages of capacity within the lead time of building generation, but those conditions have not occurred since the early 1980s (California Public Utilities Commission, 1983, pp. 220-222).

In 2017-2018, Southern California Edison claimed that some of the need for system reliability was not caused by peak loads but instead by the requirement to have adequate capacity available to ramp generation from midafternoon to the evening peak in periods of the year with relatively low loads (and relatively high output from conventional hydro plants that reduced their flexibility for use in peaking). Although many options are available to reduce the size and scope of the ramp, particularly storage and use of flexible

218 These costs do not include ramp, residual unit commitment or out-of-market costs.

loads in areas such as water supply and delivery (see Marcus, 2010b, and Lazar, 2016), one of the options the California ISO identified was gas-fired generation. New storage options may be especially well suited for dealing with problems of ramping because of the timing of both charging and discharging batteries or taking other actions like storing hot or chilled water.

Equating a marginal capacity cost based on a peaker with very short-run energy costs creates a mismatch that is detrimental to customers with peakier load shapes. Several points must be considered here.

1. Costs of peakers vary. Smaller combustion turbines and aero-derivative turbines are more expensive than larger combustion turbines. Some of these smaller turbines have costs that approach or even exceed the cost of a larger combined cycle plant.[219] When conducting marginal cost studies, some utilities and industrial customers have requested approval for expensive peakers as marginal capacity costs.[220] However, that point ignores the key finding of the NERA method: that the marginal cost of capacity is the least costly source of capacity, so that by definition the more expensive peaker installed for other reasons is not the marginal cost of capacity under that framework.
2. Financing costs for peakers vary. In California, a number of parties (including E3) have used merchant plant financing, which is more expensive than utility financing, to develop the marginal cost of capacity. Again, the issue is that a merchant plant is not the least costly source of capacity because merchant plants have higher required returns. Furthermore, merchant plants often have off-take contracts that are shorter than the physical life of the plant. Using the shorter contract life for capital recovery also inappropriately increases the marginal cost of generating capacity.
3. Even a peaking power plant would make money in the market (or save fuel and purchased power costs in a vertically integrated utility that is not closely affiliated with a market). Combustion turbines installed in the 1970s, when the NERA method was developed, had heat rates in the range of 15,000 Btu per kWh and burned expensive diesel oil. They were machines that provided essentially pure capacity — reserves that were turned on to keep the lights from going out. Much of the gas-fired load at that time came from less flexible steam plants with heat rates from 9,000 to 12,000 Btu per kWh. Modern peakers have a heat rate in the range of 10,000 Btu per kWh (or lower) and burn gas. They actually have better heat rates than many of the older intermediate steam plants, as well as greater flexibility. As a result, when modern peakers are used, they generally earn at least some money in the market or save fuel and purchased power costs.[221] They also can earn revenue from selling dispatch rights in the 10-minute (nonspinning) reserve ancillary service market. This revenue should be netted against the cost of the combustion turbine, because it pays a portion of the cost of capacity.
4. Peaking generation may not be the least-cost capacity resource. It is possible for an intermediate resource such as a combined cycle generator to have a lower net cost than a combustion turbine. In particular, the capital and long-term O&M cost of the combined cycle generator minus the revenue that it would earn in the market or the fuel it would save can be less than the cost of a combustion turbine. Even with excess capacity, this outcome can sometimes occur, particularly if a relatively expensive turbine is erroneously considered as the peaking unit (as discussed earlier in this list).
5. Storage costs may be cheaper than combustion turbines. Under current conditions, it is possible that storage costs net of energy savings relative to market prices can be cheaper than conventional peaking generation. In particular, PG&E is installing and contracting for about 550 MWs of batteries with four-hour storage to meet system needs and replace 570 MWs of RMR peaking and

219 A utility might have installed some of these smaller turbines for reasons such as alleviating transmission constraints, meeting time constraints (if the smaller turbines had less stringent siting requirements) or responding to specialized system needs such as black start capability.

220 See, for example, Phillips (2018, pp. 5-11), where the testimony argues for the usage of a 50-MW turbine costing $1,600 per kW instead of a cheaper 100-MW turbine.

221 See Section 1.1 for more discussion and quantitative examples of this phenomenon.

combined cycle generation (Maloney, 2018; California Public Utilities Commission, 2018). RMR generation receives payments on a cost of service basis including capital and operating costs, although the specific plants being replaced are partly depreciated.

6. Additionally, pure capacity can be available at considerably lower costs than a combustion turbine. Systemwide actual and projected prices in the California resource adequacy markets are $30 to $40 per kW-year over the period of 2017-2021 (Chow and Brant, 2018, p. 21) with even the peak monthly prices from July to September rising no higher than $4.50 per kW-month (Chow and Brant, p. 32). Capacity market prices are generally similar in the PJM region, with higher prices in transmission-constrained pockets of New Jersey and occasionally other areas; new demand resources, renewables and gas-fired combined cycle generation have been added at those low prices (PJM, n.d.).[222] Resource adequacy capacity does not come with the physical hedge against high market prices provided by the combustion turbine's known heat rate, but it is much less costly. It is arguably the newest version of "pure capacity" as NERA originally defined it. PG&E estimates the capacity cost during a period of surplus as the long-term O&M cost of a combined cycle generating plant, because a combined cycle plant that could not earn its long-term O&M would go out of service, reducing any available surplus (Pacific Gas & Electric, 2016, Chapter 2).

In sum, the combustion turbine peaker that is the typical choice for marginal capacity costs under the NERA method, as well as under long-run incremental costs, is likely to significantly overstate capacity costs given the economics of new large-scale storage facilities and significant capacity surpluses.

To the extent there is a marginal capacity cost for ramping capability, it can best be understood as an hourly capacity cost that is negative in the hour or two before the ramp begins, a positive hourly cost in the steepest several hours of the ramp and lower but still positive hourly cost as the ramp becomes flatter, continuing through and just beyond the evening peak.

But, for allocation purposes, the cost needs to be first divided between ramp caused by customer loads and ramp caused by generation characteristics, which should be feasible. This is another example of how the emerging wind- and solar-dominated grid challenges traditional methods of cost allocation. To the extent that the need for capacity for ramping, and hence part of its cost, is caused by generation characteristics, it should not be a load-related marginal cost for allocation to the classes that contribute to the ramp.[223] The generation-related ramp effectively becomes part of the cost of the generation resources causing the ramp under a short-run marginal cost theory, such as the one NERA defined. To the extent that generation-related ramping costs are recovered as incurred periodically in energy costs or ancillary service or other charges from the RTO, they should be part of marginal energy costs. Although these concepts are relatively clear, their implementation is not clear at all, with disagreements among parties on both the generation-related portion of ramp costs, the definition of ramp hours (for example, whether more than one large ramp should be counted on a single day) and the method of allocating costs to both hours and classes. Storage units are more effective for ramping than thermal peakers because they can both charge in the preramp hours and discharge to clip the peak, reducing the total amount of ramp more than a thermal plant, whether the storage is installed as a bulk power resource or for other purposes.

222 Similar capacity prices have prevailed in New York, outside the New York City load pocket (New York Independent System Operator, n.d.). Capacity prices in MISO are even lower due to a continuing surplus and renewable additions, while prices in New England were higher for a few years after 2016 and have recently fallen to the California range.

223 Although the generation-related cost should not be part of the class allocation, it may be appropriate to include some of that cost in rate design to provide a greater discouragement to ramping loads.

20. Transmission and Shared Distribution in Marginal Cost of Service Studies

20.1 Marginal Transmission Costs

Marginal transmission costs have not received the attention that marginal generation and distribution costs have received, because in large parts of the country transmission is partly if not wholly under FERC jurisdiction. Thus, California utilities only calculate marginal transmission costs as an input to the process of calculating the contribution to margin of economic development rates, rather than for cost allocation and rate design. Nevada calculates marginal transmission costs using the NERA method. But since there is no joint product (such as generation energy and capacity, or distribution lines and customer connections) and Nevada allocates costs by functions (see Chapter 24), there is little controversy. Southern California Edison breaks its transmission costs into transmission (115 kV and above) and subtransmission (69 kV and below) because specific factors relating to the physical layout of its system left its subtransmission system under Public Utilities Commission regulation, where it is treated as part of the company's distribution marginal costs.[224]

The NERA method for marginal transmission costs involves some analysis of the relationship between transmission system design and peak loads. Although the original method involves regression analysis between cumulative investment in load-related transmission (calculated in real, inflation-adjusted dollars) and cumulative increases to peak load, two other methods have been developed. The first, the total investment method, examines total investment divided by the change in peak load. The second, the discounted total investment method, uses discounted total investment divided by the discounted change in peak load. This assigns lower weights to investments occurring later in a projected analysis period relative to investments occurring earlier. The specific choice among these three methods can create relatively small differences (unless miscalculated). The investment cost is annualized by multiplying by the RECC. Investment costs are defined narrowly. As an example typical of most utilities, Southern California Edison stated in its most recent rate design case:

> Projects discretely identified as load growth are only considered in the analysis. All projects not related to load growth (i.e., grid reliability, infrastructure replacement projects, grid modernization, automation, etc.) are excluded from this analysis (2017b, p. 37).

The NERA method can be applied to the transmission system as a whole or to transmission and subtransmission voltage levels and to lines and substations separately.

O&M costs are added to the annualized capital costs. There are two conceptual methods for doing this. The original NERA method averages O&M costs (in real terms) divided by kWs of load (i.e., calculated in dollars per kW) over a period containing both historical and forecast years. An alternative method used by PG&E calculates O&M costs as a percentage of plant and adds it only to the new plant. Using this method, O&M costs are lower because the assumption is made that O&M is tied to new plant rather than maintaining the system in order to retain all loads.

The NERA method essentially ignores large parts of the transmission system and therefore generally ends up with marginal transmission costs well below embedded costs. It also fails to recognize that peaking resources and storage are

224 California utilities calculate a marginal cost of transmission as an element of cost when determining how much contribution to margin is provided by loads such as economic development rates, but it is not used for allocation of costs to customer classes (which is done by FERC) and is therefore not reviewed carefully in rate cases.

often strategically located near loads where transmission is constrained to reduce the need for transmission. For example, the city of Burbank, California, incurred additional costs to locate the Lake generating unit in the heart of the urban area; an offsetting benefit was avoidance of transmission costs.

First, interties to connect utilities, or to connect remote generation plants for purposes of obtaining cheaper sources of generation and increasing imports of generation capacity, are often simply ignored. They are treated as "inframarginal" sources of generation (built because they were theoretically cost-effective relative to the existing system without those lines). As a result, the cost of interties ends up neither in the marginal generation costs (where the only effect is to depress short-run marginal energy costs) nor in the marginal transmission costs (because the NERA method assumes them to be a source of cheap generation). Nor do the net revenues the utility receives for off-system energy sales (to the extent that the concept still exists in competitive wholesale markets) end up as an offset to transmission costs, even though such sales could be one reason for constructing intertie capacity.

The second set of costs that methods like the NERA method ignore is the cost of system replacement. The argument is that once the utility commits to build one system of transmission, the RECC method has the effect of deferring all replacements. The end result is that, as pieces of the system that were built 30 to 60 years ago are replaced, they are part of the embedded costs but not part of the marginal costs. System replacements can be a significant portion of the cost of new rate base. This issue is discussed further in the next section.

Third, any transmission and distribution costs related to improving reliability on the existing system (instead of specifically adding new capacity) or automating the system (to improve reliability or reduce capacity needs) are excluded under the pure version of this method. This exclusion is at variance to the theory of marginal generation costs, where in equilibrium the value of avoided shortages equals the value of the least-cost resource able to meet the need. Here, avoided shortages are assigned no value.

Fourth, the transmission and subtransmission systems are heavily networked and are built to avoid outages under various load conditions throughout the year with one or two elements of the system out of service. This networking essentially means that even though the NERA method relates investment to peak, the cost causation of that relationship is unclear, and a significant portion of costs may be related to lower-load hours than the peak. The hourly allocation methods discussed in Section 25.2 may provide guidance in treating some transmission costs in marginal cost studies, by assigning these costs to all hours in which the assets are deployed.

20.2 Marginal Shared Distribution Costs

The most controversial issue for the calculation of marginal distribution costs is the same issue raised in the embedded cost section. Is a portion of the shared distribution system, particularly the poles, conductors and transformers in FERC accounts 364 through 368, customer-related? The authors of this manual believe strongly that these costs are not customer-related; Section 11.2 on embedded costs addresses this question in detail. This section will comment only on some specific issues of the customer/demand classification as they apply specifically to marginal costs for the shared elements of the distribution system.

The NERA method for marginal distribution capacity costs unrelated to customer connections is similar to that for marginal transmission costs, involving an analysis of the relationship between distribution system design and peak loads. Again, the three methods used are regression analysis, the total investment method and discounted total investment method, all discussed in Section 20.1. The investment cost is annualized by multiplying by the RECC.

The marginal cost of distribution capacity can be developed for the distribution system as a whole, as well as separately for lines and substations. A number of utilities (including Southern California Edison, San Diego Gas & Electric and the Nevada utilities) have separate calculations for distribution substations and lines. PG&E uses regional costs. It calculates costs individually for more than 200 distribution planning areas for purposes of economic development rates and aggregates them up to 17 utility divisions for purposes of marginal cost calculation for cost allocation and rate design (Pacific Gas & Electric, 2016, chapters 5 and 6). Using all of the distribution planning areas (as was proposed in the 1990s) is so granular that it would be difficult to examine and audit the relationship of costs to cost drivers. This is true in part because costs are dependent on the amount of excess capacity in local areas. In addition, customers who are large relative to the distribution system may never pay for capacity needed to serve them in some cases. And customers in slow-growing areas are charged less than those where load is growing faster, even if those customers are using a significant portion of the distribution system.

O&M costs are added to the annualized capital costs. As with transmission, there are two conceptual methods for doing this. The original NERA method averages O&M costs (in real terms) divided by kWs of load over a period containing both historical and forecast years. The alternative would calculate O&M costs as a percentage of plant and include it as an adder only to new plant.[225]

Southern California Edison and San Diego Gas & Electric aggregate all primary distribution circuit costs, including those that are part of line extensions, and treat them as demand costs. PG&E treats all primary distribution costs associated with line extensions as demand costs, again calculated regionally, but uses a different, less diverse measure of demand — demand at the final line transformer, rather than demand at the substation, to allocate these costs (Pacific Gas & Electric, 2016, Chapter 6).

The Nevada utilities make a distinction between costs covered by the line extension allowance (which they call facilities costs) and other distribution substation and circuit costs. Facilities costs are allocated to customer classes based on the cost of facilities built for each class that are recovered from customers because they are less than the line extension allowance. Costs are higher in dollars per customer in nonresidential classes than in the residential class. These costs are annualized by the RECC and have O&M added to them (Walsh, 2013, p. 9). This treatment is identical to the **rental method** for customer connection costs discussed in Section 21.1. Thus, as the line extension allowance is increased, more costs are allocated to residential customers because land developers pay fewer of them. Unlike most utilities, the Nevada utilities have separate rates for single-family and multifamily customers. The result of this split of the residential class is that multifamily customers, with less expensive hookups on a dollars-per-customer basis, do not subsidize single-family customers, in contrast to the case across most of North America when distribution circuit costs are partly assigned on a per-customer basis. We discuss the class definition issue in Section 5.2.

Central Maine Power, which uses marginal costs to allocate distribution costs, also divides the distribution system between line extension and other distribution facilities and uses a different allocation among classes for line extension costs that allocates the costs more heavily to residential customers (Strunk, 2018, pp. 14-18).

Pacific Power's Oregon rate cases have a "commitment-related" component to primary distribution costs that is similar to the minimum system methods used by utilities conducting embedded cost studies and has similar issues (Paice, 2013, pp. 6, 9-11). Although the Oregon utility commission has accepted this for interclass cost allocation purposes, it does not include these as customer-related in the rate design phase of rate-making (B. Jenks, Oregon Citizens' Utility Board, personal communication, June 4, 2019).

The NERA method again ignores replacement costs, which constitute the majority of new distribution plant for many utilities' systems, in addition to ignoring costs of improving reliability. A good argument can be made that replacement costs are truly marginal costs and that the utility needs to make replacements to serve its existing load safely and reliably. First, regardless of the workings of the RECC method, assuming that replacement costs are automatically committed when a new piece of distribution equipment is built is a monopoly-based argument and does not work in a truly competitive market. The marginal cost relates to both incremental and decremental demand. A replacement is needed to assure that demand does not decline but is instead

225 This is PG&E's method because the company claims that O&M costs are not marginal once the plant is installed (Pacific Gas & Electric, 2016, Chapter 5, p. 11).

served reliably. The fact that replacements are a marginal cost can be analogized to other industries, such as trucking. A more detailed theoretical exposition is given in Appendix D.

Adding in replacement costs (calculated in dollars per kW like O&M costs, but with an adder for the present value of revenue requirements) has been estimated in the past to increase marginal costs for Southern California Edison by 40% for distribution and 31% for subtransmission (Jones and Marcus, 2015, p. 30) and for PG&E by 46% for primary distribution and 27% for new business (Marcus, 2010b, pp. 36-37). Replacement costs were included as marginal costs in the 1996 PG&E gas cost adjustment proceeding (California Public Utilities Commission, 1995) but have not been included in any electric marginal costs because all California cases have been settled for almost 25 years.

Some distribution costs that are similar to replacement costs are actually policy-related and may not be marginal costs as a result (e.g., urban undergrounding of overhead lines; other changes related to safety and environmental protection). As with embedded costs and for the same reasons, costs in FERC accounts 364 through 367 should be considered as common system costs rather than as costs assigned to individual customers. Even though they are included in Account 368, as with embedded costs, capacitors and regulators need to at least be functionalized as primary distribution costs when calculating marginal costs, unless the dual function of the capacitor as a generation resource is recognized,[226] just as with embedded costs. They reduce losses and increase distribution capacity by supporting voltage and reducing amounts of reactive power.

Many smart grid investments such as automated switching and integrated volt/VAR controls (as well as potential investments in storage and targeted demand response programs) increase overcapacity and reduce distribution marginal costs calculated using the NERA method by reducing the need to build new lines. Under this method, this overcapacity will cause customer costs to be emphasized relative to other distribution costs.

Distribution marginal costs end up with tricky calculation issues because of differences in the determinants on which marginal cost calculations are made and the costing determinants on which revenue allocation is conducted. Not all kWs are equal. This issue is referenced here as a concern regarding marginal distribution costs but is addressed in more detail in Chapter 24 on reconciling marginal costs to embedded costs.

The transformer is an intermediate piece of equipment. In the larger C&I classes, a transformer will often serve a single secondary voltage customer, while for residential customers it may serve a single rural customer, a group of six to 10 suburban customers or 50 apartments or more. In the small and medium commercial classes, several customers are served by a single transformer in some cases, while some customers (particularly larger or three-phase customers) are served with single transformers. There are also differences in cost between single-phase and three-phase transformers. Single-phase equipment is adequate for serving nearly all residential customers and many small commercial customers.

Some utilities have allocated these costs to classes as marginal costs based on the average cost of a transformer serving the class. If this treatment is used for class allocation, transformer costs should not be fixed customer costs for purposes of rate design because of the wide variety of customer sizes and transformer configurations. In older urban areas, secondary line is often networked across several transformers, with some service drops connected directly to the transformer and some connected to the networked secondary line. In these cases, the use of secondary lines to connect the transformer to the customer is more of a common cost than a connection cost, unlike in more modern design configurations, where secondary distribution might be an economic alternative for customer connection.

If a transformer cost is considered part of the customer connection function, a portion of transformer costs is likely not marginal costs, and only the cost of the smallest transformer should be included. Transformers typically are purchased using an algorithm to minimize the present value of capital costs and load-related and nonload-related (core) losses. The extra costs of the transformers above the

226 If a capacitor is deemed to have a generation function, it is not a marginal cost at all under the NERA method.

minimum costs would be inframarginal costs of providing energy and capacity rather than customer connection costs. However, these extra costs have been difficult to measure in past cases. Also, many utilities claim that the new energy standards for line transformers mean they no longer need to optimize transformer costs against losses and they only need to meet but not exceed the federal standard. Capacitors and voltage regulators are also not part of transformer costs for either customer connection or secondary distribution demand but instead should be quantified together with other primary distribution costs.

21. Customer Connection and Service in Marginal Cost of Service Studies

The customer connection costs, also known as point of delivery costs, include the service drop and meter and may include the final line transformer and any secondary distribution lines that are not networked with other transformers.[227] Primary lines are typically not point of delivery costs, although several utilities include either line extension costs or some type of minimum system as customer costs. The basic customer method primarily includes the service and meter, although some states include a transformer. As a matter of calculation, it is necessary to determine a meter cost for each customer class. Additionally, customers cause the utility to incur costs of billing, collections and similar items.

21.1 Traditional Computation Methods

There are two longstanding methods for computing marginal customer connection costs. The first is the rental method, where the cost of new customer connection equipment is multiplied by the RECC to obtain a value at which a customer could be presumed to rent the equipment from the utility. O&M costs are added to these annualized capital costs. This method is a direct continuation of the NERA method.

The second method is the new-customer-only (NCO) method. It calculates a marginal cost based on the number of new hookups (and possibly replacements) of customer connection equipment in the same time frame as used to measure other marginal costs for generation and transmission. This cost is adjusted by a present value of revenue requirements multiplier to reflect the costs of income taxes and property taxes under utility ownership. Elements of the method were introduced by consumer advocates who recognized that the incremental and decremental costs of hooking up new customers were different (unlike most marginal cost elements) in the mid- to late 1980s. The specific NCO method was first presented by PG&E (in 1993; it has since disavowed the NCO method) and was adopted by consumer advocates with modifications after that time. Again, O&M costs are added.

The rental method has the longest time horizon of all the marginal cost methods in the entire panoply of marginal costs developed by NERA and used by regulators. All customers are assumed to rent equipment based on today's costs and configurations of customer connection equipment, which is largely underground in most newly constructed urban and suburban distribution systems. The method as utilities now implement it generally does not consider the standing stock of equipment. As a result, the rental method assumes that customers with overhead service in urban areas are charged in marginal costs as if they had underground service. So these customers not only have to look at wires and poles, but they face a revenue allocation that assumes they have the amenities of modern suburbs. By failing to use the standing stock, the rental method also assumes that the percentage of new housing stock built as apartments is the same as the percentage of existing housing units that are apartments.[228]

Besides these computational issues, there are significant theoretical issues that caused the development of the NCO

227 A secondary distribution line that is not networked is installed to reduce costs (including line losses) relative to running all services directly off a single transformer. It is thus an economic substitute for longer service lines.

228 The exception to this concern is Nevada, where separate marginal customer costs are calculated for single-family and multifamily homes based on new costs but are applied to the existing stock of each type of housing. This practice has been in place since at least 1999 when the utilities presented the division of the residential class in Public Utilities Commission of Nevada dockets 99-04001 and 99-04005. San Diego Gas & Electric calculates customer connection costs based on the noncoincident demand of the customers and uses demand estimates of existing customers, which also ameliorates this problem to some degree (Saxe, 2016, pp. 6-10).

method. Aside from computational inaccuracies from not using the standing stock, the rental method is not the outcome of a true competitive market. The NCO method reflects as marginal only those costs that are avoidable — incurred at the time when the choice to spend or not spend money on new hookups is made — when the customer chooses to connect to the utility system or when a hookup is replaced. It is thus a shorter-run marginal cost method than the rental method, making the NCO method more consistent with the other short- and intermediate-term means of calculating costs included in the rest of the NERA method. The cost analyst must carefully examine the consistency between the NCO method, which considers the full costs of system replacement, and the methods used for G&T. If replacement costs are used for one category, they should be used for all categories, moving the study toward a total service long-run incremental cost study (see Section 25.1).

The NCO method also comports better with competitive markets and consumer behavior. Consumers typically have the choice to either own or rent any equipment affixed to their homes that costs several hundred to a few thousand dollars. In many cases, consumers nearly always own the equipment, as in the case of curtains or chandeliers. In other cases, there is consumer choice as to ownership or rental, as with propane tanks, solar energy systems,[229] internet routers and (in some parts of North America) water heaters. Even where the rental option is present, the consumer can choose to purchase the equipment. In contrast, the rental method does not simulate the outcome of a competitive market. It is equivalent to assuming there are enough landlords that there is a competitive rental market, who own all the property in a given community. Anyone who wants to live in that community has to rent from one of these owners; no one is allowed to buy property. Rather, this is a market with barriers to entry that prevent true competition. Thus, the analogy of the current rental method to the housing market places an anti-competitive constraint on consumers that would limit their economic choices while protecting the profits of the landlord — or the utility, in this case — from the vagaries of competition.

There is one additional computational issue in the NCO method, where the replacement rate may or may not be considered. In California, the utility commission advocacy office has omitted replacements from the NCO method as well as from calculations of marginal distribution costs. The Utility Reform Network tends to include them for both, yielding higher costs for both demand distribution and customer-related costs. If a replacement cost is needed for the NCO method, utilities often use the highest possible number — the inverse of the depreciable life of the equipment. Although data for service drops may be limited, utilities often have actual rates of replacement of meters and transformers, as well as information that could allow the replacement rates for service drops to be inferred from capital budgeting documents.[230]

21.2 Smart Meter Issues

For utilities installing smart meters, a joint product issue arises. A smart meter with the associated data collection network hardware and software serves multiple functions. It provides customer connection and billing while reducing the labor costs of meter reading and other functions. It can also provide a number of other peak load, energy and reliability functions, including enabling TOU pricing and measuring demand response; load research; distribution smart grid functions such as outage detection and (if tied to utility GPS and mapping functions) identification of potential transformer overloads; and even, in some cases, internet access for utility customers.

The NERA method provides a theoretical underpinning that customer connections (analogous to generation capacity) should be provided by the least-cost method. In evaluating past smart meter cases, about 70% of the cost of the AMI system was covered by meter reading benefits; the remainder of the cost was justified by other benefits. Therefore, California

229 Solar systems may be a special case. Renting the equipment generates some tax benefits that can be passed to the consumer in lower rent, while ownership would not have the same tax advantages. This will change if the solar investment tax credit is allowed to expire after 2020 as would occur under current law.

230 There is an accounting issue for meter replacement, because the cost of the meter is capitalized but the cost of meter replacement O&M is often expensed (see Section 21.3). It is important not to count the same cost twice.

ratepayer advocates typically have argued that only 70% of the cost was a customer connection and billing cost and the remainder was not a marginal customer cost. Alternatively, in other studies, more than 100% of the smart meter and data collection installation cost is justified by other savings in power supply and line losses, rendering the metering and meter reading function as a cost-free byproduct.

The division of the smart meter into connection and billing and other benefits can be analyzed in a different way — by netting out all benefits from the smart meter aside from those associated with meter reading and customer accounts, leaving the remainder as connection-related. This is analogous to calculating a marginal capacity cost based on a combined cycle power plant net of savings of fuel and purchased power if it is cheaper than a combustion turbine.

21.3 Operations and Maintenance Expenses for Customer Connection

Most utilities that use marginal costs assign the costs of FERC accounts 586 and 597 (meter operations and maintenance) and possibly portions of accounts 583, 584, 593 and 594 (operations and maintenance of underground and overhead lines) related to services and transformers as customer-related. If a transformer is customer connection equipment, Account 595 (transformer maintenance) is also customer-related. Utilities also assign portions of overhead accounts 580 (supervision and engineering), 588 (miscellaneous operating expenses), 590 (maintenance supervision) and 598 (miscellaneous maintenance expenses) to the customer costs. The treatment of these expenses is often an issue, as the specific costs in many of these areas may be more related to shared distribution system costs than to customer connections. These costs typically are developed using an average of several years of historical data and several years of future data.

There are several computational issues.

First, at least some utilities include the labor cost of replacing a meter in Account 586 (Jones and Marcus, 2016, citing San Diego Gas & Electric testimony). Effectively, the cost of replacing meters for customers needing replacement is included in both the O&M costs and the capital costs (because the lessor has the responsibility of replacement in the rental method and the replacement is included in the NCO method). Therefore, replacement meter costs should be removed from Account 586 in the rental method because they would otherwise be double-counted as part of the rental cost. In the NCO method with replacement, the costs of meter installation should be removed from the capital costs for replaced units and left in Account 586 to reflect recurring replacements.

Second, there are issues relating to the real costs of operating and maintaining service drops, some of which also must be dealt with in embedded cost analysis. Utilities may assign costs to service drops based on investment or line miles. But as a practical matter, utilities spend very little on service drops as compared with primary distribution lines. In particular, many utilities have vegetation management standards almost entirely tied to primary lines. They rarely trim trees around secondary wires, except incidentally when primary line trimming is needed, and even more rarely trim trees around service drops, except under emergency conditions. Aside from tree trimming, patrols and inspections are driven by primary lines, not service drops. Therefore, it is necessary to conduct utility-specific analysis on service drop maintenance.

A third issue is that some of the costs in Account 588 are not marginal costs at all. For example, PG&E in a previous case included costs of obtaining additional revenue from nontraditional sources and costs of performing work reimbursed by others. Other costs do not apply to customer connection equipment (environmental costs and mapping expenses that generally do not apply to services and meters).

In addition, if smart metering is in the process of being installed or has just been installed, O&M costs of smart meter installation may be part of accounts 586 and 587 in some historical years. In that case, it will be necessary to identify and remove those costs or use a historical period of time entirely after smart meter installation.

21.4 Billing and Customer Service Expenses

A marginal cost analysis of billing and customer service expenses is usually done in one of two ways. The most common way, following the NERA method, is to average costs over a number of historical and projected years. These costs are calculated per weighted customer, recognizing that certain activities are more heavily related to some customers than others. The second method is to use the costs of revenue cycle services, which are **short-run incremental costs** used to pay competitive service providers, plus similar short-run calculations for call centers and other activities. These costs are less than embedded costs of the same functions used in the NERA method. PG&E chose this method in Phase 2 of its 1999 general rate case to be consistent with the lower marginal costs it calculated for paying competitors; it has kept this design ever since. A method based on revenue cycle services is more consistent with a short-run marginal cost theory, but many utilities may not have the ability to implement it.

Many of the issues related to the appropriate calculation of marginal costs of billing and customer service are similar to the embedded cost issues raised in this manual. As with the discussion of this issue in Section 12.1, the frequency of billing and collection is driven by usage; if customers used minuscule amounts of power, it would not be cost-effective to read meters (without smart meters) or even bill on a monthly basis. For utilities without AMI, costs in excess of bimonthly meter reading and billing could be considered revenue-related rather than related to customer accounting. Relatedly, if smart meters are being implemented or have recently been implemented, meter reading costs from periods before smart meter implementation (as well as other costs such as call center costs associated with the implementation process) must be removed to prevent double counting of the capital cost of the smart meter and the operating cost of the mechanical meter that the smart meter replaces. As with embedded costs (see Section 12.3), the costs associated with major account representatives assigned to serve large customers (regardless of the FERC accounts in which they are found) should be considered part of the marginal costs of serving those customers and should be assigned to them.

As with customer-related distribution costs, in jurisdictions using long averages with both present and future costs, the future cost forecast must be reasonable. In the specific case of customer accounting costs, a trend toward declining costs and increasing productivity has persisted for almost a decade. More customers are receiving and paying bills online or through automatic bank transactions, both of which are less expensive to the utility than mailing bills and payment envelopes to the customer and then opening and processing return envelopes with payments from customers. Phone calls to the utility are being replaced with internet transactions (even for items such as changing service or making payment arrangements) and the use of interactive voice response units. Even though utilities may claim that the remaining calls may be more complex, customer service representatives are logging fewer total hours. As a result, it is important to examine any set of averaged costs carefully. If costs are declining, as they should be, then an average would include costs from a period of worse productivity than the present and should not be used. Similarly, if the future is projected to be more expensive than recent history, that assumption should be probed for reasonableness.

Some customer accounting and customer-related metering and distribution O&M expenses are paid by fees, not rates (see Chapter 15). As a result, they are not marginal costs associated with the general body of ratepayers. Costs of activities such as establishing service; disconnection and reconnection after customer nonpayment; field collections; meter testing; and returned checks are offset by fees received from individual customers (largely residential customers). If the costs paid by the fees are allocated heavily to residential customers, but the fees are not included in the revenue to be allocated, this would effectively cause residential customers to pay twice: once in the rate and a second time when assessed the fee. This problem can be dealt with in either of two ways. Nevada includes the fees in the revenue to be allocated and directly assigns the fees as revenues received from the classes that pay them. California generally removes an amount equal to the fees from the marginal customer accounting cost. The methods are not identical, but both will address the double counting. Costs (and uncollectible accounts if necessary) related to billing and collecting money from non-energy activities such as line extension advances and other products and services besides the utility's energy bills may be in accounts 901 through 905, but they are not marginal costs of serving electric customers and should be excluded from marginal customer costs. This is similar to the approach in Section 15.2 for embedded costs.

In some cases, the difference between marginal and embedded cost analysis is that costs are excluded from marginal costs while being allocated differently from other costs as embedded costs. Examples are economic development rates and uncollectible accounts expenses. Economic development rates, as well as any costs for marketing and load retention, are not marginal costs. These programs are not needed for customer service and theoretically should pay for themselves by attracting or retaining loads or improving economic conditions in the area. Uncollectible accounts expenses are not marginal costs associated with current bill-paying customers and conceptually should not be included in marginal costs. This is a similar issue to the embedded cost issue, discussed in Section 12.2, regarding whether uncollectible accounts expenses are costs associated with present customers (direct assigned) or former customers (allocated by usage or revenue). California regulators removed uncollectible accounts expenses from marginal costs in 1989 (California Public Utilities Commission, 1989); the Nevada commission includes them (Public Utilities Commission of Nevada, 2002, p. 109). If uncollectible accounts are included, then late payment revenues must be treated consistently, by adding them to the distribution revenues to be allocated and subtracting them from the classes that pay them.

Lastly, a number of cost elements that are sometimes mistakenly classified as customer service do not fit a marginal cost analysis well, particularly if the programs are undertaken for public policy reasons. A cost undertaken for public policy reasons is not a marginal cost, even if it might theoretically vary with the number of customers. An energy efficiency program or demand response program is established by the state or regulators for policy reasons, theoretically to provide a cost-effective or environmentally preferred substitute for other investments and expenses. Subsidy programs for low-income customers are also established for policy reasons. Certain other programs are also policy-related, such as promoting solar energy, battery storage and electric vehicles; allowing customers to opt out of smart meters; and research and development programs. These are not marginal costs, and their allocation to customers outside of a marginal cost framework will be discussed in Chapter 23.

21.5 Illustrative Marginal Customer Costs

Tables 42 and 43 on the next pages illustrate a calculation of marginal customer costs using the NCO and rental methods, with a set of assumptions that are generally realistic but not tied to any specific utility.

Table 44 on Page 213 shows the impact of the choice of marginal customer cost methods on the MCRR of distribution and thus on the overall allocation of distribution costs. To illustrate this impact, there is also an assumption as to demand distribution costs. Costs for primary customers are assumed to be lower than for other classes largely because they do not need line transformers. In this example, the residential class has 41% of the MCRR for distribution costs with the rental method but 38.8% with the NCO method.

Table 42. Illustrative example of new-customer-only method for marginal customer costs

	Residential	Small commercial	Secondary large commercial	Primary industrial
Initial investment				
Service	$800	$1,200	$3,000	N/A
Meter	$200	$300	$3,000	$9,000
Total	$1,000	$1,500	$6,000	$9,000
Present value of revenue requirements (PVRR) factor				
Service	1.3	1.3	1.3	1.3
Meter	1.25	1.25	1.25	1.25
Investment with PVRR				
Service	$1,040	$1,560	$3,900	N/A
Meter	$250	$375	$3,750	$11,250
Total	$1,290	$1,935	$7,650	$11,250
New customers (% of system)	1%	1%	0.5%	0%
Replacements (% of system)				
Service	0.5%	0.5%	0.5%	0.5%
Meter	2%	2%	2%	2%
Marginal cost for new customers (investment with PVRR x new customer %)				
Service	$10.40	$15.60	$19.50	N/A
Meter	$2.50	$3.75	$18.75	N/A
Total	$12.90	$19.35	$38.25	N/A
Marginal cost for replacement (investment with PVRR x replacement %)				
Service	$5.20	$7.80	$19.50	N/A
Meter	$5.00	$7.50	$75.00	$225
Total	$10.20	$15.30	$94.50	$225
Total investment marginal cost for new and replacement customers				
Service	$15.60	$23.40	$39.00	N/A
Meter	$7.50	$11.25	$93.75	$225
Total	$23.10	$34.65	$132.75	$225
Customer operations and maintenance cost	$30	$50	$500	$700
Total marginal customer cost	$53.10	$84.65	$632.75	$925
Number of customers	1,000,000	100,000	10,000	1,000
Marginal cost revenue requirement for customer costs	$53,100,000	$8,465,000	$6,327,500	$925,000

Table 43. Illustrative example of rental method for marginal customer costs

	Residential	Small commercial	Secondary large commercial	Primary industrial
Initial investment				
Service	$800	$1,200	$3,000	N/A
Meter	$200	$300	$3,000	$9,000
Total	$1,000	$1,500	$6,000	$9,000
Real economic carrying charge rate				
Service	7%	7%	7%	7%
Meter	10%	10%	10%	10%
Annualized investment cost				
Service	$56	$84	$210	N/A
Meter	$20	$30	$300	$900
Total	$76	$114	$510	$900
Annual customer operations and maintenance cost	$30	$50	$500	$700
Total customer cost	$106	$164	$1,010	$1,600
Number of customers	1,000,000	100,000	10,000	1,000
Marginal cost revenue requirement for customer costs	$106,000,000	$16,400,000	$10,100,000	$1,600,000

Table 44. Illustrative comparison of rental versus new-customer-only method for overall distribution costs

	Residential	Small commercial	Secondary large commercial	Primary industrial
Marginal cost revenue requirement for customer costs				
Rental method	$106,000,000	$16,400,000	$10,100,000	$1,600,000
New-customer-only method	$53,100,000	$8,465,000	$6,327,500	$925,000
Marginal distribution demand cost per kW	$100	$110	$110	$75
Demand per customer (kWs)	4	25	250	2,000
Number of customers	1,000,000	100,000	10,000	1,000
Marginal cost revenue requirement for distribution demand costs	$400,000,000	$275,000,000	$275,000,000	$150,000,000
Results: Rental method				
Total distribution marginal cost revenue requirement	$506,000,000	$291,400,000	$285,100,000	$151,600,000
Share of distribution costs	41.0%	23.6%	23.1%	12.3%
Results: New-customer-only method				
Total distribution marginal cost revenue requirement	$453,100,000	$283,465,000	$281,327,500	$150,925,000
Share of distribution costs	38.8%	24.3%	24.1%	12.9%

Note: Based generally on California examples, except transformer part of demand cost. Marginal demand cost is higher in commercial classes than residential because residential has more customers per transformer. Demand is lower in industrial class because no transformers or secondary lines are included. Percentages may not add up to 100 because of rounding.

22. Administrative and General Costs in Marginal Cost of Service Studies

Both A&G expenses and general plant costs are typically considered "loaders" to marginal costs, applied to the generation, transmission and distribution functions. Fundamentally, at least some A&G expenses and general plant costs are marginal costs, though over varying time horizons and in varying amounts because of economies of scale in running a large corporation.

The NERA method in the 1970s used an extremely long-run marginal cost method for A&G costs. It developed loading factors based on what appears to be a fairly arbitrary mix of labor, O&M expenses and total plant for A&G expenses, and it allocated general plant based on other plant (other capital investments). As with other elements of the NERA method, the mismatch in time frames is a serious theoretical concern. One method of addressing this is to eliminate consideration of joint and common A&G costs from the marginal cost analysis. This leaves only short-run marginal A&G costs as a better match with short-run generation marginal costs.

Short-run marginal costs include at least workers' compensation and pensions and benefits associated with other marginal costs that are labor-related. Similarly, incentive pay, to the extent recorded to A&G accounts, is a short-run marginal cost assigned to labor. Property insurance is a plant-related marginal cost to the extent that the amount of insured property affects the premiums.

If longer-term A&G costs are included, one can either include all of them as variable in the long run with the size of the utility or recognize potential economies of scale, which would mean that only a portion of costs is marginal. The best example of an intermediate-term marginal cost is the human resources department, which varies with the size of the workforce. Other examples of costs that will vary with the size of the utility in the intermediate term are benefits administration, accounts payable, payroll processing and capital accounting. Over a longer period, portions of an even broader set of costs are variable. For example, executive salaries are related (though possibly not proportional) to the size of the company, as a larger company will have more executives and pay them more (Marcus, 2010a, pp. 90-93 and Exhibit WBM-18). Other examples relate to buildings and other general plant items. A utility with fewer workers will own, rent and maintain less building space and have fewer vehicles and tools.

Recently a number of utilities, following the FERC method of unbundling transmission, have allocated both A&G expenses and general plant costs (using a long-run marginal cost basis) based on labor with the exception of (1) property insurance, which is based on plant, and (2) franchise fees based on revenue. The labor allocation method for A&G expenses tends to be less favorable to small customers than the plant-based method, but it has analytical merit. Key issues here are (1) ensuring that specific elements of A&G expenses are truly recurring marginal costs and (2) whether a given cost should be functionalized differently among generation, transmission and distribution. This can be as simple as, for example, removing a large one-time fire claim (which has no relationship to any cost drivers) from a utility's recorded A&G expenses and removing nuclear insurance from liability insurance allocated by company labor when the company had no labor costs at a jointly owned nuclear plant (Jones and Marcus, 2016, pp. 20-21). Or it can involve a more complex analysis of which specific A&G costs are marginal, an exercise Southern California Gas Co. undertook in its gas marginal cost studies (Chaudhury, 2015, pp. 21-22).

23. Public Policy Programs

There are a number of costs related to public policy decisions by state regulators that generally should not be considered marginal costs. Consideration should be given to allocating these costs separately from marginal costs. Many states have explicit cost allocations for public policy or energy efficiency costs that are separate from base rates or distribution rates. In California, energy efficiency costs are largely, though not entirely, allocated in proportion to total system revenues, with generation revenues imputed to customers who do not receive generation service from the utility so that direct access and community choice aggregation customers do not pay lower rates for public purpose programs than bundled customers with otherwise similar characteristics.[231] California allocates low-income rate subsidies in equal cents per kWh to all customers except municipal streetlights and those customers receiving the subsidies.[232]

However, some policy-oriented costs related to demand response programs and other items have been included in distribution costs, so that all customers, including those who may purchase generation from others besides the utility, can be required to pay for them. In these cases, the allocation of a cost such as demand response by an allocator such as a distribution equal percentage of marginal cost (EPMC) creates concerns. If costs of a demand response program that avoids generation are allocated by distribution EPMC (or even total EPMC), residential customers might be better off if the utility instead built generation of equivalent or, in some cases, higher cost, even if society would be worse off — because a smaller portion of the higher cost would be allocated to them. Even if a demand response cost is designed to avoid some T&D, the demand response measure generally will also reduce the need for generation capacity.

One framework used by consumer advocates in California applies different approaches to different subsets of public policy costs. It allocates the costs of direct programs that provide generation in distribution rates (e.g., interruptible and load management rate credits) by EPMC of generation (with generation marginal costs imputed to those not served by the utility). At the same time, it allocates programs that provide more broad public benefits (e.g., electric vehicle programs, research and development) or that create infrastructure to enable demand response (e.g., computer systems, the portion of AMI costs in excess of those that are cost-effective operationally for the distribution system) based on the equal percentage of revenue method discussed above for energy efficiency.

231 This method was essentially codified in A.B. 1890, California's restructuring legislation of 1996. Although the specifics of that legislation no longer apply, relatively similar methods have been used throughout the last two decades in a number of settled cases.

232 California Public Utilities Code § 327(a)(7): "For electrical corporations and for public utilities that are both electrical corporations and gas corporations, allocate the costs of the CARE program on an equal cents per kilowatt hour or equal cents per therm basis to all classes of customers that were subject to the surcharge that funded the program on January 1, 2008."

24. Reconciling Marginal Costs to Embedded Costs

It is only happenstance if marginal costs and embedded costs produce the same revenue. This raises questions as to how to reconcile these items. The most common method allocates embedded cost revenue requirements in the same proportion that marginal costs are allocated. This is typically called the equal percentage of marginal cost method but may also be known as equiproportional.

There are two types of EPMC allocation. The first allocates the entire revenue requirement by the entire marginal cost revenue responsibility, called total EPMC allocation.[233] This method was used in both California and Nevada through the 1990s. Under this method, if generation marginal costs are low (because of excess capacity, renewable penetration, low gas prices or other reasons), more of the system costs are allocated based on distribution costs, which are allocated more heavily to small customers. The result is problematic for small consumers. This was particularly evident in California, where high costs in the 1980s — created by power purchase contracts required under PURPA and additions of nuclear power — were heavily allocated based on distribution costs because of excess capacity, low system incremental heat rates due to large amounts of baseload power, and falling gas prices that did not reflect the expectation at the time the excess capacity was being constructed.

A second problem with this total EPMC allocation method is that it does not work well in quasi-competitive markets. If some customers have market options to acquire generation and others do not, as in California and Nevada, using an EPMC method based on total marginal costs could distort competitive choices by setting generation rates based on a mix of generation, transmission and distribution marginal costs. As a result, both of these states now use an EPMC allocation by function. They separately allocate generation, transmission (in Nevada; California transmission used by investor-owned utilities is entirely under FERC jurisdiction) and distribution based on EPMC.[234]

The other less used approach for reconciling marginal costs to embedded costs is an economic approach known as Ramsey pricing and the resulting inverse elasticity rule.[235] Under this construct, any deviation from marginal costs creates an economic distortion. Advocates of this approach would reconcile marginal costs to embedded costs in the "least distortive" manner. At a high level this is reasonable, but there are many disputes about which choice is least distortive. Many advocates of this approach take a narrow view of societal costs and externalities and argue that the responsiveness of customer classes with respect to higher or lower costs — a concept known as elasticity of demand — is the key criterion. Relative elasticity of demand between rate classes, and between different rate elements for each rate class, is difficult to measure. Some advocates of the Ramsey pricing approach assume that residential customers are less responsive to changes in cost in the short term, particularly with respect to changes in the customer charge. But according to these advocates, if embedded costs are higher than the MCRR, then this leads to a larger share of costs being borne by residential customers, with those costs being recovered through higher customer charges for residential customers. These underlying assumptions may not have been true historically, but changing circumstances may weigh

233 The use of EPMC as a whole in California was first clearly adopted in 1986 (California Public Utilities Commission, 1986, pp. 636-646).

234 The unbundling of revenue allocation in California by function after the incomplete adoption of utility restructuring is discussed in Schichtl (2002). The functionalization of EPMC in Nevada is found in Public Utilities Commission of Nevada (2007, pp. 162-167).

235 This method was named after Frank B. Ramsey, who found this result in the context of taxation. Later, Marcel Boiteux applied the rule to natural monopolies in declining cost industries.

even more heavily against this approach in the future. If externalities are incorporated, then in many circumstances per-kWh rates are actually lower than the full societal marginal cost of consumption — meaning it would be socially efficient to classify incremental costs as energy-related. Full incorporation of externalities, in fact, argues for a differential approach depending on whether the MCRR is lower or higher than embedded costs, classifying any incremental costs as energy-related for inclusion in kWh rates while classifying any excess revenue as customer-related to provide a reduction in customer charges.

In addition, certain types of multifamily buildings often face a choice between master metering and individual meters. This choice affects the number of customers and overall customer charge revenue but has almost no effect on system cost other than meters and billing. The declining cost of storage and solar may enable growing numbers of customers to disconnect entirely from the grid as well. The experience in the cable television and telephone industries shows how people are willing to "cut the cord" to rely on nonmonopoly service providers. Lastly, even if the underlying claims from certain advocates of Ramsey pricing are correct, there are significant equity issues between classes at stake in the allocation of additional costs solely to the residential class. Similarly, using Ramsey pricing to pass those costs on through customer charges raises significant equity issues within the residential class, disproportionately affecting small users.[236]

236 It could be the case that lower-income customers have a more elastic demand to pay for electric service if prices are increased because of limited ability to pay.

25. Cutting-Edge Marginal Cost Approaches

> It is important to sketch out a new paradigm for marginal costs, even though many of the calculations on which it could be constructed have not been developed.

The NERA method for calculating marginal costs, particularly for generation, becomes less sustainable as the utility systems move toward major technological change and reductions in carbon. While the effect may be different in different regions of the country, the short-term avoided energy cost will reflect diminishing variable costs to the extent that natural gas is replaced with renewables and storage. Capacity costs may be moving toward batteries given that renewable integration can be achieved better with storage resources that can both use overgeneration and provide ramping and integration more effectively than fossil-fueled plants that do nothing about overgeneration. Thus, it is important to at least sketch out a new paradigm for marginal costs, even though many of the calculations on which it could be constructed have not been developed yet or integrated into a whole.

25.1 Total Service Long-Run Incremental Cost

The basic theory presented here is the total system long-run incremental cost method that was developed in the telecommunications industry during its period of rapid technological change before deregulation. Under this method, all costs are variable but may be very different from historical costs. This is important when examining the generation system in particular, because the optimal system going forward is likely to have very few traditional variable costs.

The TSLRIC is theoretically defined as the total cost of building and operating an optimal new system to serve the current load with changes that can be reasonably foreseen and changes to reflect environmental priorities (e.g., additional efficiency and demand response, changes to electrification for purposes of decarbonizing existing fossil fuel end uses and development of more loads with storage or other controls). The system will be different from the current system in a number of ways. The theory is that it will be optimally sized with optimal technology, which should in most cases reduce costs (or at least societal costs reflecting environmental constraints) relative to current technology — although that may not always be true. However, the system would also be built at current construction costs, so it could be more expensive in that regard. Since TSLRIC represents an optimal system, it removes one of the key problems of the NERA method, which can disproportionately assign excess capacity to specific customer classes if not undertaken carefully to remove the excess capacity.

Although the theory is relatively easy to state, it has not been implemented for an electric utility, and the data to implement it will need to be collected and analyzed.

To make this calculation, one needs to start with the cost of the existing system. This is then adjusted for inflation since the time when it was built, yielding what is usually referred to as "replacement cost new." But a TSLRIC study goes beyond simply a study of the replacement cost of the system as it exists today. Other sources of data should be acquired for resources whose costs are declining due to technological change and data availability. From that point, one examines the changes in the generation resource mix to move it toward optimality. Substitution of storage or other DERs for upstream generation and transmission may reduce TSLRIC costs. A complex engineering analysis would also be required to review the magnitude of the cost-decreasing and cost-increasing drivers for transmission and distribution costs, which are likely to be different by utility. The discussion below outlines qualitative issues relating to the cost changes that would result from using a system constructed under TSLRIC.

25.1.1 Generation

Without full quantification, an optimal system 15 to 20 years out will contain considerably more wind generation, solar generation, possibly some other renewable generation and more storage than the current system. The mix of solar and wind generation is likely to be region-specific, depending on available resources that can be economically brought to market. Some storage could be centralized, providing generation for peaking, ramping and renewable integration. At the grid level, storage could be related to batteries, compressed air and pumped hydro, as well as the load-related operations of large water projects (e.g., hydroelectric capacity and flexible pumping loads and storage associated with large water supply projects). The question of black start capability of storage resources may need to be addressed because, if storage can provide this capability, it may supplant the need for certain gas-fired resources.

Storage could be decentralized, also serving to reduce the need to build distribution capacity while serving the distribution system with greater reliability in addition to G&T displacement. At the decentralized level, batteries would be an option, but so would end-user storage such as controllable water heaters (which would have significant benefits for dealing with ramp), thermal energy storage to supplant peak air conditioning, and use of existing or new water storage to control timing of pumping and delivery by local water agencies and irrigators. This storage is a joint product that must be functionalized among generation, distribution and possibly transmission.

Controls on electric vehicle charging — to keep them out of peak periods, avoid distribution overloads, preferentially charge to mitigate ramp and possibly reverse flows (vehicle to grid) — could also create flexibility, since there would be little or no resource costs except controls (incremental changes in costs of charging and discharging only). These controls are installed at the end user level but may be critical to reduce generation and distribution costs in an optimal system and as such would be part of TSLRIC.

Other demand response programs beyond traditional programs (such as interruptible industrials and air conditioner cycling) likely would become cost-effective as part of an optimal system. Examples include smart appliances that would run discretionary loads such as washing, drying or dishwashing at times when the loads match system needs, and variable-speed drives for heating, ventilation and air conditioning systems that could both save energy and respond automatically to peak or ramp conditions. These also may be part of TSLRIC, functionalized among generation, transmission and distribution as joint products.

Most existing conventional hydro and pumped storage resources probably would remain part of an optimal system, although the timing of their usage may change from the current system. In part, even under TSLRIC, it is not reasonable to ignore high decommissioning costs that can be avoided by keeping them in operation. More importantly, hydro resources with storage also provide energy at zero incremental costs, as well as ancillary services and significant amounts of flexibility to the grid. These resources may be devalued rather than being included at full replacement cost to recognize that their continued operation depends in part on avoiding the costs of removing them — which is generally not considered in a TSLRIC environment. However, some smaller resources would be closed, particularly run-of-river plants and those in areas where there are significant environmental impacts. At current and projected costs (considering those related to capital, operations and emissions), coal and traditional nuclear units[237] likely would not be part of the new optimal system under TSLRIC.

The role of natural gas-fired generation for reliability and bulk energy generation in an optimal system that recognizes carbon constraints is a large question. In all likelihood, some of the most efficient gas generating units would remain for a significant period, although the amount of energy they produce could be considerably less than at present. Gas plants could include:

- CHP, which has very high efficiency and uses thermal energy to produce steam for industrial processes or chilled water to displace air conditioning loads.

237 Consider the abandonment of South Carolina Electric and Gas Co.'s Summer Nuclear Station and the cost overruns at Georgia Power's Vogtle units 2 and 3, which cost $23 billion — or more than $10,000 per kW (Ondieki, 2017).

- Combined cycle generation designed for flexible use that could also make up for any shortages in bulk energy if adverse weather conditions reduce output from hydro and renewables.
- Potentially, gas turbine peakers. The modern gas turbine supplanted less-efficient older gas-fired steam units. But storage and demand response are likely to make even modern gas turbines less economic, particularly for reserves, needle peak use and ramping.[238] Nevertheless, in some places, particularly where gas turbines are considerably cheaper than combined cycle units and where other flexible resources (such as hydro) are not widely available, there may be a dispatch range (for example, a 10% to 20% capacity factor) where gas turbines might be economic in an optimal system.

For any fossil generation, to the extent not otherwise internalized, a carbon adder based on residual damage or mitigation costs would be included under TSLRIC, but much of the TSLRIC system is being rebuilt to optimize for the need to reduce carbon emissions as well as for financial costs.

25.1.2 Transmission

Assuming no major technological advances (e.g., superconductors), some changes in transmission from the current system would arise from changing generation patterns. Long-distance transmission from existing coal and nuclear stations may no longer be part of an optimal system, but long-distance transmission from distant wind regions may replace it as a significant factor, either because of new construction or wheeling costs.[239] Interties would likely remain, although there may be more bidirectional power, and their role may be clearing renewable surpluses across wide regions. These transmission facilities for delivery of bulk energy, explicitly excluded from the NERA method, probably would be allocated over hours of use — making them energy-related, since they are not constructed for peak loads.

There may be other efficiencies associated with both better controls and with the possible use of strategically located storage devices if cheaper than both transmission lines and conventional RMR gas-fired generation. PG&E's use of batteries to displace an RMR contract in an area south of San Jose (discussed in Section 18.3) suggests the potential of this outcome. It is also possible that a further analysis of a more optimal network of transmission lines may reveal significant portions of those lines are, in fact, related to off-peak use or contingencies that could occur at nonpeak times and should thus be spread over more than peak hours.

25.1.3 Shared Distribution

The whole distribution system would become part of TSLRIC, instead of just the narrowly defined portions where the NERA method suggests investments are needed to serve increases in demand. The optimal distribution system is likely to need less capacity and to serve load more reliably and with fewer losses than the current system, because of technologies such as automatic switching and integrated volt/VAR controls — which would reduce costs — and because energy efficiency (particularly related to space conditioning), decentralized storage, demand response and controls on electric vehicles could reduce distribution peaks.

There are likely to be customers for whom usage is so low that they are better served by DERs than by a grid. They will include many rural customers (particularly in areas with high potential fire danger) but also small loads in an urban area. Solar-powered school crossing signals are being installed today, simply because the cost of connecting to the grid exceeds the cost of the distributed energy system. Other applications using low-wattage LED lights (e.g., traffic signals and remote streetlights) may ultimately also find a distributed alternative to be cheaper than grid service. Factoring this into a TSLRIC study will ensure that low-use customers are not assigned costs that will not benefit them economically.

Distribution is also likely to be bidirectional at least in some places, particularly if whole neighborhoods are served with distributed solar (or solar plus storage) resources. This change may require more expensive control systems in some

238 In 2018, NV Energy executed contracts for four-hour battery storage at a cost of $73 per kW-year, less than the carrying cost plus nondispatch O&M for a peaker (Bade, 2018).

239 For example, capacity freed up on transmission lines bringing coal-fired electricity from Four Corners to Southern California Edison is now being used to deliver wind energy from New Mexico. (Southern California Edison, 2015, p. 4).

places but is also likely to have a net effect of economizing on system sizing. Some primary distribution feeders (along with service lines and transformers) may need to be reconstructed if neighborhoods are converted from gas to electric space heating or if electric vehicles become ubiquitous, but those costs would be spread over more kWhs of load. Beneficial electrification of heating and transportation could increase total distribution costs, but because these technologies add energy loads, the costs per kWh may be stable or decline, and the amount of winter peaking load is likely to increase.

However, costs can increase from other aspects of the optimal distribution system. More of the optimal system is likely to be underground in urban areas, increasing system capital costs. Although overhead wires are cheaper, they also have nonmonetary costs related to worse aesthetics, poorer reliability (particularly in areas subject to ice storms and tropical storms) and to some extent worse safety (fires, downed wires). There would be some cost offset because the oldest and least reliable underground technologies that are currently being replaced at significant cost would have been supplanted, thereby reducing TSLRIC maintenance and replacement costs compared with current costs. Urban vegetation management costs would also be reduced in a system with more undergrounding. The overall costs of increased underground service (even after netting out the relevant costs avoided, such as maintenance, replacement of aging lines and vegetation management) likely would still be higher than current costs.

The optimal distribution grid is likely to have other cost-increasing features. It will need more resilience against natural disasters such as hurricanes, more patrols and maintenance to prevent fires, and costlier and more extensive vegetation management. It will also incur costs for protection against stronger winds, dealing with safety hazards from pole overloading by both electric utilities and communications companies, and possibly undergrounding in some remote areas to prevent outages and fires.

One potential outcome in the Western U.S. may even be that significant parts of the grid routinely begin to receive interruptible service to prevent wildfires. Even more remote portions of the grid serving few customers in areas with high fire danger may be completely abandoned. In essence, those parts of the system could be turned back to individual customers who use solar and storage to serve their loads and establish small microgrids. They may possibly be some of the last customers with fossil fuels (propane or compressed natural gas) as a source for meeting relatively large energy loads such as space and water heating in a mainly decarbonized system.

25.1.4 Customer Connection, Billing and Service Costs

The design of customer connection equipment may not change greatly, except for replacement of urban overhead lines with underground equipment and possibly some advances in controls that can optimize transformer capacity for small customers. As noted earlier, some service lines and transformers may need to be resized if neighborhoods are converted from gas to electric space heating or electric vehicles become ubiquitous. As with the current system, costs of advanced metering would need to be divided between the pure connection and billing function and the costs of other services that AMI provides (to reduce grid costs and to provide platforms for demand response and storage behind the meter).

Customer accounting and service O&M will be reduced due to the continuation of greater productivity from internet and interactive voice response systems and the prevalence of cheaper methods of receiving and paying bills that were discussed in Section 21.4. These items have been increasing productivity for the last decade and are likely to continue to do so.

25.2 Hourly Marginal Cost Methods

Although the hourly marginal cost method has not been explicitly used (a variant is used in Nevada), the Energy and Environmental Economics long-run marginal cost study points to how such a method could be used. Rather than dividing costs into demand and energy costs and allocating by kWs, E3 assigns its various types of avoided costs to individual hours so that specific energy efficiency, demand response and distributed generation costs could be measured against the hourly costs given their operational patterns. When costs are assigned to hours, the allocation to classes can be based on customer loads in those hours without calling the costs "demand" or "energy" costs. As with hourly allocation embedded cost methods, this may be an approach that will serve the cost analyst as the utility system evolves to include widespread renewable and distributed resources.

To convert the marginal costs calculated using a variant of the NERA method into hourly costs, and after considering the E3 hourly cost calculation, the following method could be used. This method still has some of the potential drawbacks of the NERA method discussed in detail above (possible mismatches in short-run and long-run analysis, failure to consider certain plant such as transmission interties, ambiguous treatment of replacement equipment, etc.). The NERA approach is also a fundamentally peak-oriented method, as opposed to the methods based on hours of use of capacity suggested in Chapter 17. Nevertheless, with some modification, it can be amenable to hourly calculations.

25.2.1 Energy and Generation

Energy costs can be calculated on a time period basis, as in Oregon or California. Otherwise, energy costs can be calculated on an hourly basis, as in Nevada, and aggregated into time periods based on hourly loads (including losses) by each class in each time period. Generation capacity costs need to be originally calculated in dollars per kW of capacity and divided between peaking capacity and other capacity needs (e.g., ramp) in ways described in Section 19.3. The peaking costs would be assigned to a subset of hours using methodologies such as loss-of-energy expectation, PCAF, loads or load differentials in largest ramp periods, or other multihour methods. Costs in each hour would then be calculated in cents per kWh and multiplied by the loads in each hour (including losses). The hourly costs can be aggregated into time periods. Consideration should be given to the establishment of a super-peak period for hourly cost allocation containing the highest peak-related costs based on loss-of-energy expectation or PCAF allocations to encourage the use of short-term resources such as demand response. If ramp costs are calculated, they could largely be based on storage operations and could have negative capacity costs in hours when storage is charging immediately before a ramp and positive capacity costs from the beginning of the ramp through the daily peak and shortly afterward.

25.2.2 Transmission and Shared Distribution

For transmission and distribution costs (except possibly for distribution costs for new business, including primary lines installed to connect new customers and transformers), a method that skips the dollars-per-kW step and goes directly to total dollars per hour has advantages. It avoids the significant problems associated with mismatches of kWs of capacity (calculated based on extreme weather peak loads or size of equipment that is added) and kWs of load (calculated based on a smaller number of kWs such as PCAF or a peak or diversified demand); see Appendix C. This also provides a clearer path toward design of TOU pricing. If a figure in cents per kWh is needed in an hour or time period, total dollars can be divided by the loads in each hour. Such an allocation method would need to be disaggregated by voltage (transmission if not FERC jurisdictional, possibly subtransmission, distribution). Additionally, a disaggregation at each voltage between substations and circuits would improve an hourly calculation because substations and circuits may have different time patterns of usage and cost causation.

For each component (excluding the transmission components for utilities with fully FERC jurisdictional transmission), the total investment in capacity-related equipment including automation and controls — unlike the NERA method, which excludes them — would be calculated in real dollars and averaged over a period such as 10 years. This should perhaps include both forward-looking and historical data as with the NERA method. The costs should then be annualized using an RECC and with O&M and possibly replacements added (in real dollars per year). The O&M and replacement costs would be based on either averaged costs or forward-looking costs if changes from the average have been observed or are expected.

Substation capacity needs are generally oriented to the peak loads of the equipment, although they are also related to the duration of heavy energy use, suggesting a broader allocation than a single coincident peak. An allocation of total dollar costs to time periods consistent with the NERA method's emphasis on capacity could be based on some hybrid of the percentage of kVA of substation peaks in each season and time period and a PCAF, which has an energy component because all loads in excess of 80% of the peak are assigned some capacity value. The PCAF could be set differently for summer and winter peaking kVA if applicable. For rate design purposes, a super-peak period could also be carved out that recognizes stress on components and high marginal line losses during extreme loads.

Transmission and subtransmission line marginal capacity under the NERA method involves a highly networked system, where at least some of the installed capacity is needed to meet contingencies that may occur at times other than during peak hours. The hourly causation and allocation of costs is likely to require further analysis that has not yet been conducted. But it could be some mix of peak loads (i.e., PCAF) and hourly loads (weighted into time periods when contingencies are most likely to occur to the extent possible).

Distribution substations are generally oriented to diversified peak loads on the equipment while also being related to the duration of energy use and should be allocated to hours in a manner like the allocation of transmission substations. Distribution lines are more radial in nature, although switching among feeders has been installed in some places, and more automation and volt/VAR controls are likely to cause distribution systems to become more networked. The cost causation for distribution line capacity has a peak-oriented component — which is likely to increase as the system networking and switching increases — and a component related to individual feeder peak loads, which is likely to decline. To allocate these costs to hours, one could start with a cost component for specific lines that would be directly assigned based on the individual peak of customers who are very large in relation to feeder sizes (i.e., customers over a particular MW size or a high percentage of the feeder's peak load). Remaining costs could be allocated to hours based on a mix of PCAF or top hours, a component based on the timing of individual feeder peaks (taking into account differences in residential and commercial load patterns) and a base load to all hours. For cost allocation, the hourly loads for feeder peaks could segregate the residential and commercial loads into different hours. If large customers are directly assigned costs, they would not be allocated any of the hourly costs.

New business distribution lines could be part of distribution circuits or could be segregated into a separate cost item for allocation. If new business lines and line transformers are separated from other distribution costs, the costs could be calculated in dollars per kW using a method with a demand measure such as changes in the demand at the final line transformer[240] (which reflects diversity for those customers sharing transformers). These costs can then be allocated to hours within each class based partly on class peak load characteristics (e.g., assigning more costs to residential customers in summer evening hours or to commercial customers during summer afternoons) and partly to additional hours to reflect that transformer performance is degraded if more energy is used in high-load (nonpeak) hours, as discussed in Section 5.1. A class allocation based on loads at the transformer would reflect that these very localized costs have some relationship to the customer's own demand (diversified to the transformer). Some utilities may have a small secondary distribution marginal capacity component reflecting that capacity may need to be added to networked secondary systems. This cost, if applicable, could be treated similarly to new business and line transformer costs, assigned in dollars per kW based on demand at the final line transformer and assigned to classes on the secondary system in the same way as line transformers.

O&M costs for substations and circuits generally should be allocated in the same way as the plant, except that costs of vegetation management and various periodic patrols and inspections should be assigned to all hours because they are not caused by peak loads.

If T&D replacement costs are included as recommended in Chapter 20, the costs should be allocated to hours either in a manner like the underlying allocation for plant of each type or based on all hours, reflecting that replacements are not based on peak demand. Some mix of the two methods may also be used.

240 With an allocation to primary voltage customers based on maximum demand but excluding transformer costs.

26. Summary of Recommendations for Marginal Cost of Service Studies

This chapter provides recommendations on two sets of issues: how to make incremental improvements to the predominantly used NERA method and how to work toward developing an hourly TSLRIC method, which has not yet been implemented.

26.1 Improving Marginal Cost Methods

Nine key items are distilled from Part IV as to how to improve marginal cost methods from the NERA method.

1. Analyze whether demand response can provide relief for the highest 20 to 50 hours of system load more cost-effectively than supply options, and substitute these costs for peak-hour costing if they are available and cost-effective.
2. Analyze whether grid-sized batteries are the least-cost capacity resource in the near term, instead of combustion turbine peakers, to meet the highest few hundred hours of system load — recognizing that they may take on a different role in the long term as systems become more heavily reliant on variable renewable generation. This is particularly important if reliability has a grid integration or ramping function as well as a peaking function in the relevant jurisdiction, because a battery can reduce ramp approximately twice as much as a generator of the same size and can smooth intermittent resource output better than a fossil-fueled plant.
3. Move toward long-run incremental costs for generation containing less carbon as a first step toward the TSLRIC method. Oregon uses 75% combined cycle and 25% solar in its long-run incremental cost. To the extent that it can be reasonably justified, a decarbonized long-run incremental cost would have storage for capacity, more renewables and less gas.
4. If the NERA-style short-run energy and generation capacity cost methods are used in the relevant jurisdiction, use a longer period of time for analyzing marginal energy costs than one to six years to deal with the mix of short-run and long-run costs currently used. Also ensure that carbon costs are included and a renewable portfolio standard adder is used if relevant to the jurisdiction. And examine whether pure capacity purchased from the market is cheaper than either a combustion turbine or battery for near-term application.
5. Make the definition of marginal costs more expansive for transmission and distribution to include automation, controls and other investments in avoiding capacity or increasing reliability, and consider including replacement costs.
6. Use the NCO method of calculating marginal customer costs. If replacement is included for any assets, a replacement rate should be based on actual experience, which would typically be less often than the accounting lifetime suggests.
7. Functionalize marginal costs in revenue reconciliation; use EPMC by function, not in total.
8. If demand costs are used, make sure that kWs used to calculate marginal costs and kWs used to allocate them are harmonized.
9. To the extent feasible, use an hourly method, such as the one E3 developed, to assign costs to hours and then to customer class loads. This avoids the need to separate costs into the demand and energy classification.

26.2 Moving Toward Broader Reform

TSLRIC will require both vision and research to be implemented for all utility functions. How a TSLRIC approach might look different from simply using replacement cost new for existing facilities was sketched out in Section 25.1.

The first place where a TSLRIC approach could be used is for generation, where it could be built up from a lower-carbon long-run incremental cost. Other resources may also be available to assist in constructing the TSLRIC of generation. They include the low-carbon grid study for the Western grid and similar studies that build out potential future resource plans (Brinkman, Jorgenson, Ehlen and Caldwell, 2016, and Marcus, 2016). This is a data-intensive approach that will require envisioning and costing out future systems and determining the resilience of the cost estimates to various assumptions. TSLRIC for generation probably suggests starting with a "cost by hours of use" approach, since there is only a limited amount of resources with fossil fuel that may not be dispatched in all hours. This means that price shapes based on short-run marginal cost may no longer make sense. This method would end up giving batteries and storage negative energy costs when they are charging and positive costs when discharging. Distributed generation would require functionalization.

Developing TSLRIC for transmission and distribution would require considerable amounts of engineering analysis to determine how the various cost drivers would work when developing a more optimal system and would likely involve a longer process.

Works Cited in Part IV

Bade, G. (2018, June 13). NV Energy 2.3-cent solar contract could set new price record. Utility Dive. Retrieved from https://www.utilitydive.com/news/nv-energy-23-cent-solar-contract-could-set-new-price-record/525610/

Barker, D. (2014, January 31). Testimony on behalf of San Diego Gas & Electric. California Public Utilities Commission Application No. 14-01-027. Retrieved from https://www.sdge.com/sites/default/files/RDW_Barker_SDGE_Testimony_0.pdf

Bohrman, J. (2013, June 3). Testimony on behalf of NV Energy. Public Utilities Commission of Nevada Docket No. 13-06-002. Retrieved from http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2010_THRU_PRESENT/2013-6/26978.pdf

Brinkman, G., Jorgenson, J., Ehlen, A., and Caldwell, J. (2016). *Low carbon grid study: Analysis of a 50% emission reduction in California* (NREL/TP-6A20-64884). Golden, CO: National Renewable Energy Laboratory. Retrieved from https://www.nrel.gov/docs/fy16osti/64884.pdf

California Public Utilities Commission. (1983). Decision No. 83-12-068 in Pacific Gas & Electric general rate case, 14 CPUC 2d 15.

California Public Utilities Commission. (1986, August 20). Decision No. 86-08-083 in 1986 energy cost adjustment charge case, 21 CPUC 2d 613.

California Public Utilities Commission. (1989, December). Decision No. 89-12-057 in Pacific Gas & Electric general rate case.

California Public Utilities Commission. (1995, December). Decision No. 95-12-053 in Pacific Gas & Electric biennial gas cost allocation proceeding.

California Public Utilities Commission. (2018, November 8). Resolution E-4949 approving Pacific Gas & Electric battery procurements with modifications. Retrieved from http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M240/K050/240050937.PDF

Chaudhury, S. (2015, November 19). Testimony on behalf of Southern California Gas Co. and San Diego Gas & Electric. California Public Utilities Commission Application No. 15-07-014. Retrieved from https://www.socalgas.com/regulatory/documents/a-15-07-014/TCAP%20Phs%202%20-%20Chaudhury%20Revised%20(clean).pdf

Chow, L., and Brant, S. (2018). *The 2017 resource adequacy report.* California Public Utilities Commission, Energy Division. Retrieved from http://www.cpuc.ca.gov/RA/

Goodman, I., and Marcus, W. (1990, July 23). Joint testimony on behalf of Concerned Citizens of Manitoba, Sierra Club of Western Canada, Manitoba Branch, and Conservation Strategy Association of Manitoba. Manitoba Public Utilities Board proceeding regarding Manitoba Hydro submission in respect to major capital projects.

Horii, B., Price, S., Cutter, E., Ming, Z., and Chawla, K. (2016). *Avoided costs 2016 interim update.* Energy and Environmental Economics Inc. Retrieved from https://www.ethree.com/wp-content/uploads/2017/01/20160801_E3_-Avoided_Cost-2016-Interim_Update.pdf

Jones, G., and Marcus, W. (2015, March 13). Testimony on behalf of The Utility Reform Network. California Public Utilities Commission Application No. 14-06-014.

Jones, G., and Marcus, W. (2016, July 5). Testimony on behalf of Utility Consumers' Action Network. California Public Utilities Commission Application No. 15-04-012.

Lazar, J. (2016). *Teaching the "duck" to fly* (2nd ed.). Montpelier, VT: Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/teaching-the-duck-to-fly-second-edition/

Maloney, P. (2018, July 3). PG&E to replace 3 gas plants with world's biggest battery projects. *Utility Dive.* Retrieved from https://www.utilitydive.com/news/pge-to-replace-3-gas-plants-with-worlds-biggest-battery-projects/526991/

Marcus, W. (1984, September 21). Testimony on behalf of Cogentrix. North Carolina Utilities Commission Docket No. E-100, Sub 41A. Retrieved from https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=d91cce39-c161-4dfb-b1d4-56677499106f

Marcus, W. (1988, September). *Electric utility planning for the 1990s* [Presentation for the Ontario Legislature Select Committee on Energy].

Marcus, W. (2010a, February 26). Testimony and exhibits on behalf of the Arkansas attorney general. Arkansas Public Service Commission Docket No. 09-084-U. Retrieved from http://www.apscservices.info/pdf/09/09-084-u_151_1.pdf and http://www.apscservices.info/pdf/09/09-084-u_152_1.pdf

Marcus, W. (2010b, October 6). Testimony on behalf of The Utility Reform Network. California Public Utilities Commission Application No. 10-03-014.

Marcus, W. (2010c, October 12). Testimony on behalf of the Bureau of Consumer Protection. Public Utility Commission of Nevada Docket No. 10-06-001/-002. Retrieved from http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2010_THRU_PRESENT/2010-6/4649.pdf

Marcus, W. (2016). *Low carbon grid study: Comparison of 2030 fixed costs of renewables, efficiency, and integration with production cost savings*. JBS Energy.

National Economic Research Associates. (1977a). *A framework for marginal cost-based time-differentiated pricing in the United States.* Palo Alto, CA: Electric Power Research Institute.

National Economic Research Associates. (1977b). *How to quantify marginal costs.* Palo Alto, CA: Electric Power Research Institute. Palo Alto, CA: Electric Power Research Institute.

New York Independent System Operator. (n.d.). *Installed capacity market (ICAP)* [Webpage]. Retrieved from https://www.nyiso.com/installed-capacity-market

Ondieki, A. (2017, December 21). Georgia PSC votes to continue construction at Plant Vogtle. *The Atlanta Journal-Constitution*. Retrieved from https://www.ajc.com/news/local-govt--politics/georgia-psc-votes-continue-construction-plant-vogtle/Tu0ja76KWtR3YGlhaFLTeM/

Pacific Gas & Electric. (2016, December 2). *2017 generation rate case Phase II updated and amended prepared testimony.* California Public Utilities Commission Application No. 16-06-013. Retrieved from https://drpwg.org/wp-content/uploads/2017/07/PGE-09-v1_GRC-2017-PhII_Test_PGE_20161202_396470.pdf

Paice, C. (2013, March 1). Testimony on behalf of PacifiCorp. Public Utility Commission of Oregon Docket No. UE 263. Retrieved from https://edocs.puc.state.or.us/efdocs/UAA/ue263uaa11547.pdf

Phillips, N. (2018, March 23). Testimony on behalf of Energy Producers and Users Coalition. California Public Utilities Commission Docket No. 17-06-030.

PJM. (n.d.). *Capacity market (RPM)* [Webpage]. Retrieved from https://www.pjm.com/markets-and-operations/rpm.aspx

Pollard, T. (2010, June 1). Testimony on behalf of NV Energy. Public Utility Commission of Nevada Docket No. 10-06-001. Retrieved from http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2010_THRU_PRESENT/2010-6/1869.pdf

Public Utilities Commission of Nevada. (2002, March 29). Dockets No. 01-10001 and 01-10002, order in Nevada Power Co. general rate case. Retrieved from http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2001_THRU_2004/2001-10/7107.pdf

Public Utilities Commission of Nevada. (2007, July 17). Dockets No. 06-11022 and 06-11023, modified final order in Nevada Power Co. general rate case. Retrieved from http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2005_THRU_PRESENT/2006-11/12604.pdf

Saxe, W. (2012, March 30). Testimony on behalf of San Diego Gas & Electric. California Public Utilities Commission Application No. 11-10-00. Retrieved from https://www.sdge.com/sites/default/files/Saxe_Revised_Testimony_Ch_3_FINAL%2520_Second%2520Revised__0.pdf

Saxe, W. (2016, February 9). Testimony on behalf of San Diego Gas & Electric. California Public Utilities Commission Application No. 15-04-012. Retrieved from https://www.sdge.com/sites/default/files/Saxe%2520Clean%2520w_Attachments.pdf

Schichtl, J. (2002, October). Revenue allocation testimony on behalf of Southern California Edison. California Public Utilities Commission Application No. 02-05-004.

Southern California Edison. (2014, June 20). *Phase 2 of 2015 general rate case: Marginal cost and sales forecast proposals.* California Public Utilities Commission Application No. 14-06-014. Retrieved from http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/CA145802C8F9719A88257CFD0073857B/$FILE/A.14-06-XXX_2015%20GRC%20Phase%202%20-%20SCE-02%20Marginal%20Cost%20and%20Sales%20Forecast.pdf

Southern California Edison. (2015, October 27). Advice Letter No. 3299-E. Retrieved from https://cpucadviceletters.org/search/?source=&q=3299-E&submit=

Southern California Edison. (2017a, July 7). *2018 general rate case Phase 2 workpapers.* California Public Utilities Commission Application No. 17-06-030. Retrieved from http://www3.sce.com/law/cpucproceedings.nsf/frmMainPage?ReadForm

Southern California Edison. (2017b, November 1). *Errata to Phase 2 of 2018 general rate case: Marginal cost and sales forecast proposals.* California Public Utilities Commission Application No. 17-06-030. Retrieved from http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/F40D6AEFD8622526882581CB007FC097/$FILE/A1706030-%20SCE-02A-2018%20GRC%20Ph2-Various-Errata%20Marginal%20Cost%20and%20Sales%20Forecast.pdf

Strunk, K. (2018, October 15). *Marginal cost of distribution service: Prepared for Central Maine Power Company* (Exhibit Strunk-2). Maine Public Utility Commission Docket No. 2018-00194. Retrieved from https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/CaseMaster.aspx?CaseNumber=2018-00194

Walsh, L. (2013, June 3). Testimony on behalf of NV Energy. Public Utilities Commission of Nevada Docket No. 13-06-002. Retrieved from http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2010_THRU_PRESENT/2013-6/26978.pdf

Xcel Energy. (2018, October 2-4). *Leading the energy future* [Presentation at the Wolfe Research Conference]. Retrieved from investors.xcelenergy.com/file/4025308/Index?KeyFile=1500113448

Part V:

After the Cost of Service Study

27. Using Study Results to Allocate the Revenue Requirement

Ultimately, the purpose of a cost of service study is to inform utility regulators about the relative contribution to costs by the various customer classes as one element in the decision on how to apportion the revenue requirement among classes. In most states, regulators have a great deal of discretion about how they use the results of cost allocation studies. Therefore, the way the results are presented is important because the regulators will want to see important impacts clearly to use their time efficiently.

Embedded cost of service studies and marginal cost of service studies approach this very differently, and we discuss each separately in this chapter. After that, we discuss approaches regulators use to implement, or diverge from, the results of these studies.

27.1 Role of the Regulator Versus Role of the Analyst

The role of the regulator is different from that of the analyst. Regulators typically are appointed or elected into the position based upon their broad perspectives of what "fair, just and reasonable" means in the context of utility regulation and pricing. These perspectives are necessarily subjective.

The analyst, on the other hand, may be tempted to work on a strictly scientific and mathematical basis. This may not adequately serve the needs of the regulator, who may need the analysis to take note of public policy goals, economic conditions in the service territory and other factors.

In the simplest terms, the regulator may need a range of reasonable options for cost allocation and for rate design, based on a range of reasonable analytical options, not a single recommendation based on a single framework or approach. The analyst must be prepared to develop more than one cost allocation study, based on more than one analytical approach, and let the regulator consider the principles guiding each study. The analyst must be prepared to develop multiple approaches to rate design, all sharing the same goals of overall revenue recovery and efficient forward-looking pricing.

27.2 Presenting Embedded Cost of Service Study Results

Embedded cost of service studies typically include conclusions regarding the relative margin to the utility from each customer class. Relative margin is a measure of profitability, based on the revenues, expenses and rate base allocated to each class.[241] Class profitability is often presented in the following forms:

1. Calculated rate of return on rate base (expressed both by class and for the total utility):

   $$\text{rate of return} = \frac{\text{allocated annual operating income}}{\text{allocated rate base}}$$

   Where allocated annual operating income = annual revenues – annual allocated expenses

2. Calculated utility profit margin (expressed both by class and for the total utility):

   $$\text{profit margin} = \frac{\text{annual revenues}}{\text{annual allocated expenses}} - 1$$

3. Ratio of class revenue to total class-allocated costs:

   $$\text{revenue ratio} = \frac{\text{revenues}}{\text{allocated expenses + allocated return}}$$

   Where allocated return = allocated rate base x allowed rate of return

4. Revenue shortfall:

   $$\text{shortfall} = (\text{allocated return + allocated expenses}) - \text{current revenues}$$

5. Percentage increase required for equal rate of return:

   $$\text{increase for equal rate of return} = \frac{\text{shortfall}}{\text{revenues}}$$

Table 45 on the next page shows an illustrative example of the computation of these measures.

241 These computations may use historical revenues and costs or projected revenues and costs.

Table 45. Computing class rate of return in an embedded cost study

	Total	Residential	Small (up to 20 kWs)	Medium (20 to 250 kWs)	Large (more than 250 kWs)	Large primary	Other
Revenues	$117,760,688	$28,116,419	$8,342,138	$26,156,458	$38,730,796	$15,134,759	$1,280,117
Allocated expenses	$112,438,805	$28,297,246	$8,997,362	$23,807,377	$35,927,265	$14,280,041	$1,129,515
Operating income	$5,321,883	-$180,827	-$655,223	$2,349,081	$2,803,532	$854,718	$150,603
Allocated rate base	$87,878,094	$24,935,855	$8,339,503	$18,481,728	$26,069,711	$9,399,629	$651,667
Allocated return	**$5,321,883**	**$1,510,111**	**$505,039**	**$1,119,251**	**$1,578,778**	**$569,240**	**$39,465**
Rate of return	6.06%	-0.73%	-7.86%	12.71%	10.75%	9.09%	23.11%
Profit margin	4.52%	-0.65%	-7.82%	8.94%	7.21%	5.62%	13.33%
Revenue-cost ratio	100.00%	94.33%	87.79%	104.93%	103.27%	101.92%	109.51%
Revenue shortfall (or surplus)		$1,690,938	$1,160,262	($1,229,831)	($1,224,754)	($285,478)	($111,138)
Percentage increase for equal rate of return		6.01%	13.91%	-4.70%	-3.16%	-1.89%	-8.68%

Note: Independent rounding may affect results of calculations.

To the extent that the results of the cost of service study are reliable, the class rates of return indicate which classes are paying more or less than the average return. In the example in Table 45, the rate of return results show that the utility is earning less than the average return from the residential class and the small general service class and more than average from the other classes. These class rate of return results do not provide much information about the size of the revenue shift that would produce equal rates of return (or any class-specific differential return requirement), or whether a negative rate of return represents a very serious situation.

The profit margin, while commonly used in many industries, ignores the return on capital. The revenue-cost ratio provides a more intuitive metric. The most useful results may be the revenue shortfall and the increase required to produce class return equal to the system average return.

These metrics show a very different picture of interclass equity. The residential class may be providing a negative rate of return, -0.73% in Table 45, but its revenues are equal to 94.33% of the system revenue requirement. Because of uncertainties in sampled load data, variation in load patterns among years and the difficulty of defining the causation of many costs, regulators define a "range of reasonableness" of one or more of the profitability metrics. For example, if the regulator considered reasonable the range of revenue-cost ratio from 93% to 107%, it is possible a regulator might find that the residential class is producing a reasonable level of revenue but that small general service customers should be paying a somewhat higher share of system costs than 87.79% and the "other" class (which might be mostly street lighting) should be paying somewhat less than 109.51%.

The cost allocation process usually assumes that all classes and all assets impose the same cost of capital. The results in Table 45 reflect that assumption, effectively stating that an equal return is the goal. In some cases, the regulator may determine that different customer classes impose different financing costs in percentage terms — for example, to reflect the higher undiversifiable risks of serving industrial loads through the economic cycle. In addition, some assets are riskier than others; generation is generally riskier than T&D, while nuclear and coal generation are often regarded as being riskier than other generation. In this situation, the cost of service study could be modified to reflect the differential risks (different required rates of return can be applied to different classes of customers or different categories of utility plant). Or the cost of service study results could be presented in a manner that allows the user to compare the achieved return to the class target return.

To summarize, presenting embedded cost of service study results in multiple ways is often helpful to regulators. The revenue-cost ratio is probably the easiest way for regulators to understand and use the results of cost of service studies in determining the fair, just and reasonable apportionment of costs. It is important to note that the result of this allocation process is to determine a level of revenue that the regulator deems cost-related. The regulator will often apply other non-cost criteria to establish the level of revenue that each customer class will pay.

27.3 Presenting Marginal Cost of Service Study Results

Marginal cost of service studies reach a very different set of conclusions than embedded cost of service studies. While an embedded cost of service study divides up the allowed revenue requirement among classes, a marginal cost of service study measures (over a short-, intermediate- or long-run time frame) the costs that would change as customer count and usage change.

A marginal cost of service study produces a cost for each increment of service: the cost of connecting additional customers, peak capacity at different levels of the system and energy costs by time period. These can be multiplied by customer usage to generate a marginal cost revenue requirement for each class. Table 46 shows an illustrative marginal unit cost result.

Table 46. Illustrative marginal cost results by element

	Units	Cost per unit
Customer connection	Dollars per year	$80
Secondary distribution	Dollars per kW	$40
Primary distribution	Dollars per kW	$80
Transmission	Dollars per kW	$50
Generation capacity	Dollars per kW	$100
Energy by time period		
On-peak	Dollars per kWh	$0.10
Midpeak	Dollars per kWh	$0.07
Off-peak	Dollars per kWh	$0.05

Table 47 shows load research data for an illustrative utility system with three classes with identical kWh consumption but different per-customer usage and very different load shapes. The residential class and secondary commercial class both take power at secondary voltages, but the secondary commercial class has a more peak-oriented usage and 10 times the average consumption per customer.

Table 47. Illustrative load research data for marginal cost of service study

	Units	Residential	Secondary commercial	Primary industrial
Customer connection	# of customers	100,000	10,000	1,000
Secondary distribution	kWs	300,000	320,000	N/A
Primary distribution	kWs	303,000	325,000	250,000
Transmission	kWs	305,000	325,000	255,000
Generation capacity	kWs	307,000	330,000	258,000
Energy by time period				
On-peak	kWhs	245,600,000	396,000,000	206,400,000
Midpeak	kWhs	614,000,000	825,000,000	825,000,000
Off-peak	kWhs	614,000,000	252,600,000	442,200,000
All periods	kWhs	1,473,600,000	1,473,600,000	1,473,600,000
Class load factor		55%	51%	65%

Table 48. Illustrative marginal cost revenue requirement

	Residential	Secondary commercial	Primary industrial	Total
Customer connection	$8,000,000	$800,000	$80,000	$8,880,000
Secondary distribution	$12,000,000	$12,800,000	N/A	$24,800,000
Primary distribution	$24,240,000	$26,000,000	$20,000,000	$70,240,000
Transmission	$15,250,000	$16,250,000	$12,750,000	$44,250,000
Generation capacity	$30,700,000	$33,000,000	$25,800,000	$89,500,000
Energy by time period				
On-peak	$24,560,000	$39,600,000	$20,640,000	$84,800,000
Midpeak	$42,980,000	$57,750,000	$57,750,000	$158,480,000
Off-peak	$30,700,000	$12,630,000	$22,110,000	$65,440,000
Total	$188,430,000	$198,830,000	$159,130,000	$546,390,000
Average marginal cost per kWh	$0.128	$0.135	$0.108	$0.124

The primary industrial class has a less peak-oriented usage and 100 times the average consumption per customer of the residential class.

Table 48 combines the marginal costs by element with the load research data to compute a marginal cost revenue requirement for each class, as well as the combined total.

As shown in Table 48, the illustrative MCRR for all classes combined is $546,390,000. It would be pure happenstance if this equaled the embedded cost revenue requirement determined in the rate case. More likely, the revenue requirement will be significantly more or less. The next step in a marginal cost of service study is reconciliation between the MCRR results and the establishment of class-by-class responsibility for the embedded cost revenue requirement.

There are two commonly used methods to reconcile the class marginal cost responsibility, as determined by a marginal cost of service study, to the utility embedded cost revenue requirement determined in the rate proceeding. The first method is equal percentage of marginal cost, which itself has two variants. The second is the inverse elasticity rule derived from Ramsey pricing. The approaches are very different.

In the EPMC approach, the embedded cost revenue requirement is compared with the total of the class marginal cost revenue requirements, also known as the system MCRR. For example, we offer two possible situations in tables 49 and 50 — one where the marginal cost is less than the revenue requirement, the other where it is more — and show the result of adjusting the revenue for each class by a uniform percentage. The class marginal cost revenue requirements

Table 49. EPMC adjustment where revenue requirement less than marginal cost

	Residential	Secondary commercial	Primary industrial	Total
Marginal cost revenue requirement	$188,430,000	$198,830,000	$159,130,000	$546,390,000
Embedded cost revenue requirement				$500,000,000
Ratio of embedded cost to marginal cost				92%
Reconciled revenue requirement	$172,431,779	$181,948,791	$145,619,429	$500,000,000

Table 50. EPMC adjustment where revenue requirement more than marginal cost

	Residential	Secondary commercial	Primary industrial	Total
Marginal cost revenue requirement	$188,430,000	$198,830,000	$159,130,000	$546,390,000
Embedded cost revenue requirement				$600,000,000
Ratio of embedded cost to marginal cost				110%
Reconciled revenue requirement	$206,918,135	$218,338,549	$174,743,315	$600,000,000

are adjusted by the ratio of the embedded cost revenue requirement to the system MCRR, resulting in the amount of the embedded cost revenue requirement that each class is responsible for. In Table 49, the cost responsibility for each class is reduced 8% below the marginal cost of service.

It is important to note that the result of this allocation process is to determine a level of revenue that the regulator deems cost-reflective. The regulator often will apply other non-cost criteria to establish the level of revenue that each customer class will pay.

The EPMC is often functionalized, particularly in jurisdictions where power supply is a competitive non-utility service. Assume for purposes of the illustration in Table 50 that the total embedded cost revenue requirement of $600 million comprises $400 million of generation costs, $60 million of transmission costs and $140 million of distribution costs. Table 51 shows how to reconcile costs for each function separately, which are then used to calculate the overall responsibility of each class for the embedded cost revenue requirement.

The illustrative functionalized EPMC results in Table 51 are close to the total EPMC results but slightly higher for

Table 51. Illustrative functionalized equal percentage of marginal cost results

	Residential	Secondary commercial	Primary industrial	Total
Distribution				
Customer connection	$8,000,000	$800,000	$80,000	$8,880,000
Secondary distribution	$12,000,000	$12,800,000	N/A	$24,800,000
Primary distribution	$24,240,000	$26,000,000	$20,000,000	$70,240,000
Marginal cost revenue requirement	$44,240,000	$39,600,000	$20,080,000	$103,920,000
Embedded cost revenue requirement				$140,000,000
Reconciled distribution revenue requirement	$59,599,692	$53,348,730	$27,051,578	
Transmission				
Marginal cost revenue requirement	$15,250,000	$16,250,000	$12,750,000	$44,250,000
Embedded cost revenue requirement				$60,000,000
Reconciled transmission revenue requirement	$20,677,966	$22,033,898	$17,288,136	
Generation				
Capacity	$30,700,000	$33,000,000	$25,800,000	$89,500,000
Total energy	$98,240,000	$109,980,000	$100,500,000	$308,720,000
Marginal cost revenue requirement	$128,940,000	$142,980,000	$126,300,000	$398,220,000
Embedded cost revenue requirement				$400,000,000
Reconciled generation revenue requirement	$129,516,348	$143,619,105	$126,864,547	
Total reconciled revenue requirement	$209,794,006	$219,001,733	$171,204,261	$600,000,000

Table 52. Total EPMC results with lower marginal generation costs

	Residential	Secondary commercial	Primary industrial	Total
Marginal cost revenue requirement	$133,170,000	$137,240,000	$103,720,000	$374,130,000
Embedded cost revenue requirement				$600,000,000
Ratio of embedded cost to marginal cost				160%
Reconciled revenue requirement	$213,567,476.55	$220,094,619.52	$166,337,903.94	$600,000,000

residential and slightly lower for primary industrial customers.

However, if the marginal generation costs are considerably lower, functionalization can have a different impact. Assume that marginal energy costs are half of the estimates in Table 48 and marginal generation capacity costs are 80% of those in Table 48 (e.g., because of low gas prices, a shorter time horizon for cost estimation and excess capacity). These results are shown in tables 52 and 53.

As shown in Table 53, functionalization blunts the impact of lower marginal generation costs. Compared with Table 52, the residential class actually has a lower share of the embedded cost revenue requirement under functionalization with lower marginal generation costs. Table 54 on the next page compares the results for the residential class from tables 50, 51, 52 and 53.

Comparing the two functionalization scenarios, the residential share of embedded costs ends up very slightly higher in the lower marginal generation scenario, but the difference is less than 1%.

The second general approach used for marginal cost of service study application is the inverse elasticity rule.

Table 53. Functionalized EPMC example with lower marginal generation costs

	Residential	Secondary commercial	Primary industrial	Total
Distribution				
Customer connection	$8,000,000	$800,000	$80,000	$8,880,000
Secondary distribution	$12,000,000	$12,800,000	N/A	$24,800,000
Primary distribution	$24,240,000	$26,000,000	$20,000,000	$70,240,000
Marginal cost revenue requirement	$44,240,000	$39,600,000	$20,080,000	$103,920,000
Embedded cost revenue requirement				$140,000,000
Reconciled distribution revenue requirement	$59,599,692	$53,348,730	$27,051,578	
Transmission				
Marginal cost revenue requirement	$15,250,000	$16,250,000	$12,750,000	$44,250,000
Embedded cost revenue requirement				$60,000,000
Reconciled transmission revenue requirement	$20,677,966	$22,033,898	$17,288,136	
Generation				
Capacity	$24,560,000	$26,400,000	$20,640,000	$71,600,000
Total energy	$49,120,000	$54,990,000	$50,250,000	$154,360,000
Marginal cost revenue requirement	$73,680,000	$81,390,000	$70,890,000	$225,960,000
Embedded cost revenue requirement				$400,000,000
Reconciled generation revenue requirement	$130,430,165	$144,078,598	$125,491,237	$400,000,000
Total reconciled revenue requirement	$210,707,823	$219,461,226	$169,830,951	$600,000,000

Table 54. Residential embedded cost responsibility across four scenarios

	High generation marginal costs	Low generation marginal costs
Total EPMC results	$206,918,135	$213,567,477
Functionalized EPMC results	$209,794,006	$210,707,823

As discussed in Chapter 24, it is based on Ramsey pricing, an economic theory that efficiency is enhanced when the elements of the rate that are "elastic" with respect to price are set equal to some measure of marginal cost, and that adjustments to reconcile the revenue requirement should be applied to the least elastic component or components in order to maximize economic efficiency. This approach was popular during the era when marginal costs were significantly higher than average costs reflected in the revenue requirement.[242] For that reason, we show the application of the inverse elasticity rule only for a situation where the revenue requirement is lower than system marginal costs.

The least elastic element of utility service is often deemed to be the connection to the grid: the customer-related component of costs such as billing and collection, and the secondary service lines to individual structures. Evidence suggests this to be true historically. Whether utilities assess a monthly customer charge of $5 or $35, nearly all residences and businesses subscribe to electric service, although customer charges likely influence decisions whether to master-meter multifamily buildings, accessory dwelling units and offices. Economists generally agree that price more significantly influences actual customer usage of kWs and kWhs.

This may become significantly different where customers have more feasible choices to disconnect from the grid or obtain some services from on-site generation and storage. For example, pedestrian crossing signals often are now being installed with solar panels and batteries, without any connection to the grid. This phenomenon potentially could extend to larger users, depending on the levels of monthly customer charges, usage-related charges, and solar and storage costs.

Table 55 shows a marginal cost reconciliation of the same costs in Table 49 but by first reducing the customer and secondary costs by class and then applying an EPMC adjustment to the residual class marginal costs until the revenue requirement is reached.

In this illustrative example, the residential class benefits substantially and the secondary commercial class benefits somewhat compared with the straightforward application of the EPMC method in Table 49. As a result, the primary industrial class ends up paying a larger share of the overall embedded cost revenue requirement.

Table 55. Use of inverse elasticity rule

	Residential	Secondary commercial	Primary industrial	Total
Marginal cost revenue requirement	$188,430,000	$198,830,000	$159,130,000	$546,390,000
Customer connection costs	$8,000,000	$800,000	$80,000	
Secondary distribution costs	$12,000,000	$12,800,000	N/A	
Adjusted marginal cost revenue requirement	$168,430,000	$185,230,000	$159,050,000	$512,710,000
Embedded cost revenue requirement				$500,000,000
Ratio of embedded cost to adjusted marginal cost				98%
Reconciled revenue requirement	$164,254,647	$180,638,178	$155,107,176	$500,000,000

242 Until the early 1980s, for example, Oregon excluded customer and joint costs from the marginal cost reconciliation process on the theory that these were highly inelastic components of customer demand — to simply be connected to the system. When overall rates rose and later costs declined, Oregon moved to an EPMC approach (Jenks, 1994, p. 12).

27.4 Gradualism and Non-Cost Considerations

This section discusses the methods regulators use to reach a decision on the fair apportionment of the revenue requirement based on both cost and non-cost considerations. Regulators frequently depart from the strict application of cost of service study results. Often, regulators reject the studies that are presented due to inclusion of one or more allocation factors they find unacceptable. A common example is the use of the minimum system method to measure a customer-related share of electric or gas distribution system costs; many regulators have found this methodology as unacceptable today as Bonbright did in 1961. In many cases where multiple studies are presented, the regulator may choose a result that reflects the "range of reasonableness" these studies suggest. In many cases where regulators do accept the results of a specific cost of service study, they may choose to move only gradually in the direction of the accepted study results.

It is quite common for regulators to consider the results of multiple cost of service studies in determining an equitable allocation of costs among customer classes. This can occur in various ways:

- Considering multiple embedded cost of service studies or marginal cost of service studies using different classification or allocation methods, to determine a range of reasonableness.
- Considering both embedded cost of service studies as an indicator of current costs and marginal cost of service studies as an indicator of cost trajectories in setting a reasonable cost allocation.

For example, in one docket, the Washington Utilities and Transportation Commission compared results of four cost of service studies before making a decision on cost allocation, with the results shown in Table 56 (1984, p. 46).[243]

Table 56. Consideration of multiple cost of service studies

Source of study	Revenue as percentage of revenue requirement by class: Residential	Small general service	Large general service	Extra large general service
Utility	91%	113%	110%	108%
Industrial advocate	91%	112%	110%	110%
Consumer advocate	93%	115%	105%	104%
Low-income advocate	97%	113%	103%	99%

Source: Washington Utilities and Transportation Commission. (1984). Cause U-84-65, third supplemental order in rate case for Pacific Power

Based on multiple studies using widely different methodologies for the classification and allocation of generation, transmission and distribution costs, the commission was able to determine a fair allocation of the revenue requirement responsibility, taking into account specific elements within each study where it ruled for or against those elements. The end result of multiple studies produced a range of reasonableness in the allocation of costs. The commission adjusted revenues gradually toward the common result of the studies: that residential customers were paying slightly less than their share of costs and that small and large general service customers were paying slightly more than their share.

Gradualism is the movement only partway toward the results of cost of service studies in apportioning the revenue requirement based on an accepted cost study. If a cost of service study indicates that a class is paying much less than its fair share of the revenue requirement, immediately moving it to pay its full share of allocated costs may result in excessive financial pain and dislocation for the affected customers. Regulators sometimes impose generic limits on rate changes (such as limiting the increase for any class to 150% of the system average increase) and often impose ad hoc limits, based on the facts of the case.[244]

243 Similarly, the Wisconsin Public Service Commission has routinely reviewed multiple cost of service studies and selected a revenue allocation without specifically relying on any one study. See Wisconsin Public Service Commission (2016, pp. 31-32): "As a result, the Commission finds that it is reasonable to continue its long-standing practice of relying on multiple models, as well as other factors, such as customer bill impacts, when determining the final allocation of the revenue requirement."

244 Where this sort of guideline takes the form of "no class will be assigned more than twice the rate increase applied to any other class," it is known as 2:1 gradualism.

There are several reasons a regulator will move gradually, including:

- To avoid rate shock on any individual customer class. Rate shock is often defined as a rate increase of more than 5% or 10% at any one rate adjustment. There is no firm standard, but many regulators hesitate to impose a rate adjustment that upsets the budgets of households or businesses. If an accepted cost of service study (or group of studies) suggests that one class should receive a 15% rate increase while others require no increase, a regulator may reasonably determine to spread the rate increase across all classes in a way that avoids rate shock within any one.
- To recognize that the cost of service study is a snapshot and that costs and cost responsibility may shift over time. The allocation of cost may vary significantly from one year to another because of factors such as fluctuating weather (which may change the peakiness of load, shift highest loads from summer to winter or dramatically change irrigation pumping loads). Under these circumstances, shifting revenue requirements back and forth among classes in each rate proceeding will not improve equity. Unnecessary volatility in prices may confuse customers, complicate budgeting and create unnecessary political and public-relations problems.
- To avoid overcorrecting a temporary imbalance in revenue responsibility, in recognition that technology is evolving and the cost structure will be different in the future. Cost of service studies measure costs based only on either test-year results of operations (embedded cost of service studies) or an estimate of future costs (marginal cost of service studies) at the time they are produced. Costs change dramatically over time as fuel costs change, new technologies become available and older assets shift to new roles. For example, the study may reflect the costs of legacy steam-electric generation scheduled for retirement in the next few years, to be replaced by demand response measures and distributed storage, which will also have T&D benefits.
- To avoid perceptions of inequity and unfairness. Bonbright (1961) identified perceptions of equity and fairness as a core principle of rate design, but they represent an overwhelmingly subjective metric. Many regulators, for example, have declined to reduce rates for any customer class in the context of an overall increase but may apply a lower increase to some classes than others. This is a matter of judgment, so this manual cannot provide any policy guidance on the right approach.

Each of these factors may represent a reasonable basis for deviating from precise recovery from each customer class of its full allocated cost. Legislatures generally grant regulators a great deal of flexibility in determining rates that are fair, just and reasonable and expect them to consider such factors in their decisions.

In addition to the principles of gradualism discussed in this section, many regulators consider non-cost factors in determining a fair apportionment of costs, including:

- Retention of load that cannot (or will not) pay for its fully allocated cost but can pay more than its incremental cost and thus can reduce the revenue requirement borne by other classes. Examples include electric space heat customers in summer-peaking utilities, irrigation customers in winter-peaking utilities and industrial customers facing global competition. Utilities frequently develop load retention tariffs to keep those customers on the system, contributing to paying off embedded costs. Charging full embedded cost to those tariff classes could result in higher, not lower, bills for other customers if the price-sensitive customers depart the system.

  The objective in those cases is to maximize the benefits to the customers paying full cost, without any particular concern about the interest of the class paying the reduced rate. If faced with the potential loss of a major industry, a regulator may opt to offer a rate significantly below the cost basis that would otherwise apply. Some, for example, have relied on an embedded cost of service study to determine the general allocation of costs among classes but relied on a short-run marginal cost of service study to determine a "load retention" or "economic development" rate to retain or attract a major customer. This is often done in recognition that failure to do so would result in the loss of sales, not to mention broader harms (e.g., increased unemployment) to the jurisdiction. The loss of sales could trigger a difficult regulatory decision on whether to apportion the surplus capacity that results among the remaining customers or to impose a regulatory disallowance on the utility, forcing utility investors to absorb the stranded asset costs.

- Serving loads that would otherwise impose higher environmental costs of alternative fuels. Examples include shore-service rates to discourage ships from running their high-emitting onboard generation while in port, special rates to displace on-site diesel generation and special rates for irrigators that would otherwise use diesel-powered pumps.
- Protection of vulnerable customers, for their own sake. Utilities, regulators and even legislatures seek to reduce the burden on groups of customers that are financially stressed. Most frequently, the target group is low-income residential customers, but the same approach is applied in some places for agricultural customers, important employers facing competition from outside the service territory and the like.

It is beyond the scope of this manual to attempt to identify the entire variety of non-cost factors a regulator may consider. The process of cost allocation does not occur in a vacuum but rather in the context of broader social and political currents.

28. Relationship Between Cost Allocation and Rate Design

At its heart, cost allocation is about equity among customer classes. Rate design has a different set of goals.

As indicated at the outset, cost allocation is the second of three steps in the rate-making process, beginning with the determination of the revenue requirement and ending with the design of rates. This manual has been careful to explain that these are separate phases of a proceeding and may have separate principles that apply, and the results may not always flow neatly from one phase to the next.

At its heart, cost allocation is about equity among customer classes — providing an analytical basis for assigning the revenue requirement to the various classes of customers on a system. This may be done strictly on the basis of an analytical cost of service study or, more often, using quantitative cost of service studies as a starting point, with broader considerations including gradualism, economic impacts on the service territory and attention to changes anticipated in future costs.

Rate design has a different set of goals. Rates must be sufficient to provide the utility with an opportunity to recover the authorized revenue requirement, but rate design is also about equity among customers within a class and about understandable incentives for customers to make efficient decisions about their consumption that will affect future long-term costs. It is common for a regulator to use a backward-looking embedded cost allocation method and a forward-looking rate design approach that considers where cost trajectories will go. Rate design can also incorporate public policy objectives, including environmental and public health requirements. In *Smart Rate Design for a Smart Future* (Lazar and Gonzalez, 2015), RAP articulated three principles for modern rate design:

- Principle 1: A customer should be able to connect to the grid for no more than the cost of connecting to the grid.
- Principle 2: Customers should pay for grid services and power supply in proportion to how much they use these services and how much power they consume.
- Principle 3: Customers that supply power to the grid should be fairly compensated for the full value of the power they supply.

These principles provide guidance on how to modernize rate design, in conjunction with the traditional considerations of customer bill impacts and understandability.

28.1 Class Impacts Versus Individual Customer Impacts

The data used to examine changes in overall costs and bills for rate design are often much more granular, among types of customers, than data used for cost allocation.

Most cost allocation studies group customers into a relatively small number of classes for analysis. This is done for analytical simplicity, to provide the regulator a general guide to cost responsibility among the classes. Some do this grouping by voltage level, some by type of customer (e.g., residential vs. commercial vs. irrigation), but nearly all utilities have more individual tariffs than classes examined in the cost of service study. For example, "residential" may be a single class in the cost of service study, but separate tariffs may apply to single-family, multifamily, electric heating, electric water heating and electric vehicle loads. A utility may have a default rate design (e.g., inclining block) and one or more optional rate designs (e.g., TOU or seasonal customers). "Secondary general service" may be a single class in the cost of service study including all secondary voltage business customers that are nonresidential but will include urban commercial retail and office customers, as well as rural agricultural customers.

It is common to have separate rate tariffs that focus on the usage by specific groups of customers to enable them to control their bills by focusing their attention on elements of their consumption they can easily manage. A cost of service study provides broad guidance on how costs should be apportioned among customer classes. The result may be a uniform percentage allocation of a rate increase (or decrease) or one that is differentially apportioned among the customer classes.

The class definitions for cost allocation typically look at large groups of customers with similar service characteristics. Rate design often looks at smaller groups of customers with similar usage characteristics or even individual customers. For example, a shift of rate design from an inclining block rate to a time-varying rate may result in sharp increases in the bills for some customers with low usage.

The municipal utility for Fort Collins, Colorado, encountered this situation in its 2018 rate review and included a "tier charge" for all usage over 700 kWhs in part to avoid this kind of impact. The cost of service study did not contain sufficient detail to provide an analytical framework for this decision, but the rate design analysis showed that apartment residents and other small users would be adversely affected without this consideration of customer impacts. Similarly, when the Arizona Corporation Commission adopted inclining block rates in the 1980s for Arizona Public Service Co., it also created optional residential TOU and demand-charge rates to provide a pathway for larger residential users to avoid sharp bill impacts by shifting usage to lower-cost periods.

28.2 Incorporation of Cost Allocation Information in Rate Design

It is often the case that the information developed in the process of cost allocation is relevant to important issues in rate design. In most states, embedded cost of service studies are used to allocate costs among customer classes,[245] but regulators consider long-run marginal costs, either implicitly or explicitly, in designing rates within classes. The Washington Utilities and Transportation Commission stated in adopting an embedded cost framework that it wanted to be looking ahead in some parts of the rate-making process:

> In order to obtain forward-looking embedded costs which are required by the generic order, it is necessary to use historical cost for allocation to production plant and other categories, followed by a classification method which recognizes the current cost relationships between baseload and peak facilities (1982, p. 37).

This mix of embedded cost principles for cost allocation and marginal cost principles for rate design reflects a sense of balance between the notions of equity of overall cost allocation between classes and efficiency of rates applied within classes. Even in states where the embedded cost of service study does not contain any time differentiation of generation, transmission or distribution costs, regulators have adopted time-varying retail rates for many classes of customers to encourage behavior expected to reflect forward-looking and avoidable costs.

Although marginal cost of service studies typically do differentiate between time periods, even these studies provide limited guidance for rate design, simply because the factors that affect utility system design and construction may not be understandable to consumers. The core principles from Bonbright and many others — that rates be simple, understandable and free from confusion as to calculation and application — remain important, no matter what the results of a cost study may suggest. As a result, further refinements to this information may be necessary to apply in rate design.

Many analysts who still use legacy cost allocation techniques or otherwise problematic methods argue that this analysis is relevant to rate design. In most cases, this is doubling down on a mistake. For example, use of the minimum system method for determination of residential customer charges is a mistake because it greatly overstates the cost of connecting a customer to the grid. However, some

245 As discussed in Section 6.1, there is a direct relationship between an embedded cost of service study and the revenue requirement, which makes it an analytically convenient method of dividing the revenue requirement. Using a marginal cost of service study for cost allocation requires additional adjustments to ensure the correct amount of revenue will be recovered.

states allow use of the minimum system method for cost allocation between classes but require the narrower basic customer method for the determination of customer charges within classes in the rate design process.

28.3 Other Considerations in Rate Design

Regulators often include non-cost considerations in the design of rates. This is an appropriate exercise of their responsibility to ensure that rates are fair, just and reasonable. These terms are, by their nature, subjective, with ample room to include considerations other than electric utility costs in the ultimate decisions. For example, the Washington Utilities and Transportation Commission has stated:

> We recognize the substantial elements of judgment which are involved in the development of any cost of service study. We also recognize that many factors beyond an estimate of cost of providing service are important in the design of rates. These factors … include acceptability of rate design to customers; elasticities of demand, or the variation of demand when prices change; perceptions of equity and fairness; rate stability over time; and overall economic circumstances within the region.
>
> Based upon all these factors, we believe it is necessary to make some movement toward the cost of service relationships which the respondent has presented, although we do not believe that it is appropriate to fully implement the study in this proceeding. For policy reasons, including those stated above, we do not feel it necessary to infer that any cost of service study should be automatically or uncritically accepted and applied in rate design (1981, p. 24).

Some jurisdictions also explicitly incorporate broader societal costs, particularly environmental and public health externalities, into rate design decisions. In Massachusetts, the Department of Public Utilities has longstanding principles of efficiency that include: "The lowest-cost method of fulfilling consumers' needs should also be the lowest-cost means for society as a whole. Thus, efficiency in rate structure means that it is cost-based and recovers the cost to society of the consumption of resources to produce the utility service" (Massachusetts Department of Public Utilities, 2018, p. 6).

These types of broader policy priorities can be reflected in many ways. For example, a state with a policy to encourage customer-owned renewable energy supply may develop rates that are favorable to customers with solar panels. A state with a policy to encourage energy conservation may have an additional reason to adopt inclining block rates. A state with real or perceived peak load limitations may prefer a critical peak pricing rate.

One very common public policy goal is the use of postage stamp rates, with the same rates applying to all customers of a class within a service territory. As discussed in Section 5.2, there are trade-offs in terms of the number of customer classes. A larger number of customer classes may capture more cost-based distinctions than a smaller number. For example, in most utility systems, multifamily customers that are less expensive to serve pay the same rates as single-family customers, and rural customers pay the same rates as urban. Having separate customer classes to reflect these distinctions would arguably lead to a much more equitable distribution of costs. These are probably the largest deviations from cost principles in today's utilities — dwarfing other deviations such as perceived undercharging of residential customers as a class or of solar customers as a subclass.

However, additional customer classes can lead to additional administrative and oversight costs. Furthermore, regulators, utilities and stakeholders must all have confidence that there are true cost differentials among the customer types and that there will be little controversy in applying these differentials. Some analysts object to customer classes based on adoption of particular end uses, although this may serve as a proxy for significantly different usage profiles. Some analysts may prefer separate classes for distinct types of customers, such as schools and churches. As discussed previously, rates that automatically reflect cost distinctions (e.g., time-varying rates or different residential customer charges for single-family and multifamily) can accomplish the same objective as the creation of additional customer classes, often with additional efficiency benefits from improved pricing.

Proper data must be available so all parties can scrutinize whether distinctions made between customer classes are based on cost and not improper motives like price discrimination.

Proper data must be available to all parties so they can scrutinize the distinctions made between customer classes and whether these are truly based on cost and not improper motives like price discrimination. Some analysts feel that a smaller number of rate classes will be fairer on balance, and many equity issues within a customer class can be dealt with through rate design.

Other common non-cost considerations come into play in designing rates for low- and limited-income consumers. In an engineering sense, these customers may differ very little from other residential consumers in the metrics typically used in a cost of service study. But regulators, on their own initiative or under direction from their legislatures, may adopt non-cost-based discounts for these customers. The same non-utility cost principles often apply to special rates for new industrial customers to encourage economic development within a service territory.

Lastly, in some states, legislatures have dictated some elements of rate design, constraining the discretion of the commission. In Connecticut and California, statutory limitations on residential customer charges dictate, respectively, the basic customer method[246] and a cap of $10 a month adjusted for inflation.[247]

246 See Connecticut General Statutes, Title 16, § 16-243bb, limiting the residential fixed charge to “only the fixed costs and operation and maintenance expenses directly related to metering, billing, service connections and the provision of customer service.”

247 California Public Utilities Code § 739.9(f).

Works Cited in Part V

Bonbright, J. (1961). *Principles of public utility rates.* New York, NY: Columbia University Press.

Jenks, B. (1994, September). *The incredible, disappearing residential exchange benefit.* Oregon Citizens' Utility Board.

Lazar, J., and Gonzalez, W. (2015). *Smart rate design for a smart future.* Montpelier, VT: Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future/

Massachusetts Department of Public Utilities. (2018, January 5). Docket No. 17-05, order establishing Eversource's rate structure. Retrieved from https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9170110

Washington Utilities and Transportation Commission. (1981). Cause U-81-41, second supplemental order in rate case for Puget Sound Power and Light Co.

Washington Utilities and Transportation Commission. (1982). Cause U-82-10, second supplemental order in rate case for Washington Water Power.

Washington Utilities and Transportation Commission. (1984). Cause U-84-65, third supplemental order in rate case for Pacific Power.

Wisconsin Public Service Commission. (2016, December 22). Docket No. 6680-UR-120, final decision in rate case for Wisconsin Power and Light Co. Retrieved from http://apps.psc.wi.gov/vs2015/ERF_view/viewdoc.aspx?docid=295820

Conclusion

Cost allocation is a complex exercise dependent on sound judgment. No less an authority than the U.S. Supreme Court has made this point:

> A separation of properties is merely a step in the determination of costs properly allocable to the various classes of services rendered by a utility. But where, as here, several classes of services have a common use of the same property, difficulties of separation are obvious. Allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science.[248]

These words from Justice William Douglas are just as applicable today as they were when written in 1945. What has changed since 1945 are the facts, which in turn require new judgments. In particular, advancements in technology have had a great impact and reverberating effects on our power system. Multiple aspects of our power system are continuing to evolve, and cost allocation methods must change to reflect what we are experiencing. Over the past few decades, key changes in the power system that have consequences on how we allocate costs include:

- Renewable resources are replacing fossil-fueled generation, substituting invested capital in place of variable fuel costs.
- Peaking resources are increasingly located near load centers, eliminating the need for transmission line investment to meet peak demand served by peaking units. Long transmission lines are often needed to bring not only baseload coal and nuclear resources but also wind and other renewable resources, even if they may have limited peaking value relative to their total value to the power system.
- Advanced battery storage is a new form of peaking resource — one that can be located almost anywhere on the grid and has essentially no variable costs. The total costs of storage still need to be assigned to the time period when the resource is needed, to ensure equitable treatment of customer classes.
- Consumer-sited resources, including solar and storage, are becoming essential components of the modern grid. The distribution system may also begin to serve as a gathering system for power flowing from locations of local generation to other parts of the utility service territory, the opposite of historical top-down electric distribution.
- Short-run variable costs are generally diminishing as capital and data management tools are substituted for fuel and labor.

Simply stated, this means that many of the cost allocation methods used in the previous century are not appropriate to the electric utilities of tomorrow. As we've discussed in this manual, new methods, new metrics and new customer class definitions will be needed. The role of the cost analyst remains unchanged: We are assigned the task of determining an equitable allocation of costs among customer classes. The methods analysts used in the past must give way to new methods more applicable to today's grid, today's technologies and today's customer needs.

This manual has identified current best practices in cost allocation methodology. These will also need to evolve to keep up with the technological changes our electric system is experiencing. Perhaps the most important evolution in methodology recognizes that utility grids are built for the general purpose of providing electricity service. The largest single cost of building the grid is to ensure that it provides kWhs to customers during all hours of the day and night. Thus, similar to the way we price gasoline, groceries and clothing, most costs of the grid should be assigned on a usage basis, recovered in the sale of each kWh. In this same context, the cost of connecting to the grid may be a customer-specific cost. For items such as groceries and clothing, customers bear

248 Colorado Interstate Gas Co. v. Federal Power Commission, 324 U.S. 581, 589 (1945).

the cost of "connecting to the grid," by traveling to a retailer. The balance of the "grid" cost can and should be recovered in the price of each unit.

As we have noted in this manual, a variety of cost allocation methods are currently in use across the country. There are certain changes in cost allocation methodology that will be specific to the approach appropriate for different regions. However, this manual identifies certain changes in methodology that will be of general application across the continent, including:

- Assigning costs to time periods of usage (such as critical peak, on-peak, midpeak, off-peak and super-off-peak), rather than the much coarser metrics of "demand" and "energy" used in the past.
- Differentiating among types of generation, recognizing that some are relied on during peak periods, while others are relied on during all hours or some other subset of hours during the year.
- Considering that the utilization of some utility assets may have changed. Plants that were built as baseload units may now be operated only intermittently, as newer resources with different cost characteristics become more valuable to the grid.
- Realizing that most utility assets serve shared customer loads, with different customers using these at different times. The application of time-differentiated cost analysis to apportioning the costs of a shared system becomes critical.
- Recognizing that smart grid systems make it possible to provide better service at lower cost by including targeted energy efficiency and demand response measures to meet loads at targeted times and places, and thus that those costs must, to some extent, follow the savings they enable.

Embedded cost of service modeling practices must also be modified to account for new changes in the electric system. Key in this is the need to consider each asset and resource for the purposes for which it was constructed and the functions it provides today. In general, assets that serve in all hours should have their costs assigned to all hours; those that serve only in limited periods, or are upsized at additional cost for certain periods, should have costs assigned to the relevant periods. The traditional methods of defining costs as customer-related, demand-related and energy-related must give way to time-varying purposes, so costs can be fairly assigned among time periods in the new era.

Not surprisingly, marginal cost methods also must change. Although these are used in fewer states than embedded cost methods, they also need significant changes to be relevant in the modern electric industry environment. Methods must be updated to recognize both (1) the substitution of capital costs for short-run variable operating costs and (2) DER solutions for generation, transmission and distribution.

Whether the cost allocation method has changed or not, it is always important to present cost allocation data clearly, so that regulators can do their job. Most regulators expect quality technical analysis of costs but apply judgment in the application of those results. They may want to consider the results of multiple studies using different methods. Gradualism in the implementation of change has important value to avoid sudden impacts that may devastate residential, commercial or industrial customers. Data and analytical results should be presented in a way that informs regulators. We must still recognize, however, that "allocation of costs is not a matter for the slide-rule," as Justice Douglas wrote nearly a century ago.

This manual attempts to define methods that are relevant today and will be applicable into the future as the industry continues to evolve and as technology continues to drive changes in costs, investment and expenses. The reasoned analyst will always need to apply creativity and skill to the task of allocating costs.

Appendix A: FERC Uniform System of Accounts

Since about 1960, the Federal Energy Regulatory Commission has required electric utilities to follow its Uniform System of Accounts. The system has accounts for both a utility's balance sheet and its income statement.[249]

The balance sheet accounts include 100 to 299, with 300 to 399 providing more detail on utility plant and accounts 430 to 439 providing more detail on retained earnings. Income statement accounts are 400 to 499, excepting 430 to 439. Many of the accounts relevant to utility rate case filings and cost of service studies are identified below.

100 to 199: Assets and Other Debits

The asset accounts include plant in service (Account 101) and depreciation reserve (Account 108) — which constitute plant in rate base — and construction work in progress (Account 107), along with a number of smaller accounts.

In most states, not all of these accounts are in rate base,[250] but the ones that typically are include:

- Accounts receivable other than from customers (Account 143).
- Fuel inventories (accounts 120 — nuclear, 151 and 152).
- Emissions allowances inventories (Account 158).
- Materials and supplies inventories (Account 154).
- Prepayments (Account 165, for items such as postage and insurance and in some cases pensions).
- Certain deferred debits (Account 182, especially regulatory assets for which the utility has invested money but not recovered it).
- Deferred tax assets (Account 190, usually netted with accounts 282 and 283).

200 to 299: Liabilities and Other Credits

The liability accounts (200 series) have some accounts traditionally in rate base and some not.

The largest elements included as offsets that reduce rate base are accumulated deferred income tax liabilities (accounts 282 and 283). In addition, rate base reductions come from:

- Customer deposits (Account 235, in most but not all states).
- Customer advances for construction (Account 252).[251]
- Deferred credits (regulatory liabilities, in Account 254).
- Unfunded pension liabilities (no specific account).

Elements of the amount of debt and equity, including discounts on issuance and amounts arising from refinancing past debt, are included in the capital structure, while most accounts payable are subsumed in the cash working capital computation.

300 to 399: Plant Accounts

The accounts in the 300 series are plant-in-service accounts (providing more detail into utility plant included in Account 101, by type). The accounts are subdivided for electric service[252] into:

Accounts 301 to 303: intangible plant. Today, the costs cover mostly computer software, although there are some

249 The information here comes from Title 18, Part 101 of the Code of Federal Regulations. Retrieved from https://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&SID=054f2bfd518f9926aac4b73489f11c67&rgn=div5&view=text&node=18:1.0.1.3.34&idno=18. For a useful summary, see Phan, D. (2015, August). *Uniform System of Accounts* [Presentation for NARUC]. Retrieved from https://pubs.naruc.org/pub.cfm?id=53720E26-2354-D714-5100-3EBD02A2034E

250 Most states use a cash working capital calculation that encompasses the utility's accounts receivable and accounts payable for utility service (not always uniformly) so that these items are not in rate base directly but are included in the cash working capital calculation. Arkansas is an exception, so this general discussion does not apply. Arkansas' modified balance sheet approach puts most of the asset items in rate base and most of the liabilities (200-series accounts) in the capital structure as zero-cost capital.

251 Unlike customer advances for construction, contributions in aid of construction do not have a specific place in the Uniform System of Accounts but are simply subtracted from the amount of plant included in summary Account 109 and the detailed accounts 364 to 370.

252 The 300-series accounts used for gas, water and so on are different from the electric accounts.

legacy items for paying for franchises. These costs are usually included with general and common plant as an overhead in cost allocation.

Accounts 310 to 317: steam production plant. These costs include costs of coal, oil and gas steam plants; some utilities include combined cycle steam turbines here. Biomass and geothermal plants owned by utilities would also appear here. Most utilities maintain records of these accounts to the level of the power plant, if not the individual unit of each plant, which are reported in each utility's annual report to FERC (FERC Form 1), although they may be summarized in cost of service studies.

Accounts 320 to 326: nuclear plant. Again, utilities maintain separate records for each nuclear plant or unit, which are presented in FERC Form 1.

Accounts 330 to 337: hydroelectric plant. Utilities generally maintain separate records for each hydro plant, which are also required to be filed as part of FERC Form 1. Pumped storage is included with other hydroelectric plant.

Accounts 340 to 347: other power generation. These include a mix of combustion turbines, combined cycles (as some utilities place entire combined cycles in these accounts), reciprocating engines, and wind and solar generation owned by the utility.

Account 348 is for energy storage plant with a generation function, excluding pumped hydro. This is a new addition to the Uniform System of Accounts and includes batteries, flywheels, compressed air and other storage.

Asset retirement obligations are included in each of the broad categories of production plant (accounts 317, 326 and 347). Asset retirement obligations are not included in rate base and are not directly found in cost of service studies. Aside from nuclear power plants (where they are related to the decommissioning fund), these costs only appear indirectly through the calculation of negative net salvage as part of depreciation.

Accounts 350 to 357: transmission accounts. Costs are divided by type of plant, not by the function or voltage level of plant. Account 351 is a recently added account for energy storage plant used on the transmission system.

Accounts 360 to 374: distribution accounts. Of the major accounts, 362 is distribution substations, 364 is poles, 365 overhead wires, 366 underground conduit, 367 underground wires, 368 line transformers (also including capacitors and voltage regulators), 369 services (sometimes divided into overhead and underground subaccounts), 370 meters, 371 installations on customer premises (usually lighting excluding streetlights but may include demand response equipment) and 373 streetlights. Account 363, used very infrequently now, is the FERC account where energy storage plant installed on the distribution system would be included.

Accounts 382, 383 and 389 to 399: general plant or common plant.

Accounts 382 and 383 are for general plant (largely computer systems) used in regional market operations, particularly for utilities that are members of ISOs.

Accounts 389 to 399 include land, buildings, furniture, computer hardware, vehicles and other similar items. Items at specific power plant sites can be allocated with the plant. Others are part of overhead costs. For an electric and gas utility, some items in these accounts can be "electric general plant" (items used at a power plant site, for example), while others are the portion of "common plant" allocated to the electric department of an electric and gas utility. General plant can also be allocated from a holding company serving a number of utilities.

400 to 499: Income and Revenue Accounts

Account 403 (depreciation) and Account 405 (amortization) are subdivided at least by type of plant (different types of production plant, transmission, distribution and general). Many utilities subdivide this further by the FERC plant accounts and by individual power plant or unit.

Account 408 (taxes other than income) is subdivided into accounts for property taxes, payroll taxes and other taxes (usually a small amount).

Current and deferred income taxes are found in accounts 409 and 410 and are usually calculated with significant detail in revenue requirement studies.

The remainder of these accounts do not appear directly in rate cases. Account 426 is noteworthy because it includes nonoperating expenses such as fines and penalties, lobbying, donations and so on. Revenue requirement analysts often try to assess whether costs booked to operating accounts instead belong in this account.

Accounts 433 and 436 to 439 are retained earnings accounts. These accounts, which reflect profits not distributed to shareholders as dividends, do not appear in rate cases.

Accounts 440 to 449 are revenue accounts, using broad customer classes developed by FERC (residential, commercial, industrial, railways, other public authority and sales for resale). These FERC accounts often do not correspond to utility rate classes in a cost allocation study.

Accounts 450 to 456 are revenues that do not come from rates or wholesale transactions. They include late payment charges (Account 450), tariffed service charges (mostly in Account 451), rents (Account 453) and other revenues (Account 456).

500 to 599: Production, Transmission and Distribution Expenses

Production expenses are divided similarly to plant and are broken down at the level of individual plants in FERC Form 1.

Steam production operating expenses are in accounts 500 to 509, and maintenance expenses are in accounts 510 to 514.

Nuclear production operating expenses are accounts 517 to 527, and nuclear maintenance expenses are in accounts 528 to 532.

Hydroelectric production expenses are in accounts 535 to 540, and hydro maintenance expenses are in accounts 541 to 545.

Other production plant expenses are in accounts 546 to 550, and other maintenance expenses are in accounts 551 to 554. Again, the definition includes combustion turbines, wind and solar, as above.

Purchased power is in Account 555; production load dispatching is in Account 556; and miscellaneous production expenses (e.g., power procurement administration, renewable energy credits) are in Account 557.

Transmission operating expenses are in accounts 560 to 567; maintenance expenses are in 568 to 573. Of note, wheeling expenses (transmission by others) are in Account 565, and certain expenses paid to ISOs under FERC tariffs are included as subaccounts of Account 561.

Regional market expenses are in accounts 575 (operating) and 576 (maintenance). The bulk of these costs are expenses paid to ISOs under FERC tariff and some internal market monitoring and similar costs.

Distribution operating expenses follow plant and are in accounts 580 to 590. Corresponding maintenance expenses are in accounts 591 to 598.

600 to 899: Accounts Reserved for Gas and Water Utilities

Not discussed further.

900 to 949: Customer Accounts; Customer Service and Information, Sales, and General and Administrative Expenses

Customer accounting expenses are accounts 901 to 905. Accounts 901 and 905 are generalized expenses, while Account 902 is meter reading. Account 903 is the catchall, including sending bills, collecting money, credit, call centers and similar items. Account 904 is uncollectible accounts expense.

Customer service and information expenses are accounts 907 to 910. Energy efficiency and demand response costs are typically found in Account 908, and Account 909 is instructional advertising.

Sales and marketing expenses are accounts 911 to 916. They include an advertising component in Account 913.

Administrative and general expenses are accounts 920 to 935. There are elements for administrative salaries (920) and nonlabor expenses (921) and contracts (923), as well as insurance (924 and 925), pensions and benefits (926), regulatory commission expenses (928), miscellaneous expenses (930) and rental of buildings and maintenance of general plant (931 to 935). They may include costs from holding companies. Costs in Account 922 are transferred out, either to capital or to other utility affiliates.

In these areas, the FERC Uniform System of Accounts is not particularly uniform. For example, the costs for the same function, such as a key account representative, can appear in accounts 903, 908, 912 or administrative account 920, depending on the utility. Generation procurement expenses, which appear to belong in Account 557, can also end up in the administrative accounts 920 and 921.

Appendix B: Combustion Turbine Costs Using a Real Economic Carrying Charge Rate[253]

A real economic carrying charge (RECC) rate is designed to measure the economic return expected for an asset whose value increases at the rate of inflation every year. An economic carrying charge also has the property of measuring the value of deferring the construction of an asset from one year to the next.

A levelized nominal-dollar stream of numbers is one way to represent the cost of a power plant. It reflects that if the utility actually bought a combustion turbine today, its costs would be locked in for the 30-year life of the plant. However, using a RECC is more appropriate because it enables the analyst to develop a cost stream for a period shorter than the full life of the plant.[254]

The first step in calculating the RECC begins with calculating the year-by-year revenue requirement of a given asset. One must look at the entire time stream of ownership of an asset and calculate a present value of revenue requirements over the life of the asset using utility accounting. The discount rate used in such a calculation is typically the utility rate of return. (However, there are arguments among analysts as to whether that discount rate is reduced for the tax deductibility of bond interest.[255]) The present value of revenue requirements includes return, depreciation, and income and property taxes and may include certain other costs such as property insurance. From this present value of revenue requirements, one can then calculate the RECC. This is the number of dollars in the first year that, when increased at the rate of inflation every year, results in the same present value at the end of the time period as the present value of revenue requirements.[256]

Figure 47 on the next page is a conceptual example to show the capital and operations and maintenance (O&M) costs for a combustion turbine with a 30-year life. The assumptions used in this example regarding the combustion turbine's capital and O&M costs, as well as capital structure, were developed in a Southwest Public Service Co. case in Texas.[257] The result is that, for this example, the nominal dollar revenue requirement (capital plus O&M) in the first year is $83.54 per kW-year, declining to about $33 per kW-year at the end of the plant's 30-year life as the plant is depreciated. The nominal levelized cost is $63.20. The first-year cost using the RECC is $53.47.

Costs are somewhat sensitive to financial input assumptions. For example, using the capital structure (51% equity and 49% debt) and return on equity (9.3%) offered by the Office of Public Utility Counsel, the first-year RECC in this case would be $52.32. Using Southwest Public Service Co.'s capital structure (58% equity and 42% debt) and return on equity (10.25%), the first-year RECC would be $57.51.

---

253 This appendix is adapted from Marcus, W. (2018, May). Cross-rebuttal testimony on behalf of the Office of Public Utility Counsel, Appendix A. Public Utility Commission of Texas Docket No. 47527.

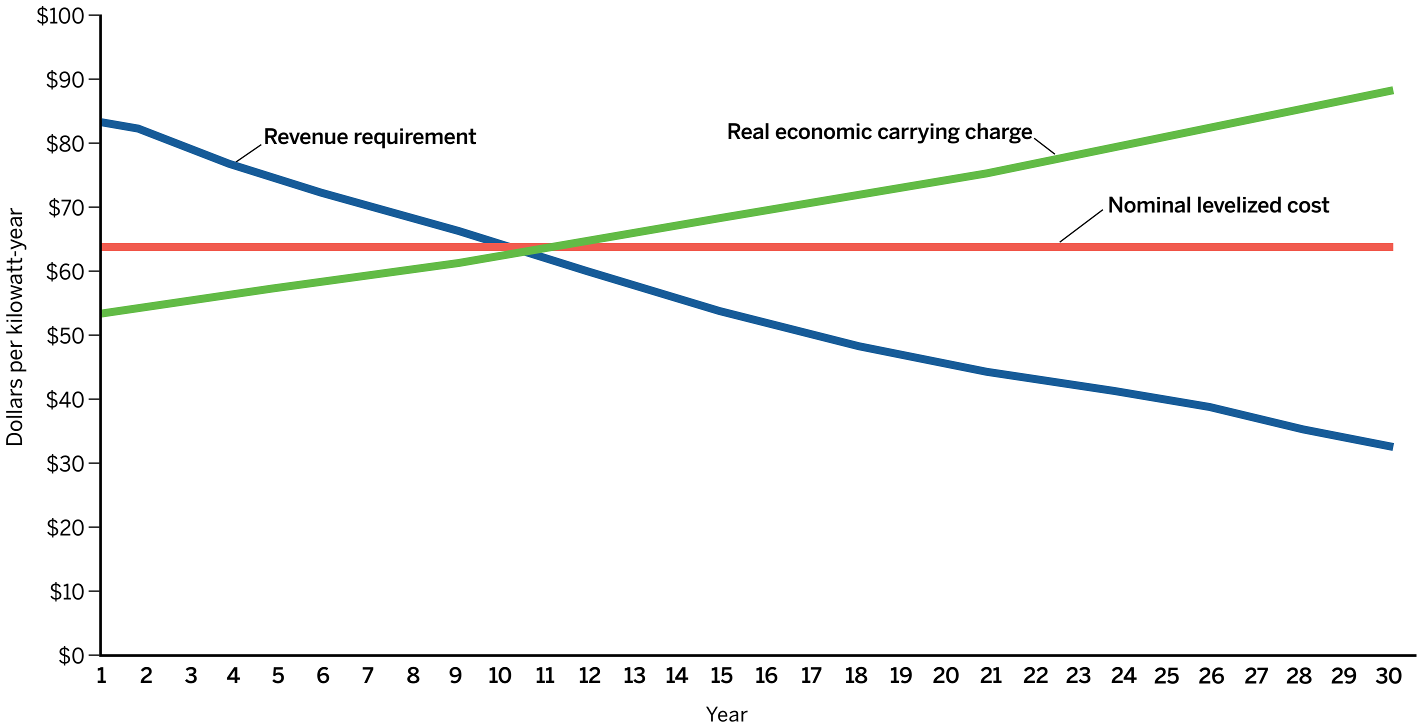
254 Costs calculated based upon time periods shorter than 25 years are considered deferred rather than avoided because combustion plant life cycles are 25 years or greater.

255 Marcus, W. (2013, December). Testimony on behalf of The Utility Reform Network, pp. 2-5. California Public Utilities Commission Application No. 13-04-012.

256 This method of calculating the RECC was developed by National Economic Research Associates (now known as NERA Economic Consulting) in the late 1970s.

257 The case is Public Utility Commission of Texas Docket No. 47527. The capital and O&M costs ($621 per kW and $7.27 per kW-year, respectively) and the inflation rate (1.74%) are from testimony of J. Pollock on behalf of Texas Industrial Energy Consumers (2018, April 25). Property tax rates (0.67%) are those estimated in testimony of N. Koch on behalf of Southwest Public Service Co., Attachment NK-RR-5 (2017, August 21). In addition, the capital structure (48% debt, 52% equity) and return on equity (9.6%) are from the settlement of Southwest Public Service's previous case in Docket No. 45524, with the cost of debt adjusted to the level from Docket No. 47527 (4.38%).

Figure 47. Comparison of temporal distributions for combustion turbine cost recovery



Sources: Based on testimony in Public Utility Commission of Texas Docket No. 47527 and settlement of Docket No. 45524 involving Southwest Public Service Co.

Appendix C: Inconsistent Calculation of Kilowatts in Marginal Cost Studies

Two examples of problematic inconsistencies in measures of demand are identified here to illustrate the problem. Although we have chosen these particular examples, we recognize that additional inconsistencies are likely to be found when analyzing other cost studies.

Pacific Gas & Electric measures demand (except for new hookups, which are measured based on demand at the transformer) using the hottest year in 10 years to develop the marginal cost per kW of regional distribution demand. It thus develops a lower cost per kW than if it used a normal year. The company then multiplies this cost by a peak capacity allocation factor based on a normal year.[258] The peak capacity allocation factor is lower than even the peak demand of the normal year. As a result of the inconsistent measures of demand, its marginal cost revenue requirement of demand is too low relative to its marginal cost revenue requirement of customer costs, inflating the role of customer costs in distribution marginal costs.

Southern California Edison has the same problem, only worse. Its marginal costs are calculated based on system capacity, not demand. System capacity is usually much higher than system demand. As an example, Southern California Edison's subtransmission substation capacity is about 37,000 MWs, even though its time-varying system demand is about 16,000 MWs. The result is that the company obtains a low figure in dollars per kW of capacity (developed using a NERA Economic Consulting regression based on 37,000 MWs of capacity). It then multiplies this figure by 16,000 MWs of time-varying demand. As a result, about 57% of real costs of Edison subtransmission investments disappear in the NERA cost allocation methodology. This mismatch benefits large customers, whose total distribution costs have a larger fraction of subtransmission costs than smaller customers.[259]

258 California Office of Ratepayer Advocates. (2017, February). Testimony, Chapter 4. California Public Utilities Commission Application No. 16-06-013.

259 Marcus, W. (2018, March 23). Testimony on behalf of The Utility Reform Network, pp. 23-28. California Public Utilities Commission Application No. 17-06-030.

Appendix D: Transmission and Distribution Replacement Costs as Marginal Costs[260]

A competitive business could not continue to operate in the intermediate term if its prices did not recover its costs of doing business. These include the full amount of its O&M costs, plus a return on new capital expenditures (including both capital additions and replacements to the existing system that are necessary to serve the loads of its existing customer base) and investments required to serve new loads and customers. This definition would exclude all sunken capital costs.

To understand this point, an example from another industry might be helpful. Assume that package delivery growth has stagnated in a given area, such that only the same number of packages must be delivered for each of the next 10 years. Then assume that the delivery company (which serves only this area) must replace a portion of its fleet of delivery trucks in order to keep delivering this stable number of packages at some point during this time frame. The NERA method of marginal cost analysis would assume that the replacement trucks are not a marginal cost of serving the demand for packages in this area. As a result, the NERA method assumes that it would be economically inefficient for the trucking company to recover the cost of those replacement trucks (unless a portion of the costs could be recovered in advance at a time when the package demand in the area was growing, prior to the time when truck replacement was actually required), because it would require charging more than the marginal cost of operating the existing trucks.

Moreover, assume that the real cost of trucks increased dramatically in the period between the time the delivery company purchased its original delivery truck fleet and the time it ultimately needs to make replacements of the original fleet (similar to real increases in, for example, the cost of pole replacement and substation transformers due to higher materials costs). Assume also that the price the trucking firm is able to charge its customers has not increased in real terms and the number of packages that its existing customers send and have delivered, on average, has not changed. The question for the delivery company is then: Is the marginal cost of replacing its trucks at least equal to the marginal revenue it will retain by continuing its ability to serve its existing customer base? If not, then the company will not make the replacements, and it will choose to exit the delivery business and employ its capital elsewhere. Just because the decision does not include the possibility of new, additional customers does not mean the delivery company would not make its decision to replace its fleet on the basis of marginal cost and revenue.

The difference between the NERA utility system and the trucking company is largely of degree, not kind: Utility replacements are required less frequently than those of the trucking company and can often be deferred for years; wires must serve a fixed route, whereas the route of a delivery truck may change; and the utility is a monopoly, whereas a trucking company may not be. However, the recovery of the cost of replacements is still part of the long-run marginal cost structure of both companies. Neither could stay in business in a competitive market if each does not recover replacement costs in some way.

In essence, the NERA method's view of this issue is based on the assumption that marginal cost applies only to new demand and not to the retention of existing demand. But this view of marginal cost is not economically correct. First, if the utility does not make required replacements, it will no longer be able to supply load. If it cannot supply load, the quantity

260 This discussion is adapted from Jones, G., and Marcus, W. (2015, March 13). Testimony on behalf of The Utility Reform Network, pp. 23-26. California Public Utilities Commission Application No. 14-06-014.

demanded from the utility will necessarily decline — utility customers will necessarily have to demand their electrons from other sources, such as exclusive distributed generation and storage. Second, marginal cost principles include small changes in costs for small changes in production (not necessarily increases) as a result of changes in demand. Without replacement, and therefore continued service, the utility would not be able to serve the load demanded by existing customers. Were this to occur, the marginal change would be a decline in demand, but it would still be a change in demand, which is what the marginal principles with which we are concerned are to measure in the first place. Finally, a business that cannot continue to serve its existing customers under its cost structure cannot stay in business without losing demand from customers that it can no longer serve economically. Replacement costs (with a few exceptions like undergrounding for policy and aesthetic reasons) are required to assure that loads of existing customers do not decline due to a dilapidated and disintegrating system.

Appendix E: Undervaluation of Long-Run Avoided Generation Costs in the NERA Method

The theoretical framework of the NERA method to justify the marginal costs based on a combustion turbine for capacity plus projected short-run marginal costs (SRMC) for energy is predicated on the assumption that a utility will add a baseload resource only at the time it will lower average generation costs. Using this fact alone, it can be demonstrated mathematically that SRMC, assuming the existence of the new plant (SRMC1 henceforth), can be below the price that a utility would pay to cost-effectively build a new plant.

The following discussion focuses on the energy cost term. For the cost-effectiveness above to hold, the annual capital cost plus total operating costs of the new plant, less the annual and fixed operating costs of peaking capacity, must be less than the energy costs on the new system avoided by the new plant. Only if these conditions hold would the new plant reduce energy costs.

In the following mathematical demonstration:

- SRMC refers solely to energy costs.
- The cost of a peaker is subtracted from the cost of the new plant.
- SRMC1 is the SRMC with the new plant included.
- The avoided cost from a new plant (ACNP) is the energy cost on the existing system avoided by the new plant.
- SRMC2 is the SRMC without the new plant.
- The new plant cost (NPC) is the total capital plus operating cost of the new plant net of peaker capital and fixed operating costs.

The following inequality must hold:

$$\text{SRMC1} \le \text{ACNP} \le \text{SRMC2}$$

It essentially states that the SRMC curve declines as resources with low fuel costs are added to a utility system that is otherwise the same. In nonmathematical terms, the equation embodies the fact that, for example, the SRMC calculated for a utility system with 100 MWs of must-take wind generation added to the system is below that calculated in the base case without the wind generation.

For the average cost to decline when a new plant is added, a second inequality must also hold:

$$\text{NPC} < \text{ACNP}$$

The new plant must be cheaper than the costs avoided on the existing system by the plant.

Since SRMC1 <= ACNP, a new utility generating station can be cost-effective if its cost is greater than SRMC1, as the following inequality shows:

$$\text{SRMC1} <> \text{NPC} \le \text{ACNP}$$

If SRMC1 > NPC, then the resource is an "inframarginal" resource with costs well below system marginal costs and would be cost-effective at a time of system need for capacity. If the only resources that a utility was building were inframarginal, then SRMC1 represents avoided cost because the utility plant would be cheaper.

If utility plant were infinitely divisible and the utility system were in equilibrium, the special case of a fourth equation would be true:

$$\text{SRMC1} = \text{ACNP} = \text{NPC}$$

In other words, short-run and long-run avoided cost would be equal.

However, if SRMC1 < NPC, then the utility's short-run marginal costs under the NERA method are less than long-run avoided costs. Use of SRMC1 for resource plan evaluation and rate design thus would skew results away from options that may be cheaper than the new plant and would result in allocation and rate design decisions that undervalue energy relative to other components of marginal cost.

Glossary

Adjustment clause
A rate adjustment mechanism implemented on a recurring and ongoing basis to recover changes in expenses or capital expenditures that occur between rate cases. The most common adjustment clause tracks changes in fuel costs and costs of purchased power. Some utilities have weather normalization adjustment clauses that correct for abnormal weather conditions. See also **tracker** and **rider/tariff rider**.

Administrative and general costs *Abbreviation:* **A&G**
Capital investments and ongoing expenses that support all of a utility's functions. One example of such a capital investment is an office building that houses employees for the entire utility. An example of such an ongoing expense is the salaries of executives who oversee all parts of the utility.

Advanced metering infrastructure *Abbreviation:* **AMI**
The combination of smart meters, communication systems, system control and data acquisition systems, and meter data management systems that together allow for metering of customer energy usage with high temporal granularity; the communication of that information to the utility and, optionally, to the customer; and the potential for direct end-use control in response to real-time cost variations and system reliability conditions. AMI is an integral part of the smart grid concept.

Allocation/cost allocation
The assignment of utility costs to customers, customer groups or unbundled services based on cost causation principles.

Allocation factor/allocator
A computed percentage for each customer class of the share of a particular cost or group of costs each class is assigned in a cost of service study. Allocation factors are based on data that may include customer count, energy consumption, peak or off-peak capacity, revenue and other metrics.

Alternating current *Abbreviation:* **AC**
Current that reverses its flow periodically. Electric utilities generate and distribute AC electricity to residential and business consumers.

Ampere
The standard unit of electrical current, formally defined as a quantity of electricity per second. This unit is often used to describe the size of the service connection and service panel for an electricity customer.

Ancillary service
One of a set of services offered and demanded by system operators, utilities and, in some cases, customers, generally addressing system reliability and operational requirements. Ancillary services include such items as voltage control and support, reactive power, harmonic control, frequency control, spinning reserves and standby power. The Federal Energy Regulatory Commission defines ancillary services as those services "necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."

Automated meter reading *Abbreviation:* **AMR**
Automated meter reading systems use radio or other means to download data from meters periodically without a need for a meter reader to visit each location. They typically do not include interval data of sufficient precision to support advanced services such as critical peak pricing. More sophisticated systems are usually called advanced metering infrastructure.

Average-and-peak method

A method of apportioning demand-related generation, transmission or distribution costs that assigns a portion of costs equal to the system load factor to all classes based on the kWh usage (average demand) of the class and the balance of costs to each class based on peak demand of each class. The metric for peak demand can be any of those described under **peak responsibility method**.

Avoided cost

The cost not incurred by not providing an incremental unit of service. Short-run avoided cost is the incremental variable cost to produce another unit from existing facilities. Long-run avoided cost includes the cost of the next power plant a utility would have to build to meet growing demand, plus the costs of augmenting reliability reserves, additional transmission and distribution facilities, environmental costs and line losses associated with delivering that power.

Base-intermediate-peak method *Abbreviation:* **BIP**

The base-intermediate-peak cost allocation method assigns each component of generation and often transmission and distribution plant to a category of whether it is fully required in all hours (base) or required only in intermediate or peak hours. It then allocates those costs based on the usage of customer classes in each time period.

Baseload generation/baseload units/baseload capacity/baseload resources

Electricity generating units that are most economically run for extended hours. Typical baseload units include coal-fired and nuclear-fueled steam generators.

Basic customer method

A distribution cost allocation approach that classifies only customer-specific costs — such as meters, billing and collection — as customer-related costs, with all other distribution and operating costs assigned based on demand or energy measures of usage.

Behind the meter

Installations of electrical equipment at customer premises, connected to the building or facility wiring at a point where any impacts are measured by the flow through the customer meter. This may include solar photovoltaic or other generating resources, batteries or other storage, or load control equipment. Behind-the-meter installations are usually owned by the retail customer but may be called upon to provide grid services.

British thermal unit *Abbreviation:* **Btu**

A unit of heat, defined as the amount necessary to raise the temperature of 1 pound of water by 1 degree Fahrenheit. Multiples of this unit are frequently used to describe the energy content of fuels.

Capacity

The ability to generate, transport, process or utilize power. Capacity is measured in watts, usually expressed as kilowatts (1,000 watts), megawatts (1,000 kilowatts) or gigawatts (1,000 megawatts). Generators have rated capacities that describe the output of the generator when operated at its maximum output at a standard ambient air temperature and altitude.

Capacity factor

The ratio of total energy produced by a generator for a specified period to the maximum it could have produced if it had run at full capacity through the entire period, expressed as a percentage. Fossil-fueled generating units with high capacity factors are generally considered baseload power plants, and those with low capacity factors are generally considered peaking units. These labels do not apply to wind or solar units because the capacity factors for these technologies are driven by weather conditions and not decisions around optimal dispatch.

Capacity-related costs

See **demand-related costs**.

Circuit
This generally refers to a wire that conducts electricity from one point to another. At the distribution level, multiple customers may be served by a single circuit that runs from a local substation or transformer to those customers. At the transmission level, the term "circuit" may also describe a pathway along which energy is transported or the number of wires strung along that pathway. See also **conductor**.

Classification
A step in some cost allocation methods in which costs are defined into categories such as energy-related, demand-related and customer-related.

Coincident peak *Abbreviation:* CP
The combined demand of a single customer or multiple customers at a specific point in time or circumstance, relative to the peak demand of the system, in which "system" can refer to the aggregate load of a single utility or of multiple utilities in a geographic zone or interconnection or some part thereof.

Combined cycle unit
A type of generation facility based on combustion that combines a combustion turbine with equipment to capture waste heat to generate additional electricity. This results in more efficient operation (higher output per unit of fuel input).

Combustion turbine
A power plant that generates electricity by burning oil or natural gas in a jet engine, which spins a shaft to power a generator. Combustion turbines are typically relatively low efficiency, have lower capital costs than other forms of generation and are used primarily as peaking power plants.

Community choice aggregation
Community choice aggregation involves a municipality or other local entity serving as the electricity purchasing central agent for all customers within a geographic area. The distribution system is still operated by a regulated utility. In some cases, customers can opt out and use another method to obtain electricity supply.

Competitive proxy method
The usage of information on energy and capacity revenue in competitive wholesale markets in order to classify generation assets for vertically integrated utilities between energy-related and demand-related.

Conductor
The individual wire or line that carries electricity from one point to another.

Connection charge
An amount to be paid by a customer to the utility, in a lump sum or installments, for connecting the customer's facilities to the supplier's facilities.

Contribution in aid of construction
Utilities sometimes require customers to pay a portion of the cost of extending distribution service into sparsely populated areas. These contributions are recorded as a contribution in aid of construction or sometimes as a customer advance that is refundable if additional customers in that area opt for electricity service.

Cooperative *Abbreviation:* co-op
A not-for-profit utility owned by the customer-members. A co-op is controlled by a member-elected board that includes representatives from business customers.

Cost allocation
Division of a utility's revenue requirement among its customer classes. Cost allocation is an integral part of a utility's cost of service study.

Cost of service
Regulators use a cost of service approach to determine a fair price for electric service, by which the aggregate costs for providing each class of service (residential, commercial and industrial) are determined. Prices are set to recover those costs, plus a reasonable return on the invested capital portion of those costs.

Cost of service study

An analysis performed in the context of a rate case that allocates a utility's allowed costs to provide service among its various customer classes. The total cost allocated to a given class represents the costs that class would pay to produce an equal rate of return to other classes. Regulators frequently exercise judgment to adopt rates that vary from study results.

Critical peak

A limited number of hours every year when the electric system, or a portion of it, is under a significant amount of stress that could cause reliability problems or the need for nontrivial capital investments.

Critical peak pricing

A form of dynamic retail rate design where a utility applies a substantially higher rate, with advance notice to customers, for a limited number of hours every year when the electric system is projected to be under a significant amount of stress.

Curtailment

This can refer to different sets of practices for either load or variable renewable generation. With respect to load, curtailment represents a reduction in usage in response to prices and programs or when system reliability is threatened. Price-responsive load curtailment is also known as demand response. Utilities and independent system operators typically have curtailment plans that can be used if system reliability is threatened. Curtailment of variable renewable generation can take place if there is an economic or system reliability reason why the electric system cannot take incremental energy from these units. This could occur when there is more energy available than can be transmitted given delivery constraints, or if the operating constraints of other generators are such that it is more efficient to curtail renewable generation rather than ramp down other units.

Customer charge

A fixed charge to consumers each billing period, typically to cover metering, meter reading and billing costs that do not vary with size or usage. Also known as a basic service charge or standing charge.

Customer class

A collection of customers sharing common usage or interconnection characteristics. Customer classes may include residential (sometimes called household), small commercial, large commercial, small industrial, large industrial, agriculture (primarily irrigation pumping), mining and municipal lighting (streetlights and traffic signals). All customers within a class are typically charged the same rates, although some classes may be broken down into subclasses based on the nature of their loads, the capacity of their interconnection (e.g., the size of commercial or residential service panel) or the voltage at which they receive service.

Customer noncoincident peak demand (or load)

The highest rate of usage in a measurement period of an individual customer — typically in a one-hour, 30-minute or 15-minute interval — unaffected by the usage of other customers sharing the same section of a distribution grid. Also known as maximum customer demand. See also **noncoincident peak**.

Customer-related costs

Costs that vary directly with the number of customers served by the utility, such as metering and billing expenses.

Decomposition method

A legacy method that jointly classifies and allocates generation assets. This method assumes that customer classes with high load factors are served by high-capacity-factor baseload resources. In many cases, such a method would advantage the large industrial customer class, although that does depend on the cost of the baseload resources in question. Among other issues, this method ignores reserve requirements or other backup supply needs and any need to equitably share the costs of excess capacity.

Decoupling

Decoupling fixes the amount of revenue to be collected and allows the price charged to float up or down between rate cases to compensate for variations in sales volume in order to maintain the set revenue level. The target revenue is sometimes allowed to increase between rate cases on the basis of an annual review of costs or a fixed inflator, or on the basis of the number of customers served. The latter approach is sometimes known as revenue-per-customer decoupling. The purpose is to allow utilities to recover allowed costs, independent of sales volumes, without under- or overcollection over time. Also known as revenue regulation.

Default service/default supply

In a restructured electric utility, the power supply price a customer will pay if a different supplier than the distribution utility is not affirmatively chosen. Most residential and small-business consumers are served by the default supply option in areas where it is available. Also known as standard service offer or basic service.

Demand

In theory, an instantaneous measurement of the rate at which electricity is being consumed by a single customer or customer class or the entirety of an electric system, expressed in kilowatts or megawatts. Demand is the load-side counterpart to an electric system's capacity. In practical terms, electricity demand is actually measured as the average rate of energy consumption over a short period, usually 15 minutes or an hour. For example, a 1,000-watt hair dryer run for the entirety of a 15-minute demand interval would cause a demand meter using a 15-minute demand interval to record 1 kilowatt of demand. If that same hair dryer were run for only 7.5 minutes, however, the metered demand would be only 0.5 kilowatt. Not all electric meters measure demand.

Demand charge

A charge paid on the basis of metered demand typically for the highest hour or 15-minute interval during a billing period. Demand charges are usually expressed in dollars per watt units, such as kilowatts. Demand charges are common for large (and sometimes small) commercial and industrial customers but have not typically been used for residential customers because of the very high diversity among individual customers' usage and the higher cost of demand meters or interval meters. The widespread deployment of smart meters would enable the use of demand charges or time-of-use rates for any customer served by those meters.

Demand meter

A meter capable of measuring and recording a customer's demand. Demand meters include interval meters and smart meters.

Demand-related costs/capacity-related costs

Costs that vary directly with the system capacity to meet peak demands. This can be measured separately for the generation, transmission and distribution segments of the utility system.

Demand response

Reduction in energy use in response to either system reliability concerns or increased prices (where wholesale markets are involved) or generation costs (in the case of vertically integrated utilities). Demand response generally must be measurable and controllable to participate in wholesale markets or be relied upon by system operators.

Depreciation

The loss of value of assets, such as buildings and transmission lines, owing to age and wear.

Direct current *Abbreviation:* DC

An electric current that flows in one direction, with a magnitude that does not vary or that varies only slightly.

Distributed energy resource *Abbreviation:* DER

Any resource or activity at or near customer loads that generates energy, reduces consumption or otherwise manages energy on-site. Distributed energy resources include customer-site generation, such as solar photovoltaic systems and emergency backup generators, as well as energy efficiency, controllable loads and energy storage.

Distributed generation

Any electricity generator located at or near customer loads. Distributed generation usually refers to customer-sited generation, such as solar photovoltaic systems, but may include utility-owned generation or independent power producers interconnected to the distribution system.

Distribution

The delivery of electricity to end users via low-voltage electric power lines (usually 34 kV and lower).

Distribution utility

A utility that owns and operates only the distribution system. It may provide bundled service to customers by purchasing all needed energy from one or more other suppliers or may require that customers make separate arrangements for energy supply. See also **vertically integrated utility**.

Distribution system

That portion of the electric system used to distribute energy to customers. The distribution system is usually distinguished from the transmission system on the basis of voltage and function. Components operating above 100 kV are considered transmission. Components operating below 50 kV are considered distribution. Facilities between 50 kV and 100 kV are often termed subtransmission but are normally included in the distribution service FERC accounts. After energy is received from a large generating facility, its voltage is stepped up to very high levels where it is transported by the transmission system. Power from distributed generating facilities such as small photovoltaic systems is normally delivered into the distribution system and transported to nearby customers at the distribution system level without ever entering the transmission system.

Distribution system operator

The entity that operates the distribution portion of an electric system. In the case of a vertically integrated utility, this entity would also provide generation and transmission services. In many restructured markets, the distribution system operator provides only delivery services and may provide only limited energy services as a provider of last resort.

Diversity/customer diversity/load diversity

The measurement of how different customers use power at different times of the day or year, and the extent to which those differences can enable sharing of system generation, transmission or distribution capacity. For example, schools use power primarily during the day, and street lighting uses power exclusively during hours of darkness; they are able to share system capacity. By contrast, continuous-use customers, such as data centers and all-night mini-marts, preempt the use of capacity. Irrigators use power in summer, and space heat uses power in winter, also allowing the seasonal sharing of generation but sometimes not of distribution capacity.

Dynamic pricing

Rates that may be adjusted frequently, such as hourly or every 15 minutes, based on wholesale electricity costs or actual generation costs. Also known as real-time pricing. See also **critical peak pricing**.

Embedded cost of service study

A cost allocation study that apportions the actual historic test year or projected future rate year system costs among customer classes, typically using customer usage patterns in a single yearlong period to divide up the costs. Sometimes called a fully allocated cost of service study. See also **marginal cost of service study** and **total service long-run incremental cost**.

Embedded costs

The actual current costs, including a return on existing plant, used to provide service. These are reflected in the FERC system of accounts reported in each utility's FERC Form 1 filing. See also **marginal costs**.

Energy

A unit of power consumed over a period of time. Energy is expressed in watt-time units, in which the time units are usually one hour, such as a kilowatt-hour, megawatt-hour and so on. An appliance placing 1 kilowatt of demand on the system for an hour will consume 1 kilowatt-hour of energy. See also **watt** and **watt-hour**.

Energy charge
A price component based on energy consumed. Energy charges are typically expressed in cents per kilowatt-hour and may vary based on the time of consumption.

Energy efficiency
The deployment of end-use appliances that achieve the same or greater end-use value while reducing the energy required to achieve that result. Higher-efficiency boilers and air conditioners, increased building insulation, more efficient lighting and higher energy-rated windows are all examples of energy efficiency. Energy efficiency implies a semipermanent, longer-term reduction in the use of energy by the customer, contrasted with behavioral programs that may influence short-term usage habits. Because energy efficiency reduces the need for generation, transmission and distribution, these costs are properly allocated using the methods applied to all three functions.

Energy-related costs
Costs that vary directly with the number of kilowatt-hours the utility provides over a period of time.

Equal percentage of marginal cost *Abbreviation:* **EPMC**
A method of adjusting the results of a marginal cost of service study to the system revenue requirement by adjusting the cost responsibility of each class by a uniform percentage. Often applied within the functional categories of generation, transmission and distribution.

Equivalent forced outage rate
The percentage of the hypothetical maximum output of a generating unit during a year that is unavailable due to unplanned outages, either full or partial, of the unit.

Equivalent peaker method
A method of classifying production and transmission costs that assigns a portion of investment and maintenance costs as demand-related — based on the cost of a peaking resource such as demand response or a peaking power unit that can be deployed within the service territory — and the balance of costs as energy-related. Commonly used for nuclear, coal and hydroelectric resources and associated transmission.
Also known as the peak credit method.

Externalities
Costs or benefits that are side effects of economic activities and are not reflected in the booked costs of the utility. Environmental impacts are the principal externalities caused by utilities (e.g., climate impacts or health care costs from air pollution).

Extra-high voltage *Abbreviation:* **EHV**
Transmission lines operating at 765 kV (alternating current) or roughly 400 kV (direct current) or above.

Federal Energy Regulatory Commission
Acronym: **FERC**
The U.S. agency that has jurisdiction over interstate transmission systems and wholesale sales of electricity.

Fixed charge
Any fee or charge that does not vary with consumption. Customer charges are a typical form of fixed charge. In some jurisdictions, customers are charged a connected load charge that is based on the size of their service panel or total expected maximum load. Minimum bills and straight fixed/variable rates are additional forms of fixed charges.

Fixed cost
This accounting term is meant to denote costs that do not vary within a certain period of time, usually one year, primarily interest expense and depreciation expense. This term is often misapplied to denote costs associated with plant and equipment (which are themselves denoted as fixed assets in accounting terms) or other utility costs that cannot be changed in the short term. From a regulatory and economics perspective, the concept of fixed costs is irrelevant. For purposes of regulation, all utility costs are variable in the long run. Even the costs associated with seemingly fixed assets, such as the distribution system, are not fixed, even in the short run. Utilities are constantly upgrading and replacing distribution

facilities throughout their systems as more customers are served and customer usage increases, and efforts to reduce demand can have immediate impacts on those costs.

Flat volumetric rate
A rate design with a uniform price per kilowatt-hour for all levels of consumption.

Fuel adjustment clause
An adjustment mechanism that allows utilities to recover all or part of the variation in the cost of fuel or purchased power from the levels assumed in a general rate case. See also **adjustment clause**.

Fuel cost
The cost of fuel, typically burned, used to create electricity. Types include nuclear, coal, natural gas, diesel, biomass, bagasse, wood and fuel oil. Some generators, such as wind turbines and solar photovoltaic and solar thermal generators, use no fuel or, in the case of hydroelectric generation, virtually cost-free fuel.

Functionalization
A step in most cost allocation methods in which costs are defined into functional categories, such as generation-related, transmission-related, distribution-related, or administrative and general costs.

General service
A term broadly applied to nonresidential customers. It sometimes includes industrial customers and sometimes is distinct from an industrial class. It is often divided into small, medium and large by maximum demand or into secondary and primary by voltage.

Generation
Any equipment or device that supplies energy to the electric system. Generation is often classified by fuel source (i.e., nuclear, coal, gas, solar and so on) or by operational or economic characteristics (e.g., “must-run,” baseload, intermediate, peaking, intermittent, load following).

Grid
The electric system as a whole or the nongeneration portion of the electric system.

Heat rate
The number of British thermal units that a thermal power plant requires in fuel to produce 1 kilowatt-hour.

Highest 100 (or 200) hours method
A method for allocating demand-related or capacity-related costs that considers class demand over the highest 100 (or 200) hours of usage during the year.

High-voltage direct current *Abbreviation:* **HVDC**
An HVDC electric power transmission system uses direct current for the bulk transmission of electrical power, in contrast to the more common alternating current systems. For long-distance transmission, HVDC systems may be less expensive and suffer lower electrical losses.

Hourly allocation
An allocation approach in which costs or groups of costs are assigned to hourly time periods rather than classified between demand- and energy-related costs.

Incremental cost
The short-run cost of augmenting an existing system. An incremental cost study rests on the theory that prices should reflect the cost of producing the next unit of energy or deployment of the next unit of capacity in the form of generation, transmission or distribution. See also **long-run marginal costs**, **short-run marginal costs** and **total system long-run incremental cost**.

Independent power producer
A power plant that is owned by an entity other than an electric utility. May also be referred to as a non-utility generator.

Independent system operator *Abbreviation:* **ISO**
A non-utility entity that has multi-utility or regional responsibility for ensuring an orderly wholesale power market, the management of transmission lines and the dispatch of power resources to meet utility and non-utility needs. All existing ISOs also act as regional transmission organizations, which control and operate the transmission system independently of the local utilities that serve customers. This usually includes control of the dispatch of generating units and calls on demand response resources over the course of a day or year. In regions without an ISO, less formal entities and markets exist for wholesale trading and regional transmission planning. See also **regional transmission organization**.

Intermediate unit
A generic term for units that operate a substantial portion of the year but not at all times or just hours near peaks or with reliability issues. As a result, these units can be described as neither baseload nor peaking. Over the past two decades, this role has been filled by natural gas combined cycle units in many places. Intermediate units are also known as midmerit or cycling units.

Intermittent resources
See **variable resources**.

Interruptible rate/interruptible customer
An interruptible rate is a retail service tariff in which, in exchange for a fee or a discounted retail rate, the customer agrees to curtail service when called upon to do so by the entity offering the tariff, which may be the local utility or a third-party curtailment service provider. A customer's service may be interrupted for economic or reliability purposes, depending on the terms of the tariff. Customers on these rates are sometimes described as interruptible customers, and it is said that they receive interruptible service.

Interval meter
A meter capable of measuring and recording a customer's detailed consumption data. An interval meter measures demand by recording the energy used over a specified interval of time, usually 15 minutes or an hour.

Inverse elasticity rule
A method of reconciling the marginal cost revenue requirement with the embedded cost revenue requirement. In principle, the adjustment of the least-elastic element of costs (and thus the underlying rates) produces a less distortive and more optimal outcome for customer behavior. The inverse elasticity rule follows this principle by adjusting the least-elastic element upward if there is a shortfall or downward if there is a surplus. There are numerous theoretical and practical difficulties in determining which element of costs or rates is least elastic.

Investor-owned utility *Abbreviation:* **IOU**
A utility owned by shareholders or other for-profit owners. A majority of U.S. electricity consumers are served by IOUs.

Kilovolt *Abbreviation:* **kV**
A kilovolt is equal to 1,000 volts. This unit is the typical measure of electric potential used to label transmission and primary distribution lines.

Kilovolt-ampere *Abbreviation:* **kVA**
A kilovolt-ampere is equal to 1,000 volt-amperes. This unit is the typical measure for the capacity of line transformers.

Kilowatt *Abbreviation:* **kW**
A kilowatt is equal to 1,000 watts.

Kilowatt-hour *Abbreviation:* **kWh**
A kilowatt-hour is equal to 1,000 watt-hours.

Line transformer
A transformer directly providing service to a customer, either on a dedicated basis or among a small number of customers. A line transformer typically is stepping down power on a distribution line from primary voltage to secondary voltage that consumers can use directly.

Load
The combined demand for electricity placed on the system. The term is sometimes used in a generalized sense to simply denote the aggregate of customer energy usage on the system,

or in a more specific sense to denote the customer demand at a specific point in time.

Load factor

The ratio of average load of a customer, customer class or system to peak load during a specific period of time, expressed as a percentage.

Load following

The process of matching variations in load over time by increasing or decreasing generation supply or, conversely, decreasing or increasing loads. One or more generating units or demand response resources will be designated as the load following resources at any given time. Baseload and intermediate generation is generally excluded from this category except in extraordinary circumstances.

Load shape

The distribution of usage across the day and year, reflecting the amount of power used in low-cost periods versus high-cost periods.

Long-run marginal costs/long-run incremental costs

The costs of expanding or maintaining the level of utility service, including the cost of a new or replacement power plants, transmission and distribution, reserves, marginal losses, and administrative and environmental costs, measured over a period of years in which new investment is expected to be needed.

Losses/energy losses/line losses

The energy (kilowatt-hours) and power (kilowatts) lost or unaccounted for in the operation of an electric system. Losses are usually in the form of energy lost to heat, sometimes referred to as technical losses; energy theft from illegal connections or tampered meters is sometimes referred to as nontechnical losses.

Loss-of-energy expectation

A mathematical study of a utility system, applying expected availability of multiple generating resources, that estimates the expected energy loss at each hour of the year when power supply and demand response resources are insufficient to meet customer demand. Related terms: loss-of-load probability, loss-of-load hours, loss-of-load expectation, probability of peak and expected unserved energy.

Loss-of-energy expectation method

A method for allocating demand-related costs in a manner that is weighted over all of the hours with reliability risks.

Marginal cost of service study

A cost allocation study that apportions costs among customer classes using estimates of how costs change over time in response to changes in customer usage. See also **embedded cost of service study** and **total service long-run incremental cost.**

Marginal costs

The cost of augmenting output. Short-run marginal costs are the incremental expenses associated with increasing output with existing facilities. Long-run marginal costs are the incremental capital and operating expenses associated with increasing output over time with an optimal mix of assets. Total system long-run incremental costs are the costs of building a new system in its entirety, a measure used to determine if an existing utility system is economical.

Marginal cost revenue requirement *Abbreviation:* MCRR

An output in a marginal cost of service study, where the marginal unit costs for each element of the electric system are multiplied by the billing determinants for each class to produce a class marginal cost revenue requirement for each element. These can be aggregated to produce a system MCRR. It is only happenstance if the system MCRR equals the embedded cost revenue requirement, so the elements of the MCRR can be used in different ways to allocate embedded costs among the customer classes. See also **reconciliation**.

Megawatt *Abbreviation:* **MW**

A megawatt is equal to 1 million watts or 1,000 kilowatts.

Megawatt-hour *Abbreviation:* **MWh**

A megawatt-hour is equal to 1 million watt-hours or 1,000 kilowatt-hours.

Megawatt-year

A megawatt-year is the amount of energy that would equal 1 megawatt continuously for one year, or 8.76 million kilowatt-hours. Also known as an average megawatt.

Meter data management system

A computer and control system that gathers metering information from smart meters and makes it available to the utility and, optionally, to the customer. A meter data management system is part of the suite of smart technologies and is integral to the smart grid concept.

Midpeak

Hours that are between on-peak hours and off-peak hours. These are typically the hours when intermediate power plants are operating but peaking units are not. Used primarily in the base-intermediate-peak cost allocation method and in time-of-use rate design.

Minimum system method

A method for classifying distribution system costs between customer-related and demand- or energy-related. It estimates the cost of building a hypothetical system using the minimum size components available as the customer-related costs and the balance of costs as demand-related or energy-related.

Municipal utility *Abbreviation:* **muni**

A utility owned by a unit of government and operated under the control of a publicly elected body.

National Association of Regulatory Utility Commissioners *Acronym:* **NARUC**

The association of state and federal regulatory agencies that determine electric utility tariffs and service standards. It includes the state, territorial and federal commissions that regulate utilities and some transportation services.

NERA method

An approach to measuring marginal costs for electric utilities that considers a mix of time frames. It looks at customer-related costs such as metering on a full replacement or new install basis and at transmission or distribution capacity costs over a time frame of 10 years or more to include at least some capacity upgrades. Generation costs consider the new install costs for peaking capacity and a dispatch model approach to variable energy costs. The NERA method has formed the foundation for the methods used in several states today, but each state has modified the approach. This approach is named after the firm that developed it in the 1970s, National Economic Research Associates (now NERA Economic Consulting).

New-customer-only method *Abbreviation:* **NCO**

A short-run method for estimation of marginal customer connection costs based on the cost of hookups for new customers. This method may or may not include the percentage of existing hookups that are replaced every year. See also **rental method**.

Noncoincident peak *Abbreviation:* **NCP**

The maximum demand of a customer, group of customers, customer class, distribution circuit or other portion of a utility system, independent of when the maximum demand for the entire system occurs.

Off-peak

The period of time that is not on-peak. During off-peak periods, system costs are generally lower and system reliability is not an issue, and only generating units with lower short-run variable costs are operating. This may include high-load hours if nondispatchable generation, such as solar photovoltaic energy, is significant within the service area. Time-of-use rates typically have off-peak prices that are lower than on-peak prices.

On-peak
The period of time when storage units and generating units with higher short-run variable costs are operating to supply energy or when transmission or distribution system congestion is present. During on-peak periods, system costs are higher than average and reliability issues may be present. Many rate designs and utility programs are oriented to reducing on-peak usage. Planning and investment decisions are often driven by expectations about the timing and magnitude of peak demand during the on-peak period. Time-of-use rates typically have on-peak prices that are higher than off-peak prices.

Operational characteristics method
The traditional version of this method uses the capacity factor of a resource to determine the energy-related percentage of the costs of a generation asset and designates the remainder as demand-related. Although this provides a reasonable result in some circumstances, it inaccurately increases the demand-related percentage for less-reliable resources. A variation on this approach is to use the operating factor — the ratio of output to the equivalent availability of the unit — as the energy-related percentage.

Operations and maintenance costs *Abbreviation:* **O&M**
All costs associated with operating, maintaining and supporting the utility plant, including labor, outside services, administrative costs and supplies. For generation facilities, this includes O&M expenses that vary directly with the output of the facility (dispatch O&M), such as fuel and water treatment, and expenses that do not vary with output but are incurred yearly or monthly (nondispatch O&M).

Peak capacity allocation factor *Acronym:* **PCAF**
An allocation factor where a weighted portion of demand-related costs is assigned to every hour in excess of 80% of peak demand. This method, used in California, is weighted such that the peak hour has an allocation that is 20 times the allocation for the hours at 81% of peak demand and twice the allocation of an hour at 90% of peak demand.

Peak demand
The maximum demand by a single customer, a group of customers located on a particular portion of the electric system, all of the customers in a class or all of a utility's customers during a specific period of time — hour, day, month, season or year.

Peaking resources/peaking generation/peakers
Generation that is used to serve load during periods of high demand. Peaking generation typically has high fuel costs or limited availability (e.g., storage of hydrogeneration) and often has low capital costs. Peaking generation is used for a limited number of hours, especially as compared with baseload generation. Peaking resources often include nongeneration resources, such as storage or demand response.

Peak load
The maximum total demand on a utility system during a period of time.

Peak responsibility method
A method of apportioning demand-related generation or transmission costs based on the customer class share of maximum demand on the system. The metric can be a single hour (1 CP), the highest hour in several months (such as 4 CP), the highest hour in every month (12 CP) or the entire group of highest peak hours (such as 200 CP). See also **coincident peak**.

Performance-based regulation *Abbreviation:* **PBR**
An approach to determining the utility revenue requirement that departs from the classical formula of rate base, rate of return, and operation and maintenance expense. It is designed to encourage improved performance by utilities on cost control or other regulatory goals.

Postage stamp pricing
The practice of having separate sets of prices for a relatively small and easily identifiable number of customer classes. Every customer in a given customer class generally pays the same prices regardless of location in a utility's service territory, although separate prices may exist for subclasses in some cases.

Power factor
The fraction of power actually used by a customer's electrical equipment compared with the total apparent power supplied, usually expressed as a percentage. A power factor indicates the extent to which a customer's electrical equipment causes the electric current delivered at the customer's site to be out of phase with system voltage.

Power quality
The power industry has established nominal target operating criteria for a variety of properties associated with the power flowing over the electric grid. These include frequency, voltage, power factor and harmonics. Power quality describes the degree to which the system, at any given point, is able to exhibit the target operating criteria.

Primary voltage/primary service
Primary voltage normally includes voltages between 2 kV and 34 kV. Primary voltage facilities generally are considered part of the distribution system.

Probability-of-dispatch method *Abbreviation:* **POD**
A cost allocation methodology that considers the likelihood that specific generating units and transmission lines will be needed to provide service at specific periods during the year and assigns costs to each period based on those probabilities.

Public utilities commission/public service commission
The state regulatory body that determines rates for regulated utilities. Although they go by various titles, these two are the most common.

Public Utilities Regulatory Policy Act
Acronym: **PURPA**
This federal law, enacted in 1978 and amended several times, contains two essential elements. The first requires state regulators to consider and determine whether specific rate-making policies should be adopted, including whether rates should be based on the cost of service. The second requires utilities to purchase power at avoided-cost prices from independent power producers.

Rate base
The net investment of a utility in property that is used to serve the public. This includes the original cost net of depreciation, adjusted by working capital, deferred taxes and various regulatory assets. The term is often misused to describe the utility revenue requirement.

Rate case
A proceeding, usually before a regulatory commission, involving the rates, revenues and policies of a public utility.

Rate design
Specification of prices for each component of a rate schedule for each class of customers, which are calculated to produce the revenue requirement allocated to the class. In simple terms, prices are equal to revenues divided by billing units, based on historical or assumed usage levels. Total costs are allocated across the different price components such as customer charges, energy charges and demand charges, and each price component is then set at the level required to generate sufficient revenues to cover those costs.

Rate of return
The weighted average cost of utility capital, including the cost of debt and equity, used as one of the three core elements of determining the utility revenue requirement and cost of service, along with rate base and operating expense.

Rate year
The period for which rates are calculated in a utility rate case, usually the 12-month period immediately following the expected effective date of new rates at the end of the proceeding.

Real economic carrying charge *Acronym:* **RECC**
An annualized cost expressed in percentage terms that reflects the annual "mortgage" payment that would be required to pay off a capital investment at the utility's real (net of inflation) cost of capital over its expected lifetime. It is used in long-run marginal cost and total system long-run incremental cost studies.

Reconciliation/revenue reconciliation/ cost reconciliation
In a marginal cost of service study, it is only happenstance if the system marginal cost revenue requirement is equal to the embedded cost revenue requirement that needs to be recovered by the utility to earn a fair return. As a result, the marginal cost revenue requirement must be reconciled to the embedded cost revenue requirement. There are two primary methods for this: equal percentage of marginal cost and the inverse elasticity rule. See also **marginal cost revenue requirement**.

Regional Greenhouse Gas Initiative
An agreement among Northeast and mid-Atlantic states to limit the amount of greenhouse gases emitted in the electric power sector and to price emissions by auctioning emissions allowances.

Regional transmission organization *Abbreviation:* **RTO**
An independent regional transmission operator and service provider established by FERC or that meets FERC's RTO criteria, including those related to independence and market size. RTOs control and manage the high-voltage flow of electricity over an area generally larger than the typical power company's service territory. Most also serve as independent system operators, operating day-ahead, real-time, ancillary services and capacity markets, and conduct system planning. See also **independent system operator**.

Renewable portfolio standard *Abbreviation:* **RPS**
A requirement established by a state legislature or regulator that each electric utility subject to its jurisdiction obtain a specified portion of its electricity from a specified set of resources, usually renewable energy resources but sometimes including energy efficiency, nuclear energy or other categories.

Rental method
A method of estimating marginal customer connection costs where the cost of new customer connection equipment is multiplied by the real economic carrying charge to obtain an estimate of a rental price. This is a long-run method for customer connection costs that has been a part of the NERA method for marginal costs. See also **new-customer-only method**.

Reserves/reserve capacity/reserve margin
The amount of capacity that a system must be able to supply, beyond what is required to meet demand, to assure reliability when one or more generating units or transmission lines are out of service. Traditionally a 15% to 20% reserve capacity was thought to be needed for good reliability. In recent years, due to improved system controls and data acquisition, the accepted value in some areas has declined to 10% or lower.

Restructured state/restructured utility/ restructured market
Replacement of the traditional vertically integrated utility with some form of competitive market. In some cases, the generation and transmission components of service are purchased by the customer-serving distribution utility in a wholesale competitive market. In other cases, retail customers are allowed to choose their generation suppliers directly in a competitive market.

Retail competition/retail choice
A restructured market in which customers are allowed to or must choose their own competitive supplier of generation and transmission services. In most states with retail choice, the incumbent utility or some other identified entity is designated as a default service provider for customers who do not choose another supplier. In Texas, there is no default service provider and all customers must choose a retail supplier.

Revenue requirement
The annual revenues that the utility is entitled to collect (as modified by adjustment clauses). It is the sum of operations and maintenance expenses, depreciation, taxes and a return on rate base. In most contexts, "revenue requirement" and "cost of service" are synonymous.

Rider/tariff rider

A special tariff provision that collects a specified cost or refunds a specific consumer credit, usually over a limited period. See also **adjustment clause** and **tracker**.

Secondary voltage/secondary service

Secondary voltage normally includes only voltages under 600 volts. Secondary voltage facilities generally are considered part of the distribution system.

Service line/service drop

The conductor directly connecting an electricity customer to the grid, typically between the meter and the line transformer. The term "service drop" derives from the fact that in many cases this line literally drops down from shared transformers attached to overhead lines, but today many are underground.

Short-run marginal costs/short-run incremental costs

The costs incurred immediately to expand production and delivery of utility service, not including any capital investments. They are usually much lower than the average of costs but may be higher than average costs during periods of system stress or deficiency of capacity.

Site infrastructure

The utility investment that is located at the customer premises and serves no other customers than those located at a single point of delivery from the distribution system. Site infrastructure costs are either paid by the customer at the time of service connection or else classified as customer-related costs in cost of service studies.

Smart grid

An integrated network of sophisticated meters, computer controls, information exchange, automation, information processing, data management and pricing options that can create opportunities for improved reliability, increased consumer control over energy costs and more efficient utilization of utility generation and transmission resources.

Smart meter

An electric meter with electronics that enable recording of customer usage in short time intervals and two-way communication of data between the utility, the meter and optionally the customer.

Spinning reserve

Any energy resource or decremental load that can be called upon within a designated period of time and that system operators may use to balance loads and resources. Spinning reserves may be in the form of generators, energy storage or demand response. Spinning reserves may be designated by how quickly they can be made available, from instantaneously up to some short period of time. In the past, this meant actual rotating (spinning) power plant shafts, but today "spinning" reserves can be provided by battery storage, flywheels or customer load curtailment.

Straight fixed/variable

A rate design method that designate much or all of the distribution system as a fixed cost and places all of those costs on customers through customer charges. There are related cost allocation approaches, which designate the entire distribution system as a customer-related cost and transmission and generation capacity as entirely demand-related. See also **minimum system method** and **basic customer method**.

Stranded costs

Utility costs for plant that is no longer used or no longer economic. This may include fossil-fueled power plants made uneconomic by new generating technologies; assets that fail to perform before they are fully depreciated; or distribution facilities built to serve customers who are no longer taking utility service, such as failed industrial sites and customers choosing self-generation as a replacement for utility service. Some regulators allow recovery of stranded costs from continuing customers and the inclusion of these costs in the cost of service methodology.

Substation
A facility with a transformer that steps voltage down from transmission or subtransmission voltage to distribution voltage, to which one or more circuits or customers may be connected.

System load factor
The ratio of the average load of the system to peak load during a specific period of time, expressed as a percentage.

System peak demand
The maximum demand placed on the electric system at a single point in time. System peak demand may be a measure for an entire interconnection, for subregions within an interconnection or for individual utilities or service areas.

Tariff
A listing of the rates, charges and other terms of service for a utility customer class, as approved by the regulator.

Test year
A specific period chosen to demonstrate a utility's need for a rate increase or decrease. It may include adjustments to reflect known and measurable changes in operating revenues, expenses and rate base. A test year can be either historical or projected (often called "future" or "forecast" test year).

Time-of-use rates/time-varying rates *Abbreviation:* **TOU**
Rates that vary by time of day and day of the week. TOU rates are intended to reflect differences in underlying costs incurred to provide service at different times of the day or week. They may include all costs or reflect only time differentiation in a component of costs such as energy charges or demand charges.

Total service long-run incremental cost *Abbreviation:* **TSLRIC**
The cost of replicating the current utility system with new power supply, transmission and distribution resources, using current technology, and optimizing the system for current service needs. Used as a metric for the cost that a new competitive entrant would incur to provide utility services, as an indicator of the equitability of current class cost allocations and rate designs.

Tracker
A rate schedule provision giving the utility company the ability to change its rates at different points in time to recognize changes in specific costs of service items without the usual suspension period of a rate filing. Costs included in a tracker are sometimes excluded from cost of service studies. See also **adjustment clause** and **rider/tariff rider**.

Transformer
A device that raises (steps up) or lowers (steps down) the voltage in an electric system. Electricity coming out of a generator is often stepped up to very high voltages (230 kW or higher) for injection into the transmission system and then repeatedly stepped down to lower voltages as the distribution system fans out to connect to end-use customers. Some energy loss occurs with every voltage change. Generally, higher voltages can transport energy for longer distances with lower energy losses.

Transmission/transmission system
That portion of the electric system designed to carry energy in bulk, typically at voltages above 100 kV. The transmission system is operated at the highest voltage of any portion of the system. It is usually designed to either connect remote generation to local distribution facilities or to interconnect two or more utility systems to facilitate exchanges of energy between systems.

Transmission and distribution *Abbreviation:* **T&D**
The combination of transmission service and equipment and distribution service and equipment.

Used and useful
A determination on whether investment in utility infrastructure may be recovered in rate base, such that new rates will enable the utility to recover those costs in the future

when that plant will be providing service (i.e., when it will be used and useful). In general, "used" means that the facility is actually providing service, and "useful" means that, without the facility, either costs would be higher or the quality of service would be lower.

Variable resources/variable renewable resources/ intermittent resources
Technologies that generate electricity under the right conditions, such as when the sun is shining for solar.

Vertically integrated utility
A utility that owns its own generating plants (or procures power to serve all customers), transmission system and distribution lines, providing all aspects of electric service.

Volt *Abbreviation:* **V**
The standard unit of potential difference and electromotive force, formally defined to be the difference of electric potential between two points of a conductor carrying a constant current of 1 ampere, when the power dissipated between these points is equal to 1 watt. A kilovolt is equal to 1,000 volts. In abbreviations, the V is capitalized in recognition of electrical pioneer Alessandro Volta.

Volt-ampere
A unit used for apparent power in an alternating current electrical circuit, which includes both real power and reactive power. This unit is equivalent to a watt but is particularly relevant in circumstances where voltage and current are out of phase, meaning there is a non-zero amount of reactive power. This unit and its derivatives (e.g., kilovolt-ampere) are typically used for line transformers.

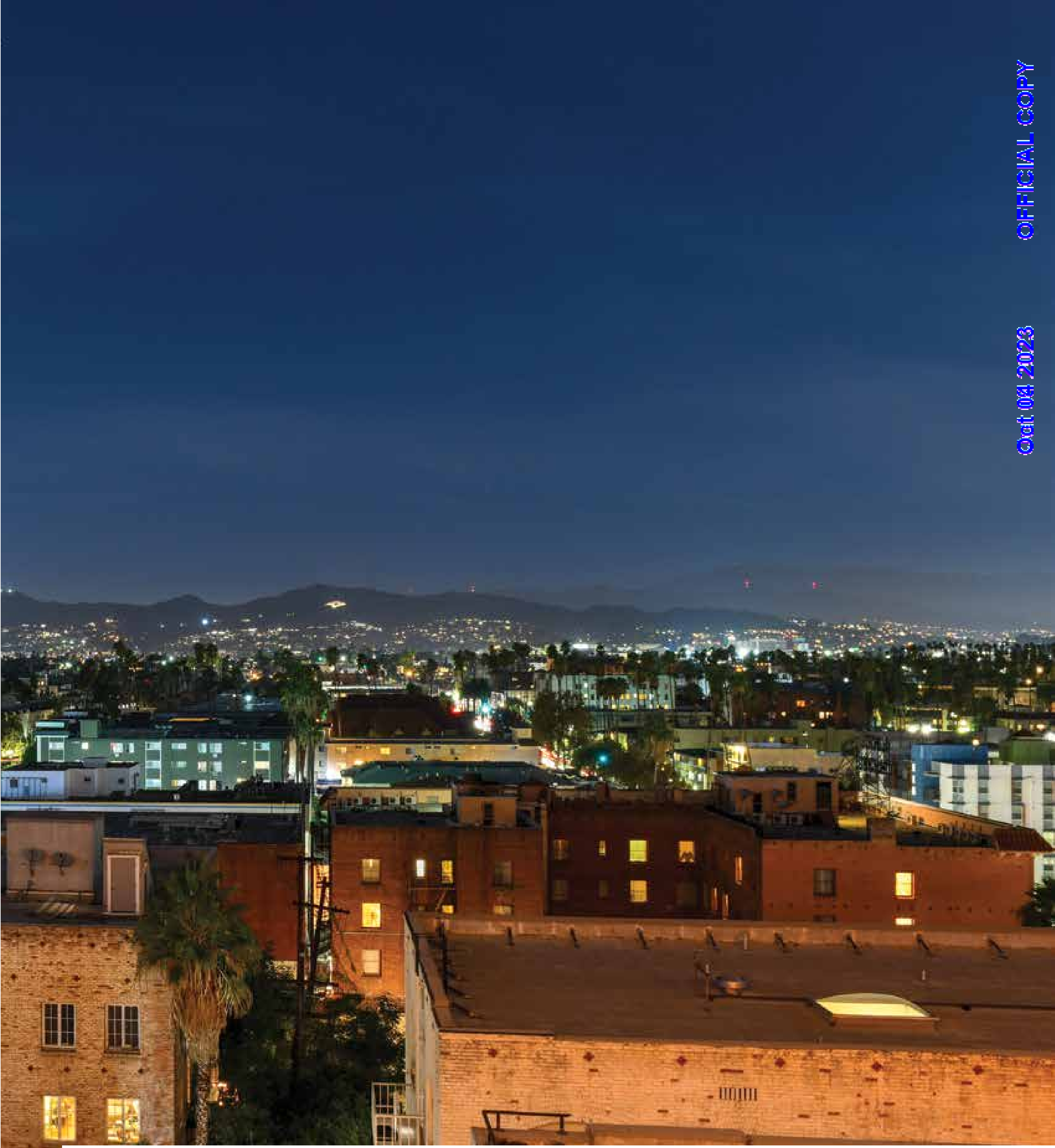
Volt-ampere reactive *Acronym:* **VAR**
A unit by which reactive power is expressed in an alternating current electric power system. Reactive power exists in an alternating current circuit when the current and voltage are not in phase.

Volumetric energy charges/volumetric rate
A rate or charge for a commodity or service calculated on the basis of the amount or volume the purchaser receives.

Watt
The electric unit used to measure power, capacity or demand. A kilowatt equals 1,000 watts; a megawatt equals 1 million watts or 1,000 kilowatts.

Watt-hour
The amount of energy generated or consumed with 1 watt of power over the course of an hour. One kilowatt-hour equals 1,000 watts consumed or delivered for one hour. One megawatt-hour equals 1,000 kilowatt-hours. One terawatt-hour equals 1,000 megawatt-hours. In abbreviations, the W is capitalized in recognition of electrical pioneer James Watt.

Zero-intercept approach/zero-intercept method
A method for classifying distribution system costs between customer-related and demand- or energy-related that uses a cost regression calculation to compare components of different size actually used in a system to estimate the costs of a hypothetical zero-capacity distribution system.



RAP®

Energy Solutions for a Changing World

Regulatory Assistance Project (RAP)®
Belgium · China · Germany · India · United States

50 State Street, Suite 3
Montpelier, VT 05602
USA

802-223-8199
raponline.org

DECEMBER 2017

Smart Non-Residential Rate Design

Optimizing Rates for Equity, Integration, and DER Deployment

Carl Linvill, PhD, Jim Lazar, Max Dupuy, Jessica Shipley, and Donna Brutkoski

Executive Summary

According to the Energy Information Administration, electricity use by non-residential customers accounts for nearly 66% of California's total consumption. Many of these customers are interested in adopting distributed energy resource (DER) technologies and many have access to sophisticated energy management and load control technologies, which means that these customers can be an important grid support resource. All utility customers stand to benefit if non-residential customers support a reliable, clean, and least-cost grid.

Current non-residential rate design, however, does not adequately encourage the deployment and use of non-residential customer resources in support of grid needs. Instead, current rate design encourages customers to control their own bills without synchronizing their consumption and production with the situation on the grid. Getting rate design right will ensure that price signals conveyed to the customer reflect what the power system needs. In other words, non-residential customer resources will become an important resource for integrating renewables and ensuring grid reliability. Well-designed price signals will induce cost-effective use of energy efficiency, self-generation, and demand response for the benefit of both the non-residential customer and all customers. Effective price signals will increase supply, decrease demand, and thus decrease market clearing prices for energy, capacity, and services.

Many California businesses, educational institutions, and city and county governments have commitments to the state's decarbonization goals, some have made commitments that go beyond state-level mandates. With well-designed rates, these leaders will have an economic incentive to make private investments that serve the public interest. These non-residential customers could become a large and beneficial contributor to least-cost, reliable decarbonization in California, but aligning their private choices with the public interest requires rate design reform.

Ascending clean energy technologies and aggressive California policy are changing the power system from one where we focused on ensuring adequate supply to meet anticipated demand, to one where active supply and active demand are optimized to ensure balance. Smart grid innovations allow utilities and customers to make more granular decisions about their energy use, while new storage technologies (including thermal storage) offer unprecedented opportunities to absorb variable energy production and shift usage. Wholesale markets are increasingly open to DER aggregators, introducing new value streams to customers who invest in DERs. Load control technologies and new end uses for electricity, especially, add new opportunities for system flexibility. For the past 125 years, the electricity industry has focused on controlling resources to match varying loads. In this new landscape, the challenge is increasingly to ensure that the power system is able to use demand and supply resources together to ensure reliability at least cost.

Rate design needs to embrace these changes—ensuring that customers have incentives to shift or control load and DER production when it benefits the system. Time-varying pricing (TVP) rate designs are necessary to better align private choice with the public interest.[1] Dynamic pricing options such as critical peak pricing (CPP) further refine price signals and are easy for customers to understand. More complicated dynamic rates like real-time pricing (RTP) can further refine price signals but require more sophisticated energy management, so are likely to be of interest to those organizations that have or hire sophisticated energy managers.

California's existing rate design evolved over decades, and transmission and distribution rates in particular have not been generally been updated to reflect the profound changes in customer loads, metering technology, and DER technologies. California is making changes like adapting the time-of-use (TOU) peak periods to match solar impacts, establishing default TOU rates, and encouraging movement toward coincident demand rates from non-coincident demand rates. Despite these interesting steps forward, California non-residential rate design has room for further improvement.

RAP's *Smart Rate Design for a Smart Future*[2] undertook an extensive discussion of residential and small commercial rate design, and identified three principles that should, in our opinion, apply to all customer classes:

- Principle 1: A customer should be able to connect to the grid for no more than the cost of connecting to the grid.
- Principle 2: Customers should pay for grid services and power supply in proportion to how much they use and when they use it.
- Principle 3: Customers who provide services to the grid should be fairly compensated for the value of what they supply.

In this paper, we propose smart non-residential rate principles that build off of these three. We propose:

---

[1] Throughout this paper we use the terms time-of-use (TOU) and time-varying pricing (TVP) to mean a volumetric price per kilowatt-hour that varies across the day, and that recovers both relevant capacity costs and relevant fixed and variable energy costs incurred to provide service in each time period.

[2] Jim Lazar and Wilson Gonzalez, "Smart Rate Design for a Smart Future," Regulatory Assistance Project, 2015, http://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future/

- Non-Residential (NR) Principle 1: The service drop, metering, and billing costs should be recovered in a customer fixed charge, but the cost of the proximate transformer most directly affected by the non-coincident usage of the customer, along with any dedicated facilities installed specifically to accommodate the customer, should be recovered in a non-coincident peak (NCP) demand charge.
- NR Principle 2.1: De-emphasize NCP demand charges except as noted in NR Principle 1. All shared generation and transmission capacity costs should be reflected in system-wide time-varying rates so that diversity benefits are equitably rewarded.
- NR Principle 2.2: Shift shared distribution network revenue requirements into regional or nodal time-varying rates. This recognizes that some costs are required to provide service at all hours, and that higher costs are incurred to size the system for peak demands.[3]
- NR Principle 2.3: Consider short-run marginal cost pricing signals and long-run marginal cost pricing signals together in establishing time-varying rates for system resources.
- NR Principle 2.4: Time-varying rates should provide pricing signals that are helpful in aligning controllable load, customer generation, and storage dispatch with electric system needs.
- NR Principle 2.5: Non-residential rate design options should exist that provide all customers with an easy-to-understand default tariff that does not require sophisticated energy management, along with more complex optional tariffs that present more refined price signals but require active management by the customer or the customer's aggregator.
- NR Principle 2.6: Optimal non-residential rate design will evolve as technology and system operations matures, so opportunities to revisit rate design should occur regularly.

RAP applied these principles to evaluate existing commercial rate designs at each of California's investor owned utilities. We found that if rate design is not changed to better align with these principles, California will continue to see underinvestment in DER resources and under-utilization of DER resources toward meeting California's policy goals.

RAP searched for rate design examples that better comport with these principles in California and elsewhere. The non-residential rate design we found that best comports with the principles and elements we have described above is that of the Sacramento Municipal Utility District. SMUD's non-commercial rate has a fixed charge to recovery customer-specific costs of billing, collection, and customer service; a site infrastructure cost ($/kW) to recover location-specific capacity costs; a super-peak demand charge ($/kW) to recover marginal T&D capacity costs associated with oversizing the system for extreme hours; and a TOU energy cost to recover all generation costs and

[3] One California municipal utility, for example, has TOU rates for commercial customers that include weekends as off-peak, but for residential customers, summer afternoons remain on-peak due to distribution system capacity constraints on residential circuits. The same concept could apply in different regions or nodes of a distribution system serving non-residential customers, where capacity constraints are reached at different times of the day or year.

remaining T&D costs. SMUD's rate sets it apart as an industry pace-setter, but we believe their rate design can be improved further.

One important goal for revision of non-residential rate design should be to better adapt to the incorporation of customer resources, such as thermal or electrical storage, customer provision of ancillary services through smart inverters, and customer load control for peak load management. The general framework of the rate design we propose directly compensates many of these through simple, clear, and compensatory TOU rate elements:

Table ES-1. Proposed Illustrative Rate Design for Non-Residential Consumers

	Production	Transmission	Distribution	Total	Unit
Metering, Billing			$100.00	$100.00	Month
Site Infrastructure Charge			$2/kW	$2/kW	kW
Summer On-Peak	$0.140	$0.020	$0.040	$0.20	kWh
Summer/Winter Mid-Peak	$0.100	$0.015	$0.035	$0.15	kWh
Summer/Winter Off-Peak	$0.070	$0.010	$0.020	$0.10	kWh
Super Off-Peak	$0.030	$0.010	$0.010	$0.05	kWh
Critical Peak	Maximum 50 hours per year			$0.75	kWh

This design is generally similar to SMUD's, with three important differences. First, it is unbundled between generation, transmission, and distribution to enable more granular application. Second, rather than have a super-on-peak demand charge, those costs are reflected in a critical peak price for up to 50 hours per year. The amount recovered is similar to that for SMUD's super-peak demand charge, but converted to an hourly rate to directly track high-cost hours and to enable better customer response as system conditions change. Third, we have introduced a super off-peak rate, consistent with the recommendation of CAISO. We have intentionally left the definition of time periods unstated, as these will be specific to particular utilities and particular nodes within each service territory, and will change over time as loads and resources evolve.

RAP also reviewed a number of real time pricing tariffs and, while we did not identify one in particular that we would classify as best practice, we did identify lessons learned from Texas, Illinois, Georgia, and Maryland that will be useful to the CPUC as it considers RTP optional tariffs. We suggest designing an RTP option that builds from our TOU plus CPP recommendation, and propose the following simple initial design:

- A wholesale energy cost component, charged on a per kWh basis, that fluctuates hourly. This would be based on the relevant CAISO zonal locational marginal price and would replace the "production cost" component of our recommendation above.
- Transmission costs and distribution costs would be collected in the same way that they are

collected under our recommendation above, as would any generation capacity costs that aren't accounted for in wholesale rates.

Note that this design would not achieve the full benefits of an ideal RTP approach. In particular, this would not include comprehensive price signals reflecting conditions on the local distribution network. Instead, the hourly pricing innovation here is increased exposure of end users to existing CAISO wholesale prices. Over time, as California introduces new approaches that animate the value stack for resources at the distribution level, new rate designs will be able to incorporate more complex and comprehensive RTP components.

Table of Contents

I. Introduction

Designing non-residential rate tariffs well is essential to California meeting its policy objectives at least cost. The consumption price signals conveyed through tariffs inform consumer choices on consuming and conserving energy and on investing in energy efficiency measures. If prices are too low when supply or delivery capacity is constrained, non-residential customers will conserve too little and invest too little in energy efficiency. If prices are too high during periods of oversupply, non-residential customers will forestall beneficial load shifting and beneficial electrification that could have helped with renewable integration. Since about two-thirds of all electricity consumption happens in the non-residential sector in California, failing to get non-residential prices right will make achieving California's carbon reduction, clean energy, energy conservation, and energy efficiency goals noticeably more expensive than necessary.

The price signals conveyed through tariffs also communicates the value of producing distributed energy resources (DER) energy and services. Getting these price signals right can encourage private investment that addresses distribution and bulk electric system needs. Some non-residential customers stand ready to help California meet its goals, so failing to get these price signals right will deprive the state of significant private investment. Private sector innovators like Stone Edge Winery, the signatories to the Corporate Energy Buyers Principles, and cities represented by the Climate Mayors have committed capital toward the clean energy future that can help California achieve its goals at least cost by leveraging private investment.[4]

Consumer and prosumer choices also affect needs on the distribution and even the wholesale electric system and affect the system costs required to ensure sustained reliable service. Utility and system operator assessments of system need and evaluation of alternatives to address identified needs are affected by non-residential consumer choices, which in turn are affected by the price signals embodied in the tariffs.

California's aggressive carbon reduction and clean energy goals have depended on and will continue to depend on wise public and private consumption, production, and investment choices to keep the cost achieving California's goals as cost-effective as possible. The fundamental goal of rate design is to align prices and costs, so that customers who use more and cause system costs pay for what they use, and those who constrain their use and reduce system costs receive appropriate savings.

Section II explains that while the fundamental goals of designing non-residential tariffs have not changed, underlying technological and policy changes have shifted far enough that fundamental changes in tariffs are necessary. Existing tariff designs generally do not support current technological capabilities as well as they could, do not reflect the changing needs of the electric system as well as they could, and they do not support wise public and private investment choices toward meeting California policy goals as well as they could. The effective adoption and use of

---

[4] See "Sonoma Vineyard Evacuated in Recent Wildfires Highlights Microgrid Benefits," *California Energy Markets*, November 3, 2017, p. 3; Corporate Renewable Energy Buyers' Principles (http://buyersprinciples.org/for-energy-buyers/); and the Climate Mayors website (http://climatemayors.org/) for stories of how private clean energy investment is being deployed and could potentially support the grid..

ascending technologies is creating a space for more cost-effective implementation of California's decarbonization and clean energy policies in the power, buildings, and transportation sectors, but rate design needs to be changed to support their adoption.[5] Section II provides several concrete examples that demonstrate how rate design needs to change to align with current and emerging technologies and policies.

Section III builds on Section II and presents a set of principles and regulatory policy recommendations to guide non-residential rate design. These principles and policy recommendations are the core of the paper, and we apply them in Section III to propose a prototypical TOU rate design and a RTP rate design that adhere to the principles and recommendations.

In Section IV, we turn to exploring how current rate designs are counterproductive to achieving California's goals. We contrast the current rate design landscape in California with rate designs that reflect the principles. We call out problems with current rate designs and lessons that can be learned from SMUD's relatively well-implemented non-residential rate design. We then provide examples demonstrating how current rate designs adversely affect several important DER technologies.

In Section V, we turn to a number of examples from around the country that offer important lessons in the possibilities for better rate design. California is a leader in implementing policies that support DER adoption and power sector carbon reduction. Nonetheless, it is useful to observe some successful innovations from other parts of the country and the world. The examples presented reinforce the principles and recommendations that conclude the report.

Section VI concludes with some summary recommendations on implementing the principles in California and presents two prototype rate designs.

[5] We introduce the term to encompass emerging technologies (i.e., new technologies that are not yet deployed but have future promise) and technologies that have been successfully deployed but will assume much broader adoption over time). Ascending technologies are collectively the transformative technologies that are moving the power sector toward a multi-way transactive sector. The text box in the next section provides examples that distinguish emerging from ascending technologies.

II. Rate Design Foundations, Ascending Technologies and California Policies

Rate design needs to change to align price signals with current technological and policy realities. This is not to say that rate design principles developed over the last 60 years do not provide useful lessons. So before turning to how ascending technologies and California policies are driving changes in rate design, we offer a very brief survey of the time-honored principles of rate design. This section then turns to highlighting how changes in technology are driving changes in rate design and a section that looks at how California policies are also driving change. This section is intended to set the stage for a discussion of rate design principles in the next section.

Rate Design Foundations

Rate design has multiple goals, including the fundamental goal of communicating cost information and aligning cost causation with prices, but also preventing price discrimination that would not occur in competitive markets, ensuring rates are fair within and among customer classes, ensuring the utility a reasonable opportunity to recover their allowed revenues, and supporting other regulatory and policy goals. Attaining these goals requires that cost allocation among classes of customers is done correctly, according to sound economic principles, and that alignment of cost causation with price paid is carefully considered. These goals sound straightforward, but their practical implementation has never been easy. For example, the terms “cost-based” and “cost-reflective” pricing have many meanings. There are as many ways of determining utility cost as there are analysts doing cost studies. And within each major approach to cost determination—including embedded cost studies, marginal cost studies, and incremental cost studies—there are many different methods used.

Fortunately, several authors of seminal texts have proposed regulatory and rate design principles that have stood the test of time, and they can guide us today in seeking to align prices and costs. We have provided a brief appendix summarizing their contributions and directing readers to useful literature reviews. For example, the observation that “the single most widely accepted rule for the governance of the regulated industries is to regulate them in such a way as to produce the same results as would be produced by effective competition, if it were feasible,” helps to guide our thinking even in the far more complex world we face today.[6] However, the fundamental task of this paper is to review these regulatory and rate design principles in light of the fundamental changes we see today.

Public policy and increasing customer demand for clean energy are affecting the mix of resources on the electric system and changing what it means for supply and demand to be in balance. Traditional rate design presumed that supply needed to chase and meet demand. However, the ascendance of variable renewable energy technologies and DER technologies means that (1) both supply and metered demand have become much more time-variant, (2) DER placement and

[6] Alfred Kahn, *The Economics of Regulation*, 1988. p. 17.

operation have location-specific effects on the distribution system that need to be accounted for, and (3) rate design now must recognize that supply and demand resources can be optimized to ensure system balance and cost minimization. Traditional rate design principles are still useful, but they have different implications in light of these changes. In this paper, we focus on how non-residential rate design needs to change to account for greater time-varying supply and demand and to support the optimization of system supply and demand.

The next two subsections summarize how ascending technologies and California policies are creating a need for fundamental change in non-residential rate design.

Ascending Technologies and Their Impact on Rate Design

Ascending technologies driven by technological advances, changes in the market structure of the industry in the western states, and changes in the expected end uses of electricity are combining to make the next decade one of likely monumental innovation.

Smart grid innovations and "big data" are an important element of this, allowing both utilities and consumers to have much greater understanding of their consumption and greater ability to make more granular decisions on production, consumption, storage, and conservation. Innovation in renewable energy has brought the cost of new wind and solar generation below the total costs of new natural gas power plants, and will likely soon fall to the level of the operating costs of existing plants.[7] Improvements in electricity storage technology, and deployment of new technologies for thermal energy storage, offer an opportunity to absorb variable energy production and to shift energy usage as never before.

Market changes are equally seismic in scale. The integration of the western energy grid through the evolution of the Energy Imbalance Market is offering the entire western region an opportunity for economic savings. A full western regional system operator, a much-discussed possibility, would create further benefits. Renegotiation of treaties with Canada will change the flexibility of the Canadian and US hydro systems to respond to new demands imposed by variable wind and solar resources. The rapid expansion of community choice aggregators is accelerating the shift in diminishing the role of California's investor-owned utilities as integrated power suppliers/purchasers.

Evolving markets for aggregators in providing demand response, storage, and delivering customer supplied energy to the grid is creating many new opportunities for customers to make self-oriented investments and enjoy market benefits from the operation of these resources. Expanded technology for load control, particularly of thermal loads (including water heating, space conditioning, and refrigerated warehouses), is creating system flexibility not previously available. New end uses for electricity—primarily from electrification of transportation, water heating, and space heating loads traditionally served by direct use of fossil fuels—are creating new market opportunities, but also potentially add new opportunities for system flexibility. If vehicles, water heaters, and cold storage

[7] See Michael Liebrich, Bloomberg New Energy Finance, "Trends in Clean Energy and Transportation," CAISO Stakeholder Symposium, October 18, 2017.

warehouses can be charged when the sun is shining or the wind is blowing, and charging curtailed when other loads demand service—that is, if these end uses are electrified in a beneficial fashion[8]—then the system gains immensely in its ability to absorb new low-cost variable renewable energy sources.

Taken together, these changes present challenges, but at the same time present plentiful opportunities to manage the challenges. For the past 125 years, the electricity industry has focused on controlling resources to match varying loads; now the challenge is increasingly to ensure the power system is able to adjust loads to match resources. Measures to deal with this include demand response, which including storage and controllable load can be used to ensure that system capacity is not exceeded by system demand, and to ensure that available resources are productively utilized. Time-varying pricing is a crucial tool in this load shaping effort.

Any new approach to rate design needs to embrace these changes. Rate design should ensure that customers make efforts to shift load to where it is valuable, and to control load when it is worthwhile to do so. The historical focus on annual, monthly, or even daily load factor becomes irrelevant in a system where the resources themselves do not produce steadily. Time-varying pricing, to reflect production, transmission, and distribution service costs, will be essential. Because the underlying costs of providing electricity vary hourly and seasonally, it is impossible for the customer to see to an appropriate price signal without that signal also varying over time. As smart technologies take hold, the connection between customer usage patterns and underlying costs will become apparent. As this happens, it is inevitable that time-differentiated pricing will become more widespread. Options such as critical peak pricing and demand response are simple, understandable, deployable, and effective. Real time pricing, where prices change as often as hourly, is another time-varying pricing tool that will be a viable option for organizations with sophisticated energy managers and customers with end uses, such as many EV charging systems, that can automatically respond to real-time prices.

Ascending and Emerging Technologies

The smart thermostat is a real product available in the market today, but only a small percentage of customers have installed them. It enables energy efficiency savings and peak demand savings. Nest proved that this technology could deliver significant load relief during the 2017 total solar eclipse. This is an **ascending technology**: available to deploy, and potentially rapidly deployed with economic and programmatic support.

The residential ice-storage air conditioner has been produced in very limited quantities by Ice Energy, for a pilot deployment overseas. It will enable load shifting and peak demand savings. It is not available for purchase in California now. The technology and control systems are being perfected as this is written. This is an **emerging technology**: it could be available for future deployment with economic and programmatic support.

[8] For more on the topic of beneficial electrification, see Keith Dennis, Jim Lazar, and Ken Colburn (July 2016), "Environmentally Beneficial Electrification: The Dawn of 'Emissions Efficiency,'" *Electricity Journal* 29/6, 52–58; and RAP's blog series: http://www.raponline.org/?sfid=5489&_sf_s=Beneficial Electrification&_sft_category=blog&sort_order=date+desc&post_date=01092017+02092017

Example 1: From Load Factor to Load Shape

An example illustrating how optimizing supply and demand resources affects pricing is the needed shift in focus from "load factor" to "load shape." "Load factor" is the ratio of average demand to peak demand. Historically, utilities and rate design have focused on improving the "load factor" of individual customers, with the expectation that this will improve the load factor of the system and thereby improve the utilization of capital investments in production, transmission, and distribution capacity. This made sense when all resources were dispatchable by injecting more fuel and a high system load factor was a primary economic planning criteria, but in a world of variable renewable energy supply, focusing on load factor without considering load shape is a serious mistake. A low-load-factor customer with irregular usage, but at off-peak times, is a beneficial load to the system because that customer increases system utilization without adding to system peak; an example is a high school football stadium, with usage only in the evening hours and mostly in the autumn. A high-load-factor customer with continuous usage, on the other hand, is always imposing a load at system peak times. Thus, focusing on load factor without considering load shape can lead to rate design decisions that are out of line with cost causation.

Precisely because of situations like this example, analysts have begun to focus on "load shape," meaning the distribution of the loads across the day, month, and year. Loads that predominantly occur during off-peak periods are more desirable (lower-cost to serve) than loads that are continuous and thus occur at the time of the system peak or distribution system peak. The advent of electric vehicle charging, customer electricity storage, ice and chilled-water storage for air conditioning, and other tools to shift load mean that some controllable but intermittent loads are more desirable—and potentially lower-cost to serve—than stable and continuous loads.

A focus on load shape is particularly important when it comes to the issue of demand charges. A demand charge measured on a customer's highest 15-minute non-coincident peak (NCP demand charge, will encourage a customer to reduce its own individual peak, regardless of the correlation with the system peak. A demand charge measured on the customer's highest usage during the expected system peak period (CP demand charge) will encourage a customer to have a high load factor relative to that customer's peak demand within the system peak window. This means that the customer likely will use similar levels of power throughout the system peak period. The effect of the demand charge price signal is to reduce benefits of diverse loads. More dynamic pricing methods can better match price to system impact than either NCP or CP demand charges. For example, a time-of-use (TOU) volumetric charge will apply equal weighting for capacity cost recovery to each hour within the peak period. This will encourage customers who may need high levels of power at 5 p.m. to decrease that usage at 6 p.m., as it is hourly use, not maximum use, that drives nearly all of their bill.

The only costs that are "caused" by an individual customer's NCP demand are those near the point of delivery, where the shared distribution circuit ends and the individual customer connection occurs. Typically, the only system components sized based on the customer NCP are the final line transformer[9] and the service wire to the meter. Everything upstream is sized based on the

[9] In the large non-residential sector, dedicated customer line transformers are the norm; for residential and very small commercial customers, shared transformers, with diversity considerations between the multiple customers, are common.

combined usage of many customers, and once upstream of the distribution substation, the correlation of local demand with system demands becomes quite close.

Example 2: Metering and Information Technology Enable Billing that Recognizes Load Diversity Benefits

Historically, system capacity costs have been recovered through non-coincident demand charges that measure each customer's individual highest usage during a month, regardless of whether the usage is coincident with the system peak. This measurement was used as a proxy for that customer's contribution to system capacity costs driven by coincident peak demands. Demand charges were implemented in this way due to the limitations of metering technology.[10] Until electronic interval meters became widespread, mechanical meters only recorded total kWh consumed and the maximum demand that occurred during the billing period. This shortcut was implemented partially because of the inability of traditional electric meters to provide more granular data on customers' usage. The availability of smart meters, and the dynamic data they provide, is now giving utility regulators the ability to focus rate designs on time-varying volumetric (per kWh) charges and dynamic pricing.

Using a non-coincident demand charge fails to bill customers accurately in two ways. First, a customer's maximum demand may occur during off-peak hours rather than during system peak periods. Though this method is roughly accurate for many large commercial customers because their highest usage *usually* coincided roughly with the system peak, even that is not always the case and is still an approximation of those customers' contributions to the incurrence of capacity costs. For smaller and more intermittent users, such as schools, churches, sports stadiums, and emergency facilities, there may be very little correlation between individual customer maximum demand and system demand.

Second, billing customers based on their individual maximum demands may unfairly allocate costs to customers with more variable demands due to the benefits of load diversity and the related ability of multiple customers to share capacity. A simple example this diversity is a school, with usage occurring primarily during the week, and a nearby church, with loads on Sunday that are much higher than other days. Clearly these two customers can share generation, transmission, and network distribution capacity; if each pays the same demand charge as a continuous-use customer (like a 24-hour mini-mart), the school and church are being overcharged, and the continuous-use customer undercharged. Conversely: a religious campus that contains both a church and a school that takes power through a single meter avoids this rate design problem. Table 4 on p. 28 presents a quantitative example that demonstrates this situation.

Rate designs that focus on non-coincident peak demand charges have the effect of focusing customers on optimizing load management to reduce their bills in ways that do not contribute to controlling system peak demand. Instead, customers will work to levelize their own demand relative to their individual peak. NCP charges also have the effect of shifting costs, without justification from cost causation, from continuous-demand customers (who are always drawing

[10] Yakubovich et al., 2005, "Electric charges: The social construction of rate systems," *Theory and Society*, 34: 579–612.

power at the time of the peak) to more sporadic customers (whose usage varies, meaning that multiple customers can share the same capacity).

With smart meters and dynamic data regulators can consider more accurate coincident peak and off-peak demand charges, not just the single hour (or 15 minutes) of usage typically used to compute non-coincident demand charges, but these are a second-best approach in light of load diversity.[11] The availability of more precise usage data makes demand charges a largely antiquated approach for all customer classes.

California Policies

California has been leading the nation in adapting utility regulation to the challenges and opportunities posed by DERs. The CPUC DER Action Plan directs utilities to plan for DER growth, preserve a role for third-party players, and utilize DERs for system operations. Senate Bill 350, a 2015 law, codified the state's 50% renewable energy mandate for 2030 (second highest in the nation, with Hawaii at 100% renewables by 2045), established a 2030 GHG reduction target of 40% below 1990 levels, and required a doubling of energy efficiency savings by 2030. The bill also specifically requires an integrated resource plan (IRP) process in which the CPUC is to recognize linkages to the transportation and building sectors and "to identify optimal portfolios of resources," including DERs, to meet California's policy goals. California's policy goals recognize and seek to leverage the ascending technology trends identified earlier in this report.

In November 2016, the CPUC released a DER Action Plan for aligning the Commission's support of DERs with the ongoing work of staff across numerous proceedings.[12] The DER Action Plan recognizes the need to remove unintentional barriers to DER deployment behind the meter and in front of the meter, and clarify the DER value proposition. In fact, the action plan specifically requires the review of non-residential demand charges and the consideration of changes to these customers' rate designs, specifically for the alignment of pricing with the DER vision. The Action Plan further directs that, "by 2017, consider changes to non-residential rate design including modification of demand charges." [13]

Rate design is debated and determined in Commission processes separate from the detailed planning processes in an IRP. But rate designs directly affect IRP assumptions and modeling results. Rate design impacts load growth and consumer behavior. These, in turn, are important assumptions that go into IRP models and influence utilities forecasts of their future needs. Pricing also affects customer decisions about whether to adopt DERs, which similarly influences the outcomes of IRP modeling. With good rate design, DER portfolios and customer load management activities can help to meet system needs and achieve benefits for customers. Rate design that does

[11] Mathematically, a demand charge spread over demand in all on-peak hours is equal to a time-varying energy charge recovering the same costs over the same hours, but such a granular demand charge has no advantage relative to dynamic pricing so these highly granular demand charges are not useful.

[12] The CPUC endorsed the DER Action Plan on November 10, 2016, and subsequently produced "California's Distributed Energy Resources Action Plan: Aligning Vision and Action," May 3, 2017.

[13] Ibid, see Action Item 1.9 on p. 3.

not properly reflect changing costs and advancing customer-side DER technologies will lead to an IRP that does not acknowledge trends already underway. That could lead to unnecessary cost burdens on society, and could fall short of optimally advancing state policy goals around DERs.

California Policy Example 1: Rate Design Affects Renewable Integration

The DER Action Plan states, "Senate Bill 350 requires the Commission to implement an integrated resource plan (IRP) process to identify optimal portfolios of resources to achieve the state's GHG goals and meet the challenge of renewable integration, and DERs will play an important role."[14]

In addition to California policy driving a need to reexamine rate design practices, there is a need to provide customers the opportunity to contribute to the cost-effective operation of the power system. Specifically, rate design affects how much and when customers choose to consume power, and influences whether they opt to install on-site generation or storage. These choices, in turn, affect whether customers can contribute to the least-cost integration of renewable energy. Improper rate design can lead to overconsumption at times when the system is already stressed or under consumption when there is an abundance of solar. It can also lead to a lack of incentive for commercial and industrial customers to invest in storage, which could be a cost-effective means for integrating California's abundant rooftop solar resource. This means that utilities must bear the entire cost of integrating variable generation, which could come at a higher cost to the system and all customers. For example, non-coincident demand charges can actually exacerbate integration challenges and cause costs for other customers by encouraging consumption at times that increase system stress.

California Policy Example 2: Rate Design Affects Beneficial EV Charging

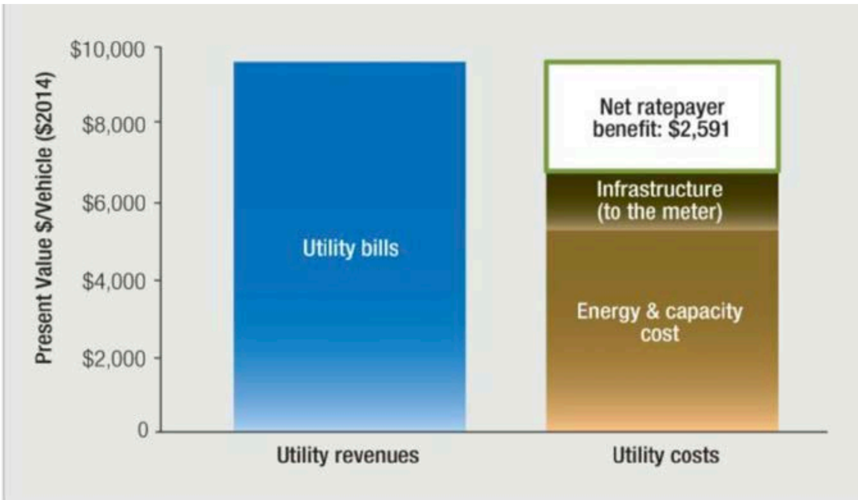
A cost-effective electricity sector can lead to least-cost power for all customers. Rate design has ramifications for this outcome as well. Commercial customers can be incented to participate in the cost-effective supply and storage of power, as well as to consume power in a way that is beneficial to the grid, which will help lower costs for all customers. For example, electric vehicles with smart charging capabilities will help reduce costs for all customers.

An analysis by Energy and Environmental Economics (E3) of EV adoption scenarios in California highlighted the significant utility system benefits from DERs (see Figure 1 on the following page). Utilities' cost to serve EV charging load was found to be less than the revenue they would be bringing in from those customers, meaning a net benefit to the utility system and to all ratepayers (not just EV drivers). Off-peak charging of EVs increases the utilization of the transmission and distribution system, lowering the average cost to serve all customers. Controlled charging enables greater integration of variable renewable energy resources.

---

[14] Ibid, p. 1.

Figure 1. Light-Duty Plug-In Electric Vehicle Load at California Utilities, Under TOU Rates



It is important to note that system and EV user benefits greatly increase with (though are not entirely dependent on) the ability to move the majority of EV charging to charge off-peak times. This point argues for appropriate rate design that includes time-of-use elements—through peak and off-peak energy—which will more accurately communicate system costs to consumers and reward those who respond by shifting their demand to low-cost hours. Dynamic pricing elements will encourage controlled charging, as customers use programmable and interactive charge controllers to avoid high-cost hours and take advantage of low-cost hours.

III. Principles for Smart Non-Residential Rate Design

In *Smart Rate Design*, RAP published an extensive discussion of residential and small commercial rate design, but identified three principles that should, in our opinion, apply to all customer classes:

1. **Principle 1: A customer should be able to connect to the grid for no more than the cost of connecting to the grid.** That is, the fixed charges should not exceed the recovery of customer-specific costs such as the final transformer (for secondary voltage customers), plus the service drop, metering, billing, and basic customer service expenses. Distribution circuit costs should not be included in the cost to connect.
2. **Principle 2: Customers should pay for grid services and power supply in proportion to how much they use and when they use it.** That is, the costs of power supply, transmission, and distribution costs should generally be recovered through volumetric charges linked to season, time of day, and other cost-reflective metrics.
3. **Principle 3: Customers who provide services to the grid should be fairly compensated for the value of what they supply.** While customers purchase *from* the grid on a "cost of service" basis, those who are suppliers *to* the grid should be treated like other suppliers, with compensation based on the value of what is supplied. This may be significantly different than the cost of service retail price, reflecting the characteristics of the products and services supplied.

Principle 1–connecting to the grid for no more than the cost of the grid—is relevant for non-residential rate design. The cost of dedicated facilities for the customer and the cost of facilities directly sized to the NCP demand is normally much greater than for residential and small commercial customers so the demand charge takes on more significance.

- Non-residential (NR) Principle 1: The service drop, metering and billing costs should be recovered in a customer fixed charge but the cost of the proximate transformer most directly affected by the non-coincident usage of the customer along with any dedicated facilities installed specifically to accommodate the customer should be recovered in a NCP demand charge.

Principle 2—recovering costs based on how much and when energy is used—is the most important of these in the California non-residential rate design context, because the costs of the shared generation, transmission, and network distribution constitute the clear majority of utility costs. NR Principle 2 includes several parts.

- NR Principle 2.1: De-emphasize NCP demand charges except as noted in NR Principle 1. All shared generation and transmission capacity costs should be reflected in system-wide time-varying rates so that diversity benefits are equitably rewarded.
  - Rationale: Non-residential customers often place diverse demands upon the electric system that can use resources in a complementary manner.
- NR Principle 2.2: Shift shared distribution network revenue requirements into regional or

nodal time-varying rates. This recognizes that some costs are required to provide service at all hours, and that higher costs are incurred to size the system for peak demands.[15]

  - Rationale: The distribution network is a shared resource where incremental investment is driven by system stress conditions. System stress conditions should align with time-varying rates that reflect the degree of stress being placed upon the system, and time-varying rates rather than coincident peak demand charges should be relied upon to communicate system stress.

- NR Principle 2.3: Consider short-run marginal cost pricing signals and long-run marginal cost pricing signals together in establishing time-varying rates for system resources.

  - Rationale: The resources and load shape needed in five to ten years should be a focus, including extensive workplace charging of EVs, higher levels of PV and wind, and eventually rising natural gas prices. Customers are making investments in durable technologies that will become part of the power system for 20 years or more, so ratemaking should be forward-looking. Short-run marginal costs, like locational marginal prices (LMP), convey important system stress price signals that should be recognized. However, long-run marginal cost price signals are also relevant in establishing time-varying rates, because new resources have durable value that displaces the need for future infrastructure and system resources and thus is responsible for avoiding certain future costs.

- NR Principle 2.4: Time-varying rates should provide pricing signals that are helpful in aligning controllable load, customer generation, and storage dispatch with electric system needs.

  - Rationale: Customers will dispatch their resources to manage their bills, but aligning price with system needs will prompt customers to dispatch their systems in a manner that supports system need. Rate design tools like critical peak pricing, time-of-use pricing, and dynamic pricing can support aligning customer resource dispatch with system needs.

- NR Principle 2.5: Non-residential rate design options should exist that provide all customers with an easy-to-understand default tariff that does not require sophisticated energy management, along with more complex optional tariffs that present more refined price signals but require active management by the customer or the customer's aggregator.

  - Rationale: The non-residential class of customers is very broad, and customers on the medium to small side of the spectrum may not have the desire or capacity to manage a complex tariff. Other customers do have that capability or will be willing to pay an aggregator to manager their consumption and resources to handle more complex pricing structures like granular dynamic pricing.

[15] One California municipal utility, for example, has TOU rates for commercial customers that include weekends as off-peak, but for residential customers, summer afternoons remain on-peak, due to distribution system capacity constraints on residential circuits. The same concept could apply in different regions or nodes of a distribution system serving non-residential customers, where capacity constraints are reached at different times of the day or year.

- NR Principle 2.6: Optimal non-residential rate design will evolve as technology and system operations matures so opportunities to revisit rate design should occur regularly.
    - Rationale: Over time, locational pricing will become more granular, perhaps with nodal pricing down to the level of the substation or the feeder. The opportunity to meet wholesale electric system needs with aggregated DERs is expanding, but is not yet matured. The opportunity to meet distribution system operator needs with direct or aggregated customer loads and DERs will mature over time. Each of these changes will affect opportunities and will affect optimal pricing signals so the rate designs implemented today should take advantage of the system as it exists but at the same time recognize it is a system in transition.

Principle 3, on DER compensation, is worth considering whether non-residential tariffs require more specific treatment to implement Principle 3, but it is beyond the scope of this paper.

One can apply these costing principles to the various components of the electric utility system in a structured manner, with rate design elements tracking the function and nature of each component of the system. Shared assets should generally be recovered on a volumetric, TOU, or RTP basis, so that shared capacity costs are paid by all consumers using that capacity on an equitable basis. The costs associated with customer-specific investments should accrue to the specific customer. Table 1 shows an example of how the different components of the system may logically track into rates.

Table 1: Tracking Electric System Elements into Rate Design

Category	Characteristics	Notes
Generation Capacity	Shared systemwide	TVR recovery appropriate across all hours when resources provide service
Generation Operating	Shared systemwide	TVR recovery appropriate
Bulk Transmission	Shared systemwide	TVR recovery appropriate
Network Transmission	Shared regional/nodes	Nodal TVR recovery appropriate
Substations	Shared local/nodes	Nodal TVR recovery appropriate
Distribution Circuits	Shared local/nodes	Nodal TVR recovery appropriate
Final Line Transformer	Dedicated or shared multi-customer	Customer-specific $/kW
Secondary Service Lines	Dedicated or shared multi-customer	Customer-specific $/kW
Meters	Customer-specific	Portion of meter costs attributable to DR, EE, loss reduction
Billing/Collection	Customer-specific	Billing frequency is volume-related

The application of the above characteristics to rate design raises an important issue: the question of whether rates should vary by sub-region, distribution circuit, or “node” within a system. We will not address these issues in depth in this paper, but a brief note on each is helpful.

Important Caveats and Future Considerations

We are attempting to stay focused on the immediate rate design issues that need to be confronted in California today. However, there are several ancillary issues that should be considered by readers today but may more appropriately be dealt with at a later time or in a different CPUC proceeding.

First, there is no doubt that local peak demand on the distribution system is not perfectly correlated with system peak demand and using local demand and local DER resources to address local distribution system stress will be a consideration to be dealt with soon. Dealing with local system stress in an equitable way is a complex issue. Historically this has not been done, with a single "on-peak" period applied system-wide. This is generally out of a sense of "perceptions of equity and fairness," one of Bonbright's key ratemaking principles. Adding differentiation by sub-region may be perceived as discriminatory (even though it is sometimes justifiable discrimination), but there is no question that distribution system nodal differences in power cost exist, and no question that peak periods sometimes vary from circuit to circuit. The CPUC has begun dealing with this for larger distribution upgrades by requiring utilities to hold non-wires alternatives competitive RFP opportunities for certain upgrades. Addressing this issue and ensuring consistency with non-residential rate design is an important issue but is beyond the scope of this paper.

Second, ensuring revenue adequacy for California's investor owned utilities so that safe, reliable and affordable grid service persists is an important goal of rate design that we did not explicitly mention in a principle. First of all, a myth exists that demand charges are likely to support revenue adequacy better than energy based charges; the text box to the right seeks to dispel this myth. Recovering costs when prices are set at short-run marginal costs has been a persistent challenge; Borenstein (2016) explains the problem well.[16] Further exacerbating this problem is the prevailing trend of diminishing variable costs (see text box below). RAP believes that a guiding principle for ensuring revenue adequacy for the utility while establishing a level playing field for new DERs is to align these goals with long-run marginal cost price signals, and this is a point of disagreement with Borenstein.[17]

Revenue Adequacy: Demand Charges vs. Energy Charges

Some rate analysts have opined that demand charges produce a more stable revenue stream than volumetric energy charges, and raise this as an objection to moving towards time-varying pricing.

RAP believes this concern is unfounded, for two reasons. First, customer NCP and CP demand tends to be highly weather-sensitive, while about 70% of energy consumption is for uses other than space conditioning, and thus not weather-affected. Second, California has a decoupling mechanism that ensures that revenue stability is not an issue for its utilities from year to year.

Looking ahead, however, we believe that time-varying volumetric pricing will be easier for consumers to understand, and thus to estimate savings that can be achieved through electrification of existing fossil energy end uses. This may help open new market opportunities for California electric utilities, and contribute to the achievement of California's energy policy goals.

[16] Severin Borenstein, "The Economics of Fixed Cost Recovery by Utilities," *Electricity Journal,* 29 (2016), 5-12.

[17] One important role of regulation is to create a level playing field between the incumbent utility's pricing and the market-derived pricing for

It is not necessary to consider this debate further here, as that is likely to detract from the central purpose of this paper, which is to provide concrete guidance on how rate design should be structured in the near future. RAP has written on this issue before, and we recommend the Weston (2000) appendix on the economics of regulation as a good resource on this view.[18]

The third caveat we wish to raise here is implications of a more transactional grid for pricing and cost recovery. Ascending technologies are setting the stage for a more transactional grid where there will be multilateral sales and purchases happening on the grid involving many transactional parties. Ensuring that all beneficiaries of the transactional grid contribute to the maintenance and improvement of a transactional grid will be paramount. Traditional models of cost causation are not well-adapted to cost recovery of transactive grid investment. This topic is beyond the scope of this paper but highly relevant to the longer-term future of rate design in California. We commend readers interested in these issues to Cazalet et al (2016).[19]

Diminishing Variable Costs Force Us to Reconsider Rate Design

California is at the forefront of a global trend in which renewable resources and technology for energy storage and load control is replacing the use of fossil fuel generation to meet varying customer requirements through the day and the year.

Many decades ago, cost allocation was relatively simple, and directly fed rate design: Nearly all generation was local (oil and gas), long distance transmission lines had not been deployed, and fuel costs were more than half the total cost of service for California electric utilities. High load factors were considered desirable.

The first and second oil embargoes of 1973-74 and 1978-79 began a transition, and the more recent directives of the California legislature to reduce carbon emissions and rely on renewable energy sources, along with decline in cost of renewables has redoubled the pace of change. As non-fuel resources are substituted for older resources, within a few years it is likely that, variable costs will be no more than 20% of the cost of service.

The challenge for cost allocation and rate design is to ensure that costs incurred to serve specific uses—baseload versus peak demand, for example—are assigned to the right customer classes in the cost allocation process, and targeted at the right periods of usage in the rate design process. Traditional embedded cost and marginal cost methods do not do this.

We can no longer rely on the notion of “fixed” or “variable” costs for guidance in designing rates. Solar and wind projects are “fixed” costs incurred to reduce emissions from burning fuel, long-considered a variable cost. Capital-intensive long-distance transmission may be built to integrate capital-intensive variable renewable resources, and while these are both “fixed” costs, they may have little or no role in meeting peak demand.

The challenge today is to ensure that costs are assigned to the purpose for which they are incurred, and those costs are recovered over the appropriate time periods when those resources provide service. The focus in this paper on shifting from demand charges to time-varying usage charges recognizes this evolution.

competitive alternatives such as on-site generation, storage, and efficiency. In RAP’s view, rates based on short-run marginal cost do not do this; only rates that reflect the full long-run incremental costs of electricity supply and distribution perform this function.

[18] Frederick Weston, “Charging for Distribution Utility Services: Issues in Rate Design,” Regulatory Assistance Project, 2000.

[19] Cazalet, De Martini, Price, Woychik, and Caldwell, “Transactive Energy Models,” prepared by the NIST Transactive Challenge: Business and Regulatory Models Working Group, September 2016.

IV. Non-Residential Rate Design in California Today

This section looks at current California IOU commercial and industrial rate design in practice, with a focus on the question of whether rates are correctly aligned with cost causation and how the alignment with cost causation can be improved. We look at rate design for generation, distribution, and transmission service components and consider whether and how well the rate designs line up with the principles outlined above. In particular, we consider whether rates for each component are time-dependent in California.

Generation

The determination of generation costs reflects energy costs (which fluctuate throughout the day with CAISO wholesale electricity market prices) and additional capacity costs incurred in resource procurement. The cost of compliance with resource adequacy and flexible capacity requirements is included in the cost of bilateral contracts and embedded, as needed, in long-term power purchase agreements.

Table 2 on p. 24 presents a SCE, PG&E, and SDG&E rate design for reference. Rate design for generation for medium and large commercial and industrial customers of California IOUs is typically as follows:

- Medium/large commercial customers of IOUs face both per/kWh and per/kW rate components related to generation.
- The per/kWh components are TOU.
- The per/kW components reflect generation capacity costs and are almost always recovered using coincident demand charges, with the demand charges applying only in the summer peak period for some utilities.

Transmission

Transmission costs are determined in a process where each transmission owner seeks approval from FERC (Federal Energy Regulatory Commission) for a “transmission revenue requirement” (TRR).[20] This revenue requirement is then allocated to end users. Here we focus on the allocation of transmission costs to the IOU distribution companies and their customers.

As with the distribution case, some transmission assets (costs) are “shared” and some can be attributed to a particular user or group of users. Currently there is a process for allocating “regional” (high-voltage) and “local” (low-voltage) transmission costs, with the “local” costs being allocated to end users in each given locality. All high-voltage assets are lumped together into an

[20] For detailed discussion of transmission revenue requirements and allocation to distribution companies, see CAISO, “How Transmission Cost Recovery Through the Transmission Access Charge Works Today,” 2017.

aggregate revenue requirement (known as R-TRR) and a "postage stamp" rate (known as the regional transmission access charge or R-TAC) is determined by dividing the R-TRR by the aggregate forecasted gross loads of all transmission owners. A local L-TAC is also calculated on a similar basis but unlike the R-TAC, the L-TAC is specific to each participating transmission owner.

The R-TAC and L-TAC are assigned to the IOU distribution companies. In particular, the R-TAC is allocated across different IOU distribution companies based on the gross load of each.[21] These distribution companies, in turn, collect from LSEs, and ultimately from end users. (The LSE may be the distribution company itself, retail service providers, or community choice aggregators.) Once the IOUs' TRRs are determined, they are allocated to customer classes (residential, small commercial, medium and large commercial, etc.) based on 12-coincident peak (12-CP) methodology that accounts for the customer class's contribution to system peak demand on the transmission system.

Finally, end-user retail transmission rates are calculated by dividing the class allocated TRR by the class billing determinant (either kWh sales, for smaller customers, or the sum of class non-coincident kW, for medium and large commercial customers). This approach results in flat (non-time-dependent) volumetric retail transmission rates for residential and small commercial customers, and (non-time-dependent) non-coincident transmission demand charges for SCE's medium and large retail commercial customers.

Therefore, while the allocation of TRR to a class of customers' accounts for the customer class's contribution to system peak demand on the transmission system, the individual customer's transmission rates do not reflect the individual customer's contribution to coincident peak demand.

End users of an IOU distribution company face the same retail transmission rates and rate design, regardless of LSE type. This rate design is approved by FERC.[22]

In summary, medium/large customers of California IOUs face transmission charges that are structured largely as non-coincident peak charges.

The CPUC has recently encouraged some IOUs to file with FERC to reduce reliance on maximum non-coincident demand charges to recover transmission costs—and move toward time-dependent rates.[23] Among the IOUs, SDG&E has taken early steps in this regard: In 2008, FERC approved SDG&E's request to have a portion of transmission revenue collection from medium/large commercial customers moved from non-coincident peak charges toward seasonally differentiated coincident peak charges. Recently, the CPUC required SDG&E to perform studies of its transmission rate design to determine if further changes are warranted.[24]

---

[21] CAISO, 2017.

[22] The involvement in retail rate design by FERC is an unusual situation that stems from California's particular restructuring situation. In other states, FERC is not typically involved with retail rate design. See: "What FERC Does Not Do" at https://www.ferc.gov/about/ferc-does.asp.

[23] See CPUC, Decision 14-12-080, p. 21, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K631/143631744.PDF; or CPUC, Decision 17-08-030, p. 92, ordering paragraph 34.

[24] In addition to these costs, there is an adjustment made called the EPMC, which is an important aspect of implementing the NERA

Distribution

For distribution network costs, two types of marginal costs are developed: marginal customer access costs (MCACs) and marginal distribution demand costs (MDDCs).

- MDDCs reflect common (shared) demand-related costs (e.g., utility wires, line transformers[25], substations). Marginal distribution demand cost ($/kW/year) is estimated based on NERA methodology.[26]
- MCACs reflect customer-specific costs, such as final line transformer investments, customer hookup costs, and customer service costs (meter reading, billing, etc.).

As with the generation component, an EPMC is calculated. Crucially, the EPMC for a given customer class is calculated as a function of customer class's annual non-coincident demand (kW) along with customer-class-specific MCAC.

Rate design for the distribution component includes the following:

- Monthly per-meter fee that reflects a portion of the MCAC;
- Per kW (non-coincident) demand charge for medium and large customers plays a larger role at SCE but PG&E and SDG&E and the NCP charge for all three is differentiated by:
  - season (summer vs. winter) and
  - voltage level;
- Per kW (coincident) demand charge for medium and large customers at PG&E and SDG&E is differentiated based on:
  - season (summer vs. winter) and
  - voltage level.

In short, medium and large customers of IOUs face charges substantially based on non-coincident peak use for shared distribution costs, while these have little cost-causative impact on distribution system investment. While the California IOUs also collect part of their distribution revenues via CP demand charges, there is good reason to believe that NCP demand charges are overused.[27]

California's existing rate design has evolved over decades with recent changes include a shift in TOU peak hours, the increasing use of CP demand charges rather than NCP demand charges, the shifting of demand charges to volumetric charges under the Option R, and, most significantly, the shift to mandatory default critical peak pricing and mandatory TOU rates by 2019. Despite these significant changes, non-residential rate design has retained features from the earlier era.

The rest of this section identifies a number of situations where rate design may need to change to match the current technological and policy context. Some are situations faced in many places, while a couple of others are specific to the California situation.

---

methodology. Detailed discussion is beyond the scope of the report, but suffice to say that the EPMC is a multiplier that is used to scale up marginal costs. It is worth noting that for distribution costs, the multiplier is driven by the NCP demand charge.

[25] Other than the final line transformer, which is closest to the customer and considered customer-related.

[26] See Appendix B for a discussion of the NERA Marginal Cost Methodology.

[27] The recent SDG&E decision, D.17-08-030, recognized this and shifted some of SDG&E's distribution NCP demand charges to CP demand charges (OP 17).

Table 2. Comparison of California IOU Rates for 500 kW Secondary Voltage Customer[28]

	SCE (Sched TOU-8)	PG&E (Sched E-19)	SDGE (Sched AI-TOU
Generation			
per kWh component			
Summer On-Peak	$0.07	$0.15	$0.12
Summer Mid-Peak	$0.05	$0.11	$0.11
Summer Off-Peak	$0.03	$0.08	$0.08
Winter On-Peak	-	-	$0.11
Winter Mid-Peak	$0.05	$0.11	$0.09
Winter Off-Peak	$0.04	$0.09	$0.07
per kW component			
Summer On-Peak	$18.92	$12.63	-
Summer Mid-Peak	$3.63	$3.12	-
Summer Maximum Demand (NCP)	-	-	$10.88
Transmission			
per kW			
Base, NCP	$4.88	$7.19	$12.05
Summer On-Peak	-	-	$2.13
Winter On-Peak	-	-	$0.66
Distribution			
per kWh component (including UDC costs, such as public purpose programs)	$0.024	$0.021	$0.004
of which, distribution only	$0.002	$0.000	$0.001
per kW component			
Base, NCP	$13.67	$10.37	$12.41
Summer On-Peak	$0.00	$6.01	$8.12
Summer Mid-Peak	$0.00	$2.06	-
Winter Mid-Peak	$0.00	$0.12	-
Winter On-Peak	-		$6.91
Customer charge per meter per month	$634.89	$599.59	$465.74

28 SCE rates: https://www.sce.com/wps/portal/home/regulatory/tariff-books/rates-pricing-choices/business-rates/!ut/p/b1/tVJNU8IwEP01PYaktPTDWwccbB1UBMa2FyYNSRttk5IGUX-9geGgDogczCnZffuy7-3CHKYwF_iVl1hzKXC9e-feMolHkT12-_HYT0Yoehj5o8WjZ7u3tgFkBoBOnAidq3-COcyJ0K2uYNYRuiRSaCr0kgoLHe4WUrTc1FhL9W4hjRVnDBRSvnQmgzXtQKs44aIEpJKcUBMuNh0XtOvAPr_7oyV8BbP-gCCfhRjYrHCAawcrEBQ-Box5RUBYyBwawuQPovtqMpyUhhbrCnDBJEy_NgbTo43B9Edjhok_r9d5ZEzYiX3TMP03F_ZeG2XhGF3fJPcoHs-nDoqdKbqbRZGDkHcA_DJO401Zy2K_GlkkCicwJijKqKKqt1EmXGnddlcWstB2u-2VUpY17RHZWOhYSSU7I_k7EmZmqfyTAxi6cHbhRM8QehcTts2iCZxBXQY6jEFevDsfc9Y00Sdd9rfQ/dl4/d5/L2dBISEvZ0FBIS9nQSEh/
PGE rates: https://www.pge.com/tariffs/index.page
SDGE rates: http://regarchive.sdge.com/tm2/ssi/inc_elec_rates_comm.html and http://www2.sdge.com/tariff/com-elec/eecc.pdf

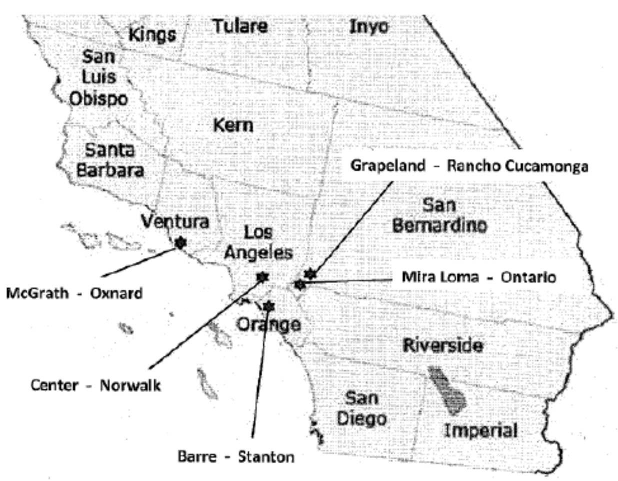
Coincident-Peak-Related Costs Should Be Recovered With Time-Varying and Critical Peak Rates

The vast majority of the power system is needed to provide service at all hours of the year, so while there are some expenses that are specifically peak-demand-related, many expenses are incurred to ensure reliable service over a broader number of hours of the year. Baseload and intermediate generation, reserves, variable renewable generation, transmission and distribution systems, billing and collection systems, and overhead are all required even if power systems have completely uniform loads. But there are some very significant costs that are required to meet peak demands, particularly during extreme peak events that occur for very few hours of the year. These costs include:

- Peaking generation and associated fuel supply
- Additional distribution system capacity needed only for peak hours
- Demand response capability to reduce loads

Many costs that are often classified as demand-related in utility cost studies, however, are typically not associated with meeting extreme peak demand. For example, peaking generators are typically built close to load centers specifically to avoid the need for transmission upgrades. Today's pollution control technology has allowed a limited number of peakers to be built in dense urban areas; units like the Lake (Burbank) and Canyon (Anaheim), which are located in the heart of these municipal service territories, and SCE peaker locations are shown on the map below. [29] Similarly, demand response measures, such as smart thermostats, industrial load rescheduling, or deployment of local storage (thermal or electrical), avoids not only generation, but may also avoid the distribution capacity needed to serve extreme events if deployed geographically where distribution loads are coincident to system loads.

Figure 3. SCE Primary Peaker Locations

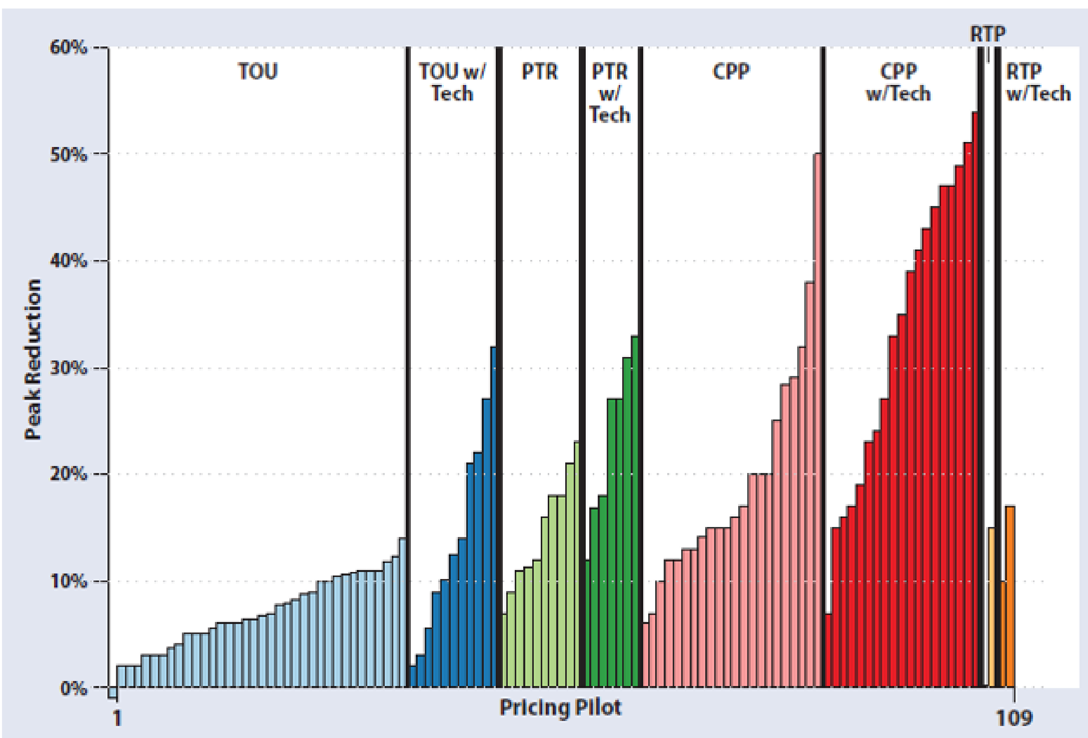


[29] From SCE-02 Vol. 09, 2015 General Rate Case.

The bulk transmission system is normally sized only to bring remote generation, sited for economic reasons, into the load centers, and to facilitate economy energy transfers with out-of-region utilities. Today, transmission is increasingly used to move power from remote wind and solar production locations, so the extent to which transmission expense is caused by peak demand is subject to debate. By contrast, the company's baseload, wind, solar, and geothermal resources are spread across California and beyond California's borders, reaching into five other states.

Extreme system coincident peaks are not predictable far in advance. A combination of extreme weather, reduced output of one or more generating units, and possible transmission and distribution system failures or maintenance activities comes together to create sporadic periods when the system is under great stress. A rate design that simply defines "4-8 p.m., Monday-Friday, June-September" as the "on-peak" period (about 350 hours, in this definition) will likely capture the period when the system is under stress—but will *also* capture hundreds of hours per year that are less stressed, and when rates should not really discourage consumption as aggressively. A coincident peak demand charge, such as that used by SCE, has a similar effect. Conversely, a critical peak pricing alternative, invoked during periodic periods of system stress (that will nearly always, but not universally, fit within the defined time window used for CP demand charges), will more accurately convey to consumers the actual times of system stress when active load management is particularly valuable.

Figure 4: Average Peak Reduction Results from Critical Peak Pricing Pilots[30]



[30] Ahmad Faruqui, Ryan Hledik, & Jennifer Palmer, "Time-Varying and Dynamic Rate Design," Regulatory Assistance Project, 2013.

California has experimented with critical peak pricing, as have other states. The load reductions achieved with CPP have exceeded 40% in some pilots. Figure 4 on the previous page shows the results of more than 100 pricing pilots; as is evident, the *combination* of **critical peak pricing** and **load control technology** deployment to help consumers adapt has proven most effective.

Because the timing of system peaks is difficult to predict, and based on the effectiveness of critical peak pricing and other dynamic pricing mechanisms like real-time pricing, RAP recommends that demand charges generally be eliminated or de-emphasized as tools for signaling the need to constrain usage at times of system stress. The costs currently recovered in most demand charges should be reflected in time-varying energy rates.

Shared Capacity Costs Should Be Recovered With Time-Varying Rates

The recovery of capacity costs (the investment in generation, transmission, and distribution system capacity) is the most significant departure from historical practice that we discuss in this paper, and the genesis of that proposal is important to understand.

Ultimately it is the result reached, not the method employed, that determines the effectiveness of a rate design in achieving regulatory and policy goals. In their seminal text *Public Utility Economics*, Garfield and Lovejoy identified a set of criteria to consider in the recovery of system capacity-related costs.

Table 3. Garfield and Lovejoy Criteria and Alternative Rate Forms

Garfield and Lovejoy Criteria	CP Demand Charge	NCP Demand Charge	TOU Energy Charge
All customers should contribute to the recovery of capacity costs.	No	Yes	Yes
The longer the period of time that customers pre-empt the use of capacity, the more they should pay for the use of that capacity.	No	No	Yes
Any service making exclusive use of capacity should be assigned 100% of the relevant cost.	Yes	No	Yes
The allocation of capacity costs should change gradually with changes in the pattern of usage.	No	No	Yes
Allocation of costs to one class should not be affected by how remaining costs are allocated to other classes.	No	No	Yes
More demand costs should be allocated to usage on-peak than off-peak.	Yes	No	Yes
Interruptible service should be allocated less capacity costs, but still contribute something.	Yes	No	Yes

Table 3[31] lists the criteria identified by the authors, and roughly compares the use of coincident-

[31] Source: Jim Lazar, "Use Great Caution in the Design of Residential Demand Charges," *Natural Gas and Electricity Journal*, February 2016.

peak demand charges, non-coincident-peak demand charges, and TOU and/or dynamic energy charges with respect to whether they serve the above criteria. While the black/white nature of this table may oversimplify, these criteria collectively recognize the importance of load diversity. Most demand charges, by applying a charge for the entire month based on use in 15 minutes to one hour of load, do not recognize diversity. The only rate forms that satisfies all the criteria are the TOU and dynamic energy rates to recover shared system costs.

This clearly shows that the TOU rate design is a more equitable and efficient way to recover capacity costs than either CP or NCP demand charges. The TOU rate recognizes that multiple customers can share the same capacity if their loads have diversity, and do require customers that utilize capacity continuously during the on-peak period to pay for the full cost of the capacity they require. Demand charges by their nature (dividing a pool of costs by a sum of demand billing determinants) inevitably shift costs from higher-load-factor customers to lower-load-factor customers, without justification by cost causation.

Simply put, if a designated “capacity-related cost” is spread over all of the hours of the period for which these costs are incurred (as a time-varying energy rate does), then any user at any window will contribute equally to recovery of the capacity costs. Five customers with intermittent usage, whose combined demands and usage are equivalent to the demand and total usage of a single larger customer, will collectively pay exactly the same amount as the single customer who utilizes the same power and energy at separate intervals of time. The shared capacity customers will likely pay much more than the continuous-demand customer.

We will present a couple of examples of how different customers with complimentary demand may be overbilled if demand charges are the basis of capacity cost recovery.

Table 4: Illustrative Example of Three Commercial Customers On A Shared Circuit

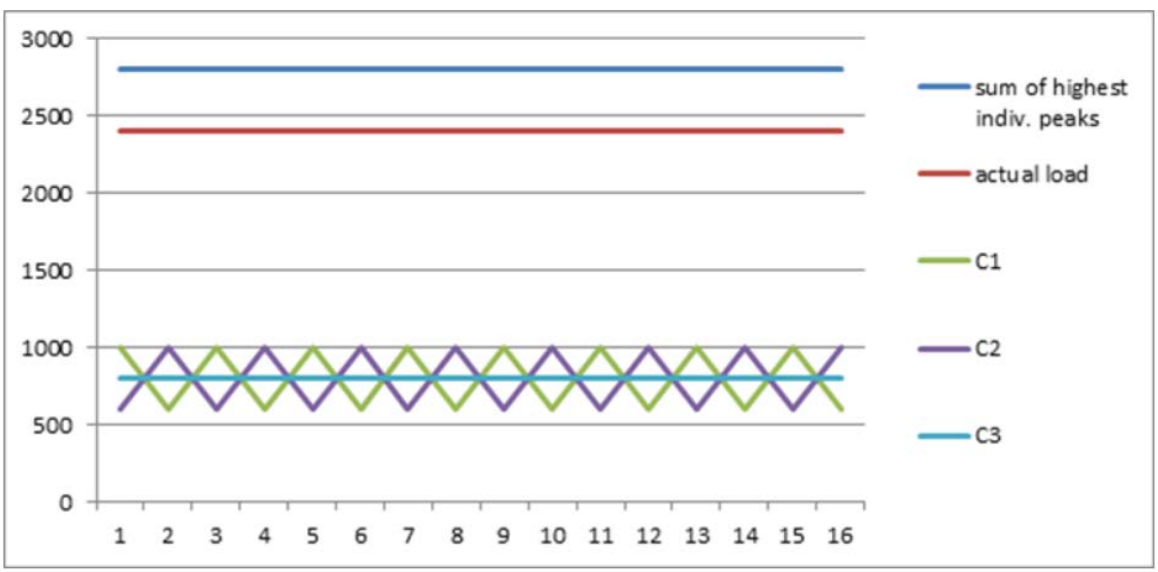
Hours	System Peak	Church	School	Mini-Mart	Total
Weekday 9-4	Mid-Peak	5	45	50	100
Weekday 4-8	On-Peak	5	15	50	70
Nights	Off-Peak	5	5	50	60
Weekend	Off-Peak	45	5	50	100
NCP		45	45	50	140
%		32%	32%	36%	
CP		5	15	50	70
%		7%	21%	71%	

One can illustrate this by looking at Table 4, which outlines a very simple node of a distribution system with three closely located customers: a school, a church, and a 24-hour mini-mart. The school has demand primarily during weekdays, with some after-school loads, and much lower loads during non-school hours. The church has demand primarily on weekends, with much lower loads during all other hours. And the mini-mart has continuous loads at all hours. Table 4 shows the loads in three broad periods, and computes the nodal demand that drives local distribution system capacity needs, as well as the contribution of each customer and the group to the system peak demand. The point is that the school and church are very complementary low-load-factor loads, that can share generation, transmission, and distribution capacity, while the mini-mart requires capacity at all times and cannot share.

Several things are evident from this simple example:

- The school and church have very complementary loads, and can easily share 50 kW of capacity.
- The mini-mart has continuous demand, and requires that capacity at all hours.
- The group of three customers has their individual peak of 100 kW at hours other than the system peak; while they require 100 kw of distribution capacity, they require only 70 kW of generation capacity at the time of the system peak.
- If billed on an NCP basis, the school and church will pay for 64% of of the billed demand, even though they never use more than 50% of the combined capacity requirement. The mini-mart will pay for only 36% of the billed demand, even though it uses 50% of the nodal demand and 71% of the group contribution to system coincident peak demand.
- The group, as a whole, does not peak at the time of the system peak.

Figure 5. Illustrative Example of Three Commercial Customer Loads



Another way of looking at this issue graphically is to compare three hypothetical utility system customers (see Figure 5 above). Customers 1 and 2 each have varying loads, with individual peak demands of 1,000 kW, but at exactly complementary times. Their combined usage never exceeds 1,600 kW. Customer 3 has a 100% load factor, with constant usage at all times of 800 kW, and exactly the same annual energy use as Customer 1 and Customer 2. If demand charges are used to collect system capacity costs, each customer would be billed based on their highest peak demand. Customers 1 and 2 would each be billed for 1,000 kW, (even though their combined load is always 1,600 kW, or 800 kW each) and Customer 3 for 800 kW, a total billing determinant of 2,800 kW. However, since only 2,400 kW of system capacity is required and used, the demand charges would be set at about 86% of the system cost per kW (2400 / (1,000 + 800 + 800)) to produce the system revenue requirement. The result would be that Customer 3, with the 100% load factor, would pay only 86% of their cost of service, while Customer 1 and Customer 2 would each pay 107% of the cost of providing their service, subsidizing the service for Customer 3.

This comes back to the basic premise of this paper that we discuss in Section II: In today's energy environment, load **shape** matters much more than load **factor**. If customer usage is at low-cost times, lower prices should apply. A customer that consumes power continuously is always going to be taking power during peak periods. Customers with varying usage may take power primarily during high-cost or during low-cost periods. Customers with diverse usage patterns can share generation, transmission, and network distribution capacity. Only the site-specific distribution system components are sized to (and thus cost-correlated to) the customer's individual maximum demands.

Street lights are approximately a 50% load factor load, but concentrated in off-peak hours. This is inexpensive to serve. By contrast, office buildings are also approximately a 50% load factor load, concentrated in high-cost hours. While the load *factor* is similar, the load *shape* is not.

Diversity is highest at the bulk power (generation and transmission) level, where hundreds of thousands (or even millions) of customers are served by the same resources. Any customer anywhere on the system can complement the usage of any other customer. At the distribution substation level, there are still hundreds or thousands of customers whose diverse usage patterns create the substation capacity requirement. At the point of connection to the distribution circuit, however, for larger commercial customers, it is most common to find a dedicated transformer or transformer bank for each customer, meaning the components must be sized for the individual customer's highest demand whenever it occurs. However, if distribution costs are recovered in time-varying charges, the continuous demand customer, who uses the distribution circuit capacity more uniformly, will benefit from the off-peak rates that will apply to much of their usage. Shared-demand customers will bear the same costs—but those with on-peak usage will bear more, and those with off-peak usage less.

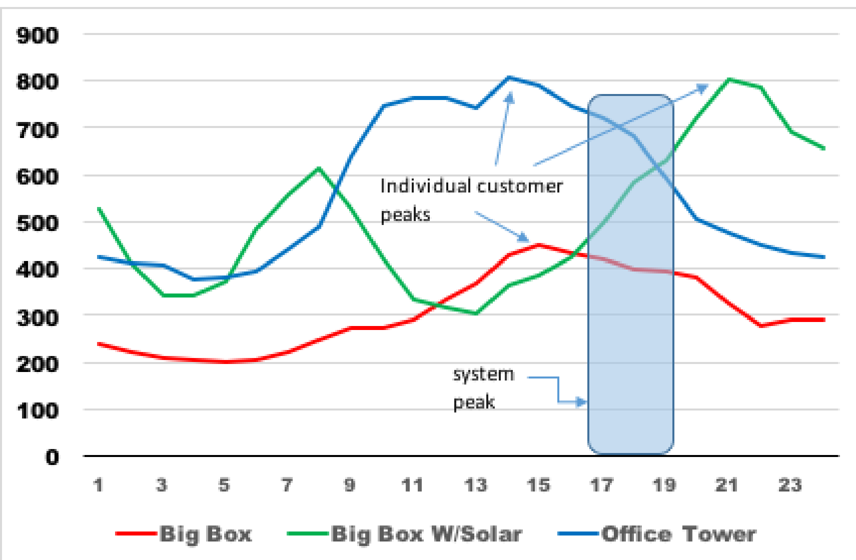
An Example of Diversity: The 2014 Commercial Solar Case

The CPUC recognized many of the issues this paper is addressing in a 2014 rate case (Application 12-12-002). In that docket, a group of large commercial customers with rooftop solar systems petitioned the Commission for relief from the utility rate design, which included both NCP and CP demand charges. The argument was that these facilities posed their highest peak demands to the system on cloudy days, and those were not system peak days. That decision explicitly discusses the arguments against both NCP demand charges (misaligned timing of charges with system peaks) and CP demand charges (failure to recognize load diversity *within* the peak period). The Commission ruled that 75% of generation-related demand charges should be shifted to the TOU energy blocks. They found that this would result in an equitable sharing of capacity costs. In a separate docket (D. 12-12-080), the Commission extended this finding to PG&E.

The evidence in that docket showed that even at the large commercial level, individual customers have diversified peaks that may differ from the system peak. This means that any demand charge measured on a short interval of one hour or less will shift costs to those customers with lower load factors who will have diversity with other customers and can share generation, transmission, and to a lesser extent, distribution capacity.

Simply looking at three specific Southern California customers illustrates this. The curves show the hourly loads on a peak day for a big-box store with solar, one without solar, and an office tower. The two non-solar customers peak around mid-day; the solar customer's load on the utility peaks in the evening. The combined peak of these three customers occurs at a time different from the peak use of any of the three. With hundreds of thousands of commercial customers in California, the diversity effect is very large. Only time-varying volumetric rates, whether TOU or dynamic, equitably share system capacity costs among multiple customers with different load patterns. Any rate design that bases capacity cost recovery on short intervals, whether concurrent with the system peak or not, is ineffective at encouraging each customer to shape load based on true system needs.

Figure 6: Hourly Loads for Three Southern California Customers[32]



Three things are important to note in this depiction of the diversity effect of multiple customers:

1. All three customers peak at different times of the day;
2. None of the three customers has their individual peak at the time of the maximum combined system peak; and
3. A customer assigned a demand charge based on their highest usage within a multi-hour

[32] Source: Sean Swe, Rate Analyst, Burbank Water and Power.

coincident peak period will bear a higher share of capacity cost than their actual share of usage at the system peak period.

A TOU rate recovering capacity costs will provide an incentive for customers to constrain their usage during each hour of the on-peak period. A CPP rate will provide an incentive for customers to constrain their usage during specific hours of system stress. Both of these are superior price signals compared with a demand charge levied on the highest use within a pre-defined multi-hour period.

What Can We Learn from SMUD?

C&I customers have the potential to invest in cost-effective DERs or DER portfolios that benefit the enterprises themselves and the management of the electric system, while contributing to achievement of California's clean energy goals. For example, combined solar and storage systems can make it possible for a customer to meet part of its own energy needs while providing capacity benefits to the system if the storage unit can be called upon during peak hours that may differ from the customer's own peak hours. Ice storage systems that "charge up" during times of system excess can help reduce renewable curtailment, help eliminate periods of negative pricing, and provide customers with a way to more cost-effectively cool spaces. EV charging, either for fleets, a company's own workforce, or the patrons visiting a commercial entity, can be managed to occur when solar is plentiful and power is cheap, thus enhancing the economics of transportation electrification, and curtailed when energy costs are high. These are but a few examples of the potential contributions that C&I customers can make toward integrating renewable energy, managing demand and reducing the need for expensive, higher-carbon peak resources.

The examples discussed above can be encouraged with good rate design—or hindered by the opposite. For example, non-coincident peak demand charges can be a significant barrier to commercial and industrial customers' willingness to provide EV charging on site or to meet its own EV fleet charging needs. Though the individual customer's peak may not coincide with the system's most stressed time, this rate structure would give the customer a strong disincentive to allow EVs to charge, if doing so would cause them to trigger a new spike in their local monthly demand. Reducing or eliminating NCP demand charges, with more costs recovered through a CP demand charge or TOU energy charges, will greatly enhance the economics for C&I customers debating whether to host EV charging at low-cost times for the grid, as well as for the drivers of EVs (assuming some amount of the charging cost is passed through to them).

Table 5 on the following page compares the rates for a 300 kW secondary voltage electricity customer (supermarket; medium office building; big box retail) on the Southern California Edison system and the Sacramento Municipal Utility District system. We pick one utility to compare with SMUD for simplicity, but any one of the three utilities could have been used for this comparison. We do not intend to call out SCE as having worse rate design than the other IOUs. The notes discuss the effect of each rate element.

Table 5. Comparison of SCE and SMUD rates for 300 kW Secondary Voltage Customer

SCE TOU-3					
	Rate	**Unit**	**Metric**	**Costs Covered**	**Comment**
Customer Charge	$446.13	Month		Customer-specific and transformer	Greatly exceeds metering and billing costs; transformer cost varies with kW. Lower to a cost-based level consistent with customer-specific metering and billing costs.
Distribution Demand Charge	$13.17	kW	NCP	~60% of distribution cost	NCP application does not reflect cost causation; concentrates costs on lower load factor customers who can share capacity. Isolate customer-specific capacity costs such as final transformer in demand charge, perhaps in contract facilities charge. Shift balance to a TOU energy rate to reflect sharing of capacity.
Distribution Energy[33]	$0.02570	kWh	All	~40% of distribution cost	Lack of TOU differentiation does not reflect cost causation; shift to a TOU basis, with off-peak at current level, and demand charges shifted into mid-peak and on-peak periods.
Transmission Demand	$4.64	kW	NCP	All transmission cost	NCP application does not reflect cost causation; concentrates costs on lower load factor customers who can share capacity. Shift to a TOU basis with baseload transmission costs reflected in all hours; peaking transmission reflected in peak hours.
Generation Demand					
Summer On-Peak	$17.42	kW	15-minute	Most generation capacity cost	Exceeds peaking capacity cost for short-duration capacity such as DR appropriate to 15-minute metric. Shift to TOU or critical peak volumetric prices.
Summer Mid-Peak	$3.43	kW	15-minute	Limited generation capacity cost	Shift to TOU.
Winter Mid-Peak	-				.
Generation Energy					Shift to a broad TOU rate
Summer On-Peak	$0.08819	kWh	12-6 pm	Marginal variable energy cost	Include relevant capacity costs in TOU rates.
Summer Mid-Peak	$0.05095	kWh	Other	Marginal variable energy cost	Include relevant capacity costs in TOU rates.
Summer Off-Peak	$0.03226	kWh	Night/ weekend	Marginal variable energy cost	Include relevant capacity costs in TOU rates.
Winter Mid-Peak	$0.04662	kWh	8 am-9 pm	Marginal variable energy cost	Include relevant capacity costs in TOU rates.
Winter Off-Peak	$0.03712	kWh	Night/ weekend	Marginal variable energy cost	Include relevant capacity costs in TOU rates.
SMUD Equivalent Rate: GS-TOU-3 300-499 kW					
	Rate	**Unit**	**Metric**	**Costs Covered**	**Comment**
Customer Charge	$106.85	Month		Metering, billing, collection, customer service	Reflects customer-specific costs for metering and billing.
Site Infrastructure	$3.76	kW	Contract demand	At-site equipment, including transformer	Consistent with site-specific costs; fixed from month to month.
Summer Super Peak	$7.57	kW	15-minute	Needle-peaking generation, transmission, distribution?	Only applicable five hours a day, weekdays, summer. Use of longer metric would improve equity to shared demand customers.
Energy Charge					
Summer Super Peak	$0.1986	kWh		Baseload, intermediate, peaking generation, transmission, distribution	Incorporation of most capacity costs into TOU energy rates adds simplicity, equity.
Summer On-Peak	$0.1357	kWh		Baseload, intermediate generation, transmission, distribution	
Summer Off-Peak	$0.1079	kWh		Baseload generation, transmission, distribution	
Winter On-Peak	$0.1032	kWh		Baseload, intermediate generation, transmission, distribution	
Winter Off-Peak	$0.0820	kWh		Baseload generation, transmission, distribution	Off-peak energy rates recover baseload resource costs.

[33] Calling this "distribution energy" may be misleading or confusing. Almost all of the charge is Public Purpose Programs Charge, New System Generation Charge, etc. Only $0.0021 is “distribution.”

The SCE on-peak energy charge in summer is about one-third that of SMUD, while the demand charges are three-times those of SMUD. The SCE rate creates powerful incentives, in the form of a combined generation, transmission, and distribution demand charge of about $30/kW, for customers to focus on limiting their individual 15-minute peak demand within the on-peak period. By contrast, the SMUD rate, by recovering most of these costs in the TOU energy rate, provides a limited incentive for focus on the 15-minute demand, and a much larger focus on controlling usage across the entire super-peak period. Since generation, transmission, and network distribution capacity is shared, an individual customer's 15-minute demand is largely irrelevant to system capacity planning; the collective usage of all customers in the various periods drives the resource development needed to provide reliable service.

The SMUD rate is not ideal, in that the super-peak demand charge is still based on the customer's highest 15-minute usage within a 132-hour (six hours a day, weekdays, per month) period. A lot of diversity is possible within that period. The challenge, of course, is to identify in advance when the system peak will occur, to set prices that coincide with that peak. A better approach, in our opinion, is to use TOU energy charges to recover predictable capacity costs across the broad system-peak period, and then to use critical peak pricing or other demand-response measures for the extreme system peak periods, which occur only sporadically on days that cannot be predicted in advance. California's extensive experience, and global experience, with critical peak pricing shows that it is effective.

NCP demand charges incentivize customers to use storage in a way that benefits their own load shape, not provide grid benefits (i.e., at the system's peak times).

Optional Real-Time Pricing for Sophisticated Energy Managers

Some analysts argue that real-time pricing—where a significant amount of shared system costs are recovered through an energy charge that fluctuates freely every hour—gives customers a much stronger incentive to curtail loads at high-cost times in a way that reduces costs and carbon emissions. Others argue that real-time pricing signals in California today are not strong enough nor predictable enough to induce investment in energy management technologies. These analysts would argue that a TOU pricing targeted on a narrow period, say a two-hour period, or a critical peak price is a more concentrated price signal and more certain, and thus would more readily elicit active load management and possibly even an incremental DER investment response. Real-time prices more accurately convey short-run market price information and they can be readily extended to more granular locational pricing on the distribution system over time, so there is reason to proceed with RTP pilots that give active energy managers the opportunity to build value propositions around these prices. However, there is also a case to be made for continuing to offer TOU and critical peak pricing options, as they may better reflect long-run costs and facilitate greater customer understanding and response during occasional periods of system stress.

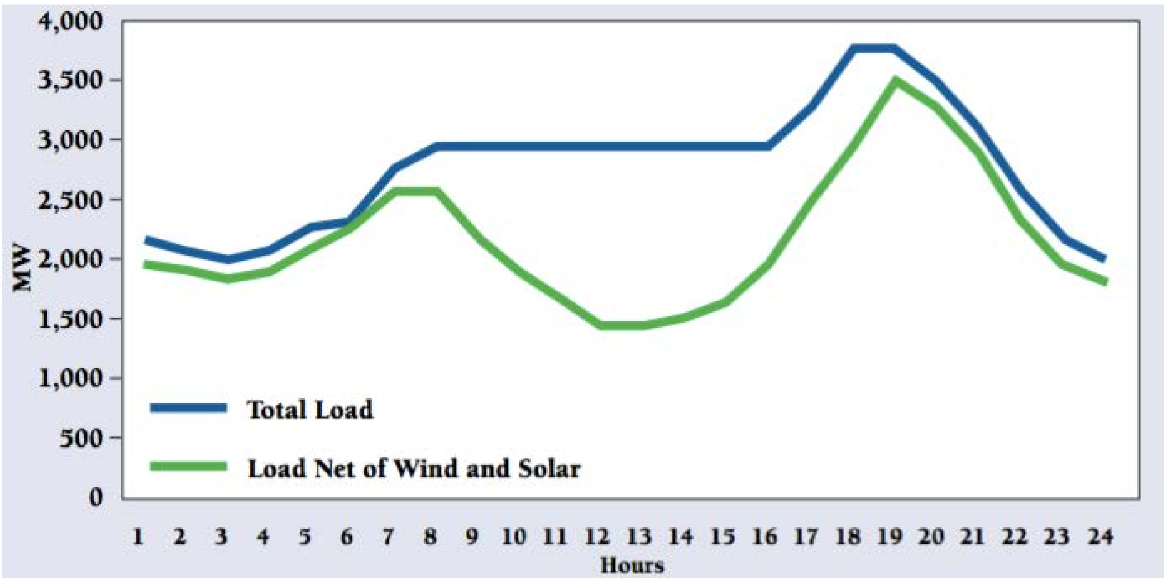
We will talk about experiences with RTP and CPP more in Section V, as we examine what we can learn from others outside California.

Some Examples of How Rate Design Affects Beneficial DER Adoption and Operation

California faces the challenge of increasing reliance on variable renewable resources, and many opportunities to utilize emerging technologies to meet that challenge. Beneficial adoption and operation of DER resources can help with these integration challenges, but rate design needs to support and not deter such beneficial use.

The prospect of managing larger ramping requirements, along with attendant grid stability challenges, is raising some concerns among utility engineers and managers. See Figure 7 below.[34]

Figure 7. Illustration of Daily Load Pattern Faced by Utility



These issues are being exacerbated by the problems with California's rate design—particularly the still insufficient emphasis (discussed above) on time-varying rate designs. We identify below several separate elements of these challenges and opportunities.

1. High-impact EE providing savings in key hours

There is need for increased energy efficiency programs targeted at specific customer uses in problem hours. For example, LED lighting retrofits can help reduce the upward movement seen in both the blue and green lines in Figure 7 during the hours around 5 p.m. (i.e., the "shoulder period").

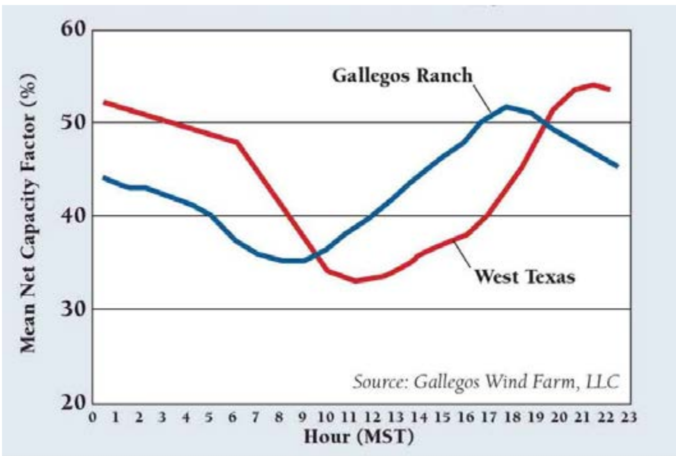
In addition, air conditioning is a major driver of peak demand, and could be a profitable target for EE and thermal storage investments. A time-varying rate directed toward A/C would pay a double dividend, as A/C has great potential for both demand response and thermal energy storage).

[34] Jim Lazar, "Teaching the 'Duck' to Fly (Second Edition)," Regulatory Assistance Project, https://www.raponline.org/knowledge-center/teaching-the-duck-to-fly-second-edition/.

2. DG that performs in key hours

Except in the spring months, solar energy is a generally load-matched resource, serving loads during the business day, when loads historically have increased. But at some point, other times of day become a challenge, and solar ceases to be well matched to loads. For example, one wind developer in New Mexico published a very favorable wind profile:

Figure 8. Annual 80-m Diurnal Wind Energy Patterns



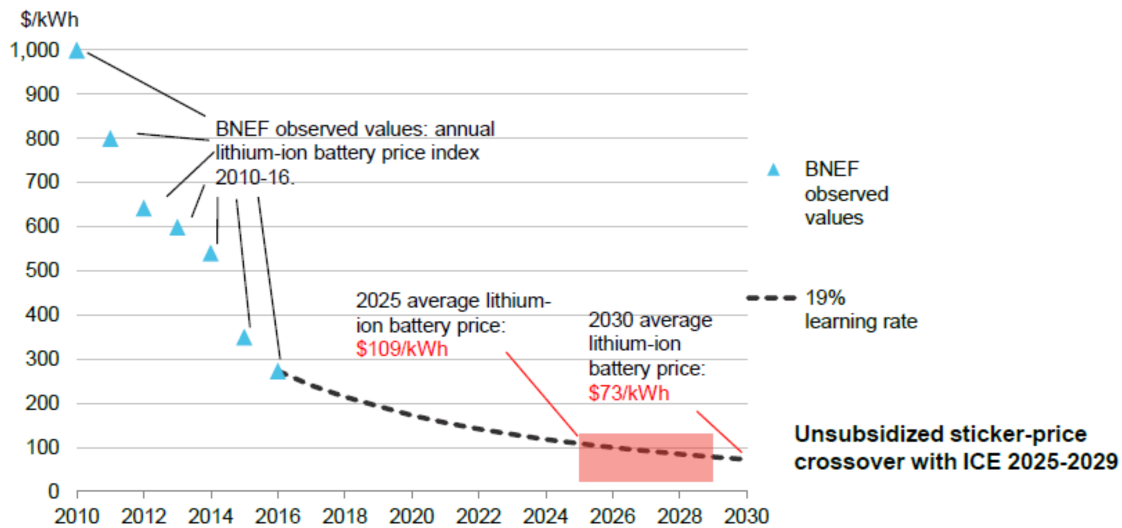
Using biomass resources, which are generally fully dispatchable, becomes an important option. Redispatch of California's extensive hydro resources is an important opportunity; these have historically been dispatched during the mid-day peak, but as the peak to be served with controllable resources shifts, so can the dispatch of these resources.

3. Storage: both thermal and electrical storage

The cost of electrical energy storage has been coming down rapidly, although it is still quite expensive. There are growing expectations of further price declines.

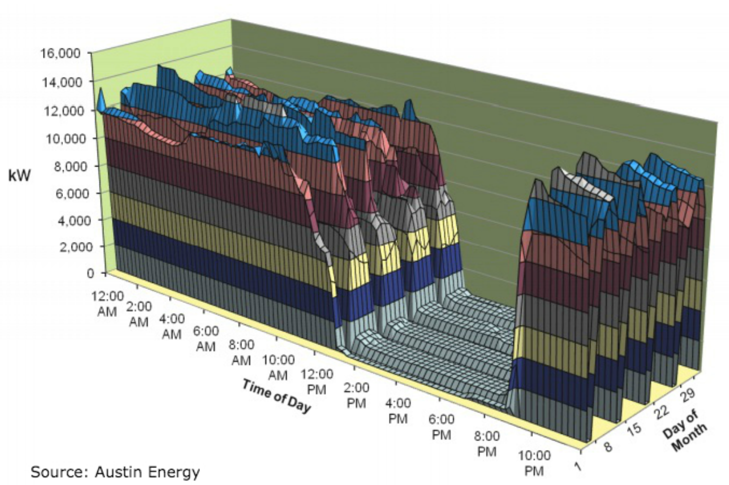
Storage can provide peak power anytime (and almost anywhere); renewable energy produced during low-demand periods of the day can effectively be stored until a later, more valuable time period. An extremely important potential resource is ice and chilled water storage for air conditioning. These technologies can be charged during low-cost periods of wind and solar production, and then utilized for cooling later in the day. Austin Energy has deployed several central cooling plants in their commercial core. Advanced non-residential rate design will encourage cost-effective deployment of customer storage resources.

Figure 9. Declining Costs of Battery Storage[35]



A less effective, but still valuable form of thermal storage can be achieved without any capital investment, by simply pre-cooling a structure before the on-peak period, and allowing it to "coast through" the high-cost period. In buildings with substantial structural, furniture, paper, and equipment thermal mass, the temperature will rise slowly during the coast-through period.

Figure 10. Central Cooling Energy Management at Austin Energy



Source: Austin Energy

35 Bloomberg New Energy Finance.

4. EV fleets

EV batteries present the opportunity to control the timing of when they are charged, and perhaps the future option of reversing flow from batteries during periods of severe grid stress.

Ideally, EV owners and operators will choose to charge EVs during the times of day when power is plentiful and lower-cost, and impose little or no incremental peak demand to the system.

A key emerging opportunity is the charging of EV fleets. Providing the right incentives for commercial managers of these fleets is a promising area, because these fleets many ramp up quickly in size and because these managers should be sensitive to charging costs and have the flexibility to manage charging.

However, demand charges (especially NCD charges) are a major barrier to economic EV fleet charging. A recent study from the Rocky Mountain Institute identified demand charges as a major barrier to EV deployment.[36]

5. Workplace charging of employee EVs

Another significant opportunity is in the area of workplace charging of employee EVs. Under current typical NCP demand charge rate designs, employers would likely spike their monthly demands by allowing workplace charging. But, if it can be limited to low-cost hours, workplace charging can help adapt the system to higher levels of variable renewables. Employees who own EVs sometimes need to charge during the day, while at work, and may take advantage of such opportunities at the workplace. From a power system point of view, this may make sense as it can help align power usage with, say, low-energy-cost late mornings. Good rate design—particularly time-dependent design principles discussed in this paper—can help encourage more workplaces to offer employee and visitor charging.

The Electric School Bus: A Special Opportunity

Many transit agencies are implementing electrification programs, and SCE recently filed for a five-year waiver of demand charges to help enable transit electrification. However, electric school buses may be an even more attractive option:

a) Transit buses operate for up to 300 miles per day; carrying adequate battery capacity is difficult and expensive, and deploying high-speed charging systems is expensive and challenging for the grid.

b) School buses typically travel about 50 miles per day, making the battery capacity lower, and adding flexibility to charge at mid-day (solar) or overnight (wind).

c) School buses are typically sedentary from 10–2, peak hours to absorb excess solar generation.

d) School buses could be an ideal vehicle-to-grid resource. One study by the Vermont Energy Investment Corporation showed that the school bus fleet of New England could supply about 1,000 MW of peaking capacity to the grid in a V2G configuration.

e) BUT: Charging on this type of schedule will produce extremely poor load factors, but can produce very good load shape.

Rate design will have a significant influence on the viability of this technology.

---

36 Rocky Mountain Institute, "From Gas to Grid," 2017, https://www.rmi.org/insights/reports/from_gas_to_grid/

6. Suboptimal operation of existing "flexibility"

California's power system has existing flexibility in several forms. There are existing hydro resources (discussed above) that provide great flexibility. The Helms pumped storage facility, originally constructed to provide flexibility to the output of the Diablo Canyon nuclear plant, can be used for any purpose. System flexibility resources can be directly controlled by the grid operator, and easily redeployed.

But customer flexibility is a different matter. Customers will respond to economic incentives and programmatic offerings. Existing air conditioner cycling programs, for example, may require programmatic changes to align the ability to control these loads to current needs.

Current rate designs misalign customer benefits (opportunities for bill reduction) with grid benefits, causing misuse of storage resources (from a grid perspective) and neglected opportunities to provide grid benefits (e.g., by increasing energy uptake during renewable curtailment hours or by pre-cooling during hot summer days).

Customer investment in new storage technology, whether electrical or thermal, depends on the rate design the customer faces. And proper utilization of that technology is important. High demand charges, as now exist, will indeed encourage customer investment in storage; Calmac, a leading provider of ice storage for commercial air conditioning, has indicated to the authors that a demand charge of $14/kW (or a $.06/kWh TOU differential) will produce an acceptable return on their systems for most commercial building operators to invest in storage. BUT, with a demand charge in place, the incentive then will be to use that storage to levelize load at the lowest level achievable, not to optimize load across all hours of the day. Only a time-varying rate will encourage the building operator to optimize usage in the context of overall grid costs. For example, the office tower in Figure 6 on p. 31 would likely use storage between 10 a.m. and 4 p.m., to reduce their demand charge (and thereby their demand charge); however, the system would be better off if that same storage were used to reduce load between 5 p.m. and 8 p.m., when the system peak occurs. The shift of demand charge revenues into TOU rate periods will enhance customer deployment and utilization of cost-effective on-site storage technologies.

7. Solar plus storage: Bad rate design results in uneconomic deployment

NCP demand charges can influence C&I customers with solar PV generation on-site to invest in otherwise uneconomic storage in order to reduce demand charges. In particular, customers with on-site solar may serve their daytime peak demand with solar, leaving a short spike at the end of the solar day before operations wind down. This may be uneconomic when the customer's on-peak load does not match the system load—the storage may be deployed to shave a peak that has little or no consequence for the utility system, and then the storage may be unavailable to reduce system peak demand. RAP addressed this in a posting earlier this year[37], and a recent paper from NREL and LBNL studied this phenomenon in greater detail.[38]

---

[37] Jim Lazar, "With Sinking Storage Costs, Big Box Solar Could Really Take Off," Regulatory Assistance Project, 2017, http://www.raponline.org/blog/with-sinking-storage-costs-big-box-solar-could-really-take-off/

[38] Gagnon et. al., "Solar + Storage Synergies for Managing Commercial-Customer Demand Charges," Lawrence Berkeley National Laboratory, https://emp.lbl.gov/publications/solar-storage-synergies-managing

V. What Can We Learn from Others?

Comparison of Large Commercial Rates of Major US Utilities

As a part of this project, RAP reviewed the commercial rates of general application for many of the largest electric utilities in the US, for the large utilities in California, and a few selected international examples. Table 6 on p. 41 shows a partial summary of that review.

In keeping with the principles of smart rate design we outlined above and the other opportunities and challenges we have explored thus far, key features we looked for in these rate designs include:

- Reasonable customer charges reflecting the recovery of customer-specific costs such as the service drop, metering, billing, and basic customer service expenses;
- Small NCP demand charges focused on the most local distribution cost recovery, such as the final line transformer, where component sizing must track individual customer load;
- Coincident peak demand charges for generation, transmission, and shared distribution system costs, focused on no more than a five-hour peak period;
- Seasonal energy charges;
- TOU energy charges; and,
- The emphasis of cost recovery in energy charges, rather than demand charges.

We note that few of the national examples are as sophisticated as the existing California IOU rates. In fact, no other domestic utility that we surveyed offers a tariff with both seasonal and time-varying energy charges (some have one but not the other). We also found it notable that very few other utilities outside of California from non-restructured states offer separate distribution and generation demand charges. This additional level of information granularity available in California may become useful as more customer-sited generation resources are brought onto the system, though we note that both LADWP and PG&E do not yet offer that type of rate. We were surprised to find a number of Wright-Hopkinson rate forms (load factor blocks), as we generally view this rate design as quite antiquated. We found very few utilities with coincident peak demand charges, though several do have time-varying energy charges. Outside of California, most utilities offer a low customer charge (with the exception of Portland General Electric). Georgia Power's tariff is notable because it is one of the few with a CP demand charge and time-varying energy charges.

Pragmatically, the only example that met all of our general criterial is the current rate from SMUD, set forth earlier in Table 5 on p. 33, which we consider a good illustrative rate for discussion for the other California utilities. SCE offers a generation demand charge that is time-varying, but it is not coincident with system peak and it is combined with an NCP distribution demand charge. SDG&E is quite similar in that they offer time-varying generation and distribution demand charges, but neither are coincident with system peak. The SMUD rate design is not perfect, but it aligns with most principles.

Table 6. Overview of Non-Residential Rates Applicable to 300kW Commercial Customer

		Customer Charge	Combined or Distribution Demand Charges				Separate Generation Demand Charges			Hopkinson Rate	Energy Charges	
Utility	Schedule	$/Month	Flat?	Seasonal?	TOU?	Coincident ≤ 5 Hours	Seasonal?	TOU?	Coincident ≤ 5 Hours	Load Factor Blocks	Seasonal?	TOU?
LADWP	A2B	28	No	No	Yes	Yes	No	No	No	No	Yes	Yes
PG&E	A10	138	No	Yes	No	No	No	No	No	No	Yes	Yes
SDG&E	AL-TOU	116	No	Yes	Yes	No	Yes	Yes	No	No	Yes	Yes
SCE	TOUGS3	446	Yes	No	No	No	Yes	Yes	No	No	Yes	Yes
SMUD	GSTOU3	107	Yes	No	No	Yes	Yes	Yes	Yes	No	Yes	Yes
Florida Power	GSDT1	25	Yes	No	No	No	Yes	Yes	No	No	No	Yes
Virginia Electric	GS2t	26	Yes	No	No	No	Yes	Yes	No	No	No	Yes
Georgia Power	GSD10	209	No	No	Yes	Yes	-	-	-	No	No	Yes
Duke SC*	LGS	17	Yes	No	No	No	-	-	-	Yes	No	No
Detroit Edison	D4	14	Yes	No	No	No	-	-	-	Yes	No	No
Duke Florida	GSDT1	12	No	No	Yes	No	-	-	-	No	No	Yes
Ameren Missouri*	LGS	94	No	Yes	No	No	-	-	-	Yes	Yes	No
Alabama Power*	LPM	50	Yes	No	No	No	-	-	-	Yes	No	No
Duke NC	SGSTOU42A	29	No	No	Yes	No	-	-	-	No	No	Yes
NoStates Power*	A14	26	No	Yes	No	No	-	-	-	Yes	No	No
PEPCO MD	MGT3A	40	No	Yes	Yes	No	-	-	-	No	Yes	No
Portland GE	NEDNR	420	No	No	Yes	No	-	-	-	No	No	Yes
Eskom South Africa	Megaflex		Yes	No	No	No	-	-	-	No	Yes	Yes
Shanghai China			Yes	No	No	No	No	Yes	No	No	Yes	Yes

Note: "Flat" demand charges are those that do not have any time or seasonal variation to them. Utilities marked with * also offer customers of this size optional tariffs with time-varying energy charges.

Texas: Energy-Only Market

Texas has some features worth paying attention to in California, related to the design of the ERCOT market. First, because the ERCOT energy market—which has a footprint that covers most of the state—does not include any generation capacity cost mechanism, there is no per-kW cost that needs to flow through to generation cost allocation and rate design. In other words, ERCOT is an "energy-only" market in which generators (and other resources) in the ERCOT market recover their captial costs during peak periods when energy prices are high.[39] All generation costs (including fuel costs and capital costs, etc.) are allocated down to the LSE level in the form of energy (per/kWh) prices. As a result, the scope for efficient time-varying allocation of generation costs to end users is, at least in principle, greater than in jurisdictions where generator fixed costs are recovered through fixed charges.[40]

Second, in ERCOT, embedded transmission costs are allocated to some medium/large commercial end-users based on the individual customer's coincident peak, with usage in four ERCOT peak hours (one in each of four summer months) used to determine charges for the subsequent year. In the ERCOT footprint, service providers help commercial and industrial consumers to predict the ERCOT system peak hours, so that usage can be adjusted and costs reduced.[41] These customers typically receive forecasted warnings of upcoming grid peak periods that will determine the customer's transmission charge for the following year.

Illinois Hourly Pricing Tariffs

In Illinois, the two largest utilities offer real-time pricing options known as "hourly pricing."[42] These options are for residential customers, but we discuss them here because the general approach could easily be applied to non-residential customers in California. The tariff includes a generation (production) energy cost component—a per-kWh price that fluctuates hourly, in line with PJM LMP wholesale market prices. Other per kWh and per kW components collect transmission and distribution costs, as well as generation capacity costs not included in the PJM LMP wholesale prices. The results reported to date indicate that residential customers would have paid on average $86 less per year had they been on the real-time pricing tariff, and the benefits were broadly evident with more than 90% of customers projected to have lower bills under the RTP tariff**.**

Georgia Power Real-Time Pricing Tariffs

Georgia Power is a large investor-owned utility with a significant industrial base. For more than ten years, it has offered these customers a real-time pricing option. This is characterized as "baseline-

---

[39] Note that, as in California, congestion costs are also reflected in ERCOT wholesale energy market prices (and these congestion costs reflect the marginal cost of grid usage at a given location).

[40] It is important not to try to make a direct analogy between California and Texas. Texas has a much greater degree of retail competition. Retailers offer a range of different rate options, some of which are time-varying in nature.

[41] For detailed discussion, see http://energytariffexperts.com/blog/2013/7/17/ercot-4cp-june-2013-review and https://www.electricchoice.com/blog/4-coincident-peak-program/

[42] See Jeff Zehtmayr and David Kolata, "The Costs and Benefits of Real-Time Pricing," Illinois Citizens Utility Board, 2017, https://citizensutilityboard.org/wp-content/uploads/2017/11/20171114_FinalRealTimePricingWhitepaper.pdf

referenced," because customers only experience real-time prices for deviations in their usage (up or down), not for the total usage. The mechanism has the following characteristics:

- A customer baseline is established for each participating customer;
- Usage at the baseline is priced at a price determined through regulation, based on the utility cost of service;
- The customer is given notice of day-ahead prices; and
- Deviations from the baseline usage are charged or credited at the real-time price.

In essence, the customer "subscribes" to power at a regulated price, and then can consume greater or lesser amounts at a real-time price.[43] These tariffs have proven acceptable, and in 2011 became the standard tariff for large-use customers. An option to choose a fixed-price tariff is available after three years on a real-time rate.

Washington Real-Time Pricing Experiment

In 1996, industrial customers of Puget Sound Energy, the largest electric utility in Washington State, requested access to wholesale market pricing for electricity. The approach that was approved had three key elements:

a) a transition charge for three years, during which time they paid a portion of the cost for stranded utility generating capacity until it could be absorbed by growth in usage by other customers;

b) a delivery charge based on the cost of transmission services; and

c) a daily price for on-peak and for off-peak power, based on day-ahead wholesale prices at the largest regional trading hub for electricity.

For the first three years, wholesale market prices were significantly lower than the costs embedded in retail rates, and the customers saved millions of dollars. In the fourth year, the western United States suffered a drought that reduced hydropower availability and put extreme pressure on natural gas supplies to provide relief generation, generally known as the California Energy Crisis of 2000-2001. Wholesale market prices soared to previously unknown levels. The customers, fully exposed to market prices, took drastic steps to adapt, including renting onsite diesel generators and curtailing operations. One major industrial facility, the Georgia-Pacific pulp and paper mill in Bellingham, WA, did not survive the economic impact of the power crisis, and closed permanently. Eventually, in October 2000, the customers approached the Washington Utilities and Transportation Commission for regulatory relief, which was granted in the form of permission to enter into long-term contracts for power with non-utility suppliers, a form of open access not available to other retail customers.

Experience in regions providing open access to industrial customers suggests that some large users will choose a fixed-price plan over a dynamic rate, because the stability of cost allows them to make

[43] Georgia Real Time Pricing Day-Ahead With Adjustable CBL Schedule "RTP-DAA-4."

reasoned business decisions. An industry making sales commitments at contract prices for delivery months or even years ahead may prefer to "lock in" as many cost drivers as possible, including power supply costs.

We hope the experience of the energy crisis period is never repeated, but this is a cautionary tale worth remembering as customers assume greater risk for self-provision.

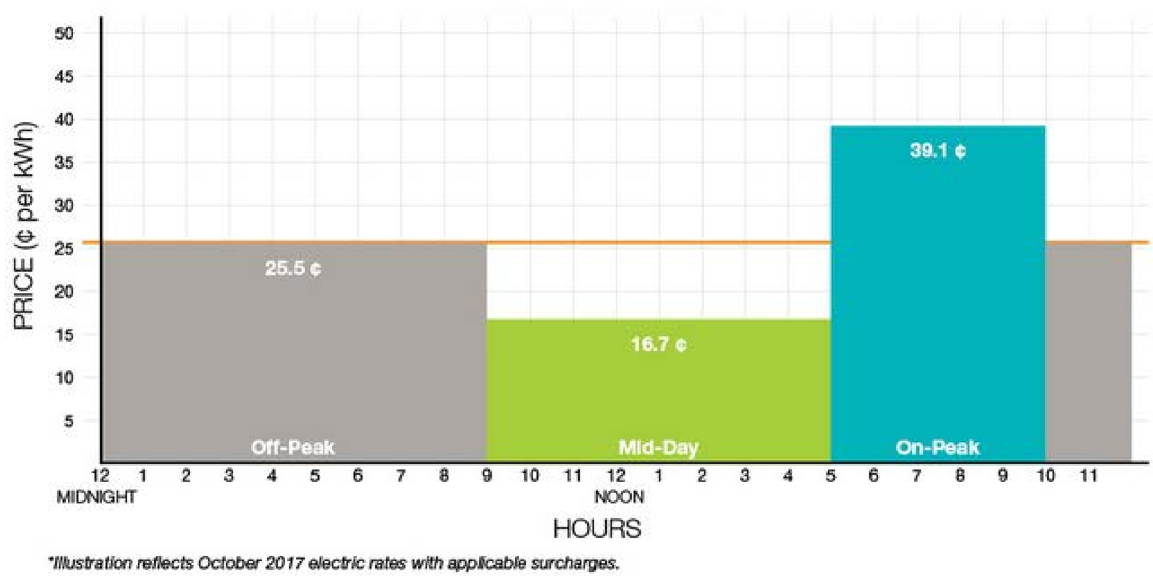
Hawaii TOU Rates

Hawaii has the highest level of installed solar as a percentage of system load of any US state, with installed solar exceeding 50% of peak demand on some islands. Renewables are being regularly curtailed, and new solar connections are being strictly limited to enable adequate grid management capability. The Hawaii PUC recently allowed additional solar installations if they are controllable by the grid operator, or have attached storage that can be programmed to take any excess generation that might be exported.

While this is a residential example, it is relevant as the only example we have found of a system where solar energy deployment has resulted in the mid-day being the lowest-cost pricing period. The CAISO has suggested that this is appropriate for California, at least during the spring months and weekends.

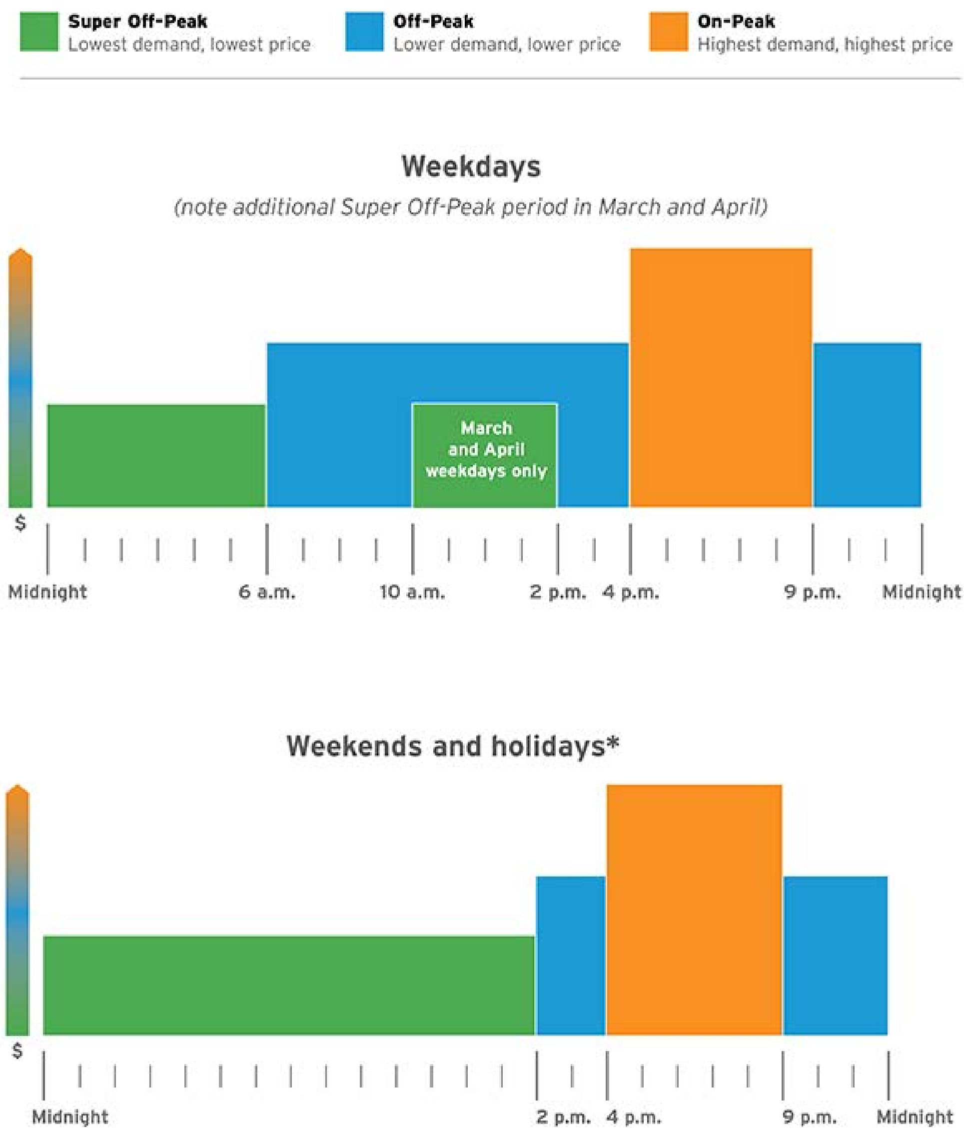
The pilot TOU residential rate in Hawaii may be an indicator of the type of rate form that will become applicable in other sunny regions in the future:

Figure 11. Interim Time-of-Use Rates, Hawaii Pilot



San Diego Gas and Electric has recently filed rates that move in this direction, but do not yet reflect the sharp mid-day depression in costs being experienced in Hawaii. Effective December 1, 2017, SDG&E large commercial TOU rates will have the following form, with a super-off peak rate at night, and during the daytime in the spring "Duck Curve" months. We expect this transition in rates to continue to evolve into the shape of the Hawaii TOU pilot rate design.

Figure 12: San Diego Gas and Electric Commercial Rates, Effective December 1, 2017



Maryland: Exploring Time-Varying Distribution Rates in a Restructured State

In a November 2017 order, the Maryland Public Service Commission took a next step toward time-of-use pricing for residential customers, augmenting their critical peak rewards program that applies to all customers. The Commission directed a workgroup of stakeholders and experts to develop two pilots for each of the three largest utilities. The pilots are worth mentioning because they include both a time-varying rate for distribution service and a time-varying rate for supply, both under default service (called "standard offer service") and through retail supply. For all six pilots, there is to be a five-hour afternoon peak for distribution rates from June to September and a three-hour morning peak from October to May. Retail supplier pilots must offer a three-to-five-hour afternoon peak for supply from June to September, with a winter morning peak being optional. The Commission also allows suppliers to offer additional innovations, such as “free Saturdays,” subject to review. The Commission hopes that this will better incent real-time peak-shaving behavior that advanced meters are now enabling, and is clearly thinking about the innovations needed in rate design to enable the ongoing transformation of the electric sector. These pilots, as described in the Commission’s order, will result in data on customers’ response to time-varying elements of distribution and supply rates that can enable future opportunities for more innovative tariffs. The disaggregated nature of the rate structures to be tested (e.g., separate distribution and supply time-varying elements) should provide insights into how rate design can make things like smart thermostats, electric vehicles, distributed generation, and energy storage more attractive to ratepayers and beneficial to the system.

SMUD: Most Costs in TOU; Coincident Peak Demand Charges

The non-residential rate design we found that best comports with the principles and elements we have described earlier in this paper is that for the Sacramento Municipal Utility District. SMUD’s non-commercial rate has the following characteristics:

- Fixed charge to recovery customer-specific costs of billing, collection, and customer service;
- Site infrastructure cost ($/kW) to recover location-specific capacity costs;
- Super-peak demand charge ($/kW) to recover marginal T&D capacity costs associated with oversizing the system for extreme hours; and
- TOU energy cost to recover all generation costs and remaining T&D costs.

Table 7: SMUD Large Commercial Rate Design

Customer Charge	$108/month	
Site Infrastructure Charge	$3.80/kW/month	
Super Peak Demand Charge	$7.65/kW	
Energy Charge	Summer	Winter
Super Peak	$0.20	N/A
On-Peak	$0.137	$0.104
Off-Peak	$0.109	$0.083

Takeaway Lessons

From our examination of commercial rates globally for this project, we found many antiquated rates, and a few examples of modern rate principle application.

- Most utilities retain NCP demand charges to recover shared capacity costs, which we consider to be poor guidance for cost control, and inequitable to lower load-factor classes;
- A few utilities have migrated to CP demand charges, which are better, but still inferior to time-varying rates;
- Many utilities have implemented TOU rates for large commercial customers, but in many cases only for variable energy-related costs;
- Texas, Illinois, and Georgia have implemented real time pricing programs that have produced benefits, but the Washington experience with market pricing is a cautionary tale indicating that while there are benefits, there also potential risks;
- Hawaii is experimenting with aggressive changes in TOU structure in response to very high solar DG penetration;
- Maryland is implementing an interesting example of a distribution rate with time-varying pricing components; and,
- SMUD has set itself apart as an industry pace-setter with a rate design that reflects most modern rate principles, but we believe their rate design can be improved further.

VI. Concluding Recommendations

RAP's *Smart Rate Design for a Smart Future*[44] undertook an extensive discussion of residential and small commercial rate design, and identified three principles that apply to all customer classes:

- Principle 1: A customer should be able to connect to the grid for no more than the cost of connecting to the grid.
- Principle 2: Customers should pay for grid services and power supply in proportion to how much they use and when they use it.
- Principle 3: Customers who provide services to the grid should be fairly compensated for the value of what they supply.

In this paper, we propose smart non-residential rate principles that build off of the first two of these three. We propose:

- Non-Residential (NR) Principle 1: The service drop, metering, and billing costs should be recovered in a customer fixed charge, but the cost of the proximate transformer most directly affected by the non-coincident usage of the customer, along with any dedicated facilities installed specifically to accommodate the customer, should be recovered in a NCP demand charge.
- NR Principle 2.1: De-emphasize NCP demand charges except as noted in NR Principle 1. All shared generation and transmission capacity costs should be reflected in system-wide time-varying rates so that diversity benefits are equitably rewarded.
- NR Principle 2.2: Shift shared distribution network revenue requirements into regional or nodal time-varying rates. This recognizes that some costs are required to provide service at all hours, and that higher costs are incurred to size the system for peak demands.[45]
- NR Principle 2.3: Consider short-run marginal cost pricing signals and long-run marginal cost pricing signals together in establishing time-varying rates for system resources.
- NR Principle 2.4: Time-varying rates should provide pricing signals that are helpful in aligning controllable load, customer generation, and storage dispatch with electric system needs.
- NR Principle 2.5: Non-residential rate design options should exist that provide all customers with an easy-to-understand default tariff that does not require sophisticated energy management, along with more complex optional tariffs that present more refined

[44] Jim Lazar and Wilson Gonzalez, "Smart Rate Design for a Smart Future," Regulatory Assistance Project, 2015, http://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future/

[45] One California municipal utility, for example, has TOU rates for commercial customers that include weekends as off-peak, but for residential customers, summer afternoons remain on-peak, due to distribution system capacity constraints on residential circuits. The same concept could apply in different regions or nodes of a distribution system serving non-residential customers, where capacity constraints are reached at different times of the day or year.

price signals but require active management by the customer or the customer's aggregator.

- NR Principle 2.6: Optimal non-residential rate design will evolve as technology and system operations matures, so opportunities to revisit rate design should occur regularly.

RAP applied these principles to evaluate existing commercial rate designs at each of California's investo- owned utilities. We concluded that if rate design is not changed to better align with these principles, California will continue to see underinvestment in DER resources and under-utilization of DER resources toward meeting the state's policy goals.

RAP searched for rate design examples that better comport with the principles in California and elsewhere. As mentioned, the non-residential rate design we found that best does so is that of SMUD. SMUD's non-commercial rate has a fixed charge to recovery customer-specific costs of billing, collection, and customer service; a site infrastructure cost ($/kW) to recover location-specific capacity costs; a super-peak demand charge ($/kW) to recover marginal T&D capacity costs associated with oversizing the system for extreme hours; and a TOU energy cost to recover all generation costs and remaining T&D costs. SMUD's rate sets it apart as an industry pace-setter, but we believe their rate design can be improved further.

One important goal for revision of non-residential rate design should be to better adapt to the incorporation of customer resources, such as thermal or electrical storage, customer provision of ancillary services through smart inverters, and customer load control for peak load management. The general framework of the rate design we propose directly compensates many of these through simple, clear, and compensatory TOU rate elements:

Table 8. Proposed Illustrative Rate Design for Non-Residential Consumers

	Production	Transmission	Distribution	Total	Unit
Metering, Billing			$100.00	$100.00	Month
Site Infrastructure Charge			$2/kW	$2/kW	kW
Summer On-Peak	$0.140	$0.020	$0.040	$0.20	kWh
Summer/Winter Mid-Peak	$0.100	$0.015	$0.035	$0.15	kWh
Summer/Winter Off-Peak	$0.070	$0.010	$0.020	$0.10	kWh
Super Off-Peak	$0.030	$0.010	$0.010	$0.05	kWh
Critical Peak	Maximum 50 hours per year			$0.75	kWh

This design is generally similar to SMUD's, with three important differences. First, it is unbundled between generation, transmission, and distribution to enable more granular application. Second, rather than have a super-on-peak demand charge, those costs are reflected in a critical peak price for up to 50 hours per year. The amount recovered is similar to that for SMUD's super-peak demand charge, but converted to an hourly rate to directly track high-cost hours, and to enable better customer response as system conditions change. Third, we have introduced a super off-peak rate, consistent with the recommendation of CAISO. We have intentionally left the definition of time periods unstated, as these will be specific to particular utilities, to particular nodes within each service territory, and will change over time as loads and resources evolve.

RAP also reviewed a number of real-time pricing tariffs and, while we did not identify one in particular that we would classify as best practice, we have identified lessons learned from Texas, Illinois, Georgia and Maryland that will be useful to the CPUC as it considers RTP optional tariffs. We suggest designing an RTP option that builds from our TOU plus CPP recommendation, and propose the following simple initial design:

- A wholesale energy cost component, charged on a per kWh basis, that fluctuates hourly. This would be based on the relevant CAISO zonal locational marginal price and would replace the "production cost" component of our recommendation above.
- Transmission costs and distribution costs would be collected in the same way that they are collected under our recommendation above, as would any generation capacity costs that aren't accounted for in wholesale rates.

Note that this design would not achieve the full benefits of an ideal RTP approach. In particular, this would not include comprehensive price signals reflecting conditions on the local distribution network. Instead, the hourly pricing innovation here is increased exposure of end users to existing CAISO wholesale prices. Over time, as California introduces new approaches that animate the value stack for resources at the distribution level, new rate designs will be able to incorporate more complex and comprehensive RTP components.

Appendix A: Some Important Rate History

Early Foundations

The best recognized text on utility ratemaking is Bonbright's 1961 *Principles of Public Utility Rates*. Bonbright set forth some principles for a fair rate design that include:

- The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
- Freedom from controversies as to proper interpretation.
- Effectiveness in yielding total revenue requirements under the fair-return standard.
- Revenue stability from year to year.
- Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")
- Fairness of the specific rates in the apportionment of total costs of service among the different customers.
- Avoidance of "undue discrimination" in rate relationships.
- Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
    - in the control of the total amounts of service supplied by the company; and
    - in the control of the relative uses of alternative types of service (on peak versus off peak electricity, Pullman travel versus coach travel, single party telephone service versus service from a multi party line, etc.).

Bonbright also provides detailed guidance on fully allocated and marginal cost, on elements of rate design, and on how to approach the "perceptions of equity and fairness" issue.

Another landmark text in utility rate making is Garfield and Lovejoy's *Public Utility Economics* (1964). A portion of this focuses specifically on the recovery of utility system capacity costs—the costs of constructing and maintaining generation, transmission, and distribution facilities. Garfield and Lovejoy cite extensively from a 1949 NARUC rate manual (which we do not have), identifying multiple criteria to set equitable rates to recover these costs. This work is particularly on-point to the issue of commercial rate design that is the focus of this project. We have addressed these in Section II.

Alfred Kahn, an architect of airline deregulation, published *The Economics of Regulation* in 1970, advocating that pricing should reflect marginal costs. After the Public Utility Regulatory Policies Act required states to "consider and determine" whether electricity rates should be based on the cost of service, several states, including California, Oregon, and New York, adopted costing principles based on marginal cost. Most states have retained cost allocation based on accounting (embedded) costs, but many of those use marginal cost principles for rate design, reflecting an accounting cost approach to equity in cost allocation between classes, but accepting the Kahn principles for rate design within class revenue requirements.

Demand Charges: Wright, Hopkinson, and TOU

Demand charges began over a century ago. A significant debate ensued over the better rate form, and demand charges emerged as the preferred alternative, due entirely to the simplicity of demand metering. At that time, the only way to measure TOU energy consumption was with chart recorders that were manually interpreted. Some very large (multi-megawatt) industrial customers were fitted with such systems, but until the emergence of electronic metering, TOU measurement remained relatively difficult.

The early commercial rate forms were the Wright rate (demand charge plus energy charge), and the Hopkinson rate (multiple load factor blocks). Some incorporated both features into rates. An example of a Wright-Hopkinson rate is that for DTE (Detroit Edison):

Figure A-1. Sample Wright-Hopkinson Rate

Power Supply Charges:	
Demand Charge:	$***13.88*** per kW applied to the Monthly Billing Demand
Energy Charges:	***4.7806¢*** per kWh for the first 200 kWh per kW of billing demand
	3.7806¢ per kWh for the excess

First, an NCP demand charge recovers most capacity costs. Second, the balance of capacity costs is embedded in the first 200 kWh/kW of energy charges. Higher-load-factor customers enjoy the end-block rate after capacity costs are recovered.

Decades ago, when all forms of capacity had similar costs, and detailed metering was expensive, this rate form may have been reasonable. In an evolved industry, where advanced metering is available and "capacity" needs are met with a mix of storage, demand response, dispatchable generation, inflexible baseload generation, and intermittent renewable resources, it no longer makes sense.

Rate Design References

- James Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961.
- Paul Garfield and Wallace Lovejoy, *Public Utility Economics*, Prentice Hall, 1963.
- Alfred Kahn, *The Economics of Regulation*, MIT Press, 1988.
- Frederick Weston, "Charging for Distribution Utility Services: Issues in Rate Design," Regulatory Assistance Project, 2000, http://www.raponline.org/knowledge-center/charging-for-distribution-utility-services-issues-in-rate-design/.

- Carl Linvill, John Shenot, and Jim Lazar, "Designing Distributed Generation Tariffs Well," Regulatory Assistance Project, 2014, http://www.raponline.org/knowledge-center/designing-distributed-generation-tariffs-well.
- Jim Lazar and Wilson Gonzalez, "Smart Rate Design for a Smart Future," Regulatory Assistance Project, July 2015, http://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future.
- Jim Lazar and Ryan Hledik, "Distribution System Pricing With Distributed Energy Resources," Future of Electric Utility Regulation series, National Renewable Energy Laboratory, May 2016, http://www.raponline.org/knowledge-center/distribution-system-pricing-with-distributed-energy-resources.
- "Distributed Energy Resources Rate Design and Compensation," NARUC Staff Subcommittee on Rate Design, November 2016, https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0.

Appendix B: Traditional Cost of Service Methods and Their Application to Rate Design

Different states use different methods to apportion costs between classes, and to design rates within classes. This is a short summary of the types of approaches RAP experts have seen in our long experience.

Embedded Cost Approaches

Most states use fully allocated cost of service studies for apportioning rates between classes. Some use the results of these studies to design rates within classes as well. But embedded cost studies come in an infinite variety. All of these divide accounting costs, and the results exactly equal the utility revenue requirements, but produce very different results by class and by the cost drivers to retail rate elements. We have grouped them into just a few categories.

Peak-Responsibility Methods: Fixed production and transmission costs are classified as demand-related, and allocated on some measure of peak demand: 1 CP, 4 CP, and 12 monthly CP are common methods.

Energy-Weighted Methods: Fixed production and transmission costs are classified as partly demand-related, based on the cost of peaking resources, and the balance as energy-related. The demand-related costs are allocated on some measure of peak demand.

Minimum-System Methods: Distribution plant is classified as customer related based on the hypothetical cost of a minimum-sized distribution (or zero intercept) calculation, with the balance classified as demand-related.

Basic-Customer Methods: Distribution plant is divided between customer-specific costs (service drops and meters, typically), and joint costs (poles, wires, and transformers). The joint costs are apportioned on some measure of usage: CP, NCP, and energy allocators are variously used.

Marginal Cost Approaches

A few states use marginal cost studies for electric and gas cost allocation. As with embedded cost studies, however, there is a wide variety of methodologies that have evolved.

Short-Run Marginal Cost: The cost of supplying additional customer requirements using existing facilities. Only costs that vary in the short run (fuel, purchased power, and line losses) are considered. The result is typically much lower than the revenue requirement. This approach is most often used to set economic development and other incentive rates.

NERA-Methodology: Costs that vary within an intermediate planning horizon, such as 10-years, are considered. This will typically include some peaking generation, some transmission, and some distribution capital costs, plus variable costs, but not new baseload generation or remote long-distance transmission. If the utility system is in equilibrium (no excess or deficiency of generation, transmission, or distribution capacity), this method produces a similar result to TSLRIC, below. But, where utilities have temporary excess generation capacity, as is common, this method typically produces a marginal cost for production that is somewhat lower than the production revenue requirement, and is therefore favorable to large-user classes (for whom production costs are a larger share of the cost responsibility). California has used a variation of this approach for many years.

Total-System Long-Run Incremental Cost (TSLRIC): The cost of building an optimized system for the current complement of customers and loads is measured. This has been widely used in telecom, but less often for electricity and gas. It is the theoretically appropriate metric for determining if competitive suppliers are viable. Because existing facilities are typically on utility books at far less than replacement cost, this approach generally produces a marginal cost that is somewhat greater than the revenue requirement.

RAP® Energy Solutions for a Changing World

The Regulatory Assistance Project (RAP)®
Belgium · China · Germany · India · United States

50 State Street, Suite 3
Montpelier, Vermont 05602
USA

1 802-223-8199
info@raponline.org
raponline.org

AGO Palmer Exhibit 4

PC44 Time of Use Pilots: Year One Evaluation

PREPARED BY

Sanem Sergici

Ahmad Faruqui

Nicholas Powers

Sai Shetty

Jingchen Jiang

PREPARED FOR

Maryland Joint Utilities

SEPTEMBER 15, 2020

THE Brattle GROUP

AUTHORS

Sanem Sergici, Ph.D. Dr. Sanem Sergici is a Principal in The Brattle Group's Boston, MA office specializing in program design and evaluation in the areas of rate design, energy efficiency, demand response, and electrification. Dr. Sergici has been at the forefront of the design and impact analysis of innovative retail pricing, enabling technology, and behavior-based energy efficiency pilots and programs in many states and regions including District of Columbia, Connecticut, Florida, Illinois, Maryland, Michigan, Ontario, CA and New Zealand. She has led numerous studies that were instrumental in regulatory approvals of Advanced Metering Infrastructure (AMI) investments and smart rate offerings for electricity customers. She has expertise in resource planning; economic analysis of distributed energy resources (DERs); their impact on the distribution system operations and assessment of emerging utility business models and regulatory frameworks.

Sanem.Sergici@brattle.com

Ahmad Faruqui, Ph.D. Dr. Ahmad Faruqui's consulting practice focuses on ways to enhance customer engagement. He advises clients on matters related to rate design, load flexibility, energy efficiency, demand response, distributed energy resources, demand forecasting, decarbonization, and electrification. He has worked for over 150 clients on five continents, and provided expert testimony and appeared before regulatory bodies, governments, and legislative councils. Dr. Faruqui has authored or coauthored more than 100 papers on energy economics in peer-reviewed and trade journals and is the co-editor of four books on industrial structural change, customer choice, and electricity pricing.

Ahmad.Faruqui@brattle.com

Nicholas Powers, Ph.D. Dr. Powers has broad experience in applying econometric analysis to more a variety of economic questions in the electric and other industries. His electricity experience includes several key analyses of price effects, market power, and anticompetitive behavior. In addition, he conducts econometric analysis of innovative pricing programs in the electric industry. He has supported expert testimony in three separate litigation proceedings arising from the California electricity crisis of 2000–2001. He has also overseen the statistical analyses in several New Source Review cases and performed damages and other analyses in energy-related litigation proceedings. Dr. Powers also has extensive experience estimating cartel impacts in large-scale price-fixing cases and conducting analysis for and submitting expert reports in regulatory proceedings in other industries.

Nicholas.Powers@brattle.com

NOTICE

- This report was prepared for the Maryland Joint Utilities, in accordance with The Brattle Group's engagement terms, and is intended to be read and used as a whole and not in parts.
- The report reflects the analyses and opinions of the authors and does not necessarily reflect those of The Brattle Group's clients or other consultants.
- Authors are grateful for the support and collaboration of Joint Utility staff throughout the analysis process.
- There are no third party beneficiaries with respect to this report, and The Brattle Group does not accept any liability to any third party in respect of the contents of this report or any actions taken or decisions made as a consequence of the information set forth herein.

Table of Contents

Executive Summary

As part of the Maryland Public Service Commissions' PC44 proceedings, three investor-owned utilities in Maryland –BGE, Pepco, and DPL—are running pilots with time-of-use (TOU) rates. The utilities are henceforth going to be referenced as the Joint Utilities (JUs). The JUs designed the pilots through a Work Group process that was created by the Commission. Customers began transferring to the TOU rates beginning in April of 2019. This report contains the results from an impact evaluation of the first year of the pilot, which began in June 2019 and ran through May 31, 2020. The year was divided into two periods, summer and the rest of the year, which was labeled non-summer. While there is a long history in the US of running TOU pilots, the PC44 pilots have several unique features that make them stand out:

- They include TOU rates with quite sizeable differentials between peak and off-peak periods. The ratio of peak to off-peak prices ranges from 4 to 6 across the three JUs, providing customers a strong incentive to save money by consuming power during the substantially less expensive off-peak period.
- The peak periods are relatively short, allowing customers to respond more easily by reducing peak usage and shifting some of it to off-peak periods. In the summer, the peak period runs from 2 PM to 7 PM on weekdays. All weekend hours are off-peak as were all the hours on holidays. In the non-summer, the peak period runs from 6 AM to 9 AM.
- The TOU rates apply to charges for generation, transmission and distribution, and not just to the generation as is often the case with TOU pilots.
- The pilots are designed to separately measure the impact of TOU rates on low and moderate income (LMI) customers and non-LMI customers, by creating designated treatment cells for these groups.
- The pilots feature a quasi-experimental design. Specifically, customers were randomly chosen for recruitment; recruited customers then had the opportunity to opt in to the pilot. Using a large pool of eligible customers that were not targeted for recruitment, we select a "matched control group" by utilizing a widely used technique called "propensity score matching" in order to minimize pre-pilot differences between the treatment and customer groups.
- During the recruitment phase, customers who were randomly chosen for recruitment in the pilot were provided with a personalized estimate of their potential savings under the TOU rate, based on their load profiles. Based on their pre-pilot consumption patterns, about two-thirds of the customers who chose to participate would have seen a decrease in their bills even without changing their behavior. We call these customers "structural winners" in this report.
- The pilots were designed not only to yield information on the impact of the specific TOU rates being tested but also to yield econometric models that can be used to predict the impact of alternative

TOU rates. These models also yield estimates of two types of elasticities that are often of interest to analysts: (1) the elasticity of substitution, which measure the extent to which load shifting takes place between peak and off-peak periods; and (2) the daily price elasticity, which measures the change in daily usage induced by change in daily prices.

- Treatment customers were provided online messages on a weekly basis. These e-mails reminded treatment customers about the timing of the peak period and also provided tips on how to curtail peak loads and to shift some of that load to the off-peak period. This tool, known as "behavioral load shaping" was combined with the TOU rate price signal to facilitate changes in behavior. The impacts quantified in the pilot are the combined effect of pricing and the information treatment.
- We analyzed the load data econometrically using a widely-used technique known as panel data regression analysis. A panel data has repeated time series information on individual customers as well as cross-sectional information across customers. Essentially, this approach allows us to: (a) compare the usage of treatment customers before and during the pilot period; (b) compare the usage of control group customers before and during the pilot period; and (c) net out the latter change from the former change, yielding the "difference-in-differences," which is the estimate of the impact of TOU rates on peak and off-peak usage.

An unexpected development in the non-summer season was the outbreak of COVID-19. In Maryland, the pandemic broke out in March 2020 and affected all customers in the pilots, whether they were on TOU rates or on standard rates. We leveraged the econometric model to identify the impact of COVID-19 on customer behavior.

Results

Customer enrollment rates in the pilots ranged from 0.5% to 1.9% across the JU's. About two-thirds of the customers who enrolled would have experienced bill reductions by switching to TOU rates without changing their load behavior. This was true of both the LMI and non-LMI customers.

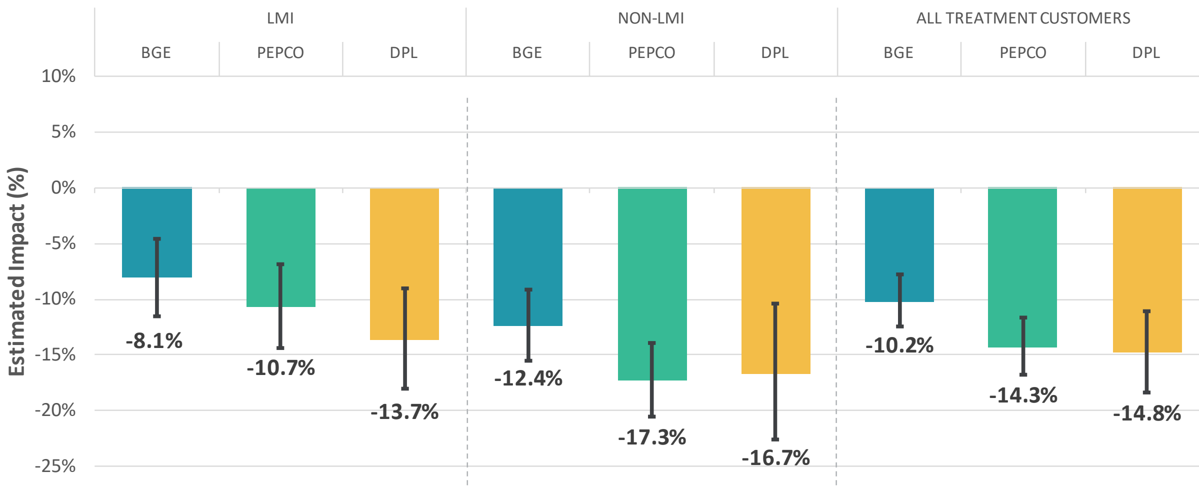
Intuitively, we would expect that the TOU rates would induce customers to lower their consumption in peak hours, relative to what they would have consumed on a flat rate, and to shift some of that consumption to the off-peak hours. It is difficult to predict in advance what would happen to daily consumption. Behavioral messaging would further stimulate a change in customer behavior.

SUMMER IMPACTS

The summer results are presented below. The Figure ES.1 shows the summer weekday peak impacts by utility, initially by LMI and non-LMI customers, and then for all treatment customers combined. The peak impacts for the combined customer group range from -10.2% to -14.8%. Peak demand falls in all cases and the magnitude of the reduction is statistically significant in all cases.

What is also noteworthy is that the demand response of LMI customers is statistically significant for each of the JUs. Furthermore, the magnitude of the LMI impact cannot be statistically distinguished from that of non-LMI customers, with the exception of Pepco. **This provides conclusive evidence that LMI customers respond to the TOU prices by as much or nearly as much as non-LMI customers.**

FIGURE ES.1: SUMMER WEEKDAY PEAK IMPACTS



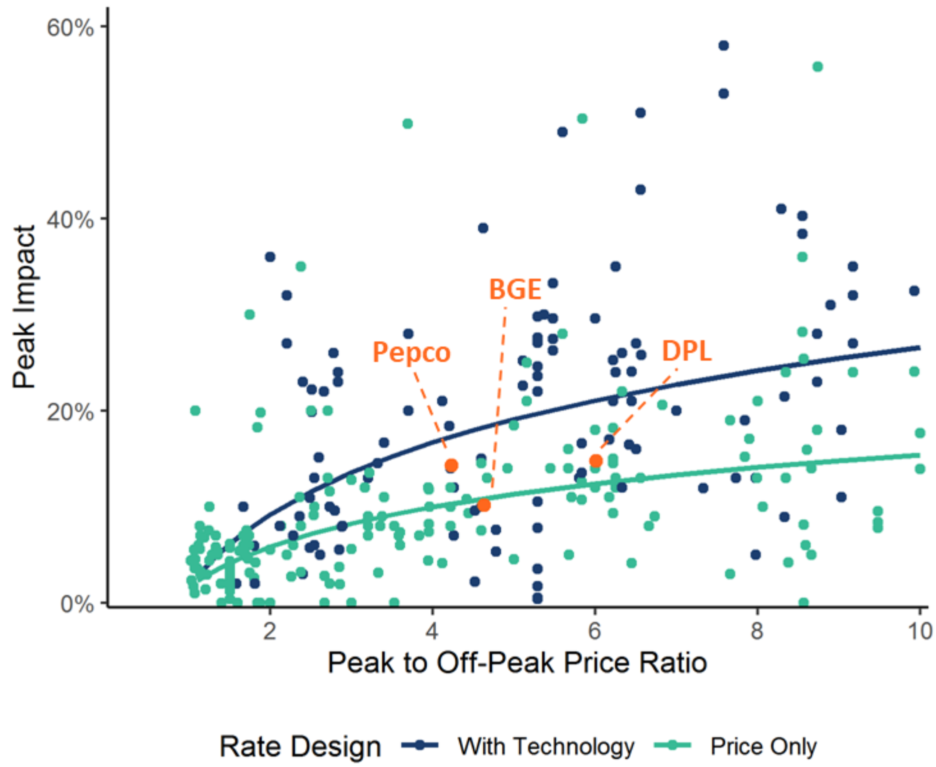
Note: The error bands in each bar show confidence bands. There is a 95% chance that the actual impact lies within the bands.

Surprisingly, off-peak usage does not appear to rise on weekdays, as we would expect, in response to the lower prices. Furthermore, on weekends, usage during the hours that correspond to the peak period is lower. These unexpected off-peak and weekend effects could be “spillover effects” from the BLS messaging tool, or customers may be using the same schedule for their smart thermostats during both the weekdays and weekends, resulting in a reduction in peak period hours even during weekends.

We also detect statistically significant weekday conservation impacts for all three JUs in the range of -2.8% to -4.9%. These results do not significantly differ between LMI and non-LMI customers.

The summer reductions in peak periods, when correlated with the price ratios in the PC44 TOU pilots, line up well with the results of other pricing pilots in the Arcturus database that Brattle has developed over the years. Figure ES.2 below shows this comparison.

FIGURE ES.2: SUMMER PEAK IMPACTS FROM OTHER TIME VARYING PRICING PILOTS AND PC44 TOU IMPACTS

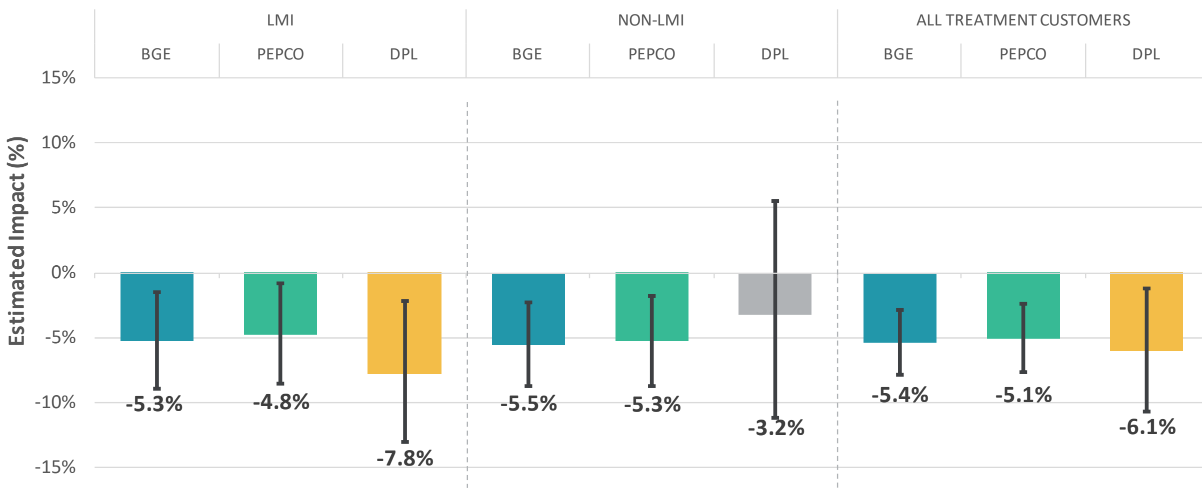


Note: The PC44 data points are based on the results for all customers (combined LMI and non-LMI effects).

NON-SUMMER IMPACTS

The non-summer results are presented below. For all three utilities, we detect economically and statistically significant peak load reductions that range from -5.1% to -6.1% for the combined sample. The non-summer impacts are generally smaller than the summer impacts, which has also been observed in other pilots which had two seasons in them. Demand response of LMI customers is statistically significant for each of the JUs. The magnitude of the impact cannot be statistically distinguished from that of non-LMI customers. Accordingly, a key summer result is also confirmed in the non-summer months: **LMI customers respond to the TOU prices at comparable magnitudes to non-LMI customers.**

FIGURE ES.3: NON-SUMMER WEEKDAY PEAK IMPACTS



COVID-19 IMPACTS

COVID-19 tended to lead to flatter load shapes and higher consumption levels in all three utilities for the control group customers who were not on TOU rates. This strikes us as being intuitively plausible since customers were sheltering in place during the pandemic. **Non-summer peak impacts remained largely similar for BGE and Pepco during COVID-19 months, while they were lower for DPL**. All JUs revealed a larger tendency to conserve load during COVID months, as exhibited by large daily price elasticities.

SUBGROUP IMPACTS

We also analyze customers' response to TOU rates by subgroup. We find that impacts were generally similar between NEM and non-NEM customers, and between structural winners and others. The latter finding is particularly important in the sense that customers who would observe bill savings on the TOU rates (due to their favorable load profiles) even without changing their usage did not tune out the price signals. On the contrary, they achieved peak load reductions as large as those of other customers who did not have similarly favorable load profiles. **This contradicts a commonly held belief that opt-in pilots will only attract "structural winners" and that once on the rate, these customers will not respond to the price signals.**

BILL IMPACTS

Finally, we find that on average, customers on the TOU rates enjoyed bill savings in the range of 5% to 10% across the three JUs. These bill savings were not generally uniform across seasons or JUs. For example, while Pepco TOU customers enjoyed substantial bill savings in the summer but smaller bill savings in the non-summer period; TOU customers at BGE and DPL both experienced bill increases in the summer but considerable savings in the non-summer period. We find that on average, both LMI and non-LMI customers enjoyed bill savings on an annual basis.

I. Introduction

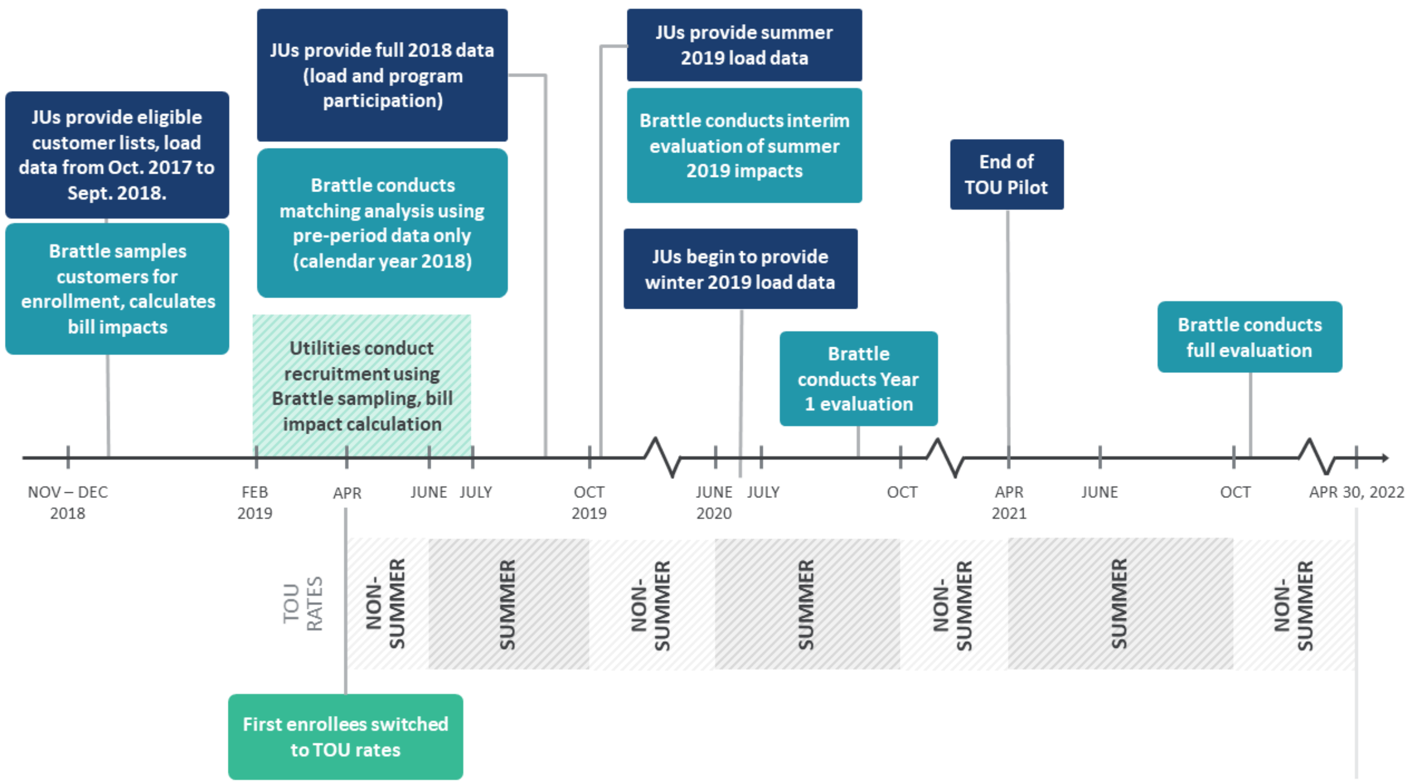
This report presents the results of the first year of the PC44 Time-of-Use ("TOU") pilots. The Maryland Public Service Commission ("PSC" or "the Commission") initiated Public Conference 44 ("PC44") on September 26, 2016 for the purposes of ensuring that the "electric distribution systems in Maryland are customer-centered, affordable, reliable, and environmentally sustainable."[1] In furtherance of that goal, the Commission instituted a Rate Design Work Group ("Work Group") to "explore time-varying rates for traditional electric service…and considering pilot programs for driving desired results through performance-based compensation."[2] It was the Commission's hope that these pilots would "more effectively reintroduce time-varying rates to Maryland customers, and better reach the potential to incent the real-time, peak shaving behavior now enabled by the deployment of Advanced Metering Infrastructure available to more than 80 percent of Maryland electric customers."[3] The PC44 TOU pilots were designed in a collaborative Work Group process that took place in late 2018 and early 2019. Customers began transferring to the TOU rates beginning in April of 2019. The Year 1 analysis covers June 1, 2019 through May 31, 2020. A timeline with key pilot milestones, as well as milestones for the evaluation, measurement, and verification ("EM&V") of the pilot, is presented in Figure 1: Pilot Timeline.

1 PC 44 Notice, September 26, 2016, p. 1.

2 PC 44 Notice, September 26, 2016, p. 3.

3 ML# 217978, p. 2.

FIGURE 1: PILOT TIMELINE



A. Purpose

As described in the Evaluation, Measurement, and Verification Plan filed with the Commission for these PC44 TOU pilots, this is the first of two reports evaluating those pilots.[4] The objective of this evaluation report is to assess whether the customers participating in the pilots have modified their electricity consumption in response to the price signals conveyed by the TOU rates, in a statistically significant manner. In this report, we present the results of our evaluation of the impacts of the TOU rates on pilot customers, relative to comparable customers who have not enrolled in the pilot ("control group"). We evaluate a variety of impacts, including:

- peak load reductions;
- load impacts during off-peak times;
- overall conservation impact;
- substitution elasticities, which measure the extent to which pilot customers substitute away from consumption in high-priced peak hours;

[4] Sanem Sergici, Ahmad Faruqui, and Nicholas Powers, "Evaluation, Measurement and Verification Plan for the PC44 Time-of-Use Rate Pilots." June 15, 2018, p. 2. ("EM&V Plan")

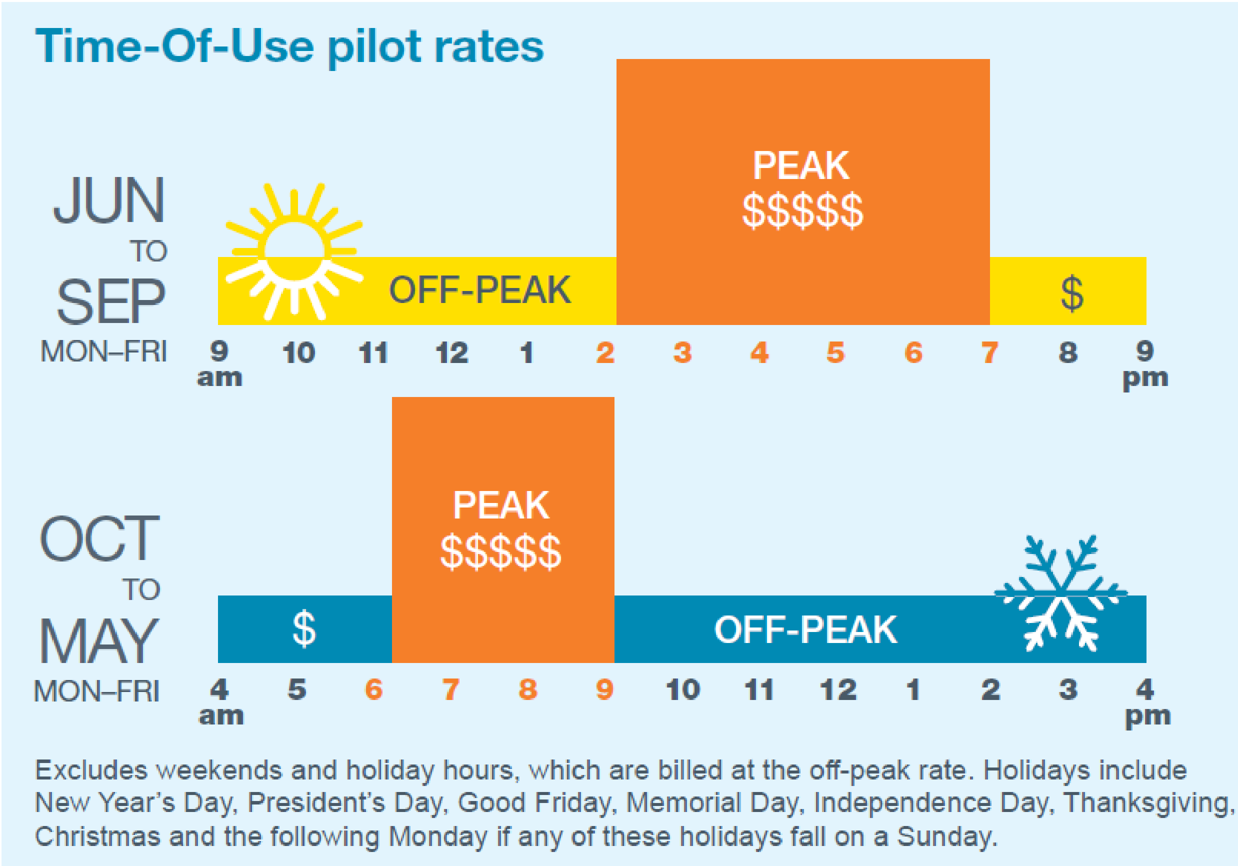
- demand elasticities, which measures the extent to which customers conserve in response to higher average prices; and
- load impacts for various sub-groups.

B. Pilot Overview, Including Key Differences From Previous Pilots

Three Maryland utilities are conducting the PC44 TOU pilots: Baltimore Gas & Electric (“BGE”); Pepco Maryland (“Pepco”), and Delmarva Power & Light Maryland (“DPL”). We refer to the three utilities as the Joint Utilities (“JUs”) for the rest of this report. While each JU is conducting its own TOU pilot, the three pilots share the same fundamental design features:

- opt-in enrollment by eligible customers who were randomly selected for recruitment into the pilot;
- a seasonal rate structure, in which summer rates apply from June to September and non-summer or “non-summer” rates apply from October to May;
- season-specific definition of peak hours, in which the peak is from 2 PM to 7 PM on non-holiday weekdays in the summer months, and from 6 AM to 9 AM on non-holiday weekdays in the non-summer months. In both seasons, all other hours, including weekends, are off-peak;
- the peak and off-peak rates as set by each utility vary, but are designed to be revenue neutral on an annual basis in the absence of load shifting.

FIGURE 2: SEASONS AND PEAK HOURS



Source: BGE recruitment letter

The PC44 pilots differ from previous TOU pilots in several key ways:

1. Unlike the majority of previous TOU pilots that imposed higher peak prices only on the energy supply portion of enrolled customers' bills, both the energy and the delivery portions of rates faced by customers participating in the PC44 TOU pilot are higher in the peak than in the off-peak. As a result, most of the customers' bill is subject to the TOU peak and off-peak prices, potentially strengthening their incentives to respond to the price signals.

2. All-in peak rates faced by enrolled customers are between 4 and 6 times the off-peak rates, as summarized in Figure 3, and represent meaningful incentives for customers to shift their usage from peak to off-peak periods.

FIGURE 3: RATES DURING THE FIRST YEAR OF THE PILOT

	Summer (June 2019 - September 2019)				Non-Summer (October 2019 - May 2020)			
	Peak	Off-Peak	Peak to Off-Peak Ratio	Default "R" Rate	Peak	Off-Peak	Peak to Off-Peak Ratio	Default "R" Rate
BGE	$0.343	$0.074	4.63	$0.108	$0.360	$0.080	4.52	$0.115
Pepco	$0.406	$0.096	4.22	$0.163	$0.426	$0.105	4.07	$0.139
DPL	$0.493	$0.082	6.01	$0.135	$0.501	$0.086	5.82	$0.137

Note: Rates for each period are simple averages of all variable components of rates in each month, as provided by the JUs. Variable rates include all applicable volumetric charges for transmission, distribution, generation, administrative credits, receipt taxes, stabilization adjustments, procurement adjustments, and county surcharges. The default "R" rate column refers to the flat volumetric rate tariff that applies to the majority of residential customers who have not opted to purchase energy from a third-party supplier.

3. The Maryland Public Service Commission was particularly interested in assessing the impacts of TOU rates on low-to-moderate income ("LMI") customers in addition to average residential customers. Accordingly, the pilot designs involved separate treatment groups for LMI customers to ensure that the JUs recruited a sufficient number of LMI customers to enable estimation of statistically significant impacts for that category of customers.

4. Recruitment materials provided detailed and *individualized* information on predicted customer bill impacts under the TOU rates, based on each customer's 2018 load data and various load response assumptions including no load response, 5% peak load shifting and 10% peak load shifting. This implies that PC44 customers made an informed decision to participate in the pilot by reviewing different bill impact scenarios. It is reasonable to expect that "structural winners", or customers with flatter load profiles, will participate in the pilot at higher rates. Since JUs indicated that any future full-scale opt-in TOU program would also include a similar bill comparison element, this recruitment feature does not violate the external validity of the results.

5. Motivated by the Commission's interest in determining whether TOU rates can help lower customer bills, enrolled customers also received weekly e-mails as part of a behavioral load shaping ("BLS") tool. These e-mails provided regular reminders to pilot customers as to the timing of the peak, and provided tips for how customers could shift or conserve their load. As a result, we cannot attribute the customer impact solely to a price response; instead, we interpret the impacts to be the combined effect of the two components. Since JUs indicated that any future full-scale opt-in TOU program would always include a similar informational element, estimation of a combined treatment impact is instructive in this context.

II. Methodology

In this section, we provide an overview of the methodology we used to analyze the results from the first year of the pilot. The pilot design approach that we use is known as “random sampling with a matched control group”. Under this pilot design approach, the selection of pilot participants depends in part on randomization, in that the utility randomly selects which customers are offered the opportunity to participate in the pilot.

Under this approach, the analysis proceeds in two stages. First, we undertake a matching stage to ensure that the control group that serves as the benchmark against which we measure pilot impacts is as comparable as possible to the enrolled or “treatment” group. In the second stage, we conduct the impact evaluation by comparing the outcomes of the pilot group to those of the control group, using regression analysis.

This approach is known as a “quasi-experimental” approach. The ability to identify a control group that is similar to the treatment group on a variety of observable dimensions significantly mitigates concerns that there are systematic differences between the two groups that might bias the resulting impact estimates. Furthermore, this approach avoids the potential for either negative customer experience risks or higher recruitment costs associated with other approaches that were considered, such as recruit-and-deny and randomized encouragement design approaches.[5]

In the remainder of this section, we provide a summary of pilot eligibility and the recruitment process. We then describe in additional detail on the matching process. Finally, we describe the regression-based approaches used to evaluate the impacts of the pilot. We cover details of a more technical nature in the Appendix.

A. Summary of Eligibility and Recruitment

In November and December of 2018, each of the three utilities provided lists of eligible customer IDs. Consistent with the criteria specified in the EM&V Plan, we requested that the utilities determine eligible customers as follows:[6]

[5] EM&V plan, pp. 7-10.

[6] EM&V Plan, pp. 10-11.

- only residential customers who had been at the current address and for whom the utilities had consistent AMI data dating back to at least January 1, 2018 could be included;7
- customers with medical needs flags were excluded;
- participants in virtual net energy metering or Community Solar programs were excluded;
- customers who had been included in the control group of other programs (such as Opower Home energy reports) were excluded;
- BGE customers participating in the Prepaid Pilot Program were also excluded.

To ensure that there was no personally identifiable information ("PII"), the utilities created unique identifiers that were anonymized and different from any identifier used internally. In addition to this identifier, each utility provided the zip code of the premise of each eligible customer ID. BGE also provided household-level income estimates, as provided by a third-party data supplier, for roughly 73% of BGE customers; for the remaining customers, the household income variable reflected zip-code averages from U.S. Census data.

In its PC44 Workgroup Order, the Commission specified that "the pilots should be designed with a separate LMI sample to collect statistically significant results."[8] Following guidance from the JUs, we classify customers with annual household income below $74,000 as LMI customers.[9] Given the importance of LMI customers to this pilot, and the possibility that targeted LMI customers would be less likely to enroll than other customers, the recruitment plan for BGE and Pepco targeted customers who were more likely to be LMI customers.[10] In the case of DPL, a much higher share of the households in the service territory has household incomes below the LMI threshold.[11] Accordingly, we used simple random sampling when selecting the DPL customers for recruitment.

For each utility, we sampled "waves" of customers for recruitment, pursuant to discussion with each of the JUs regarding their recruitment strategies and costs. As part of this sampling process, we set aside

7 In fact, the list BGE provided included some customers who moved into their premises after January 1, 2018. Some of these customers were subsequently randomly selected to receive recruitment materials, and 325 targeted customers with move-in dates after January 1, 2018 thus enrolled in the pilot. Many of these customers nevertheless had accumulated a full year of AMI data at the same residence prior to the start of the pilot. We include in our analysis all enrolled customers with move-in dates after January 1, 2018, truncating the pre-period data to ensure that only the enrolled customer's data is included in the impact evaluation.

8 Maryland Public Service Commission, Letter Order RE: Public Conference 44 – Rate Design Workgroup, dated May 7, 2018.

9 This LMI threshold, provided by the JUs, is equal to 80% of the median state income of $92,500 in 2017. See "Income Limits 2017," Maryland Department of Housing and Community Development, at p. 2. https://dhcd.maryland.gov/HousingDevelopment/Documents/prhp/2017_MD_Income_Limits.pdf.

10 As customers' LMI status was unknown unless and until they enrolled in the pilot, we could not generally observe whether eligible customers fell into this group. As explained above, BGE had provided third-party data for most of its eligible customers. For the remainder, and for Pepco, we relied on zip-code level data. All things equal, the lower median household income in a zip code, the higher the likelihood that a randomly selected household would be an LMI household.

11 According to U.S. Census data provided by the utilities, 59.4% of the eligible customers live in zip codes where the median household income is below the LMI threshold.

for each utility a large pool of potential control customers in order to ensure that the matching process would generate a balanced control group.

- For BGE, 100,000 customers were sampled into 2 recruitment waves, leaving a control customer pool of over 600,000 customers.
- For Pepco, 303,634 customers were sampled into 9 recruitment waves, leaving a control customer pool of 20,000 customers.
- For DPL, 100,000 customers were samples across 6 recruitment waves, leaving a control customer pool of 13,300 customers.

The utilities sent the recruitment letters, beginning in early February 2019. BGE and DPL recruited for all waves in February 2019, whereas Pepco's recruitment effort lasted through mid-April. The recruitment letters included, for each customer, a summary of the bill impacts, based on the: (1) the prevailing tariffs for that customer's rate class as of the end of 2018; (2) the tariff for the pilot rates; and (3) that customer's 2018 load data. The BGE letters provided bill impacts for three scenarios:

- no load response
- in both seasons, the customer would shift 5% of their pre-pilot peak load to off-peak (but would not reduce their total load)
- in both seasons, the customer would shift 10% of their pre-pilot peak load to off-peak (but would not reduce their total load).

The letters that Pepco and DPL sent to targeted customers provided bill impacts for two scenarios:

- no load response
- in both seasons, the customer would shift 8% of their pre-pilot peak load to off-peak (but would not reduce their total load).

In the discussion that follows, we refer to customers who would see their bills decrease without any load response as "Structural Winners." These customers, based on their pre-recruitment consumption patterns, would see bill savings simply by switching rates, without making any additional effort to shift or conserve load.

FIGURE 4: RECRUITMENT SUMMARY AS OF JULY 26, 2019

	Target	BGE	Pepco	DPL
Enrollment Summary				
Targeted customers		95,012	266,707	86,035
Enrolled customers	1,400	1,772	1,380	674
Enrollment rate		1.9%	0.5%	0.8%
Enrollment Rate Detail				
Structural winners without load shift		2.0%	0.8%	1.0%
Non-savers without load shift		1.5%	0.3%	0.6%
LMI/Non-LMI Breakdown				
LMI enrollees	700	925	617	416
(as share of total)		52%	45%	62%
Share of LMI enrollees who are structural winners without load shift		67%	67%	65%
Non-LMI enrollees	700	847	763	258
(as share of total)		48%	55%	38%
Share of non-LMI enrollees who are structural winners without load shift		66%	68%	64%

Note: Includes all enrolled customers, some of whom are subsequently excluded from the impact analysis due to incomplete data. The last enrollment occurred on July 26, 2019 (Pepco).

Figure 4 summarizes enrollment status by utility at the end of the recruitment window. BGE enjoyed the highest enrollment rate, with 1.9% of the targeted customers opting to enroll. Unsurprisingly, structural winners were more likely to enroll (at around 65-68%) than non-savers without load shift. This is true for all three utilities.

Both BGE and Pepco attained the target number of non-LMI enrollees; BGE also attained the target for LMI customers. The share of both LMI and Non-LMI enrollees that are structural winners is similar across all three utilities. Based on their 2018 load usage patterns, roughly two-thirds of the enrollees in all six customer groups could expect to save when moved to the pilot rate, even before shifting any load.

Excluding enrollees for whom we do not have sufficient pre-period data to be included in the impact assessment, 1,614 treatment customers from BGE, 1,342 from Pepco, and 653 from DPL remain in the study, as discussed in Section III.A below.

B. Summary of Matching Process

Based on observable pre-treatment data for all targeted customers (i.e., all customers to whom recruitment materials were sent), we identify the variables (such as electricity consumption at particular times of the day, or participation in other utility programs) that are most highly correlated with the decision to participate in the pilot.[12] Then, using the identified variables, we estimate a "propensity score" for each customer who was targeted for enrollment (regardless of their acceptance or refusal to participate). Conceptually, this propensity score represents the probability that a targeted customer with that set of observable characteristics would choose to enroll in the pilot. We then use the parameters from this regression analysis to estimate the propensity score for each customer in the pool that was set aside for control group selection. Then, for each enrolled treatment customer, we identify the single set-aside control customer whose propensity score is most similar and place this matched customer in the control group.[13]

After the matched control group was formed, we undertook several diagnostics and confirmed that the resulting match was satisfactory and the matched control group would accurately represent the "but-for" usage of the treatment customers. Information on the results of this matching process, as well as the diagnostics we performed to assess the resulting balance between the treatment group and the matched control group, are discussed later in this report.

As described below, the difference-in-difference approach we use in our impact analysis controls for persistent customer differences between the "treatment" group and the control group. As long as the trends of the control group and the treatment group would have been the same in the absence of the pilot, then the resulting estimates are valid even without matching. This condition is known as the "parallel trend assumption." The primary benefit of matching is that by accounting for observable pre-

12 We identify the included variables based on an algorithm that is similar to that developed by Imbens and Rubin. *See* Imbens, Guido W. and Donald B. Rubin. 2015. Causal Inference in Statistics, Social, and Biomedical Sciences. New York: Cambridge University Press ("Imbens and Rubin"). Provided with a set of *k* candidate variables, the algorithm first estimates *k* univariate logit regressions and identifies the variable that is the single best predictor of enrollment. Then, it keeps that variable, and estimates *k-1* logit regressions with both the selected variable and one of the remaining *k-1* variables, ultimately identifying the variable that provides the greatest improvement (in terms of predicting enrollment) over the single-variable logit regression. This process is iterated until the improvement from adding an additional variable falls below a threshold we specified.

For each of the three utilities, the algorithm selects more than 35 variables, including a mix of seasonal hourly load variables (*e.g.*, average load on hour 18 of summer weekdays) and other non-load variables, such as participation in direct load control programs and median household income in the customer zip code. Additional details are available in Section III.C.

13 We impose minimal restrictions on the match. One such restriction is to separate both the set of enrolled customers and the pool of potential control customers according to whether those customers have net metering. We identify such customers using a combination of information from the utility and by observing load patterns displaying negative net load.

We also experimented with a geographic restriction, whereby we limited each enrolled customer's match based on zip code of the respective premises. However, the control group balance was not as strong, and furthermore we found for each utility that the unrestricted match yielded geographic distributions of matched customers that were similar to the geographic distribution of enrolled customers. Maps demonstrating these distributions are provided in the Appendix A.3.

pilot differences in constructing the control group, we increase the likelihood that the parallel trend assumption holds.

C. Methodological Approach to Impact Evaluation

We have employed a dual approach to evaluating the impacts of the PC44 TOU pilots. The first set of analyses involves models to estimate load impacts resulting from exposure to the TOU rates. The second set of analyses uses models to estimate substitution and daily price elasticities representing customers' sensitivity to prices. These estimated elasticities can subsequently be used to model the impact of prices that are different from those tested in the pilots. This is important because the prices in a future full-scale roll-out might differ from those tested in the pilot.

Below, we describe each of these approaches in more detail.

1. Load Impact Analysis

We employ panel data analysis as the load impact evaluation method for the PC44 TOU pilots. There are several reasons for this decision. First, the TOU pilots run over multiple years and yield repeated measurements for the treatment and control groups. Furthermore, several months' worth of pre-treatment data are available for both treatment and control group customers. Given that the repeated measurements are available for both groups before and during the treatment period, a panel data regression can utilize the variations in the data across individuals, as well as across time, to fit a relationship between dependent and independent variables and as a result yield the most precise impact estimate. Second, this panel data approach provides flexibility in how we control for differences in weather, seasonality and other factors. Third, through the use of customer-level "fixed effects," panel data analysis allows us to control for time-invariant but unobservable characteristics of individuals that could otherwise introduce bias into the estimation results.[14]

The general form of the preferred regression models we estimated, which are also known as *difference-in-differences regressions* is as follows:

[14] These factors could be certain socio-demographic characteristics such as the education level of the head of household, housing characteristics, or whether the home has electric heating. If a researcher does not observe, or have reliable data on these characteristics, it is not possible to employ these variables as independent variables even though they have the potential to explain the variation in the dependent variable. Omission of these variables from the regression model leads to an "omitted variable" problem, which may result in biased parameter estimates.

Fixed-effects (FE) estimation assumes that the unobservable factor (in the error term) is related to one or more of the model's independent variables. Therefore, it removes the unobserved effect from the error term prior to model estimation using a data transformation process. During this process, other independent variables that are constant over time are also removed. This drawback of the FE estimation implies that it is not possible to estimate the impact of variables that remain constant over time, such as ownership of a single-family house.

For additional discussion of the methodological approaches considered, please refer to Section III of the EM&V Plan.

$$Load_{it} = \kappa_i + \pi PilotPeriod_t + \gamma PilotPeriod * Treatment_{it} + \theta_t + \delta Z_i + \varepsilon_{it} \quad (1)$$

where:

- $Load_{it}$ is the natural log of the electricity consumed by customer *i* in hour *t*;
- κ_i is a time-invariant customer-specific effect or intercept, which we model as a fixed effect;
- $PilotPeriod_t$ is an indicator (dummy) variable equal to 1 during the pilot period and 0 otherwise;
- π measures the difference in consumption between the pre-treatment period and the pilot period that is common to both control and treatment customers;
- $PilotPeriod * Treatment_{it}$ is the treatment indicator, which will be 0 for all control group customers at all time, and will be equal to 0 for treated customers prior to the treatment and will equal 1 once those customers are on the TOU rates;[15]
- γ is the primary parameter of interest, as it measures the average impact of the TOU pilot treatment on load;
- θ_t is a vector of variables which measures a shift in consumption (possibly due to weather or other seasonal effects) that affects all customers similarly;[16]
- Z_i is a vector of time-invariant customer characteristics of interest, such as self-reported LMI status;[17]
- δ measures the effect on load associated with the Z_i vector; and
- ε_{it} is the residual or error term.

In the course of our analysis, we have estimated separate impacts for the summer period and the non-summer period. We do this within the framework laid out here by estimating this regression on the corresponding subsets of the data. Specifically, we estimated equation (1) on a summer-only dataset (covering June through September, including both pre-treatment data from 2018 and pilot period data from 2019) in order to estimate the average summer impact. We have estimated analogous regressions on non-summer data in order to estimate the average non-summer impact. Similarly, another

---

15 If a customer opts to leave the PC 44 pilot, either because they switch to a different rate, switch to a third-party supplier, or move, we exclude all post-unenrollment data for that customer from the analysis.

16 In our primary specification, we include in θ_t a variety of terms, including calendar month dummies, the temperature heat index ("THI") which should capture the effects of weather, as well as month-THI interaction terms, which allow the effect of THI to vary. For example, we do not generally expect the impact of a 10-degree increase in temperature to have the same effect on customer load in May that it does in January. In sensitivity checks, we instead model θ_t using daily fixed effects, which do not impose any functional form assumptions regarding the effects of weather on load. As discussed further in other sections of this report, the coefficients and standard errors of the main parameters of interest (namely γ) are nearly identical under these two approaches.

17 Note that because we include customer-specific fixed effects, the Z_i term is no longer identifiable and is omitted from the regression, due to multi-collinearity. However, when interacted with $PilotPeriod * Treatment_{it}$, the resulting interaction term allows us to measure differential impacts of the TOU treatment on subsets of customers.

requirement of the TOU pilot is the estimation of impacts for LMI customers. Thus, to estimate impacts for LMI customers, we limited the data to the set of LMI treated customers and their matched control customers.[18]

Equation (1) can also be augmented with various interaction terms in order to estimate the impact on specific groups of customers, or during specific time periods. For example, customer response to the pilot rates during the summer period might differ depending on the weather. Thus, we also perform estimation of the following variation on equation (1):

$$Load_{it} = \kappa_i + \pi PilotPeriod_t + \gamma PilotPeriod * Treatment_{it} + \gamma_2 PilotPeriod * Treatment_{it} * THI_t + \delta Z_i + \theta_t + \varepsilon_{it} \quad (1')$$

where:

- THI_t is a vector of indicator variables categorizing days as high-, or low-THI days;[19] and
- γ_2 measures the additional impact of the treatment on days with a given THI classification.

The other variables are as described above, but the interpretation of γ changes in equation (1'), relative to equation (1), as it now measures the average impact on medium-THI days. This is just one example of how, in the course of our subgroup analysis, we use interaction terms to estimate differential impacts on different subsets of the data; another possible example would be measuring a differential impact for structural winners relative to other customers.

In order to minimize the influence of confounding factors, we conduct the impact evaluation of the PC44 pilot after excluding Peak Time Rewards event days from the data.[20]

2. Price Response

After estimating the load impacts using the difference-in-differences approach described above, we next estimated electricity demand models that represent the electricity consumption behavior of the PC44 TOU customers. These models yield estimates of substitution and own-price elasticities, along with the demand curve of the average customer, which are vital to being able to estimate the impact of rates other than those used in the pilot.

---

18 In order to test for differences between the impacts on LMI and non-LMI customers, we have also estimated these regressions using data from all customers and employing interaction terms that measure the differential impacts of the pilot on LMI customers.

19 In this example, the THI_t vector does not include an indicator for medium-THI days, in order to avoid multi-collinearity issues.

20 In our extended analyses, we also run one interaction specification where we include these days and test whether the impact of TOU prices varies on PTR event days.

Consistent with common practice in the literature on demand models, we use a constant elasticity of substitution (CES) model to estimate peak/off-peak substitution and own price elasticities. The CES model allows the elasticity of substitution to take on any value and it has been found to be well-suited to TOU pricing studies involving electricity since there is strong prior evidence that these substitution and own-price elasticities are generally small.

For a two-period rate structure, the CES model consists of two equations. The first equation models the ratio of the log of peak to off-peak quantities as a function of the ratio of the log of peak to off-peak prices and yields the "elasticity of substitution". The second equation models average daily electricity consumption as a function of the daily price of electricity and yields the "own price elasticity of demand". The two equations constitute a system for predicting electricity consumption by time period where the first equation essentially predicts the changes in the load shape caused by changing peak to off-peak price ratios and the second equation predicts the changes in the level of daily electricity consumption caused by changing average daily electricity price.

i. Substitution Demand Equation:

The final specification of the substitution demand model will be determined during the estimation process, but the functional form below represents a starting point for the model to be tested and estimated:

$$\ln\left(\frac{Peak\_kWh}{OffPeak\_kWh}\right)_{it} = \alpha_0 + \alpha_1 THI\_DIFF_t + \alpha_2 ln(\frac{Peak\_Price}{OffPeak\_Price})_{it} +$$
$$\sum_{k=1}^{K} \delta_k (THI\_DIFF_t xD\_Month_k) + \alpha_3 D\_TreatPeriod_t + \sum_{k=1}^{K} \beta_k D\_Month_k + \nu_i + u_{it}$$

Where:

$\ln(\frac{Peak\_kWh}{OffPeak\_kWh})_{it}$	Logarithm of the ratio of peak to off-peak load for a given day
THI_DIFF_t	The difference between average peak and average off-peak temperature-humidity index ("THI"). THI= 0.55 x Drybulb Temperature + 0.20 x Dewpoint + 17.5
$\ln(\frac{Peak\_Price}{OffPeak\_Price})_{it}$	Logarithm of the ratio of peak to off-peak load for a given day
$\ln(\frac{Peak\_Price}{OffPeak\_Price})_{it} xTHI\_DIFF_t$	Interaction of ratio of peak to off-peak prices and *THI_DIFF* for a given day
$THI\_DIFF_t xD\_Month_k$	Interaction of THI_DIFF variable with monthly dummies.
$D\_TreatPeriod_t$	Dummy variable is equal to 1 if treatment period
D_Month_k	Dummy variable that is equal to 1 when the month is k.
v_i	Time invariant fixed effects for customers.
u_{it}	Normally distributed error term.

In the estimated model, α_2 represents the substitution elasticity.

ii. Daily Demand Equation:

The daily demand equation captures the change in the level of overall consumption due to the changes in the average daily price. Similar to the substitution equation, the final specification of the daily demand equation will be specified in the estimation stage, but below we present a starting point for the model to be tested and estimated:

$$\ln(kWh)_{it} = \alpha_0 + \alpha_1 \ln(THI)_t + \alpha_2 ln(Price)_{it} + \sum_{k=1}^{K} \delta_k (\ln(THI)_t xD\_Month_k) + \alpha_3 D\_TreatPeriod_t + \sum_{k=1}^{K} \beta_k D\_Month_k + \nu_i + u_{it}$$

where:

$\ln(kWh)_{it}$	Logarithm of the daily average of the hourly load.
$\ln(THI)_{it}$	Logarithm of the daily average of the hourly THI.
$\ln(Price)_{it}$	Logarithm of the daily average of the hourly Price.
$\ln(THI)_t xD\_Month_k$	Interaction of ln(*THI)* variable with monthly dummies.
$D\_TreatPeriod_t$	Dummy variable is equal to 1 if treatment period.
D_Month_k	Dummy variable that is equal to 1 when the month is k.
v_i	Time invariant fixed effects for customers.
u_{it}	Normally distributed error term.

In the estimated model, α_2 represents the daily price elasticity.

III. Description of Data

A. Enrollment and Attrition Summary

Our ability to quantify the impact of the pilot rates depends on having a large enough sample size to detect an average impact that stands out from inevitable variation or statistical "noise." During the pilot design stage, we undertook statistical power calculations to determine the sample sizes required to estimate a minimum detectable peak impact of 6% at the 5% statistical significance and 80% power.[21] The resulting sample size target is 700 customers for each of the LMI and non-LMI treatments, and for each of the JUs. While JUs were able to meet this target to a large extent (with the exception of DPL), it is natural to observe some attrition during the pilot. Figure 5 below presents the attrition statistics over the course of the first year of the pilot. As of May 2020, 21% of BGE, 15% of Pepco and 14% of DPL treatment customers have left the pilot. It is important to note that most of the attrition was due to customers moving or switching to other suppliers, rather than opting-out of the pilot.[22] Figure 6 through Figure 8 present the pilot sample evolution for each of the JUs.

[21] Note that these sample size assumptions are different from those filed in the EM&V report and have been revised following lower than expected initial recruitment statistics, by relaxing some of the earlier highly conservative assumptions.

[22] 49% of BGE attrition is due to customers moving or closing their account, 28% is due to the customer switching to a third-party supplier, and the remaining 23% indicated "work," "savings," or "other" as unenrollment reasons. Of the 90 DPL customers for whom the reason for attrition is known, 40% moved out of their homes, 22% opted out of the pilot, and 38% moved their service to a third-party supplier. Among 194 Pepco customers who unenrolled, 32% moved out, 26% opted out of the pilot, and 42% moved to a third-party supplier. There are 13 Pepco customers and 1 DPL customer for whom the reason for unenrollment is not known.

FIGURE 5: ENROLLMENT AND ATTRITION AS OF MAY 31, 2020

# of customers	BGE		Pepco		DPL	
Enrolled	1,772		1,380		674	
Attrition						
By 6/1/2019	97	5%	57	4%	22	3%
By 10/1/2019	232	13%	127	9%	55	8%
By 5/31/2020	367	21%	207	15%	91	14%
Potential Sample Size						
For summer analysis	1,675	95%	1,323	96%	652	97%
For non-summer analysis	1,540	87%	1,253	91%	619	92%
Eligible						
For summer analysis	1,614	91%	1,247	90%	620	92%
For non-summer analysis	1,487	84%	1,177	85%	571	85%

Notes: The reported "Enrolled" total includes all customers who ever enrolled in the pilot, regardless of the date or duration of their enrollment. The difference between the "Potential Sample Size" and the "Eligible" totals reflects the removal of customers due to high amounts of missing or incomplete data.

The remaining number of customers eligible for analysis is sufficient for the summer analysis. However, we occasionally run into some issues with statistical significance in the non-summer analysis, as the realized impacts (and hence impacts to be detected) tend to be lower. As the pilot proceeds into the second year, we may observe further attrition.

FIGURE 6: BGE PILOT SAMPLE EVOLUTION, AS OF 5/31/2020

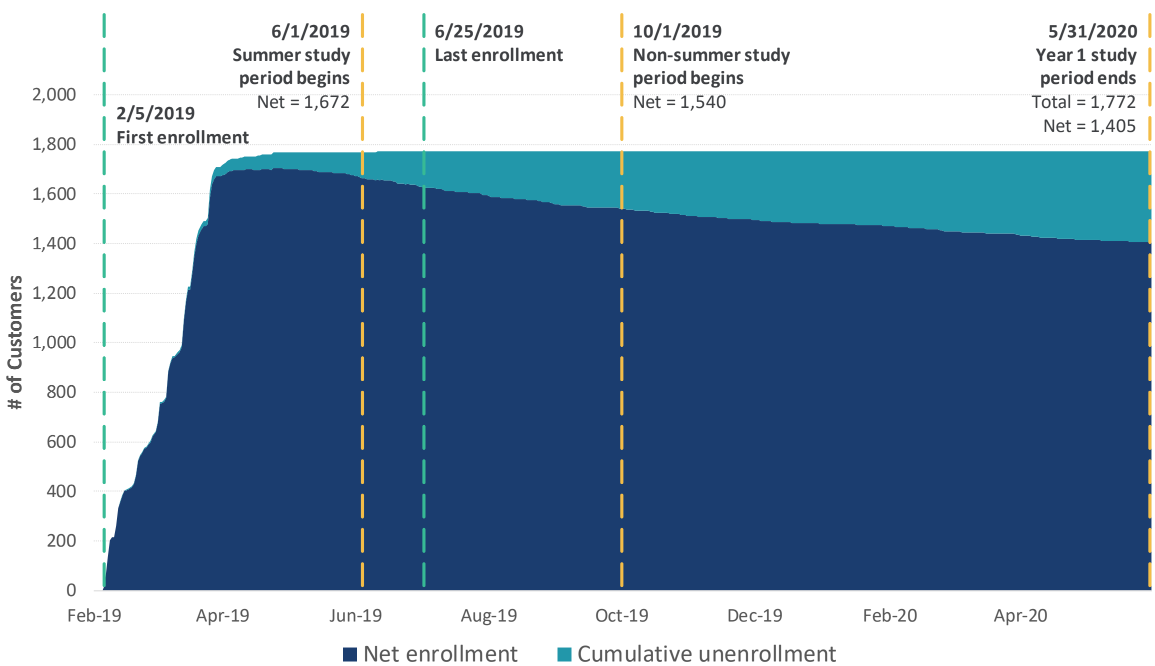


FIGURE 7: PEPCO PILOT SAMPLE EVOLUTION, AS OF 5/31/2020

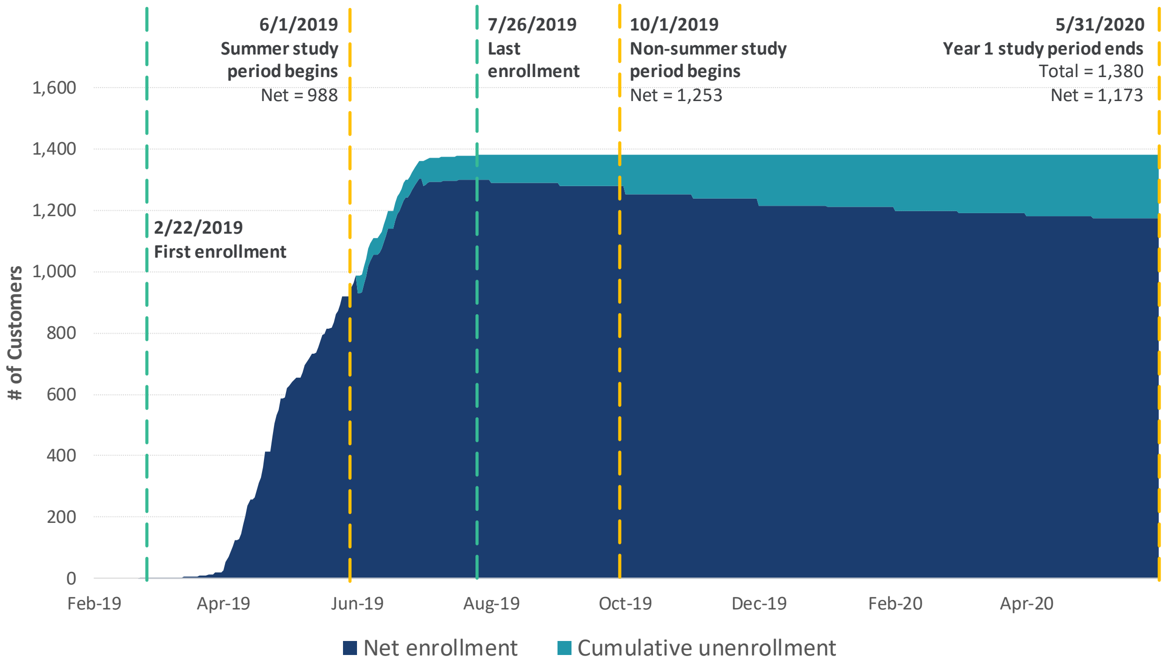
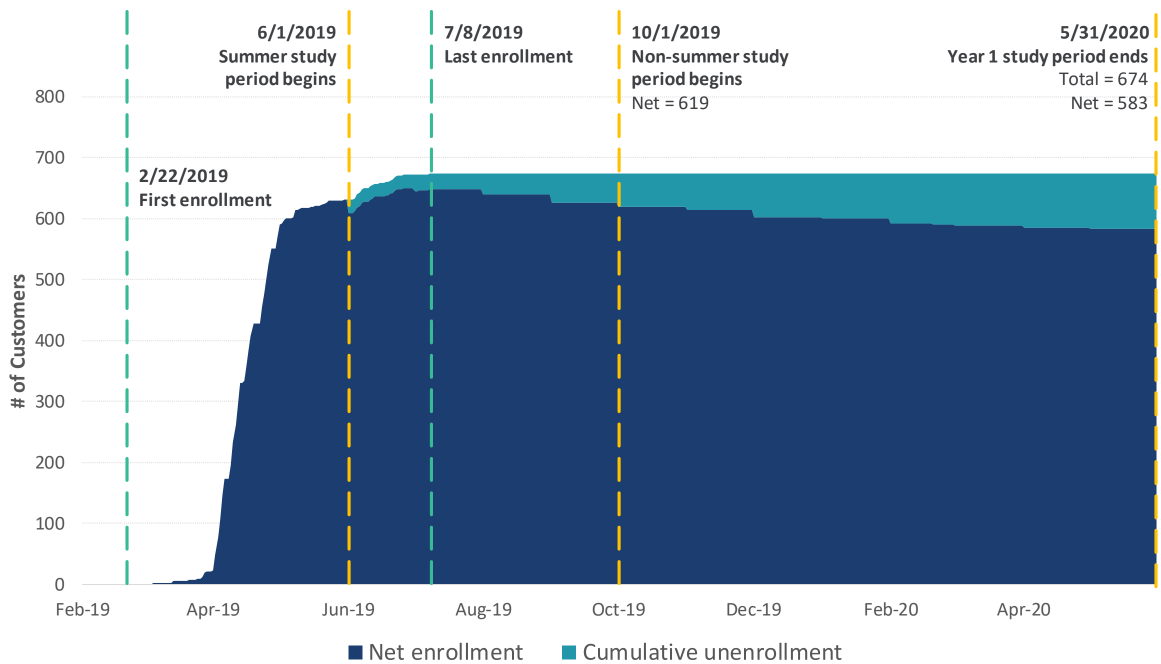


FIGURE 8: DPL PILOT SAMPLE EVOLUTION, AS OF 5/31/2020



B. Summary of Datasets

In addition to regular enrollment and attrition updates, the JUs also provided the following datasets that we subsequently used in our Year 1 analysis:

- hourly load data covering all residential customers from January 2018 through the end of May 2020;
- zip codes for each masked customer ID;
- information, for each masked customer ID, on enrollment in various energy efficiency and other utility programs at various points over the relevant time period;
- hourly weather data used by each of the utilities;[23]
- information, for each masked customer ID, on move-outs, switches to third-party suppliers, and tariff code changes; and
- detailed monthly rates data for the relevant tariff classes, covering the 2018 through 2020 period.

Using these input data, we eventually construct three main datasets for analysis for each utility, as described below.[24]

1. We use the first dataset to **analyze the participation decision** – which factors made target customers more likely to opt in to the TOU pilot? This dataset is limited to recruitment target customers, including both those who ended up enrolling in the pilot and those who did not. This dataset includes:
   - average load data for 2018, by season and hour of day;
   - other utility data about the customer, including their tariff code and data on the customer's participation status in various utility programs as of the end of 2018;
   - estimates of household income, whether at the zip code level or, for most BGE customers, an estimate provided by a third-party data provider; and
   - the outcome of the enrollment decision – did the target customer decide to enroll or not?
2. We use the second dataset to **construct the matched control group**. Specifically, we apply the results of the participation decision analysis to enrolled customers and to eligible potential control group customers in order to identify a control group that is as similar as possible to the treatment group. This dataset contains the same variables as is described above, but for a different set of customers.

[23] For BGE, the weather data is from the Baltimore-Washington International airport, Pepco provided weather data from Washington National Airport, and DPL provided weather data from New Castle Airport

[24] We take various steps to clean and process the data in order to deal with missing or incomplete data and changes in customer status. Those processing steps are described in detail in the Appendix A.2.

3. Finally, we construct, for each season, a dataset that we use to **analyze the impacts of the pilot**. This dataset contains daily observations from the pre-pilot and pilot periods, for enrolled and matched control customers, with the following variables:[25]
   - average hourly load in peak hours, off-peak hours, and all hours;
   - the average THI in peak hours, off-peak hours, and all hours;
   - indicators for whether the customer is a treatment customer or control customer, and whether the treatment customer remains enrolled on a given day;
   - time indicators, including month dummies, weekday and weekend indicators, and a pilot period indicator; and
   - the effective rates (in cents/kWh) at any given point in time, for that customer (for use in the elasticity analysis).

C. Control Group Balance

The matching analysis as described in Section II.B above yielded a number of key insights. Generally speaking, the results validated the decision to consider non-load variables when identifying a control group. Load variables are certainly correlated with targeted customers' participation decisions, with the results generally comporting with expectations. All things equal, higher off-peak loads made customers more willing to enroll, while higher peak loads made targeted customers less likely to enroll. However, several non-load variables were among the variables most highly correlated with the participation decision.

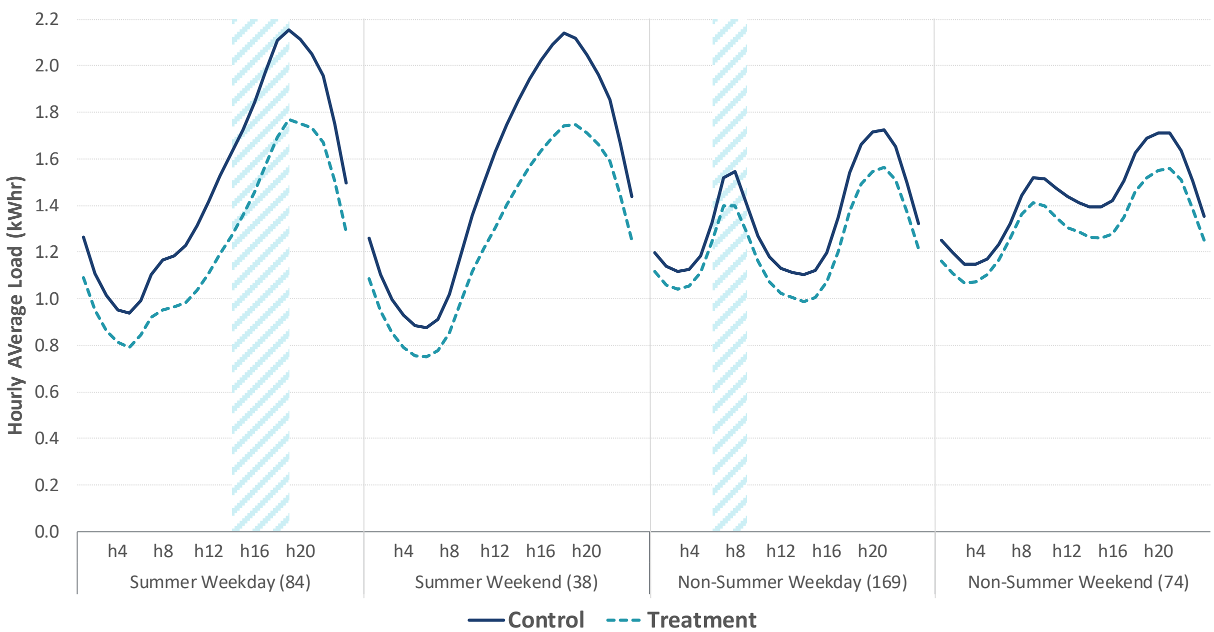
For example, BGE provided information indicating whether the customer's air conditioning unit (or multiple air conditioning units) is connected to a programmable thermostat that allows for cycling on event days. This variable was the single best predictor of enrollment in BGE's TOU pilot. Similarly, for Pepco and DPL, participation in the direct load control program, which is very similar to BGE's Peak Rewards program, was the single best predictor of participation in the TOU pilots. Other non-load variables that were highly correlated with the participation decision for one or more utility's customers included income measures, previous participation in home energy audits, and enrollment in net metering.[26] Many of these variables indicate a level of engagement with the utility or a willingness to be a more active utility customer. Including these variables in our matching analysis means that our control group is more similar to the treatment group than if we relied on load data alone.

[25] Note that the original datasets are hourly; we collapse them into daily period granularity after standard data cleaning procedures.

[26] Six of the first seven variables selected by our algorithm when applied to BGE were non-load variables. In addition to the Peak Rewards Air Conditioning variable, these included an analogous Peak Rewards Water Heater variable, the natural log of household income, the Quick Home Energy Check variable, a Home Energy Audit indicator, and the legacy TOU rate tariff.

After completing the matching analysis, we next undertake various diagnostics to assess our success in identifying comparable control groups. The following charts and tables indicate that we were generally successful in achieving the objective of the matching analysis. First, for each utility, we present two graphs. Beginning with BGE, Figure 9 compares the average load profiles of the "treatment" customers in dark blue with the average load profiles of all potential control customers (residential customers who the utility did not approach about the pilot) in light blue. The figure depicts four such average load profiles, one for each combination of season (summer or non-summer) and day type (weekdays and weekends). While the shape of the load profiles of the potential control group is similar to that of the treatment group, the average load is uniformly higher than the treatment group, indicating that there are some substantial differences between the two groups.

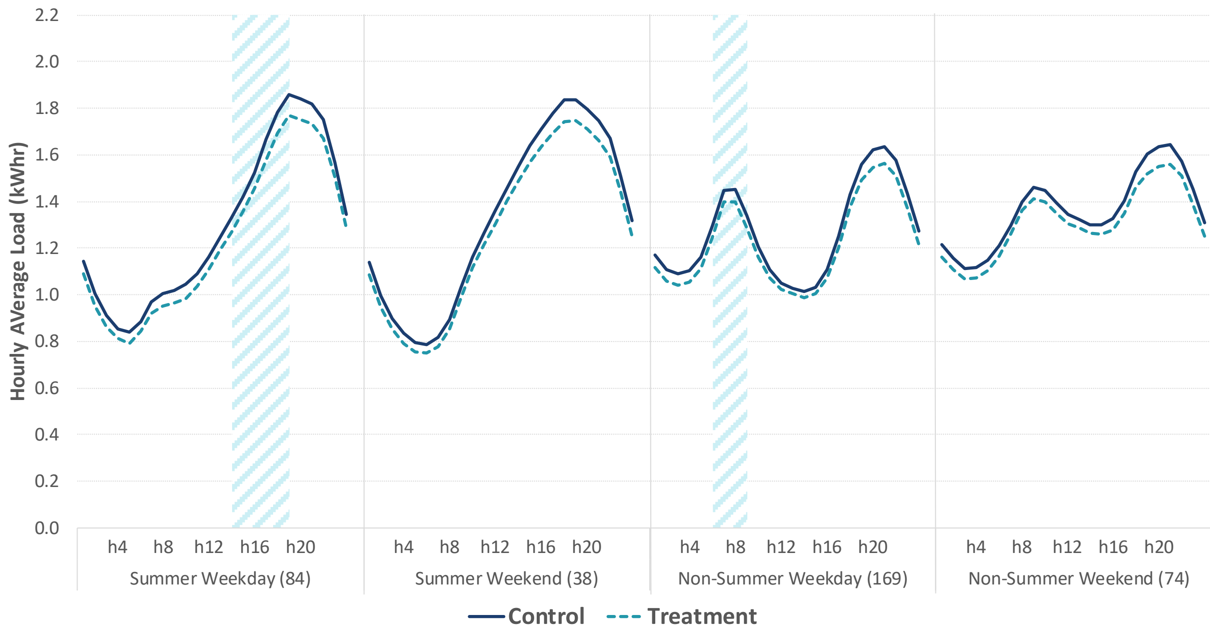
FIGURE 9: BGE AVERAGE LOAD PROFILE, 2018 – UNMATCHED (# OF CONTROL = 398,222)



Note: Numbers in parenthesis indicate the number of days in the period. Only includes customers eligible for the matching process and regression analysis.

Figure 10 instead compares the same treatment customer load profiles (in dark blue) with the average load profiles from matched control customers. While the load profiles are not identical, shifting to the matched control group eliminates the majority of the difference between the treatment group's average load profile and that of the control group.

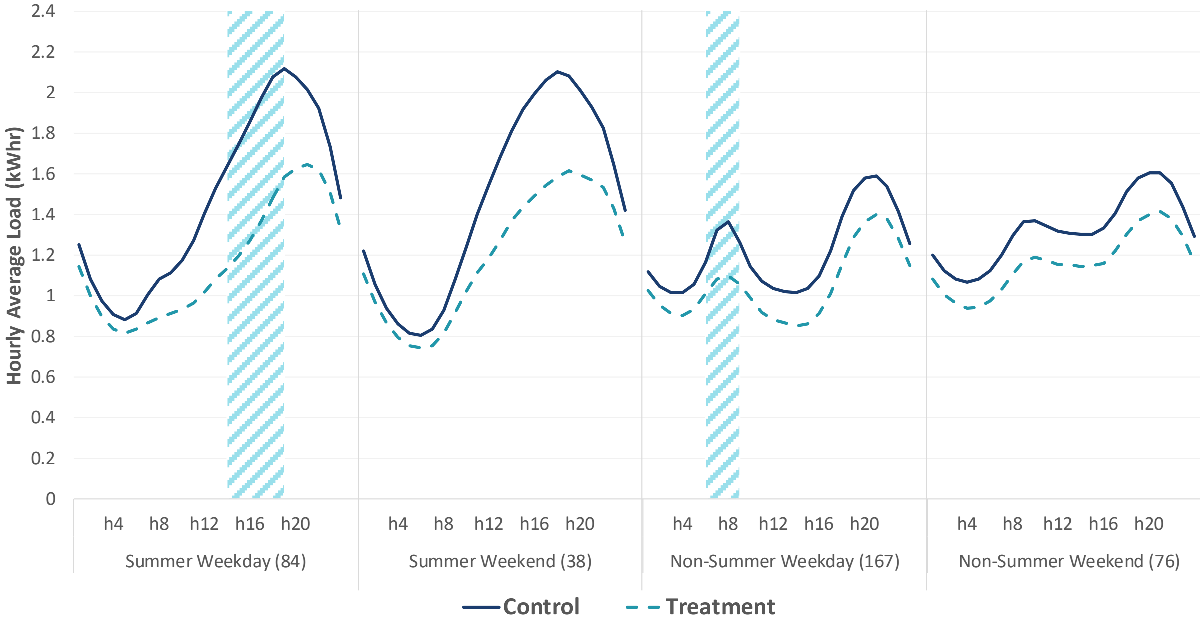
FIGURE 10: BGE AVERAGE LOAD PROFILE, 2018 – MATCHED (# OF CONTROL = 1,614)



Note: Numbers in parenthesis indicate the number of days in the period. Only includes customers eligible for the matching process and regression analysis.

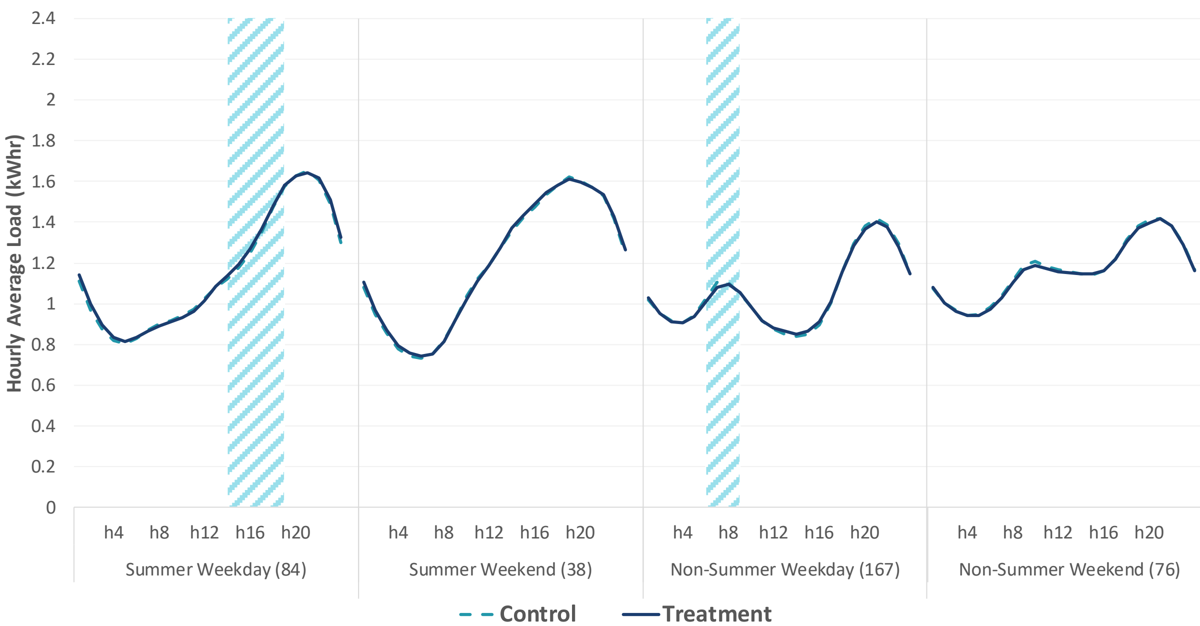
In Figure 11 through Figure 14, we perform the same diagnostic exercise for the Pepco and DPL treatment and control groups. Again, the load profiles of the matched control group are much more similar to those of the treatment group than are the load profiles of the potential control group. In the case of both Pepco and DPL, the average load profiles of the matched control group are almost identical to those of the treatment group, as indicated by the high degree of overlap between the dark blue and light blue lines in Figure 12 and Figure 14.

FIGURE 11: PEPCO AVERAGE LOAD PROFILE, 2018 – UNMATCHED (# OF CONTROL = 14,803)



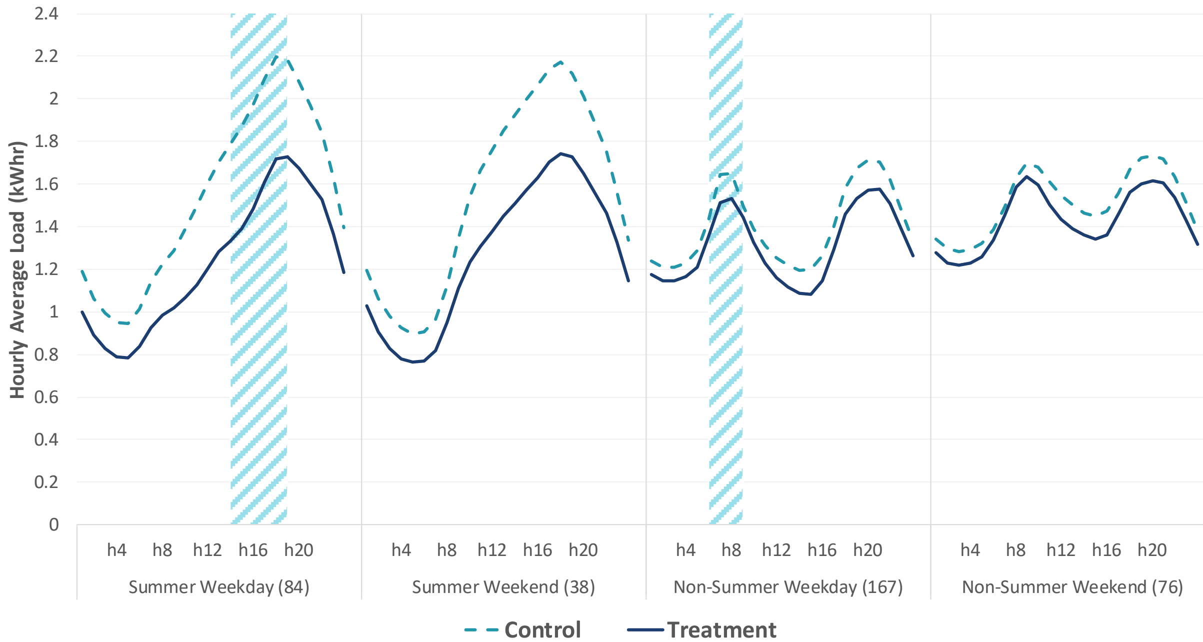
Note: Numbers in parenthesis indicate the number of days in the period. Only includes customers eligible for the matching process and regression analysis.

FIGURE 12: PEPCO AVERAGE LOAD PROFILE, 2018 – MATCHED (# OF CONTROL = 1,716)



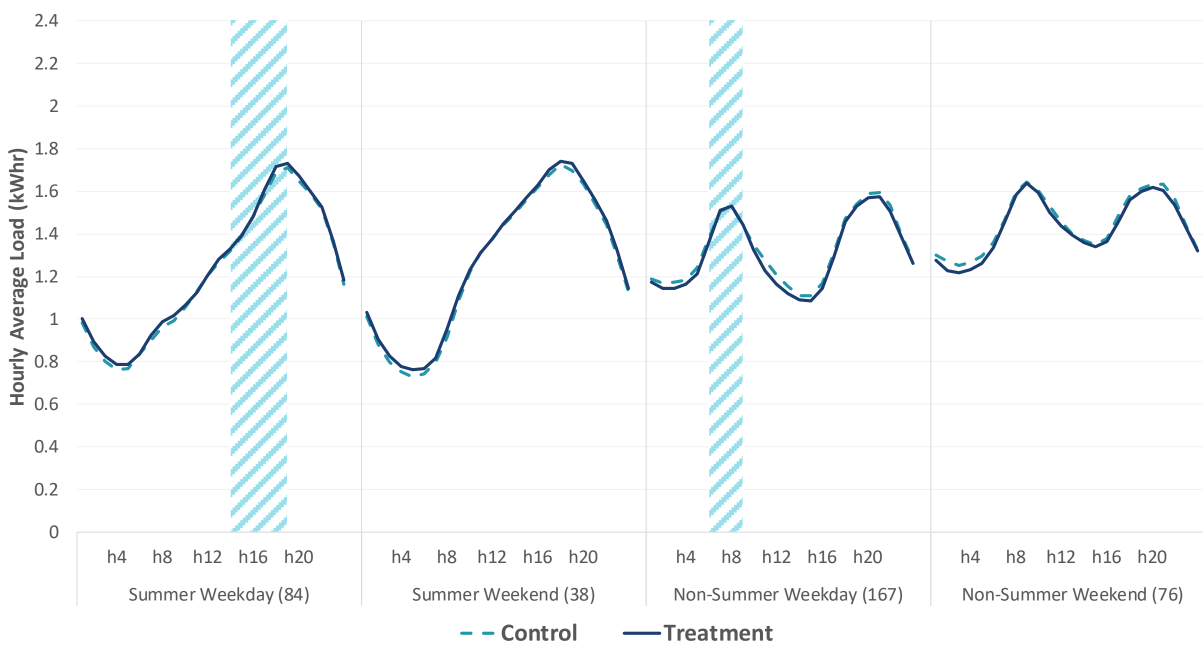
Note: Numbers in parenthesis indicate the number of days in the period. Only includes customers eligible for the matching process and regression analysis.

FIGURE 13: DPL AVERAGE LOAD PROFILE, 2018 – UNMATCHED (# OF CONTROL = 8,050)



Note: Numbers in parenthesis indicate the number of days in the period. Only includes customers eligible for the matching process and regression analysis.

FIGURE 14: DPL AVERAGE LOAD PROFILE, 2018 – MATCHED (# OF CONTROL = 595)



Note: Numbers in parenthesis indicate the number of days in the period. Only includes customers eligible for the matching process and regression analysis.

The inclusion of non-load variables in the matching analysis also has implications for covariate balance with respect to these customer characteristics. The control group that resulted from the matching process is much more similar to the treatment group on these non-load dimensions than is the unmatched control group. The following three figures demonstrate these results for selected non-load variables. For example, in Figure 15, we see that the average number of Peak Rewards Air Conditioner devices was 0.59 per customer for the treatment group, compared with 0.32 for the unmatched control group. In other words, treatment customers were about twice as likely to have a Peak Rewards-enabled Air Conditioner as was a randomly-selected control customer. However, in the matched sample, this difference between treatment and control group is largely eliminated. Figure 15 through Figure 17 present selected control variables for each respective utility, demonstrating significant improvements in the control group balance due to matching. The Appendix A.3 includes extended versions of these tables, with the full set of non-load variables used for each utility's control matching procedure.

FIGURE 15: BGE COVARIATE BALANCE OF SELECTED NON-LOAD VARIABLES

	LMI	Non-LMI	All Treatment	Unmatched Control	Matched Control
Energy Efficiency Measures					
Quick Home Energy Check (QHEC)	18.7%	15.8%	17.3%	9.1%	15.1%
Home Energy Audit	2.4%	5.9%	4.2%	2.0%	4.2%
Net Metering	2.3%	5.1%	3.7%	2.9%	3.8%
# of Peak Rebate Devices					
Air Conditioner	0.51	0.68	0.59	0.32	0.62
Water Heater	0.08	0.09	0.09	0.02	0.08

Note: An extended version of this table, with additional variables, is provided in Appendix A.3.

FIGURE 16: PEPCO COVARIATE BALANCE OF SELECTED NON-LOAD VARIABLES

	LMI	Non-LMI	All Treatment	Unmatched Control	Matched Control
Energy Efficiency Measures					
Net Metering	2.3%	4.5%	3.5%	2.5%	3.9%
Direct Load Control (DLC)	54.0%	54.9%	54.4%	38.6%	53.2%
HVAC Efficiency Program	0.8%	2.7%	1.9%	1.1%	2.0%

Note: An extended version of this table, with additional variables, is provided in Appendix A.3.

FIGURE 17: DPL COVARIATE BALANCE OF SELECTED NON-LOAD VARIABLES

	LMI	Non-LMI	All Treatment	Unmatched Control	Matched Control
Energy Efficiency Measures					
Net Metering	2.7%	4.8%	3.5%	1.6%	4.4%
Direct Load Control (DLC)	36.8%	47.6%	40.9%	19.0%	39.4%
Quick Home Energy Check (QHEC)	2.2%	0.8%	1.7%	1.0%	1.5%

Note: An extended version of this table, with additional variables, is provided in Appendix A.3.

In addition to the balance diagnostics presented here, we also calculate for each pre-treatment variable analyzed here a variety of metrics that measure the balance between the control group and the treatment group.[27] The variables assessed include the non-load variables discussed here as well as 96 load variables, corresponding to average load values for each of 24 hours in each of two seasons and for each of two day types (non-holiday weekdays and weekends/holidays). For all three utilities and for all variables analyzed, the matched control sample performs well on these balancing diagnostics, providing further reassurance that the matched control samples are sufficiently comparable on all observable characteristics, supporting the validity of the results that we describe in the following section.

[27] Specifically, we calculate the standardized difference in averages, the logarithm of the ratio of standard deviations, and assessments of the frequency with which an observed value for a given variable in one group (*i.e.*, the treatment group) would be a statistical outlier had it been observed in the control group (and vice versa). The construction of and rationale for these diagnostics are described in detail in Chapter 14 of Imbens and Rubin. The details of the results of these diagnostics as applied to our data are available upon request.

IV. Year 1 Impact Evaluation Results

A. Introduction

In this section, we present the results of our impact evaluation. This section is primarily organized by utility, and by season within each utility subsection. For each utility, we focus on the impact results from our preferred econometric specification and dataset. To test the sensitivity of our main impact results, we also estimate several alternative specifications. While the results of these sensitivity specifications differ somewhat from our primary results, any differences are modest; the sensitivity results are broadly supportive of the same fundamental conclusions from the results presented here. These sensitivity results are presented in the Appendix A.7. In each utility sub-section, we also present a series of "subgroup analyses" that investigate how the peak weekday impact results differ across various periods and customer groups.

After discussing the impact results for each utility, we also investigate whether the main results of the pilot changed after the onset of the COVID-19 pandemic, which undoubtedly had effects on electricity consumption by Maryland customers, as we will demonstrate. Finally, we will discuss the results of our price elasticity analysis.

Before discussing the results, a brief reminder of the expected impacts of TOU rates is appropriate. Broadly speaking, we expect the significant changes in price experienced by TOU customers to induce them to lower their consumption in peak hours, relative to what they would have consumed on a flat rate. At the same time, we generally expect the lower prices faced by TOU customers in the off-peak period to induce additional consumption, again relative to what they would have consumed on a flat rate. The extent to which these predictions are borne out depends on the relative magnitude of the peak to off-peak differential, but also on the price responsiveness of electricity customers. Total consumption can decrease, increase, or remain more or less unchanged, depending on factors including relative prices, the length of the peak windows, and other factors already discussed. In the PC44 TOU pilots, the presence of the behavioral load shaping tool and information provision to the customers add an additional factor that is of particular interest.

For simplicity and clarity, in the exposition that follows, we illustrate the key impacts of our econometric analysis in a graphical format. *In the graphs that follow, the error bars denote the 95% confidence interval of the estimated impact. This provides a sense of the precision of each of our estimates; roughly speaking we can be 95% confident that the true effect lies within the range depicted by the error bar. Relatedly, when the column depicting a point estimate is shaded gray, the 95% confidence interval includes 0, indicating a lack of statistical significance for that impact estimate. In other words, for impact estimates that are "grayed out," we are less than 95% confident that there is a measurable effect of the pilot for that customer group and time period.*

For those readers who are interested in the econometric details, the underlying regression tables are available in the Appendix A.4.

B. Baltimore Gas & Electric

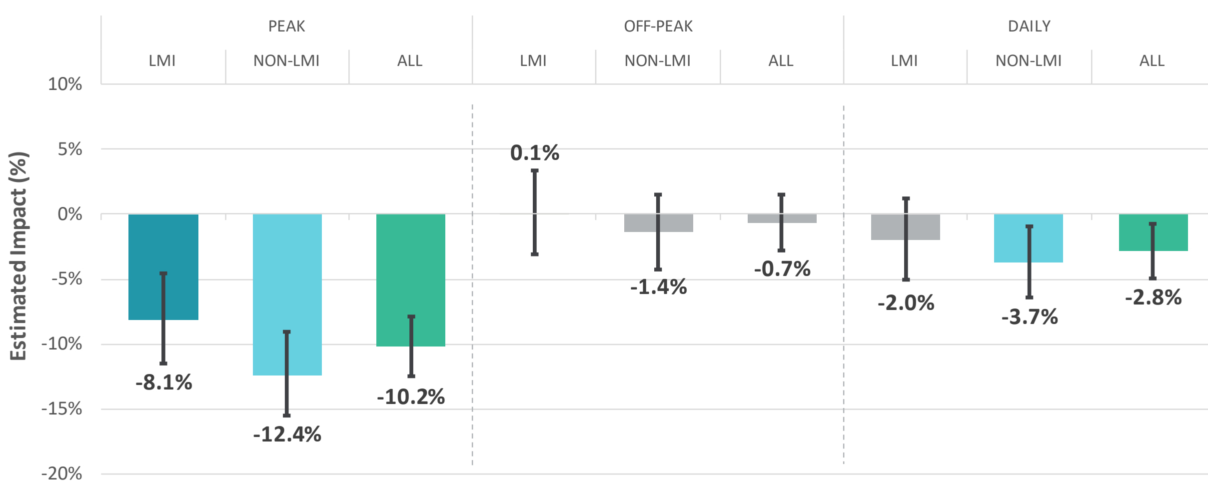
1. Main Impact Results

i. Summer Analysis

We begin our discussion of the primary impact results by presenting the summer results for BGE, which are summarized in Figure 18. Weekday peak impacts across all pilot customers average a 10.2% reduction. This is in effect a weighted average of the LMI peak load reduction (8.1%) and the non-LMI peak load reduction (12.4%). This is an important finding. While the difference between the LMI and non-LMI groups is *weakly* statistically significant, the LMI impact itself is statistically different from zero.[28] These weekday peak impacts are presented in the left-most panel of Figure 18.

At the same time, as the middle panel of Figure 18 indicates, we find little evidence that BGE treatment customers (regardless of household income level) altered their weekday off-peak consumption in response to the TOU pilot. In aggregate, as depicted in the right-most panel of Figure 18, there was some conservation on weekdays. On average, the pilot reduced customers' weekday consumption by 2.8%, an effect which was statistically significant; the daily impact was also significant for non-LMI customers but not for LMI customers.

FIGURE 18: ESTIMATED BGE SUMMER WEEKDAY IMPACTS BY CUSTOMER GROUP AND PERIOD



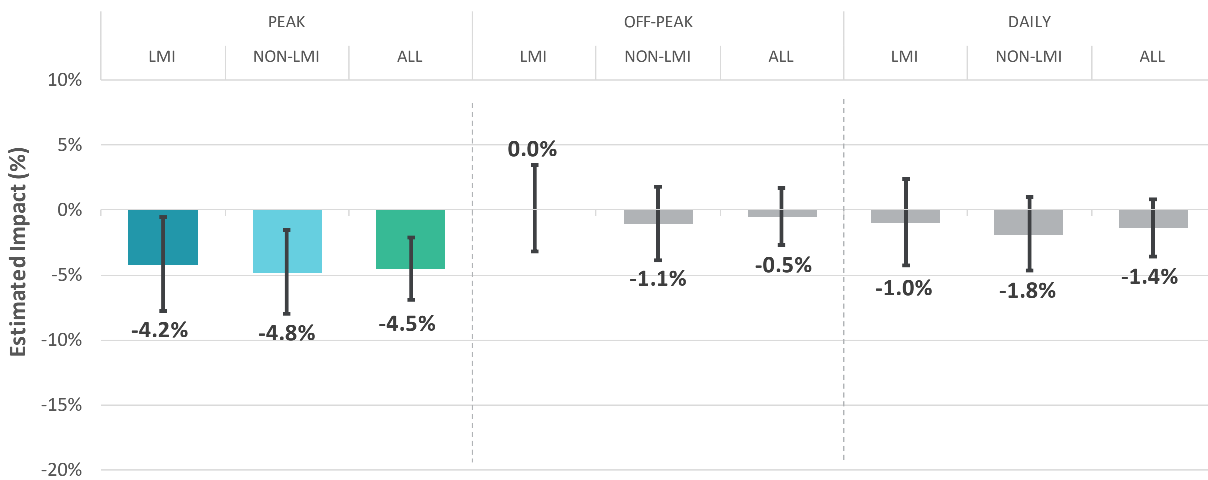
28 Here, our use of the term weak statistical significance indicates that the null hypothesis (here, that the LMI effects are equal) can be rejected when the significance level, α, is set to 10% but not when it is set to 5% in a two-tailed test. Generally, it indicates a slightly lower degree of confidence that the estimated impacts are meaningful as opposed to the result of statistical noise.

Note: Error bars indicate the 95% confidence interval of the regression coefficients. Grey bars denote statistical insignificance at the 5% level.

Turning to weekend summer impacts for BGE, the results are somewhat surprising. On weekends (including holiday weekdays), all hours are considered off-peak, implying lower rates throughout the day. Economic theory suggests that to the extent that there is a price response, consumption should increase, relative to the counterfactual. Yet as Figure 19 shows, there are statistically significant reductions in “peak” hours (that is to say, weekend hours between 14:00 and 19:00), relative to the control group. This is true across customer groups; furthermore the LMI effect is not significantly different from the non-LMI effect in this time period.

As we will demonstrate later in this Section of the report, this pattern, of weekend load reductions during “peak” hours is repeated across Pepco and DPL as well. These weekend effects could be “spillover effects” from the BLS messaging tool, or customers may be using the same schedule for their smart thermostats during both the weekdays and weekends, resulting in a reduction in peak period usage. In any case, load reductions in “off-peak” weekend hours are either non-existent or too small to be statistically different from zero. Overall weekend daily effects also surprisingly indicate conservation, though these impacts are not statistically significant.

FIGURE 19: ESTIMATED BGE SUMMER WEEKEND IMPACTS BY CUSTOMER GROUP AND PERIOD



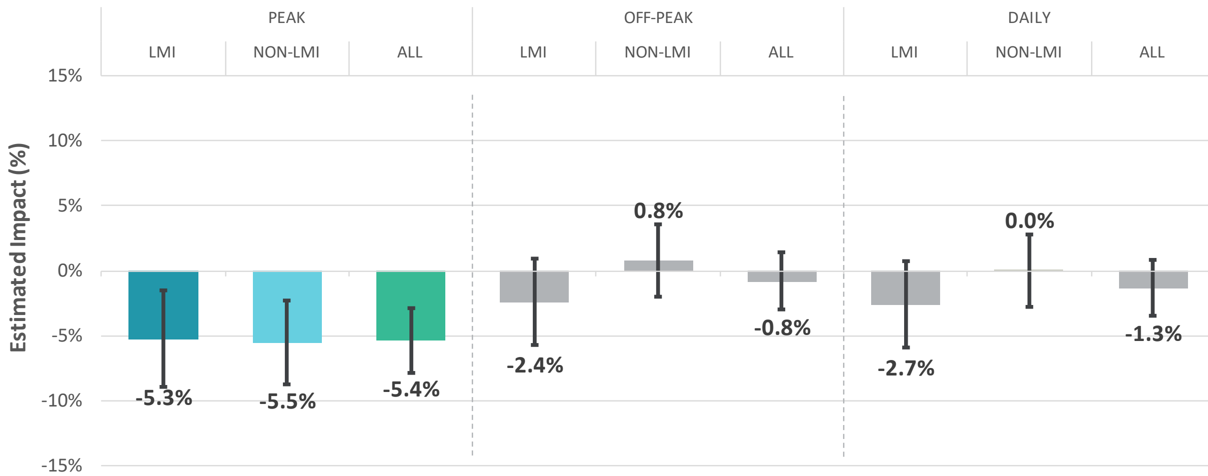
Note: Error bars indicate the 95% confidence interval of the regression coefficients. Grey bars denote statistical insignificance at the 5% level.

ii. Non-summer Analysis

On October 1, 2019, the pilot rates changed, along with the definition of the peak. The peak moved from a five-hour period covering the afternoon and early evening in the summer to a 3-hour window, again on weekdays, covering the hours 6 AM to 9 AM.

In the non-summer period, the weekday peak impacts experienced by BGE pilot customers were lower than those experienced in the summer. The average impact for pilot customers was a 5.4% reduction, as displayed in Figure 20; the small difference between LMI and non-LMI groups is not statistically significant. For both groups, as well as for pilot customers as a whole, the estimated effects are significantly different from zero. However, the off-peak and daily conservation impacts are generally not statistically significant; there are no conclusive effects with respect to either off-peak or overall impact reductions on non-summer weekdays.

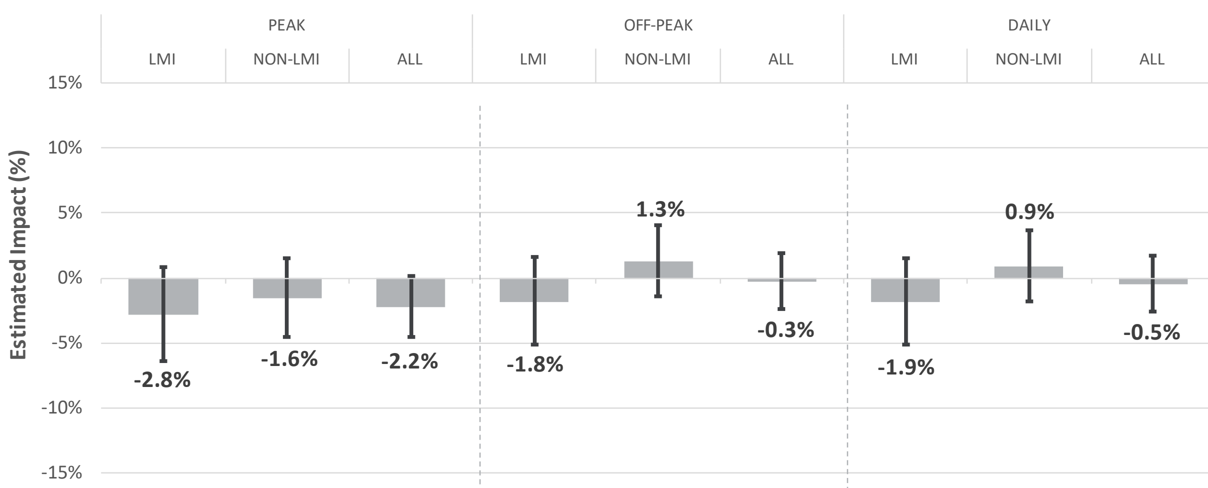
FIGURE 20: ESTIMATED BGE NON-SUMMER WEEKDAY IMPACTS BY CUSTOMER GROUP AND PERIOD



Note: Error bars indicate the 95% confidence interval of the regression coefficients. Grey bars denote statistical insignificance at the 5% level.

As depicted in Figure 21, the estimated coefficients for weekend "peak" hours are suggestive of the weekend spillover effects we identified in the summer period, but are not statistically significant for any of the customer groups. The "off-peak" and overall daily effects are similarly inconclusive on non-summer weekends for BGE customers, regardless of the customer group being analyzed.

FIGURE 21: ESTIMATED BGE NON-SUMMER WEEKEND IMPACTS BY CUSTOMER GROUP AND PERIOD



Note: Error bars indicate the 95% confidence interval of the regression coefficients. Grey bars denote statistical insignificance at the 5% level.

2. Subgroup Analysis

The impact results presented above represent average impacts for the specified period (*e.g.*, summer weekday peak hours) and customer group (*e.g.*, NEM customers). In order to understand better how these impacts vary along other observable dimensions, we estimate a series of additional regressions. In each of these extended analyses, we allow the estimated impacts to vary with some observable factor. This allows us to conduct formal statistical tests for different responses by different groups of customers or on different types of days. We conduct these analyses for weekday peak impacts, as that is the period with the largest estimated impacts and therefore is the most likely to reveal statistically significant differences among various subgroups. The following discussion refers entirely to weekday peak impacts.

The results of these extended analyses are presented in Figure 22. For reference, the top panel in Figure 22 presents the base impacts in each season. We include in the top panel the results of a base specification estimated not in natural logs but in kilowatt-hours, which allows us to include NEM customers.[29] Each of the subsequent panels of Figure 22 presents the results, in terms of estimated impacts, for each of the subgroups relevant to that analysis. In each such analysis, we use red shading to indicate the "base" group. For the base group, statistical significance is measured with respect to the null hypothesis of zero effect. For the other groups, statistical significance is measured with respect to the base group.

[29] Net-metering customers are not included in our primary regression analyses as these customers have negative net loads in some hours, and the natural log of a negative number is undefined.

FIGURE 22: BGE WEEKDAY PEAK IMPACT BY SEASON AND SUBGROUP

	Summer weekday peak	Non-summer weekday peak
Baseline Results		
% (non-NEM customers)	-10.2%***	-5.4%***
kWh (all customers)	-0.164***	-0.0919***
Group by NEM vs. non-NEM (kWh)		
Non-NEM	-0.163***	-0.0891***
NEM	-0.196	-0.160
Group by pre-treatment seasonal usage		
Medium-usage	-11.9%***	-3.3%
Lowest-usage	-3.6%***	0.7%
Highest-usage	-14.5%	-13.0%***
Group by structural winners vs. others		
Others	-9.3%***	-5.0%**
Winners	-10.7%	-5.6%
Group by daily THI		
Medium 50%	-11.1%***	-6.0%***
Coolest 25%	-8.3%**	-4.8%
Warmest 25%	-10.4%	-4.7%
Group by month		
June	-10.6%***	
July	-11.4%	
August	-9.7%	
September	-9.1%	
January		-5.5%***
February		-5.1%
March		-6.9%
April		-6.1%
May		-5.5%
October		-3.7%
November		-5.4%
December		-5.2%
Event day effects		
Non-event day	-10.2%***	
Event day	-12.3%	

Note: The red highlight indicates the base group within each analysis. ***, **, and * denote statistically significant results at the 1%, 5%, and 10% level, respectively. For the base group, statistical significance is measured with respect to zero effect. For the other groups, statistical significance is measured with respect to the base group. For the pre-treatment seasonal usage, customers were divided into three groups based on their average daily pre-pilot load during the respective seasons.

i. Net Metering Customers

As the second panel indicates, pilot customers who are net metering customers experienced larger estimated impacts than non-NEM customers. For example, in the summer, NEM customers reduced their average hourly load by 0.196 kWh while non-NEM customers' reductions were 0.163 kWh.

However, these differences are not significant in either season, perhaps due to the relatively small sample of NEM customers.[30]

ii. Pre-Pilot Customer Usage

We also test whether pilot impacts varied in conjunction with the size of the customer's pre-pilot load. To that end, for each season we divide the set of pilot customers included in the analysis into three evenly sized groups based on their average daily pre-pilot load during the respective seasons. Here, the relative effects vary by season. In the summer, the highest-usage customers saw load reductions of 14.5%, while medium- and low-usage customers saw reductions of 11.9% and 3.6%, respectively. The effect for lowest-usage customers was significantly different from that of medium-usage and high-usage customers.

In the non-summer, the order is unchanged, with the largest load reductions experienced by the highest-usage customers. In fact, the impacts for medium-usage customers are not significantly different from zero, and the estimated impact for low-usage customers is actually positive (though not significant). This suggests that the highest-usage customers, whose load impacts actually exceeded the average summer impact, are driving the overall non-summer results for the BGE pilot.

iii. Structural Winners vs. Others

As explained above, BGE provided targeted customers with information regarding their projected bill savings under the TOU pilot tariff with and without load shifting behavior, based on their 2018 usage. As indicated in Figure 4, enrollment rates were higher among these "structural winners", those who could expect savings without any change in behavior or load consumption patterns. This raised the possibility that a large share of the enrolled pilot customers would not respond to the incentives embedded in the pilot rates. We thus test whether the peak load impact for these automatic winners would differ from the impact for others, who faced potential bill increases if they didn't shift load or reduce consumption.

Our results reveal that there is not a significant difference in the load reductions realized by these two groups. In fact, automatic winners saw slightly larger load impacts in both summer (10.7% vs 9.3% for others) and non-summer (5.6% vs 5.0%), though these differences are not statistically significant.

iv. Weather-Related Variations in Impact

We also test whether pilot customers' ability to reduce their peak load varied with the weather. Specifically, we identified the 25% coolest and 25% warmest days and allowed the peak impacts to vary from those that we measure on days with more typical or average weather, which we label the medium

[30] There are 62 BGE pilot customers with NEM, each of which we matched to a control customer who also has NEM.

50% in Figure 22.[31] We rank days on the basis of THI, which has been shown to be highly correlated with electric load.[32]

In the summer period, we find that the estimated impact on the coolest days (8.3%) is significantly lower than the impact on medium days (11.1%). This may occur because the cooling load is lower on cooler days, leaving less opportunity for conservation or load shifting. On hotter days, the peak load impact (10.4%) is also slightly below that of medium days, but this difference is not statistically significant.

In the non-summer, we do not generally find a large difference in weekday peak load impacts among these groups of days. Medium-weather days saw load reductions of 6.0%, with cooler and warmer days having experienced load reductions of 4.8% and 4.7%, respectively, neither of which is statistically different from the impact on medium-weather days.

v. Impacts by Month

We also test for differences in weekday peak impacts by calendar month. In summer, we designate June as the base month, and find that while the impacts vary in the other three months, the difference between each of those months and June is never statistically significant.[33] In the non-summer months, we designate January as the base month, and fail once again to find significant differences between the January impact and the impact in any other month.[34] We also investigate whether or not the COVID-19 pandemic had an effect on the impacts in a separate analysis, discussed below.

vi. Impacts on Event Days

In conducting our primary analysis, we want to minimize the influence of other existing demand response programs already in place, which could influence our impact estimates. Thus, for example, the primary analysis, and all analysis discussed thus far, excludes peak time rebate and direct load control event days from the data. However, in an extension to our primary analysis, we restore those days to the regression sample in order to test whether the impacts differ. We find that the peak impact (12.3%) is slightly higher than the non-event day impact (10.2%). However, the difference is not statistically significant, perhaps because of the relatively few event days.

31 We do not include Peak Time Rewards event days in our main analysis, in order to minimize the influence of other existing demand response programs already in place such as peak time rebate and direct load control programs. Thus those event days are also excluded from this and other subgroup analyses, unless specifically indicated otherwise. They are therefore not included when we rank and determine the cutoff points when constructing the interaction terms used in this analysis. There were 3 such days in the summer of 2018 and 2 in the summer of 2019.

32 Ahmad Faruqui and Sanem Sergici (2011). Dynamic pricing of electricity in the mid-Atlantic region: econometric results from the BGE Experiment. Journal of Regulatory Economics.

33 Even the difference between the July impact (-11.4%) and September impact (-9.1%) is only marginally significant.

34 Again, even the difference between the highest monthly impact (March, at -6.9%) and the lowest monthly impact (October, at -3.7%) is only significant at the 10% level.

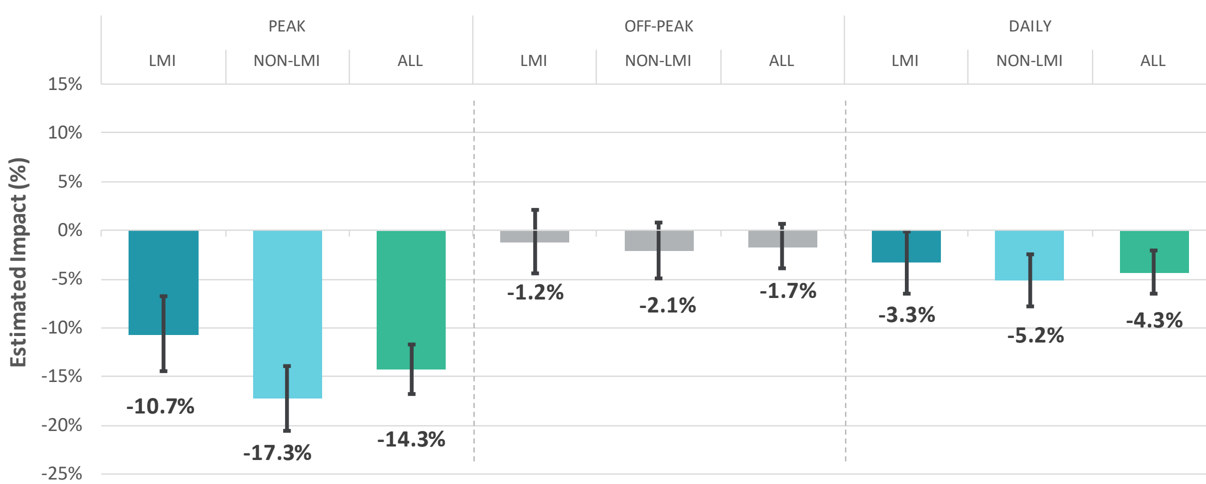
C. Pepco Maryland

1. Main Impact Results

i. Summer Analysis

The summer impact results for Pepco are broadly similar to those presented above for BGE. Beginning with weekday peak impacts, we find that the average pilot customer reduced their peak load by 14.3% relative to the control group. This is the result of a 10.7% reduction by LMI customers and a 17.3% reduction by non-LMI customers. This difference in peak load reductions is statistically significant; we can safely conclude that LMI customers' load reductions were smaller. These results are depicted in the left-hand panel of Figure 23. The center panel of that same figure illustrates that while the point estimates from the weekday off-peak analysis indicate that there were modest load reductions, there is not enough information to separate these effects from statistical noise and reach a conclusive finding. Nevertheless, the sizeable peak reductions mean that the overall impacts, presented in the rightmost panel of Figure 23, are a statistically significant load reduction. Pepco's TOU pilot customers reduced their load by 4.3% in the first year of the pilot; the differences between LMI customers (who reduced their load by 3.3%) and non-LMI customers (who reduced their load by 5.2%) are not statistically significant. However, we can conclude that both groups achieved statistically significant reductions in daily weekday load.

FIGURE 23: ESTIMATED SUMMER WEEKDAY IMPACTS BY CUSTOMER GROUP AND PERIOD

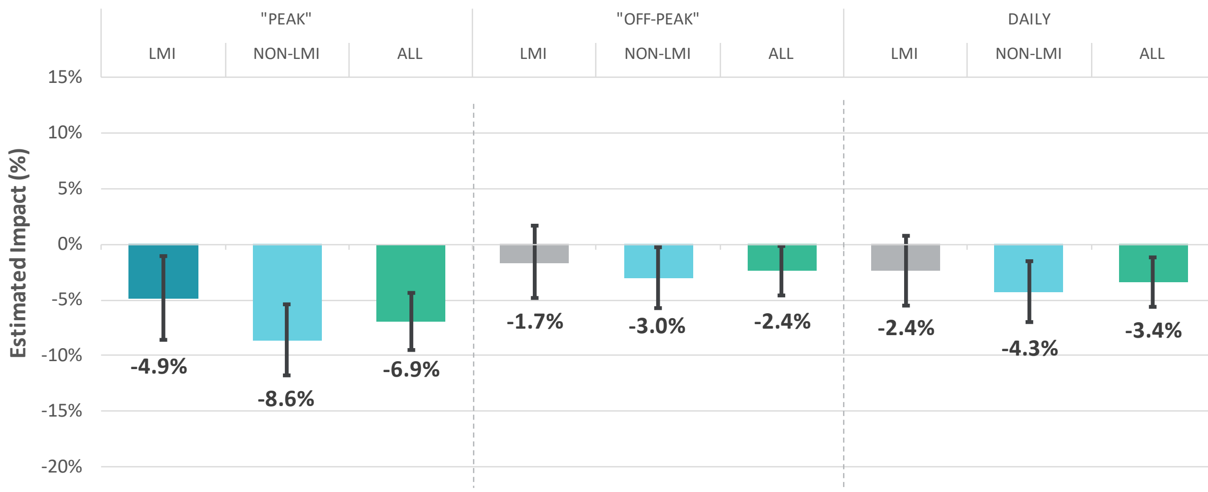


Note: The error bar indicates the 95% confidence interval of the regression coefficient. Grey bars denote statistical insignificance at the 5% significance level.

On weekends, we again find evidence of a "spillover effect" in that Pepco customers reduced their load in the hours that would have fallen in the peak window on weekdays. As shown in the first panel of Figure 24, weekend "peak" load reductions averaged 6.9% for Pepco's pilot customers. These "peak" window spillover effects are statistically significant for both LMI and non-LMI customers.

Interestingly, even in the "off-peak" weekend window, there were small but statistically significant load reductions for non-LMI customers and for the average pilot customer as well. As a result, Pepco pilot customers saw statistically significant weekend conservation effects of 3.4%.

FIGURE 24: ESTIMATED SUMMER WEEKEND IMPACTS BY CUSTOMER GROUP AND PERIOD

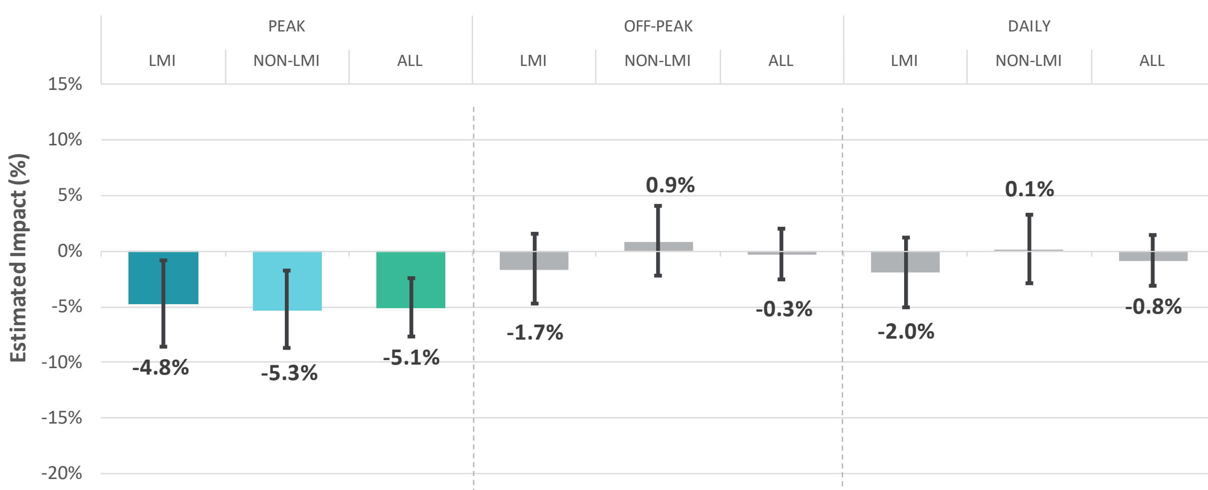


Note: The error bar indicates the 95% confidence interval of the regression coefficient. Grey bars denote statistical insignificance at the 5% significance level.

ii. Non-summer Analysis

In the non-summer, we again find that Pepco pilot customers reduced their load during weekday peak hours, a statistically significant finding. On average, customers reduced their load by 5.1%, which is a smaller reduction than was measured in the summer. The LMI and non-LMI groups experienced similar levels of weekday peak load reductions. In both weekday off-peak hours and for weekdays as a whole, the impacts are not statistically significant. We summarize our findings with respect to Pepco's non-summer weekday impacts in Figure 25.

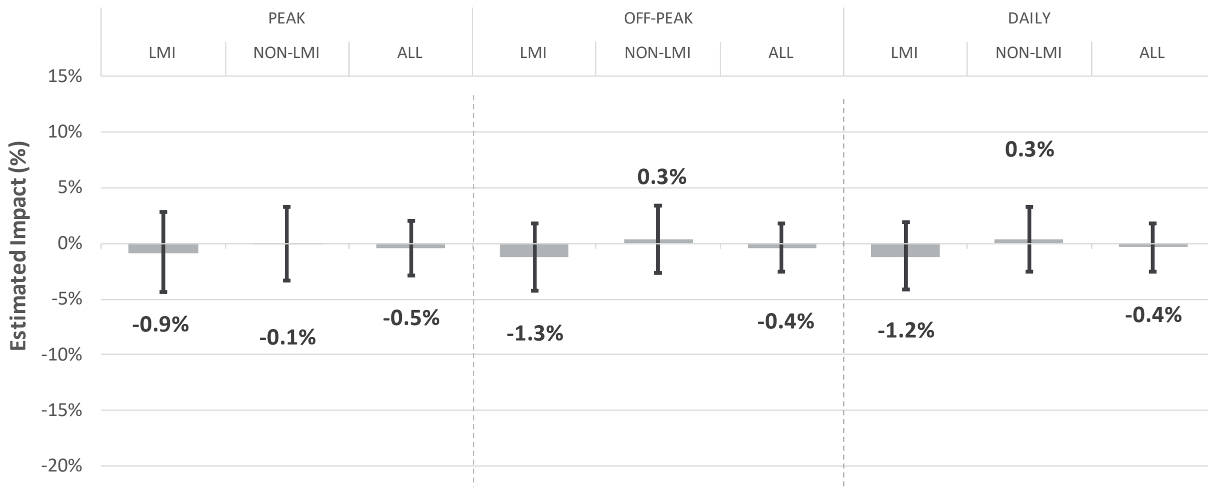
FIGURE 25: ESTIMATED NON-SUMMER WEEKDAY IMPACTS BY CUSTOMER GROUP AND PERIOD



Note: The error bar indicates the 95% confidence interval of the regression coefficient. Grey bars denote statistical insignificance at the 5% significance level.

On non-summer weekends, there are no statistically detectable impacts for Pepco pilot customers, regardless of which period or customer group is being considered. These findings are summarized in Figure 26.

FIGURE 26: ESTIMATED NON-SUMMER WEEKEND IMPACTS BY CUSTOMER GROUP AND PERIOD



Note: The error bar indicates the 95% confidence interval of the regression coefficient. Grey bars statistical insignificance at the 5% significance level.

2. Subgroup Analysis

As reported for BGE, we estimate for Pepco a series of supplementary regressions using interaction terms in order to provide some insight into the extent to which the average weekday peak impacts reported above vary along different dimensions. In what follows, we discuss those results, which we summarize in Figure 27.[35]

[35] Our discussion of the Pepco subgroup analysis is similar to that of the BGE subgroup analysis above. For reference, the top panel in Figure 27 presents the baseline impacts in each season. We include in that top panel the results of a base specification estimated not in natural logs but in kilowatt-hours, which allows us to include NEM customers. Each of the subsequent panels of Figure 27 presents the results, in terms of estimated impacts, for each of the subgroups relevant to that analysis. In each such analysis, we use red shading to indicate the "base" group. For the base group, statistical significance is measured with respect to the null hypothesis of zero effect. For the other groups, statistical significance is measured with respect to the base group.

For further details on the rationale or interpretation of various aspects of the subgroup analysis, please refer to the corresponding BGE discussion above.

FIGURE 27: PEPCO WEEKDAY PEAK IMPACT BY SEASON AND SUBGROUP

	Summer weekday peak	Non-summer weekday peak
Baseline Results		
% (non-NEM customers)	-14.3%***	-5.1%***
kWh (all customers)	-0.183***	-0.0593***
Group by NEM vs. non-NEM (kWh)		
Non-NEM	-0.174***	-0.0564***
NEM	-0.401	-0.1256
Group by pre-treatment seasonal usage		
Medium-usage	-14.8%***	-5.6%**
Lowest-usage	-12.1%	1.8%**
Highest-usage	-15.8%	-11.0%*
Group by structural winners vs. others		
Others	-13.6%***	-9.3%***
Winners	-14.6%	-2.9%**
Group by daily THI		
Medium 50%	-15.2%***	-5.0%***
Coolest 25%	-9.7%***	-7.1%*
Warmest 25%	-17.0%**	-3.0%
Group by month		
June	-13.2%***	
July	-15.8%**	
August	-15.6%*	
September	-12.0%	
January		-6.4%***
February		-6.3%
March		-5.7%
April		-4.3%
May		-2.6%
October		-2.5%
November		-5.6%
December		-7.3%
Event day effects		
Non-event day	-14.2%***	
Event day	-11.7%*	

Note: The red highlight indicates the base group within each analysis. ***, **, and * denote statistically significant results at the 1%, 5%, and 10% level, respectively. For the base group, statistical significance is measured with respect to zero effect. For the other groups, statistical significance is measured with respect to the base group. For the pre-treatment seasonal usage, customers were divided into three groups based on their average daily pre-pilot load during the respective seasons.

i. Net Metering Customers

The point estimates for net metering customers indicate that the peak load impacts associated with the pilot were much higher than for non-NEM customers. For example, our results indicate that NEM customers reduced their load by 0.401 kWh/hour in the summer weekday peak, compared to 0.174 kWh/hour for non-NEM customers. However, the difference is not statistically significant in either the summer or non-summer. This is likely an artifact of the relatively small sample size of NEM pilot customers.[36]

ii. Pre-Pilot Customer Usage

After using pre-pilot load to identify the heaviest and lightest users in each season, we also explore whether the weekday peak impacts varied in conjunction with usage by allowing for separate impact estimates for low users, medium users, and high-usage customers. In the summer, the differences were small in magnitude and not statistically significant, as the estimated impacts range from 12.1% to 15.8% across the three groups. In the non-summer, there was a wide range of impacts. While medium-usage customers saw load reductions of 5.6%, the lowest-usage customers saw load *increases* of 1.8%, a difference that is statistically significant.[37] On the other hand, the highest-usage customers saw load reductions of 11%, a difference (relative to the medium group) that is statistically significant at the 10% level.

iii. Structural Winners vs. Others

We also test whether the "structural winners" – those who could expect bill increases on the PC44 TOU rate without changing their load levels or patterns – nevertheless saw peak impacts. In the summer, we find that the load impacts of the two groups are statistically indistinguishable, as structural winners saw peak load reductions of 14.6% while other enrollees saw peak load reductions of 13.6%. In the non-summer, on the other hand, structural winners' load reductions (2.9%) were significantly smaller than those of other enrolled customers (9.3%).

iv. Weather-Related Variations in Impact

The pilot's weekday peak impacts varied with weather conditions, especially in the summer. Employing the same interaction term-based approach described above, we find that for Pepco, the weekday peak impacts in the summer increased with the temperature. On medium-THI days, the impact was a 15.2% reduction. However, on cooler days the reduction was smaller, at 9.7%, while on the warmest days, the reduction was larger, at 17.0%. Both the cool-day impact and the warm-day impact are significantly different from the medium-day impact. In the non-summer, differences were not as stark. The impact on medium-THI days was 5.0%, and the impact on cool days was 7.1%. The difference between the two is only marginally significant, and the impact on warmer non-summer days was similar to that of the medium-THI days.

[36] For example, only 53 of the 1,247 pilot customers included in the summer regression for this NEM subgroup analysis were NEM customers.

[37] This 1.8% load increase is not statistically different from zero either.

v. Impacts by Month

We also identify some differences in weekday peak impacts by month, but only in the summer. June and September had slightly smaller reductions, at 13.2% and 12.0%, respectively. July and August had slightly larger reductions, at 15.8% and 15.6%, respectively. The July and August differences are significant and marginally significant, respectively, relative to the baseline effects in June.[38] In non-summer, we do not generally identify statistically significant differences between each month's impacts. The January effect was a 6.4% reduction. While reductions in the other non-summer months ranged from 2.5% to 7.3%, none are significantly different from the January effect.

vi. Impacts on Event Days

Finally, we also test whether the impact of the pilot varies on event days, which are excluded from the primary analysis. Here, when we include the event days in the estimation sample and allow their effects to differ from non-event days, we find that the reduction (11.7%) was somewhat smaller than the non-event day reduction (14.2%), and that the difference is marginally significant. This is in line with expectations, as control customers also have increased incentives to reduce their peak load on event days, relative to non-event days.

D. DPL Maryland

1. Main Impact Results

Below, we present the impact results for DPL. It is important to note that DPL sample sizes for LMI and non-LMI treatments are materially smaller than those of BGE and Pepco. Therefore, some of the impacts we estimate for individual customer groups (LMI and non-LMI) fall short of statistical significance.

i. Summer Analysis

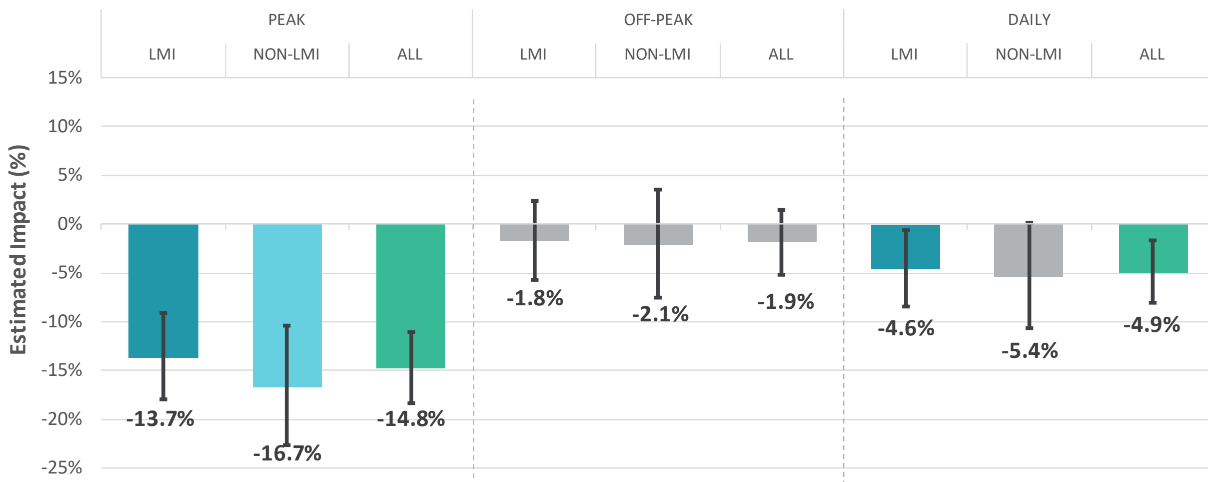
DPL pilot customers exhibit behavior that largely aligns with that of their counterparts at Pepco and BGE. The leftmost panel in Figure 28 shows that non-LMI customers reduced their usage during peak hours by 16.7%, while LMI customers showed a relatively lower impact, with a reduction of 13.7%. The difference between the impacts for the two groups, however, is statistically insignificant. In other words, peak usage behavior for the two groups of customers is statistically indistinguishable from each other. In aggregate, DPL customers reduced peak usage on weekdays by 14.8%, which is higher than the impact observed for both Pepco and BGE. Given that DPL customers were exposed to the largest price signal

[38] Note that these differences in month effects are above and beyond the weather controls we include in all regressions.

(see Figure 3), this finding is consistent with our observations in past pilots which show that higher price signals, on average, produced higher peak reductions.[39]

The point estimates for impacts during the off-peak hours on weekdays, depicted in the center panel in Figure 28, are negative for all customers, implying some reduction during low-price hours. These estimates, however, are statistically insignificant. Therefore, we cannot definitively say that customers reduced load during off-peak hours. Turning to the daily conservation impacts, the right-hand panel in the figure below shows that DPL customers, on average, reduced their load by 4.9% during the first summer of the pilot. While non-LMI customers exhibit a statistically insignificant reduction of 5.4%, it is not statistically different from the 4.6% reduction that the LMI customers observed.

FIGURE 28: ESTIMATED SUMMER WEEKDAY IMPACTS BY CUSTOMER GROUP AND PERIOD



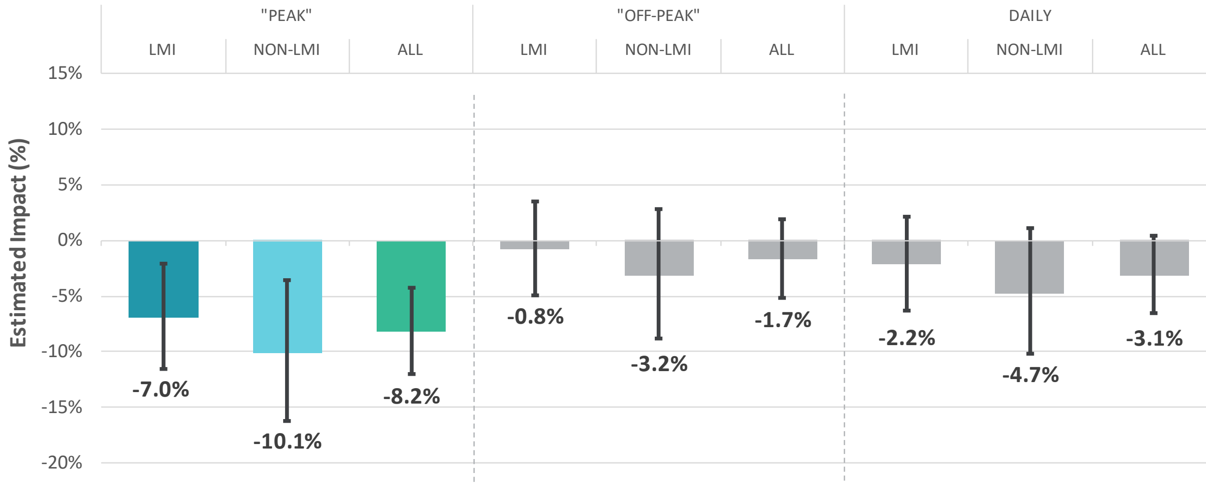
Note: The error bar indicates the 95% confidence interval of the regression coefficient. Grey bars statistical insignificance at the 5% significance level.

The "spillover" effect on weekends noted above for BGE and Pepco is observed for DPL customers as well. The left-hand panel in Figure 29 shows that, in aggregate, DPL's pilot customers reduced their weekend consumption during "peak" hours by 8.2%. The point estimate for non-LMI customers, at -10.1%, indicates a higher impact than for LMI customers, who reduced their usage by 7%. The difference between the impacts for the two groups, however, is statistically insignificant.

Point estimates during weekend "off-peak" hours for DPL pilot customers, LMI and non-LMI alike, are negative but statistically insignificant (center panel in Figure 29). The same is true for weekend conservation impacts, shown in the right-hand panel below. All customers exhibit a negative point estimate, albeit statistically insignificant.

[39] Faruqui, Ahmad, Sanem Sergici and Cody Warner, "Arcturus 2.0: A Meta Analysis of Time Varying Rates of Electricity", The Electricity Journal, Volume 30, Issue 10, December 2017, Pages 64-72.

FIGURE 29: ESTIMATED SUMMER WEEKEND IMPACTS BY CUSTOMER GROUP AND PERIOD



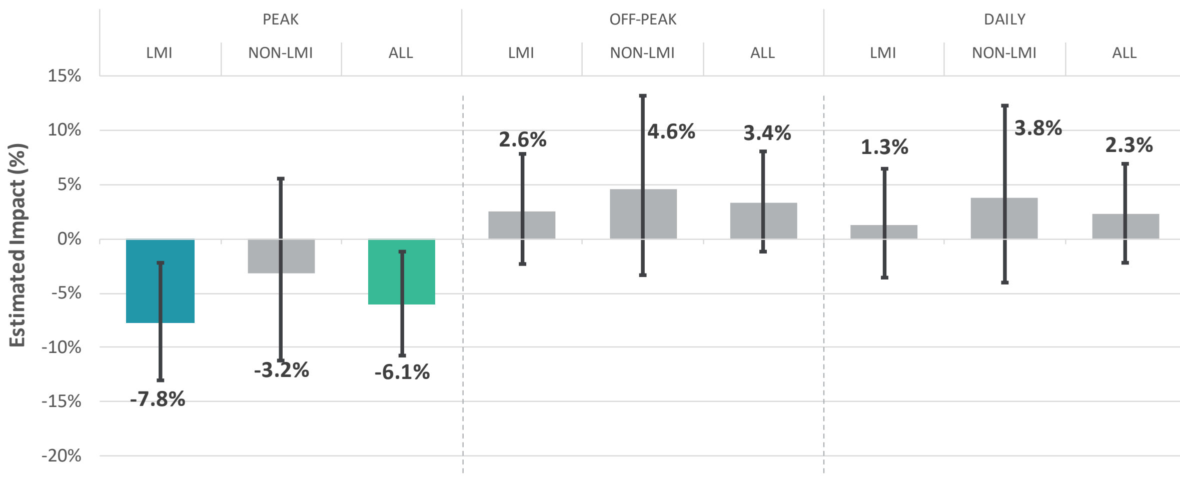
Note: The error bar indicates the 95% confidence interval of the regression coefficient. Grey bars statistical insignificance at the 5% significance level.

ii. Non-summer Analysis

In the non-summer, we measure statistically significant peak reductions on weekdays that are smaller than are those seen in the summer. As summarized in Figure 30, DPL pilot customers reduced their peak weekday usage by 6.1%. Once again, this impact is higher when compared to BGE and Pepco. LMI customers, with a statistically significant peak reduction of 7.8%, appear to be more responsive than non-LMI customers who show a statistically insignificant reduction. The difference between the impacts for the two groups, however, is statistically insignificant. We therefore cannot draw definite conclusions on the difference in their behavior.

DPL pilot customers differ from BGE and Pepco in that the point estimates for off-peak and conservation impacts, depicted in the center- and right-hand panels of Figure 30, respectively, are positive. This implies that pilot customers appear to have increased their usage during off-peak hours and on a daily basis. All estimates for off-peak and conservation impacts, however, are statistically insignificant.

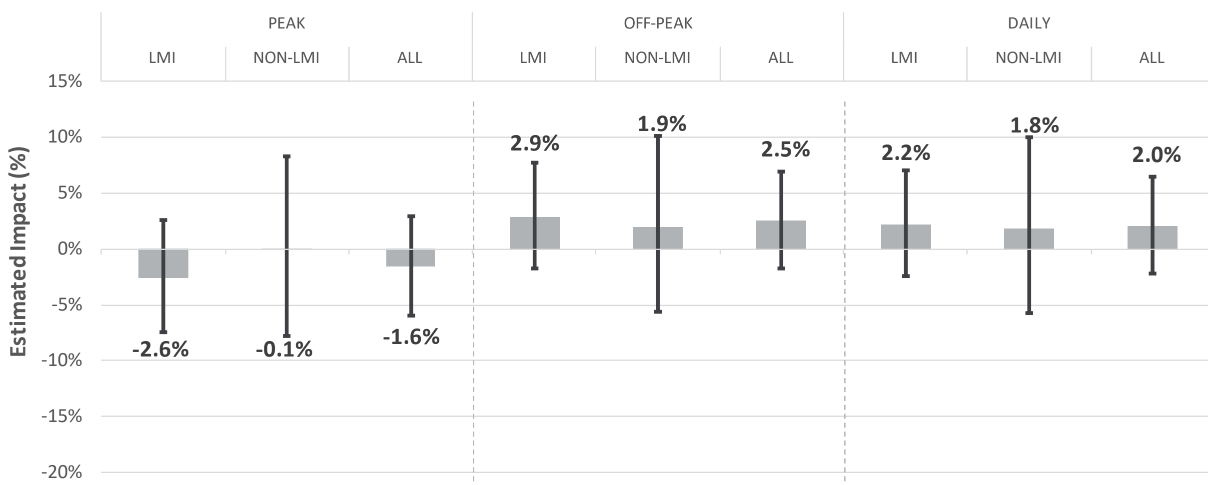
FIGURE 30: ESTIMATED NON-SUMMER WEEKDAY IMPACTS BY CUSTOMER GROUP AND PERIOD



Note: The error bar indicates the 95% confidence interval of the regression coefficient. Grey bars statistical insignificance at the 5% significance level.

Figure 31 shows that impacts on non-summer weekends are statistically insignificant, regardless of the pricing period and the customer group being considered.

FIGURE 31: ESTIMATED NON-SUMMER WEEKEND IMPACTS BY CUSTOMER GROUP AND PERIOD



Note: The error bar indicates the 95% confidence interval of the regression coefficient. Grey bars statistical insignificance at the 5% significance level.

2. Subgroup Analysis

As discussed above for BGE and Pepco, we estimate for DPL a series of supplementary regressions using interaction terms in order to provide some insight into the extent to which the average weekday peak impacts reported above vary along different dimensions. In what follows, we discuss those results, which we summarize in Figure 32.[40]

FIGURE 32: DPL WEEKDAY PEAK IMPACT BY SEASON AND SUBGROUP

	Summer weekday peak	Non-summer weekday peak
Baseline Results		
% (non-NEM customers)	-14.8%***	-6.1%**
kWh (all customers)	-0.234***	-0.0962***
Group by NEM vs. non-NEM (kWh)		
Non-NEM	-0.226***	-0.0997***
NEM	-0.402	-0.0128
Group by pre-treatment seasonal usage		
Medium-usage	-14.4%***	-9.1%**
Lowest-usage	-10.7%	2.0%**
Highest-usage	-19.0%	-10.5%
Group by structural winners vs. others		
Others	-17.6%***	-9.7%**
Winners	-13.4%	-4.0%
Group by daily THI		
Medium 50%	-15.9%***	-6.2%**
Coolest 25%	-10.5%***	-10.4%*
Warmest 25%	-17.1%	-1.0%**
Group by month		
June	-15.8%***	
July	-17.8%	
August	-14.1%	
September	-11.3%**	
January		-8.9%***
February		-11.7%
March		-6.2%
April		-1.2%**
May		1.1%**
October		-4.4%
November		-7.0%
December		-10.1%
Event day effects		
Non-event day	-14.8%***	
Event day	-12.7%	

Note: The red highlight indicates the base group within each analysis. ***, **, and * denote statistically significant results at the 1%, 5%, and 10% level, respectively. For the base group, statistical significance is measured with respect to zero effect. For the other groups, statistical significance is measured with respect to the base group. For the pre-treatment seasonal usage, customers were divided into three groups based on their average daily pre-pilot load during the respective seasons.

[40] Our discussion of the DPL subgroup analysis is similar to that of the BGE subgroup analysis above. For reference, the top panel in Figure 32 presents the baseline impacts in each season. We include in that top panel the results of a base specification estimated not in natural logs but in kilowatt-hours, which allows us to include NEM customers. Each of the subsequent panels of Figure 32 presents the results, in terms of estimated impacts, for each of the subgroups relevant to that analysis. In each such analysis, we use red shading to indicate the "base" group. For the base group, statistical significance is measured with respect to the null hypothesis of zero effect. For the other groups, statistical significance is measured with respect to the base group. For further details on the rationale or interpretation of various aspects of the subgroup analysis, please refer to the corresponding BGE discussion above.

i. Net Metering Customers

We test for differences in behavior among NEM and non-NEM customers. As NEM customers have lower pre-pilot net usage on average, and some negative net load hours, we conduct this analysis in absolute (kWh) rather than relative (%) terms. The results are depicted in the second panel in Figure 32. Point estimates for NEM customers show that they reduced more than non-NEM customers did in the summer (0.402 kWh vs. 0.226 for non-NEM), but that the reduction was lower than that of non-NEM customers in the non-summer. The difference in impacts, however, is statistically insignificant in both seasons. Therefore, we cannot make conclusory statements on any differences in behavior.

ii. Pre-Pilot Customer Usage

We also test for differences in customers' peak impacts based on their level of load consumption. We split customers into three groups based on their pre-pilot average daily load. The fourth panel in Figure 32 summarizes our findings for the three subgroups. In the summer, we do see some differences in the magnitude of reductions, with the lowest usage group having reduced peak load by 10.7% while the highest usage group reduced peak load by 19%. There is no statistical difference in the reduction between the groups, however. In the non-summer, medium usage customers, our base comparison group, reduced usage by 9.1%. The highest usage customers showed no statistical difference in reduction when compared to the medium usage cohort. The lowest usage group appear to have *increased* their usage during peak hours by 2%[41], and this result is statistically different from that exhibited by the medium usage customers.

iii. Structural Winners vs. Others

Similar to the analysis conducted for BGE and Pepco, we also test whether structural winners – customers identified prior to the pilot as beneficiaries of the PC44 pilot rates – responded differently to TOU pricing. Point estimates indicate that these customers reduced peak usage – by 13.4% in the summer and by 4% in the non-summer - less than others (reductions of 17.6% in the summer and 9.7% in the non-summer). The difference in impacts, however, is statistically insignificant for both seasons.

iv. Weather-related Variations in Impact

There is also evidence that the TOU peak impacts as measured in the DPL pilot vary with weather conditions. In the summer, the impacts on the warmest days (a 17.1% reduction) were consistent with those on more typical weather days, when the average reduction was 15.9%. However, the reductions on cooler summer days, at 10.5%, were significantly lower, perhaps because there was less discretionary peak load to reduce or shift on those days.

---

[41] The 2% peak non-summer weekday impact for the lowest usage customer group is not statistically different from zero.

In the non-summer months, peak impacts also varied with weather. The impact on days with more typical levels of THI was a 6.2% reduction, which is consistent with the average over the entire non-summer. However, on warmer (higher-THI) days, the load reductions were significantly smaller, at 1.0%. In fact, on these days, the load reductions were not significantly different from zero. On the other hand, on cooler days, when the electric heating load would tend to be higher, the peak reduction was higher, at 10.4%. This difference, relative to the medium-THI days, is marginally significant.

v. Impacts by Month

We also identify impacts that vary by month in both seasons. In June, the base comparison group for the summer, customers reduced peak usage by 15.8%. Peak impacts in July and August, while numerically different, were not statistically different from those in June. Peak reduction in September, however, was lower, at 11.3%, and statistically different from June.

In the non-summer months, customers reduced peak usage by 8.9% in January; most non-summer months show no statistical difference in peak reduction relative to January. Customers reduced peak usage by a considerably lower amount (1.2%[42]) in April, and appear to have *increased* their peak usage in May by 1.1%[43], both of which are statistically different from the impacts in January. These effects may be confounded by the onset of restrictions due to COVID-19, which we discuss in the section that follows.

vi. Impact on Event Days

Finally, we also estimate the summer weekday peak impacts for peak event days, which were otherwise excluded from the primary analysis. The point estimates indicate that the TOU impacts were slightly lower on event days (which saw a 12.7% reduction) than on non-event days (where the reduction measures 14.8%), which comports with expectations. However, this difference is not statistically significant.

E. Potential Implications of COVID-19 for the Analysis

1. Changes in Load Profiles

Before discussing the impact of COVID-19 on the TOU pilots, it is first helpful to provide some context for that analysis. Governor Hogan confirmed the first known cases of COVID-19 in Maryland and

[42] The 1.2% estimated peak reduction in April is not statistically different from zero.

[43] The 1.1% estimated increase in peak usage in May is not statistically different from zero.

declared a state of emergency on March 5, 2020.[44] Over the next week, the state gradually shut down, with school closures announced on March 12th and taking effect on March 16th.[45] As people spent more time at home during the weekday daytime hours (and perhaps to a lesser extent during weekend hours), we would expect load patterns to shift, with increases in midday consumption and some possible offsetting reductions in the early mornings and evenings.

These predictions are largely borne out in the data, as presented in the figures that follow. Figure 33 through Figure 35 display average weekday load profiles for each of the first five months of the calendar year, for each of the past three calendar years, using data from the full pool of potential control customers.[46] Beginning with January and February in Figure 33, we see that while there are differences in the levels of consumption (likely related to weather, as these charts are not weather-normalized), the load *shapes* in January and February of 2020 are consistent with those in January and February from the two preceding years. In particular, all display an early-morning peak followed by a mid-afternoon valley and then a second higher evening peak.

However, beginning in March, we start to see differences in the 2020 load shape relative to the load shapes in the corresponding months for 2018 and 2019, as the daytime load begins to flatten somewhat. This is especially apparent in April, when 2020 midday loads are substantially above the 2018 and 2019 levels, despite the evening peaks being at similar levels. In May, the pattern is less salient due to seasonal shifts in load shapes (and perhaps due to a loosening of the COVID-related restrictions), but the 2020 loads have less of a mid-day “dip” than in 2018 and 2019.[47] The same patterns described here are repeated to varying degrees in the analogous charts for Pepco and DPL.

---

[44] Cohn, Meredith; Wood, Pamela (March 5, 2020). "First three cases of coronavirus confirmed in Maryland, all in Montgomery County". The Baltimore Sun; State of Maryland, "Declaration of State of Emergency and Existence of Catastrophic Health Emergency – COVID-19". March 5, 2020.

[45] Swanson, Ian (March 12, 2020). "Maryland confirms community spread, will close schools". TheHill

[46] For this examination of general effects of COVID-19 on load profiles, we focus on this group in order to avoid having the impacts of the PC44 pilots influence this cross-year comparison.

[47] Richman, Talia. "Baltimore City extends stay-at-home order; Baltimore, Anne Arundel, Howard counties announce limited reopening". baltimoresun.com.

FIGURE 33: MONTHLY AVERAGE WEEKDAY LOAD PROFILE – BGE CONTROL CUSTOMERS (N = 398,222)

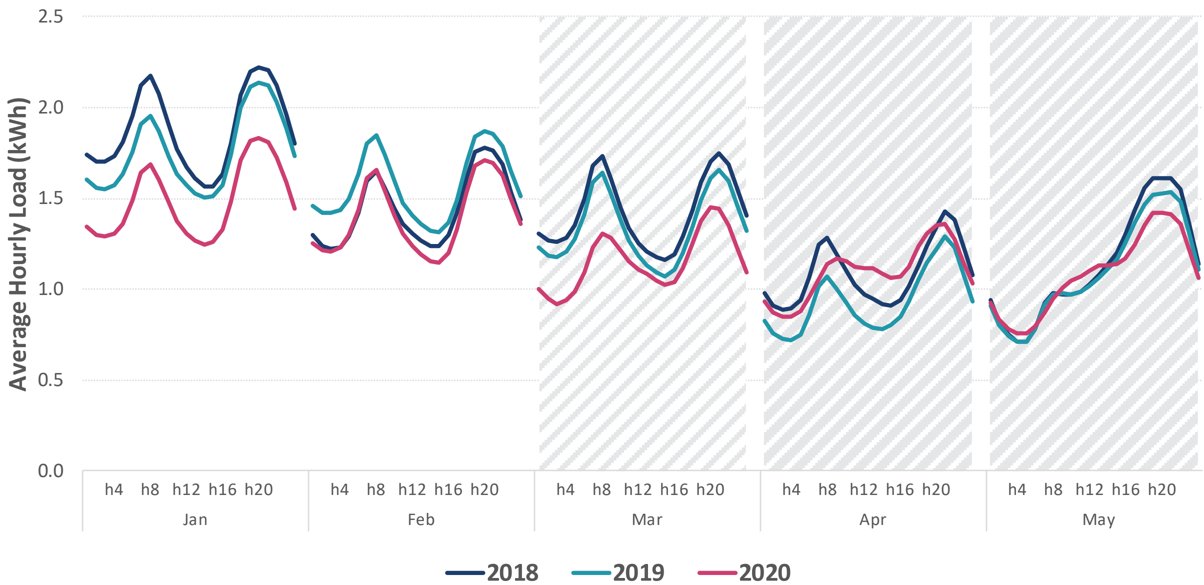


FIGURE 34: MONTHLY AVERAGE WEEKDAY LOAD PROFILE – PEPCO CONTROL CUSTOMERS (N = 14,803)

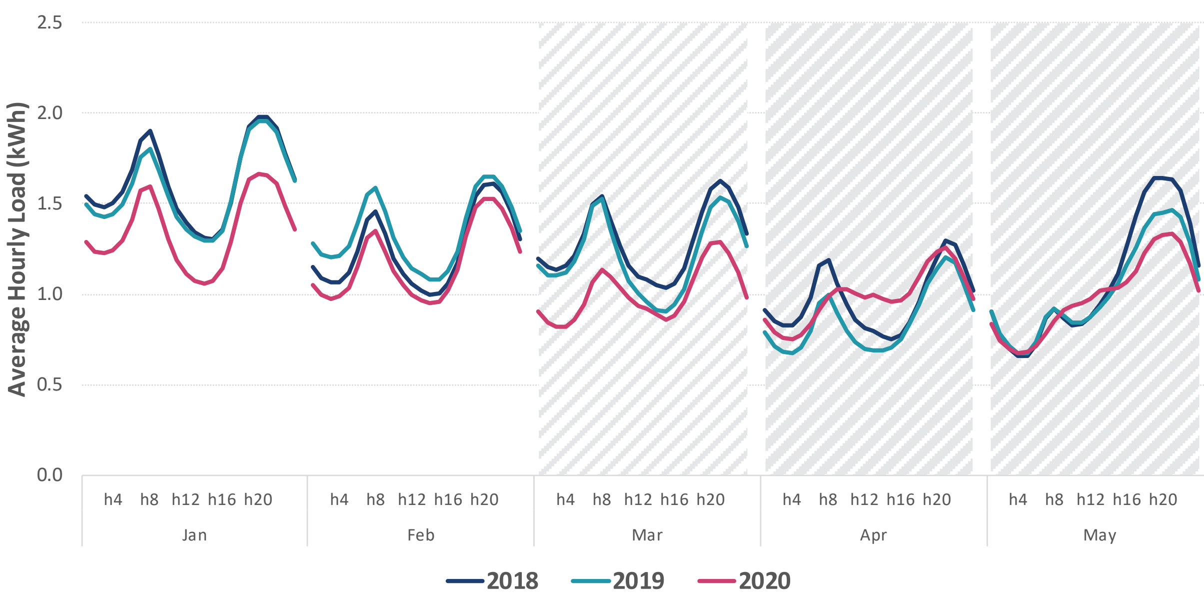
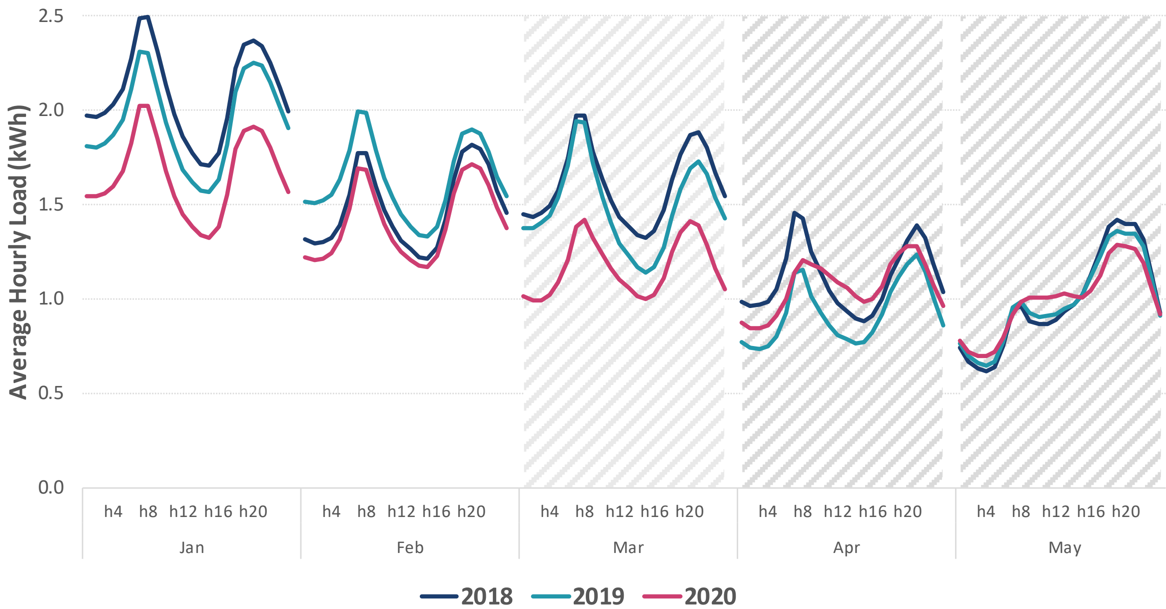


FIGURE 35: MONTHLY AVERAGE WEEKDAY LOAD PROFILE – DPL CONTROL CUSTOMERS (N = 8,050)



2. Econometric Analysis

The changes in load shapes as displayed in the figures above demonstrate clearly that residential customers' load patterns shifted substantially as part of the changes in daily life brought about by the COVID-19 pandemic. We now turn to the question of whether the TOU pilots' impacts differed during the months after the onset of the COVID-19 pandemic. This upheaval to daily life that happened to coincide with the Maryland TOU pilots provides a unique opportunity to understand further the effects of TOU pricing.

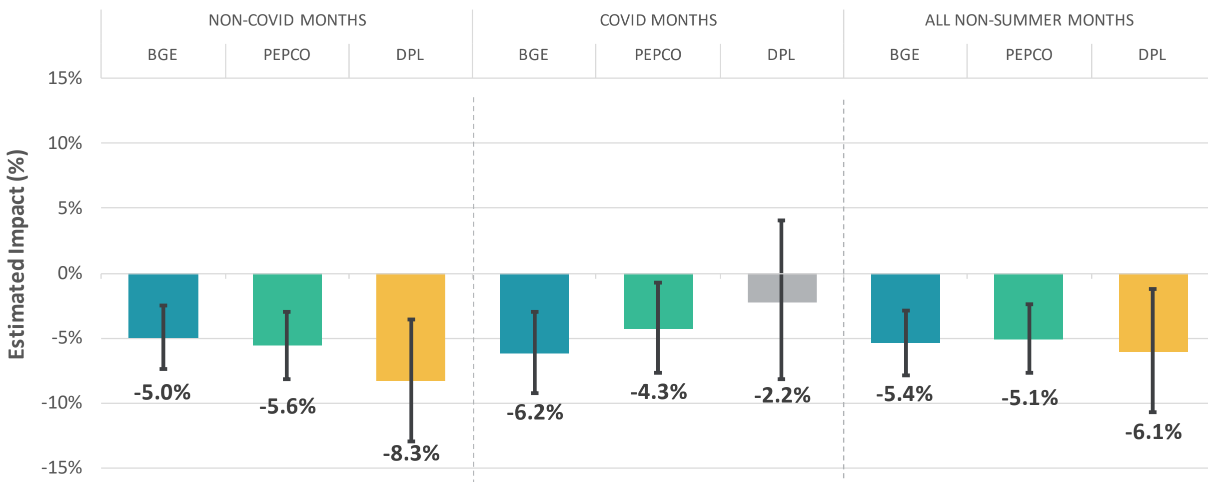
In order to assess the effects of COVID-19 on the TOU impacts, we estimate variants of our primary regression analyses, in which we allow the effect of the pilots to differ during the three months in our sample where COVID-19 had become a factor.[48] We implement this using interaction terms, as described above in Section II.C.1. As with the sub-group analysis, we focus on weekday peak impacts, which we explore for both customer groups (LMI vs. non-LMI) as well as the combined group (all customers).

Looking first at weekday peak effects for all customers, displayed in Figure 36, we find mixed results. *In the case of BGE and Pepco, while the point estimates change between COVID months and non-COVID*

[48] Note that, to the extent that seasonal factors would have caused the pilot impacts to vary in these three months relative to the earlier non-summer months (October through February), we are not able to disentangle those effects from changes brought about by COVID. That said, we do control for: systemic calendar month differences (*e.g.*, those that affect load in March, April, or May in every year) through the inclusion of month dummies; weather differences (through the use of the THI variable, whose impacts we allow to vary by month); and common COVID impacts (*i.e.*, changes to load affecting both control and treatment customers).

months, the differences are not statistically significant. For example, the weekday peak impact for Pepco customers in the first five months of the non-summer was a 5.6% reduction in load. During the COVID months, that decrease was slightly lower, at 4.3%, but the difference in impacts is not statistically significant. However, *there are significant differences in the weekday peak impacts for DPL customers, where the estimated effects shift from an 8.3% reduction in the first five months of the non-summer to a 2.2% reduction that is statistically indistinguishable from zero in the March to May period.* Furthermore, the difference itself is statistically significant.

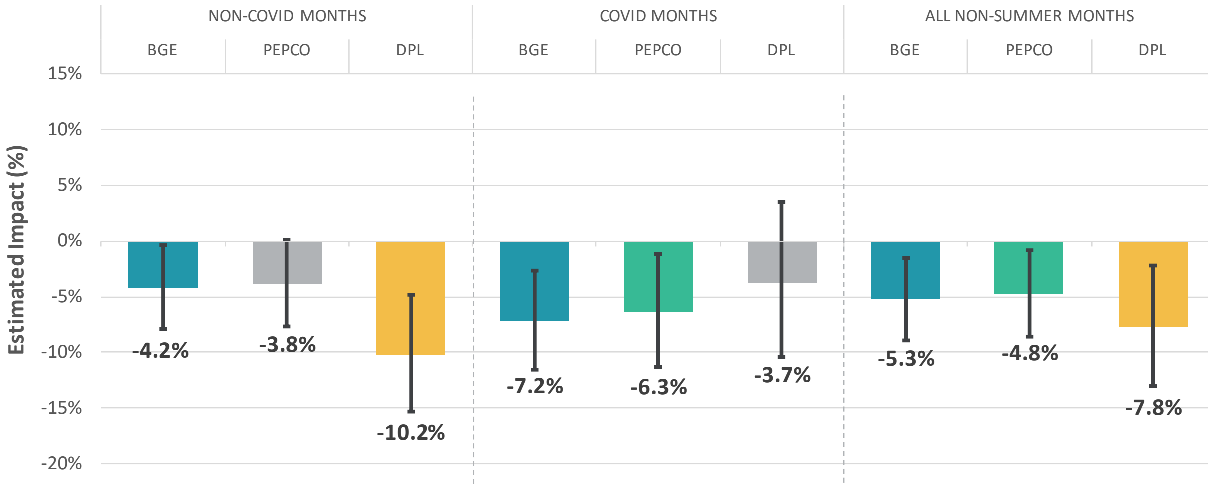
FIGURE 36: COVID-19 EFFECTS – WEEKDAY PEAK – ALL CUSTOMERS



Note: The error bar indicates the 95% confidence interval of the regression coefficient. Grey bars denote statistical insignificance at the 5% significance level.

Turning to LMI customers, the differences in the weekday peak impacts between the non-COVID non-summer months and the COVID months are similar to those above. In particular, while LMI customers show a higher peak impact during COVID months for BGE and Pepco, the difference is statistically insignificant. On the other hand, DPL LMI customers exhibit a reduced peak impact during COVID months that is statistically different from that observed during non-COVID months. These results are depicted in Figure 37.

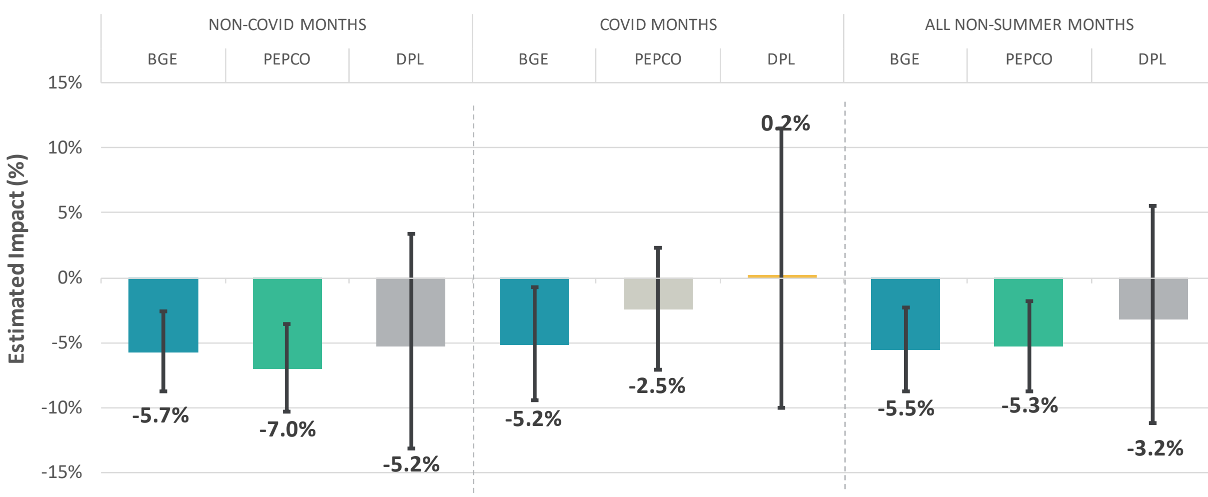
FIGURE 37: COVID-19 EFFECTS – WEEKDAY PEAK – LMI CUSTOMERS



Note: The error bar indicates the 95% confidence interval of the regression coefficient. Grey bars denote statistical insignificance at the 5% significance level.

Finally, we complete our discussion of pandemic-related differences in weekday peak impacts with an examination of non-LMI customers (see Figure 38). In general, non-LMI customers show a lower peak impact during COVID months for DPL and Pepco. However, that difference is only statistically significant in the case of Pepco.

FIGURE 38: COVID-19 EFFECTS – WEEKDAY PEAK – NON-LMI CUSTOMERS



Note: The error bar indicates the 95% confidence interval of the regression coefficient. Grey bars denote statistical insignificance at the 5% significance level.

To summarize, DPL's LMI customers saw significant reductions in their weekday peak impacts during the COVID period, which is also true of Pepco's non-LMI customers. At the same time, weekday peak impacts for BGE customers was largely unchanged.

F. Price Response Results

In addition to the difference-in-differences impacts that are the focus of the results presented to this point, we also estimated a series of regressions that measure the price response of the pilot participants. As discussed in the Methodology section above, for each utility, customer group, and season, we estimate the following two parameters of interest:

- **the substitution elasticity**, which measures the extent to which changes to the ratio of peak to off-peak prices results in changes in the ratio of peak to off-peak consumption on weekdays; and
- **the daily demand elasticity**, which measures the extent to which changes in the daily average price[49] result in changes to the total amount consumed in a day.

We generally expect both elasticities to be negative. This analysis is vital in order to be able to estimate the impact of rates other than those used in the pilot. The results of this analysis are summarized in Figure 39 and Figure 42.

FIGURE 39: SUMMARY OF PRICE ELASTICITY – SUMMER

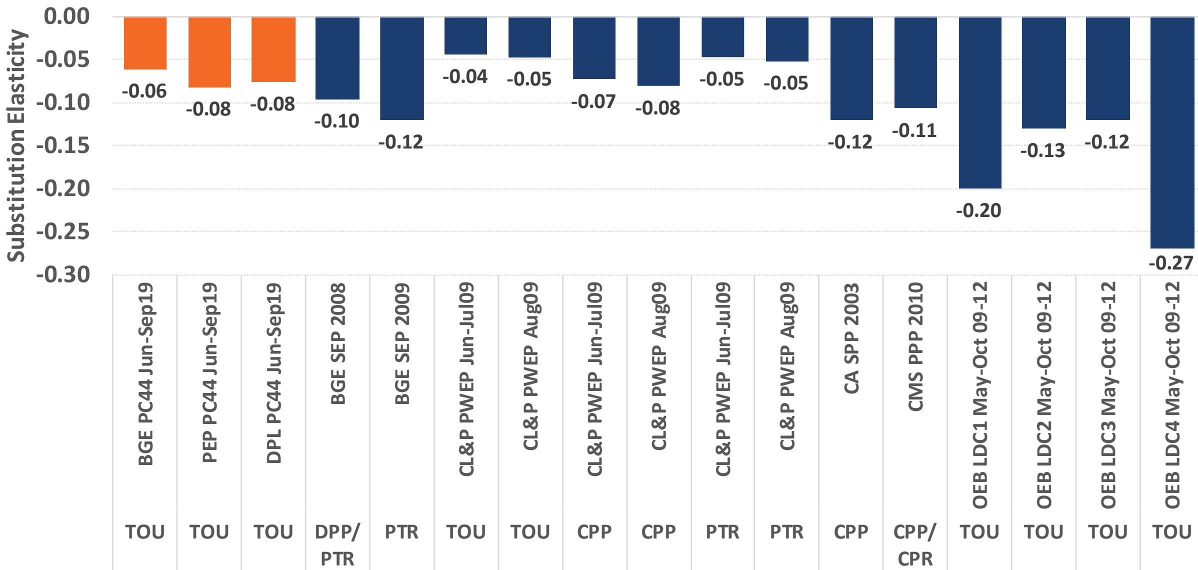
	BGE			Pepco			DPL		
	All	LMI	Non-LMI	All	LMI	Non-LMI	All	LMI	Non-LMI
Substitution elasticity									
Summer	-0.061***	-0.048***	-0.075***	-0.082***	-0.057***	-0.104***	-0.076***	-0.069***	-0.087***
Daily demand elasticity									
Summer	-0.047	-0.017	-0.076	-0.046	-0.100	-0.008	-0.092**	-0.099**	-0.075

Note: Excludes net-metering customers and treatment-control pairs who have ever been on three-period rates other than PC44 TOU. Prices only include major components of the bill (supply, transmission, and distribution). Average daily price is weighted by pre-treatment monthly peak/off-peak share of usage.

Beginning with the summer, we find that substitution elasticities of LMI customers are in the range of -0.048 to -0.069. Non-LMI substitution elasticities range from -0.087 to -0.104, and the substitution elasticities for all customers ranges from -0.061 to -0.082. In all cases, the substitution elasticities are significant at the 1% level. In Figure 40, we compare the "all customer" summer substitution elasticities from each of the three PC44 pilots to substitution elasticities we have estimated in a variety of other summer pricing pilots with time-varying rates, and find that they are generally consistent with these benchmarks.

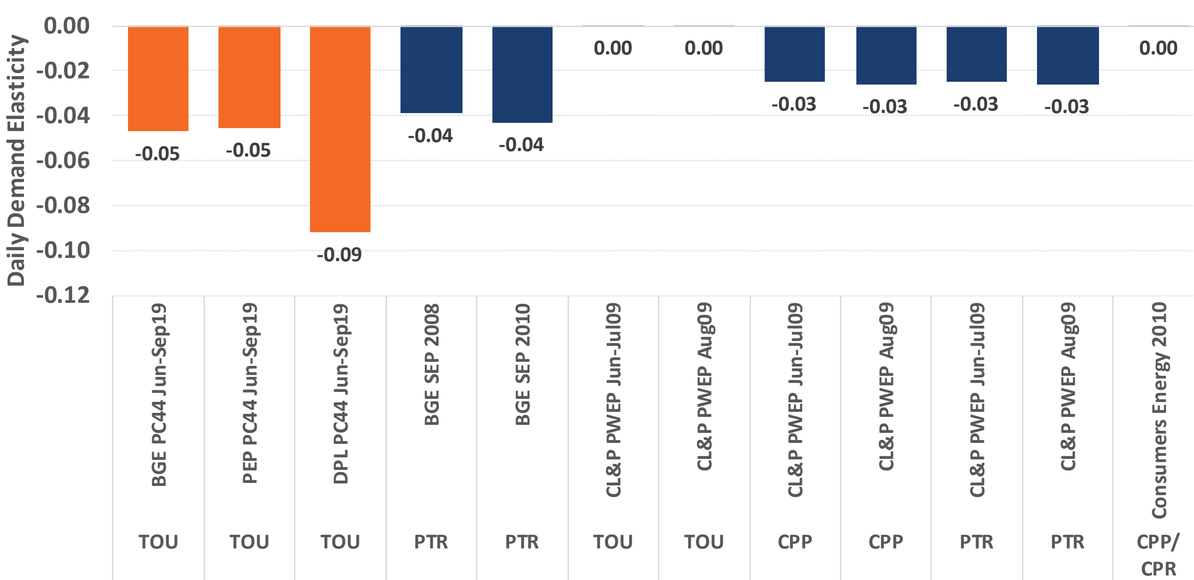
[49] In calculating the daily average price, we focus on the primary components of the bill and thus exclude various administrative charges. We need to weight peak and off-peak prices in order to calculate average daily prices for pilot customers. To do this, we exploit variation at the customer and month levels in consumption patterns; we weight the peak and off-peak price for each customer and month based on that customer's pre-pilot shares for the corresponding month in the pre-pilot period.

FIGURE 40: COMPARISON OF SUBSTITUTION ELASTICITY ACROSS SUMMER PRICING PILOTS



The daily demand elasticities we estimate for the summer period are generally negative but, with the exception of DPL, not statistically significant. In Figure 41, we compare the point estimates for the daily demand elasticities with the corresponding results, again from summer pricing pilots, and find that while the BGE and Pepco estimates are roughly in line with previous demand elasticity estimates, the DPL elasticity is somewhat larger.

FIGURE 41: COMPARISON OF DAILY DEMAND ELASTICITY ACROSS SUMMER PRICING PILOTS



Moving to the non-summer period and Figure 42, we find that substitution elasticities are again negative and for the most part significant. The "all customer" substitution elasticities range from -0.027 to -0.052. For all three utilities, the non-summer substitution elasticities are somewhat lower than those from the summer, suggesting that customers are more willing or able to shift peak load in the summer than in the non-summer. Exclusion of the COVID-19 months does not significantly change the estimated substitution elasticities.

FIGURE 42: SUMMARY OF PRICE ELASTICITY – NON-SUMMER

	BGE			Pepco			DPL		
	All	LMI	Non-LMI	All	LMI	Non-LMI	All	LMI	Non-LMI
Substitution elasticity									
Non-summer	-0.027***	-0.011	-0.043***	-0.028***	-0.018*	-0.037***	-0.052***	-0.058***	-0.042***
Pre-COVID non-summer	-0.023***	-0.006	-0.040***	-0.034***	-0.022**	-0.044***	-0.052***	-0.058***	-0.042***
Daily demand elasticity									
Non-summer	-0.312***	-0.235**	-0.395***	-0.234***	-0.377***	-0.098	-0.241***	-0.102	-0.484***
Pre-COVID non-summer	-0.023	-0.055	0.019	-0.200**	-0.311**	-0.087	-0.122	-0.031	-0.286

Note: Excludes net-metering customers and treatment-control pairs who have ever been on three-period rates other than PC44 TOU. Prices only include major components of the bill (supply, transmission, and distribution). Average daily price is weighted by pre-treatment monthly peak/off-peak share of usage.

Surprisingly, the non-summer daily demand elasticities that we estimate are substantially higher than those we observe in the literature, which typically fall in the range of -0.01 to -0.15. Exclusion of the COVID-19 months (March-May 2020) substantially reduces these elasticities. The BGE and DPL elasticities become insignificant after the exclusion, while the Pepco elasticity is still significant but lower. One hypothesis is that a later start to the day experienced in many households during the COVID-19 months made it easier for customers to conserve or shift morning load. However, additional data from Year 2 of the pilot may allow us to improve the precision and reliability of these non-summer demand elasticity estimates.

G. Bill Impact Analysis

One key question regarding TOU rates is whether they lead to lower bills. Ideally, we would calculate bill impacts by comparing, for each enrolled customer, their bill in the first year of the pilot to the bill they would have had if they continued on the default "R" rate, also known as their "but-for" bill. Of course, the challenge is we do not observe each customer's "but-for" consumption.

Instead, in order to calculate bill impacts for the first year of the pilot, we undertake a difference-in-differences approach that relies on the matched control groups. This approach allows us to isolate the "bill impacts" experienced by the treatment customers due to the TOU rates, by netting out the bill changes that were experienced by the control customers for reasons unrelated to the pilot (i.e., due to weather or technology-driven changes to demand). We followed the steps below:

1. Calculate the actual monthly bills for each enrolled customer and their matched control covering two 12-month periods:[50] February 2018 to January 2019 (the last 12 month period before recruitment began); and June 2019 to May 2020 (the Year 1 evaluation period).
2. Divide each customer's annual bill by twelve to calculate an average monthly bill in both the pre-period and the pilot period and calculate for each customer the average percentage change in the average monthly bills between the two periods.
3. Calculate, across customers in each group, the average percentage change in average monthly bills, where there are distinct groups for the treatment and matched control customers for each JU
4. Use a difference-in-differences approach (by subtracting the control group customers' bill impact from that of treatment customers) to calculate each pilot's average bill impact.

Figure 43 summarizes the results of this analysis.

FIGURE 43: AVERAGE MONTHLY BILL IMPACT BY UTILITY

	BGE	Pepco	DPL
Pre-Pilot Avg. Monthly Bill ($)	$116	$121	$139
Pilot Customers	-10.4%	-8.2%	-9.5%
Control Customers	-5.3%	2.0%	-4.0%
Net Impact %	-5.0%	-10.1%	-5.6%

Note: Excludes net-metering customers, customers who were on three-period rates before enrolling in the pilot, and customers who enrolled after May 31, 2019 or unenrolled before June 1, 2020. Details of calculations described in text.

As Figure 43 indicates, before introducing the control group bill impact adjustment, the average monthly and therefore annual savings are comparable across the three JUs, with bill reductions ranging from 8.2% for Pepco to 10.4% for BGE. However, it is of course important to net off the bill increases or reductions experienced by control group customers during the same period. Once we make that adjustment, we see that Pepco TOU customers have enjoyed markedly larger bill impacts (savings of 10.1%) than their counterparts at BGE and DPL (who saw savings of 5.0% and 5.6%, respectively). While Pepco's TOU customers saw bill reductions, its control customers saw modest bill increases. The latter is partly a function of higher rates for Pepco default customers during the pilot period.

Figure 44 reveals some seasonal detail underlying the net impacts presented in Figure 43. Interesting differences emerge, in that at both BGE and DPL, the summer TOU bill impacts took the form of bill increases of 7.5% and 3.6%, respectively, while the non-summer bill impacts were large bill

[50] We exclude net-metering customers, customers who were on three-period rates before enrolling in the pilot, and customers who enrolled after May 31, 2019 or unenrolled before June 1, 2020.

reductions, of 11.4% and 10.1%, respectively. On the other hand, at Pepco, pilot customers enjoyed bill savings in both seasons, with the summer bill impact of 15.5% exceeding that of the non-summer period. These differences are largely driven by differences in the underlying TOU rate structures implemented at each utility.[51]

FIGURE 44: SEASONAL DETAIL OF AVERAGE BILL IMPACTS

	BGE	Pepco	DPL
Summer	7.5%	-15.5%	3.6%
Non-summer	-11.4%	-6.6%	-10.1%
Annual	-5.0%	-10.1%	-5.6%

Note: Excludes net-metering customers, customers who were on three-period rates before enrolling in the pilot, and customers who enrolled after May 31, 2019 or unenrolled before June 1, 2020.

Finally, it is also important to understand whether these bill impacts differed for LMI customers. As summarized in Figure 45, there are some differences, though customers in all groups enjoyed bill savings stemming from the pilot. At BGE, LMI customer savings as a percentage of their bill were somewhat larger than those enjoyed by non-LMI customers. At Pepco and DPL, the converse was true as non-LMI customers saved more than LMI customers.

FIGURE 45: SUMMARY OF ANNUAL AVERAGE BILL IMPACTS BY CUSTOMER GROUP

	BGE	Pepco	DPL
All Customers	-5.0%	-10.1%	-5.6%
LMI Customers	-6.4%	-9.6%	-4.4%
Non-LMI Customers	-3.7%	-10.6%	-7.5%

Note: Excludes net-metering customers, customers who were on three-period rates before enrolling in the pilot, and customers who enrolled after May 31, 2019 or unenrolled before June 1, 2020.

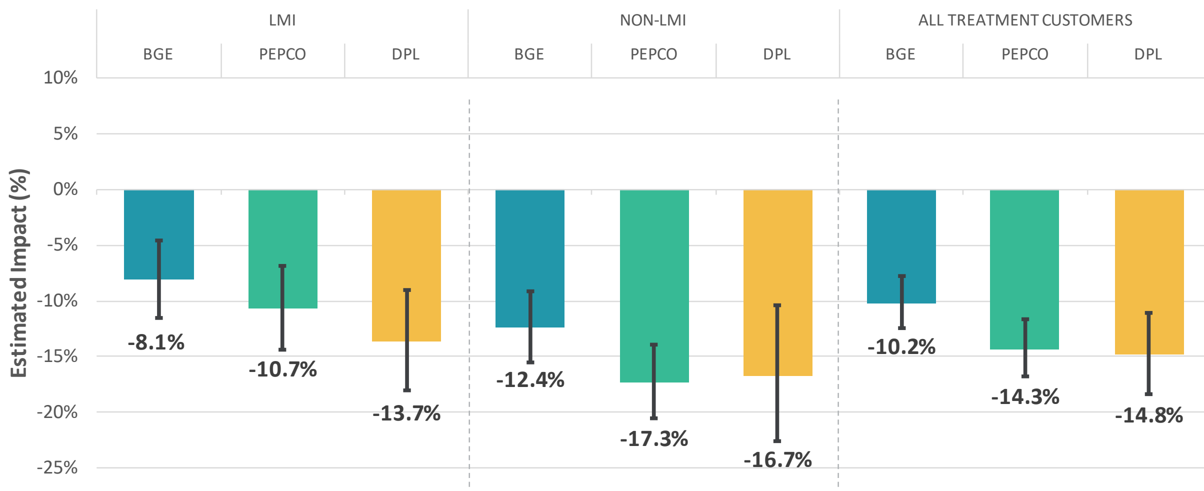
51 The pilot rates for all three JUs were set with the objective of revenue neutrality (assuming no load shifting) over the course of the full year. For both BGE and DPL, this led to rates that were generally not revenue neutral within seasons. Rather, customers moving from the standard "R" rate to the TOU tariff could expect to see dis-savings in the summer, which would then, in aggregate, be offset in the winter. This was not the case for Pepco, where the setting of rates subject to annual revenue neutrality happened to generate rates that were also roughly revenue neutral on a seasonal basis.

V. Summary

The results from the first year analysis of the PC44 TOU pilots reveal that customers respond to higher peak prices by reducing their consumption in both summer and non-summer seasons. This result holds for all three JUs and for both LMI and non-LMI groups. We identified seven key results from the 1st year analysis:

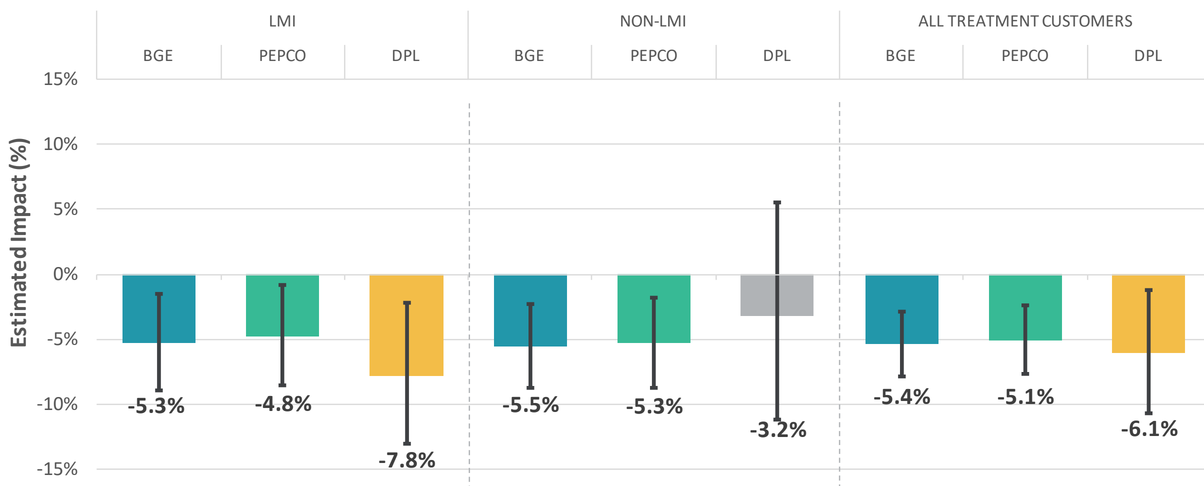
1. Summer peak impacts range from -10.2% to -14.8% and non-summer peak impacts range from -5.1% to-6.1% for all three JUs (see Figure 46 and Figure 47).
2. Daily weekday summer conservation impacts range from -2.8% to -4.9%, while the daily non-summer weekday conservation impacts are statistically insignificant.
3. Peak demand reductions and substitution and daily elasticities estimated from the 1st year analysis of the TOU pilots are consistent with those from prior pilots (see Figure 48 through Figure 50).
4. By including separate treatment cells for LMI and non-LMI customers, the PC44 pilots conclusively showed that LMI customers respond to the price signals just like the non-LMI customers, and in most cases in similar magnitudes.
5. While we expected customers to increase their usage during off-peak hours (including weekends), we find evidence of conservation during weekday off-peak hours and weekends (though impacts are usually insignificant). This result, while unexpected, may be an artifact of the behavioral load shaping tool, which encouraged customers to conserve across all hours. Another potential explanation might be customers’ use of a single smart thermostat schedule for both weekdays and weekends.
6. Non-summer peak impacts remained largely similar for BGE and Pepco during months affected by the COVID-19 pandemic, while they were lower for DPL. All JUs revealed larger conservation tendency during COVID-19 months exhibited by large daily price elasticities.
7. Structural winners’ peak reductions were comparable to those of others’ in most cases, indicating that structural winners still respond to the incentives embedded in price signals.

FIGURE 46: SUMMER WEEKDAY PEAK IMPACTS



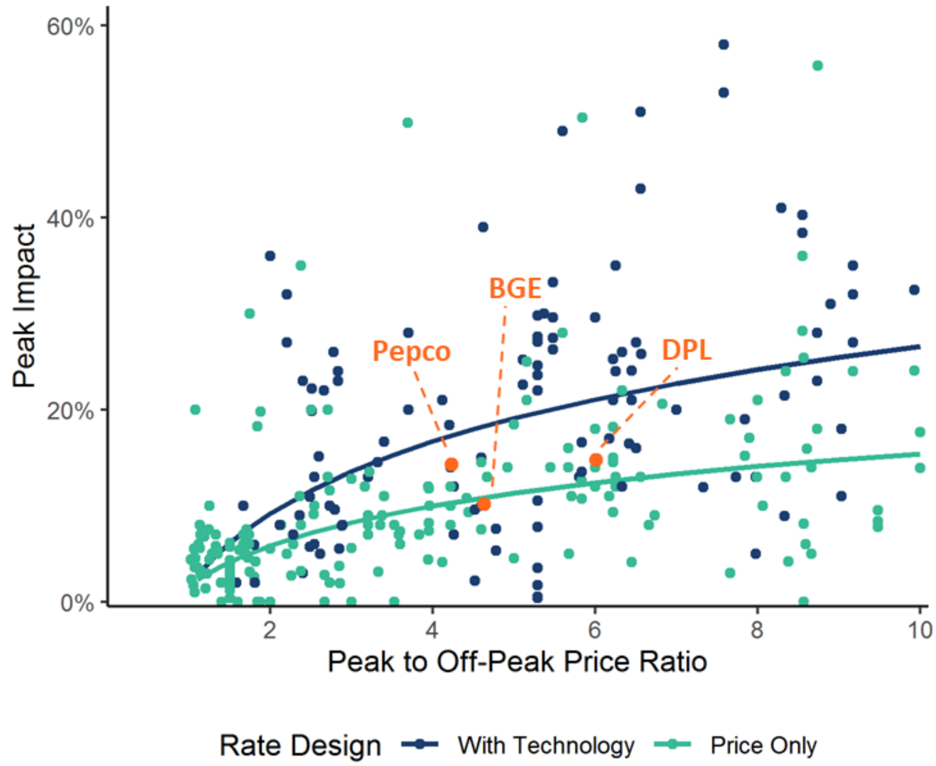
Note: Error bars indicate the 95% confidence interval of the regression coefficients. Grey bars denote statistical insignificance at the 5% level.

FIGURE 47: NON-SUMMER WEEKDAY PEAK IMPACTS



Note: Error bars indicate the 95% confidence interval of the regression coefficients. Grey bars denote statistical insignificance at the 5% level.

FIGURE 48: SUMMER PEAK IMPACTS FROM OTHER TIME VARYING PRICING PILOTS AND PC44 TOU IMPACTS



Note: The PC44 data points are based on the results for all customers (combined LMI and non-LMI effects).

FIGURE 49: PC44 TOU PILOT SUBSTITUTION ELASTICITIES AND THOSE FROM OTHER TIME VARYING PRICING PILOTS

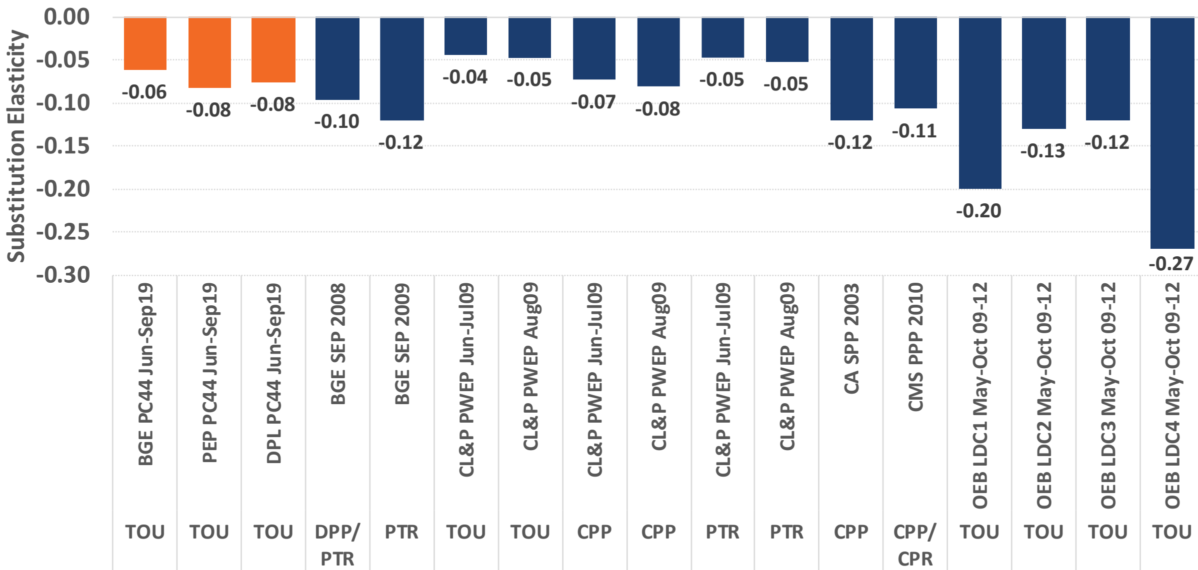
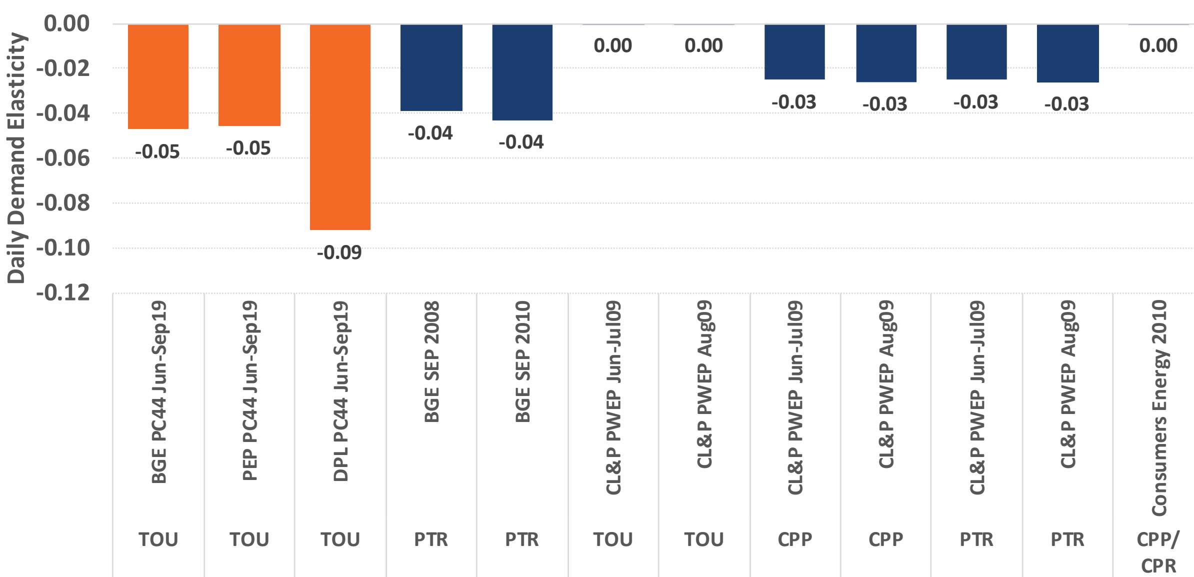


FIGURE 50: PC44 TOU PILOT DAILY PRICE ELASTICITIES AND THOSE FROM OTHER TIME VARYING PRICING PILOTS

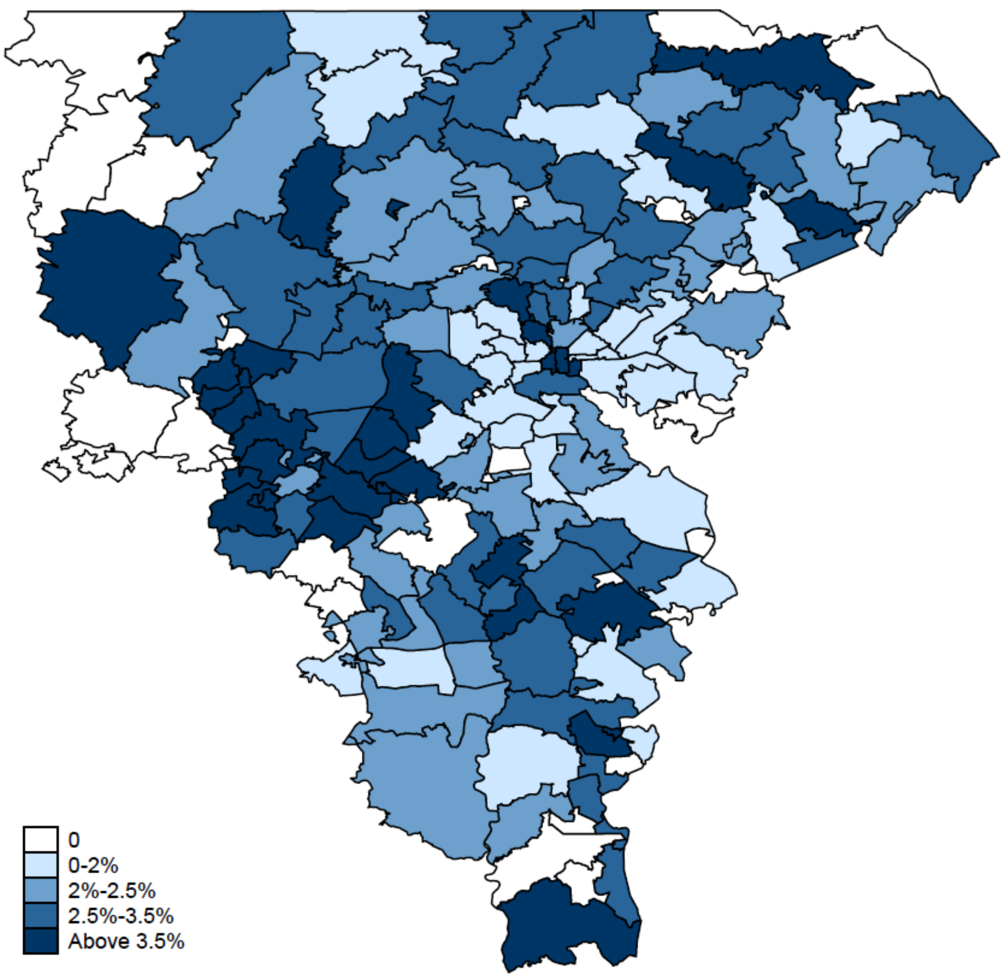


Appendix A – Supplemental Analyses

A.1 Recruitment - Geographical Details

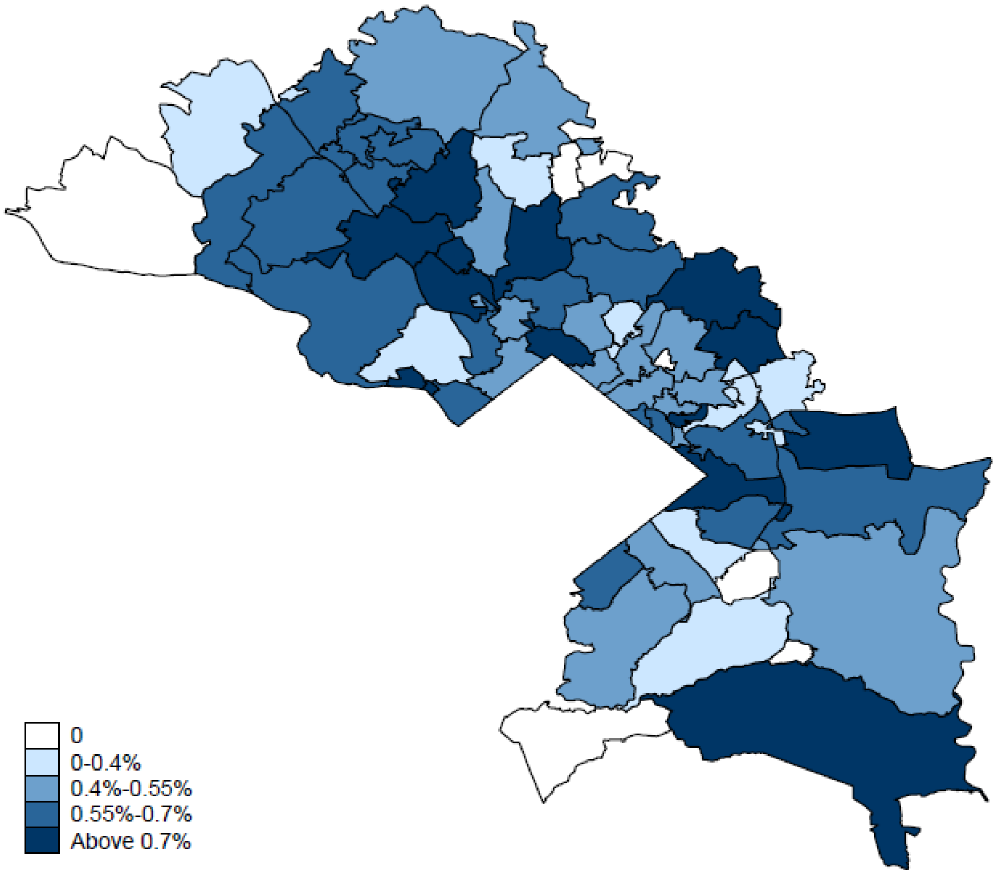
The following maps illustrate variation in the enrollment rate by zip code tabulation areas (geographically contiguous areas that are largely consistent with zip code definitions).

FIGURE 51: BGE ENROLLMENT RATE BY ZIP CODE



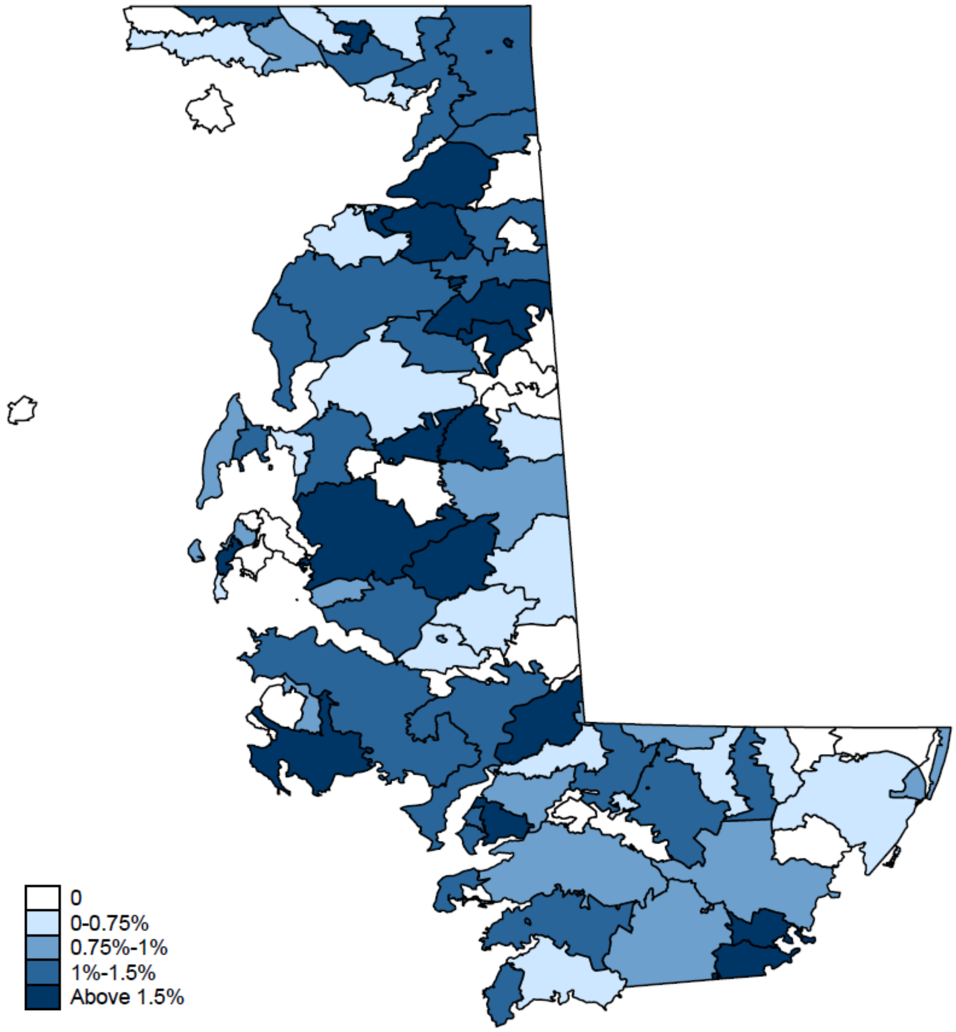
Notes: Enrollment rates by zip code tabulation area (ZCTA).

FIGURE 52: PEPCO ENROLLMENT RATE BY ZIP CODE



Notes: Enrollment rates by zip code tabulation area (ZCTA).

FIGURE 53: DPL ENROLLMENT RATE BY ZIP CODE



Notes: Enrollment rates by zip code tabulation area (ZCTA).

A.2 Data Cleaning and Processing

We applied a series of criteria to exclude customers with data issues. We first removed customers with account or tariff-related issues, as follows:

- Control customers
  - whose account with the relevant JU started after January 1, 2018;
  - who closed their account between January 1, 2018 and May 31, 2020; or
  - who switched rates between January 1, 2018 and May 31, 2020, including volunteer enrollees to the PC44 TOU tariff.
- Targeted non-enrollees
  - who closed account in 2018;
  - who switched to third-party supplier during the recruitment period (between February 1, 2019 and May 31, 2019)
- Enrollees
  - who unenrolled by June 1, 2019; and
  - who unenrolled between June 1, 2019 and September 30, 2019 (excluded from the non-summer analysis only).

Then we implemented the following steps to exclude customers with insufficient load data:

- We set all hours with exactly zero load to missing.
- If a customer's load is missing in one or more hours on a given day, we drop that customer-day.
- Enrolled and control customers are dropped from the analysis if
  - They have incomplete load data on more than 10 days in the summer control (Jun – Sept 2018, 122 days total) or treatment (Jun – Sept 2019, 122 days total) period OR
  - They have incomplete load data on more than 20 days in the non-summer control (Jan – May 2018, Oct 2018 – Jan 2019, 274 days total) or treatment (Oct 2019 – May 2020, 244 days total) period.
- Targeted non-enrollees are dropped from the logit estimate if
  - They have incomplete load data on more than 10 days in summer (Jun – Sept) 2018 (122 days total) OR
  - They have incomplete load data on more than 20 days in non-summer (Jan – May and Oct – Dec) 2018 (243 days total).

A.3 Control Group Balance

Here, we provide additional details from the balance diagnostics we conducted to ensure that the matched control group was similar to the treatment group with respect to observable pre-pilot information. In addition to the load profile comparison provided in the main body of the report, we first present a comparison of treatment customer means for non-load variables with that of both the unmatched (naïve) control group and the matched control group. We then provide maps illustrating the geographic balance between the treatment group and the matched control group. These generally indicate that zip codes with high numbers of pilot enrollees also contain high numbers of matched control customers.

FIGURE 54: FULL COVARIATE BALANCE OF NON-LOAD VARIABLES – BGE

	LMI	Non-LMI	All Treatment	Unmatched Control	Matched Control
Energy Efficiency Measures					
Quick Home Energy Check (QHEC)	18.7%	15.8%	17.3%	9.1%	15.1%
New Home	0.4%	1.8%	1.1%	1.2%	0.9%
HVAC Equipment	2.4%	7.3%	4.8%	5.3%	5.1%
Home Performance with Energy Sta	0.9%	2.8%	1.8%	0.7%	2.4%
Home Energy Audit	2.4%	5.9%	4.2%	2.0%	4.2%
Appliance Recycle	2.3%	2.9%	2.6%	1.6%	2.7%
Appliance Rebate	10.3%	16.9%	13.6%	12.8%	12.8%
Net Metering	2.3%	5.1%	3.7%	2.9%	3.8%
High Bill	8.1%	5.8%	6.9%	6.1%	5.0%
Electric Vehicle TOU	0.0%	0.5%	0.2%	0.0%	0.2%
Residential Optional TOU	7.2%	12.3%	9.7%	7.0%	9.9%
# of Peak Rebate Devices					
Air Conditioner	0.51	0.68	0.59	0.32	0.62
Water Heater	0.08	0.09	0.09	0.02	0.08
Customer Characteristics					
Average Income ($)	$75,004	$135,485	$104,870	$111,352	$122,820
Total Annual Energy (kWh)	6,760	10,543	8,910	10,855	9,269

FIGURE 55: FULL COVARIATE BALANCE OF NON-LOAD VARIABLES - PEPCO

	LMI	Non-LMI	All Treatment	Unmatched Control	Matched Control
Energy Efficiency Measures					
Net Metering	2.3%	4.5%	3.5%	2.5%	3.9%
Direct Load Control (DLC)	54.0%	54.9%	54.4%	38.6%	53.2%
Appliance Rebate	0.8%	3.0%	2.0%	1.3%	1.5%
Appliance Recycling	0.5%	0.3%	0.4%	0.4%	0.2%
Home Performance with Energy Star	0.8%	1.2%	1.1%	0.5%	1.1%
HVAC Efficiency Program	0.8%	2.7%	1.9%	1.1%	2.0%
Quick Home Energy Check (QHEC)	3.3%	1.9%	2.6%	2.2%	3.0%
Customer Characteristics					
Average Income ($)	$99,777	$119,631	$110,717	$113,752	$111,689
Total Annual Energy (kWh)	9,516	9,970	9,778	11,599	9,775

FIGURE 56: FULL COVARIATE BALANCE OF NON-LOAD VARIABLES - DPL

	LMI	Non-LMI	All Treatment	Unmatched Control	Matched Control
Energy Efficiency Measures					
Net Metering	2.7%	4.8%	3.5%	1.6%	4.4%
Direct Load Control (DLC)	36.8%	47.6%	40.9%	19.0%	39.4%
Appliance Rebate	0.5%	2.4%	1.2%	0.8%	0.5%
Appliance Recycle	0.2%	1.6%	0.8%	0.3%	0.9%
Home Performance with Energy Star	0.5%	0.0%	0.3%	0.1%	0.5%
HVAC Efficiency Program	0.5%	1.2%	0.8%	0.5%	0.3%
Quick Home Energy Check (QHEC)	2.2%	0.8%	1.7%	1.0%	1.5%
Customer Characteristics					
Average Income ($)	$72,550	$77,649	$74,487	$75,482	$75,446
Total Annual Energy (kWh)	11,763	10,997	11,472	12,919	11,540

FIGURE 57: BGE GEOGRAPHICAL DISTRIBUTION OF ENROLLED AND MATCHED CONTROL CUSTOMERS

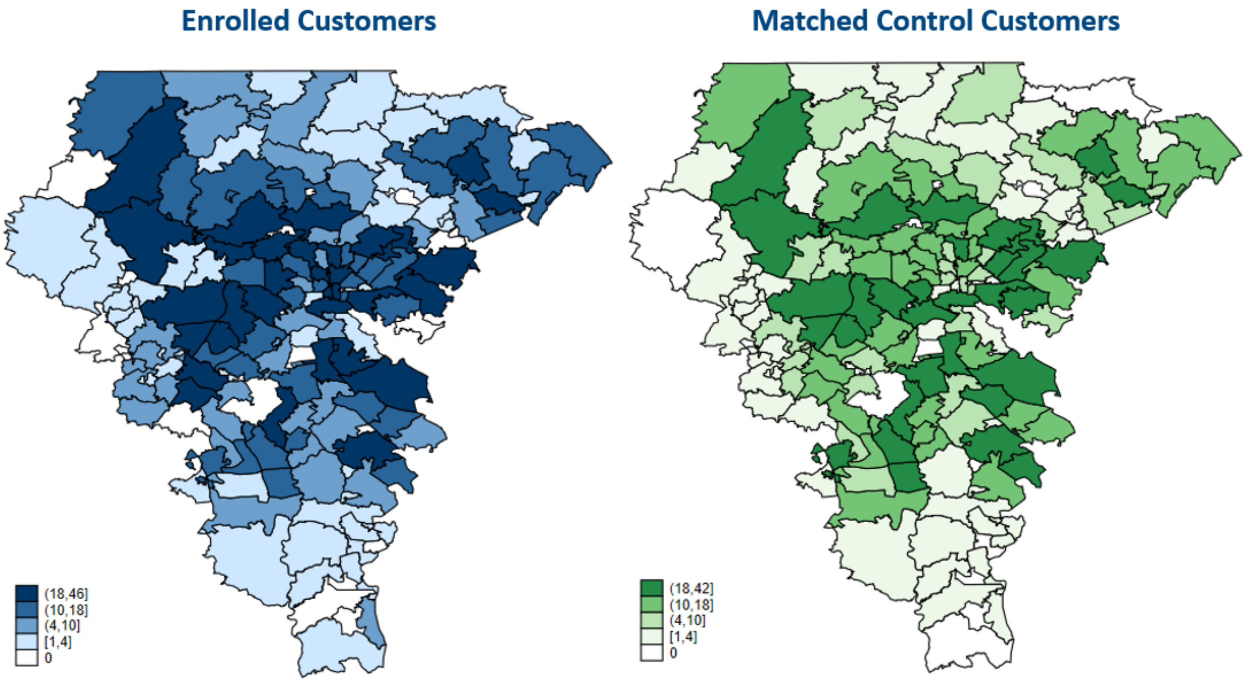


FIGURE 58: PEPCO GEOGRAPHICAL DISTRIBUTION OF ENROLLED AND MATCHED CONTROL CUSTOMERS

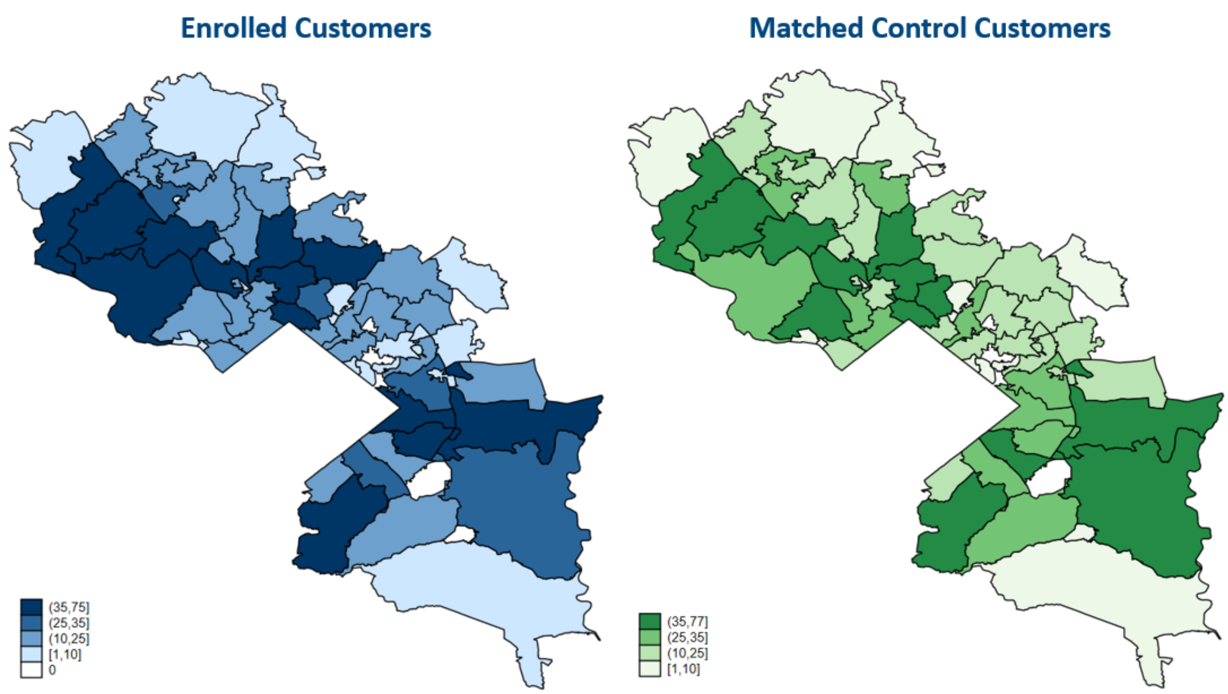
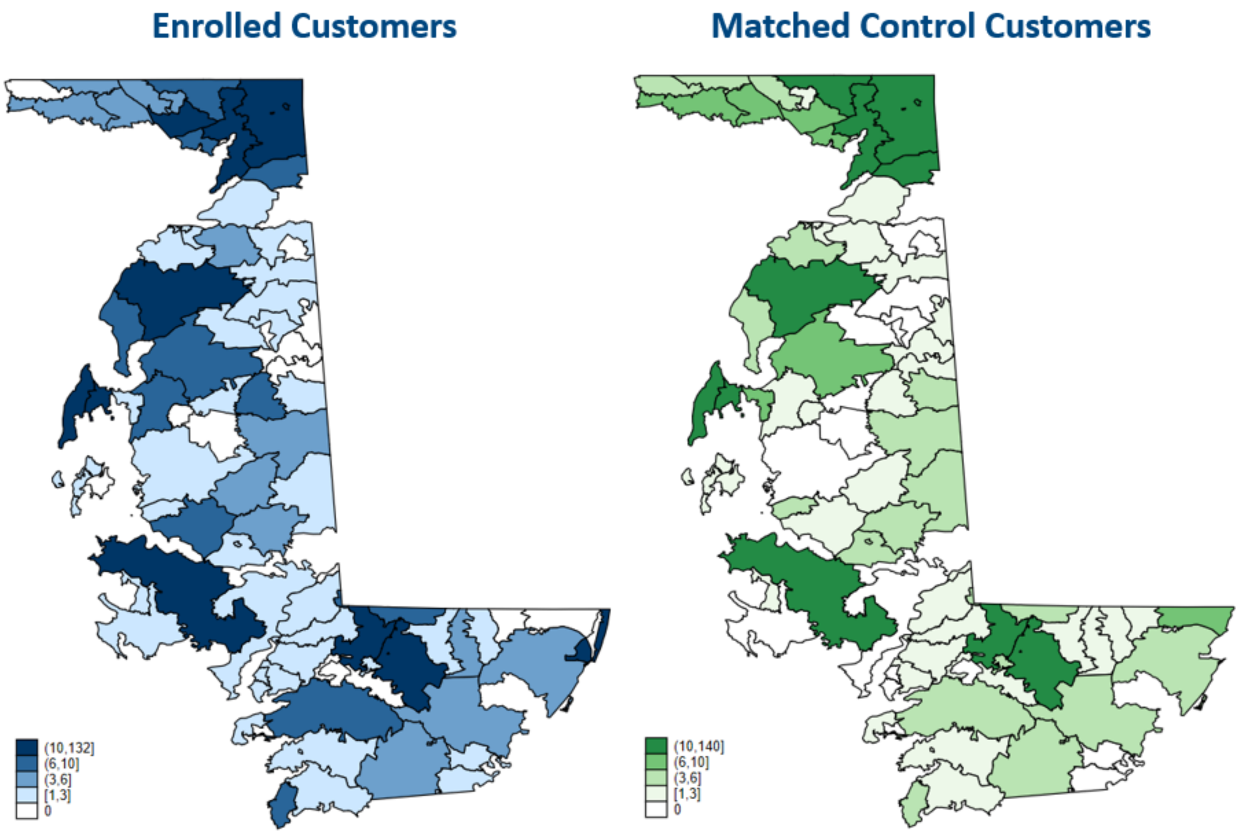


FIGURE 59: DPL GEOGRAPHICAL DISTRIBUTION OF ENROLLED AND MATCHED CONTROL CUSTOMERS



A.4 Regression Tables – Main Impact Results

This section presents detailed regression results for the main impact analyses presented in section IV for each utility and season.

FIGURE 60: BGE SUMMER WEEKDAY REGRESSION RESULTS

	All Customers			LMI Customers			Non-LMI Customers		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
VARIABLES	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)
Pilot Period	0.00308	0.00847	0.0117*	-0.00231	0.000974	0.00548	0.00870	0.0162*	0.0181*
	(0.00807)	(0.00697)	(0.00698)	(0.0113)	(0.00986)	(0.00985)	(0.0115)	(0.00985)	(0.00989)
Pilot x Treatment	-0.108***	-0.00668	-0.0288***	-0.0844***	0.000601	-0.0200	-0.132***	-0.0142	-0.0379***
	(0.0134)	(0.0110)	(0.0110)	(0.0192)	(0.0164)	(0.0163)	(0.0187)	(0.0147)	(0.0147)
July	1.093***	-2.644***	-1.743***	0.910***	-2.878***	-1.987***	1.285***	-2.403***	-1.490***
	(0.233)	(0.185)	(0.192)	(0.333)	(0.263)	(0.275)	(0.326)	(0.259)	(0.268)
August	-1.112***	-4.007***	-3.678***	-0.909***	-3.952***	-3.567***	-1.317***	-4.064***	-3.793***
	(0.197)	(0.161)	(0.166)	(0.281)	(0.230)	(0.239)	(0.275)	(0.225)	(0.229)
September	1.003***	-1.207***	-1.169***	0.958***	-1.275***	-1.232***	1.053***	-1.142***	-1.106***
	(0.158)	(0.125)	(0.125)	(0.225)	(0.177)	(0.179)	(0.221)	(0.176)	(0.176)
ln(THI)	4.360***	2.968***	3.375***	4.290***	2.981***	3.371***	4.433***	2.953***	3.378***
	(0.0497)	(0.0358)	(0.0380)	(0.0705)	(0.0512)	(0.0543)	(0.0701)	(0.0500)	(0.0530)
July x ln(THI)	-0.228***	0.631***	0.420***	-0.184**	0.686***	0.478***	-0.274***	0.573***	0.360***
	(0.0536)	(0.0431)	(0.0447)	(0.0765)	(0.0613)	(0.0639)	(0.0750)	(0.0604)	(0.0623)
August x ln(THI)	0.270***	0.943***	0.864***	0.225***	0.931***	0.840***	0.314***	0.954***	0.889***
	(0.0454)	(0.0376)	(0.0386)	(0.0648)	(0.0538)	(0.0557)	(0.0635)	(0.0525)	(0.0535)
September x ln(THI)	-0.240***	0.274***	0.264***	-0.228***	0.290***	0.280***	-0.254***	0.258***	0.248***
	(0.0366)	(0.0294)	(0.0294)	(0.0522)	(0.0416)	(0.0418)	(0.0513)	(0.0416)	(0.0413)
Constant	-18.80***	-12.77***	-14.49***	-18.60***	-12.92***	-14.57***	-19.01***	-12.62***	-14.40***
	(0.215)	(0.153)	(0.163)	(0.305)	(0.219)	(0.233)	(0.303)	(0.213)	(0.226)
Observations	506,740	506,740	506,740	258,341	258,341	258,341	248,399	248,399	248,399
Number of Customers	3,104	3,104	3,104	1,594	1,594	1,594	1,510	1,510	1,510
Adjusted R-squared	0.222	0.222	0.256	0.212	0.219	0.250	0.235	0.225	0.263
Customer FE	Y	Y	Y	Y	Y	Y	Y	Y	Y

Note: The unit of observation is a customer-day. Control customers were matched to treatment customers using a propensity score approach. As the dependent variable is expressed in natural logs, matched pairs in which one or both customers experienced negative load in one or more hours and net metering customers have been dropped from the analysis. Robust standard errors in parentheses. *** p<0.01, ** p<0.05, * p<0.1.

FIGURE 61: BGE SUMMER WEEKEND REGRESSION RESULTS

	All Customers			LMI Customers			Non-LMI Customers		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
VARIABLES	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)
Pilot Period	-0.0337***	-0.0141**	-0.0171**	-0.0376***	-0.0256**	-0.0266***	-0.0298**	-0.00234	-0.00741
	(0.00809)	(0.00707)	(0.00706)	(0.0113)	(0.0100)	(0.00996)	(0.0116)	(0.00997)	(0.00999)
Pilot x Treatment	-0.0463***	-0.00518	-0.0141	-0.0433**	0.000391	-0.00988	-0.0494***	-0.0109	-0.0184
	(0.0129)	(0.0113)	(0.0112)	(0.0192)	(0.0170)	(0.0170)	(0.0173)	(0.0147)	(0.0147)
July	-6.008***	-1.852***	-1.774***	-5.566***	-1.926***	-1.746***	-6.475***	-1.785***	-1.811***
	(0.255)	(0.228)	(0.227)	(0.366)	(0.320)	(0.320)	(0.353)	(0.326)	(0.321)
August	-7.424***	-0.667***	-1.200***	-7.157***	-0.693**	-1.105***	-7.702***	-0.648**	-1.306***
	(0.322)	(0.231)	(0.236)	(0.459)	(0.327)	(0.333)	(0.452)	(0.327)	(0.335)
September	-0.667***	2.254***	1.812***	-0.327	2.330***	1.991***	-1.021***	2.172***	1.623***
	(0.229)	(0.209)	(0.206)	(0.328)	(0.303)	(0.298)	(0.320)	(0.286)	(0.282)
ln(THI)	3.103***	3.377***	3.596***	3.136***	3.443***	3.658***	3.068***	3.306***	3.530***
	(0.0503)	(0.0483)	(0.0485)	(0.0721)	(0.0696)	(0.0698)	(0.0701)	(0.0667)	(0.0672)
July x ln(THI)	1.405***	0.446***	0.426***	1.306***	0.465***	0.422***	1.511***	0.429***	0.433***
	(0.0587)	(0.0533)	(0.0527)	(0.0844)	(0.0747)	(0.0744)	(0.0813)	(0.0760)	(0.0747)
August x ln(THI)	1.727***	0.163***	0.288***	1.667***	0.171**	0.267***	1.790***	0.157**	0.311***
	(0.0744)	(0.0542)	(0.0551)	(0.106)	(0.0766)	(0.0778)	(0.104)	(0.0766)	(0.0781)
September x ln(THI)	0.145***	-0.537***	-0.432***	0.0663	-0.555***	-0.474***	0.227***	-0.518***	-0.388***
	(0.0532)	(0.0492)	(0.0482)	(0.0761)	(0.0714)	(0.0700)	(0.0743)	(0.0674)	(0.0662)
Constant	-13.23***	-14.47***	-15.35***	-13.48***	-14.84***	-15.72***	-12.96***	-14.07***	-14.97***
	(0.217)	(0.206)	(0.207)	(0.311)	(0.297)	(0.299)	(0.303)	(0.284)	(0.287)
Observations	229,502	229,502	229,502	117,046	117,046	117,046	112,456	112,456	112,456
Number of Customers	3,104	3,104	3,104	1,594	1,594	1,594	1,510	1,510	1,510
Adjusted R-squared	0.162	0.192	0.209	0.158	0.193	0.209	0.167	0.191	0.211
Customer FE	Y	Y	Y	Y	Y	Y	Y	Y	Y

Note: The unit of observation is a customer-day. Control customers were matched to treatment customers using a propensity score approach. As the dependent variable is expressed in natural logs, matched pairs in which one or both customers experienced negative load in one or more hours and net metering customers have been dropped from the analysis. Robust standard errors in parentheses. *** p<0.01, ** p<0.05, * p<0.1.

FIGURE 62: BGE NON-SUMMER WEEKDAY REGRESSION RESULTS

	All Customers			LMI Customers			Non-LMI Customers		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
VARIABLES	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)
Pilot Period	-0.0408***	-0.0155*	-0.0194**	-0.0373***	-0.00797	-0.0128	-0.0442***	-0.0230**	-0.0259**
	(0.00896)	(0.00800)	(0.00797)	(0.0135)	(0.0121)	(0.0121)	(0.0118)	(0.0104)	(0.0104)
Pilot x Treatment	-0.0556***	-0.00839	-0.0134	-0.0542***	-0.0246	-0.0270	-0.0569***	0.00760	3.56e-05
	(0.0133)	(0.0113)	(0.0112)	(0.0200)	(0.0175)	(0.0174)	(0.0174)	(0.0142)	(0.0141)
February	0.890***	0.440***	0.495***	0.804***	0.437***	0.483***	0.974***	0.442***	0.506***
	(0.0442)	(0.0408)	(0.0396)	(0.0618)	(0.0577)	(0.0559)	(0.0632)	(0.0576)	(0.0560)
March	1.130***	0.400***	0.469***	1.031***	0.449***	0.503***	1.226***	0.350***	0.435***
	(0.0789)	(0.0783)	(0.0767)	(0.116)	(0.119)	(0.116)	(0.106)	(0.102)	(0.101)
April	1.123***	-0.198***	-0.0119	1.245***	0.0124	0.186*	1.000***	-0.408***	-0.210**
	(0.0732)	(0.0755)	(0.0723)	(0.108)	(0.112)	(0.108)	(0.0990)	(0.101)	(0.0961)
May	-2.318***	-5.990***	-5.550***	-2.302***	-5.650***	-5.242***	-2.335***	-6.327***	-5.856***
	(0.123)	(0.132)	(0.128)	(0.182)	(0.194)	(0.188)	(0.167)	(0.178)	(0.173)
October	-2.331***	-6.727***	-6.063***	-2.379***	-6.508***	-5.883***	-2.283***	-6.945***	-6.243***
	(0.0912)	(0.107)	(0.103)	(0.133)	(0.157)	(0.150)	(0.125)	(0.146)	(0.140)
November	0.838***	0.728***	0.723***	0.902***	0.875***	0.855***	0.774***	0.582***	0.591***
	(0.0536)	(0.0526)	(0.0513)	(0.0780)	(0.0780)	(0.0761)	(0.0737)	(0.0705)	(0.0686)
December	0.566***	-0.203***	-0.0586	0.549***	-0.129**	0.00785	0.581***	-0.277***	-0.125**
	(0.0434)	(0.0426)	(0.0404)	(0.0605)	(0.0606)	(0.0570)	(0.0622)	(0.0597)	(0.0572)
ln(THI)	-0.780***	-0.898***	-0.880***	-0.740***	-0.847***	-0.830***	-0.820***	-0.948***	-0.930***
	(0.0130)	(0.0136)	(0.0134)	(0.0182)	(0.0194)	(0.0190)	(0.0186)	(0.0190)	(0.0187)
February x ln(THI)	-0.246***	-0.128***	-0.142***	-0.221***	-0.127***	-0.138***	-0.270***	-0.129***	-0.145***
	(0.0117)	(0.0107)	(0.0104)	(0.0164)	(0.0151)	(0.0146)	(0.0168)	(0.0151)	(0.0147)
March x ln(THI)	-0.318***	-0.119***	-0.137***	-0.291***	-0.132***	-0.147***	-0.344***	-0.105***	-0.128***
	(0.0143)	(0.0267)	(0.0257)	(0.0208)	(0.0392)	(0.0376)	(0.0196)	(0.0363)	(0.0350)
April x ln(THI)	-0.334***	0.0194	-0.0287	-0.365***	-0.0342	-0.0792***	-0.303***	0.0728***	0.0217
	(0.0143)	(0.0137)	(0.0257)	(0.0208)	(0.0204)	(0.0376)	(0.0196)	(0.0184)	(0.0350)
May x ln(THI)	0.509***	1.443***	1.333***	0.504***	1.356***	1.254***	0.513***	1.529***	1.412***
	(0.0143)	(0.0137)	(0.0134)	(0.0208)	(0.0204)	(0.0199)	(0.0196)	(0.0184)	(0.0179)
October x ln(THI)	0.528***	1.616***	1.455***	0.540***	1.561***	1.409***	0.516***	1.671***	1.501***
	(0.0115)	(0.0137)	(0.0134)	(0.0160)	(0.0204)	(0.0199)	(0.0165)	(0.0184)	(0.0179)
November x ln(THI)	-0.245***	-0.209***	-0.208***	-0.260***	-0.246***	-0.242***	-0.229***	-0.172***	-0.175***
	(0.0115)	(0.0112)	(0.0134)	(0.0160)	(0.0159)	(0.0199)	(0.0165)	(0.0157)	(0.0179)
December x ln(THI)	-0.153***	0.0592***	0.0205*	-0.148***	0.0390**	0.00243	-0.158***	0.0794***	0.0385**
	(0.0115)	(0.0112)	(0.0106)	(0.0160)	(0.0159)	(0.0149)	(0.0165)	(0.0157)	(0.0150)
Constant	2.947***	3.418***	3.360***	2.689***	3.135***	3.077***	3.204***	3.699***	3.642***
	(0.0510)	(0.0536)	(0.0527)	(0.0710)	(0.0760)	(0.0746)	(0.0729)	(0.0751)	(0.0741)
Observations	999,632	999,632	999,632	497,822	497,822	497,822	501,810	501,810	501,810
Number of Customers	2,854	2,854	2,854	1,426	1,426	1,426	1,428	1,428	1,428
Adjusted R-squared	0.181	0.174	0.185	0.163	0.159	0.169	0.200	0.191	0.203
Customer FE	Y	Y	Y	Y	Y	Y	Y	Y	Y

Note: The unit of observation is a customer-day. Control customers were matched to treatment customers using a propensity score approach. As the dependent variable is expressed in natural logs, matched pairs in which one or both customers experienced negative load in one or more hours and net metering customers have been dropped from the analysis. Robust standard errors in parentheses. *** p<0.01, ** p<0.05, * p<0.1.

FIGURE 63: BGE NON-SUMMER WEEKEND REGRESSION RESULTS

	All Customers			LMI Customers			Non-LMI Customers		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
VARIABLES	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)
Pilot Period	-0.0278***	-0.0213***	-0.0217***	-0.0214	-0.0157	-0.0166	-0.0340***	-0.0268***	-0.0268***
	(0.00871)	(0.00795)	(0.00794)	(0.0132)	(0.0122)	(0.0122)	(0.0114)	(0.0103)	(0.0102)
Pilot x Treatment	-0.0222*	-0.00266	-0.00470	-0.0287	-0.0181	-0.0188	-0.0158	0.0126	0.00928
	(0.0123)	(0.0112)	(0.0111)	(0.0190)	(0.0176)	(0.0174)	(0.0156)	(0.0139)	(0.0138)
February	0.160***	-0.511***	-0.403***	0.186**	-0.424***	-0.321***	0.133*	-0.597***	-0.485***
	(0.0548)	(0.0515)	(0.0497)	(0.0809)	(0.0760)	(0.0734)	(0.0738)	(0.0696)	(0.0671)
March	1.375***	0.705***	0.857***	1.265***	0.706***	0.824***	1.483***	0.704***	0.889***
	(0.0689)	(0.0815)	(0.0758)	(0.0986)	(0.118)	(0.110)	(0.0963)	(0.112)	(0.105)
April	1.195***	-0.903***	-0.725***	1.082***	-0.695***	-0.551***	1.306***	-1.111***	-0.898***
	(0.0940)	(0.0839)	(0.0820)	(0.134)	(0.120)	(0.118)	(0.131)	(0.117)	(0.114)
May	-1.615***	-4.963***	-4.497***	-1.649***	-4.745***	-4.308***	-1.584***	-5.180***	-4.685***
	(0.108)	(0.105)	(0.101)	(0.157)	(0.151)	(0.146)	(0.148)	(0.145)	(0.140)
October	-2.173***	-4.211***	-4.024***	-2.249***	-3.919***	-3.769***	-2.096***	-4.503***	-4.279***
	(0.113)	(0.116)	(0.113)	(0.161)	(0.172)	(0.166)	(0.158)	(0.156)	(0.152)
November	1.204***	0.266***	0.458***	1.073***	0.411***	0.580***	1.334***	0.122	0.335***
	(0.0832)	(0.0728)	(0.0707)	(0.123)	(0.108)	(0.105)	(0.112)	(0.0975)	(0.0950)
December	0.628***	0.0818	0.177***	0.588***	0.0979	0.180**	0.668***	0.0658	0.174**
	(0.0551)	(0.0536)	(0.0512)	(0.0791)	(0.0764)	(0.0729)	(0.0767)	(0.0751)	(0.0721)
ln(THI)	-0.849***	-0.850***	-0.843***	-0.802***	-0.806***	-0.798***	-0.896***	-0.893***	-0.887***
	(0.0142)	(0.0137)	(0.0136)	(0.0201)	(0.0195)	(0.0193)	(0.0200)	(0.0192)	(0.0192)
February x ln(THI)	-0.0348**	0.126***	0.100***	-0.0427*	0.104***	0.0788***	-0.0267	0.149***	0.121***
	(0.0150)	(0.0137)	(0.0133)	(0.0222)	(0.0202)	(0.0196)	(0.0201)	(0.0184)	(0.0178)
March x ln(THI)	-0.386***	-0.212***	-0.250***	-0.357***	-0.211***	-0.241***	-0.415***	-0.212***	-0.259***
	(0.0220)	(0.0288)	(0.0280)	(0.0324)	(0.0426)	(0.0412)	(0.0297)	(0.0387)	(0.0378)
April x ln(THI)	-0.348***	0.192***	0.147***	-0.319***	0.139***	0.103***	-0.378***	0.244***	0.191***
	(0.0220)	(0.0189)	(0.0280)	(0.0324)	(0.0280)	(0.0412)	(0.0297)	(0.0253)	(0.0378)
May x ln(THI)	0.356***	1.197***	1.082***	0.364***	1.140***	1.032***	0.348***	1.253***	1.131***
	(0.0220)	(0.0189)	(0.0184)	(0.0324)	(0.0280)	(0.0272)	(0.0297)	(0.0253)	(0.0247)
October x ln(THI)	0.481***	0.993***	0.947***	0.499***	0.921***	0.883***	0.463***	1.066***	1.010***
	(0.0145)	(0.0189)	(0.0184)	(0.0208)	(0.0280)	(0.0272)	(0.0202)	(0.0253)	(0.0247)
November x ln(THI)	-0.327***	-0.0933***	-0.141***	-0.293***	-0.129***	-0.172***	-0.360***	-0.0574**	-0.111***
	(0.0145)	(0.0138)	(0.0184)	(0.0208)	(0.0197)	(0.0272)	(0.0202)	(0.0194)	(0.0247)
December x ln(THI)	-0.159***	-0.0205	-0.0448***	-0.149***	-0.0244	-0.0455**	-0.169***	-0.0166	-0.0441**
	(0.0145)	(0.0138)	(0.0132)	(0.0208)	(0.0197)	(0.0188)	(0.0202)	(0.0194)	(0.0186)
Constant	3.113***	3.312***	3.275***	2.831***	3.048***	3.006***	3.395***	3.575***	3.543***
	(0.0550)	(0.0538)	(0.0535)	(0.0779)	(0.0763)	(0.0757)	(0.0774)	(0.0756)	(0.0752)
Observations	442,042	442,042	442,042	220,193	220,193	220,193	221,849	221,849	221,849
Number of Customers	2,854	2,854	2,854	1,426	1,426	1,426	1,428	1,428	1,428
Adjusted R-squared	0.188	0.148	0.162	0.167	0.135	0.147	0.209	0.163	0.178
Customer FE	Y	Y	Y	Y	Y	Y	Y	Y	Y

Note: The unit of observation is a customer-day. Control customers were matched to treatment customers using a propensity score approach. As the dependent variable is expressed in natural logs, matched pairs in which one or both customers experienced negative load in one or more hours and net metering customers have been dropped from the analysis. Robust standard errors in parentheses. *** p<0.01, ** p<0.05, * p<0.1.

FIGURE 64: PEPCO SUMMER WEEKDAY REGRESSION RESULTS

	All Customers			LMI Customers			Non-LMI Customers		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
VARIABLES	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)
Pilot Period	0.0444***	0.0227**	0.0319***	0.0349**	0.0196	0.0276**	0.0525***	0.0253**	0.0355***
	(0.0107)	(0.00898)	(0.00892)	(0.0147)	(0.0124)	(0.0123)	(0.0136)	(0.0108)	(0.0107)
Pilot x Treatment	-0.154***	-0.0169	-0.0440***	-0.113***	-0.0122	-0.0335**	-0.189***	-0.0209	-0.0530***
	(0.0153)	(0.0118)	(0.0117)	(0.0216)	(0.0170)	(0.0169)	(0.0204)	(0.0148)	(0.0146)
July	-1.198***	-1.778***	-1.260***	-0.697	-1.949***	-1.365***	-1.608***	-1.621***	-1.155***
	(0.320)	(0.227)	(0.238)	(0.445)	(0.321)	(0.338)	(0.437)	(0.302)	(0.317)
August	-1.792***	-3.598***	-3.305***	-1.270***	-3.517***	-3.169***	-2.219***	-3.655***	-3.406***
	(0.267)	(0.206)	(0.212)	(0.377)	(0.304)	(0.313)	(0.362)	(0.267)	(0.275)
September	3.239***	-0.0581	0.419***	3.404***	0.252	0.728***	3.115***	-0.310	0.171
	(0.214)	(0.151)	(0.154)	(0.297)	(0.215)	(0.219)	(0.296)	(0.204)	(0.207)
ln(THI)	4.343***	3.173***	3.548***	4.259***	3.083***	3.449***	4.419***	3.253***	3.635***
	(0.0667)	(0.0467)	(0.0497)	(0.0940)	(0.0679)	(0.0719)	(0.0903)	(0.0622)	(0.0662)
July x ln(THI)	0.289***	0.419***	0.298***	0.175*	0.459***	0.323***	0.384***	0.382***	0.274***
	(0.0734)	(0.0526)	(0.0550)	(0.102)	(0.0745)	(0.0782)	(0.100)	(0.0699)	(0.0733)
August x ln(THI)	0.417***	0.829***	0.760***	0.297***	0.812***	0.730***	0.515***	0.841***	0.782***
	(0.0615)	(0.0481)	(0.0494)	(0.0870)	(0.0708)	(0.0726)	(0.0835)	(0.0623)	(0.0641)
September x ln(THI)	-0.763***	-0.00277	-0.114***	-0.801***	-0.0755	-0.186***	-0.734***	0.0563	-0.0564
	(0.0498)	(0.0357)	(0.0361)	(0.0691)	(0.0506)	(0.0513)	(0.0687)	(0.0481)	(0.0487)
Constant	-18.96***	-13.78***	-15.38***	-18.64***	-13.45***	-15.02***	-19.24***	-14.06***	-15.70***
	(0.289)	(0.200)	(0.213)	(0.408)	(0.291)	(0.309)	(0.392)	(0.266)	(0.284)
Observations	380,427	380,427	380,427	175,687	175,687	175,687	204,740	204,740	204,740
Number of Customers	2388	2388	2388	1098	1098	1098	1290	1290	1290
Adjusted R-squared	0.182	0.230	0.257	0.175	0.225	0.248	0.190	0.235	0.264
Customer FE	Y	Y	Y	Y	Y	Y	Y	Y	Y

Note: The unit of observation is a customer-day. Control customers were matched to treatment customers using a propensity score approach. As the dependent variable is expressed in natural logs, matched pairs in which one or both customers experienced negative load in one or more hours and net metering customers have been dropped from the analysis. Robust standard errors in parentheses. *** p<0.01, ** p<0.05, * p<0.1.

FIGURE 65: PEPCO SUMMER WEEKEND REGRESSION RESULTS

	All Customers			LMI Customers			Non-LMI Customers		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
VARIABLES	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)
Pilot Period	-0.0236**	-0.0109	-0.0130	-0.0268*	-0.0177	-0.0187	-0.0208	-0.00512	-0.00806
	(0.0104)	(0.00894)	(0.00891)	(0.0144)	(0.0123)	(0.0122)	(0.0131)	(0.0106)	(0.0106)
Pilot x Treatment	-0.0719***	-0.0244**	-0.0348***	-0.0506**	-0.0168	-0.0246	-0.0902***	-0.0309**	-0.0436***
	(0.0140)	(0.0116)	(0.0116)	(0.0201)	(0.0168)	(0.0166)	(0.0180)	(0.0145)	(0.0145)
July	-10.69***	-1.441***	-2.983***	-10.54***	-1.430***	-3.049***	-10.81***	-1.446***	-2.920***
	(0.348)	(0.302)	(0.297)	(0.504)	(0.425)	(0.426)	(0.463)	(0.400)	(0.388)
August	-9.733***	0.473	-1.115***	-9.339***	0.174	-1.391***	-10.06***	0.733*	-0.871**
	(0.405)	(0.298)	(0.295)	(0.586)	(0.415)	(0.416)	(0.547)	(0.409)	(0.402)
September	-2.997***	3.372***	2.022***	-2.547***	3.295***	2.010***	-3.376***	3.444***	2.041***
	(0.266)	(0.254)	(0.240)	(0.389)	(0.365)	(0.345)	(0.348)	(0.342)	(0.323)
ln(THI)	2.462***	3.650***	3.538***	2.373***	3.532***	3.409***	2.538***	3.751***	3.649***
	(0.0554)	(0.0639)	(0.0605)	(0.0819)	(0.0909)	(0.0864)	(0.0723)	(0.0863)	(0.0814)
July x ln(THI)	2.473***	0.336***	0.695***	2.440***	0.334***	0.711***	2.501***	0.337***	0.680***
	(0.0798)	(0.0702)	(0.0689)	(0.116)	(0.0989)	(0.0987)	(0.106)	(0.0931)	(0.0900)
August x ln(THI)	2.244***	-0.121*	0.251***	2.153***	-0.0489	0.317***	2.320***	-0.183*	0.193**
	(0.0933)	(0.0695)	(0.0687)	(0.135)	(0.0968)	(0.0968)	(0.126)	(0.0957)	(0.0937)
September x ln(THI)	0.675***	-0.804***	-0.487***	0.573***	-0.785***	-0.484***	0.762***	-0.822***	-0.492***
	(0.0616)	(0.0596)	(0.0562)	(0.0902)	(0.0856)	(0.0808)	(0.0806)	(0.0803)	(0.0757)
Constant	-10.58***	-15.74***	-15.22***	-10.27***	-15.30***	-14.74***	-10.85***	-16.12***	-15.65***
	(0.240)	(0.273)	(0.259)	(0.354)	(0.389)	(0.371)	(0.313)	(0.369)	(0.349)
Observations	177,272	177,272	177,272	81,861	81,861	81,861	95,411	95,411	95,411
Number of Customers	2388	2388	2388	1098	1098	1098	1290	1290	1290
Adjusted R-squared	0.136	0.203	0.212	0.129	0.198	0.206	0.142	0.207	0.217
Customer FE	Y	Y	Y	Y	Y	Y	Y	Y	Y

Note: The unit of observation is a customer-day. Control customers were matched to treatment customers using a propensity score approach. As the dependent variable is expressed in natural logs, matched pairs in which one or both customers experienced negative load in one or more hours and net metering customers have been dropped from the analysis. Robust standard errors in parentheses. *** p<0.01, ** p<0.05, * p<0.1.

FIGURE 66: PEPCO NON-SUMMER WEEKDAY REGRESSION RESULTS

	All Customers			LMI Customers			Non-LMI Customers		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
VARIABLES	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)
Pilot Period	-0.0387***	-0.0175**	-0.0208**	-0.0387***	-0.0168	-0.0201*	-0.0388***	-0.0180	-0.0214*
	(0.00994)	(0.00879)	(0.00866)	(0.0144)	(0.0116)	(0.0115)	(0.0129)	(0.0120)	(0.0118)
Pilot x Treatment	-0.0521***	-0.00299	-0.00842	-0.0491**	-0.0168	-0.0199	-0.0545***	0.00865	0.00124
	(0.0141)	(0.0117)	(0.0116)	(0.0207)	(0.0163)	(0.0161)	(0.0187)	(0.0159)	(0.0157)
February	0.944***	0.569***	0.634***	1.045***	0.649***	0.720***	0.859***	0.501***	0.561***
	(0.0428)	(0.0401)	(0.0394)	(0.0616)	(0.0596)	(0.0583)	(0.0571)	(0.0518)	(0.0508)
March	1.101***	0.646***	0.686***	1.265***	0.792***	0.839***	0.962***	0.521***	0.556***
	(0.0648)	(0.0643)	(0.0627)	(0.0929)	(0.0930)	(0.0903)	(0.0865)	(0.0845)	(0.0828)
April	1.004***	0.206**	0.319***	1.098***	0.400***	0.499***	0.926***	0.0422	0.169*
	(0.0696)	(0.0815)	(0.0779)	(0.101)	(0.120)	(0.115)	(0.0939)	(0.106)	(0.101)
May	-2.303***	-5.671***	-5.284***	-2.176***	-5.209***	-4.850***	-2.412***	-6.065***	-5.653***
	(0.133)	(0.155)	(0.150)	(0.199)	(0.225)	(0.218)	(0.171)	(0.206)	(0.198)
October	-1.685***	-5.735***	-5.124***	-1.754***	-5.422***	-4.867***	-1.625***	-6.002***	-5.343***
	(0.0972)	(0.128)	(0.122)	(0.144)	(0.187)	(0.177)	(0.127)	(0.168)	(0.159)
November	0.618***	0.701***	0.676***	0.702***	0.763***	0.745***	0.546***	0.647***	0.617***
	(0.0458)	(0.0483)	(0.0464)	(0.0641)	(0.0672)	(0.0646)	(0.0635)	(0.0669)	(0.0642)
December	0.619***	0.227***	0.302***	0.685***	0.261***	0.346***	0.564***	0.199***	0.266***
	(0.0410)	(0.0448)	(0.0420)	(0.0591)	(0.0623)	(0.0585)	(0.0552)	(0.0623)	(0.0582)
ln(THI)	-0.522***	-0.658***	-0.638***	-0.539***	-0.679***	-0.658***	-0.507***	-0.640***	-0.621***
	(0.0102)	(0.0115)	(0.0112)	(0.0149)	(0.0167)	(0.0163)	(0.0135)	(0.0152)	(0.0148)
February x ln(THI)	-0.266***	-0.162***	-0.180***	-0.292***	-0.182***	-0.201***	-0.244***	-0.146***	-0.162***
	(0.0116)	(0.0106)	(0.0105)	(0.0167)	(0.0158)	(0.0155)	(0.0156)	(0.0138)	(0.0136)
March x ln(THI)	-0.314***	-0.178***	-0.190***	-0.358***	-0.216***	-0.229***	-0.276***	-0.147***	-0.157***
	(0.0174)	(0.0167)	(0.0164)	(0.0251)	(0.0243)	(0.0237)	(0.0233)	(0.0220)	(0.0216)
April x ln(THI)	-0.298***	-0.0687***	-0.0998***	-0.326***	-0.119***	-0.146***	-0.275***	-0.0267	-0.0608**
	(0.0184)	(0.0209)	(0.0201)	(0.0268)	(0.0310)	(0.0296)	(0.0248)	(0.0270)	(0.0261)
May x ln(THI)	0.524***	1.376***	1.280***	0.489***	1.258***	1.169***	0.554***	1.476***	1.374***
	(0.0332)	(0.0383)	(0.0371)	(0.0498)	(0.0557)	(0.0541)	(0.0428)	(0.0507)	(0.0489)
October x ln(THI)	0.384***	1.380***	1.232***	0.397***	1.298***	1.165***	0.373***	1.449***	1.290***
	(0.0249)	(0.0320)	(0.0305)	(0.0371)	(0.0467)	(0.0445)	(0.0325)	(0.0418)	(0.0399)
November x ln(THI)	-0.179***	-0.198***	-0.192***	-0.201***	-0.215***	-0.211***	-0.160***	-0.184***	-0.176***
	(0.0124)	(0.0127)	(0.0123)	(0.0174)	(0.0177)	(0.0171)	(0.0171)	(0.0176)	(0.0170)
December x ln(THI)	-0.171***	-0.0593***	-0.0799***	-0.188***	-0.0680***	-0.0912***	-0.157***	-0.0522***	-0.0706***
	(0.0112)	(0.0120)	(0.0112)	(0.0162)	(0.0167)	(0.0157)	(0.0151)	(0.0166)	(0.0156)
Constant	1.693***	2.310***	2.234***	1.732***	2.375***	2.296***	1.659***	2.254***	2.181***
	(0.0394)	(0.0454)	(0.0442)	(0.0573)	(0.0661)	(0.0643)	(0.0523)	(0.0602)	(0.0587)
Observations	789,442	789,442	789,442	361,505	361,505	361,505	427,937	427,937	427,937
Number of Customers	2254	2254	2254	1036	1036	1036	1218	1218	1218
Adjusted R-squared	0.144	0.148	0.157	0.155	0.166	0.176	0.135	0.135	0.143
Customer FE	Y	Y	Y	Y	Y	Y	Y	Y	Y

Note: The unit of observation is a customer-day. Control customers were matched to treatment customers using a propensity score approach. As the dependent variable is expressed in natural logs, matched pairs in which one or both customers experienced negative load in one or more hours and net metering customers have been dropped from the analysis. Robust standard errors in parentheses. *** p<0.01, ** p<0.05, * p<0.1.

FIGURE 67: PEPCO NON-SUMMER WEEKEND REGRESSION RESULTS

	All Customers			LMI Customers			Non-LMI Customers		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
VARIABLES	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)
Pilot Period	-0.0527***	-0.0416***	-0.0429***	-0.0513***	-0.0407***	-0.0424***	-0.0537***	-0.0423***	-0.0433***
	(0.00955)	(0.00861)	(0.00854)	(0.0137)	(0.0117)	(0.0116)	(0.0123)	(0.0116)	(0.0115)
Pilot x Treatment	-0.00454	-0.00401	-0.00375	-0.00867	-0.0127	-0.0120	-0.00111	0.00326	0.00317
	(0.0128)	(0.0112)	(0.0111)	(0.0186)	(0.0157)	(0.0157)	(0.0169)	(0.0151)	(0.0150)
February	0.432***	0.0847*	0.148***	0.397***	0.0508	0.104*	0.463***	0.114*	0.186***
	(0.0430)	(0.0439)	(0.0416)	(0.0604)	(0.0594)	(0.0557)	(0.0584)	(0.0619)	(0.0591)
March	2.307***	0.832***	1.070***	2.494***	1.146***	1.363***	2.150***	0.567***	0.822***
	(0.0913)	(0.100)	(0.0962)	(0.132)	(0.148)	(0.142)	(0.120)	(0.129)	(0.124)
April	1.109***	-0.333***	-0.164	1.266***	-0.0420	0.132	0.976***	-0.581***	-0.416***
	(0.103)	(0.108)	(0.106)	(0.147)	(0.156)	(0.153)	(0.137)	(0.144)	(0.142)
May	-1.213***	-4.127***	-3.706***	-1.201***	-3.733***	-3.359***	-1.223***	-4.460***	-4.000***
	(0.111)	(0.120)	(0.115)	(0.164)	(0.170)	(0.164)	(0.147)	(0.160)	(0.154)
October	-1.810***	-3.794***	-3.629***	-1.830***	-3.654***	-3.505***	-1.793***	-3.913***	-3.734***
	(0.118)	(0.126)	(0.123)	(0.167)	(0.181)	(0.176)	(0.159)	(0.167)	(0.163)
November	1.184***	0.658***	0.717***	1.240***	0.722***	0.772***	1.137***	0.605***	0.670***
	(0.0733)	(0.0702)	(0.0672)	(0.102)	(0.0943)	(0.0896)	(0.101)	(0.0989)	(0.0951)
December	1.095***	0.791***	0.845***	1.211***	0.794***	0.870***	0.998***	0.789***	0.825***
	(0.0569)	(0.0561)	(0.0538)	(0.0780)	(0.0772)	(0.0741)	(0.0789)	(0.0772)	(0.0742)
ln(THI)	-0.528***	-0.572***	-0.562***	-0.540***	-0.592***	-0.581***	-0.519***	-0.554***	-0.546***
	(0.0102)	(0.0108)	(0.0105)	(0.0148)	(0.0155)	(0.0151)	(0.0136)	(0.0143)	(0.0140)
February x ln(THI)	-0.108***	-0.0252**	-0.0406***	-0.0960***	-0.0138	-0.0263*	-0.119***	-0.0350**	-0.0528***
	(0.0121)	(0.0118)	(0.0113)	(0.0171)	(0.0159)	(0.0150)	(0.0165)	(0.0167)	(0.0160)
March x ln(THI)	-0.632***	-0.229***	-0.291***	-0.683***	-0.310***	-0.367***	-0.590***	-0.161***	-0.228***
	(0.0248)	(0.0262)	(0.0252)	(0.0359)	(0.0388)	(0.0374)	(0.0326)	(0.0336)	(0.0324)
April x ln(THI)	-0.320***	0.0596**	0.0166	-0.362***	-0.0141	-0.0585	-0.285***	0.122***	0.0804**
	(0.0267)	(0.0274)	(0.0271)	(0.0384)	(0.0397)	(0.0391)	(0.0358)	(0.0365)	(0.0361)
May x ln(THI)	0.270***	1.003***	0.900***	0.265***	0.903***	0.812***	0.274***	1.087***	0.975***
	(0.0284)	(0.0299)	(0.0289)	(0.0418)	(0.0426)	(0.0412)	(0.0375)	(0.0398)	(0.0384)
October x ln(THI)	0.403***	0.897***	0.856***	0.406***	0.860***	0.823***	0.402***	0.928***	0.884***
	(0.0297)	(0.0313)	(0.0305)	(0.0420)	(0.0450)	(0.0439)	(0.0400)	(0.0414)	(0.0404)
November x ln(THI)	-0.312***	-0.186***	-0.200***	-0.327***	-0.203***	-0.215***	-0.299***	-0.171***	-0.187***
	(0.0197)	(0.0184)	(0.0176)	(0.0275)	(0.0247)	(0.0235)	(0.0272)	(0.0259)	(0.0250)
December x ln(THI)	-0.288***	-0.212***	-0.226***	-0.320***	-0.213***	-0.232***	-0.261***	-0.213***	-0.221***
	(0.0154)	(0.0148)	(0.0142)	(0.0211)	(0.0204)	(0.0196)	(0.0214)	(0.0204)	(0.0196)
Constant	1.641***	2.074***	2.021***	1.660***	2.129***	2.071***	1.625***	2.028***	1.978***
	(0.0387)	(0.0419)	(0.0409)	(0.0559)	(0.0603)	(0.0587)	(0.0515)	(0.0559)	(0.0547)
Observations	361,325	361,325	361,325	165,460	165,460	165,460	195,865	195,865	195,865
Number of Customers	2254	2254	2254	1036	1036	1036	1218	1218	1218
Adjusted R-squared	0.162	0.138	0.149	0.169	0.155	0.167	0.157	0.125	0.136
Customer FE	Y	Y	Y	Y	Y	Y	Y	Y	Y

Note: The unit of observation is a customer-day. Control customers were matched to treatment customers using a propensity score approach. As the dependent variable is expressed in natural logs, matched pairs in which one or both customers experienced negative load in one or more hours and net metering customers have been dropped from the analysis. Robust standard errors in parentheses. *** p<0.01, ** p<0.05, * p<0.1.

FIGURE 68: DPL SUMMER WEEKDAY REGRESSION RESULTS

	All Customers			LMI Customers			Non-LMI Customers		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
VARIABLES	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)
Pilot Period	0.00780	0.00727	0.0126	-0.00709	-0.00285	0.00204	0.0322	0.0238	0.0297
	(0.0152)	(0.0134)	(0.0134)	(0.0178)	(0.0160)	(0.0158)	(0.0263)	(0.0214)	(0.0220)
Pilot x Treatment	-0.161***	-0.0192	-0.0506***	-0.147***	-0.0178	-0.0473**	-0.183***	-0.0211	-0.0557*
	(0.0219)	(0.0174)	(0.0174)	(0.0265)	(0.0210)	(0.0209)	(0.0374)	(0.0289)	(0.0290)
July	-3.396***	-3.535***	-3.463***	-3.218***	-3.624***	-3.468***	-3.692***	-3.386***	-3.455***
	(0.457)	(0.323)	(0.354)	(0.527)	(0.369)	(0.404)	(0.821)	(0.583)	(0.641)
August	0.205	-2.547***	-2.255***	0.123	-2.937***	-2.601***	0.344	-1.899***	-1.678***
	(0.375)	(0.284)	(0.299)	(0.446)	(0.331)	(0.348)	(0.632)	(0.508)	(0.536)
September	0.888***	0.124	-0.00431	0.745**	-0.121	-0.251	1.116**	0.524	0.396
	(0.302)	(0.220)	(0.230)	(0.374)	(0.273)	(0.285)	(0.474)	(0.352)	(0.367)
ln(THI)	3.934***	2.351***	2.715***	4.028***	2.378***	2.755***	3.778***	2.306***	2.647***
	(0.0857)	(0.0531)	(0.0585)	(0.104)	(0.0648)	(0.0717)	(0.142)	(0.0888)	(0.0971)
July x ln(THI)	0.812***	0.850***	0.832***	0.768***	0.870***	0.831***	0.884***	0.818***	0.833***
	(0.105)	(0.0755)	(0.0825)	(0.122)	(0.0864)	(0.0944)	(0.189)	(0.136)	(0.149)
August x ln(THI)	-0.0146	0.616***	0.548***	-0.000742	0.704***	0.624***	-0.0380	0.472***	0.421***
	(0.0865)	(0.0665)	(0.0698)	(0.103)	(0.0772)	(0.0809)	(0.146)	(0.119)	(0.125)
September x ln(THI)	-0.214***	-0.0370	-0.00710	-0.181**	0.0200	0.0498	-0.264**	-0.130	-0.0995
	(0.0704)	(0.0520)	(0.0543)	(0.0872)	(0.0646)	(0.0674)	(0.111)	(0.0834)	(0.0867)
Constant	-17.12***	-10.33***	-11.85***	-17.44***	-10.39***	-11.96***	-16.58***	-10.23***	-11.66***
	(0.370)	(0.226)	(0.250)	(0.449)	(0.276)	(0.306)	(0.613)	(0.378)	(0.414)
Observations	191,325	191,325	191,325	119,363	119,363	119,363	71,962	71,962	71,962
Number of Customers	1184	1184	1184	740	740	740	444	444	444
Adjusted R-squared	0.187	0.174	0.195	0.201	0.193	0.216	0.167	0.150	0.168
Customer FE	Y	Y	Y	Y	Y	Y	Y	Y	Y

Note: The unit of observation is a customer-day. Control customers were matched to treatment customers using a propensity score approach. As the dependent variable is expressed in natural logs, matched pairs in which one or both customers experienced negative load in one or more hours and net metering customers have been dropped from the analysis. Robust standard errors in parentheses. *** p<0.01, ** p<0.05, * p<0.1.

FIGURE 69: DPL SUMMER WEEKEND REGRESSION RESULTS

	All Customers			LMI Customers			Non-LMI Customers		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
VARIABLES	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)
Pilot Period	-0.0640***	-0.0310**	-0.0384***	-0.0760***	-0.0392**	-0.0473***	-0.0442*	-0.0175	-0.0239
	(0.0163)	(0.0145)	(0.0144)	(0.0193)	(0.0170)	(0.0169)	(0.0267)	(0.0231)	(0.0233)
Pilot x Treatment	-0.0853***	-0.0173	-0.0319*	-0.0722***	-0.00811	-0.0219	-0.107***	-0.0322	-0.0484
	(0.0216)	(0.0184)	(0.0184)	(0.0259)	(0.0217)	(0.0218)	(0.0360)	(0.0306)	(0.0305)
July	-8.255***	-2.535***	-2.943***	-8.631***	-2.947***	-3.373***	-7.631***	-1.852***	-2.229***
	(0.470)	(0.372)	(0.377)	(0.560)	(0.435)	(0.440)	(0.804)	(0.648)	(0.664)
August	-5.434***	-0.0945	-0.860**	-5.341***	-0.349	-1.155**	-5.588***	0.326	-0.371
	(0.525)	(0.396)	(0.402)	(0.618)	(0.457)	(0.464)	(0.901)	(0.702)	(0.716)
September	-0.729**	1.408***	1.006***	-1.082**	1.515***	0.982**	-0.141	1.230*	1.045*
	(0.362)	(0.361)	(0.357)	(0.422)	(0.418)	(0.409)	(0.633)	(0.627)	(0.629)
ln(THI)	2.496***	2.753***	2.910***	2.472***	2.765***	2.906***	2.534***	2.732***	2.915***
	(0.0718)	(0.0775)	(0.0756)	(0.0861)	(0.0910)	(0.0887)	(0.120)	(0.131)	(0.128)
July x ln(THI)	1.936***	0.617***	0.710***	2.021***	0.711***	0.808***	1.796***	0.461***	0.547***
	(0.108)	(0.0867)	(0.0877)	(0.129)	(0.102)	(0.102)	(0.185)	(0.151)	(0.154)
August x ln(THI)	1.293***	0.0428	0.224**	1.267***	0.0986	0.289***	1.336***	-0.0493	0.117
	(0.121)	(0.0927)	(0.0939)	(0.142)	(0.107)	(0.108)	(0.208)	(0.164)	(0.167)
September x ln(THI)	0.160*	-0.331***	-0.237***	0.241**	-0.357***	-0.232**	0.0261	-0.288*	-0.244*
	(0.0844)	(0.0855)	(0.0842)	(0.0981)	(0.0988)	(0.0965)	(0.148)	(0.148)	(0.148)
Constant	-10.74***	-11.93***	-12.55***	-10.58***	-11.95***	-12.50***	-11.00***	-11.89***	-12.64***
	(0.309)	(0.330)	(0.323)	(0.371)	(0.388)	(0.379)	(0.517)	(0.559)	(0.547)
Observations	89,269	89,269	89,269	55,696	55,696	55,696	33,573	33,573	33,573
Number of Customers	1184	1184	1184	740	740	740	444	444	444
Adjusted R-squared	0.134	0.164	0.173	0.142	0.184	0.193	0.122	0.139	0.148
Customer FE	Y	Y	Y	Y	Y	Y	Y	Y	Y

Note: The unit of observation is a customer-day. Control customers were matched to treatment customers using a propensity score approach. As the dependent variable is expressed in natural logs, matched pairs in which one or both customers experienced negative load in one or more hours and net metering customers have been dropped from the analysis. Robust standard errors in parentheses. *** p<0.01, ** p<0.05, * p<0.1.

FIGURE 70: DPL NON-SUMMER WEEKDAY REGRESSION RESULTS

	All Customers			LMI Customers			Non-LMI Customers		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
VARIABLES	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)
Pilot Period	-0.0471**	-0.0416**	-0.0425**	-0.0469**	-0.0489***	-0.0487***	-0.0473	-0.0297	-0.0325
	(0.0189)	(0.0173)	(0.0174)	(0.0206)	(0.0184)	(0.0184)	(0.0322)	(0.0302)	(0.0303)
Pilot x Treatment	-0.0625**	0.0330	0.0223	-0.0810***	0.0255	0.0131	-0.0326	0.0452	0.0374
	(0.0258)	(0.0228)	(0.0228)	(0.0299)	(0.0252)	(0.0252)	(0.0441)	(0.0403)	(0.0403)
February	1.243***	0.751***	0.853***	1.346***	0.828***	0.934***	1.075***	0.627***	0.722***
	(0.0709)	(0.0697)	(0.0692)	(0.0864)	(0.0775)	(0.0772)	(0.118)	(0.127)	(0.126)
March	2.134***	1.321***	1.430***	2.260***	1.498***	1.595***	1.928***	1.034***	1.160***
	(0.121)	(0.121)	(0.120)	(0.150)	(0.148)	(0.147)	(0.198)	(0.201)	(0.201)
April	1.159***	0.551***	0.683***	1.576***	1.148***	1.261***	0.479**	-0.421*	-0.259
	(0.126)	(0.152)	(0.147)	(0.150)	(0.179)	(0.173)	(0.211)	(0.255)	(0.249)
May	-1.226***	-4.039***	-3.681***	-0.916***	-3.686***	-3.335***	-1.735***	-4.620***	-4.251***
	(0.185)	(0.242)	(0.235)	(0.222)	(0.293)	(0.283)	(0.304)	(0.395)	(0.385)
October	-1.674***	-4.731***	-4.205***	-1.213***	-4.294***	-3.753***	-2.428***	-5.444***	-4.944***
	(0.151)	(0.188)	(0.181)	(0.185)	(0.228)	(0.219)	(0.244)	(0.314)	(0.303)
November	0.762***	0.818***	0.816***	0.958***	1.069***	1.058***	0.443***	0.407**	0.423**
	(0.0837)	(0.103)	(0.0999)	(0.0963)	(0.118)	(0.113)	(0.148)	(0.182)	(0.177)
December	0.678***	0.230***	0.328***	0.810***	0.389***	0.484***	0.464***	-0.0293	0.0759
	(0.0626)	(0.0760)	(0.0729)	(0.0755)	(0.0858)	(0.0827)	(0.104)	(0.138)	(0.132)
ln(THI)	-0.692***	-0.884***	-0.862***	-0.682***	-0.867***	-0.845***	-0.710***	-0.912***	-0.890***
	(0.0166)	(0.0209)	(0.0204)	(0.0201)	(0.0250)	(0.0245)	(0.0279)	(0.0360)	(0.0351)
February x ln(THI)	-0.371***	-0.224***	-0.251***	-0.401***	-0.246***	-0.275***	-0.322***	-0.187***	-0.213***
	(0.0200)	(0.0190)	(0.0190)	(0.0244)	(0.0212)	(0.0212)	(0.0331)	(0.0346)	(0.0344)
March x ln(THI)	-0.609***	-0.365***	-0.395***	-0.648***	-0.415***	-0.443***	-0.546***	-0.284***	-0.318***
	(0.0331)	(0.0319)	(0.0319)	(0.0410)	(0.0390)	(0.0390)	(0.0541)	(0.0534)	(0.0535)
April x ln(THI)	-0.370***	-0.184***	-0.219***	-0.487***	-0.344***	-0.375***	-0.179***	0.0761	0.0336
	(0.0341)	(0.0396)	(0.0385)	(0.0407)	(0.0468)	(0.0454)	(0.0566)	(0.0666)	(0.0651)
May x ln(THI)	0.216***	0.951***	0.861***	0.123**	0.850***	0.762***	0.369***	1.117***	1.024***
	(0.0473)	(0.0604)	(0.0588)	(0.0572)	(0.0731)	(0.0709)	(0.0771)	(0.0976)	(0.0954)
October x ln(THI)	0.337***	1.118***	0.988***	0.206***	0.998***	0.864***	0.551***	1.315***	1.192***
	(0.0393)	(0.0478)	(0.0462)	(0.0479)	(0.0577)	(0.0558)	(0.0642)	(0.0803)	(0.0777)
November x ln(THI)	-0.254***	-0.252***	-0.253***	-0.308***	-0.320***	-0.319***	-0.166***	-0.141***	-0.146***
	(0.0235)	(0.0279)	(0.0271)	(0.0273)	(0.0319)	(0.0309)	(0.0410)	(0.0488)	(0.0478)
December x ln(THI)	-0.204***	-0.0689***	-0.0967***	-0.240***	-0.111***	-0.138***	-0.146***	-5.85e-06	-0.0293
	(0.0174)	(0.0205)	(0.0198)	(0.0212)	(0.0234)	(0.0226)	(0.0288)	(0.0370)	(0.0355)
Constant	2.499***	3.226***	3.153***	2.588***	3.289***	3.218***	2.353***	3.123***	3.048***
	(0.0626)	(0.0800)	(0.0780)	(0.0766)	(0.0961)	(0.0937)	(0.105)	(0.138)	(0.134)
Observations	384,481	384,481	384,481	238,187	238,187	238,187	146,294	146,294	146,294
Number of Customers	1096	1096	1096	680	680	680	416	416	416
Adjusted R-squared	0.235	0.228	0.238	0.265	0.269	0.280	0.193	0.176	0.184
Customer FE	Y	Y	Y	Y	Y	Y	Y	Y	Y

Note: The unit of observation is a customer-day. Control customers were matched to treatment customers using a propensity score approach. As the dependent variable is expressed in natural logs, matched pairs in which one or both customers experienced negative load in one or more hours and net metering customers have been dropped from the analysis. Robust standard errors in parentheses. *** $p<0.01$, ** $p<0.05$, * $p<0.1$.

FIGURE 71: DPL NON-SUMMER WEEKEND REGRESSION RESULTS

	All Customers			LMI Customers			Non-LMI Customers		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
VARIABLES	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)	ln(avg peak load)	ln(avg off-peak load)	ln(avg daily load)
Pilot Period	-0.0414**	-0.0455***	-0.0450***	-0.0410**	-0.0554***	-0.0535***	-0.0420	-0.0294	-0.0311
	(0.0175)	(0.0166)	(0.0166)	(0.0191)	(0.0177)	(0.0176)	(0.0307)	(0.0293)	(0.0293)
Pilot x Treatment	-0.0164	0.0248	0.0202	-0.0261	0.0284	0.0217	-0.000640	0.0191	0.0178
	(0.0232)	(0.0217)	(0.0216)	(0.0262)	(0.0236)	(0.0235)	(0.0410)	(0.0395)	(0.0394)
February	0.800***	0.491***	0.529***	0.849***	0.395***	0.452***	0.720***	0.648***	0.655***
	(0.0601)	(0.0727)	(0.0696)	(0.0736)	(0.0852)	(0.0819)	(0.0981)	(0.128)	(0.122)
March	3.220***	3.463***	3.474***	3.356***	3.750***	3.722***	2.998***	2.994***	3.071***
	(0.132)	(0.201)	(0.187)	(0.158)	(0.232)	(0.215)	(0.222)	(0.362)	(0.337)
April	2.024***	0.506***	0.759***	2.566***	0.988***	1.259***	1.144***	-0.278	-0.0534
	(0.153)	(0.173)	(0.172)	(0.180)	(0.196)	(0.192)	(0.258)	(0.300)	(0.301)
May	-1.043***	-3.883***	-3.499***	-0.797***	-3.488***	-3.123***	-1.447***	-4.526***	-4.114***
	(0.175)	(0.192)	(0.188)	(0.217)	(0.236)	(0.231)	(0.281)	(0.309)	(0.304)
October	-1.673***	-3.557***	-3.355***	-1.394***	-3.053***	-2.852***	-2.128***	-4.380***	-4.178***
	(0.171)	(0.206)	(0.201)	(0.211)	(0.242)	(0.237)	(0.273)	(0.356)	(0.345)
November	1.203***	0.584***	0.639***	1.389***	0.847***	0.884***	0.899***	0.155	0.239
	(0.103)	(0.102)	(0.100)	(0.117)	(0.114)	(0.111)	(0.178)	(0.186)	(0.184)
December	1.183***	0.970***	1.000***	1.266***	1.092***	1.115***	1.048***	0.772***	0.813***
	(0.0725)	(0.0962)	(0.0921)	(0.0870)	(0.114)	(0.108)	(0.120)	(0.165)	(0.158)
ln(THI)	-0.553***	-0.770***	-0.746***	-0.548***	-0.765***	-0.741***	-0.561***	-0.778***	-0.755***
	(0.0129)	(0.0183)	(0.0176)	(0.0158)	(0.0224)	(0.0215)	(0.0217)	(0.0307)	(0.0298)
February x ln(THI)	-0.219***	-0.140***	-0.149***	-0.233***	-0.114***	-0.128***	-0.195***	-0.182***	-0.183***
	(0.0174)	(0.0200)	(0.0192)	(0.0216)	(0.0237)	(0.0229)	(0.0279)	(0.0347)	(0.0332)
March x ln(THI)	-0.899***	-0.927***	-0.934***	-0.940***	-1.004***	-1.001***	-0.834***	-0.800***	-0.824***
	(0.0366)	(0.0533)	(0.0498)	(0.0440)	(0.0615)	(0.0575)	(0.0616)	(0.0965)	(0.0902)
April x ln(THI)	-0.600***	-0.172***	-0.239***	-0.751***	-0.300***	-0.372***	-0.355***	0.0360	-0.0221
	(0.0408)	(0.0447)	(0.0446)	(0.0481)	(0.0504)	(0.0495)	(0.0685)	(0.0774)	(0.0780)
May x ln(THI)	0.181***	0.924***	0.827***	0.103*	0.813***	0.720***	0.309***	1.104***	1.001***
	(0.0456)	(0.0490)	(0.0482)	(0.0565)	(0.0603)	(0.0591)	(0.0725)	(0.0785)	(0.0775)
October x ln(THI)	0.331***	0.827***	0.776***	0.245***	0.690***	0.638***	0.470***	1.051***	1.000***
	(0.0439)	(0.0523)	(0.0511)	(0.0538)	(0.0612)	(0.0599)	(0.0709)	(0.0905)	(0.0879)
November x ln(THI)	-0.351***	-0.186***	-0.199***	-0.400***	-0.255***	-0.264***	-0.272***	-0.0731	-0.0942*
	(0.0285)	(0.0274)	(0.0270)	(0.0323)	(0.0305)	(0.0300)	(0.0493)	(0.0500)	(0.0496)
December x ln(THI)	-0.333***	-0.272***	-0.280***	-0.354***	-0.303***	-0.310***	-0.299***	-0.221***	-0.232***
	(0.0203)	(0.0261)	(0.0251)	(0.0244)	(0.0308)	(0.0295)	(0.0336)	(0.0447)	(0.0431)
Constant	1.928***	2.837***	2.751***	2.019***	2.930***	2.841***	1.781***	2.687***	2.602***
	(0.0478)	(0.0691)	(0.0665)	(0.0588)	(0.0850)	(0.0817)	(0.0797)	(0.116)	(0.112)
Observations	175,999	175,999	175,999	109,027	109,027	109,027	66,972	66,972	66,972
Number of Customers	1096	1096	1096	680	680	680	416	416	416
Adjusted R-squared	0.219	0.201	0.210	0.251	0.243	0.254	0.176	0.150	0.157
Customer FE	Y	Y	Y	Y	Y	Y	Y	Y	Y

Note: The unit of observation is a customer-day. Control customers were matched to treatment customers using a propensity score approach. As the dependent variable is expressed in natural logs, matched pairs in which one or both customers experienced negative load in one or more hours and net metering customers have been dropped from the analysis. Robust standard errors in parentheses. *** p<0.01, ** p<0.05, * p<0.1.

A.5 Estimated Impacts, Including Confidence Intervals

Here we present a comprehensive summary of impacts during the different pricing windows on weekdays and weekends. Presented within the tables are also the confidence interval, which provide an approximate estimate of the range of possible impacts.

FIGURE 72: BGE SUMMER IMPACT

	LMI Customers	Non-LMI Customers	All Customers
Weekday			
Peak Impact	-8.1%*** [-11.5%, -4.6%]	-12.4%*** [-15.5%, -9.1%]	-10.2%*** [-12.5%, -7.8%]
Off-Peak Impact	0.1% [-3.1%, 3.3%]	-1.4% [-4.2%, 1.5%]	-0.7% [-2.8%, 1.5%]
Overall Impact	-2.0% [-5.1%, 1.2%]	-3.7%*** [-6.4%, -0.9%]	-2.8%*** [-4.9%, -0.7%]
Weekend			
"Peak" Impact	-4.2%** [-7.8%, -0.6%]	-4.8%*** [-8.0%, -1.5%]	-4.5%*** [-6.9%, -2.1%]
"Off-Peak" Impact	0.0% [-3.2%, 3.4%]	-1.1% [-3.9%, 1.8%]	-0.5% [-2.7%, 1.7%]
Overall Impact	-1.0% [-4.2%, 2.4%]	-1.8% [-4.6%, 1.0%]	-1.4% [-3.6%, 0.8%]

FIGURE 73: BGE NON-SUMMER IMPACT

	LMI Customers	Non-LMI Customers	All Customers
Weekday			
Peak Impact	-5.3%*** [-8.9%, -1.5%]	-5.5%*** [-8.7%, -2.3%]	-5.4%*** [-7.8%, -2.9%]
Off-Peak Impact	-2.4% [-5.7%, 1.0%]	0.8% [-2.0%, 3.6%]	-0.8% [-3.0%, 1.4%]
Overall Impact	-2.7% [-5.9%, 0.7%]	0.0% [-2.7%, 2.8%]	-1.3% [-3.5%, 0.9%]
Weekend			
"Peak" Impact	-2.8% [-6.4%, 0.9%]	-1.6% [-4.5%, 1.5%]	-2.2%* [-4.5%, 0.2%]
"Off-Peak" Impact	-1.8% [-5.1%, 1.6%]	1.3% [-1.5%, 4.1%]	-0.3% [-2.4%, 1.9%]
Overall Impact	-1.9% [-5.2%, 1.6%]	0.9% [-1.8%, 3.7%]	-0.5% [-2.6%, 1.7%]

Note: The value on the top row of each cell provides the estimated impact. ***, **, and * denote significance at the 1%, 5%, and 10% level, respectively. The bracketed values on the second row of each cell provide the 95% confidence interval for the estimated impact.

FIGURE 74: PEPCO SUMMER IMPACT SUMMARY

	LMI Customers	Non-LMI Customers	All Customers
Weekday			
Peak Impact	-10.7%*** [-14.4%, -6.8%]	-17.3%*** [-20.5%, -13.9%]	-14.3%*** [-16.8%, -11.7%]
Off-Peak Impact	-1.2% [-4.4%, 2.1%]	-2.1% [-4.9%, 0.8%]	-1.7% [-3.9%, 0.6%]
Overall Impact	-3.3%** [-6.5%, 0.0%]	-5.2%*** [-7.8%, -2.4%]	-4.3%*** [-6.5%, -2.1%]
Weekend			
"Peak" Impact	-4.9%** [-8.6%, -1.1%]	-8.6%*** [-11.8%, -5.4%]	-6.9%*** [-9.5%, -4.4%]
"Off-Peak" Impact	-1.7% [-4.9%, 1.6%]	-3.0%** [-5.8%, -0.3%]	-2.4%** [-4.6%, -0.2%]
Overall Impact	-2.4% [-5.6%, 0.8%]	-4.3%*** [-7.0%, -1.5%]	-3.4%*** [-5.6%, -1.2%]

FIGURE 75: PEPCO NON-SUMMER IMPACT SUMMARY

	LMI Customers	Non-LMI Customers	All Customers
weekend			
Peak Impact	-4.8%** [-8.6%, -0.9%]	-5.3%*** [-8.7%, -1.8%]	-5.1%*** [-7.7%, -2.4%]
Off-Peak Impact	-1.7% [-4.8%, 1.5%]	0.9% [-2.2%, 4.1%]	-0.3% [-2.6%, 2.0%]
Overall Impact	-2.0% [-5.0%, 1.2%]	0.1% [-2.9%, 3.3%]	-0.8% [-3.1%, 1.4%]
Weekend			
"Peak" Impact	-0.9% [-4.4%, 2.8%]	-0.1% [-3.4%, 3.3%]	-0.5% [-2.9%, 2.1%]
"Off-Peak" Impact	-1.3% [-4.3%, 1.8%]	0.3% [-2.6%, 3.4%]	-0.4% [-2.6%, 1.8%]
Overall Impact	-1.2% [-4.2%, 1.9%]	0.3% [-2.6%, 3.3%]	-0.4% [-2.5%, 1.8%]

Note: The value on the top row of each cell provides the estimated impact. ***, **, and * denote significance at the 1%, 5%, and 10% level, respectively. The bracketed values on the second row of each cell provide the 95% confidence interval for the estimated impact.

FIGURE 76: DPL SUMMER IMPACT SUMMARY

	LMI Customers	Non-LMI Customers	All Customers
Weekday			
Peak Impact	-13.7%*** [-18.0%, -9.1%]	-16.7%*** [-22.6%, -10.4%]	-14.8%*** [-18.4%, -11.1%]
Off-Peak Impact	-1.8% [-5.7%, 2.4%]	-2.1% [-7.5%, 3.6%]	-1.9% [-5.2%, 1.5%]
Overall Impact	-4.6%** [-8.5%, -0.6%]	-5.4%* [-10.6%, 0.1%]	-4.9%*** [-8.1%, -1.6%]
Weekend			
"Peak" Impact	-7.0%*** [-11.6%, -2.1%]	-10.1%*** [-16.2%, -3.6%]	-8.2%*** [-12.0%, -4.2%]
"Off-Peak" Impact	-0.8% [-4.9%, 3.5%]	-3.2% [-8.8%, 2.8%]	-1.7% [-5.2%, 1.9%]
Overall Impact	-2.2% [-6.3%, 2.1%]	-4.7% [-10.2%, 1.1%]	-3.1%* [-6.6%, 0.4%]

FIGURE 77: DPL NON-SUMMER IMPACT SUMMARY

	LMI Customers	Non-LMI Customers	All Customers
Weekday			
Peak Impact	-7.8%*** [-13.0%, -2.2%]	-3.2% [-11.2%, 5.5%]	-6.1%** [-10.7%, -1.2%]
Off-Peak Impact	2.6% [-2.4%, 7.8%]	4.6% [-3.3%, 13.2%]	3.4% [-1.2%, 8.1%]
Overall Impact	1.3% [-3.6%, 6.5%]	3.8% [-4.1%, 12.3%]	2.3% [-2.2%, 6.9%]
Weekend			
"Peak" Impact	-2.6% [-7.4%, 2.6%]	-0.1% [-7.8%, 8.3%]	-1.6% [-6.0%, 2.9%]
"Off-Peak" Impact	2.9% [-1.8%, 7.8%]	1.9% [-5.7%, 10.1%]	2.5% [-1.8%, 7.0%]
Overall Impact	2.2% [-2.4%, 7.0%]	1.8% [-5.8%, 10.0%]	2.0% [-2.2%, 6.5%]

Note: The value on the top row of each cell provides the estimated impact. ***, **, and * denote significance at the 1%, 5%, and 10% level, respectively. The bracketed values on the second row of each cell provide the 95% confidence interval for the estimated impact.

A.6 Regression Tables – Elasticity Results

This section details regression results for the price response analyses presented in section IV. For each utility, we include tables for substitution elasticity and daily demand elasticity regressions for summer and non-summer weekdays.

FIGURE 78: SUMMER WEEKDAY SUBSTITUTION ELASTICITY – BGE

	All Customers	**LMI Customers**	**Non-LMI Customers**
	(1)	(2)	(3)
VARIABLES	ln(peak to off-peak load)	ln(peak to off-peak load)	ln(peak to off-peak load)
Pilot Period	0.0136***	0.0162**	0.0109
	(0.00496)	(0.00691)	(0.00712)
Peak to off-Peak Price Ratio	-0.0613***	-0.0482***	-0.0753***
	(0.00582)	(0.00773)	(0.00871)
July	0.0377***	0.0367***	0.0389***
	(0.00517)	(0.00723)	(0.00738)
August	-0.00780	-0.00138	-0.0144**
	(0.00520)	(0.00747)	(0.00722)
September	-0.0591***	-0.0490***	-0.0696***
	(0.00531)	(0.00766)	(0.00732)
Peak/Off-Peak THI Differential	0.0225***	0.0219***	0.0231***
	(0.000702)	(0.00101)	(0.000972)
July x THI_Diff	0.0114***	0.0112***	0.0116***
	(0.000911)	(0.00131)	(0.00126)
August x THI_Diff	0.0181***	0.0170***	0.0192***
	(0.000932)	(0.00135)	(0.00127)
September x THI_Diff	0.0133***	0.0126***	0.0141***
	(0.000872)	(0.00128)	(0.00117)
Constant	0.0519***	0.0390***	0.0658***
	(0.00488)	(0.00681)	(0.00700)
Observations	410,020	212,508	197,512
Number of Customers	2,520	1,316	1,204
Adjusted R-squared	0.041	0.036	0.048
Customer FE	Y	Y	Y

Note: Excludes net-metering customers and treatment-control pairs who have ever been on three-period rates other than PC44 TOU. Prices only include major components of the bill (supply, transmission, and distribution). Average daily price is weighted by pre-treatment monthly peak/off-peak share of usage. Robust standard errors in parentheses. *** p<0.01, ** p<0.05, * p<0.1.

FIGURE 79: NON-SUMMER WEEKDAY SUBSTITUTION ELASTICITY – BGE

	All Customers	LMI Customers	Non-LMI Customers
	(1)	(2)	(3)
VARIABLES	ln(peak to off-peak load)	ln(peak to off-peak load)	ln(peak to off-peak load)
Pilot Period	-0.0203***	-0.0249***	-0.0155*
	(0.00576)	(0.00823)	(0.00807)
Peak to off-Peak Price Ratio	-0.0269***	-0.0108	-0.0432***
	(0.00573)	(0.00790)	(0.00828)
February	0.00665**	0.0114***	0.00175
	(0.00304)	(0.00430)	(0.00428)
March	-0.0323***	-0.0247***	-0.0400***
	(0.00424)	(0.00600)	(0.00599)
April	-0.0700***	-0.0719***	-0.0680***
	(0.00486)	(0.00688)	(0.00686)
May	-0.175***	-0.165***	-0.185***
	(0.00602)	(0.00841)	(0.00863)
October	-0.0892***	-0.0839***	-0.0947***
	(0.00543)	(0.00739)	(0.00797)
November	-0.0174***	-0.0179***	-0.0169***
	(0.00335)	(0.00491)	(0.00456)
December	-0.0209***	-0.0150***	-0.0271***
	(0.00310)	(0.00445)	(0.00430)
Peak/Off-Peak THI Differential	-0.0169***	-0.0162***	-0.0176***
	(0.000445)	(0.000629)	(0.000628)
February x THI_Diff	-0.00166***	-0.00160**	-0.00171***
	(0.000465)	(0.000676)	(0.000639)
March x THI_Diff	-0.00378***	-0.00323***	-0.00434***
	(0.000641)	(0.000934)	(0.000877)
April x THI_Diff	-0.00372***	-0.00443***	-0.00299***
	(0.000605)	(0.000867)	(0.000845)
May x THI_Diff	0.0158***	0.0143***	0.0174***
	(0.000760)	(0.00109)	(0.00106)
October x THI_Diff	0.00506***	0.00516***	0.00494***
	(0.000646)	(0.000917)	(0.000910)
November x THI_Diff	-0.00323***	-0.00338***	-0.00306***
	(0.000527)	(0.000748)	(0.000743)
December x THI_Diff	0.00224***	0.00234***	0.00214**
	(0.000645)	(0.000896)	(0.000930)
Constant	-0.0273***	-0.0415***	-0.0129***
	(0.00286)	(0.00392)	(0.00416)
Observations	801,564	405,218	396,346
Number of Customers	2,294	1,164	1,130
Adjusted R-squared	0.038	0.032	0.045
Customer FE	Y	Y	Y

Note: Excludes net-metering customers and treatment-control pairs who have ever been on three-period rates other than PC44 TOU. Prices only include major components of the bill (supply, transmission, and distribution). Average daily price is weighted by pre-treatment monthly peak/off-peak share of usage. Robust standard errors in parentheses. *** p<0.01, ** p<0.05, * p<0.1.

FIGURE 80: SUMMER WEEKDAY DAILY DEMAND ELASTICITY – BGE

	All Customers	LMI Customers	Non-LMI Customers
	(1)	(2)	(3)
VARIABLES	ln(peak to off-peak load)	ln(peak to off-peak load)	ln(peak to off-peak load)
Pilot Period	0.00405	0.00476	0.00343
	(0.00633)	(0.00945)	(0.00833)
Average Daily Rate	-0.0471	-0.0168	-0.0763
	(0.0343)	(0.0483)	(0.0487)
July	-0.0170	-0.0677	0.0377
	(0.0506)	(0.0719)	(0.0711)
August	-0.637***	-0.592***	-0.684***
	(0.0443)	(0.0636)	(0.0614)
September	-0.289***	-0.315***	-0.262***
	(0.0343)	(0.0490)	(0.0479)
Daily THI	0.0495***	0.0491***	0.0500***
	(0.000620)	(0.000878)	(0.000872)
July x Daily THI	0.00107	0.00181*	0.000277
	(0.000684)	(0.000968)	(0.000964)
August x Daily THI	0.00907***	0.00855***	0.00962***
	(0.000605)	(0.000869)	(0.000838)
September x Daily THI	0.00347***	0.00386***	0.00304***
	(0.000477)	(0.000677)	(0.000673)
Constant	-3.749***	-3.740***	-3.750***
	(0.0894)	(0.125)	(0.127)
Observations	410,020	212,508	197,512
Number of Customers	2,520	1,316	1,204
Adjusted R-squared	0.254	0.243	0.266
Customer FE	Y	Y	Y

Note: Excludes net-metering customers and treatment-control pairs who have ever been on three-period rates other than PC44 TOU. Prices only include major components of the bill (supply, transmission, and distribution). Average daily price is weighted by pre-treatment monthly peak/off-peak share of usage. Robust standard errors in parentheses. *** p<0.01, ** p<0.05, * p<0.1.

FIGURE 81: NON-SUMMER WEEKDAY DAILY DEMAND ELASTICITY – BGE

	All Customers	LMI Customers	Non-LMI Customers
	(1)	(2)	(3)
VARIABLES	ln(peak to off-peak load)	ln(peak to off-peak load)	ln(peak to off-peak load)
Pilot Period	-0.0450***	-0.0377***	-0.0526***
	(0.00716)	(0.0106)	(0.00966)
Average Daily Rate	-0.312***	-0.235**	-0.395***
	(0.0694)	(0.0981)	(0.0975)
February	-0.104***	-0.0946***	-0.113***
	(0.0120)	(0.0173)	(0.0164)
March	-0.175***	-0.151***	-0.200***
	(0.0225)	(0.0342)	(0.0292)
April	-0.405***	-0.343***	-0.469***
	(0.0205)	(0.0304)	(0.0274)
May	-1.913***	-1.815***	-2.014***
	(0.0351)	(0.0502)	(0.0489)
October	-2.043***	-1.974***	-2.114***
	(0.0289)	(0.0413)	(0.0402)
November	-0.0745***	-0.0143	-0.136***
	(0.0151)	(0.0221)	(0.0203)
December	-0.167***	-0.136***	-0.198***
	(0.0122)	(0.0171)	(0.0174)
Daily THI	-0.0221***	-0.0210***	-0.0233***
	(0.000380)	(0.000534)	(0.000538)
February x Daily THI	0.00134***	0.00117***	0.00151***
	(0.000251)	(0.000361)	(0.000348)
March x Daily THI	0.00260***	0.00206***	0.00319***
	(0.000459)	(0.000703)	(0.000586)
April x Daily THI	0.00591***	0.00467***	0.00718***
	(0.000402)	(0.000598)	(0.000533)
May x Daily THI	0.0315***	0.0295***	0.0335***
	(0.000605)	(0.000873)	(0.000833)
October x Daily THI	0.0334***	0.0320***	0.0347***
	(0.000511)	(0.000735)	(0.000707)
November x Daily THI	-6.16e-05	-0.00125***	0.00116***
	(0.000317)	(0.000473)	(0.000418)
December x Daily THI	0.00387***	0.00317***	0.00458***
	(0.000260)	(0.000366)	(0.000367)
Constant	0.292*	0.328	0.246
	(0.155)	(0.218)	(0.218)
Observations	801,564	405,218	396,346
Number of Customers	2,294	1,164	1,130
Adjusted R-squared	0.176	0.163	0.191
Customer FE	Y	Y	Y

Note: Excludes net-metering customers and treatment-control pairs who have ever been on three-period rates other than PC44 TOU. Prices only include major components of the bill (supply, transmission, and distribution). Average daily price is weighted by pre-treatment monthly peak/off-peak share of usage. Robust standard errors in parentheses. *** p<0.01, ** p<0.05, * p<0.1.

FIGURE 82: SUMMER WEEKDAY SUBSTITUTION ELASTICITY – PEPCO

	All Customers	LMI Customers	Non-LMI Customers
	(1)	(2)	(3)
VARIABLES	ln(peak to off-peak load)	ln(peak to off-peak load)	ln(peak to off-peak load)
Pilot Period	0.0385***	0.0313***	0.0450***
	(0.00756)	(0.0100)	(0.0106)
Peak to off-Peak Price Ratio	-0.0822***	-0.0574***	-0.104***
	(0.00738)	(0.00956)	(0.0108)
July	-0.0368***	-0.0351***	-0.0380***
	(0.00636)	(0.00915)	(0.00857)
August	-0.0314***	-0.0315***	-0.0310***
	(0.00605)	(0.00807)	(0.00861)
September	-0.0548***	-0.0550***	-0.0543***
	(0.00644)	(0.00856)	(0.00916)
Peak/Off-Peak THI Differential	0.0126***	0.0117***	0.0134***
	(0.000869)	(0.00124)	(0.00117)
July x THI_Diff	0.0260***	0.0250***	0.0268***
	(0.00147)	(0.00202)	(0.00206)
August x THI_Diff	0.0260***	0.0244***	0.0274***
	(0.00125)	(0.00170)	(0.00174)
September x THI_Diff	0.0120***	0.0124***	0.0116***
	(0.00108)	(0.00152)	(0.00149)
Constant	-0.00849	-0.00169	-0.0148*
	(0.00554)	(0.00759)	(0.00771)
Observations	326,006	154,434	171,572
Number of Customers	2048	966	1082
R-squared	0.023	0.019	0.027
Customer FE	Y	Y	Y

Note: Excludes net-metering customers and treatment-control pairs who have ever been on three-period rates other than PC44 TOU. Prices only include major components of the bill (supply, transmission, and distribution). Average daily price is weighted by pre-treatment monthly peak/off-peak share of usage. Robust standard errors in parentheses. *** p<0.01, ** p<0.05, * p<0.1.

FIGURE 83: NON-SUMMER WEEKDAY SUBSTITUTION ELASTICITY – PEPCO

	All Customers	LMI Customers	Non-LMI Customers
	(1)	(2)	(3)
VARIABLES	ln(peak to off-peak load)	ln(peak to off-peak load)	ln(peak to off-peak load)
Pilot Period	-0.0180**	-0.0190*	-0.0173*
	(0.00733)	(0.0105)	(0.00984)
Peak to off-Peak Price Ratio	-0.0279***	-0.0175*	-0.0368***
	(0.00691)	(0.0103)	(0.00914)
February	0.00790**	0.00640	0.00917*
	(0.00389)	(0.00550)	(0.00541)
March	-0.0555***	-0.0506***	-0.0599***
	(0.00553)	(0.00797)	(0.00740)
April	-0.0744***	-0.0811***	-0.0685***
	(0.00625)	(0.00881)	(0.00857)
May	-0.166***	-0.144***	-0.186***
	(0.00808)	(0.0115)	(0.0108)
October	-0.0561***	-0.0425***	-0.0682***
	(0.00702)	(0.00998)	(0.00966)
November	0.0106**	0.0154**	0.00631
	(0.00443)	(0.00602)	(0.00626)
December	-0.00316	0.00340	-0.00892*
	(0.00413)	(0.00610)	(0.00539)
Peak/Off-Peak THI Differential	-0.0147***	-0.0154***	-0.0141***
	(0.000455)	(0.000651)	(0.000611)
February x THI_Diff	-1.32e-05	0.000198	-0.000204
	(0.000506)	(0.000746)	(0.000670)
March x THI_Diff	-0.00574***	-0.00411***	-0.00718***
	(0.000680)	(0.00100)	(0.000877)
April x THI_Diff	-0.000655	-0.000657	-0.000658
	(0.000558)	(0.000832)	(0.000728)
May x THI_Diff	0.00784***	0.00881***	0.00699***
	(0.000807)	(0.00115)	(0.00109)
October x THI_Diff	0.00105	0.00204*	0.000168
	(0.000749)	(0.00111)	(0.000972)
November x THI_Diff	-0.00223***	-0.00178**	-0.00262***
	(0.000582)	(0.000867)	(0.000761)
December x THI_Diff	0.00101	0.00141	0.000665
	(0.000643)	(0.000961)	(0.000840)
Constant	-0.117***	-0.129***	-0.105***
	(0.00394)	(0.00549)	(0.00551)
Observations	678,083	316,662	361,421
Number of Customers	1934	908	1026
Adjusted R-squared	0.031	0.027	0.036
Customer FE	Y	Y	Y

Note: Excludes net-metering customers and treatment-control pairs who have ever been on three-period rates other than PC44 TOU. Prices only include major components of the bill (supply, transmission, and distribution). Average daily price is weighted by pre-treatment monthly peak/off-peak share of usage. Robust standard errors in parentheses. *** p<0.01, ** p<0.05, * p<0.1.

FIGURE 84: SUMMER WEEKDAY DAILY DEMAND ELASTICITY – PEPCO

	All Customers	**LMI Customers**	**Non-LMI Customers**
	(1)	(2)	(3)
VARIABLES	ln(avg daily load)	ln(avg daily load)	ln(avg daily load)
Pilot Period	0.0112*	0.0163*	0.00715
	(0.00682)	(0.00971)	(0.00858)
Average Daily Rate	-0.0455	-0.0999	-0.00791
_month	(0.0493)	(0.0811)	(0.0610)
July	-0.0264	-0.0200	-0.0282
	(0.0612)	(0.0871)	(0.0816)
August	-0.605***	-0.564***	-0.638***
	(0.0551)	(0.0799)	(0.0720)
September	0.0422	0.130**	-0.0316
	(0.0390)	(0.0566)	(0.0517)
Daily THI	0.0499***	0.0484***	0.0513***
	(0.000764)	(0.00109)	(0.00102)
July x Daily THI	0.000657	0.000606	0.000650
	(0.000812)	(0.00115)	(0.00108)
August x Daily THI	0.00769***	0.00718***	0.00808***
	(0.000745)	(0.00107)	(0.000981)
September x Daily THI	-0.00158***	-0.00280***	-0.000555
	(0.000546)	(0.000789)	(0.000728)
Constant	-3.925***	-3.985***	-3.898***
	(0.113)	(0.179)	(0.144)
Observations	326,006	154,434	171,572
Number of Customers	2048	966	1082
R-squared	0.251	0.240	0.261
Customer FE	Y	Y	Y

Note: Excludes net-metering customers and treatment-control pairs who have ever been on three-period rates other than PC44 TOU. Prices only include major components of the bill (supply, transmission, and distribution). Average daily price is weighted by pre-treatment monthly peak/off-peak share of usage. Robust standard errors in parentheses. *** p<0.01, ** p<0.05, * p<0.1.

FIGURE 85: NON-SUMMER WEEKDAY DAILY DEMAND ELASTICITY – PEPCO

	All Customers	LMI Customers	Non-LMI Customers
	(1)	(2)	(3)
VARIABLES	ln(avg daily load)	ln(avg daily load)	ln(avg daily load)
Pilot Period	-0.00675	0.00407	-0.0175
	(0.00942)	(0.0143)	(0.0116)
Average Daily Rate	-0.234***	-0.377***	-0.0984
_month	(0.0762)	(0.131)	(0.0802)
February	-0.0541***	-0.0287*	-0.0764***
	(0.0111)	(0.0166)	(0.0143)
March	-0.105***	-0.0663***	-0.139***
	(0.0166)	(0.0243)	(0.0218)
April	-0.301***	-0.268***	-0.330***
	(0.0204)	(0.0297)	(0.0268)
May	-1.739***	-1.673***	-1.794***
	(0.0380)	(0.0557)	(0.0500)
October	-1.753***	-1.725***	-1.778***
	(0.0302)	(0.0437)	(0.0401)
November	-0.0718***	-0.0619***	-0.0803***
	(0.0137)	(0.0190)	(0.0191)
December	-0.0779***	-0.0730***	-0.0815***
	(0.0123)	(0.0172)	(0.0169)
Daily THI	-0.0191***	-0.0198***	-0.0185***
	(0.000358)	(0.000519)	(0.000476)
February x Daily THI	0.000476**	8.65e-05	0.000814**
	(0.000242)	(0.000362)	(0.000318)
March x Daily THI	0.00180***	0.00106**	0.00244***
	(0.000347)	(0.000519)	(0.000452)
April x Daily THI	0.00527***	0.00455***	0.00587***
	(0.000399)	(0.000592)	(0.000519)
May x Daily THI	0.0298***	0.0284***	0.0310***
	(0.000644)	(0.000955)	(0.000838)
October x Daily THI	0.0295***	0.0287***	0.0301***
	(0.000540)	(0.000791)	(0.000707)
November x Daily THI	0.000691**	0.000430	0.000920**
	(0.000287)	(0.000400)	(0.000400)
December x Daily THI	0.00191***	0.00178***	0.00201***
	(0.000277)	(0.000386)	(0.000386)
Constant	0.123	-0.173	0.402**
	(0.168)	(0.288)	(0.178)
Observations	678,083	316,662	361,421
Number of Customers	1934	908	1026
R-squared	0.163	0.184	0.147
Customer FE	Y	Y	Y

Note: Excludes net-metering customers and treatment-control pairs who have ever been on three-period rates other than PC44 TOU. Prices only include major components of the bill (supply, transmission, and distribution). Average daily price is weighted by pre-treatment monthly peak/off-peak share of usage. Robust standard errors in parentheses. *** p<0.01, ** p<0.05, * p<0.1.

FIGURE 86: SUMMER WEEKDAY SUBSTITUTION ELASTICITY – DPL

	All Customers	LMI Customers	Non-LMI Customers
	(1)	(2)	(3)
VARIABLES	ln(peak to off-peak load)	ln(peak to off-peak load)	ln(peak to off-peak load)
Pilot Period	0.0166**	0.0124	0.0237**
	(0.00748)	(0.00884)	(0.0117)
Peak to off-Peak Price Ratio	-0.0759***	-0.0692***	-0.0869***
	(0.00787)	(0.00930)	(0.0136)
July	-0.0531***	-0.0634***	-0.0359***
	(0.00848)	(0.0105)	(0.0134)
August	-0.0352***	-0.0417***	-0.0244*
	(0.00851)	(0.0104)	(0.0138)
September	-0.0889***	-0.0957***	-0.0776***
	(0.00888)	(0.0109)	(0.0144)
Peak/Off-Peak THI Differential	0.000174	-0.000151	0.000714
	(0.00128)	(0.00157)	(0.00203)
July x THI_Diff	0.0301***	0.0316***	0.0277***
	(0.00175)	(0.00217)	(0.00272)
August x THI_Diff	0.0270***	0.0277***	0.0260***
	(0.00171)	(0.00211)	(0.00270)
September x THI_Diff	0.0163***	0.0173***	0.0146***
	(0.00154)	(0.00191)	(0.00245)
Constant	0.193***	0.225***	0.140***
	(0.00762)	(0.00901)	(0.0130)
Observations	191,325	119,363	71,962
Number of Customers	1184	740	444
Adjusted R-squared	0.028	0.028	0.028
Customer FE	Y	Y	Y

Note: Excludes net-metering customers and treatment-control pairs who have ever been on three-period rates other than PC44 TOU. Prices only include major components of the bill (supply, transmission, and distribution). Average daily price is weighted by pre-treatment monthly peak/off-peak share of usage. Robust standard errors in parentheses. *** p<0.01, ** p<0.05, * p<0.1.

FIGURE 87: NON-SUMMER WEEKDAY SUBSTITUTION ELASTICITY – DPL

	All Customers	LMI Customers	Non-LMI Customers
	(1)	(2)	(3)
VARIABLES	ln(peak to off-peak load)	ln(peak to off-peak load)	ln(peak to off-peak load)
Pilot Period	-0.00433	0.00200	-0.0145
	(0.00720)	(0.00902)	(0.00991)
Peak to off-Peak Price Ratio	-0.0518***	-0.0578***	-0.0422***
	(0.00737)	(0.00935)	(0.0114)
February	-0.0139***	-0.0125**	-0.0161**
	(0.00449)	(0.00565)	(0.00720)
March	-0.0224***	-0.0344***	-0.00286
	(0.00594)	(0.00751)	(0.00915)
April	-0.0361***	-0.0442***	-0.0229**
	(0.00710)	(0.00910)	(0.0106)
May	-0.163***	-0.175***	-0.143***
	(0.00894)	(0.0114)	(0.0138)
October	-0.0910***	-0.102***	-0.0732***
	(0.00860)	(0.0108)	(0.0133)
November	-0.0123**	-0.0152**	-0.00770
	(0.00562)	(0.00718)	(0.00841)
December	-0.00250	-0.00311	-0.00151
	(0.00485)	(0.00605)	(0.00769)
Peak/Off-Peak THI Differential	-0.0205***	-0.0211***	-0.0195***
	(0.000579)	(0.000722)	(0.000934)
February x THI_Diff	0.000501	0.000641	0.000274
	(0.000646)	(0.000773)	(0.00110)
March x THI_Diff	0.000937	-0.000537	0.00334***
	(0.000794)	(0.000983)	(0.00127)
April x THI_Diff	0.00371***	0.00245**	0.00577***
	(0.000821)	(0.000990)	(0.00135)
May x THI_Diff	0.00829***	0.00727***	0.00994***
	(0.000949)	(0.00119)	(0.00152)
October x THI_Diff	0.00734***	0.00655***	0.00864***
	(0.000946)	(0.00116)	(0.00155)
November x THI_Diff	0.00274***	0.00144	0.00488***
	(0.000757)	(0.000920)	(0.00126)
December x THI_Diff	0.00324***	0.00283***	0.00391***
	(0.000709)	(0.000902)	(0.00106)
Constant	-0.0246***	-0.0266***	-0.0215***
	(0.00409)	(0.00531)	(0.00604)
Observations	384,481	238,187	146,294
Number of Customers	1096	680	416
Adjusted R-squared	0.044	0.047	0.038
Customer FE	Y	Y	Y

Note: Excludes net-metering customers and treatment-control pairs who have ever been on three-period rates other than PC44 TOU. Prices only include major components of the bill (supply, transmission, and distribution). Average daily price is weighted by pre-treatment monthly peak/off-peak share of usage. Robust standard errors in parentheses. *** $p<0.01$, ** $p<0.05$, * $p<0.1$.

FIGURE 88: SUMMER WEEKDAY DAILY DEMAND ELASTICITY – DPL

	All Customers	LMI Customers	Non-LMI Customers
	(1)	(2)	(3)
VARIABLES	ln(avg daily load)	ln(avg daily load)	ln(avg daily load)
Pilot Period	-0.00166	-0.00926	0.0102
	(0.0108)	(0.0129)	(0.0177)
Average Daily Rate	-0.0921**	-0.0986**	-0.0749
_month	(0.0429)	(0.0488)	(0.0801)
July	-0.476***	-0.479***	-0.471***
	(0.0830)	(0.0947)	(0.151)
August	-0.271***	-0.366***	-0.114
	(0.0715)	(0.0839)	(0.127)
September	-0.0109	-0.0720	0.0886
	(0.0548)	(0.0681)	(0.0873)
Daily THI	0.0395***	0.0401***	0.0386***
	(0.000851)	(0.00104)	(0.00141)
July x Daily THI	0.00797***	0.00791***	0.00807***
	(0.00113)	(0.00130)	(0.00205)
August x Daily THI	0.00503***	0.00607***	0.00332*
	(0.000974)	(0.00113)	(0.00174)
September x Daily THI	-0.000337	0.000463	-0.00164
	(0.000787)	(0.000976)	(0.00126)
Constant	-3.271***	-3.265***	-3.269***
	(0.107)	(0.123)	(0.193)
Observations	191,325	119,363	71,962
Number of Customers	1184	740	444
R-squared	0.195	0.216	0.168
Customer FE	Y	Y	Y

Note: Excludes net-metering customers and treatment-control pairs who have ever been on three-period rates other than PC44 TOU. Prices only include major components of the bill (supply, transmission, and distribution). Average daily price is weighted by pre-treatment monthly peak/off-peak share of usage. Robust standard errors in parentheses. *** p<0.01, ** p<0.05, * p<0.1.

FIGURE 89: NON-SUMMER WEEKDAY DAILY DEMAND ELASTICITY – DPL

	All Customers	LMI Customers	Non-LMI Customers
	(1)	(2)	(3)
VARIABLES	ln(avg daily load)	ln(avg daily load)	ln(avg daily load)
Pilot Period	-0.0420***	-0.0506***	-0.0290
	(0.0109)	(0.0122)	(0.0189)
Average Daily Rate	-0.241***	-0.102	-0.484***
_month	(0.0891)	(0.100)	(0.168)
February	-0.151***	-0.126***	-0.191***
	(0.0195)	(0.0216)	(0.0360)
March	-0.0998***	-0.0542	-0.176***
	(0.0325)	(0.0398)	(0.0544)
April	-0.495***	-0.362***	-0.712***
	(0.0412)	(0.0479)	(0.0713)
May	-1.728***	-1.674***	-1.818***
	(0.0608)	(0.0727)	(0.103)
October	-1.892***	-1.820***	-2.008***
	(0.0498)	(0.0614)	(0.0827)
November	-0.248***	-0.180***	-0.359***
	(0.0310)	(0.0351)	(0.0557)
December	-0.208***	-0.157***	-0.290***
	(0.0229)	(0.0253)	(0.0428)
Daily THI	-0.0299***	-0.0294***	-0.0306***
	(0.000709)	(0.000856)	(0.00121)
February x Daily THI	0.00256***	0.00184***	0.00373***
	(0.000474)	(0.000520)	(0.000872)
March x Daily THI	0.00218***	0.000863	0.00435***
	(0.000733)	(0.000893)	(0.00123)
April x Daily THI	0.00880***	0.00557***	0.0140***
	(0.000885)	(0.00104)	(0.00151)
May x Daily THI	0.0303***	0.0284***	0.0334***
	(0.00113)	(0.00136)	(0.00185)
October x Daily THI	0.0331***	0.0309***	0.0366***
	(0.000982)	(0.00119)	(0.00166)
November x Daily THI	0.00388***	0.00219***	0.00663***
	(0.000724)	(0.000825)	(0.00128)
December x Daily THI	0.00499***	0.00378***	0.00692***
	(0.000532)	(0.000597)	(0.000976)
Constant	0.684***	1.070***	0.0189
	(0.181)	(0.202)	(0.346)
Observations	384,481	238,187	146,294
Number of Customers	1096	680	416
R-squared	0.240	0.282	0.186
Customer FE	Y	Y	Y

Note: Excludes net-metering customers and treatment-control pairs who have ever been on three-period rates other than PC44 TOU. Prices only include major components of the bill (supply, transmission, and distribution). Average daily price is weighted by pre-treatment monthly peak/off-peak share of usage. Robust standard errors in parentheses. *** p<0.01, ** p<0.05, * p<0.1.

A.7 Sensitivity Analyses

This section provides results for alternate regression approaches that test the robustness of our primary results. The date fixed effects approach replaces the various controls we include in the primary specification with a dummy variable for each date in the relevant regression. The level regression approach uses the absolute level of peak, off-peak, and daily load as the dependent variable instead of the natural logarithm. This allows us to include net metering customers in the regression. “Full-time enrollees” refers to regressions that include only those customers who were enrolled for the entirety of the season. The “naïve” control group regressions consider the entire pool of eligible control customers instead of restricting to only those matched to pilot customers. In the tables for the non-summer season, we also present the impacts for pre-COVID months and the incremental impact observed during COVID months.

FIGURE 90: BGE SUMMER WEEKDAY SENSITIVITY RESULTS

	Primary Results	Date-Fixed Effects	Level Regression	Full-time enrollees	Naive Control Group
LMI Customers					
On-Peak	-8.1%***	-8.1%***	-9.4%***	-8.2%***	-7.4%***
Off-Peak	0.1%	0.1%	-1.5%	-0.1%	0.4%
Daily	-2.0%	-2.0%	-3.6%***	-2.1%	-1.5%
Non-LMI Customers					
On-Peak	-12.4%***	-12.4%***	-10.7%***	-12.5%***	-10.0%***
Off-Peak	-1.4%	-1.4%	-2.3%**	-1.4%	1.4%
Daily	-3.7%***	-3.7%***	-4.6%***	-3.8%***	-1.2%
All Customers					
On-Peak	-10.2%***	-10.2%***	-10.2%***	-10.4%***	-8.6%***
Off-Peak	-0.7%	-0.7%	-2.0%**	-0.8%	1.0%
Daily	-2.8%***	-2.9%***	-4.2%***	-2.9%***	-1.3%

Note: ***, **, and * denote significance at the 1%, 5%, and 10% level, respectively. In the “Level Regression,” the set of customers included in the estimation is larger than in the other sets of results, as net metering customers are not excluded.

OFFICIAL COPY

Oct 04 2023

FIGURE 91: BGE SUMMER WEEKEND SENSITIVITY RESULTS

	Primary Results	Date-Fixed Effects	Level Regression	Full-time enrollees	Naive Control Group
LMI Customers					
On-Peak	-4.2%**	-4.2%**	-7.7%***	-4.3%**	-3.9%**
Off-Peak	0.0%	0.0%	-3.1%**	-0.1%	0.8%
Daily	-1.0%	-1.0%	-4.3%***	-1.1%	-0.2%
Non-LMI Customers					
On-Peak	-4.8%***	-4.8%***	-4.7%***	-4.8%***	-3.0%*
Off-Peak	-1.1%	-1.1%	-1.9%*	-1.3%	0.8%
Daily	-1.8%	-1.8%	-2.7%**	-2.0%	-0.1%
All Customers					
On-Peak	-4.5%***	-4.5%***	-5.9%***	-4.5%***	-3.4%***
Off-Peak	-0.5%	-0.5%	-2.4%***	-0.7%	0.7%
Daily	-1.4%	-1.4%	-3.4%***	-1.5%	-0.3%

Note: ***, **, and * denote significance at the 1%, 5%, and 10% level, respectively. In the "Level Regression," the set of customers included in the estimation is larger than in the other sets of results, as net metering customers are not excluded.

FIGURE 92: BGE NON-SUMMER WEEKDAY SENSITIVITY RESULTS

	Primary Results	Date-Fixed Effects	Level Regression	Full-time enrollees	Non-COVID months	COVID differential coef.	Naive Control Group
LMI Customers							
On-Peak	-5.3%***	-5.3%***	-4.7%**	-5.3%***	-4.2%**	-3.2%*	-5.1%***
Off-Peak	-2.4%	-2.4%	-2.6%	-2.4%	-1.9%	-1.6%	-0.7%
Daily	-2.7%	-2.7%	-2.9%*	-2.7%	-2.1%	-1.8%	-1.2%
Non-LMI Customers							
On-Peak	-5.5%***	-5.5%***	-7.5%***	-5.3%***	-5.7%***	0.6%	-7.4%***
Off-Peak	0.8%	0.8%	-2.2%	1.4%	-0.2%	2.6%*	-1.3%
Daily	0.0%	0.0%	-2.9%**	0.5%	-0.8%	2.2%	-2.0%
All Customers							
On-Peak	-5.4%***	-5.4%***	-6.4%***	-5.3%***	-5.0%***	-1.3%	-6.3%***
Off-Peak	-0.8%	-0.8%	-2.4%**	-0.5%	-1.0%	0.5%	-1.2%
Daily	-1.3%	-1.3%	-2.9%***	-1.1%	-1.4%	0.2%	-1.8%*

Note: ***, **, and * denote significance at the 1%, 5%, and 10% level, respectively. In the "Level Regression," the set of customers included in the estimation is larger than in the other sets of results, as net metering customers are not excluded. "Full-time Enrollees" include only those customers enrolled for the entirety of the non-summer season. The COVID differential effect presents the incremental impact over that observed during the non-COVID months. The "*" indicates an impact that is statistically different from the non-COVID months.

FIGURE 93: BGE NON-SUMMER WEEKEND SENSITIVITY RESULTS

	Primary Results	Date-Fixed Effects	Level Regression	Full-time enrollees	Non-COVID months	COVID differential coef.	Naive Control Group
LMI Customers							
On-Peak	-2.8%	-2.8%	-3.4%*	-2.7%	-2.1%	-1.9%	-1.3%
Off-Peak	-1.8%	-1.8%	-2.2%	-1.8%	-1.2%	-1.7%	-1.0%
Daily	-1.9%	-1.9%	-2.3%	-1.9%	-1.3%	-1.7%	-1.0%
Non-LMI Customers							
On-Peak	-1.6%	-1.5%	-5.2%***	-1.3%	-1.9%	1.0%	-4.3%***
Off-Peak	1.3%	1.3%	-2.0%	1.8%	0.0%	3.3%**	-0.7%
Daily	0.9%	0.9%	-2.4%*	1.4%	-0.2%	3.1%*	-1.2%
All Customers							
On-Peak	-2.2%*	-2.2%*	-4.5%***	-2.0%	-2.0%*	-0.5%	-3.1%***
Off-Peak	-0.3%	-0.3%	-2.1%**	0.0%	-0.6%	0.8%	-1.0%
Daily	-0.5%	-0.5%	-2.4%**	-0.2%	-0.7%	0.7%	-1.3%

Note: ***, **, and * denote significance at the 1%, 5%, and 10% level, respectively. In the "Level Regression," the set of customers included in the estimation is larger than in the other sets of results, as net metering customers are not excluded. "Full-time Enrollees" include only those customers enrolled for the entirety of the non-summer season. The COVID differential effect presents the incremental impact over that observed during the non-COVID months. The "*" indicates an impact that is statistically different from the non-COVID months.

FIGURE 94: PEPCO SUMMER WEEKDAY SENSITIVITY RESULTS

	Primary Result	Date Fixed Effects	Level Regression	Full-time Enrollees	Naïve Control Group
LMI Customers					
On-Peak	-10.7%***	-10.7%***	-9.4%***	-11.7%***	-10.4%***
Off-Peak	-1.2%	-1.2%	-1.5%	-2.2%	-1.4%
Daily	-3.3%**	-3.3%**	-3.5%**	-4.3%**	-3.5%***
Non-LMI Customers					
On-Peak	-17.3%***	-17.3%***	-16.0%***	-17.7%***	-15.0%***
Off-Peak	-2.1%	-2.1%	-1.6%	-2.7%	-1.4%
Daily	-5.2%***	-5.2%***	-5.2%***	-5.8%***	-4.2%***
All Customers					
On-Peak	-14.3%***	-14.3%***	-13.2%***	-14.8%***	-12.8%***
Off-Peak	-1.7%	-1.7%	-1.6%	-2.5%*	-1.3%*
Daily	-4.3%***	-4.3%***	-4.5%***	-5.1%***	-3.8%***

Note: ***, **, and * denote significance at the 1%, 5%, and 10% level, respectively. In the "Level Regression," the set of customers included in the estimation is larger than in the other sets of results, as net metering customers are not excluded. "Full-time Enrollees" include only those customers enrolled for the entirety of the summer season.

FIGURE 95: PEPCO SUMMER WEEKEND SENSITIVITY RESULTS

	Primary Result	Date Fixed Effects	Level Regression	Full-time Enrollees	Naïve Control Group
LMI Customers					
On-Peak	-4.9%**	-4.9%**	-5.6%***	-5.6%**	-7.4%***
Off-Peak	-1.7%	-1.7%	-2.3%	-2.3%	-3.6%***
Daily	-2.4%	-2.4%	-3.2%**	-3.1%	-4.6%***
Non-LMI Customers					
On-Peak	-8.6%***	-8.6%***	-6.5%***	-10.8%***	-9.9%***
Off-Peak	-3.0%**	-3.0%**	-2.2%	-4.8%***	-3.4%***
Daily	-4.3%***	-4.3%***	-3.4%**	-6.1%***	-5.1%***
All Customers					
On-Peak	-6.9%***	-6.9%***	-6.1%***	-8.3%***	-8.8%***
Off-Peak	-2.4%**	-2.4%**	-2.2%**	-3.5%***	-3.5%***
Daily	-3.4%***	-3.4%***	-3.3%***	-4.6%***	-4.9%***

Note: ***, **, and * denote significance at the 1%, 5%, and 10% level, respectively. In the “Level Regression,” the set of customers included in the estimation is larger than in the other sets of results, as net metering customers are not excluded. “Full-time Enrollees” include only those customers enrolled for the entirety of the summer season.

FIGURE 96: PEPCO NON-SUMMER WEEKDAY SENSITIVITY RESULTS

	Primary Result	Date Fixed Effects	Level Regression	Full-time Enrollees	Non-COVID Months	COVID (Differential Coefficient)	Naïve Control Group
LMI Customers							
On-Peak	-4.8%**	-4.8%**	-5.1%**	-4.9%**	-3.8%*	-2.6%	-4.3%***
Off-Peak	-1.7%	-1.7%	-3.2%*	-1.7%	-0.1%	-4.3%**	-1.9%
Daily	-2.0%	-2.0%	-3.5%*	-2.0%	-0.4%	-4.1%**	-2.1%*
Non-LMI Customers							
On-Peak	-5.3%***	-5.3%***	-5.5%**	-5.5%***	-7.0%***	4.7%**	-3.2%**
Off-Peak	0.9%	0.9%	-0.4%	0.7%	0.2%	1.7%	1.4%
Daily	0.1%	0.1%	-1.1%	-0.1%	-0.6%	1.9%	0.8%
All Customers							
On-Peak	-5.1%***	-5.1%***	-5.3%***	-5.2%***	-5.6%***	1.4%	-3.6%***
Off-Peak	-0.3%	-0.3%	-1.7%	-0.4%	0.1%	-1.0%	-0.1%
Daily	-0.8%	-0.8%	-2.2%	-1.0%	-0.5%	-0.8%	-0.5%

Note: ***, **, and * denote significance at the 1%, 5%, and 10% level, respectively. In the “Level Regression,” the set of customers included in the estimation is larger than in the other sets of results, as net metering customers are not excluded. “Full-time Enrollees” include only those customers enrolled for the entirety of the non-summer season. The COVID differential effect presents the incremental impact over that observed during the non-COVID months. The “*” indicates an impact that is statistically different from the non-COVID months.

FIGURE 97: PEPCO NON-SUMMER WEEKEND SENSITIVITY RESULTS

	Primary Result	Date Fixed Effects	Level Regression	Full-time Enrollees	Non-COVID Months	COVID (Differential Coefficient)	Naïve Control Group
LMI Customers							
On-Peak	-0.9%	-0.9%	-2.6%	-1.1%	-0.1%	-2.3%	-1.9%
Off-Peak	-1.3%	-1.3%	-2.8%	-1.4%	0.1%	-4.0%**	-1.8%
Daily	-1.2%	-1.2%	-2.7%	-1.4%	0.1%	-3.8%**	-1.8%
Non-LMI Customers							
On-Peak	-0.1%	-0.1%	-0.9%	-0.3%	-1.0%	2.6%	-0.8%
Off-Peak	0.3%	0.3%	-0.4%	0.2%	0.1%	0.8%	0.4%
Daily	0.3%	0.3%	-0.5%	0.2%	0.0%	0.8%	0.3%
All Customers							
On-Peak	-0.5%	-0.4%	-1.6%	-0.7%	-0.6%	0.4%	-1.2%
Off-Peak	-0.4%	-0.4%	-1.5%	-0.5%	0.1%	-1.4%	-0.6%
Daily	-0.4%	-0.4%	-1.5%	-0.5%	0.1%	-1.3%	-0.6%

Note: ***, **, and * denote significance at the 1%, 5%, and 10% level, respectively. In the “Level Regression,” the set of customers included in the estimation is larger than in the other sets of results, as net metering customers are not excluded. “Full-time Enrollees” include only those customers enrolled for the entirety of the non-summer season. The COVID differential effect presents the incremental impact over that observed during the non-COVID months. The “*” indicates an impact that is statistically different from the non-COVID months.

FIGURE 98: DPL SUMMER WEEKDAY SENSITIVITY RESULTS

	Primary Result	Date Fixed Effects	Level Regression	Full-time Enrollees	Naïve Control Group
LMI Customers					
On-Peak	-13.7%***	-13.7%***	-13.7%***	-13.5%***	-15.1%***
Off-Peak	-1.8%	-1.8%	-0.4%	-1.8%	-3.4%**
Daily	-4.6%**	-4.6%**	-4.1%**	-4.6%**	-6.1%***
Non-LMI Customers					
On-Peak	-16.7%***	-16.7%***	-15.7%***	-17.5%***	-15.3%***
Off-Peak	-2.1%	-2.1%	-0.9%	-2.9%	-0.9%
Daily	-5.4%*	-5.4%*	-4.9%**	-6.1%**	-4.3%**
All Customers					
On-Peak	-14.8%***	-14.8%***	-14.5%***	-15.0%***	-15.0%***
Off-Peak	-1.9%	-1.9%	-0.6%	-2.2%	-2.4%**
Daily	-4.9%***	-4.9%***	-4.4%***	-5.2%***	-5.3%***

Note: ***, **, and * denote significance at the 1%, 5%, and 10% level, respectively. In the “Level Regression,” the set of customers included in the estimation is larger than in the other sets of results, as net metering customers are not excluded. “Full-time Enrollees” include only those customers enrolled for the entirety of the summer season.

FIGURE 99: DPL SUMMER WEEKEND SENSITIVITY RESULTS

	Primary Result	Date Fixed Effects	Level Regression	Full-time Enrollees	Naïve Control Group
LMI Customers					
On-Peak	-7.0%***	-7.0%***	-8.3%***	-6.4%**	-9.8%***
Off-Peak	-0.8%	-0.8%	-0.6%	-0.8%	-2.9%**
Daily	-2.2%	-2.2%	-2.8%	-2.0%	-4.6%***
Non-LMI Customers					
On-Peak	-10.1%***	-10.1%***	-7.1%***	-10.6%***	-10.9%***
Off-Peak	-3.2%	-3.2%	-1.8%	-3.4%	-4.1%*
Daily	-4.7%	-4.7%	-3.2%	-5.0%	-5.7%***
All Customers					
On-Peak	-8.2%***	-8.2%***	-7.8%***	-8.0%***	-10.1%***
Off-Peak	-1.7%	-1.7%	-1.1%	-1.8%	-3.2%***
Daily	-3.1%*	-3.2%*	-3.0%*	-3.2%*	-4.8%***

Note: ***, **, and * denote significance at the 1%, 5%, and 10% level, respectively. In the “Level Regression,” the set of customers included in the estimation is larger than in the other sets of results, as net metering customers are not excluded. “Full-time Enrollees” include only those customers enrolled for the entirety of the summer season.

FIGURE 100: DPL NON-SUMMER WEEKDAY SENSITIVITY RESULTS

	Primary Result	Date Fixed Effects	Level Regression	Full-time Enrollees	Non-COVID Months	COVID (Differential Coefficient)	Naïve Control Group
LMI Customers							
On-Peak	-7.8%***	-7.8%***	-5.3%**	-7.9%***	-10.2%***	7.0%***	-10.4%***
Off-Peak	2.6%	2.6%	2.6%	2.3%	0.0%	6.7%***	-2.6%
Daily	1.3%	1.3%	1.5%	1.0%	-1.2%	6.7%***	-3.5%**
Non-LMI Customers							
On-Peak	-3.2%	-3.2%	-7.9%**	-3.6%	-5.2%	5.6%	-7.7%**
Off-Peak	4.6%	4.6%	1.2%	4.4%	2.4%	5.5%	0.2%
Daily	3.8%	3.8%	-0.1%	3.6%	1.7%	5.4%	-0.7%
All Customers							
On-Peak	-6.1%**	-6.1%**	-6.2%***	-6.3%**	-8.3%***	6.4%***	-8.7%***
Off-Peak	3.4%	3.4%	2.1%	3.1%	0.9%	6.3%***	-1.1%
Daily	2.3%	2.3%	0.9%	2.0%	-0.1%	6.2%***	-1.9%

Note: ***, **, and * denote significance at the 1%, 5%, and 10% level, respectively. In the “Level Regression,” the set of customers included in the estimation is larger than in the other sets of results, as net metering customers are not excluded. “Full-time Enrollees” include only those customers enrolled for the entirety of the non-summer season. The COVID differential effect presents the incremental impact over that observed during the non-COVID months. The “*” indicates an impact that is statistically different from the non-COVID months.

FIGURE 101: DPL NON-SUMMER WEEKEND SENSITIVITY RESULTS

	Primary Result	Date Fixed Effects	Level Regression	Full-time Enrollees	Non-COVID Months	COVID (Differential Coefficient)	Naïve Control Group
LMI Customers							
On-Peak	-2.6%	-2.6%	-1.5%	-2.8%	-4.2%	5.0%*	-5.6%***
Off-Peak	2.9%	2.9%	3.2%	2.6%	1.4%	4.3%*	-2.3%
Daily	2.2%	2.2%	2.6%	1.9%	0.7%	4.3%*	-2.7%*
Non-LMI Customers							
On-Peak	-0.1%	-0.1%	-4.5%	-0.4%	-1.4%	4.0%	-4.3%
Off-Peak	1.9%	2.0%	-2.2%	1.6%	-0.2%	5.9%	-0.1%
Daily	1.8%	1.8%	-2.5%	1.5%	-0.1%	5.5%	-0.7%
All Customers							
On-Peak	-1.6%	-1.6%	-2.6%	-1.9%	-3.2%	4.6%*	-4.8%***
Off-Peak	2.5%	2.5%	1.2%	2.2%	0.8%	4.9%**	-1.3%
Daily	2.0%	2.1%	0.7%	1.8%	0.4%	4.8%**	-1.8%

Note: ***, **, and * denote significance at the 1%, 5%, and 10% level, respectively. In the "Level Regression," the set of customers included in the estimation is larger than in the other sets of results, as net metering customers are not excluded. "Full-time Enrollees" include only those customers enrolled for the entirety of the non-summer season. The COVID differential effect presents the incremental impact over that observed during the non-COVID months. The "*" indicates an impact that is statistically different from the non-COVID months.

AGO Palmer Exhibit 5

SMART GRID INVESTMENT GRANT
CONSUMER BEHAVIOR STUDY ANALYSIS

Time-of-Use as a Default Rate for Residential Customers: Issues and Insights

AUTHORS:
Peter Cappers, C. Anna Spurlock, Annika Todd (LBNL)

Patrick Baylis, Meredith Fowlie, Catherine Wolfram (University of California at Berkeley)

Environmental Energy Technologies Division

Lawrence Berkeley National Laboratory

June 2016

LBNL-1005704

Acknowledgments

The work described in this study was funded by the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

The authors would like to thank Joe Paladino (DOE OE) for his ongoing support. We are deeply grateful to Nate Toyama (SMUD), Jennifer Potter (previously with SMUD), Stephen George (Nexant), and Michael Sullivan (Nexant) who provided invaluable assistance at the beginning of this project by working with us to identify and collect additional data from study participants that allowed us to expand and deepen our subsequent research. In addition, the authors would like to thank the following individuals who reviewed this manuscript and provided both thoughtful and constructive suggestions for its improvement: Ahmad Faruqui (The Brattle Group); Anna McCreery, Anne McKibbin, and David Becker (Elevate Energy); Beia Spiller (Environmental Defense Fund); Brett Feldman (Navigant); James Sherwood (Rocky Mountain Institute); Nate Toyama (SMUD); Stephen George (Nexant); and Theresa Flaim (Energy Resource Economics).

Disclaimer

This report was prepared by Lawrence Berkeley National Laboratory for the Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy.

This document was final as of June 1, 2016.

If this document is referenced, it should be cited as:

Cappers, P., et al. 2016. *Time-of-Use as a Default Rate for Residential Customers: Issues and Insights.* Lawrence Berkeley National Laboratory, LBNL-1005704.

FOR MORE INFORMATION

Regarding*: Time-of-Use as a Default Rate for Residential Customers: Issues and Insights*, please contact:

Peter Cappers
Lawrence Berkeley National Laboratory
E-mail: PACappers@lbl.gov

C. Anna Spurlock
Lawrence Berkeley National Laboratory
E-mail: CASpurlock@lbl.gov v

Regarding the Smart Grid Investment Grant, please contact:

Joseph Paladino
U.S. Department of Energy
E-mail: Joseph.Paladino@hq.doe.gov
http:/www.smartgrid.gov

Table of Contents

Figures

Tables

Glossary of Acronyms, Abbreviations, and Terms

AMI	**Advanced Metering Infrastructure –** All components that allow two-way communication between meters and the electric utility's meter data management system to collect electricity usage and related information from customers and to deliver information to customers.
CA	**California**
CBS	**Consumer Behavior Study**
CBSP	**Consumer Behavior Study Plan**
CEIC	**Cleveland Electric Illuminating Company**
ComEd	**Commonwealth Edison**
CPP	**Critical Peak Pricing –** A time-based rate component that increases the price on electricity consumed for participating customers during the hours included in a declared critical event. This higher price is overlaid onto the existing retail rate. Critical events are called either on a day-ahead or in-day basis in response to forecasted or achieved, respectively, high wholesale market electricity prices, short-term system reliability problems, or both. The primary objective of this rate design is to promote reductions in the peak demand of electricity.
CPR	**Critical Peak Rebate –** A demand response program that pays participating customers for reducing electricity consumed in relation to a baseline during the hours included in a declared critical event. Critical events are called either on a day-ahead or in-day basis in response to forecasted or achieved, respectively, high wholesale market electricity prices, short-term system reliability problems, or

	both. The primary objective of this program design is to promote reductions in the peak demand of electricity.
CPUC	**California Public Utilities Commission**
DID	**Difference-in-Differences**
DOE	**Department of Energy**
DTE	**DTE Energy**
EAPR	**Energy Assistance Program**
FERC	**Federal Energy Regulatory Commission**
FOA	**Funding Opportunity Announcement**
GMP	**Green Mountain Power**
HEMS	**Home Energy Management System**
IHD	**In-Home Display**
IV	**Instrumental Variable regression**
kWh	**Kilowatt-hour**
LAC	**Los Alamos County Electric Utility**
LBNL	**Lawrence Berkeley National Laboratory**
LE	**Lakeland Electric**
MADPU	**Massachusetts Department of Public Utilities**
MMLD	**Marblehead Municipal Light Department**
MP	**Minnesota Power**
NVE	**NV Energy**

OE	**DOE Office of Energy Delivery and Electricity Reliability**
OG&E	**Oklahoma Gas & Electric**
PCT	**Programmable Communicating Thermostat**
PSE	**Puget Sound Energy**
PURPA	**Public Utility Regulatory Policies Act**
RCT	**Randomized Controlled Trial** – A research strategy in which customers who volunteer to be exposed to a treatment are randomly assigned to treatment and control conditions.
RED	**Randomized Encouragement Design** – A research design in which two groups of customers are selected from the same population at random and one is offered a treatment while the other is not. Not all customers offered the treatment are expected to take it but, for analysis purposes, all those who are offered the treatment are considered to be in the treatment group.
SGIG	**Smart Grid Investment Grant**
SMUD	**Sacramento Municipal Utility District**
SVE	**Sioux Valley Energy**
TAG	**Technical Advisory Group**
TOU	**Time-Of-Use** – A time-based rate program design that charges customers for electricity usage based on the block of time it is consumed. The price schedule is fixed and predefined, based on season, day of week, and time of day. The primary objective of this rate design is to promote overall shifting of electricity away from the peak period to other periods.

2SLS	**Two Stage Least Squares regression**
VEC	**Vermont Electric Cooperative**
VPP	**Variable Peak Pricing –** A time-based rate program design that charges customers for electricity usage based on the block of time it is consumed. The price schedule is variable and differs daily, based on bulk power system conditions during that period of the day. The primary objective of this rate design is to promote targeted shifting of electricity away from the peak period to other periods.

Foreword

As far back as the 1890s, the electric industry has been debating the issue of how to efficiently and optimally charge customers for consuming electricity (Hausman and Neufeld, 1984). At that time, there were emerging but very contentious discussions among economists about the merits of pricing the new commodity differentially based on time. The challenge with such pricing schemes revolved around metering—cost-effective technology did not exist at that time to allow electricity consumption to be captured at the required level of detail. Thus, virtually all customers were charged for their electricity consumption at a rate that was time-invariant (i.e., flat).

By the 1970s, the debate had moved beyond issues of economic efficiency and instead turned towards more practical concerns about consumer behavior—could mass-market (i.e., residential and small commercial) customers manage their electricity consumption under time-based rate programs? The results of studies undertaken by the Federal Energy Administration, the predecessor to the U.S. Department of Energy (DOE), indicated such customers were, in fact, capable of managing their electricity consumption by moving it away from the expensive "peak" period to the less-expensive "off-peak" period (see Faruqui and Malko, 1983 for a meta-analysis of these experiments). In spite of this evidence, the lack of low-cost interval or period-based metering technology continued to limit the industry's ability to expand the application of time-based rate programs at the residential level through the end of the 20th century.

Over the past ten years, however, the costs of interval meters, the communications networks to connect the meters with utilities and the back-office systems necessary to maintain and support them (i.e., advanced metering infrastructure or AMI) have dramatically decreased. The implementation of AMI and interval meters by utilities, which allows electricity consumption data to be captured, stored and reported at 5 to 60-minute intervals in most cases, provides an opportunity for utilities and policymakers to once again seriously consider the merits of the widespread deployment of time-based rate programs. However, many regulators and other key policymakers have determined that more definitive answers to key policy questions must be addressed before they will fully support a paradigm shift in the way retail electricity providers charge residential and small commercial customers for consuming electricity.

The American Recovery and Reinvestment Act of 2009 included $3.4B for the Smart Grid Investment Grant (SGIG) program with the goal of creating jobs and accelerating the transformation of the nation's electric system by promoting investments in smarter grid technologies, tools and techniques (DOE, 2012). Among other topics, the Funding Opportunity Announcement (DE-FOA-0000058) identified interest in AMI projects that examined the impacts and benefits of time-based rate programs and enabling control and information technologies through the use of randomized controlled experimental designs.

Based on responses to this FOA, DOE decided to co-fund ten utilities to undertake eleven experimentally-designed Consumer Behavior Studies (CBS) that proposed to examine a wide range of the topics of interest to the electric utility industry. Each chosen utility was to design, implement and evaluate their own study in order to address questions of interest both to itself and to its applicable regulatory authority, whose approval was generally necessary for the study to proceed. The DOE Office of Energy Delivery and Electricity Reliability (OE), however, did set guidelines, both in the FOA and subsequently during the contracting period, for what would constitute an acceptable study under the Grant.

To assist in ensuring these guidelines were adhered to, OE requested that LBNL act as project manager for these Consumer Behavior Studies to achieve consistency of experimental design and adherence to data collection and reporting protocols across the ten utilities. As part of its role, LBNL formed technical advisory groups (TAG) to separately assist each of the utilities by providing technical assistance in all aspects of the design, implementation and evaluation of their studies. LBNL was also given a unique opportunity to perform a comprehensive, cross-study analysis that uses the customer-level interval meter and demographic data made available by these utilities due to SGIG-imposed reporting requirements, in order to analyze critical policy issues associated with AMI-enabled rates and control/information technology. Over the next several years, LBNL will publish the results of these analyses in a series of research reports that attempt to address critical policy issues relating to on a variety of topics including customer acceptance, retention and load response to time-based rates and various forms of enabling control and information technologies.

Executive Summary

Ninety-eight percent of residential customers in the U.S. take electricity service under flat or inclining block rates (FERC, 2012). However, for nearly 40 years, in part because of The Public Utility Regulatory Policies Act[i] (PURPA), the vast majority have been offered a time-based rate[ii] (e.g., time-of-use) on a voluntary opt-in basis. In spite of this extensive history, the majority of U.S. utilities currently have less than 2% of their residential customers taking service under such rates (FERC, 2012). Throughout this time, most residential customers had bulk usage meters. So, if they wanted to take service under a time-based rate, they had to request that the utility install a new meter, either with multiple registers or interval-based, and incur an additional monthly meter charge. In part because of this hurdle, it is likely that residential enrollment levels in time-based rates have been low.

With increased broad penetration of interval meters as part of utility investments in advanced metering infrastructure (AMI) over the past 15 years, this major barrier to more sizable adoption of time-based rates has potentially been removed.[iii] Ubiquitous interval meters introduces the opportunity to make time-based rates the default rate design for residential customers, which would be a major policy change in the United States.

Many contend that residential customers as well as utility ratepayers could benefit from such a transition to default time-based rates in a variety of ways. All residential customers would have greater opportunities to control electricity costs and bills by altering the *timing* of electricity usage, not just using less overall. In addition, utility ratepayers as a whole can benefit because time-based rates better align the prices customers face with the cost of serving them at that time, resulting in greater economic efficiency. Lastly, broad based customer response to time-based rates can contribute to improved reliability and reduce the

---

[i] Subtitle B asked state regulatory authorities and non-regulated electric utilities to determine whether or not it is appropriate to implement time-of-use rates and other ratemaking policies.

[ii] Time-based rates capture temporal differences in the cost of providing electricity. Some time-based rate designs are static where the price schedule of electricity is set months, if not years, ahead of time to capture the diurnal and/or seasonal differences in costs (e.g., time-of-use pricing). Other time-based rate designs are more dynamic, where the price schedule is set 24 hours or less ahead of time based on anticipated or actual power system conditions, high wholesale power costs, or both (e.g., critical peak pricing, real-time pricing).

[iii] Certainly a myriad of other barriers exist (e.g., the level of marketing and customer outreach, customer-focused rate design) that may keep enrollment levels low even with the introduction of AMI.

need for the utility to invest in additional generation, and possibly distribution and transmission infrastructure.

However, risks associated with such a transition have also been identified. Consumer advocates and some utilities have raised concerns that customers will be dissatisfied with the transition (e.g., upset about having to take explicit actions to remain on a flat or inclining block rate that they know and prefer) and some may be adversely affected from the change in default rates (e.g., customers who have higher electricity consumption than the average customer in the more expensive peak period, and who cannot or do not opt out for whatever reason, will see their bills increase under a time-based rate absent any response to the rate vis-à-vis a flat or inclining block rate). [iv]

Unfortunately the U.S. electricity industry has almost no direct recent experience that can be drawn upon in this debate about the proper role of time-based rates in default rate design for residential customers.[v] Instead, the only current U.S. experience (i.e., within the last 5 years) comes by way of studies of time-based rates offered under default enrollment approaches.[vi] Results from all of those studies suggest that there are subpopulations of customers that respond to default time-based rates and other groups that are likely less inclined to do so.

The purpose of this report is to provide decision makers, policy officials, and other electric power industry stakeholders, who have either committed to (e.g., California[vii], Massachusetts[viii]) or are considering (e.g., New York[ix]) transitioning residential customers specifically to time-of-use (TOU) rates as the default rate design within the next several years, with empirical evidence that seeks to better address the concerns of a variety of industry stakeholders. Using interval meter data, survey data, and other data collected

[iv] These concerns are often times raised in regards to low income, elderly or those customers with medical needs (see for example AARP et al., 2010), but certainly could apply to the rest of the population more broadly.

[v] Since our focus is on the United States, we did not include an assessment of international experience. See, for example, Faruqui et al. (2015) for a discussion of the experience in Ontario, Canada where the default rate design for residential customers is TOU.

[vi] Incentive-based demand response programs like critical peak rebate or peak-time rebate are not herein considered time-based rates. So although Baltimore Gas and Electric has defaulted all of their residential customers onto such a program, their experience is not considered as it is outside the scope of this report.

[vii] See CPUC (2015).

[viii] See MADPU (2014).

[ix] See NYDPS (2015)

during the Sacramento Municipal Utility District's (SMUD) Smart Grid Investment Grant (SGIG) co-funded consumer behavior study (CBS) that took place during the summers of 2012 and 2013, LBNL analyzed residential customers who (1) volunteered for, or (2) were defaulted into, a study in order to quantify the differences between these two recruitment methods in terms of adoption, retention, and response to TOU rates. Of particular importance from a policy perspective is an assessment of those who might be better off for having been defaulted onto the TOU rate or who might be worse off (e.g., financially worse off, unhappy having to alter their electricity consumption behavior, frustrated that their electric rate was changed) but don't switch to another rate. In particular, improving our understanding of these different subpopulations can help policy and decision makers make that transition more successful (e.g., limited customer complaints, low opt-out enrollment rates, high retention rates, and/or high customer response).

In a default environment we define three key subpopulations:

- **Never takers**: the set of customers that would not actively opt-in to voluntary TOU rate offers, and would actively opt-out when TOU rates are the default;
- **Always takers**: the set of customers that would actively opt-in to voluntary TOU rate offers and would not actively opt-out when TOU rates are the default; and
- **Complacents**: the set of customers who would not actively opt-in to voluntary TOU rate offers, but would not actively opt-out when TOU rates are the default.

Within the context of SMUD's consumer behavior study, Figure ES-1 shows the relative sizes of these three subpopulations of residential customers.

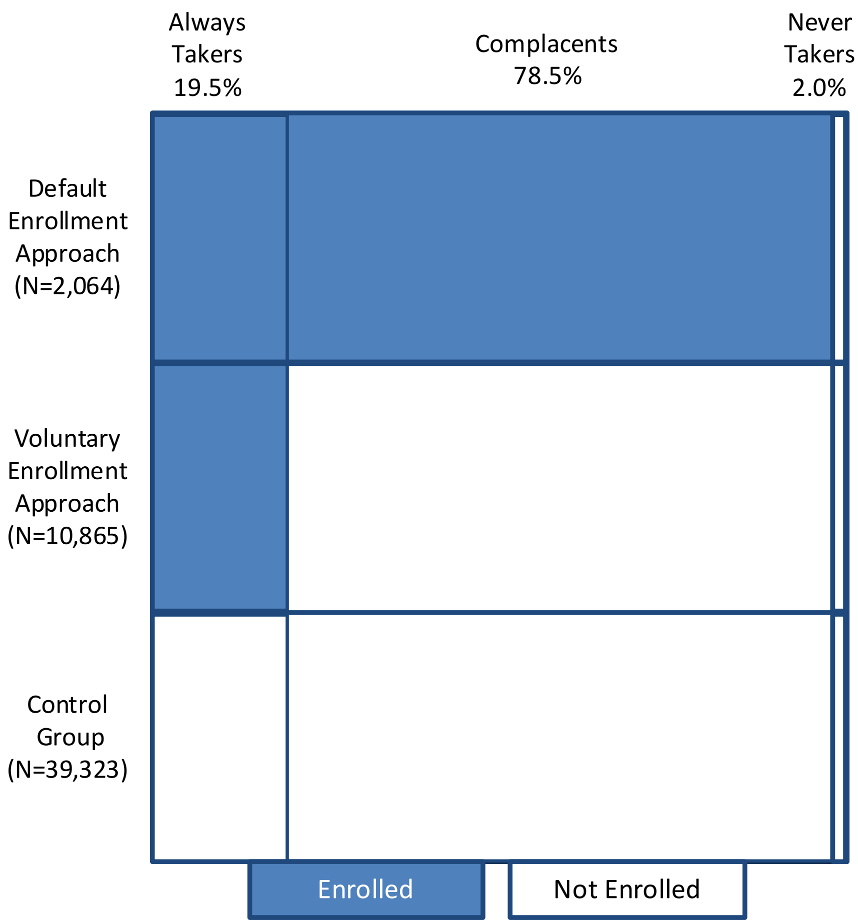


Figure ES-1. SMUD Residential Subpopulations for Analyzing Default vs. Voluntary TOU Rates

Table ES-1 summarizes the major findings of this report from analyses of these subpopulations. These findings are organized based on perceived risks that those resistant to default TOU rates have articulated.

Table ES-1. Major Findings

Perceived Risks about TOU Rates as the Default Service Option	Evidence from DOE Analysis of SMUD's CBS
Lack of customer acceptance (high drop-out rates to start, and high attrition, particularly among Complacents, over time).	• Enrollment rates were five times higher under default enrollment approaches (98%) than voluntary approaches (19.5%). • Once enrolled in the new rates, drop-out rates for both Complacents (3.7%) and Always Takers (4.4%) were very low.
Insufficient changes in consumer behaviors and potentially ineffective demand response and reductions among customers defaulted onto the rate, particularly among Complacents.	• Per-customer demand reductions were about three times higher on average for the voluntary offering (16.7%) than for the default enrollment approach (5.8%). • Per-customer demand reductions were about five times higher on average for the Always Takers (16.7%) than for the Complacents (3.1%), but impacts from both groups were statistically significant. • Comparing the first to the second summer, the demand reductions of Always Takers dropped significantly (18.2% to 14.7%), while it did not for Complacents (3.4% to 2.9%), indicating that savings from Complacents were, while smaller, potentially more persistent.
Unequitable distribution of financial benefits and bill savings.	• Differences in the distribution of Always Takers and Complacents predicted summer-long bill savings, absent any response, were very similar • Two-thirds of both the Always Takers and Complacent subpopulations were expected to see their bills change no more than +/- $20 over the course of an entire summer (+/- $5/month), before taking into account any response to the TOU rate.
Unacceptably high levels of customer dissatisfaction and bill complaints that result in poor performance and low cost-effectiveness.	• There was no evidence of dramatically higher levels of dissatisfaction or complaints from customers defaulted onto the TOU rate compared to those who opted-in, nor between Complacents and Always Takers. • Utility marketing and recruitment costs for those who opted in to the voluntary enrollment study (excluding any enabling equipment costs) were fifteen times higher than for those who did not opt out of the

	default enrollment approach ($60.77 per enrollee vs. $3.99 per enrollee). • Taken all together, a default TOU for all residential customers in SMUD's service territory is estimated to produce $34M in net benefits on a 10-year present value basis with a cost-benefit ratio of 2.04 whereas a voluntary approach would create -$5.5M in net losses at a cost-benefit ratio of 0.74.

The analysis in this report suggests that, as a group, Complacents were less engaged, attentive, and informed than the other subpopulations, either unintentionally or by choice. Looking more closely, there was some subset of the Complacent population who were fully aware of the rate, engaged enough with it to undertake substantial changes in behavior to respond to it in order to achieve bill savings and were generally satisfied with their experience on the rate. However, another subset of Complacents may have been largely indifferent about the rate, not particularly concerned about being defaulted onto it, expended a modest level of effort to respond to the rate and were satisfied enough with it to keep taking service under it after the study ended, provided they didn't see large bill increases. These customers were also likely better off for having been defaulted onto the rate. Lastly, there was a subset of customers who likely were highly unengaged and inattentive. We estimate the size of this latter group to be about 20% of the entire consumer population. They were more likely unaware of the rate SMUD had transitioned them to, as they did not provide any measurable energy savings in response to the TOU rate. In this case, contrary to the others, it is possible that these inattentive Complacents were worse off for having been defaulted onto the rate.

Key Results

Result 1 Many customers seem better off being defaulted onto a time-of-use rate relative to a voluntary rate

Result 2 Only a subset of residential customers are at-risk when defaulted on to a time-of-use rate.

Result 3 Utilities should focus on reaching inattentive customers who may be worse off

This suggests that it is not the entirety of SMUD's residential customers or even the share of residential customers that are Complacents who are at-risk of being made worse off during a transition to default TOU, but rather a subset of the latter. For utilities and states considering a transition to default TOU, it is this subpopulation of customers that requires the greatest attention from policy and decision makers. The likelihood of a successful transition could improve if utilities and others consider the needs of this subpopulation of unengaged Complacents. Ideally, utilities could identify customers who are more likely to be highly inattentive before the transition to default TOU is even announced. For example, utilities could create proxies for the level of a customer's attentiveness and engagement using data gathering activities such as registration requests for on-line access to account information, logins to on-line web portals, responses to bill inserts about utility services (e.g., energy efficiency), or the frequency of customer-service calls. Customers that seem to be less attentive and less engaged could be targeted by the utility for more direct and non-traditional communication strategies. In addition, utilities could use focus groups or other types of market research to determine the best ways to reach inattentive customers so that they can be made aware of the transition, better understand their options, and more easily navigate the opt-out process.

Most importantly, our analysis also shows that there is a sizable share of the residential customer class at SMUD that was seemingly better off on a default TOU rate relative to a voluntary enrollment approach. Policy and decision making often involves tradeoffs among different perspectives and interests. Recent industry experience shows that pursuing a voluntary approach to TOU rates typically means that less than 2% of residential customers participate (FERC 2012); although with extensive, dedicated and long-term (i.e., multi-year) commitment to recruitment efforts that employ effective marketing and customer outreach strategies on the part of a utility, which are unlikely to be attained without strong regulatory support if not directives, opt-in enrollments can be as high as 50% (e.g., Arizona Public Service[x]). SMUD achieved opt-in enrollments of about 19.5% with substantial market research to get their recruitment material optimally designed to elicit participation, all within the backdrop of a utility that has high customer satisfaction ratings. In contrast, default TOU rates substantially increase the size of the customer population seemingly benefiting from the rate transition. Certainly, with this opportunity to benefit more customers comes the challenge of mitigating the problems from the subpopulation of customers that may be at risk of being made worse off by default TOU. The question for policy and decision makers is determining whether or not that effort is worthwhile, and if so, how to best mitigate that risk.

[x] See Snook and Grabel (2015)

1. Introduction

Ninety-eight percent of residential customers in the United States (U.S.) take service under flat or inclining block rates (FERC, 2012). Yet, time-based rates[1] provide an opportunity for customers and utilities alike to achieve a variety of benefits including increased opportunity for customer bill management, lower utility power production costs, deferred future generation investments, and increased utilization of existing infrastructure. Historically, implementation of time-based rates required replacement of a traditional bulk usage electro-mechanical meter with either a multi-register electro-mechanical meter or an electronic interval meter that was accompanied by a monthly meter charge. The costs of individual meter upgrades was seen by many as a barrier to broader adoption of time-based rates. Recent broad-based deployment of Advanced Metering Infrastructure (AMI) removes this metering hurdle, thereby enabling the opportunity for broader adoption of time-based rates. Currently, utilities in the U.S. have installed more than 50 million smart meters, covering over 43% of U.S. homes (Institute for Electric Innovation, 2014).

There is an on-going debate in the U.S. electric power industry about the proper role of residential time-based rates, in particular time-of-use (TOU) rates, as either a voluntary or the default rate design. One of the major concerns raised when utilities consider time-based rates has to do with whether or not there are subpopulations of customers who might be made worse off from a transition to default TOU rates. Some customers may see higher bills simply because more of their electricity is consumed in the higher priced peak period. Other customers may be able to see bill savings, but only after considerable efforts to change their consumption patterns which may leave them resentful. Other customers may be highly inattentive, only becoming aware of the transition to a default time-based rate considerably after it occurred, resulting in dissatisfaction with the utility and state regulators. However, transitioning to time-based rates as the default provide substantially more customers the opportunity to better manage their bills based on when they use electricity, not just by limiting how much they consume overall. Furthermore, broad based response to time-based

[1] Time-based rates capture temporal differences in the cost of providing electricity. Some time-based rate designs are static, where the price schedule of electricity is set months, if not years, ahead of time to capture the diurnal and/or seasonal differences in cost (e.g., time-of-use pricing). Other time-based rate designs are more dynamic, where the price schedule is set 24 hours or less ahead of time based on anticipated or actual power system conditions, wholesale power costs, or both (e.g., critical peak pricing, variable peak pricing, real-time pricing).

rates has the opportunity to reduce utility power costs as well as to defer capital investments.

Through the U.S. Department of Energy's (DOE) Smart Grid Investment Grant Program (SGIG), the Sacramento Municipal Utility District (SMUD) designed and implemented a Consumer Behavior Study (CBS) of voluntary and default TOU rates that provide useful information and insights for addressing some of the key unresolved issues concerning a transition to default residential TOU rates.[2]

1.1 Background

The vast majority of residential time-based rate programs in the U.S. have been offered to customers on a voluntary, opt-in basis for nearly 40 years, in part because of The Public Utility Regulatory Policies Act of 1978[3] (PURPA). In spite of this extensive history, the majority of U.S. electric utilities currently have less than 2% of their customers taking service under such rates (FERC, 2012). Historically, most residential customers have had bulk-usage, electro-mechanical meters. If customers wanted to take service under time-based rates, they had to request the installation by the utility of a new multi-register or interval meter and incur an additional monthly meter charge. Residential enrollment rates in time-based rate programs have been generally low in part because of this hurdle.

With increased penetration of smart meters as part of utility investments in advanced metering infrastructure (AMI) over the past 15 years, one of the barriers to expanded deployments of time-based rates has been removed. For utilities with system-wide coverage of AMI, the opportunity exists to make time-based rates the default rate design for residential customers, which they may well desire to do for reasons described below, which would be a major policy change at the state level in the United States. Several states are in the process of evaluating this approach.

There are benefits associated with the application of time-based rates. A customer can reduce their electricity bills under a time-based rate by reducing or shifting their demand to less expensive periods. Also, customers more broadly can benefit from such rates as

[2] See Appendix A for more background on the SGIG consumer behavior study effort and Appendix B for more details about SMUD's consumer behavior study.

[3] Subtitle B asked state regulatory authorities and non-regulated electric utilities to determine whether or not it is appropriate to implement TOU rates and other ratemaking policies.

electricity costs can be more equitably distributed across the class of customers under broadly applied time-based rates, as customers who use more electricity during the most expensive times-of-day would pay more of their share of those costs. In general, aligning the prices customers pay for electricity with the full cost of providing the electricity results in greater economic efficiency. When customers reduce electricity consumption coincident with system peak demands, then such efforts contribute to improved reliability and reduce the need for the utility to invest in additional generation, and possibly distribution and transmission infrastructure.

Given these benefits, it would seem that policy-makers would be interested in applying time-based rates, and that customers might volunteer to take service under them. However, this generally has not been the case without extensive education, promotion, and encouragement from the utility.[4]

One way to encourage much more wide-scale adoption of time-based rates would be to make them the default option. There is extensive evidence that people tend to disproportionately end up on whatever option is provided to them as a default, particularly in cases when they may not have strongly defined preferences about a choice ahead of time. This phenomenon, referred to as the "default effect" or "status quo bias" has been documented in a variety of settings (e.g., organ donation, 401K contributions, car insurance).[5] Applying this phenomenon to the electricity sector suggests that there is a high likelihood that even with real benefits from voluntarily switching to a time-based rate, many consumers are unlikely to do so without being prompted in some significant way. The application of time-based rates as a default option might result in a larger set of customers willing to remain on such a rate, but would also allow them to opt-out if they have a strong preference for a flat rate.

Despite the myriad of potential benefits from a transition to time-based rates as the default service option for residential customers, there has been a lack of universal support. Consumer advocates, public utilities commissions, and many utilities have raised concerns that a substantial number of customers will be unwilling to accept default time-based rates, or might be made worse-off by them. There is of particular concern for those who are at-risk

[4] Salt River Project has over 25% of their entire residential customer population on one of two TOU rates after more than 20 years of engaging and educating customers about the merits of taking service under TOU (Institute for Energy and the Environment, 2012). Arizona Public Service has even more customers on its TOU rates (over 50% of its residential population) after almost 40 years of offering them (Snook and Grabel, 2015).

[5] For a good review see DellaVigna (2009).

for suffering higher costs and bills because they can't or won't adjust their usage, as well as for those who may simply not want to be inconvenienced by having to now manage when they use electricity, but choose not to switch to another rate.[6]

Unfortunately, there has been very little direct experience in the U.S. with default residential time-based rates[7] and therefore little empirical evidence to draw upon in order to understand the actual impact of such default rates in terms of the risks and benefits outlined above.[8] Recently, however, there is experience from several utility studies of time-based rates offered under default enrollment approaches. In addition to SMUD, there have been four other utilities in the U.S. who conducted residential time-based rate studies in the last five years that evaluated default enrollment approaches, including: (1) Commonwealth Edison (ComEd) in Chicago, Illinois (EPRI, 2011a, b); (2) Sioux Valley Energy (SVE) in Minnesota and North Dakota (Power System Engineering Inc., 2012); (3) Los Alamos County Electric Utility (LAC) in New Mexico (Ida and Wang, 2014); and (4) Lakeland Electric (LE) in Florida (Lakeland Electric, 2015). [9]

SVE, LE and LAC included evaluations of voluntary versus default enrollments, while ComEd's study focused on the latter exclusively. Three of the four studies (SVE, LAC, ComEd) evaluated critical peak pricing (CPP), while ComEd also included evaluations of other rates (i.e., day-ahead real-time pricing, TOU rates, and critical peak rebates) and LE strictly assessed a TOU rate design.

[6] These concerns are often raised in regards to low income, elderly or those customers with medical needs (see for example AARP et al., 2010), but certainly could apply to the rest of the population more broadly.

[7] Since our focus is on the United States, we did not include an assessment of international experience. See, for example, Faruqui et al. (2015) for a discussion of the experience in Ontario, Canada where the default rate design for residential customers is TOU.

[8] Puget Sound Energy (PSE) instituted a time-of-use rate as the default in 2000 for its residential and small commercial customers. Although early analysis suggested customers were willing to modestly respond to the rate, programmatic changes in July of 2002 largely eradicated any financial benefit from taking service under the rate. As a result, PSE ended the program in November 2002. See Schwartz (2003).

[9] Incentive-based demand response programs like critical peak rebate or peak-time rebate are not herein considered time-based rates. So, for example, although Baltimore Gas and Electric has defaulted all of their residential customers onto such a program, their experience is not considered as it is outside the scope of this report.

LAC, LE and ComEd all experienced very high enrollment rates under default enrollment approaches (88-98%), that were much higher than those experienced under voluntary enrollment approaches.

SVE and LAC found that under a voluntary enrollment approach for CPP, customers reduced peak demand during declared events, on average, more than those under a default enrollment. Defaulted customers were, however, able to respond and reduce demand, just not as much. LE found customers who opted-in to participate in the study reduced usage in the first 5 months of the study in response to TOU rates, while the impact estimates for the defaulted customers were small and not statistically significant. An analysis of ComEd's customers that were defaulted onto the various rates was inconclusive, on average, as differences in estimated demand reductions were not statistically significant. However, a subset of ComEd's default participants (ranging from 9% to 12%, depending on the rate design) was found to produce statistically significant demand reductions.

Results from all four studies suggest that there are some subpopulations of customers under default enrollment approaches that respond to time-based rates and other subgroups that are less likely to do so. To delve into this issue more, LBNL analyzed interval meter, survey and other data collected as part of SMUD's SGIG-funded consumer behavior study.[10]

1.2 SMUD's Consumer Behavior Study

SMUD conducted one of the largest and most extensive consumer behavior studies under the SGIG program. One of the study's main goals was to better understand how the enrollment approach (voluntary vs. default) affected enrollment rates, drop-out rates, and electricity demand impacts associated with time-based rates. SMUD implemented three different time-based rate designs, all in effect during the summer months (June to September) of 2012 and 2013: (1) a two-period TOU rate with a three-hour (4-7 p.m.) peak period, (2) CPP overlaid on an underlying tiered rate, and (3) CPP overlaid on the TOU rate (see Figure 1 and Table 1).[11] Like most of the other consumer behavior studies implemented under the SGIG program, SMUD's study utilized a true experimental design (i.e., randomized control trial and

[10] Although data from Lakeland Electric's SGIG-funded consumer behavior study, which also implemented a default enrollment treatment, was available to LBNL to analyze, it was insufficient and the experimental design was not conducive to perform the same type of exhaustive and detailed analysis described herein.

[11] Only the TOU and CPP were implemented in such a way that the effect of enrollment approach (voluntary vs. default) could be analyzed.

randomized encouragement design) in order to more credibly and precisely estimate the load response to these various rates. For purposes of this report, only the customers included in the default TOU rate with IHD offer and opt-in TOU rate with IHD offer cells will be analyzed and discussed.

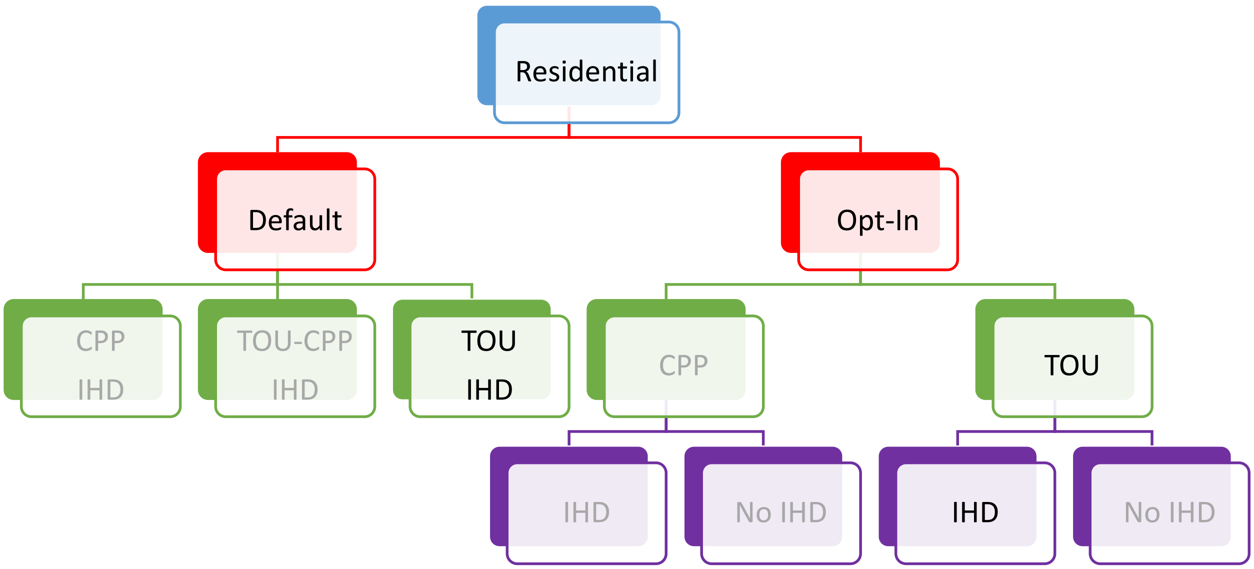


Figure 1. SMUD's Consumer Behavior Study Experimental Design

Table 1. SMUD's CBS Rate Design (¢/kWh)[12]

Period	CPP	TOU	TOU-CPP
Base (< 700 kWh)	8.51		
Base (> 700 kWh)	16.65		
Off-Peak (< 700 kWh)		8.46	7.21
Off-Peak (>700 kWh)		16.60	14.11
Peak		27.00	27.00
Critical Peak	75.00		75.00

1.3 Scope of this Report

At present, both California[13] and Massachusetts[14] have committed to transitioning residential customers to TOU rates as the default rate design within the next several years. Other states (e.g., New York[15]) have begun discussions about the viability of such a transition. Empirical analysis of SMUD's CBS data can provide information that might support the transitions in these states, while potentially contributing to discussions in similar regulatory proceedings that might occur in other states.

This analysis provides empirical evidence addressing key assumptions and preconceived notions about customer perceptions, risks, benefits and responses specifically to default

[12] Study participant on SMUD's Energy Assistance Program (EAPR) rate faced different prices than those listed in Table 1.

[13] The California Public Utilities Commission (CPUC), following a three-year examination of rate reform alternatives, ordered the state's investor-owned utilities to begin a transition to default time-of-use rates for all residential customers by 2019. See CPUC (2015).

[14] The Massachusetts Department of Public Utilities (MADPU), as part of a comprehensive suite of dockets and orders related to grid modernization, ordered the state's electric distribution companies to make a time-of-use rate with a critical peak pricing overlay the default for basic service customers following the deployment of advanced metering functionality. See MADPU (2014).

[15] As part of a proceeding that is seeking to fundamentally change the operations, roles and responsibilities of New York state's distribution utilities (i.e., Reforming the Energy Vision), the New York Public Service Commission staff wrote a white paper in 2015 that discussed the various options that could be considered to achieve broader adoption of time-based rates. See NYDPS (2015).

TOU, especially with respect to different subpopulations of residential customers transitioned to default TOU. For those states and utilities moving forward with time-based rates as default service options, this analysis can also be helpful in the design and implementation of new rates, including new strategies and techniques for addressing the needs of these different subpopulations of customers, such as those who are potentially at risk of being made worse off as a result of default TOU.

The report is organized as follows. In Chapter 2 we present the impacts of a default TOU rate at SMUD on customer acceptance, retention, demand response, bill impacts, and cost-effectiveness vis-à-vis traditional voluntary enrollment approaches. In Chapter 3, we assess how different subpopulations of residential customers are affected by a transition to default TOU. Finally, in Chapter 4 we provide a summary of the major findings and conclusions from this analysis.

2. Benefits and Risks of Default TOU Rates for Residential Customers

SMUD's consumer behavior study provides an opportunity to assess the perceived major benefits and risks of implementing default TOU for residential customers. An analysis of the data collected during their study provides information for policy and decision makers about the impacts of default rates on customer acceptance, retention, demand response, bill impacts, and cost-effectiveness vis-à-vis traditional voluntary enrollment approaches.

2.1 Potential Benefits and Risks of Default TOU

Most residential customers in the U.S. today have the opportunity to take service under TOU rates, but on a voluntary (i.e., opt-in) basis. The lack of customers signing up for these rates in large numbers (i.e., less than 2%) could be an artifact of past trends (e.g., these rate options were not always generally available, when available these rate options were poorly designed and/or ineffectively marketed) and rate economics (e.g., estimating bill savings has been challenging for a customer given the rate design and/or lack of knowledge of their own capabilities to alter electricity consumption) coupled with a tendency for consumers to stick with the status quo and/or default options (see the previous discussion of "status quo bias"). For this reason, changing the default rate structure to TOU could have several benefits. First, the variation in price from a TOU rate better reflects the increase in wholesale electricity prices as well as transmission and distribution costs due to higher demand in the peak periods. Second, on a flat rate, customers have no way of affecting the amount they pay for electricity beyond reducing use overall. In contrast, with a TOU rate, customers have an ability to adjust the timing of their consumption in a way that allows them to use the same level of services at a lower total cost. This may give customers a greater sense of control over their electricity bills. Third, because of status quo bias, making TOU a default rate in particular would be expected to increase participation in TOU without the costly recruitment efforts required to increase opt-in participation.

However, the historic low levels of voluntary participation in TOU might be an indication of a lack of awareness, interest, and/or ability to respond to this type of time-based rate design. Historically, investor-owned utilities have not had a financial incentive to vigorously pursue TOU rates for their customers, absent regulatory directives. As such, although the rates are included in their tariffs, in part due to PURPA, some contend that electric utilities have not historically rigorously marketed the rates to bolster participation levels. However, some view low participation levels less as a marketing failure on the part of the utility and more as a reflection of the fact that customers are simply not interested in taking service under a TOU rate. From the perspective of those who espouse the latter position, establishing TOU as the default rate going forward could be problematic. Customers that fail to opt-out of the pending default TOU rate during the transition stage might chose to drop-out soon after going onto the rate, resulting in substantial attrition. For customers who remain, their potential lack of awareness of a default transition in rate structure may result both in an inability to respond to the TOU rate by changing the timing of their electricity consumption, and high levels of dissatisfaction if and when they become aware of the rate change. Even if some of the remaining customers can and do respond to the rate, their load profile even after taking into account these changes may result in higher or more volatile bills than they had on the prior flat or tiered rate.

Utilities also face potential risks when implementing time-based rates as the default service option. They may contend with customer dissatisfaction if rates are poorly accepted. This can lead to low customer satisfaction ratings and an increase in customer complaints. If behavioral changes and the resulting demand impacts are smaller than expected, operation and electricity production savings to the utility may not exceed education, marketing, information and other implementation costs. In addition, utilities typically design time-based rates to collect a substantial amount of fixed costs in the higher priced peak period. As such, utilities may also experience deleterious revenue erosion if customers shift a considerable amount of load to the less expensive off-peak period.

The results from SMUD's CBS, which are expanded upon below, shows that most of these risks are not particularly substantial. In fact, SMUD's CBS showed that default residential TOU rates produced measurable benefits for both participating customers and for the utility.

2.2 Experiences with Customer Acceptance

As Figure 2 illustrates, SMUD's decision to default customers onto the TOU rate produced far higher enrollment rates than their efforts to recruit volunteers.[16] Enrollment rates were over five times larger under a default enrollment approach (98.0%) than under one that

[16] For this analysis, we consider customers that were solicited to join the TOU rate, whether voluntary or default, and also offered an in home display.

sought volunteers (19.5%) for the TOU rate.[17] SMUD reported that extensive customer outreach, education, and marketing efforts were required for achieving even this rate of voluntary enrollment. Customer recruitment costs for those who opted in to the voluntary enrollment study (excluding any enabling equipment costs) were estimated at $60.77 per enrollee. This is in comparison to $3.99 per enrollee for those who were defaulted onto the TOU rate, in spite of using nearly identical marketing material (Potter et al., 2014). As such, the significantly higher enrollment rates under default enrollment were achieved with much lower marketing and recruiting costs.

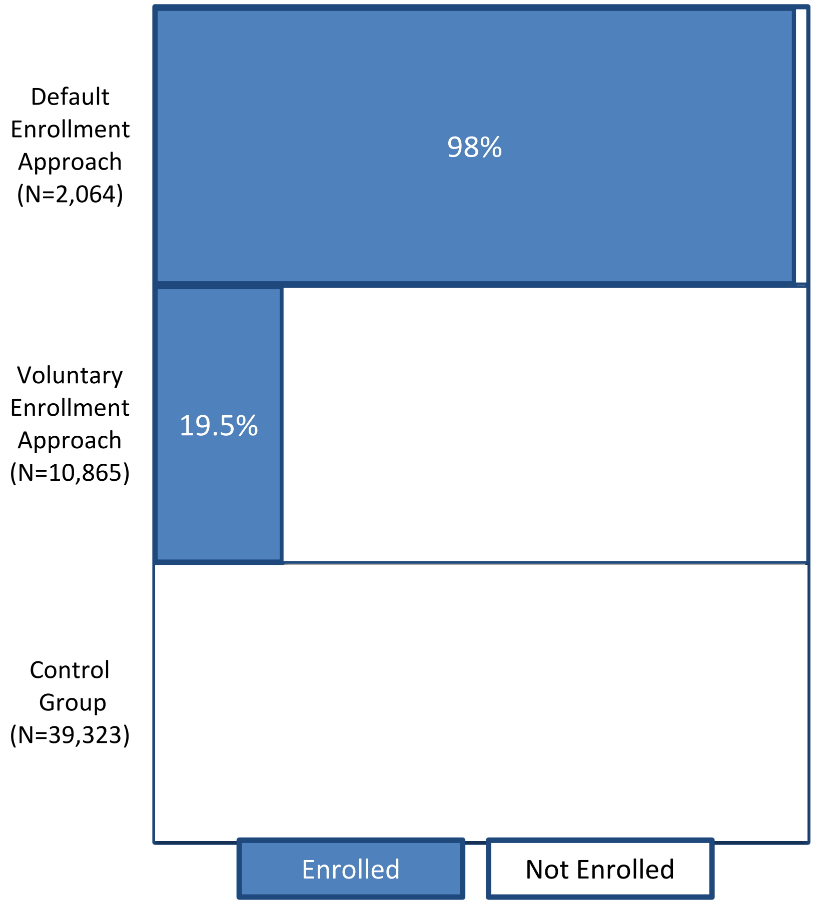


Figure 2. SMUD Enrollment Rates by Enrollment Approach

[17] These enrollment statistics reflect the share of customers enrolled in the study as of the date on which the study rates took effect (June 1st, 2012) after having omitted any customers who moved prior to that date.

2.3 Experiences with Customer Retention

In contrast to some expectations, SMUD did not experience high levels of attrition among the customers defaulted onto residential TOU rates. In fact, Figure 3 shows that drop-out rates were very low for those defaulted onto the rate (only 3.9% dropped out overall), and lower overall for those in the default group than for those in the voluntary group (4.4% dropped out overall).[18]

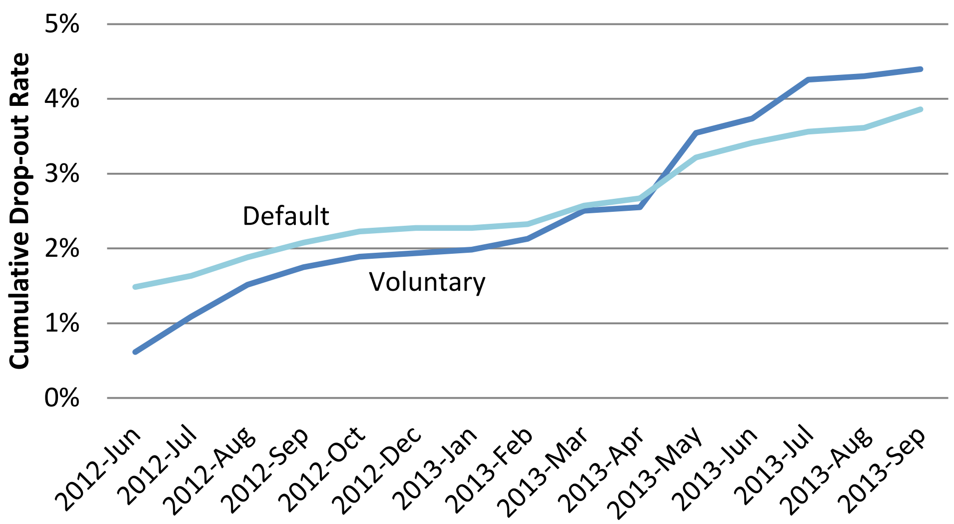


Figure 3. SMUD Drop-out Rates for Default and Voluntary Groups

An analysis of responses to SMUD's End-of-Pilot customer satisfaction survey found little difference between survey respondents who volunteered and those who were defaulted onto the rate concerning difficulties faced when adapting to the new rates.[19] However, default customers were more likely to indicate that they didn't understand or know about the new rates compared to those who volunteered. This may provide part of the explanation of why retention rates were higher for the default TOU group – they didn't bother to read the material SMUD sent indicating they were to be defaulted onto this new rate as part of a study. It is worth pointing out that this lack of awareness does not necessarily mean that customers were unhappy with being defaulted onto the rate. It is possible that they received the

[18] Attrition was measured relative to the size of the enrolled group as of June 1st, 2012 (the effective date of the study's rates).

[19] A copy of the End-of-Pilot customer satisfaction survey instrument as well as the results of its administration can be found in Appendix G of SMUD's final evaluation report (Potter et al., 2014).

information from SMUD, spent very little time reading that material only to decide that they were basically indifferent about being on the new or old rate. In essence, these customers may have been decided that it wasn't worth any additional effort to make themselves more aware of the details at the time of enrollment, but also not worth attempting to get off of the rate during the study.

2.4 Experiences with Customer Load Impacts

As may have been expected, the average customer response rates were lower for customers defaulted onto the TOU rate than for those who volunteered.[20] As shown in Figure 4, average peak period demand reductions per household for volunteers were about three times larger than for those defaulted onto the rate (16.7% vs. 5.8%; the difference is statistically significant, and each estimate on its own is statistically significant).

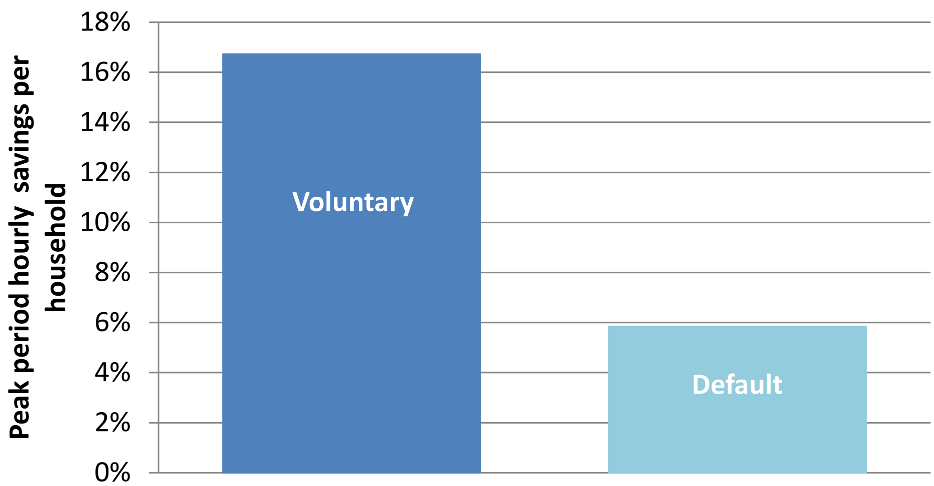


Figure 4. SMUD Average Peak Period Savings Estimates for Default and Voluntary Groups

SMUD was not only interested in the level of average response from the default and voluntary groups but also what level of aggregate response would occur if such opportunities were made available to the entire residential class. The per household estimated results can therefore be used to extrapolate the level of peak period demand reduction that could occur if TOU was made the default for all roughly 545,000 of SMUD's residential customers vs. if

[20] See Appendix C for more details on the econometric load impact analysis.

all roughly 545,000 of SMUD's residential customers were asked to opt-in to a voluntary TOU rate.[21] Under this scenario, the larger number of customers who enrolled and responded under default recruitment more than outweighs the larger per customer response of the smaller number of volunteers. As shown in Figure 5, a default TOU rate applied across the SMUD service territory would produce 5.7% (58.2 MW) aggregate peak period load reduction while a voluntary TOU offering would only produce 3.3% impact (33.2 MW).

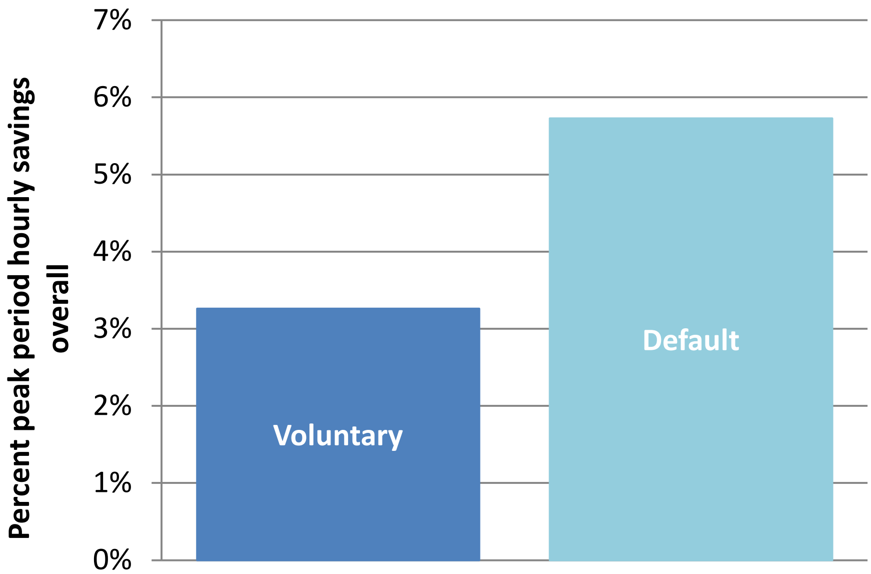


Figure 5. SMUD Aggregate Peak Period Savings Projections by Enrollment Approach for 545,000 Residential Customer Population

SMUD's survey of default and voluntary participant groups show that the vast majority of survey respondents indicated that it was not difficult to make changes in their electricity consumption patterns in response to the TOU rate. Figure 6 shows the percentage of survey respondents that undertook various actions to lower their peak period electricity usage. For nearly every action, a larger share of those who volunteered for the rate stated they undertook the action than those who were defaulted onto it. However, a majority of both types of customers who responded to the survey indicated they undertook relatively simple load shifting behaviors, such as adjusting when they did their laundry and dish washing to

[21] The average monthly residential customer count for 2015 in SMUD's service territory was 546,155. To simplify the calculations, we chose to round this down to 545,000 customers.

off peak times. In addition, well over 35% of those survey respondents defaulted onto the rate and over 48% of those who volunteered undertook actions to reduce or eliminate air conditioning use during the peak period, steps which were likely to produce much more significant peak electricity savings. [22]

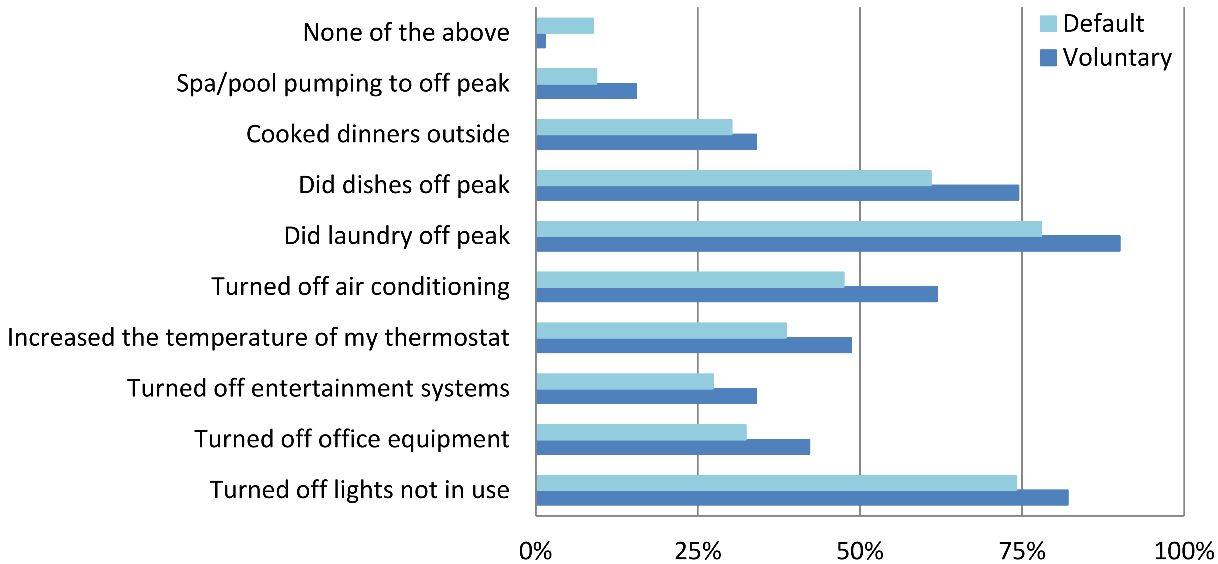


Figure 6. SMUD Survey Responses of Actions Taken by Study Participants to Lower Electricity Consumption During Peak Hours

2.5 Experiences with Customer Bill Savings

When taking service under TOU rates, the timing of when customers consume electricity matters for electricity costs and bills, whereas on flat or inclining block rates it does not. Because rates are typically designed for the average customer's load shape, moving from flat or inclining block rates to TOU rates will likely make some customers' bills larger. However, the converse is also true; those customers who consume less electricity during peak periods than the average customer may experience lower bills under a TOU rate. In SMUD's study, a larger share of customers with higher peak period consumption than the average were

[22] Note that the results from the End-of-Pilot customer satisfaction survey must be interpreted carefully as they are contingent on the subpopulation that responded to the survey. In addition, this response rate differed (not surprisingly) between the default (28.4% responded) and voluntary (45.0% responded) groups. This means that the survey responses may not reflect the experiences of the least engaged and attentive customers in general, which is more of a factor for the default group than the voluntary group.

solicited to join the study, both under default and voluntary enrollment approaches.[23] Because of this, the average customer, in both the default and voluntary treatment groups, were both expected to be slightly worse off financially from taking service under the rate, based on an analysis of their meter data from the summer prior to the start of SMUD's CBS applied to the study's TOU rate (see Table 2). Specifically, bills were expected to rise by 1.8 and 1.9% for those who volunteered or were defaulted onto the rate, respectively (i.e., -1.8% and -1.9% bill savings).[24]

Table 2. Predicted Bill Savings Absent Customer Response to TOU Rate and Actual Bill Savings in Response to the TOU Rate

	Predicted % Savings (using pre-treatment energy usage)	Actual % Savings (using post-treatment bills)
Default Rate	-1.9%	1.8%
Voluntary Rate	-1.8%	2.6%

Once exposed to TOU rates, customers were likely to reduce consumption in high-priced peak periods and potentially shift it to lower priced off-peak periods. As illustrated in Table 2, both the average default and average volunteer participant attained no measurable bill losses during the study relative to the control group – suggesting that on average customers took sufficient action to shift usage from the higher priced period to the lower priced period to offset the initially predicted bill losses from changing to the TOU rate.[25]

2.6 Experiences with Cost Effectiveness

With lower recruitment costs and higher *aggregate* demand reductions under default enrollment approaches, SMUD's cost-effectiveness analysis showed higher benefit-cost ratios and 10-year net present value for default versus voluntary enrollments, as shown in Table 3.

---

[23] SMUD randomly assigned customers from their eligible residential class to be solicited to join either the voluntary or default study. As such, this result is not representative of some systematic effort on the part of SMUD to choose such a skewed study population, but rather due to random chance.

[24] This finding was surprising as SMUD's rate was designed to be revenue neutral to the class average customer.

[25] It is worth noting that only the Actual % Savings estimate for the default group was statistically different from zero. So, in essence, there were no measurable bill savings or losses for the average customer in the Voluntary group.

Table 3. SMUD Cost Effectiveness Results by Enrollment Approach[26]

Enrollment Approach	Benefit-Cost Ratios	10-year Net Present Values ($M)
Voluntary	0.74	- $5.50
Default	2.04	+ $34.10

[26] See Potter et al. (2014).

3. Understanding Customer Subpopulations

In totality, the results of our analysis show that the average residential customer defaulted onto SMUD's TOU rate responds to the rate and doesn't experience any measurable bill losses. However, this average result masks substantial diversity in responses to new rates and the underlying customer preferences. In fact, one of the main concerns about defaulting all residential customers onto TOU is that certain subpopulations will be adversely affected.

Here we define three subpopulations of customers that can help clarify thinking about who might possibly be made better off or might be at risk of being worse off due to default TOU rates:

- **Never takers**: the set of customers that would not actively opt in to voluntary TOU rate offers, and would actively opt out when TOU rates are the default;
- **Always takers**: the set of customers that would actively opt in to voluntary TOU rate offers and would not actively opt out when TOU rates are the default; and
- **Complacents**: the set of customers who would not actively opt in to voluntary TOU rate offers, but would not actively opt out when TOU rates are the default.

We assume that the people who opt in to a voluntary TOU rate would be likewise expected to not opt out initially if defaulted onto the rate. Thus, we believe that the way in which these ***Always Takers*** enroll in the TOU rate would not affect their satisfaction from taking service under it. In fact, they may benefit from a default rate in that they are automatically placed on the rate, and don't have to take the time to opt in to the voluntary rate.

In addition, there is a subpopulation of customers who prefer their existing rate over a TOU rate. These customers will not opt in when solicited to voluntarily take up the TOU rate and will likewise opt out if defaulted onto it. These ***Never Takers*** clearly express their preferences when presented with choices.

This leaves a third group of residential customers: the group that will not opt in to a voluntary TOU rate but neither will they opt out when TOU is made the default rate design. These ***Complacents*** seem willing to go along with the tariff that they are placed on by the utility.

Figure 7 shows a breakout of the estimated proportions of these three subpopulations in SMUD's study. In using SMUD data to analyze these subpopulations, it was necessary (but reasonable from our standpoint) to assume that the group of Always Takers observed in the voluntary enrollment experimental design would represent the same proportion of, and act similarly to, those Always Takers who could not be directly identified in the default enrollment experimental design.

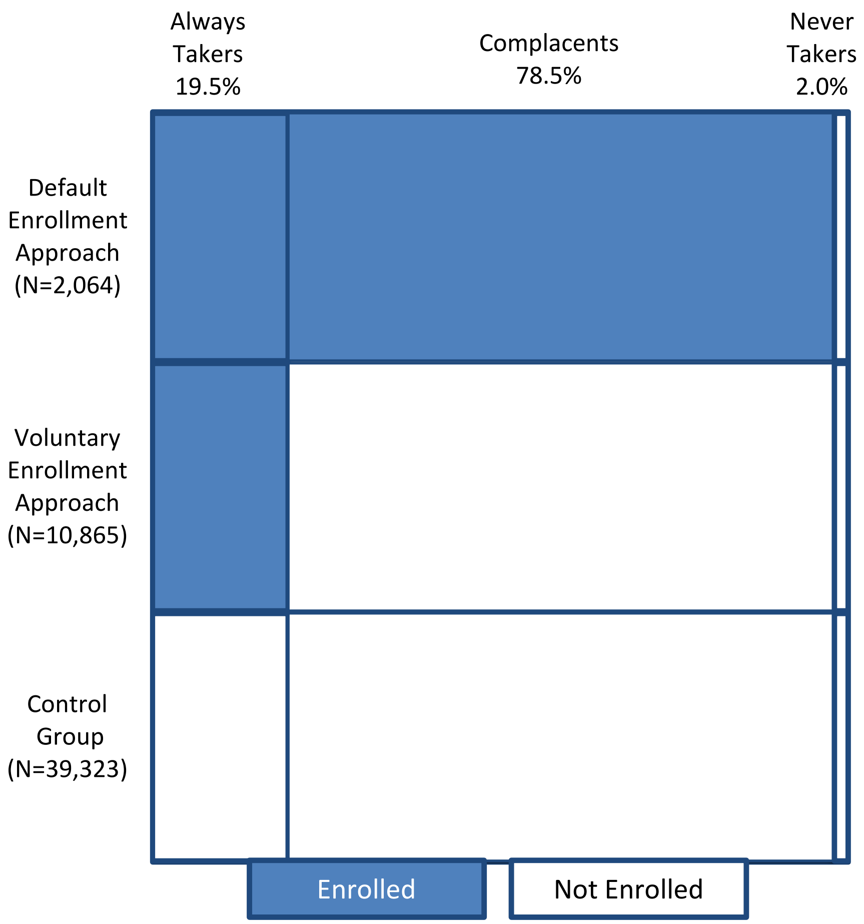


Figure 7. SMUD Residential Customer Subpopulations for Analyzing Voluntary vs. Default Enrollment

Key potential concerns one might anticipate ex-ante for the Complacent customer subpopulations under default TOU rates can be defined as follows:

- **Concerns regarding customer retention**– Complacents may not opt out initially, but once exposed to the rate, they may be more likely to drop out compared to Always Takers;

- **Concerns regarding customer response**– Complacents may be unlikely to respond as much (if at all) as compared to Always Takers; and
- **Concerns regarding customer bill impacts**– Complacents may be more likely to experience detrimental bill impacts as compared to Always Takers, if they have a more limited response.

In the following subsections we examine these three concerns in turn.

3.1 Concerns Regarding Customer Retention

One of the key concerns involves Complacents dropping out at higher rates than Always Takers. Figure 8 provides a breakdown of the drop-out rate for Always Taker and Complacent subpopulations through the course of the study and depicts a very different story. Complacents did drop out at a slightly higher rate over the first summer. However, at the beginning of the second summer we see that the rate of drop-outs for Complacents stayed relatively constant while this rate increased for Always Takers. This resulted in a larger share of Always Takers (observed to be 4.4%) dropping out overall compared to Complacents (estimated to be 3.7%).

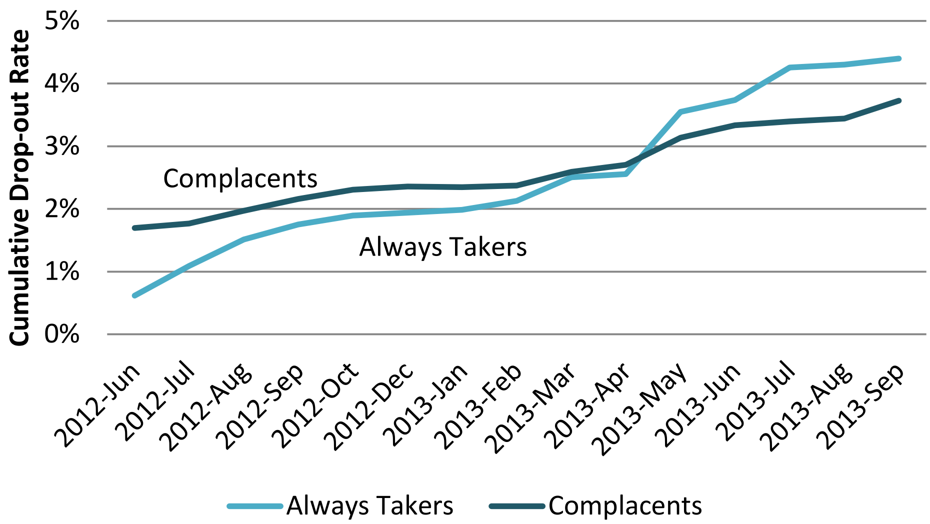


Figure 8. SMUD Drop-Out Rates by Customer Subpopulation

One explanation for this finding is that the majority of Complacents may have been satisfied with the new TOU rate once they gained experience with it. According to SMUD's End-of-Pilot customer satisfaction survey, the vast majority of survey respondents in all groups said they were generally satisfied with the new rate. A majority also indicated that they would want to stay on the new TOU rate going forward. Of survey respondents, a somewhat higher percentage of Complacents said that they did not want to stay on their TOU pricing plan (12% of Complacents vs. 6% of Always Takers who responded to the survey). In general we can conclude that, contrary to expectations, defaulting Complacents onto a TOU rate did not automatically mean high levels of dissatisfaction and in some instances seemed to actually increase satisfaction levels when customers were exposed to and understood how to use the new rate to their advantage.

However, SMUD's survey also provided evidence that Complacents were:

- Less likely to respond to the survey;
- Less likely to recognize the new TOU rates and more likely to say they were not sure about their rate when asked;
- Less likely to recall receiving the "Welcome Back" package of information from SMUD in the mail; and
- Much more likely to check the "neutral" box to most survey questions when given the option.

These survey responses (or lack thereof) suggest a few different potential reasons for the relatively low drop-out rates for Complacents. First, Complacents may have decided early in this process that it wasn't worth the mental energy and time to carefully analyze all the material sent by SMUD. These people may have learned enough from the limited time they spent reviewing the material to know they were basically indifferent to the new rate they were being put on. Thus, they were never motivated to leave the rate even though they may not have understood many of its details. Alternatively, Complacents might have decided, after their cursory perusal of the marketing material, that they didn't like the new default rate but then decided it wasn't worth the time and mental effort to get out of the study. Maybe they never got around to determining how to navigate the opt-out process or got that information but never followed through on it. Lastly, Complacents may not have been engaged enough to read any of the material sent by SMUD concerning the study and the rate transition. As such, these Complacents never attempted to get off the rate simply because they didn't know they were on it to begin with.

3.2 Concerns with Customer Response

With the potential lack of engagement, interest, and understanding among some Complacents when defaulted onto time-based rates, lower average per-customer demand reductions from them were expected.[27] Figure 9 confirms this and shows average percentage demand reductions were around five times larger for Always Takers (16.7%) as compared to Complacents (3.1%) on average across both summers of the study. The result indicates that the average Always Taker reduced their peak period hourly consumption by an estimated 18.2% on average in the first summer, while the average Complacent reduced their peak period hourly consumption by an estimated 3.4% in the first summer on average.[28] Interestingly, when comparing the impact estimates between the first and second summer of the study, we see that Always Takers peak period savings attenuated, dropping to 14.7%, resulting in a difference between the two summers that is statistically significant. On the other hand, Complacents basically maintained their level of peak period savings between the two summers (they dropped from 3.4 to 2.9% savings, but this difference is not statistically significant). This suggests that possibly the more sizable actions taken by Always Takers ended up feeling like too much over time and they eventually relaxed their efforts, while Complacents tended to take more modest actions that they were more likely to maintain.

[27] See Appendix C for more details about the econometric load impact analysis.

[28] This effect size for the Complacents in the first summer was small but statistically significant.

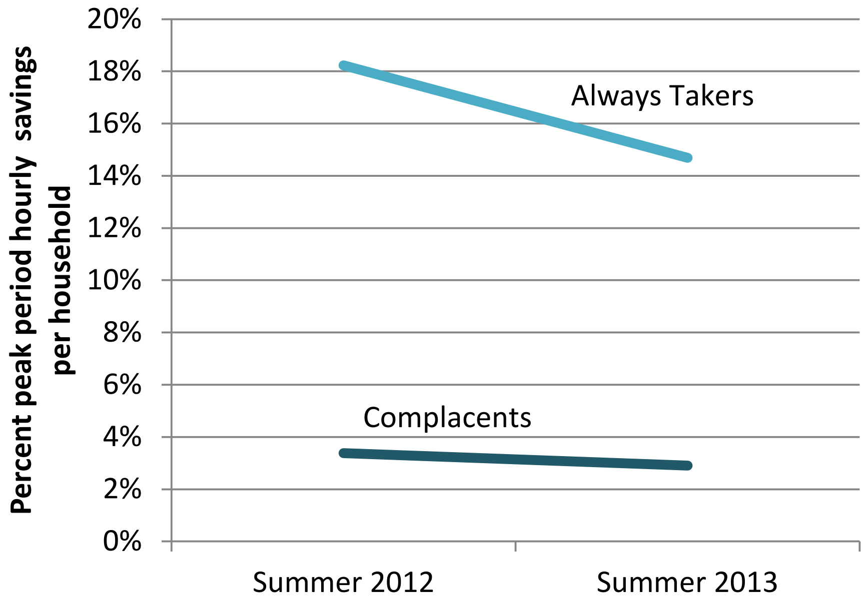


Figure 9. SMUD Average Peak Period Demand Reductions by Customer Subpopulation

From the utility's perspective, it is the aggregate demand reductions for the entire group of customers that were originally encouraged and marketed to that matters most. In the scenario discussed previously where all ~545,000 of SMUD's residential customers are defaulted onto a TOU rate, Figure 10 shows that the entire group of Complacents would provide about 2.4% (24.8 MW) of demand reductions during peak periods, while the entire group of Always Takers would provide an additional 3.3% (33.2 MW).

Collectively, these results suggest that while some Complacents may be less likely to be engaged, interested, and knowledgeable about the rate, a sizable number understood the rate well enough, were willing and able to change their consumption patterns of electricity in direct response to the default TOU rate design, and were seemingly satisfied with doing so.

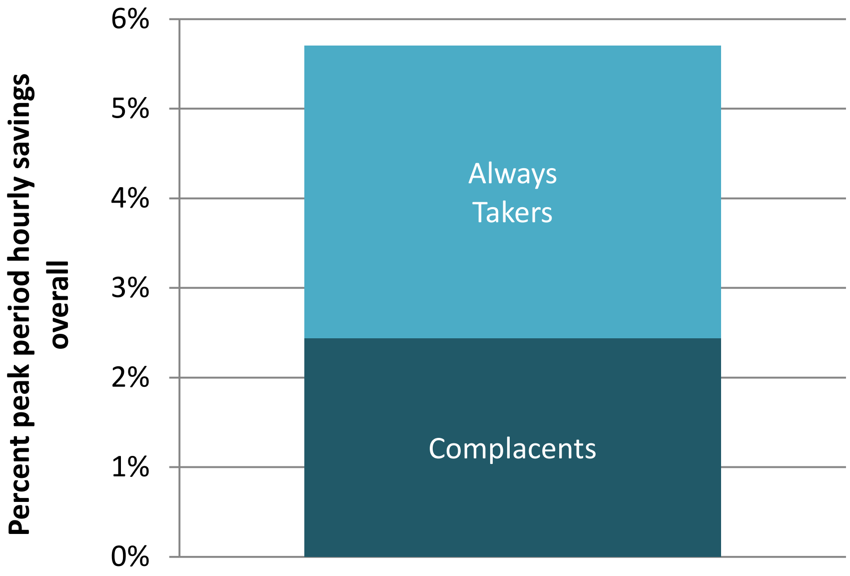


Figure 10. Aggregate Peak Period Demand Reductions by Customer Subpopulation if All of SMUD's Residential Customers were Defaulted onto TOU

3.3 Concerns with Customer Bill Impacts

During the recruitment phase of the study, SMUD did not set explicit expectations with customers that each and every participant would save money by joining the study.[29] Instead, SMUD's marketing material indicated the study's TOU rate created an opportunity for participating customers to save money by managing when they used electricity, not just how much they consumed. It is not clear if customers actually performed any calculations to assess their potential bill impacts from switching to the TOU rate, even without taking into account any change in their electricity consumption behavior.

An assessment of such predicted bill savings, based on an analysis of meter data collected prior to the commencement of the study from all of those who ultimately participated in the study under the default TOU rate, would have shown a distribution like the one in Figure 11. About 22% of the Always Takers and 22% of the Complacent subpopulations, respectively, absent any response to the rate, were predicted to see +/- $5 impact over an entire summer

[29] In fact, SMUD did not provide any customer-specific information about bill impacts during the recruitment phase of the study, nor did it provide any bill comparison tools during the study so customers could readily identify financial savings due to their participation.

on their bills in total. If that range is expanded to +/- $10 for the full summer, 40% of Always Takers and 39% of Complacents would be predicted to see such bill impacts. Broadening the range even further to +/- $20 for the whole summer would capture a majority (66% and 67%, respectively) of both Complacent and Always Taker subpopulation. It is not clear what level of bill impact might have gotten SMUD's customers' attention to either accept or eschew participation in the study, but this similarity of impacts between the two subpopulation suggests that predicted bill impacts were likely not a key driver in the choice to participate in the study.

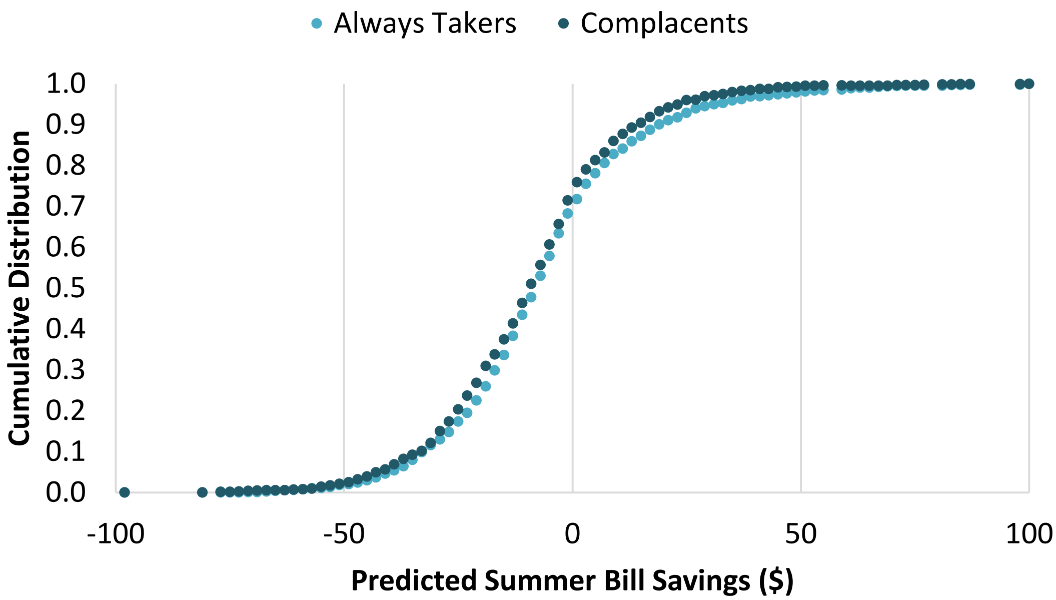


Figure 11. Distribution of Predicted SMUD Summer Bill Savings by Customer Subpopulation[30]

Predicted bill impacts also have implications for the degree to which a participating customer would need to alter their electricity consumption patterns once exposed to TOU in order to achieve any positive bill savings. By breaking the Complacent and Always Taker subpopulations into smaller groups (i.e., quintiles of the predicted full summer bill savings), Figure 12 shows how the average customer in each of these subgroups reduced their peak period load during the study. Always Takers at the extremes of the predicted bill savings

[30] Note that for the purposes of Figure 11 the distribution of predicted bill savings was truncated at +/-$100 per summer. There were 2 out of 12,925 customers with predicted losses greater than $100 and 22 out of 12,925 customers with predicted savings greater than $100.

(i.e., those with the largest predicted bill losses or savings) exhibited a substantially larger load impact than those who might see more modest bill effects. Complacents exhibited a similar but less extreme version of this phenomenon.[31] One possible explanation for this is that for some share of both Complacent and Always Taker subpopulations, a large predicted bill impact, regardless of its direction, may increase the desire, willingness, or interest of a customer to manage their electricity consumption relative to one who anticipates that their current consumption patterns is less likely to substantively alter their bill on a TOU rate option.

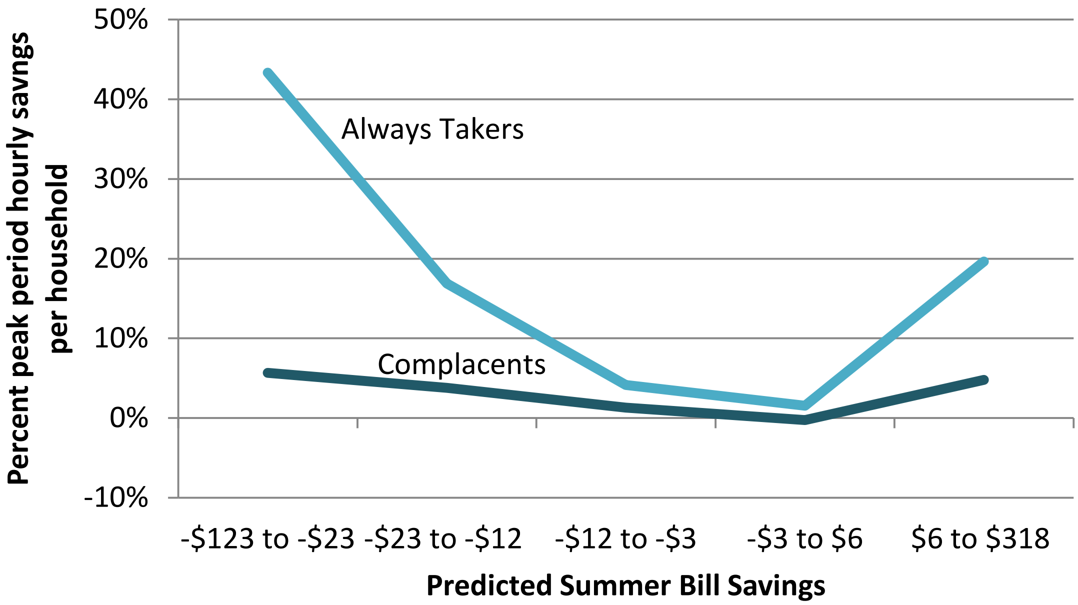


Figure 12. SMUD Peak Period Load Impacts by Customer Subpopulation and Quintile of Predicted Summer Bill Savings

Lastly, the level of the predicted bill savings may also have implications for a participant's overall satisfaction with the default TOU rate, especially as it dictates the degree to which a customer might need to adjust their consumption to actually see a bill reduction. Based on survey responses, predicted monthly bill savings, as shown in Table 4, did not appear to be a major factor in how satisfied customers were with the default TOU rate, once exposed to

[31] See Appendix C for information on which peak electricity savings estimates are statistically significantly different across the quintiles of predicted bill savings for the Complacents and Always Takers.

it.[32] In fact, the survey respondents who were predicted to save the most by taking service under such a rate (i.e., greater than $20 for the entire summer) generally had lower satisfaction levels than those predicted to see their bills increase by $5 or more over the course of the summer (e.g., -$10 to -$5). Furthermore, the estimated level of satisfaction with the rate by Complacent survey respondents varied more widely across predicted bill savings and there appeared to be little relationship between the size of the bill impacts and the share of satisfied customers.

In contrast, there does appear to be a relationship between the size of the predicted bill savings and the degree to which Complacent customers were interested in continuing with the rate, but a rather limited relationship between bill savings and satisfaction with the rate. This finding reinforces the notion that a large share of the Complacent subpopulation were seemingly indifferent – they were reasonably satisfied with the rate, regardless of the level of bill savings they achieved. However, those who were predicted to lose the most during the study expressed an interest to not continue with the rate when given a direct opportunity to get off of it. In contrast, we see that the Always Takers who responded to the survey expressed levels of satisfaction with the default TOU rate that increased as the size of the predicted bill savings dropped. One possible explanation for this result is that the increased effort by those Always Takers with the most to lose from participating in the study was an experience they actually found satisfying. Perhaps if the response required to capture bill savings were higher, the willingness and interest in responding was higher. This heightened ability to manage and/or control their bills may have been viewed positively, especially for those with the most to gain from doing so.

[32] No standard errors were developed as part of the analysis that relies on values in Table 4. Thus, the conclusions drawn in this section are based on a numerical comparison of these values, not a statistical one.

Table 4. Share of SMUD Survey Responses by Customer Subpopulation and Predicted Summer Bill Savings

Predicted Summer Bill Savings ($)	Average Share of Survey Respondents Satisfied with the Existing Rate		Average Share of Survey Respondents Interested in Continuing with the Existing Rate	
	Always Takers	Complacents	Always Takers	Complacents
Less than - $20	94%	73%	96%	69%
-$20 to -$10	87%	92%	96%	89%
-$10 to -$5	89%	67%	92%	82%
-$5 to $5	82%	73%	94%	91%
$5 to $10	85%	100%	91%	100%
$10 to $20	72%	88%	88%	100%
Greater than $20	82%	53%	94%	92%

3.4 Identifying Inattentive Complacents

While it is difficult to directly identify which customers are attentive or not, proxies for attentiveness can be derived. In particular, utilities know whether or not a customer has ever actively volunteered for one of their programs. By constructing a proxy for attentiveness through identifying all the customers who: a) participated in one of SMUD's programs in the past; b) responded to the End-of-Pilot survey; and/or c) all customers who hooked up their in-home display as part of SMUD's study, it is possible to construct a potential estimate of the size of the attentive complacent population. Using this approach, 75% of Complacents were considered attentive and engaged. This proxy can be used to segment the Complacent subpopulation. In so doing, this definition of attentiveness can be used to see if estimated load impacts are different, which would serve as a test of the validity of this proxy. The results of such an analysis shows that, assuming the inattentive Complacents did not respond to the TOU rate (as one might expect), the attentive Complacents would have provided greater peak period load response than the overall Complacent population (about 5% vs. 3%

electricity savings). Taken in total, these results suggest that a reasonable estimate of the size of the inattentive complacent population is 25% of the overall Complacent population (which constitutes 20% of the entire SMUD population).

4. Summary of Major Findings and Conclusions

This analysis suggests that many of the previously stated concerns by consumer advocates and other industry stakeholders about a transition of residential customer to a default TOU rate did not materialize, based on experiences from SMUD's consumer behavior study. Customers defaulted onto a TOU rate initially stayed where they were placed at unexpected levels, as about 98.0% did not opt out. Once on the rate, these customers did not leave in large numbers as might have been expected; 3.9% dropped out during the study period in total. Instead, a larger share of them remained on the new rate through the end of the study than their counterparts who volunteered to participate (4.4% of whom dropped out in total). In spite of the lower per-customer demand reductions, which was expected for defaulted customers, the average defaulted customer did respond to the rate by altering their consumption of electricity to the TOU rate in a statistically significant fashion resulting in peak period demand reductions of about 5.7%. When taken in aggregate for a similar population of customers who were originally solicited to participate, SMUD's TOU rate offering was more cost effective under a default enrollment approach than a voluntary one by almost 3 to 1, in part because of lower recruitment costs.

Yet, these overall results mask the variety of underlying customer experiences across several different subpopulations. For example, there was a subgroup of residential customers that would have opted in to a voluntary TOU rate and if defaulted into the same rate would not have dropped out. This subpopulation of Always Takers should not be of particular concern to policy and decision makers as they are able to express their preferences and act on them. Likewise, the subpopulation of SMUD customers that decided to opt out of the default TOU offering (i.e., Never Takers) were following their preferences and, as such, should also not be of particular concern to policy and decision makers.[33] This leaves the remainder of the residential class – those customers who would not have opted in to the voluntary TOU rate but yet did not opt out when defaulted onto the rate. It is these Complacents that regulators, policymakers, advocates and utilities need to understand better.

The analysis in this report suggests that, as a group, Complacents were less engaged, attentive, and informed than the other two subpopulations. There was certainly some subset of the Complacent population who were fully aware of the rate, engaged enough with it to

[33] Under a default enrollment, these customers would need to go through the opt-out process which is an additional level of effort they avoid under voluntary enrollment approaches.

undertake some substantial changes in behavior to respond to it in order to achieve bill savings and were generally satisfied with their experience with the study and the rate. But another subset of Complacents may have been largely indifferent about the rate, not particularly concerned about being defaulted onto it, expended a modest level of effort to respond to the rate and were satisfied enough with it to keep taking service under it after the study ended, provided they didn't see large bill increases. These customers were also likely better off for having been defaulted onto the rate, or at least not worse off. Lastly, there was a subset of customers who likely were highly inattentive and unengaged. We estimate the size of this group to be around 25% of the Complacent population, which represents 20% of the full residential customer population. They were more likely to be unaware of the rate SMUD had transitioned them to, which also helps, in part, to explain the very low attrition rates and also low average per customer peak period response rates. In this case, contrary to the others, it is possible that these inattentive Complacents were worse off for having been defaulted onto the rate.[34]

This suggests that it is not the entirety of SMUD's residential customers or even the share of residential customers that are Complacents who are at-risk of being made worse off during a transition to default TOU, but rather a minority subset of the latter. For utilities and states considering a transition to default TOU, it is this subpopulation of customers who are potentially at risk of being made worse off that requires the greatest consideration. The likelihood of a successful transition could improve if utilities and others consider the needs of this subpopulation of inattentive Complacents. Ideally, utilities could identify customers who are more likely to be highly inattentive before the transition to default TOU is even announced. For example, utilities could create proxies, as described in the previous section, for the level of a customer's attentiveness and engagement. Customers that seem to be less attentive and less engaged could be targeted by the utility for more direct and non-traditional communication strategies. In addition, utilities could use focus groups or other types of market research to determine the best ways to reach inattentive customers so that they can be made aware of the transition, better understand their options, and more easily navigate the opt-out process if they don't want to make the transition.

[34] Although even some of these inattentive Complacents could have captured bill savings absent any change in their electricity consumption suggesting they may have actually been better off.

References

AARP, National Consumer Law Center, National Association of State Utility Consumer Advocates, Consumers Union and Public Citizen (2010) The Need for Essential Consumer Protections: Smart metering proposals and the move to time-based pricing [White Paper].

Cappers, P., Todd, A., Perry, M., Neenan, B. and Boisvert, R. (2013) Quantifying the Impacts of Time-based Rates, Enabling Technology, and Other Treatments in Consumer Behavior Studies: Protocols and Guidelines. L. B. N. Laboratory, Berkeley, CA. July, 2013. 115 pages. LBNL-6301E.

CPUC (2015) *Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilitis' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations*, California Public Utilities Commission, Rulemaking 12-06-013, Decision 7/3/2015, Agenda ID 13928 (Rev. 2), July 3, 2015.

DellaVigna, S. (2009) Psychology and Economics: Evidence from the Field. *Journal of Economic Literature.* 47(2): 315-372.

DOE (2012) Smart Grid Investment Grant Program Progress Report. U.S. Department of Energy, Washington, D.C. . July 2012. 96 pages.

EPRI (2011a) The Effect on Electricity Consumption of the Commonwealth Edison Customer Application Program Pilot: Phase 1. April 2011. 1022703.

EPRI (2011b) The Effect on Electricity Consumption of the Commonwealth Edison Customer Application Program: Phase 2 Final Analysis. October 2011. 1023664.

Faruqui, A. and Malko, J. R. (1983) The residential demand for electricity by time-of-use: A survey of twelve experiments with peak load pricing. *Energy.* 8(10): 781-795.

Faruqui, A., Sergici, S., Lessem, N. and Mountain, D. (2015) Impact measurement of tariff changes when experimentation is not an option - A csae study of Ontario, Canada. *Energy Economics.* 52(A): 39-48.

FERC (2012) 2012 Assessment of Demand Response & Advanced Metering: Staff Report. Federal Energy Regulatory Commission, Washington, D.C. December 2012.

Hausman, W. J. and Neufeld, J. L. (1984) Time-of-Day Pricing in the U.S. Electric Power Industry at the Turn of the Century. *The Rand Journal of Economics.* 15(1): 116-126.

Ida, T. and Wang, W. (2014) A Field Experiment on Dynamic Electricity Pricing in Los Alamos: Opt-in Versus Opt-out. Kyoto University Graduate School of Economics, Kyoto City, Japan. September 2014. Discussion Paper No. E-14-010.

Institute for Electric Innovation (2014) Utility-Scale Smart Meter Deployments: Building Block of the Evolving Power Grid. The Edison Foundation. September 2014.

Institute for Energy and the Environment (2012) Salt River Project: Delivering Leadership on Smarter Technology & Rates. Smart Grid Case Study Series Vermont Law School. June 2012. Case 2.

Lakeland Electric (2015) Consumer Behavior Study Final Evaluation Report.Lakeland, FL. April 2015.

MADPU (2014) *Docket D.P.U. 14-04-C: Order Adopting Policy Framework for Time Varying Rates*, The Commonwealth of Massachusetts Department of Public Utilities, November 5, 2014.

NYDPS (2015) *Staff White Paper on Ratemaking and Utility Business Models*, State of New York Department of Public Service, Case 14-M-0101, Issued July 28, 2015.

Potter, J. M., George, S. S. and Jimenez, L. R. (2014) SmartPricing Options Final Evaluation. Sacramento Municipal Utility District. Prepared for U.S. Department of Energy,. September 2014.

Power System Engineering Inc. (2012) EmPOWER Critical Peak Pricing Pilot Assessment.Minneapolis, MN. Prepared for Sioux Valley Energy,. March 2012.

Schwartz, L. (2003) Demand Response Programs for Oregon Utilities.Salem, OR. Prepared for Oregon Public Utility Commission,. May 2003.

Snook, L. and Grabel, M. (2015) There and Back Again: Why a residential demand rate developed 40 years ago is increasingly relevant today. *Public Utilities Fortnightly*.

Appendix A: Background on SGIG Consumer Behavior Studies

In 2009, Congress saw an opportunity to advance the electricity industry's investment in the US power system's infrastructure by including the Smart Grid Investment Grant (SGIG) as part of the American Recovery and Reinvestment Act (Recovery Act). To date, DOE and the electricity industry have jointly invested over $7.9 billion in 99 cost-shared SGIG projects that seek to modernize the electric grid, strengthen cybersecurity, improve interoperability, and collect an unprecedented level of data on smart grid and customer operations enabled by these investments. The SGIG program includes more than 60 projects that involve AMI deployments with the aim of improving operational efficiencies, lowering costs, improving customer services, and enabling expanded implementation of time-based rate programs.[35]

In selecting project applications for SGIG awards, DOE was interested in working closely with a subset of utilities willing to conduct comprehensive consumer behavior studies that applied randomized and controlled experimental designs. DOE's intent for the studies was to encourage the utilities to produce robust statistical results on the impacts of time-based rates, customer information systems, and customer automated control systems on peak demand, electricity consumption, and customer bills. The intent was to produce more robust and credible analysis of impacts, costs, benefits, and lessons learned and assist utility and regulatory decision makers in evaluating investment opportunities involving time-based rates. Of the SGIG projects investing in AMI and implementing time-based rate programs, there were ten utilities that were interested in working with DOE to participate in the CBS program.

A.1 Scope of the CBS Projects

The ten CBS utilities set out to evaluate a variety of different time-based rate programs and customer systems. Concerning the former, the CBS utilities planned to study TOU, CPP, critical peak rebates (CPR), and variable peak pricing (VPP).[36] Many also planned to include some form of customer information system (e.g., IHDs) and/or customer automated control system (e.g., PCTs). Several CBS utilities evaluated multiple combinations of rates and

[35] When the SGIG program is completed in 2015, SGIG will have helped to deploy more than 15 million new smart meters, which represents about 23% of the 65 million smart meters that industry estimates will be installed nationwide. At that point, smart meter deployment is estimated to comprise about 45% of the electric meters in the United States.

[36] Technically, CPR is not a time-based rate; it is an incentive-based program. However, for simplicity of presentation in Table A-1, it is classified with the other event-driven time-based rate programs.

customer systems, based on the specific objectives of their SGIG projects and consumer behavior studies (see Table A-1). For example, one utility evaluated treatment groups with a CPP rate layered on top of a flat rate, in combination with and without IHDs. Another evaluated VPP as well as CPP layered on top of a TOU rate in combination with and without PCTs. Table A-1 provides a summary of the scopes of the CBS projects.

Table A-1. Scope of CBS Projects

	CEIC	DTE	GMP	LE	MMLD	MP	NVE	OG&E	SMUD	VEC
Rate Treatments										
CPP		●	●		●	●	●	●	●	
TOU Pricing		●		●		●	●	●	●	
VPP								●		●
CPR	●		●							
Non-Rate Treatments										
IHD	●	●	●					●	●	
PCT	●	●					●	●		
Education							●			
Recruitment Approaches										
Opt-In	●	●	●	●	●	●	●	●	●	●
Opt-Out				●					●	

Utility Abbreviations: Cleveland Electric Illuminating Company (CEIC), DTE Energy (DTE), Green Mountain Power (GMP), Lakeland Electric (LE), Marblehead Municipal Light Department (MMLD), Minnesota Power (MP), NV Energy (NVE), Oklahoma Gas and Electric (OG&E), Sacramento Municipal Utility District (SMUD), Vermont Electric Cooperative (VEC)

A.2 DOE Guidance on CBS Projects

DOE's goal for all of the consumer behavior studies was for them to produce load impact results that achieve internal and ideally external validity.[37] To help ensure that this goal was met, DOE published ten guidance documents for the CBS utilities. The guidelines were intended to help the utilities better understand DOE's expectations of their studies to achieve these goals, including their design, implementation, and evaluation activities.

Specifically, several of the DOE guidance documents addressed how to appropriately apply experimental methods such as randomized controlled trials and randomized encouragement designs to more precisely estimate the impact of time-based rates on electricity usage patterns, and identify the key drivers that motivated changes in behavior.[38] The guidance documents identified key statistical issues such as the desired level of customer participation, which is critical for ensuring that sample sizes for treatment and control groups were large enough for estimates of customer response to have the desired level of accuracy and precision. Without sufficient numbers of customers in control and treatment groups, it would be difficult to determine whether or not differences in the consumption of electricity were due to exposure to the treatment or random factors (i.e., internal validity).

To make best use of the guidance documents, DOE assigned a Technical Advisory Group (TAG) of industry experts to each CBS utility to provide technical assistance. The TAGs helped customize the application of the guidance documents as each of the utility studies was different and had their own goals and objectives, starting points, levels of effort, and regulatory and stakeholder interests. These latter factors, in conjunction with the DOE guidance documents, determined how each utility study was designed and implemented. For example, several utilities had prior experience with time-based rates and used the studies to evaluate needs for larger-scale roll-outs. Others had little or no experience and used the

[37] Internal validity is the ability to confidently identify the observed effect of treatments, and determine unbiased estimates of that effect. External validity is the ability to confidently extrapolate study findings to the larger population from which the sample was drawn.

[38] The experimental designs were intended to ensure that measured outcomes could be determined to have been caused by the program's rate and non-rate treatments, and not random or exogenous factors such as the local economic conditions, weather or even customer preferences for participating in a study. Most of the studies decided to use a *Randomized Controlled Trial* experimental design, which is a research strategy involving customers that volunteer to be exposed to a particular treatment and are then randomly assigned to either a treatment or a control group. A few studies chose to use a *Randomized Encouragement Design*, which is a research strategy involving two groups of customers selected from the same population at random, where one is offered a treatment while the other is not. Not all customers offered the treatment are expected to take it, but for analysis purposes, all those who are offered the treatment are considered to be in the treatment group. For more information, see Cappers et al. (2013)

studies to learn about customer preferences and assess the relative merits of alternative rates and technologies.

Each CBS utility was required to submit a comprehensive and proprietary Consumer Behavior Study Plan (CBSP) that was reviewed by the TAG and approved by DOE. In its CBSP, each utility documented the proposed study elements, including the objectives, research hypotheses, sample frames, randomization methods, recruitment and enrollment approaches, and experimental designs. The CBSP also provided details surrounding the implementation effort, including the schedule for regulatory approval and recruitment efforts, methods for achieving and maintaining required sample sizes, and methods for data collection and analysis.[39]

Each CBS utility was also required to comprehensively evaluate their own study and document the results, along with a description of the methods employed to produce them, in a series of evaluation reports that were reviewed by the TAG, approved by DOE, and posted on Smartgrid.gov. Each utility was expected to file an interim evaluation report after the first year of the study and a final evaluation report at the end of the study.

---

[39] In several cases, utilities encountered problems during implementation (e.g., insufficient numbers of customers in certain treatment groups) that required the study's initial design as described in the CBSP to be altered to maintain a high probability of achieving as many of the study's original objectives as possible. For several utilities this meant reductions in the number of treatment groups included in the studies.

Appendix B: Background on SGIG Consumer Behavior Studies

B.1. Overview

Sacramento Municipal Utility District (SMUD) is a summer peaking municipal electric utility with ~625,000 customers in its ~900 square mile service territory that covers much of the Sacramento, CA metropolitan area. SMUD's SGIG project (SmartSacramento) includes a consumer behavior study that evaluates customer acceptance and response to enabling technology combined with various time-based rates under different recruitment methods. The utility is targeting AMI-enabled residential customers across the entire service territory to participate in the study.

B.2. Goals and Objectives

This study focuses on evaluating the timing and magnitude of changes in residential customers' peak demand patterns due to exposure to varying combinations of enabling technology, different recruitment methods (i.e., opt-in vs. opt-out), and several time-based rates. SMUD is also interested in learning about customer acceptance of the different time-based rates under the alternative recruitment methods.

B.3. Treatments of Interest

Rate treatments include the implementation of three time-based rate programs in effect from June through September: a two-period TOU rate that includes a three-hour on-peak period (4 - 7 p.m.) each non-holiday weekday; a CPP overlaid on their underlying tiered rate; and a TOU with CPP overlay (TOU w/CPP) (see Table B-1). Customers participating in any CPP rate treatments receive day-ahead notice of critical peak events, called when wholesale market prices are expected to be very high and/or when system emergency conditions are anticipated to arise. CPP participants will be exposed to 12 critical peak events during each year of the study.

Control/information technology treatments include the deployment of IHDs. SMUD is offering IHDs to all opt-out customers in any given treatment group and to more than half of the opt-in customers in the treatment group. All participating customers receive web portal access, customer support and a variety of education materials.

Table B-1. SMUD CBS Rate Design (¢/kWh)

Period	CPP	TOU	TOU-CPP
Base (< 700 kWh)	8.51		
Base (> 700 kWh)	16.65		
Off-Peak (< 700 kWh)		8.46	7.21
Off-Peak (>700 kWh)		16.60	14.11
Peak		27.00	27.00
Critical Peak	75.00		75.00

B.4. Experimental Design

Due to the variety of treatments, the study includes three different experimental designs: randomized controlled trial (RCT) with delayed treatment for the control group, randomized encouragement design (RED) and within-subjects design (see Figure B-1).

In all three cases, AMI-enabled residential customers in SMUD's service territory are initially screened for eligibility and then randomly assigned to one of the seven treatments or the RED control group.

For the two treatments that are included in the RCT "Recruit and Delay" study design, customers receive an invitation to opt in to the study where participating customers receive an offer for a specific treatment. Upon agreeing to join the study, customers are told if they are to begin receiving the rate in the first year of the study (i.e., June 2012) or in the summer after the study is complete (i.e., June 2014).

For two of the three treatments that are included in the RED, customers are told that they have been assigned to a specific identified treatment but have the ability to opt out of this offer. Those who do not opt out receive the indicated treatment for the duration of the study. Those who opt out are nonetheless included in the study's evaluation effort but do not receive the indicated treatment. For one of the three RED treatments, customers receive an invitation to opt in to the study where participating customers receive a specific treatment. Customers that opt in are then assigned to receive the treatment in year 1 of the study (i.e., 2012).

For the two treatments that are included in the within-subject design, customers are told they have been assigned to either the Block w/CPP treatment or the TOU w/CPP treatment with technology.[40] In the former case, customers only have the ability to opt in to this specific treatment. In the latter case, customers only have the ability to opt out of this specific treatment.

[40] The within-subjects method was designed to use no explicit control group; instead it estimates the effects of the treatment for each participant individually, using observed electricity consumption behavior both before and after becoming a participant in the study as well as on critical peak event and non-event days. However, the control group selected for the RED design may be used as a control group.

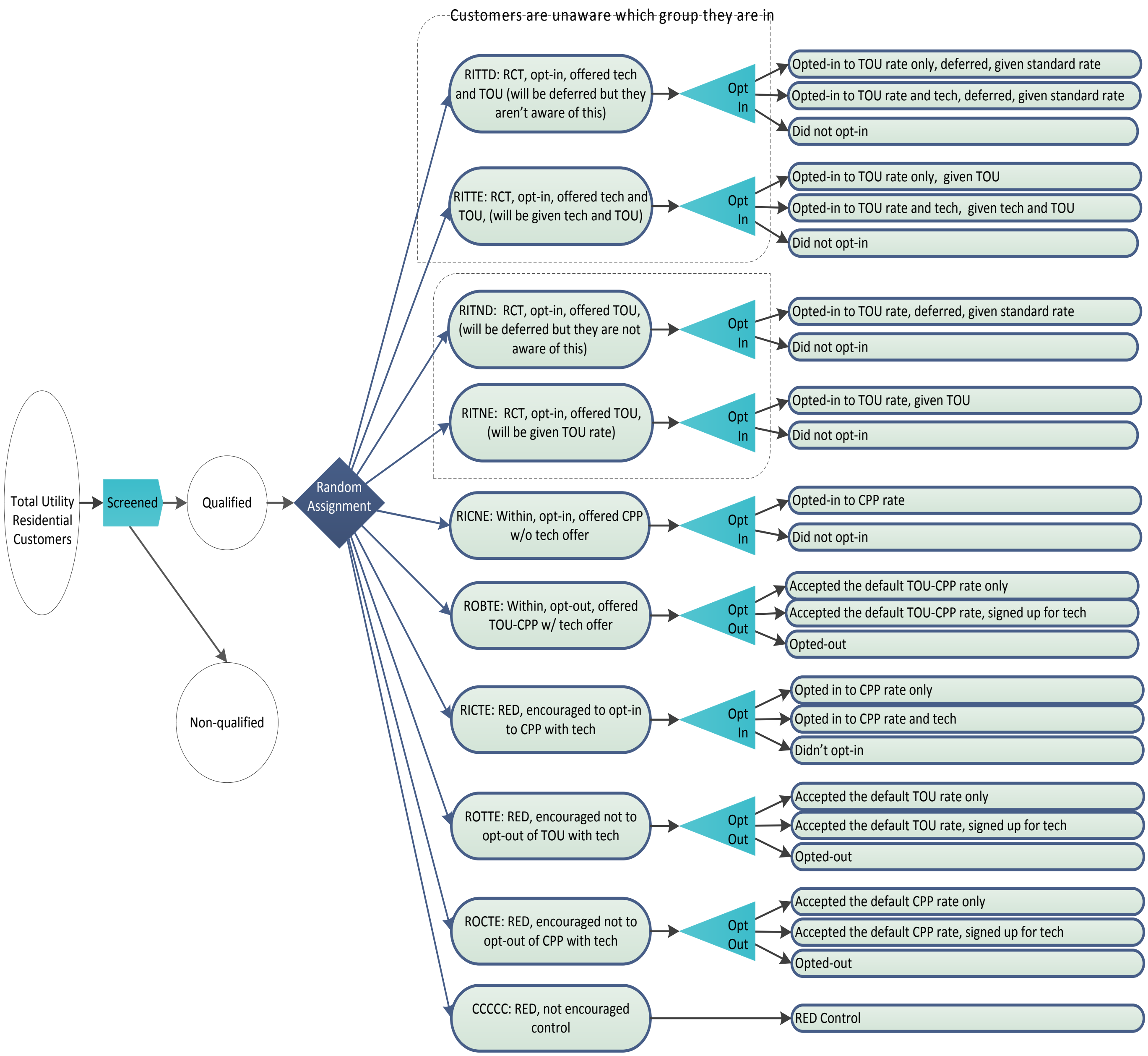


Figure B-1. SMUD Recruitment Process

Appendix C: Data Analysis and Methods

C.1. SMUD Average Peak Period Load Impacts for Default (Complacents + Always Takers), Voluntary (Always Takers), and Complacent Groups

The average peak period load impacts estimates for the two treatment groups (Default and Voluntary) were estimated using a difference-in-differences (DID) instrumental variables (IV) regression using Two-Stage Least Squares (2SLS). While whether or not a household actually experiences the study TOU electricity rates is not random (because of self-selection in or out of treatment), the assignment to a treatment group is random. We can therefore use *assignment* to treatment (or "encouragement" as it's known in the literature) as an instrument for *actual* treatment (i.e., exposure to the treatment time-of-use rate).

A separate regression is run for each treatment group (Default or Voluntary). We instrument for T_{it} with randomized assignment (or encouragement) to treatment indicator A_{it}.

$$T_{it} = \delta A_{it} + \gamma_i + \tau_t + e_{it} \qquad (1)$$

T_{it} is an indicator variable is equal to one starting on June 1st, 2012 if household i was actually enrolled in treatment and remained in the treatment group at time t, zero otherwise. A_{it} is an indicator variable equal to one starting on June 1st, 2012 if household I was encouraged to be in one of the treatment groups (random assignment to treatment), zero otherwise. The predicted values $\hat{T}_{it}$ are then used in Equation (2).

The estimating equation we use to derive the estimates in Table C1 is as follows:

$$y_{it} = \beta \hat{T}_{it} + \gamma_i + \tau_t + \varepsilon_{it} \qquad (2)$$

The variable y_{it} is hourly electricity consumption for household i in hour t; $\hat{T}_{it}$ are the predicted values generated from the regression shown in equation (1); γ_i is a household fixed effect;[41] τ_t is an hour of sample fixed effect[42]; and ε_{it} is the error term assumed to be distributed IID normal across households. In order to account for serial correlation across time observations within households, we clustered the standard errors of the estimates at

[41] In the tables that follow which show the output from the econometric analysis, the row titled "Household Fixed Effects" with a value of "Yes" indicates when these household-level fixed effects were applied.

[42] In the tables that follow which show the output from the econometric analysis, the row titled "Hour of Sample Fixed Effects" with a value of "Yes" indicates when these hour of sample fixed effects were applied.

the household level. The data used are peak hour consumption (4 pm to 7 pm) on non-holiday weekdays in both treatment summers (2012 and 2013) and in the pre-treatment summer (2011). Households in both the treatment groups and the control group are included. Coefficient β captures the average hourly treatment effect per household.

The estimates generated using this methodology for the Voluntary treatment group are shown in the first column of Table C-1. The estimates for the Default treatment group are shown in the second column of Table C-1. The third column of Table C-1 shows the estimated treatment effect of the Complacents, as isolated from the Always Takers within the Default treatment group, and was estimated using a similar, but slightly different regression.

To estimate the treatment effect for the Complacent group a regression was done using all the households from both the Voluntary treatment group and the Default treatment group (the Control group was omitted from this regression). The same estimating procedure was used as that shown in equations (1) and (2), however now, the variable T_{it} used in the first stage equation (1) is an indicator variable equal to one starting on June 1st, 2012 if household i was actually enrolled in either treatment group (Voluntary or Default) and remained in the treatment group at time t, zero otherwise. The instrument used (A_{it}) now in the first stage equation (1) is an indicator variable of whether household i was randomly assigned to the Default treatment group, zero otherwise. Therefore, the estimation isolates the effect of being in treatment, conditional on being assigned to the default group, relative to the treatment effect of the Voluntary group. In essence, it backs out the treatment effect of the Voluntary group (the Always Takers) from the treatment effect of the Default group, which includes both Always Takers and Complacents, in order to isolate the treatment effect of the Complacents alone.

Table C-1. SMUD Average Peak Period Load Impacts for Default (Complacents + Always Takers), Voluntary (Always Takers), and Complacent Groups

	Always takers (Voluntary)	Always Takers + Complacents (Default)	Complacents
Treatment Effect	-0.312***	-0.109***	-0.0580**
	(0.0301)	(0.0145)	(0.0190)
Household Fixed Effects	Yes	Yes	Yes
Hour of Sample Fixed Effects	Yes	Yes	Yes
Observations	38,335,801	31,613,593	9,879,234
Number of households	58566	48242	15138
R-squared	0.556	0.558	0.550
Average Hourly Energy Use	1.865	1.865	1.865
Standard errors clustered by household in parentheses			
*** p<0.001, ** p<0.01, * p<0.05			

C.2. Average Hourly Peak Period Demand Reductions Per Household for the Voluntary (Always Takers), Default (Always Takers + Complacents), and Complacent Groups Disaggregated Across the Two Treatment Summers

The treatment effects across the two summers were separated using a regression procedure similar to that described in equations (1) and (2), but allowing for heterogeneity between the two summers. The estimation of these effects for the Voluntary and Default treatment groups is show in equations (3), (4) and (5). Households in both the treatment groups and the control group are included. A separate regression is run for each treatment group (Default or Voluntary). The two first stage regressions are show in equation (3) and (4).

$$(T_{it} * D_{2012,t}) = \delta_{2012}(A_{it} * D_{2012,t}) + \delta_{2013}(A_{it} * D_{2013,t}) + \gamma_i + \tau_t + e_{it} \qquad (3)$$

$$(T_{it} * D_{2013,t}) = \delta_{2012}(A_{it} * D_{2012,t}) + \delta_{2013}(A_{it} * D_{2013,t}) + \gamma_i + \tau_t + e_{it} \qquad (4)$$

In equations (3) and (4), T_{it} is an indicator variable equal to one starting on June 1st, 2012 if household *i* was actually enrolled in treatment and remained in the treatment group at time *t*, zero otherwise. T_{it} is interacted with two indicator variables for the two summers: $D_{2012,t}$ is an indicator variable equal to one if time *t* is in the summer of 2012, zero otherwise, while the indicator variable $D_{2013,t}$ is equal to one if time *t* is in the summer of 2013, zero otherwise. Once again, A_{it} is an indicator variable equal to one starting on June 1st, 2012 if household I was encouraged to be in one of the treatment groups (random assignment to treatment), zero otherwise. The interaction between these indicator variables and the treatment indicator variable is instrumented for with the interaction between these two summer indicator variables and the randomized encouragement to treatment indicator A_{it}, respectively, as shown in equations (3) and (4). The predicted values from equations (3) and (4) of the two terms $(\widehat{T_{it} * D_{2012,t}})$ and $(\widehat{T_{it} * D_{2013,t}})$ are then used in the second stage regression shown in equation (5).

$$y_{it} = \beta_{2012}\,(\widehat{T_{it} * D_{2012,t}}) + \beta_{2013}\,(\widehat{T_{it} * D_{2013,t}}) + \gamma_i + \tau_t + \varepsilon_{it} \quad (5)$$

The variable y_{it} is hourly electricity consumption for household *i* in hour *t*; γ_i is a household fixed effect; τ_t is an hour of sample fixed effect; and ε_{it} is the error term assumed to be distributed IID normal across households. In order to account for serial correlation across time observations within households, we clustered the standard errors of the estimates at the household level. The data used are peak hour consumption (4 pm to 7 pm) on non-holiday weekdays in both treatment summers (2012 and 2013) and in the pre-treatment summer (2011).

The coefficients β_{2012} and β_{2013} capture the average hourly treatment effect per household in the summer of 2012 and the summer of 2013, respectively. The results of this regression for the Voluntary treatment group are shown in the first column of Table C-2, and for the Default treatment group in the second column of Table C-2. The estimates for the Complacent group are done, as in the average treatment effect case shown in Appendix C.1, by using both the treatment groups (Default and Voluntary) and not the Control group in the regression. Again, T_{it} is an indicator of whether household *i* is in treatment at time *t* (whether or not they were assigned to the Voluntary or Default treatment group), while A_{it} is now an indicator of whether household *i* was randomly assigned to be in the Default treatment group. The results for the Complacents are shown in the third column of Table C-2.

Table C-2. Average Hourly Peak Period Demand Reductions Per Household for the Voluntary (Always Takers), Default (Always Takers + Complacents), and Complacent Groups Dissaggregated Across the Two Treatment Summers

	Always Takers (Voluntary)	Always Takers + Complacents (Default)	Complacents
Summer 2012	-0.340***	-0.118***	-0.0616**
	(0.0299)	(0.0144)	(0.0190)
Summer 2013	-0.274***	-0.0969***	-0.0531*
	(0.0397)	(0.0177)	(0.0233)
Household Fixed Effects	Yes	Yes	Yes
Hour of Sample Fixed Effects	Yes	Yes	Yes
Observations	38,335,801	31,613,593	9,879,234
Number of households	58566	48242	15138
R-squared	0.556	0.558	0.550
Average Energy	1.865	1.865	1.865
Standard errors clustered by household in parentheses			
*** p<0.001, ** p<0.01, * p<0.05			

C.3. SMUD Aggregate Peak Period Load Impacts by Recruitment Method for 545,000 Residential Customer Population

The aggregate peak period load impact was estimated by taking the per-household load impact estimates from Appendix C.2, and multiplying them by 545,000*(enrollment rate) for each treatment group. So, for the Voluntary treatment group, the enrollment rate was 0.195, so the aggregate load impact predicted for 545,000 encouraged to treatment was 0.312*545,000*0.195=33,158. This was then converted to a percentage of aggregate hourly energy consumption for 545,000 households (1.865*545,000=1,016,425). This comes out to 3.3%. The same thing was done to calculate this value for the Default treatment group with an enrollment rate of 0.98 and average hourly household treatment effect of 0.109, coming out to 5.7%. You can also determine that the component of that 5.7% generated by the complacent portion of the population within the Default treatment group is 2.4%, while the Always Takers contributed 3.3% to this total savings of 5.7%.

C.4. Predicted Bill Savings Absent Customer Response to TOU Rate and Actual Bill Savings in Response to Rate by Customer Subpopulation

In order to calculate the predicted bill savings over an entire summer, the following was done. Using the standard flat rate structure, the total expenditure on electricity experienced in the pre-treatment summer of 2011 was calculated for each household. Then, this same consumption from the summer of 2011 was used to calculate how much each household would have spent that summer if they had been on the treatment TOU rate, assuming that these households hadn't changed their energy behavior. The predicted savings was calculated by subtracting the hypothetical expenditure each household would have experienced had they been on the treatment rate in 2011 from the actual expenditure they did experience during that summer on the flat rate. Therefore, if this value is positive, it means they paid more on the flat rate than they would have on the treatment rate, assuming no changes in usage. From this exercise, there is a single predicted per-summer savings value for each household. This value was then averaged across the households who enrolled in treatment in each of the treatment groups.

Table C-3. Actual Bill Savings in Response to TOU Rate by Customer Subpopulation

	Voluntary	Default
Treatment Effect	-2.992	-.2.126*
	(2.171)	(0.856)
Household Fixed Effects	Yes	Yes
Month of Sample Fixed Effects	Yes	Yes
Observations	593,018	488,993
Number of households	58,574	48,246
R-squared	0.896	0.896
Standard errors clustered by household in parentheses		
*** p<0.001, ** p<0.01, * p<0.05		

The actual bill savings were estimated using a DID 2SLS regression for the summer of 2012 and 2013 (see Table C-3). The same estimating strategy was used as was described in equation (1) and (2) above. Now, however, the y_{it} variable is the expenditure of household *i* in month *t*. The expenditure was converted from bill cycles to calendar months in order to avoid any systematic discrepancies generated based on differences in bill period start and stop dates across control and treatment groups. This conversion was done by pro-rating the total bill amount, average across all dates in that bill cycle, to each day within that bill cycle. These prorated daily expenditure amounts were then aggregated back up to the calendar month level. The results from this analysis were reported as a percent of average 2012-2013 monthly summer expenditure for the Control group ($116.6).

The distribution of predicted bill savings for the Complacents was calculated by breaking the range of observed bill savings up into $2 increment bins. Within each bin, the share of households assigned to the Voluntary and Default treatment groups appearing in each bin (b) that enrolled ($e_{V,b}$ and $e_{D,b}$, respectively) was calculated; as was the share of households enrolled in the Voluntary and Default treatment groups that appeared in each bin ($s_{V,b}$ and $s_{D,b}$, respectively). The share of Complacents households appearing in each bin that enrolled ($e_{C,b}$) is calculated directly: $e_{C,b} = e_{D,b} - e_{V,b}$.

To clarify the interpretation of these terms let me give an example. Suppose there were a total of 100 households assigned to the treatment group T. For each household, we know whether they enrolled or not, and we know what bin they are in. For simplicity, assume there are two bins (A and B). Assume there are 60 households in bin A, and 40 in bin B. Then, we observe that 30 of the households in bin A enrolled, so in that case $e_{T,A}$=0.50, while only 10 enrolled in bin B, so $e_{T,B}$=0.25. What $s_{T,A}$ captures is the share of those households that enrolled that appear in bin A, so $s_{T,A}$ =30/(30+10)=0.75 and $s_{T,B}$=10/(30+10)=0.25. These values can then be calculated for all the treatment groups. However, one more step is needed to calculate the $s_{C,b}$ values for the Complacent; these shares of enrolled Complacent households appearing in each bin (across the bins) was calculated using the following relationship.

$$s_{C,b} *(e_{C,b}/ e_{D,b})+ s_{V,b} *(e_{V,b}/e_{D,b})= s_{D,b}$$

What this is saying is that the share of all the enrolled Default households that appear in each bin ($s_{D,b}$) is a weighted average of those households that are Always Takers (identifiable as Voluntary treatment group households that enrolled, $s_{V,b}$) and enrolled Complacents (enrolled Default treatment group households that are not Always Takers, $s_{C,b}$), where the weights are determined by the enrolment rates (e) of each of these groups. All of these values are known already except for $s_{C,b}$. You can then solve out the equation for this value for each bin. The shares (s) were then added up cumulatively across all the bins to plot a graph of this cumulative distribution, as shown in Figure 11.

C.5. Drop-out rates of Always Takers and Complacents

The drop-out rates of Always Takers and Complacents were calculated using the same weighted average logic as that just described above in Appendix C.4. If the share of Always Takers that dropped out is known (because we know how many Voluntary enrollees dropped out over the course of treatment), and similarly the share of all the Default treatment group enrollees that dropped out is known, the share of Complacents that dropped out can be calculated using the fact that the Default group is made up of Always Takers and Complacents in proportions that are known based on the enrollment rates. Therefore, the drop-out rate of Complacents (r_C) can be calculated using the following relationship:

$$r_C *(e_C/ e_D)+ r_V *(e_V/e_D)= r_D$$

In this case, all the enrollment rates (e) are known, as are the drop-out rates (r) of the Voluntary (V) and Default (D) groups, so the drop-out rate of Complacents can be solved for. This was done at various points throughout the treatment period.

C.6. Peak Period Load Impacts by Customer Subpopulation and Quintile of Predicted Bill Savings

The energy savings across quintiles of predicted bill savings (defined in Appendix C.4) were estimated using the same regression approach as that presented in equations (3) and (4), only now, instead of estimating two treatment effects, five were estimated. The 2SLS regressions are show in equation (6) and (7). All variables are defined the same as in equations (1) through (5), only now $D_{k,i}$ is an indicator variable equal to one if household *i* is in percentile group *k*, zero otherwise. There are five first-stage regressions (shown in equations (6) through (10)).

$$\left(T_{it} * D_{1,i}\right) = \sum_{k=1}^{5} \delta_k \left(A_{it} * D_{k,i}\right) + \gamma_i + \tau_t + \varepsilon_{it} \quad (6)$$

$$(T_{it} * D_{2,i}) = \sum_{k=1}^{5} \delta_k \,(A_{it} * D_{k,i}) + \gamma_i + \tau_t + \varepsilon_{it} \quad (7)$$

$$(T_{it} * D_{3,i}) = \sum_{k=1}^{5} \delta_k \,(A_{it} * D_{k,i}) + \gamma_i + \tau_t + \varepsilon_{it} \quad (8)$$

$$(T_{it} * D_{4,i}) = \sum_{k=1}^{5} \delta_k \,(A_{it} * D_{k,i}) + \gamma_i + \tau_t + \varepsilon_{it} \quad (9)$$

$$(T_{it} * D_{5,i}) = \sum_{k=1}^{5} \delta_k \,(A_{it} * D_{k,i}) + \gamma_i + \tau_t + \varepsilon_{it} \quad (10)$$

The predicted values from equations (6) through (10) are then used to estimate the second stage regression shown in equation (11).

$$y_{it} = \sum_{k=1}^{5} \beta_k \,(\widehat{T_{it} * D_{k,i}}) + \gamma_i + \tau_t + \varepsilon_{it} \qquad (11)$$

The variable y_{it} is again hourly electricity consumption for household *i* in hour *t*; γ_i is a household fixed effect; τ_t is an hour of sample fixed effect; and ε_{it} is the error term assumed to be distributed IID normal across households. In order to account for serial correlation across time observations within households, we clustered the standard errors of the estimates at the household level. The data used are peak hour consumption (4 pm to 7 pm) on non-holiday weekdays in both treatment summers (2012 and 2013) and in the pre-treatment summer (2011).

The coefficients β_1, β_2, β_3, β_4 and β_5 capture the average hourly treatment effect per household for households in percentile 1 (0 – 20th percentile), 2 (20th – 40th percentile), 3 (40th – 60th percentile), 4 (60th – 80th percentile) and 5 (80th – 100th percentile) of predicted bill savings, respectively. The results are shown in Table C-4.

Table C-4. Peak Period Load Impacts by Customer Subpopulation and Quintile of Predicted Bill Savings

	Always takers		Complacents	
Percentile of Predicted Bill Savings	**Energy Savings**	**Standard Error**	**Energy Savings**	**Standard Error**
0-20th	0.808***	0.0702	0.106***	0.0322
20-40th	0.315***	0.0531	0.0706*	0.0343
40-60th	0.0771	0.0562	0.0241	0.0293
60-80th	0.0291	0.0613	-0.00498	0.0344
80-100th	0.366***	0.07	0.0892*	0.04
Observations	38,335,801		9,879,234	
R-squared	0.556		0.550	
Number of households	58566		15138	
Average Energy	1.865		1.825	
Standard errors clustered at households level				
*** p<0.001, ** p<0.01, * p<0.05				

C.7. Share of Survey Responses by Subpopulation and Predicted Bill Savings

To generate the results shown in Table C-5, households were distributed into seven bins based on their predicted bill savings (defined in Appendix C.4). These bins are: losing more than $20, losing between $20 and $10, losing between $5 and $10, gaining or losing no more than $5, gaining between $5 and $10, gaining between $10 and $20, or gaining more than

$20. The share of Always Taker survey respondents in each bin that answered that they were satisfied with the rate or wanted to continue on were measured directly, as those enrolled in the Voluntary treatment are considered Always Takers. Using the same methodology as that described in Appendix C.4 (summarized below), the share of Complacent households that both enrolled in the program and responded to the survey that appeared in each bin ($resp_{C,b}$) was calculated.

$resp_{C,b} *(e_{C,b}/ e_{D,b})+ resp_{V,b} *(e_{V,b}/e_{D,b})= resp_{D,b}$

> $e_{V,b}$: share of Voluntary treatment group (Always Takers) in bin *b* that enrolled
>
> $e_{D,b}$: share of Default treatment group (Always Takers and Complacents) in bin *b* that enrolled
>
> $e_{C,b} = e_{D,b} - e_{V,b}$: share of Complacents in bin *b* that enrolled
>
> $resp_{V,b}$: share of households enrolled in the Voluntary treatment group and responded to the survey that appeared in bin *b*
>
> $resp_{D,b}$: share of households enrolled in the Default treatment group and responded to the survey that appeared in bin *b*
>
> $resp_{C,b}$: share of Complacent households enrolled in the program and responded to the survey that appeared in bin *b* (solved for)

Finally, the shares of these respondents that answered that they were satisfied or wanted to continue on the rate in each bin was calculated again in the same way (results shown in Table C-5). For example, the following shows the calculation for the share of Complacent enrolled survey respondents that responded that they were satisfied with the rate ($sat_{C,b}$) in each bin *b*.

$sat_{C,b} *(resp_{C,b}/ resp_{D,b})+ sat_{V,b} *(resp_{V,b}/resp_{D,b})= sat_{D,b}$

> $resp_{V,b}$: share of households enrolled in the Voluntary treatment group and responded to the survey that appeared in bin *b*
>
> $resp_{D,b}$: share of households enrolled in the Default treatment group and responded to the survey that appeared in bin *b*

$resp_{C,b}$: share of Complacents households enrolled in the program and responded to the survey that appeared in bin *b* (solved for in prior step)

$sat_{V,b}$: share of households enrolled in the Voluntary treatment group, responded to the survey, and said that they were satisfied with the rate that appeared in bin *b*

$sat_{D,b}$: share of households enrolled in the Default treatment group, responded to the survey, and said that they were satisfied with the rate that appeared in bin *b*

$sat_{C,b}$: share of Complacent households that were enrolled in the program, responded to the survey, and said that they were satisfied with the rate that appeared in bin *b* (solved for)

Table C-5. Share of Survey Responses by Customer Subpopulation

Predicted Monthly Bill Savings ($)	Average Share of Respondents Satisfied w/ Rate		Average Share of Respondents Interested in Continuing with the TOU Rate	
	Always Takers	Complacents	Always Takers	Complacents
<-20	94%	73%	96%	69%
-20 to -10	87%	92%	96%	89%
-10 to -5	89%	67%	92%	82%
-5 to 5	82%	73%	94%	91%
5 to 10	85%	100%	91%	100%
10 to 20	72%	88%	88%	100%
> 20	82%	53%	94%	92%

DEFAULT EFFECTS AND FOLLOW-ON BEHAVIOR: EVIDENCE FROM AN ELECTRICITY PRICING PROGRAM

Meredith Fowlie
Catherine Wolfram
C. Anna Spurlock
Annika Todd-Blick
Patrick Baylis
Peter Cappers*

August 21, 2020

Abstract

We study default effects in the context of a residential electricity-pricing program. We analyze a large-scale randomized controlled trial in which one treatment group was given the option to opt-in to time-varying pricing while another was defaulted into the program but allowed to opt-out. We provide dramatic evidence of a default effect on program participation, consistent with previous research. A novel feature of our study is that we also observe how the default manipulation impacts customers' subsequent electricity consumption. Passive consumers who did not opt-out but would not have opted in — comprising more than 70 percent of the sample — nonetheless reduce consumption in response to higher prices. Observation of this follow-on behavior enables us to assess competing explanations for the default effect. We draw conclusions about the likely welfare effects of defaulting customers onto time-varying pricing.

*Fowlie: UC Berkeley and NBER, fowlie@berkeley.edu. Wolfram: UC Berkeley and NBER, cwolfram@berkeley.edu. Spurlock: Lawrence Berkeley National Laboratory, caspurlock@lbl.gov. Todd: Lawrence Berkeley National Laboratory, ATodd@lbl.gov. Baylis: University of British Columbia; patrick.baylis@ubc.ca. Cappers: Lawrence Berkeley National Laboratory, pacappers@lbl.gov. We received many helpful comments from seminar participants at Arizona State University, Cornell, Toulouse School of Economics, UC Berkeley and University of Oxford. The authors gratefully acknowledge contributions from and discussions with Hunt Allcott, Stefano DellaVigna, Steven George, Nick Kuminoff, Brigitte Madrian, Leslie Martin, Jennifer Potter, Lupe Strickland, Michael Sullivan and Nate Toyama. We also thank Severin Borenstein, Lucas Davis, and Michael Greenstone, for helping to make this project possible through their initial involvement with the Smart Grid Investment Grant program. This material is based upon work supported by the Office of Electricity Delivery and Energy Reliability, of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof. Corresponding author: Catherine Wolfram, Haas School of Business, UC Berkeley, Berkeley, CA 94720-1900, (510)-642-2588.

1 Introduction

When confronted by a choice with a default option, decision-makers are often predisposed to accept the default. Prior work in psychology and economics has documented this "default effect" for a range of decisions that would seem to merit deliberate choices, including retirement plans (Madrian and Shea 2001), health insurance (Handel 2013), and organ donations (Johnson and Goldstein 2003). This phenomenon is of general interest because it provides businesses and public policy makers with a relatively easy and non-intrusive way to influence choices.

Although the effect of default options on decision-making has been clearly demonstrated in the literature, the broader economic implications of these default effects have been harder to discern. One reason is that these impacts are a function of both the initial choice subject to the default manipulation and any "follow-on" behaviors that can depend on the initial choice. For example, consumers who are defaulted onto a health insurance plan with high co-payments may invest less in preventative health compared to those who actively chose such a plan. Similarly, consumers who are forced to actively choose particular privacy settings on a social media platform may subsequently share less information than consumers who are defaulted into a data-sharing regime. Given that many default manipulations aim to induce changes in some form of follow-on behavior, it is important to account for both direct and follow-on impacts of default manipulations on economic outcomes.

This study analyzes the use of a default manipulation in a new choice setting: time-varying electricity pricing. Electricity customers were randomized into two different types of treatment groups. In one type, customers were invited to opt in to a new time-varying pricing plan. In another set of treatment groups, customers were informed that they would be defaulted onto the new pricing programs unless they opted out. The field experiment was run by the Sacramento Municipal Utility District (SMUD) in 2011-2013. We observe both the initial pricing plan choice and follow-on electricity use. We are able to isolate impacts on the follow-on behavior of those who actively opted in (referred to here as "active joiners"), from those who enrolled in the new pricing structure because of the default (referred to here as "passive consumers").

It is important to understand how default manipulations can affect consumers' response to time-varying electricity pricing because a significant increase in customer participation could generate substantive efficiency gains. Benefits include lower electricity system operating costs, lower renewable energy integration costs, and a more resilient electricity grid. Importantly, the scale of these benefits increase with the number of customers confronted by, and responding to, time-varying prices, and are therefore critically contingent on both the enrollment rate and follow-on behavior once enrolled.

The vast majority (over 94 percent in 2018) of U.S. residential customers face time-invariant prices for electricity (EIA 2018). Recent investments in smart grid infrastructure, including smart meters, make it technologically feasible to enroll many customers in time-varying pricing programs. As of 2019, almost 100 million smart meters had been deployed to over half of US households (Cooper and Shuster 2019).[1] The large discrepancy between the share of customers for whom it is technologically feasible to face time-varying pricing and the share who actually do suggests that proactive approaches to increasing active participation in time-varying pricing will be required to fully leverage its potential.

We show that making time-varying pricing the default choice can significantly increase participation — over 90 percent of the customers stayed with time-varying pricing when defaulted onto it. In contrast, only 20 percent actively opted in. In this setting, the economic importance of the default effect depends critically on whether the households susceptible to the default effect, i.e., the passive consumers who neither opt in nor opt out, follow on to actively reduce their peak consumption in response to the time-varying electricity prices. If passive customers do not adjust consumption, then there is little point in defaulting them into this pricing regime. We obtain detailed measurements of electricity consumption in the periods prior to and following the experimental intervention. We show that passive customers, who comprise more than 70 percent of the sample, do reduce consumption when prices increase during peak times. Although the average demand response among passive customers is approximately half as large as the average

1. The deployment of smart grid technology was dramatically accelerated under the American Recovery and Reinvestment Act of 2009.

response among customers who actively opted in, higher participation rates in the opt-out group mean that the average effect of the opt-out offer on peak demand is significantly larger than the average effect of the opt-in offer.

These findings notwithstanding, policy makers may be reluctant to authorize the use of default provisions until they understand the consumer welfare implications. For example, if the default effect is driven by high switching costs, some customers could be considerably worse off under a new pricing plan. Because alternative explanations for the default effect can have very different welfare implications, it is important to investigate the underlying mechanisms. We assess the extent to which alternative explanations for the default effect are consistent with the participation choices and detailed electricity consumption patterns we observe. We document a striking lack of correlation between households' participation choices and the savings they stand to gain from participation, even in the presence of a program enrollment deadline. This is hard to fully explain if switching costs, discounting, or present-biased preferences drive the default effect. An alternative model in which consumers are inattentive to the participation decision performs much better in explaining observed choices. We offer further evidence to show that inattention is plausibly rational in this setting.

Previous work has analyzed follow-on behavior (though not explicitly labeled it as such) in the context of household savings, where individuals were originally subject to a default for their retirement savings plan (Chetty et al. 2014; Choukhmane 2018). Our paper adds to this literature by exploring a situation where the variation in the initial default is randomly assigned, and the subsequent impacts on follow-on behavior can be cleanly identified.

The paper proceeds as follows. Section 2 situates our paper relative to the existing work on the default effect. Section 3 describes the experiment. Section 4 describes the data and our empirical approach. Section 5 presents our main results on the default effect and follow-on behavior. Section 6 investigates alternative explanations for the default effect in light of the empirical evidence we document. In section 7, we summarize the implications of our findings for consumer welfare and present calculations on the net benefits of the time-varying pricing programs from the utility's perspective. Section 8 concludes.

2 Default Effects, Choice Modification, and Follow-on Behavior

A rich literature considers default effects in a range of settings, including participation in retirement savings plans (Samuelson and Zeckhauser 1988; Madrian and Shea 2001; Choi et al. 2002, 2004), organ donation (Johnson and Goldstein 2003; Abadie and Gay 2006), car insurance (Johnson et al. 1993), car purchase options (Park, Jun, and MacInnis 2000), and email marketing (Johnson, Bellman, and Lohse 2002). Thaler and Sunstein (2009) motivate the main thesis of their book *Nudge* with an introductory example on the default effect, suggesting that, "[a]s we will show, setting default options, and other similar seemingly trivial menu-changing strategies, can have huge effects on outcomes, from increasing savings to improving health care to providing organs for lifesaving transplant operations" (p. 8).

In many of the contexts where default provisions are used to influence choice outcomes, follow-on behavior plays a critical role in determining economic impacts. We make a distinction between two types of follow-on behavior. First, individuals may choose to subsequently modify the option they chose by default. For example, a consumer who accepts a particular health insurance plan as a default option might subsequently adjust this choice by changing to a different plan. Second, there may be important choices or actions that are contingent on — but distinct from — the initial choice. Building on the health insurance plan example, participating in a plan with a high co-pay could impact subsequent choices about whether or not to go to the doctor, lifestyle choices that can affect health outcomes, or choice of medical procedures.

To date, the literature on default effects has emphasized the initial choice and placed less emphasis on subsequent decisions that can be significantly — albeit indirectly — impacted by default manipulations. Analyses of retirement savings decisions have considered the first type of follow-on behavior: modifications to the original choice. For example, Brown, Farrell, and

Weisbenner (2016) present survey evidence suggesting that employees who were irreversibly defaulted into a defined benefit retirement plan are more likely to latter express a desire to enroll in a different plan. Sitzia, Zheng, and Zizzo (2015) consider the effects of defaults using a choice experiment on electricity tariffs, but because these decisions are hypothetical it is not possible to observe follow-on behavior. Other work includes information about follow-on choices, but does not model the impact of the default setting on those choices. For example, Ketcham, Kuminoff, and Powers (2016) include information about Medicaid recipients' prescription drug spending in their welfare calculation, but do not model how plan choice impacts drug expenditures. Our study provides an unusual opportunity to analyze not only the direct effect of a default manipulation on an initial choice, but also the ways in which the default effect operates through the initial choice to affect subsequent consumer decisions.

Our paper is most closely related to Chetty et al. (2014) and Choukhmane (2018). Chetty et al. (2014) analyze Danish policies to encourage retirement savings and differentiate "active savers," who respond to tax incentives and/or mandatory savings policies by adjusting their investments, and "passive savers," who do not. Choukhmane (2018) investigates retirement savings behavior in the U.S. and the U.K. and finds that individuals who are not enrolled by default make future adjustments to retirement savings that eventually bring them in line with those who were enrolled by default. Our choice setting is similar in that consumers must first navigate, either actively or passively, an initial participation offer which will then impact follow-on choices. One difference is that the follow-on behaviors and outcomes analyzed in the retirement savings literature are related by the budget constraint: whether or not passive savers respond explicitly, their spending and/or saving behavior must adjust in some way to the change to retirement savings induced by the default. By contrast, because electricity accounts for a small share of total consumption, and because the pricing plans we study affect a small share of electricity consumption, our passive consumers could have been defaulted onto the time-varying pricing and then completely ignored it. That they do not exposes a difference in the two decision settings.[2] Nonetheless, we

2. There are other relevant differences between Chetty et al. (2014) and Choukhmane (2018) and our work. Neither paper addresses the difference between opting out of a mandatory plan, which would be analogous to our active

also note a remarkable similarity between these two very different settings of retirement savings and electricity consumption: passive consumers comprise roughly 60-70 percent of the population. Understanding how passive consumers who are nudged onto a program by default respond to the program once enrolled is relevant to a range of settings outside of electricity consumption.[3]

Our empirical results on both the initial choice and follow-on behavior also shed light on the underlying mechanisms that can give rise to default effects. Recent papers have investigated the welfare effects of nudges in a variety of contexts, including retirement savings plan default provisions (Carroll et al. 2009; Bernheim, Fradkin, and Popov 2015), health insurance plan choices (Handel 2013; Handel and Kolstad 2015; Ketcham, Kuminoff, and Powers 2016), and home energy conservation reports (Allcott and Kessler 2019). These papers augment the more standard utility maximization framework to accommodate features of consumer behavior (such as inattention) that could rationalize a default effect. Bernheim, Fradkin, and Popov (2015) and Blumenstock, Callen, and Ghani (2018) go one step further and mediate between several different explanations for the default effect. Our work extends this line of inquiry to a context where inattention to one choice leads to economically significant efficiency gains in a subsequent set of consumer choices.

3 Empirical Setting and Experimental Design

Economists have noted for some time that efficient pricing of electricity should reflect changing electricity market conditions (e.g., Boiteux 1964b, 1964a). Electricity demand, marginal system operating costs, and firms' abilities to exercise market power vary significantly and systematically over hours of the day and seasons of the year. Figure 1 demonstrates the extent of this variation for a week during our study. The red line depicts hourly electricity demand, which

refusers group, and actively taking advantage of a non-mandatory plan, analogous to our active joiners group. Additionally, both papers take advantage of quasi-experimental variation across similar but not identical settings, while our experimental setting allows to randomly allocate customers into plans that are identical except for their enrollment mechanism.

3. In addition to health insurance and privacy on social media platforms, consider, for example, on line marketing: customers are often passively enrolled into e-mail campaigns, but the degree to which they respond to subsequent appeals is of central interest to the marketer. Other examples, such as employee incentive programs for fitness or volunteering, or car purchasing and post-purchase driving behavior, indicate that this type of two-stage decision-making is widespread.

cycles predictably over the course of a day, varying by a factor of 1.5 on some days to almost 3 on others from the middle of the night to the peak hours in the late afternoon. The blue line depicts hourly wholesale prices, which fall below $60/MWh in most hours, but spike to over $1,000/MWh at critical peak times.

[FIGURE 1 HERE]

Although wholesale electricity prices can vary significantly across hours, at least partially reflecting variations in marginal costs, retail prices do not generally reflect these dynamic market conditions. The vast majority (over 94 percent in 2018) of U.S. residential customers pay time-invariant prices for electricity (EIA 2018). If customers are not exposed to prices that reflect variable marginal operating costs, economic theory suggests that consumers will under-consume in periods of low marginal costs and over-consume in periods of high marginal costs. This further implies over-investment in capacity to meet excessive peak demand. For example, Borenstein and Holland (2005) simulate that by shifting a fraction of customers to time-varying rates, utilities could construct 44 percent fewer peaking plants.

This suggests that these inefficiencies can be mitigated — or eliminated — with the introduction of time-varying retail electricity pricing. Residential customers have an important role to play in electricity demand response, particularly in areas of the country where peak residential demand (driven by air conditioning in many parts of the U.S.) coincides with the system peak. When residential customers have been exposed to time-varying prices, prior analyses suggest they are willing and able to adjust consumption in response (see, for example, EPRI 2012).[4]

To reap benefits from time-varying pricing, however, utilities need to enroll more customers in time-varying pricing programs and these customers need to respond to the prices. In what

4. In a 2012 meta-analysis, authors identified what they deemed to be the best seven U.S. residential pricing studies up to that time (EPRI 2012). These studies document peak demand response to time-varying pricing in the range of 13-33%, depending on the existence of automated control technology (e.g., programmable communicating thermostat). These estimates imply an elasticity of substitution in the range of 0.07 - 0.24 and an own-price elasticity in the range of -0.07 - -0.3. Note that the experimental nature of our study allows us to assess many dimensions of customers' responses to time-varying pricing, including spillovers within and across days. Some previous evaluations of time-varying pricing have relied on within-customers comparisons, which assume there are no spillovers of this sort.

follows, we describe a large-scale field experiment designed to evaluate a novel approach to increasing participation among residential electricity customers.[5]

3.1 The Experiment

The experiment we analyze was implemented as part of the Smart Grid Investment Grant (SGIG) program, which received $3.4 billion in funds from the American Recovery and Reinvestment Act of 2009. The goal of this program was to invest in the expansion of the smart grid in the U.S., and thereby create jobs and accelerate the modernization of the nation's electric system (Department of Energy 2012). One of the objectives articulated in the Funding Opportunity Announcement (DE-FOA-0000058) under the heading of Consumer Behavior Studies (CBS) was to document the impacts and benefits of time-varying rate programs and associated enabling control and information technologies.

The Sacramento Municipal Utility District (SMUD), a municipal utility that serves approximately 530,000 residential households in and around Sacramento, California, implemented one of the 11 consumer behavior studies that were funded under the SGIG program.[6] They were awarded a $127 million grant overall, which comprised part of a $308 million smart grid project. SMUD viewed the opportunity to study the impact of time-varying rates within their own service territory as a major benefit to participating in the program (Jimenez, Potter, and George 2013). SMUD had some demand response programs in place prior to the SGIG program (e.g., an air conditioner direct control program and some rates that varied by time-of-day), but these programs had not been broadly emphasized or marketed for a long time. Historic adoption of their "legacy" Time-

5. A much smaller-scale experiment was conducted in Los Alamos. Results of this study are summarized in a recent working paper (Wang and Ida 2017). Residential customers were recruited to participate in a demand response experiment. Of these, 365 were given the option to opt in to a time-varying rate and 183 customers were defaulted onto the new rate. Whereas opt-in rates typically fall within the range of 2-10%, 64% of customers opted into the time varying rate. Presumably, this is because the study sample is comprised of only those customers who actively select into a field experiment. Interpretation of the estimated demand response is further complicated by the fact that program participants were insured against losses (i.e., they could only gain from participating in the experiment).

6. The other ten studies are described in Cappers and Sheer (2016). Most evaluated other aspects of time-varying pricing, such as the impact of providing customers with "shadow" bills, which documented how much they would have paid under standard pricing. Only one of the other studies compared opt-in and opt-out recruitment approaches (Lakeland Electric) but the data the utility provided did not contain enough detail to perform a comparable analysis.

of-Use (TOU) rates had been extremely low. From SMUD's perspective, the SGIG program was an opportunity to maximize the benefits of their smart-grid technology investments, and to test time-varying rates that were designed to meet their evolving load management needs (Jimenez, Potter, and George 2013).

The study sample was drawn from SMUD's population of residential customers. To define the experimental population, several selection criteria were applied. Households were excluded: if their smart meter had not provided a year's worth of data by June 2012; if they were participating in SMUD's Air Conditioning Load Management program, Summer Solutions study, PV solar programs, budget billing programs, or medical assistance programs; or if they had master-metered accounts. After these exclusions, approximately 174,000 households remained eligible for the experimental population.[7]

Households in the experimental population were randomly assigned to one of ten groups, five of which are the focus of this paper.[8] Households in four of these five groups were encouraged to participate in a new pricing program; the fifth group received no encouragement and serves as the control group. There were two pricing treatments: a TOU and a Critical Peak Pricing (CPP) program. There were also two forms of encouragement: opt-in, where households were encouraged to enroll in the rate program; and opt-out, where households were notified that they were enrolled by default, but had the opportunity to leave the program if they wished. All encouraged households (opt-in and opt-out) were also offered enabling technology — an in-home display that provided real-time information on consumption and the current price.

Figure 2 summarizes the standard, TOU, and CPP rate structures that are evaluated in this study. All SMUD customers faced an increasing block pricing structure. This means that the price paid for the first block or "tier" of electricity consumed during a billing period was lower

7. SMUD reports no statistically significant differences between the households in the study sample and the larger residential customer base. We did not have access to these sample comparisons, and we do not know which variables were analyzed. Most residential customers had smart meters in time for the experiment, though many were excluded because their meters had not reported a full year of data by June 2012.

8. The other five groups were: defaulted to another time-varying rate that did not have a corresponding opt-in group treatment (i.e., Critical Peak Pricing (CPP) plus TOU rate); encouraged to opt in to CPP or TOU without the enabling technology described below; or were part of a recruit-and-deny randomized controlled trial for TOU rates.

than the price paid for the higher tier. During the time period of our study, customers on the standard rate plan (i.e., customers in the control group) paid a $10 monthly fixed charge plus $0.0938 per kWh for the first 700 kWh of consumption and $0.1765 per kWh for consumption above 700 kWh within a monthly billing period. Under the TOU program, customers faced the same monthly fixed charge of $10. These customers paid a higher rate, $0.2700 per kWh, for electricity consumed during the "peak period" from 4PM to 7PM on non-holiday weekdays. They paid a lower rate (relative to the standard rate structure), in all other "off-peak" hours, $0.0846 per kWh for the first 700 kWh and $0.1660 for consumption above 700 kWh. (On-peak consumption did not count towards the 700 kWh total.) Customers on the CPP plan paid a significantly higher rate, $0.7500 per kWh, for consumption between 4PM and 7PM on twelve "event days" over the course of the summer. Customers were alerted about event days at least one day in advance. Consumption outside of the CPP event window was charged at a rate of $0.0851 per kWh up to 700 kWh and $0.1665 per kWh beyond.

[FIGURE 2 HERE]

Both the CPP and TOU rates were only in effect between June 1 and September 30 for the two summers in the study (2012 and 2013). Low-income customers enrolled in the Energy Assistance Program Rate (EAPR) were eligible to participate in the study. No matter the pricing plan, EAPR customers received about a 30 percent discount on their rates. Both the TOU and CPP rates were designed to be approximately revenue neutral to the utility if customers selected their rate plan randomly and did not adjust their consumption (Jimenez, Potter, and George 2013).

To summarize, the five randomized groups we study include: the CPP opt-in group, which was encouraged to enroll in the CPP program; the CPP opt-out group, which was notified of enrollment and encouraged to stay in the CPP program; the TOU opt-in group, which was encouraged to enroll in TOU program; the TOU opt-out group, which was notified of enrollment and encouraged to stay in TOU program; and the control group, which was not encouraged to participate in a time-varying rate, nor even told about the program at all, and remained on SMUD's standard rates.[9]

3.2 Encouragement Messages

Materials and messages encouraging participation were virtually identical across the opt-in and opt-out treatment groups. The encouragement effort for opt-in households consisted of two separate mailed packets. The first was sent in either October 2011, to about 20 percent of the encouraged households, or November 2011, to the remaining 80 percent. The second was sent in January 2012. Each packet included a letter, a brochure, and a postage-paid business reply card that the household could mail back to SMUD indicating their choice to either join the program or not. The recruitment materials listed generic benefits of participating in rate programs, including saving money, taking control, and helping the environment. In March of 2012, door hangers were placed on the doorknobs of encouraged households. Finally, an extensive phone bank campaign was carried out throughout April and May of 2012, with calls going out almost daily.

Recruitment activities and program enrollment are summarized in Figure 3. About half of the customers enrolled following the packet and door hanger recruitment phase, while the second half were successfully enrolled over the timeframe of the phone campaign (though about 22 percent of these still indicated their desire to enroll by way of the business reply cards).

[FIGURE 3 HERE]

The opt-out groups were mailed one packet containing a letter, brochure, and business reply card. These materials were designed to look as similar as possible to the materials received by members of the opt-in groups. Packet mailings were followed within two weeks by a reminder post card. About 10 percent of the packets were sent on March 12, 2012 and the remaining 90 percent were sent on April 5, 2012.

9. Sample sizes for control and treatment groups were determined using a set of power calculations designed to account for different enrollment probabilities between groups, required Type I and Type II error rates, minimum detectable effect size, cost of treatment, and the comparison of all treatment groups to a single control group. In general, the opt-in treatment groups were larger because a smaller proportion of these customers were expected to enroll than in the opt-out groups. Additional detail on these calculations is available in the appendix to Jimenez, Potter, and George (2013).

The TOU opt-in group received slightly different encouragement messages from the other groups because they were part of a recruit-and-delay randomized controlled trial (which we are not incorporating into this analysis). In the first packet mailed in late 2011, the households were given the same information as other groups regarding the starting date of the pricing experiment. However, in the packet mailed in January 2012, there was text that informed them that if they decided to opt-in to the rate program, they would be randomly assigned to a start date in either 2012 or 2014. The other three groups were told that their participation date would start in 2012 if they decided to opt-in or not opt-out throughout all communications they received. This means that the set of active joiners in the CPP opt-in group could be somewhat different from the active joiners in the TOU opt-in group, as the TOU active joiners had to be willing to accept some probability that their enrollment would be delayed. Thus, while the CPP opt-in group can be directly compared to the CPP opt-out group, comparisons between the TOU opt-out and opt-in groups are drawn with the caveat that these two groups were encouraged and recruited slightly differently.

4 Data and Methodology

4.1 Data Description

Our analysis uses household-specific data, electricity consumption data, and weather data. The household-specific data include experimental cell assignment, dates of enrollment, disenrollment, and account closure information for households who moved. Finally, for some households, we have responses to two large-scale surveys: a demographic survey and a customer satisfaction survey.

We also have data on households' energy consumption, as well as their associated expenditures. Specifically, we have data on hourly energy consumption for each household starting on June 1, 2011 and continuing through October 31, 2013, the end of the pilot period. Electricity consumption is measured in kilowatt hours (kWh). We collect energy consumption data for all households in the experimental sample, including the control group, for the duration of the study period. Households that moved are one exception. These households were not tracked to their new location, so data for these households ends when they moved from their initial location.

In addition to the hourly energy consumption data, billing data were also obtained for all households in the experiment. These data include the total energy (kWh) charged in each bill, as well as the total dollar amount of the bill. Hourly energy consumption and billing data are quite complete. Less than one percent of these data are missing. The frequency of missing data does not differ systematically across treatment groups.

The final type of data we use are hourly weather data, including dry- and wet-bulb temperature as well as humidity. There is only one weather station in close proximity to all participants in the SMUD service area, so the weather data do not vary across households, only over time.

4.2 Validation of Randomization

Table 1 provides summary statistics by experimental group. The top three rows summarize information on daily consumption, the ratio of peak to off-peak energy consumption, and billing from the pre-treatment summer (June to September 2011). Sample households consume slightly less electricity than the average U.S. household — approximately 27 kWh per day during the four summer months compared to almost 31 kWh per day across the U.S. in 2011. The ratio of peak to off-peak usage provides one indication of a customer's exposure to the higher peak prices under CPP or TOU, and bill amounts reflect the average monthly bill in the pre-treatment summer. Bills in our sample are very close to the national average, reflecting that SMUD customers pay higher prices than the average U.S. residential customer. For all three variables, we also report t-statistics on the test that the mean for each treatment group equals the mean for the control group.[10] The t-statistic exceeds one for only one of these comparisons, suggesting that the randomization yielded groups with very similar means across these three variables.[11]

10. We also run t-tests comparing the opt-in to opt-out treatment groups, and find no statistically significant differences.

11. Given that we will be analyzing consumption across hours of the day, we are particularly concerned about balance in consumption profiles. In addition to the ratio of peak to off-peak usage, the Appendix provides a breakdown

The "structural winner" variables measure the share of households that would pay less on either the CPP or TOU pricing policy, assuming no change in their consumption (following industry convention, we refer to households who would pay less as "structural winners" and those who would pay more as "structural losers"). Approximately half of all customers are estimated to be structural winners, based on consumption data collected before the intervention.[12]

[TABLE 1 HERE]

4.3 Methodology

4.3.1 Estimating average impacts for encouraged groups

We estimate a difference-in-differences (DID) specification using data from the pre-treatment and treatment periods to identify the average intent-to-treat (ITT) effect, i.e., the average effect for each encouraged group. Equation (1) serves as our baseline estimating equation, where y_{it} measures hourly electricity consumption for household i in hour t. All specifications described below are estimated separately for the opt-in and opt-out groups, unless otherwise noted. Z_{it} is an indicator variable equal to one starting on June 1, 2012 if household i was encouraged to be in the treatment group, and zero otherwise. γ_i is a household fixed effect that captures systematic differences in consumption across households, and τ_t is an hour-of-sample fixed effect.

$$y_{it} = \alpha + \beta_{ITT} Z_{it} + \gamma_i + \tau_t + \varepsilon_{it} \tag{1}$$

We estimate four sets of regression equations. Each set uses data from the control group and one of the four treatment groups. The coefficient of interest is β_{ITT}, which captures the average

of consumption across all 24 hours of the day (Figures 1.1, 1.2). Again, all four treatment groups look very similar to the control group.

12. For several of our analyses, including identifying structural winners under the CPP program, we need to simulate 12 CPP days in the pre-treatment period. We do this by choosing the 12 hottest non-holiday summer weekdays. To ensure that our estimates of structural winnership do not result from idiosyncratic variation on these 12 days, we also estimate specifications where we randomly select 12 of the 24 hottest non-holiday summer weekdays and recompute our estimate of pre-period CPP bills. We repeat this exercise 10,000 times and then average over the estimated pre-period CPP bills to obtain an alternative measure of structural winnership. The correlation between the two measures is 0.97.

difference in hourly electricity consumption across treated and control groups, controlling for any pre-treatment differences by group.[13] Within each set, we estimate the model separately using data from event day peak hours (4pm to 7pm on the twelve CPP days in each summer) and non-event day peak hours (4pm to 7pm on non-event, non-holiday weekdays during the summer).[14]

4.3.2 Estimating average impacts for treated households

We estimate a DID instrumental variables (IV) specification using data from the pre-treatment and treatment periods to identify a local average treatment effect (LATE). Specifically, we estimate Equation (2), where y_{it}, γ_i, and τ_t are defined as in Equation (1). $Treat_{it}$ is an indicator variable equal to one starting on June 1st, 2012 if household i was actually enrolled in the time-varying pricing program, zero otherwise (estimated separately for the opt-in and opt-out groups). We instrument for $Treat_{it}$ using the randomized encouragement to the corresponding treatment Z_{it}, which is defined as in Equation (1).

$$y_{it} = \alpha + \beta_{LATE} Treat_{it} + \gamma_i + \tau_t + \varepsilon_{it} \tag{2}$$

The β_{LATE} coefficient captures the average reduction in household electricity consumption among customers enrolled in the time-varying pricing program. To interpret β_{LATE} as a causal effect, we must invoke an exclusion restriction, which requires that the encouragement (i.e., the offer to opt in or the default assignment into treatment with the ability to opt out) affects electricity consumption only indirectly via an effect on participation. We also invoke a monotonicity assumption which requires that our encouragement weakly increases (versus reduces) the participation probability for all households.[15] In Section 1.3, we conduct a partial test of these identi-

13. We present specifications with the dependent variable measured in levels because the cost savings from time-varying pricing are a function of kWh reduced, not the percent reduction. Our results are not sensitive to alternative functional forms, and the Appendix presents specifications in logs (Tables 1.3 to 1.5).

14. Note that customers under the TOU pricing plan face the same prices on event and non-event days. We estimate separate impacts for comparison to CPP.

15. This is equivalent to "frame monotonicity" as defined by Goldin and Reck (2019), and means, for instance, that consumers would not always select against the default and opt in to time-varying pricing if its not the default and

fying assumptions using a separate treatment group that was encouraged to enroll but not given the opportunity to participate in time-varying pricing during our study. Examining the response of households in this treatment allows us to place an upper bound on the degree of possible bias resulting from a violation of the exclusion restriction via an encouragement effect. Even under conservative assumptions regarding this possibility, our findings are qualitatively unchanged.

4.3.3 Estimating average impacts for passive consumers

Conceptually, our sample of residential customers can be divided into three groups (see Figure 4). Active leavers are households who opt out of an opt-out program and do not enroll in an opt-in program. Passive consumers are households who do not actively enroll in an opt-in program, but who also do not actively drop out of an opt-out program. Active joiners are households who actively enroll in an opt-in program and remain in an opt-out program. Note that a comparison of average electricity consumption across the opt-in and opt-out groups (the top two rows in Figure 4) estimates the average effect of being assigned to the opt-in versus opt-out groups. Scaling this difference by our estimate of the population share of passive consumers yields an unbiased estimate of the average effect of time-varying rates on electricity consumption among passive consumers.[16]

[FIGURE 4 HERE]

We estimate the DID IV specification using data from the opt-in and opt-out groups, as shown in Equation (2), where all variables are defined as above, except now $Treat_{it}$ is instrumented for with an indicator variable equal to one for observations starting on June 1, 2012 if a household was encouraged into the opt-out treatment group only. This IV specification isolates the average causal effect of these pricing programs on electricity consumption among passive consumers. To interpret our estimates in this way, we again invoke the exclusion restriction which requires

opt out of it when it is the default.

16. Our approach to isolating the response of the passive consumers is very similar to Kowalski (2016), although our setting is considerably more straightforward since we randomized the assignment of both the opt-in and the opt-out treatments.

that the encouragement (the offer to opt in or the default assignment with the ability to opt out) does not directly affect electricity consumption among active joiners, active leavers, or passive consumers. As Figure 4 makes clear, we are also assuming that active joiners who actively enroll in the pricing programs under the opt-in treatment do not respond differently to time-varying pricing, on average, as compared to active joiners who are defaulted onto the programs through the opt-out treatment. Section 1.3 contains a detailed discussion of these exclusion restrictions. We note that, to the extent actively encouraging households to opt in leads to a larger demand response, our estimates of the active joiners' reductions in response to prices will be overstated and our estimates of the demand response among passives will be understated.

5 Main Results

5.1 Default Effects on Program Adoption

Table 2 summarizes customer acceptance of time-varying pricing in the opt-in and opt-out groups, respectively. The columns titled "Initial" summarize customer participation at the beginning of June 2012 (the month the new rates went into effect). The columns titled "End line" summarize participation at the end of the second summer (September 2013). In both sets of results, the first column reflects the share of customers on the time-varying rate while the second column reports the number of customers on the rate.

[TABLE 2 HERE]

The initial participation results provide striking evidence of the default effect. For both the CPP and TOU rates, approximately 20 percent of those assigned to the opt-in encouragement elected to opt in. Fewer than 5 percent opted out when defaulted onto the new rate structure, leaving over 95 percent of the customers on the new rates in the default treatment.[17]

17. It is worth noting that SMUD was more successful than expected at recruiting customers onto time-varying rates. The company's expectations, and the basis for our ex ante statistical power calculations, were that between ten and fifteen percent of customers would opt in. On the other hand, given that SMUD customers are generally

To interpret the "End line" columns, it is important to understand how we are describing the eligible population. If customers moved, they were no longer eligible for the time-varying rates, even if they moved within SMUD's service territory. Also, new occupants were not included in the pilot program. The numbers in Table 2 report rates and enrollees after dropping movers. For instance, the number of customers on CPP from the opt-in group fell from 1568 to 1169 because 399 households (approximately 25 percent) moved between June 2012 and September 2013. SMUD reports move rates of approximately 20 percent per year across their entire residential population, so a move rate of 25 percent over a 16-month period that includes the summer, when moves are most likely, is reasonable. Across the four treatment groups, the move rates are very similar, ranging from 23 percent in the CPP opt-out group to 26 percent in the TOU opt-in group.[18]

5.2 Choice Modification

We observe modifications to consumers' participation choices after the program started, although program rules constrained the set of possible changes. Customers in the opt-in group were not allowed to enroll after June 1, 2012; customers in the opt-out group who had already opted-out were not allowed to change their minds and opt back in. However, customers in both groups who had initially chosen to participate in the time-varying rate program could revert to the standard rate at any time.

The final column of Table 2 reports the difference between initial and end line participation rates, divided by the initial participation rate. Participation in both of the opt-in groups fell by fewer than 1.5 percentage points, reflecting fewer than 7 percent of the original participants. Participation in both of the opt-out groups fell by more percentage points (6.6 in the case of CPP opt out, 96.0 − 89.4, and 5.3 in the case of TOU opt out), but again reflected 7 or fewer percent of the original participants.

Although only a small share of households dropped out of these programs, we conducted

satisfied with the utility and trust its recommendations, they may have been more likely to accept the default. SMUD anticipated that approximately 50 percent of the customers would remain on the rate with opt-out.

18. Moving rates are not statistically significantly different from one another (z-statistic on the largest difference equals 1.3).

a hazard analysis of attrition, described in Appendix 1.4. Comparisons of attrition rates across the opt-in and opt-out groups are under-powered, but some suggestive patterns emerge. First, although the rates of attrition over the entire study were similar, the opt-in participants (both TOU and CPP) dropped out sooner than opt-out. For households in the opt-out groups, the reminder sent to participants before the second summer had a statistically significant effect on drop-outs.

5.3 Follow-on Behavior

5.3.1 Average impacts for encouraged households

Table 3 summarizes the estimation results for the DID specification in Equation (1) that uses data from the pre-treatment and treatment periods to identify an ITT effect. The first two columns use data from peak hours on "critical event" days. In the post-treatment period, these correspond to days when a CPP event was called. In the pre-treatment period, these correspond to the hottest non-holiday weekdays during the summer of 2011.[19] The right two columns use data from all other summer weekdays. In all cases the analysis is limited to the peak periods of the relevant days (4PM to 7PM).

[TABLE 3 HERE]

If we interpret the coefficients in Table 3 as estimates of the causal impact of encouragement to join the time-varying rates, we conclude that providing households the opportunity to opt-in to the CPP treatment leads to an average reduction in electricity consumption of 0.129 kWh during peak hours of event days (averaged across all household that received the opt-in offer). The estimate for the opt-out group is considerably larger at 0.305 kWh across all households defaulted onto the CPP rate.

The coefficients in the last two columns show that CPP customers *reduced* their consumption during peak hours on *non-event* days (by 0.029 kWh per household in the opt-in group and 0.094

19. We have also estimated specifications based on random samples of 12 days within the hottest 24 days. Our results are not sensitive to this choice.

kWh per household in the opt-out group). Recall that CPP customers faced rates that are slightly lower than the standard rates on these non-event days. These kWh reductions are considerably smaller compared to event days for the CPP households, but still statistically significant.

Why might consumers respond to a decrease in electricity price with a decrease in consumption? This is consistent with habit formation, learned preferences (e.g., if households learn that they can comfortably open windows instead of turning on the air conditioning), or a fixed adjustment cost (e.g., if customers set programmable thermostats to run air conditioning less between 4 and 7 PM on all days, even when they only face higher prices on a subset of those days).

In the case of the TOU group, who faced higher prices during peak hours for all weekdays (not just event days), the results show that households reduced their daily peak consumption by 0.091 kWh on average in the opt-in treatment, and 0.130 kWh on average in the opt-out treatment on days that were called as event days for CPP customers (i.e., relatively hotter days). On all other peak days average reductions are estimated to be 0.054 kWh per household in the opt-in treatment, and 0.100 kWh per hour in the opt-out treatment. Given that non-event-day consumption is lower, the results are approximately the same in percentage terms (3.6-5.2% for the TOU opt-in group and 5.9 - 7.3% for the TOU opt-out group – see Table 1.3).

Finally, we regenerate the results reported in Table 3 using only the post-intervention data. In other words, we do not use the pre-period data, and we simply compare treated households' consumption to the control households' during event and non-event peak hours. This exercise yield qualitatively similar results, which are summarized in Table 1.6. The average reductions for the opt-out group are nearly 3 times larger than the average reductions for the opt-in group for CPP and 2 times larger for TOU. The coefficient estimates do differ slightly from those reported in Table 3 since there were some statistically insignificant pre-period differences by group.

5.3.2 Average impacts for treated households

Table 4 reports on the instrumental variables specifications that correspond to Equation (2). Similar to Table 3, the columns on the left of the table report estimates using data from CPP event hours and the columns on the right report results estimated using data from non-event-day peak hours. The top of the table corresponds to CPP customers while the bottom corresponds to customers participating in TOU programs.

Estimates in the first two columns suggest that the active joiners in the opt-in CPP group reduced consumption during event-day peaks by almost twice as much as the larger group of active joiners plus passive consumers participating in the CPP program in the opt-out group (0.658 compared to 0.330 kWh per household). The magnitude of the reduction for the opt-in group (0.658 kWh) is large and suggests consumers did more than simply turn off a few light bulbs. Given that electricity rates increased by approximately 350 percent during critical peak events, this reduction off a mean of almost 2.5 kW is consistent with a price elasticity of approximately -0.075. This is comparable to other short-run demand elasticities estimated for electricity consumption, though typically those estimates are based on demand reductions over longer time periods (EPRI 2012).

In the fourth and fifth columns of Table 4, we see again that households in both the opt-in and opt-out CPP treatments significantly reduced their consumption on non-event peak days. Passive consumers' average reductions on non-event days comprise a larger share of the average critical peak reductions than is true for active joiners. This is consistent with the latter group fine-tuning their demand to changing conditions, whereas passive consumers may rely to a larger extent on modifications that do not require sustained attention (such as reprogramming a thermostat to reduce cooling load during peak hours on all days).

In the case of the TOU treatments, the LATE estimates indicate that active joiners reduced consumption during daily peaks that were called as event days for the CPP treatment by about three times as much as the combination of active joiners plus passive consumers in the TOU opt-out group (0.480 relative to 0.136 kWh per household), and almost three times as much (0.287 relative to 0.105 kWh per household) during non-event regular peak days.[20]

[TABLE 4 HERE]

20. In joint specifications, we can reject that the coefficient estimates are equal across the opt-in and opt-out groups in all cases except for the CPP treatment on non-event days (p=0.249).

The results in the third and sixth columns isolate the effect of time-varying rates on electricity consumption among the passive households. Comparing the results in the first column (active joiners), to the results in the third column (passive consumers), suggests that the average response among active joiners to the CPP rate was about 2.7 times larger than the response among passive consumers during event hours. Passive consumers were more similar to active joiners during non-event peak hours, reducing by only half as much.[21] Differences between active joiners and passive consumers are more pronounced with the TOU rates. Given that there are so many more passive consumers exposed to the rates under an opt-out experimental design, the aggregate savings from an opt-out design is significantly higher than from an opt-in design (as is made evident in Table 3).

Tables 3 and 4 have averaged treatment effects across all peak hours. Figure 5 illustrates these effects graphically, disaggregating by hour. The figure depicts hour-by-hour LATE estimates for event days across the four treatment groups relative to the control group. We also test for changes in consumption during non-peak hours. One might expect that some consumers would increase consumption in the hours leading up to the peak period (cooling the house when prices are relatively low, for example). However, we find that consumers are reducing consumption in the hours before the peak period, statistically significantly so for the active joiners in both the CPP and TOU groups.

[FIGURE 5 HERE]

Finally, we estimate the impacts on household electricity expenditures with an alternative form of Equation (2) that features total bill amount as the dependent variable. Table 5 summarizes these estimation results. The coefficient estimate in the first column of the top panel suggests that bills for customers who opted in to the CPP rate plan fell by 5.7% on average, with a mean reduction of $6.52 on an average summer bill of $114. Bills for the typical participant in the opt-out group fell by less — around $4.50 for the group overall and slightly less for the passive

21. Note that the coefficient estimates for the opt-out group in Table 4 are equal to the weighted sum of the coefficients for the active joiners (e.g., -0.658 for CPP event hours) and the passive consumers (-0.242), with weights set equal to the share of active joiners relative to total opt-out enrollees and one minus this number from Table 2.

consumers. This is consistent with the results presented in Table 4, which shows how passive households reduced consumption by less during critical peak periods.[22]

[TABLE 5 HERE]

5.3.3 Impacts over time

Since our study period includes two years of post-intervention data, we can analyze how electricity demand response to the time-varying rates evolves over time. In particular, we can test for differences in this evolution across customers who actively opted in and the passive households who were nudged in by the opt-out encouragement. We modify Equation (2) to include an interaction between the treatment indicator and an indicator for the second summer. Table 6 summarizes the estimation results. For the CPP treatments, the interaction term is positive for the active joiners in the opt-in group (columns 1 and 4) and negative for the passive consumers (columns 3 and 6). Three out of four of the coefficients are statistically significant.[23] This pattern suggests that demand response is attenuating over time among active joiners. In contrast, the average demand response is increasing over time among passive consumers. This could be due to a growing number of passive consumers responding over time, or an escalating demand response as passive customers gain experience with the program.[24]

[TABLE 6 HERE]

We also investigate whether customers who experienced higher than normal bills once the program took effect had different treatment effects. We construct a binary 'bill shock' indicator which equals one if a participating customer received a bill in the first year of the program that

22. Bill reductions should not be interpreted as a measure of consumer welfare impacts; customers may have made adjustments that were costly from a monetary or welfare perspective. We return to this point below.

23. The results for the TOU treatment are less pronounced, although columns 1 and 4 suggest that the active joiners are responding less over time. Since we had attrition in the set of participating customers over time, the results could also reflect changes in the types of customers who are still treated in the second summer. Table 1.2 estimates these specifications on a balanced panel, i.e., on customers who did not change their enrollment status during the treatment period. We find that the results are qualitatively the same and slightly larger in magnitude overall.

24. Table 1.1 explores additional heterogeneity in impacts by customer type. We show, for instance, that structural winners are, if anything, more responsive to time-varying rates while low-income customers are less responsive.

was 20% greater than the bills received in the pre-program summer. Presumably, this group of 'shocked' customers is largely comprised of structural losers who did not initially adjust consumption. Mechanically, demand reductions among shocked customers are smaller on average during the first year of the program as compared to unshocked customers in that first year. But notably, we find the demand reduction in the second year among shocked customers to be significantly larger (see Table 1.17). While we find no evidence that those who were structural losers dropped out of the program at a faster rate (see Section 1.4), bill shocks may have caught the attention of customers, explaining the larger than average demand reductions among these customers in the second year.

6 Explanations for the Default Effect

We next investigate the underlying mechanisms that could be generating the default effect in our setting. We assess these explanations in light of three key empirical facts. First, we have shown how switching the default choice significantly impacts the rate of participation in time-varying electricity pricing programs. Second, whereas the impacts of time-varying pricing on *aggregate* energy consumption and expenditures are economically significant, we have shown that the *household-level* impacts are quite small. Finally, we will document a striking lack of correlation between a household's likely gains from program participation and its program enrollment decision, even in the presence of an enrollment deadline. Taken together, we will argue that these empirical facts are more consistent with a model that uses inattention to generate a default effect, versus high switching costs or present-biased preferences.

6.1 Program Benefits Are Poor Predictors of Participation Choices

To model the relationship between program benefits and consumers' participation choices, we construct measures of *household-level* gains from participation. Let $\overline{X_i}$ denote the optimal vector of electricity consumption (i.e., peak versus off-peak consumption) under the standard price schedule $\overline{P}$ for a representative household i. Let $\tilde{X}_i$ denote the optimal vector of electricity consumption under the time-varying price schedule $\tilde{P}$. If we assume that utility is quasi-linear in electricity consumption and consumption of other goods, a monetary measure of the annual benefits from switching from $\overline{P}$ to $\tilde{P}$ can be summarized by: $max\{\bar{P}'\bar{X}_i - \tilde{P}'\bar{X}_i, \bar{P}'\bar{X}_i - \tilde{P}'\tilde{X}_i - A_i\}$. The first argument measures the change in electricity expenditures holding consumption patterns constant. We refer to this subsequently as 'structural gains,' recognizing that these gains will be negative if expenditures increase on the time-varying rate. The second argument measures the change in expenditures if the household re-optimizes consumption net of any adjustment costs, A_i.[25]

If we assume that the household will only choose to re-optimize if the benefits from adjustments exceed the costs, then the structural gains provide a lower bound on household-level benefits. We estimate structural gains for each household under both types of time-varying pricing programs (CPP and TOU) using hourly data on household-level electricity consumption from the pre-treatment period (2011).[26] Using these monthly benefits estimates, and assuming a discount rate of 5%, we construct household-specific estimates of the net present value of structural gains from participating in a time-varying pricing program. The bottom panel of Figure 6 summarizes the distributions of these values by group.[27] These structural gains are not large; we estimate that 96% and 93% of households would have experienced monthly bill differences of less than \$10 under CPP and TOU pricing, respectively. This is consistent with SMUD's goal to limit impacts on monthly bills for most customers (Jimenez, Potter, and George 2013).

The top panel of Figure 6 shows a striking lack of correlation between the structural gains

25. A_i captures any costs of re-optimization in response to the change in price schedule. This can include both the utility impacts of changes in energy consumption patterns (e.g., tolerating warmer indoor temperatures on hot days) or any adjustment costs (e.g., the effort required to reprogram a thermostat).

26. We use the control group to assess the extent to which a customer's structural gains in 2011 are correlated with structural gains in subsequent years. For the TOU rate, the correlation between pre-period and treatment period structural gains is 0.82 (correlation with the 2012 summer) and 0.79 (correlation with 2012-2013 summers). For the CPP rate, these correlations are 0.73 and 0.72. These strong correlations indicate that structural gains are persistent over time and support our use of pre-period data to estimate consumers' expected structural gains under time- varying pricing across all treatment groups.

27. Under CPP pricing, the average customer has structural gains of \$0.33 (in net present value) and 51% of households are structural winners. Under TOU pricing, the average customer has structural losses of \$10.54, and 34% of households are structural winners.

from participation and the participation rate. A significant share of the structural losers participate in the new rates while some of the largest structural winners don't participate.[28] Notably, 48% of the households opting out of the CPP program and 60% of the households opting out of the TOU program actively switched *away* from a pricing regime under which our lower bound estimates suggest they should expect to benefit. Formally, regressions of program participation on structural gains identify small and inconsistent effects across treatment groups, ranging from a 0.03% increase ($p < 0.01$) for each additional dollar of structural gains in the TOU opt-in group to a 0.06% decrease ($p < 0.1$) for the CPP opt-out group (see Table 1.13). Given the limited range of structural gains, these differences represent minor shifts in the likelihood of participation, as demonstrated in the figure. In what follows, we show that this lack of empirical correlation between structural gains and participation choice is inconsistent with some standard explanations of default effects.

[FIGURE 6 HERE]

6.2 Switching Cost Model

We now turn to our consideration of underlying causes of the default effect, beginning with the most standard explanation: switching costs. A simple model elucidates the mechanism and provides a framework for evaluating this explanation empirically.

We assume that the benefits from participation B_i are distributed in the population according to some distribution $f()$. As Figure 6 shows, these benefits can be negative if the household would fare worse on the time-varying program. Switching away from the default choice incurs a cost of s. In our context, this could reflect the cost of calling the utility or visiting the website to switch away from the default. If households make fully informed decisions, customers defaulted onto the standard rate will actively opt in to the time-varying rate if $B_i > s$. Customers defaulted on to the time-varying program will actively opt out if the cost of switching away from the default,

28. For example, in Figure 6, 5.6% of households are associated with structural losses that exceed $50 in net present value on the CPP rate. These losses notwithstanding, 21% of these customers participated in the new rate.

s, is less than the future cost (or negative benefit) of remaining in the pricing program: $B_i < -s$.

This simple choice model will generate a significant default effect if $F(s) - F(-s)$ is large. This will be the case if switching costs are large relative to discounted participation benefits. The model predicts that program participation will be positively correlated with discounted benefits.

Figure 6 provides graphical evidence that is inconsistent with this prediction. To demonstrate more formally how this model fails to rationalize the participation choices we observe, we implement this switching cost model empirically. In the opt-in treatment, for example, we assume that a household will actively opt in if:

$$B_i - s_i + \epsilon_i > 0. \tag{3}$$

We use the household-specific structural gains to proxy for household-specific benefits B_i. The s_i is a household-specific switching cost to be estimated.

To identify the parameters of the switching cost distribution that best rationalize observed participation choices, we must invoke some additional assumptions. We assume that the error term ϵ_i is a mean zero, type I extreme-value random variable. And we assume that households correctly anticipate how they would benefit under the new program (B_i). Section 1.5.2 describes this econometric exercise in detail. Overall, these estimates are implausibly large given that switching away from the default option required only a phone call, a text, or an email. Instructions were clearly displayed on all marketing materials.

Why are these cost estimates so large? Intuitively, switching costs are identified relative to benefits which the model assumes are fully accounted for by households. If, in fact, these benefits are not fully accounted for (or ignored) by households, the model will be mis-specified in a way that inflates switching cost estimates. Not only are these cost estimates too large (in absolute value), but a model that assumes participation choices are driven by comparisons of expected benefits against a reasonable switching cost predicts a strong correlation between expected benefits and participation. As noted above, we do not see this correlation in the data.

6.3 Present-Biased Preferences Model

The significant default effect we document could also reflect present-biased preferences and procrastination. In our context, it seems quite plausible that households might have intended to opt-out or opt-in, but did not get around to doing so. Were this the case, the participation choice should more accurately be represented as a choice between switching today, planning to switch later, or never switching at all. In addition to the exponential discount rate δ, the household may also exhibit a present-bias, parameterized by β, which additionally discounts all future periods by a constant amount. This type of discounting is also referred to in the literature as hyperbolic discounting (e.g., Frederick, Loewenstein, and O'Donoghue 2002; DellaVigna 2009).

We outline a simple model with present-biased preferences in Appendix A.5 and demonstrate how a key testable prediction of the model is that households that face a deadline and have higher structural gains will be more likely to switch, while households without a deadline may never actively make a choice to switch or not, and therefore their participation status will be uncorrelated with structural gains. In our setting only the opt-in treatment groups faced a deadline (they had to join the program by June 1st, 2012 or they would be prevented from joining for the duration of the program), while the opt-out treatment group could return to the standard rate at any point in the program and therefore did not face a specific deadline. If procrastination and present-biased preferences explain the default effect, we should see a positive correlation between structural gains and participation status in the opt-in arm, but not necessarily in the opt-out arm.[29]

Figure 6 indicates that, for the TOU group, there is a slightly higher probability that the participation decision is correlated with structural gains for the opt-in group compared to the opt-out group, consistent with present-biased preferences in the presence of a deadline for the opt-in group. However, the degree to which the correlation differs between the TOU opt-in and opt-out

29. (Gottlieb and Smetters 2019) document the role of forgetfulness in explaining why consumers miss deadline in a different context. These authors study consumers who fail to make premium payments before a scheduled deadline which results in policy termination. In this insurance setting, the insurance company stands to benefit if consumers miss the deadline. In our setting, the utility has a strong incentive to remind consumers about the approaching participation deadline. Figure 3 shows how customers in the opt-in group received frequent reminder phone calls, door hangers, and mailings right up to the participation deadline. We therefore assume that forgetting is less likely in this setting.

groups is, while statistically significant, very small. The difference is not statistically different from zero for the CPP treatments. This suggests that, while present-biased preferences may be one factor contributing to the default effect, they cannot explain all the variation observed in the data, so there must be additional explanations at play.

6.4 Inattention

We now introduce the possibility that customers are inattentive to benefits when making their participation decisions. In our context, customers must exert significant effort to collect the information they would need to fully understand how their households' energy consumption patterns would determine expenditures under the new, time-varying rate.[30] Inattention to this information could be rational if the impacts of switching from the standard rate are small relative to the effort costs required to make an informed decision (Sallee 2014).

In this augmented framework, the participation choice is modeled in two steps. First, the customer decides whether to exert the effort required to collect the information she would need to make an informed decision. Specifically, we assume there is some basic information about participation benefits b_i that she can easily assess without effort. The customer could make her decision on this basis. Or, if she exerts more effort, she can collect additional information in order to refine her estimate of benefits to $B_i = b_i + \alpha_i$, her true benefits.[31] If α_i is pivotal the household's participation decision will differ across the informed and uninformed states.

A rational decision-maker will exert effort if the expected returns exceed the effort costs. Consider, for example, opt-in households that are defaulted onto the standard rate. For customers who would opt in on the basis of b_i, the expected returns to exerting additional effort are: $(1 - F(s))E[s - B_i]$, assuming that customers know the true distribution of B_i. For those who would

30. In fact, there is considerable evidence to suggest that consumers poorly understand the relationship between energy consumption and energy bills. For example, Attari et al. (2010) show that when asked to guess, customers underestimate the electricity used by high energy activities, such as clothes dryers, by more than an order of magnitude and overestimate electricity used by other energy services such as lighting. See also Myers, Puller, and West (2019) and Todd-Blick et al. (2020).

31. We are assuming that customers who invest effort to learn their benefits learn their true benefits. Under a more complicated model, customers could invest to obtain a better, though still imperfect, estimate.

not opt in based on uninformed priors, the expected returns on effort are $F(s)E[B_i - s]$. Note that for both of these expressions, the first term is the probability that a decision-maker will change their program participation decision given the additional information α_i and the second is the expected value of the decision change.

We first demonstrate how this model can rationalize the patterns of participation we observe. We consider a scenario in which all households make uninformed program participation decisions. We assume that prior beliefs b_i are distributed normally in the population and are uncorrelated with structural gains. Given the complexity involved in mapping electricity consumption to time-varying rate schedules described above, this lack of correlation seems plausible and consistent with previous work documenting inattention to electricity consumption. If we further assume that switching costs are constant across households, we can identify the mean and variance of the distribution of uninformed priors that best rationalizes observed participation choices over a range of switching costs. The two participation shares we observe in the opt-in and opt-out groups, respectively, allow us to identify the two parameters of the distribution of prior beliefs.[32]

The "Uninformed prior" rows of Table 7 report the estimated means and standard deviation of the distribution of prior beliefs about participation benefits. For an assumed switching cost of \$10, the average benefit prior is \$3.53 (standard deviation is \$7.73). As customers could reasonably expect to reduce expenditures by a few dollars, these estimates seem reasonable.

Having estimated the distribution of prior beliefs about benefits, we can now ask whether, conditional on this distribution, inattention to the enrollment decision could be rational. More precisely, we simulate the participation choices that households would make based on uninformed priors and contrast these with informed choices. The difference in benefits net of switching costs across these two scenarios can be interpreted as an estimate of the return on effort. If these returns look small relative to the effort cost required to collect information, inattention to this decision could be rational.

To calibrate *informed* estimates of participation benefits, we construct household-specific es-

32. More specifically, the identifying conditions set $F(-s) = 0.96$ and $1 - F(s) = 0.20$.

timates of the present discounted gains associated with program participation. We consider two heuristics in particular, which we use to bound the expected returns. Under the first, the "No adjustment" heuristic, we assume that *informed* household decision-makers do not account for the possibility that they might adjust consumption in response to the time-varying rate. In other words, we use our estimates of household-specific structural gains to proxy for informed expectations about participation benefits. Under the "With adjustment" heuristic, we assume that informed household decision-makers anticipate that they will adjust their consumption patterns in response to the time-varying rate. To estimate the additional value obtained via demand response, we use the average additional monthly bill savings expected for participating customers in the opt-out group ($4.50 per month in the CPP group, see Table 5). Subtracting the average monthly structural gains under CPP pricing ($0.045) we estimate average benefits of $4.45 per month in addition to structural gains.

The second panel in Table 7 summarizes simulated choices under the two heuristics for the CPP experiment. We compare bill impacts associated with the informed choice (net of assumed switching costs) against bill impacts associated with the uninformed prior (net of assumed switching costs). This yields a distribution of estimated returns to paying attention. The distribution under the "No adjustment" heuristic provides a lower bound on the costs of inattention. Under the "With adjustment" heuristic, which assumes consumers account for demand response, this difference provides an upper bound because it reflects bill savings but does not account for the dis-utility associated with re-optimization of energy consumption.

[TABLE 7 HERE]

From the perspective of a household faced with this program participation choice, we estimate that the average returns on effort are low. Under the first heuristic, the average discounted returns on effort are in the range of $3 to $14 over the full two-year pricing program. Estimates are lower in the opt-out case because these consumers are, on average, nudged in the right direction. Upper bound estimates under the second heuristic are somewhat higher ($24 to $31). Given the time and cognitive effort required to gather and process information about how one's electricity expenditures might change under time-varying pricing, we speculate that the effort costs of making an informed decision could easily exceed the returns on this effort for a majority of households.

To summarize, the fact that benefits are largely uncorrelated with program participation (see the top of Figure 6) suggests the default effect is unlikely to be driven purely by switching costs or discount rates in our setting. To rationalize the participation patterns we observe, we need an explanation that somehow breaks the link between participation benefits and enrollment choices. Present-biased preferences could offer such an explanation; people who stand to benefit from switching away from the default could procrastinate indefinitely. However, the fact that the relationship between structural gains and participation remains weak, even in the presence of a participation deadline, suggests that present-biased preferences are not a sufficient explanation. Also, crucially, present-biased preferences do not explain active decisions to switch away from dynamic pricing even if lower bound estimates suggest they would gain.[33] Inattention is another mechanism that breaks the link between structural gains and switching. In our context, an electricity consumer would have to make a substantive effort to understand how she would benefit from participating in the time-varying pricing regimes. We offer evidence to suggest that, given relatively low returns on this effort, it could be rational for most consumers to make uninformed or inattentive participation decisions. Rational inattention also explains why some customers might switch away from dynamic pricing even if it is likely to provide benefits as these customers' uninformed priors may suggest that they will not benefit.

7 Implications for Welfare and Cost Effectiveness

We have argued that inattention offers a plausible explanation for the participation choices we observe across experimental treatment groups and the observed lack of correlation between structural gains and participation choice. If rationally inattentive households are nudged into a pricing

33. Note that households that actively switched in to dynamic pricing when our estimates of structural gains suggest they would lose money are easier to understand since our estimate is a lower bound on the gains they expect. These household may know that they will adjust their consumption in response to the electricity prices.

regime that they are more or less indifferent about, this default manipulation offers a powerful means of unlocking an economically significant (in aggregate) and social welfare improving demand response. In this section, we further investigate the implications of this default effect from both the household and utility perspective.

7.1 Consumer Welfare

In Section 5, we find that passive consumers mount an economically significant demand response to time varying prices. These results present something of a puzzle. If passive consumers are largely inattentive to the pricing program participation decision, why are they subsequently attentive to electricity consumption choices?

We posit that inattention is less likely to be rational once customers are nudged into the program. Responding to the new electricity pricing regime once enrolled required less effort as compared to understanding the implications of the initial participation choice. First, enrolled customers were provided with highly salient information (and frequent reminders) about how electricity prices vary across off peak, peak, and critical-peak hours. Second, whereas the initial time-varying pricing program participation decision was an entirely new and unfamiliar choice, all consumers have prior experience with electricity price changes. Although the new pricing plans featured a different kind of inter-temporal price variation (i.e., variation across days and hours versus across billing cycles), decisions about electricity consumption are similar to choices and trade-offs evaluated in the past.

To generate further insights into the likely welfare implications of this default effect, an endline survey was sent to all households enrolled on the CPP and TOU pricing plans and a subset of the control group after the pricing pilot had concluded. Among participants in time-varying pricing programs, survey responses in the opt-out group were lower (26%; N=566) as compared to the opt-in group (36%; N=183). Although survey respondents are not a random subset of the study sample, their responses shed light on consumers' motivations and sentiments about the pricing programs.

Overall, survey responses indicate a positive customer experience with time-varying electricity pricing. In both the opt-in and opt-out groups, fewer than 7% disagreed with the statement, "I want to stay on my pricing plan." More of the opt-in customers "strongly agree " with that statement and more of the opt-out customers express "no opinion." Similarly, across both groups, almost 90% of respondents are either "Very satisfied" or "Somewhat satisfied" with their current pricing plan, with no statistically significant differences across those two categories by group. In contrast, only 80% of the control group respondents are "very" or "somewhat" satisfied with the standard rate.

Our results are consistent with a scenario in which consumers are nudged onto an unfamiliar electricity rate structure that offers the average consumer small but positive gains. Over time, as consumers gain experience with the new pricing regime many come to prefer it. Although the evidence we document is consistent with a model of rational inattention, we cannot rule out an alternative or additional "endorsement" explanation. In this unfamiliar choice context, households may have viewed the default option as the choice endorsed by their electricity provider. Disentangling endorsement from rational inattention could be important with respect to external validity; the default effect could be less strong with a less trusted electricity supplier. However, either explanation is consistent with positive welfare gains in this particular context.

7.2 Cost-Effectiveness

Thus far, we have analyzed the empirical evidence from the perspective of the household. We now evaluate program outcomes from the perspective of the utility. More precisely, we investigate whether the default-induced demand response confers benefits to the utility that offset the additional program costs.

Table 8 compares the costs of enrolling participants and implementing the program against the benefits (i.e., costs avoided when peak consumption is reduced). Our analysis in Table 8 assumes each pricing program was scaled to SMUD's entire residential customer base and run for 10 years.[34]

[TABLE 8 HERE]

The two columns on the left summarize the two main benefits of the program. Reduced demand during CPP and TOU peak hours avoids two types of expenses: the costs incurred to supply sufficient electricity to meet peak demand during these hours, and the expected cost of new investments in peaking plants needed to meet demand in peak hours. To estimate avoided capacity investment costs, the expectation is taken over the probability that demand in CPP or TOU hours would drive capacity expansion decisions. Notably, the avoided energy costs are considerably smaller than the avoided capacity costs, particularly for the CPP programs. This reflects the fact that a small number of peak hours drives costly generating capacity expansions. Reducing demand in peak periods avoids the need to construct and maintain these "peaker" plants.[35]

We break the program costs into three components: (1) one-time fixed costs, which include items such as IT costs to adjust the billing system and initial program design costs, (2) one-time per-household costs which primarily include the customer acquisition costs, including the in-home devices offered to customers as part of the recruitment, and (3) recurring annual fixed and variable costs, which include personnel costs required to administer the program. The one-time variable cost of recruiting customers is lower under the opt-out programs than under the opt-in.

Net benefits are reported in the final column of Table 8. We estimate that both opt-out programs would be cost-effective with net benefits to the utility in excess of $55 and $23 million for the CPP and TOU programs, respectively. The CPP opt-in program is estimated to be marginally cost-effective. The TOU opt-in program, which led to much smaller demand reductions than the CPP program, is projected to incur costs in excess of savings. In other words, in the case of

34. Some of these program benefits and costs are summarized in Potter, George, and Jimenez (2014), a consulting report prepared to help SMUD decide whether to expand the pilot. We obtained additional information from personal communications with SMUD and their consultants. Section 1.3 summarizes underlying assumptions, and explains why some of the assumptions pertaining to program benefits are likely conservative.

35. As we explain in Section 1.6, the calculations reflected in Table 8 may understate the capacity benefits, for example because they do not measure reductions in transmission- and distribution-level investments. Because the numbers in Table 8 reflect private benefits to the utility, they do not incorporate the value of avoided pollution. Given that the avoided energy savings benefits are low relative to the avoided capacity, we suspect that avoided pollution would not change the overall cost-benefit calculus by much.

the TOU program, the default manipulation turns a cost-ineffective program into a cost-effective endeavour from the utlity's perspective.

8 Conclusion

The default effect is one of the most powerful and consistent behavioral phenomena in economics, with examples documented across many settings, including health care, personal finance and internet marketing. This paper studies this phenomenon in a new context — time-varying pricing programs for electricity. Residential customers served by a large municipal utility in the Sacramento area were randomly allocated to one of three groups: (1) a treatment group in which they were offered the chance to opt in to a time-varying pricing program; (2) a treatment group that was defaulted on to time-varying pricing but allowed to opt out; and (3) a control group. We document stark evidence of a default effect, with only about 20% of customers opting into the new pricing programs and over 90% staying on the programs when it was the default option. This holds for both Critical Peak Pricing and Time-of-Use programs.

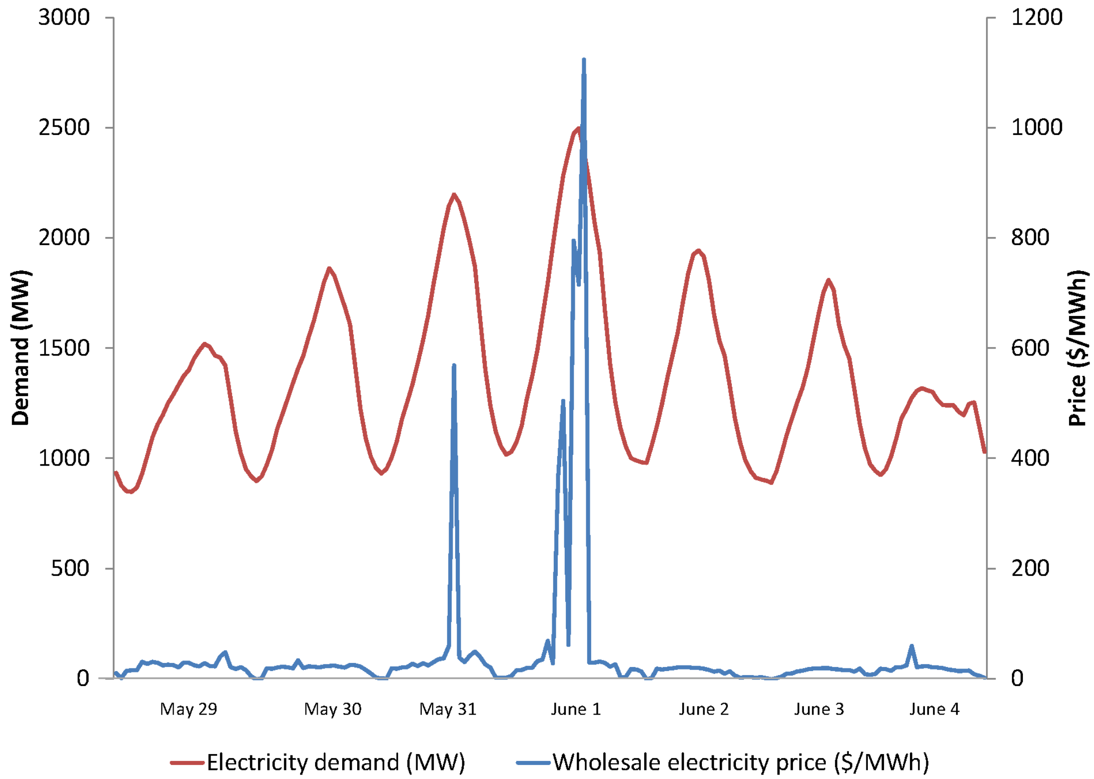
This empirical setting offers several innovations relative to the existing literature on default effects. In addition to observing the initial decision that was directly manipulated by the default effect, we also collect detailed data on follow-on behavior. We distinguish between follow-on behavior that modifies the original choice, such as opting out of the time-varying pricing program once it has begun, and behavior that is conditional on, but distinct from, the original choice. In our case, the latter involves adjusting electricity consumption in response to time-varying electric prices. We argue that this conditional behavior can be equally, if not more, important than the original choice for two reasons: (1) it is observation of the follow-on behavior that enables us to assess competing explanations for the default effect and in turn draw qualitative conclusions about the welfare implications of defaulting people onto these time-varying pricing programs; and (2) societal and grid benefits from such a program are critically contingent on whether consumers join the program, and if they change their electricity consumption in response to the program conditional on joining. We find that consumers do adjust electricity consumption in response to the time-varying prices, even if they did not actively select them.

An additional innovation of this work results from analyzing systematic differences in the initial participation choice and follow-on behavior across different groups. Notably, we find that customers who should expect to have lower bills on the program without changing their behavior (so-called "structural winners") were no more likely to enroll in the program. This observation underpins our assessment of competing explanations for the default effect. This pattern is inconsistent with explanations for the default effect that assume consumers perform well-informed, cost-benefit calculations before making their choice. We find that expected gains from making a fully attentive choice are small, on average, relative to the effort that is presumably required to make those calculations. We show how a choice model that accommodates inattention can rationalize the default effects we observe. Because Sacramento is a particularly well-regarded utility with high customer satisfaction, consumers in our study might assume the utility had their interests in mind when choosing the default. This could reduce the likelihood that consumers will attend to this choice. However, even without these potential endorsement effects, we show that the costs of inattention are low in this setting, suggesting that inattention to the participation choice is plausibly rational.

Once defaulted, passive consumers (i.e., consumers who would not have actively enrolled in the pricing program but did not opt out) are sufficiently attentive to time-varying pricing to mount an economically significant response on average. Moreover, as passive customers gain experience with the new pricing regime, their average demand response increases. We see convergence between active joiners and passive consumers in the second year of the program, which we take as evidence that nudged consumers acclimated to the new pricing regimes. We expect that future work can similarly use follow-on behavior to draw inferences about default effects.

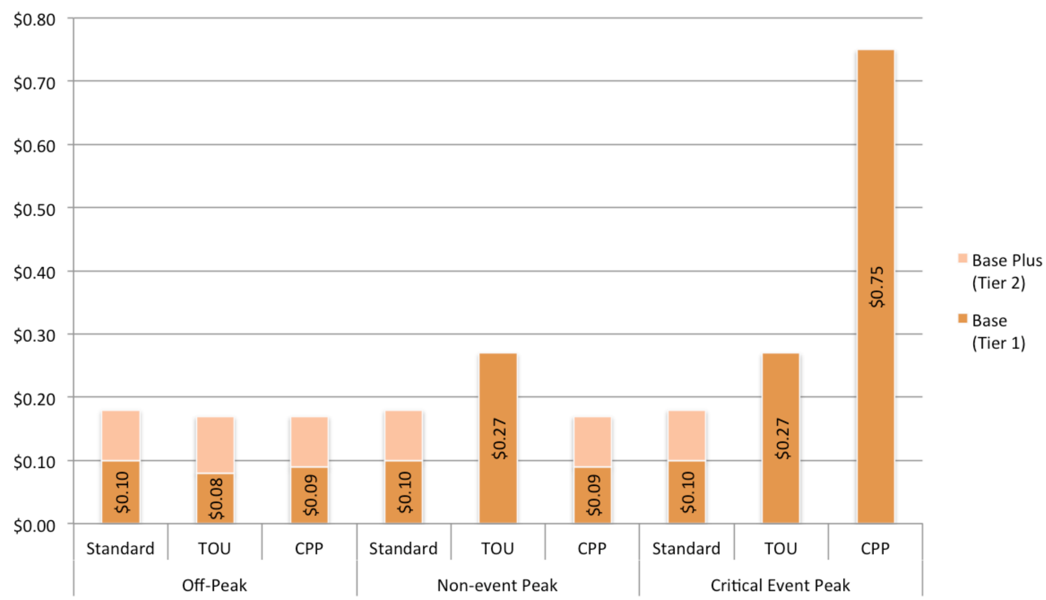
In sum, we find that placing households onto time-varying pricing by default can lead to significantly more customers on time-varying pricing and, more importantly, significantly higher aggregate responses to price changes. Inattention to this choice appears rational from the perspective of a household; the welfare implications of the default effect are small for an individual customer. Aggregated across households, the social benefits associated with higher participation in demand response are substantial.

Figure 1: Hourly electricity demand (SMUD) and wholesale electricity price (CAISO)



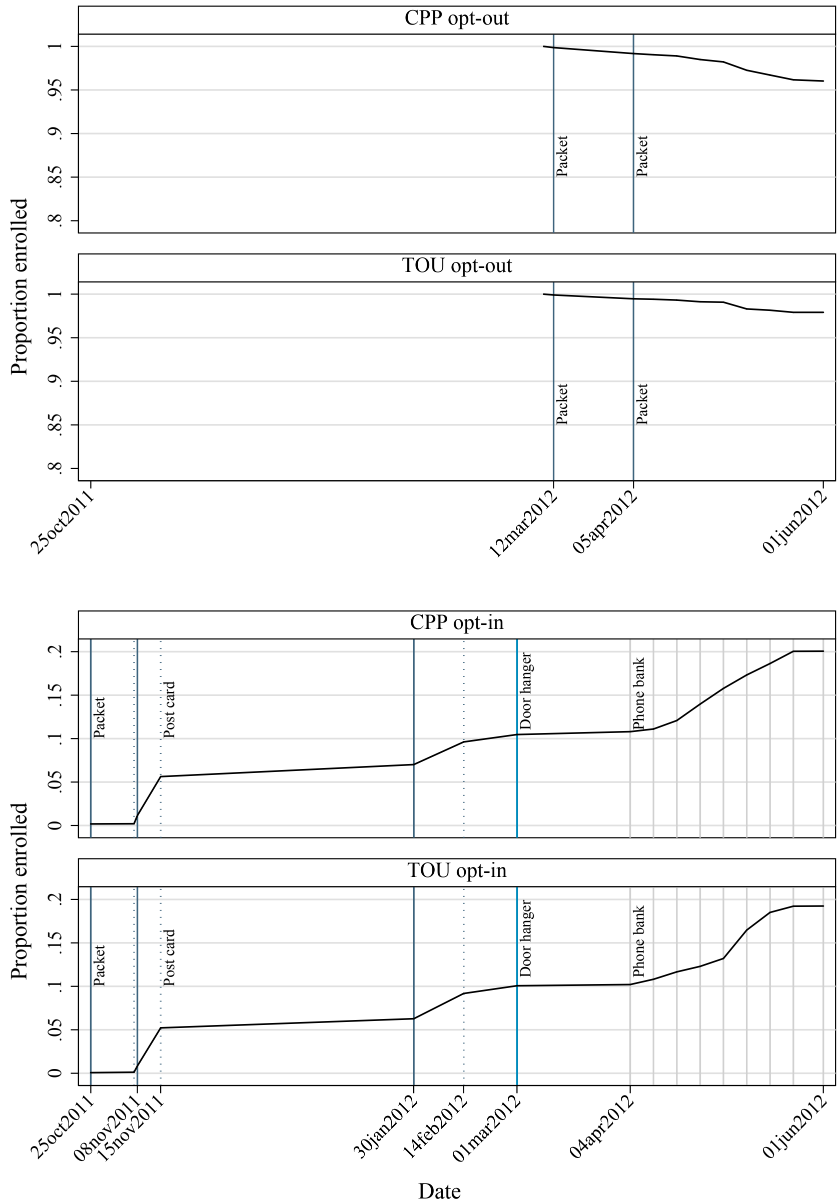
Note: This figure shows fluctuations of hourly electricity demand and wholesale spot prices over a week in June, 2011. Wholesale spot prices reported by the California independent system operator (CAISO).

Figure 2: Electricity rate structures



Notes: This figure shows SMUD electricity rate structures in place during the treatment period. On the base rate, customers are charged $0.1016 for the first 700 kWh in the billing period, with additional usage billed at $0.1830. Participants on the TOU rate were charged an on-peak price of $0.27/kWh between the hours of 4 PM and 7 PM on weekdays, excluding holidays. For all other hours, participants were charged $0.0846/kWh for the first 700 kWh in each billing period, with any additional usage billed at $0.1660/kWh. On the CPP rate, participants were charged a price of $0.75/kWh during CPP event hours. There were 12 CPP events called per summer on weekdays during the hours of 4 PM and 7 PM. For all other hours, participants were charged $0.0851/kWh for the first 700 kWh in each billing period, with any additional usage billed at $0.1665/kWh.

Figure 3: Encouragement efforts



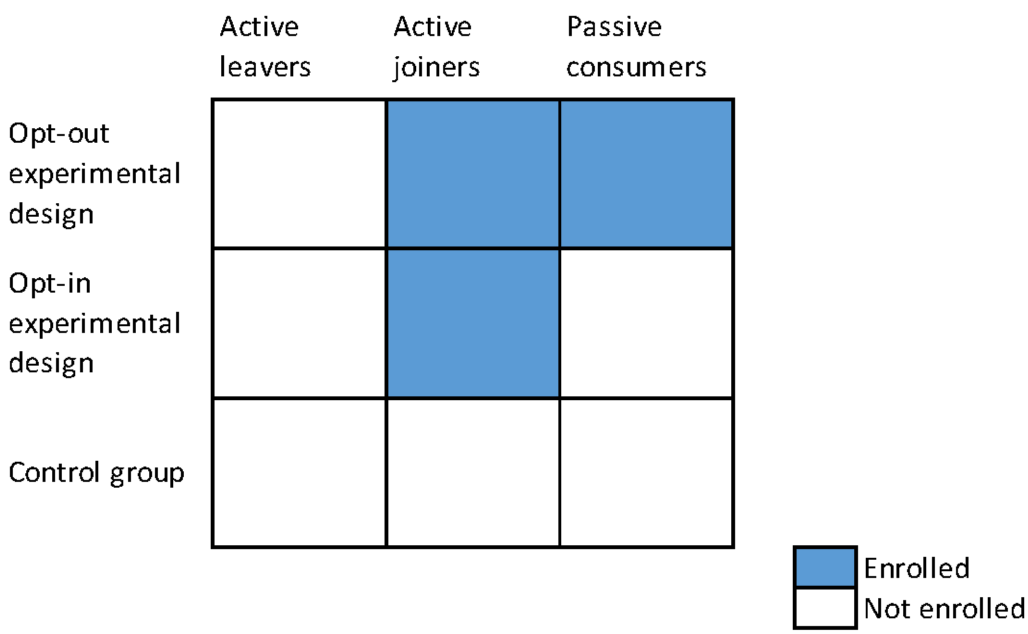
Notes: This figure shows pre-period encouragement efforts and enrollment proportion. For opt-out groups, vertical lines indicate dates on which packets were mailed out to the households. For opt-in groups, the first three solid vertical lines are dates on which packets were mailed out, the three dotted vertical lines indicate dates on which follow-up post cards were mailed out, and the final solid vertical line depicts distribution of door hangers on March 1st, 2012. Gray vertical lines between April 4th and June 1st, 2012 indicate the phone bank campaign, when calls went out on almost a daily basis. The solid decreasing (increasing) lines in each figure represent the proportion of households in the opt-out (opt-in) group that remained enrolled (chose to enroll) in treatment over the course of the recruitment efforts.

Table 1: Comparison of means by treatment assignment

	Control group	Treatment groups			
		CPP		TOU	
		Opt-in	Opt-out	Opt-in	Opt-out
Daily usage (kWh)	26.63	26.81	26.92	26.49	26.38
		(-0.82)	(-0.45)	(0.83)	(0.71)
Peak to off-peak ratio	1.77	1.77	1.78	1.78	1.78
		(0.02)	(-0.50)	(-0.57)	(-0.37)
Bill amount ($)	109.10	109.44	109.12	108.20	107.86
		(-0.34)	(-0.01)	(1.08)	(0.69)
Structural winner (CPP)	0.51	0.51	0.52	0.51	0.50
		(-0.51)	(-0.39)	(-0.11)	(0.70)
Structural winner (TOU)	0.34	0.34	0.35	0.34	0.33
		(-0.13)	(-0.15)	(0.41)	(1.14)
Households	45,839	9,190	846	12,735	2,407

Notes: This table compares pre-period usage statistics across control and treatment groups. Cells contain group means and t-statistics (in parentheses) obtained from a two-sample t-test comparing means in the control group to means in the given treatment group. Daily usage is the average per-customer electricity usage over the pre-period summer. Peak to off-peak ratio is the average hourly consumption during peak periods (4-7pm on weekdays) divided by the hourly kWh used during non-peak times over the pre-period summer. Bill amounts reflect monthly bills over the pre-period summer. Structural winner is an indicator variable for whether the household would have experienced reduced bills in the pre-period summer had they been enrolled in either the CPP or TOU pricing plans.

Figure 4: Identification of active joiners, passive consumers, and active leavers



Notes: This figure describes enrollment choice of different customer types by experimental group. Rows indicate the three groups into which customers in our sample were randomly assigned: opt-out, opt-in, and control. Columns signify types of customers (active leavers, active joiners, and passive consumers). Shading indicates that the customer type enrolls in time-varying pricing program under the associated experimental group.

Table 2: Participation rates

	Initial		Endline		Attrition
	Proportion	Count	Proportion	Count	Change
CPP opt-in (AJ)	0.201	1,568	0.189	1,169	0.057
CPP opt-out (AJ + PC)	0.960	701	0.894	537	0.070
TOU opt-in (AJ)	0.193	2,088	0.181	1,551	0.062
TOU opt-out (AJ + PC)	0.979	2,019	0.926	1,507	0.055

Notes: This table describes participation by experimental group. AJ stands for active joiners, PC stands for passive consumers. Proportions are the count of enrolled customers divided by the count of total customers in each group at a given point in time. Counts include only customers who have not moved away by a given point in time. Initial participation reflects the beginning of the treatment period (June 1st, 2012), while endline participation reflects the end of the treatment period (September 30th, 2013). An enrolled customer is one who entered the program (either by opting in or by being defaulted in) and did not opt-out before the given date. Attrition is the percentage change between initial and end-line participation proportions (where a value of 0.057 signifies a percent change of 5.7 percent).

Table 3: Average effects for encouraged groups

	Critical event		Non-event peak	
	Opt-in	Opt-out	Opt-in	Opt-out
Encouragement (CPP)	-0.129^{***}	-0.305^{***}	-0.029^{***}	-0.094^{***}
	(0.010)	(0.037)	(0.006)	(0.020)
Mean usage (kW)	2.49	2.5	1.8	1.8
Customers	55,028	46,684	55,028	46,684
Customer-hours	4,832,874	4,104,263	31,198,201	26,495,612
Encouragement (TOU)	-0.091^{***}	-0.130^{***}	-0.054^{***}	-0.100^{***}
	(0.008)	(0.019)	(0.006)	(0.013)
Mean usage (kW)	2.49	2.49	1.79	1.79
Customers	58,573	48,245	58,573	48,245
Customer-hours	5,141,976	4,240,163	33,195,961	27,374,276

* $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$. Standard errors in parentheses.

Notes: This table presents estimates of the impact of encouragement assignment on average hourly electricity usage in kilowatts, irrespective of enrollment status. To estimate the critical event hour effects, data include 4-7pm during simulated CPP events in 2011 (hottest 12 non-holiday weekdays) and 4-7pm during actual CPP events in 2012-2013. To estimate the peak period non-event hour effects, data include 4-7pm on all non-holiday weekdays during the 2011, 2012 and 2013 summers, excluding simulated CPP event days in 2011 and excluding actual CPP event days in 2012 and 2013. Intent to treat effects are identified by comparing the opt-in and opt-out experimental groups to the control group. Intent to treat effects are estimated using ordinary least squares. All regressions include customer and hour-of-sample fixed effects. Standards errors are clustered by customer.

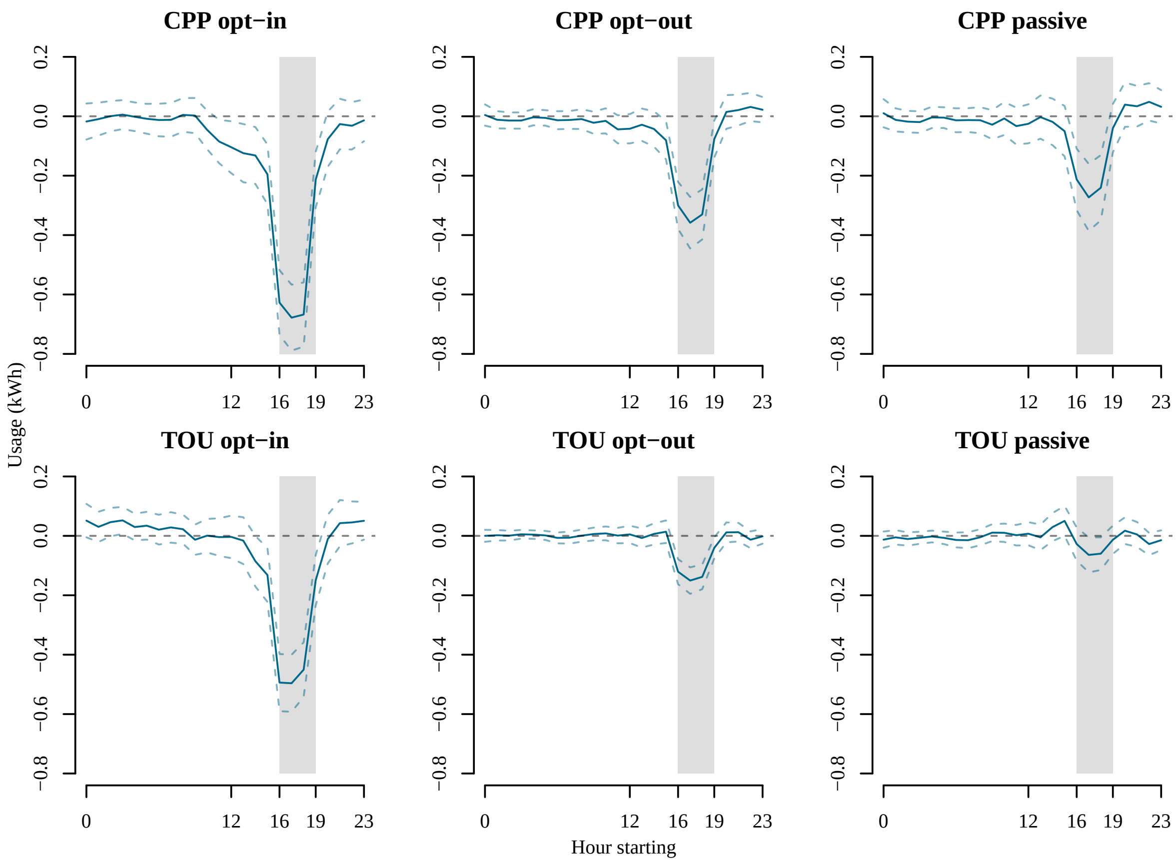
Table 4: Average effects for treated households

	Critical event hours			Non-event day peak hours		
	Opt-in (AJ)	Opt-out (AJ+PC)	Passive (PC)	Opt-in (AJ)	Opt-out (AJ+PC)	Passive (PC)
Treatment (CPP)	−0.658***	−0.330***	−0.242***	−0.146***	−0.101***	−0.089***
	(0.051)	(0.040)	(0.053)	(0.031)	(0.022)	(0.028)
Mean usage (kW)	2.49	2.50	2.44	1.80	1.80	1.79
Customers	55,028	46,684	10,036	55,028	46,684	10,036
Customer-hours	4,832,874	4,104,263	880,075	31,198,201	26,495,612	5,679,023
Treatment (TOU)	−0.480***	−0.136***	−0.051*	−0.287***	−0.105***	−0.059***
	(0.044)	(0.020)	(0.027)	(0.029)	(0.014)	(0.018)
Mean usage (kW)	2.49	2.49	2.43	1.79	1.79	1.75
Customers	58,573	48,245	15,142	58,573	48,245	15,142
Customer-hours	5,141,976	4,240,163	1,325,077	33,195,961	27,374,276	8,555,447

* $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$. Standard errors in parentheses.

Notes: This table presents estimates of the impact of enrollment on average hourly electricity usage in kilowatts. AJ stands for active joiners, PC stands for passive consumers. The sample for critical event hours includes hours between 4pm and 7pm during simulated CPP events in 2011 (hottest 12 non-holiday weekdays between June and September) and actual CPP events in 2012-2013. Sample for non-event day peak hours include hours between 4pm and 7pm of non-holiday, non-CPP event weekdays during the 2011-2013 summers (June to September). Opt-in and opt-out effects are estimated by comparing the opt-in and opt-out experimental groups, respectively, to the control group. Passive consumer effects are estimated by comparing the opt-out experimental group to the opt-in experimental group. Treatment effects are estimated using two-stage least squares, with randomized encouragement into treatment used as an instrument for treatment enrollment. All regressions include customer and hour-of-sample fixed effects. Standard errors are clustered at the customer level.

Figure 5: Event day effects for treated households by hour



Notes: This figure depicts hourly impacts of enrollment on electricity usage in kilowatts during event days. The sample includes simulated CPP events in 2011 (hottest 12 non-holiday weekdays between June and September) and actual CPP events in 2012-2013. Opt-in and opt-out effects are estimated by comparing the opt-in and opt-out experimental groups, respectively, to the control group. Passive consumer effects are estimated by comparing the opt-out experimental group to the opt-in experimental group. Treatment effects are estimated using two-stage least squares, with randomized encouragement into treatment used as an instrument for treatment enrollment. Dashed lines indicate the 95 percent confidence interval of the estimates with standard errors clustered by customer. The vertical bars indicate the peak period, between 4pm and 7pm.

Table 5: Average bill impacts for treated households

	Opt-in (AJ)	Opt-out (AJ+PC)	Passive (PC)
Treatment (CPP)	−6.515***	−4.499***	−3.121**
	(2.358)	(1.428)	(1.485)
Mean bill ($)	114	114	114
Customers	55,029	46,685	10,036
Customer-months	552,087	468,843	100,552
Treatment (TOU)	−2.816	−1.985**	−1.423
	(2.196)	(0.872)	(0.935)
Mean bill ($)	114	114	113
Customers	58,574	48,246	15,142
Customer-months	587,406	484,364	151,392

* $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$. Standard errors in parentheses.

Notes: This table documents the impact of treatment enrollment on monthly bills. The sample is composed of summer months. AJ stands for active joiners, PC stands for passive consumers. Opt-in and opt-out effects are estimated by comparing the opt-in and opt-out experimental groups, respectively, to the control group. Passive consumer effects are estimated by comparing the opt-out experimental group to the opt-in experimental group. Treatment effects are estimated using two-stage least squares, with randomized encouragement into treatment used as an instrument for treatment enrollment. All regressions include customer and month-of-sample fixed effects. Standard errors are clustered at the customer level.

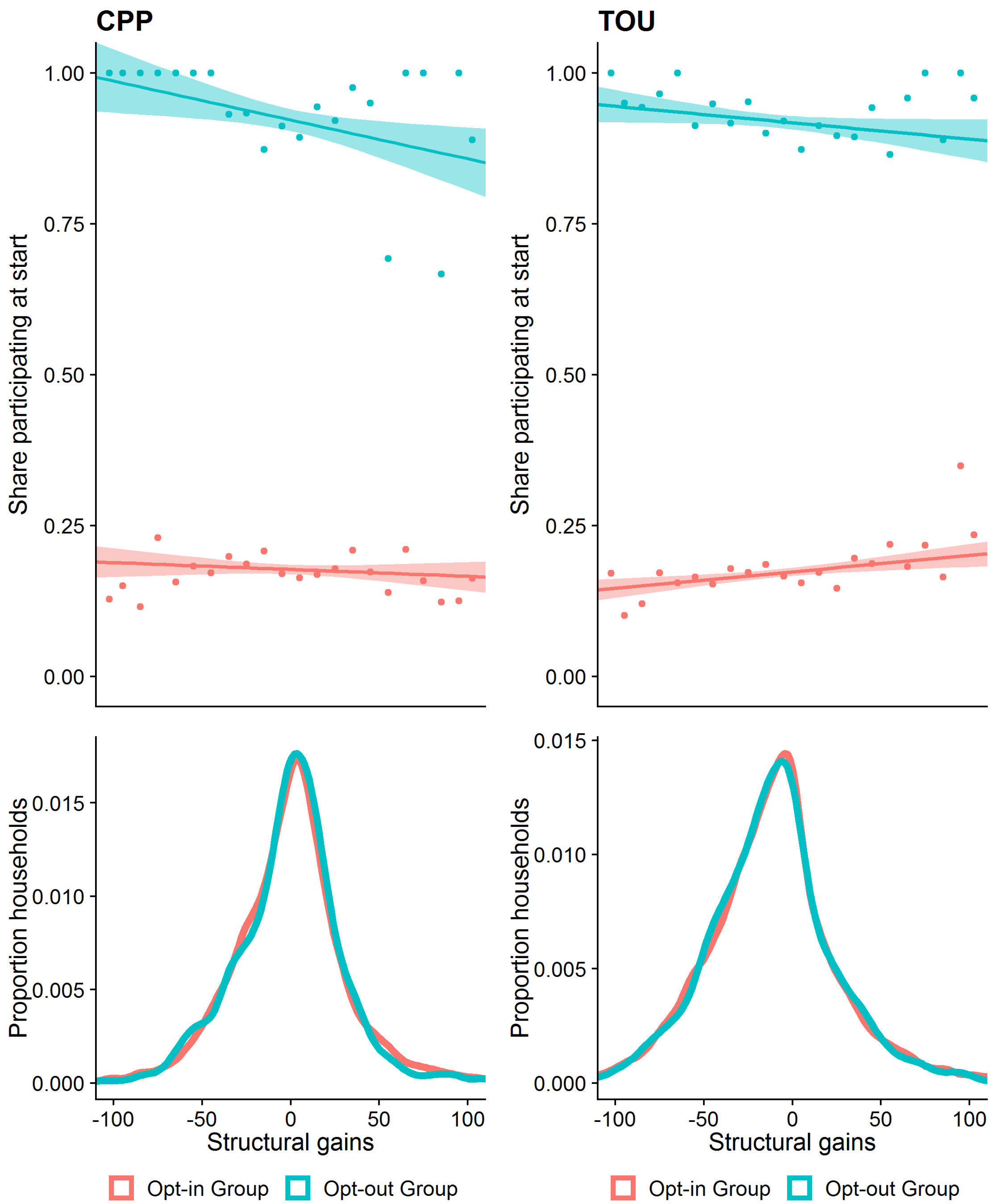
Table 6: Usage impacts vary by year of program

	Critical event hours			Non-event day peak hours		
	Opt-in (AJ)	Opt-out (AJ+PC)	Passive (PC)	Opt-in (AJ)	Opt-out (AJ+PC)	Passive (PC)
Treatment (CPP)	-0.714^{***}	-0.298^{***}	-0.186^{***}	-0.161^{***}	-0.079^{***}	-0.057^{**}
	(0.054)	(0.043)	(0.056)	(0.031)	(0.022)	(0.029)
× Year 2	0.126^{**}	-0.069^{*}	-0.124^{**}	0.036	-0.051^{**}	-0.075^{**}
	(0.054)	(0.037)	(0.049)	(0.035)	(0.023)	(0.030)
Treatment (TOU)	-0.545^{***}	-0.156^{***}	-0.058^{**}	-0.310^{***}	-0.112^{***}	-0.062^{***}
	(0.046)	(0.021)	(0.028)	(0.029)	(0.014)	(0.018)
× Year 2	0.146^{***}	0.044^{**}	0.017	0.056^{*}	0.018	0.007
	(0.049)	(0.020)	(0.027)	(0.033)	(0.013)	(0.017)

* $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$. Standard errors in parentheses.

Notes: This table presents estimates of the treatment effects separately for each year of the program. Year 2 refers to the the second year of treatment period, 2013. For the first, second, fourth and fifth columns regressors are instrumented with indicators for encouragement group and its interaction with the indicator variable for structural winners. The sample for these four columns is composed of the control group and given treatment group. For the third and sixth columns, the instruments are enrollment into opt-out group and its interaction with the indicator variable for Year 2 and the sample includes only opt-in and opt-out treatment groups. Event hours include 4 to 7 PM on simulated critical peak event days in 2011 and actual event days in 2012 and 2013. Non-event peak day hours include all peak hours excluding critical event hours. All models include customer and hour of sample fixed effects. Standard errors are clustered at the customer level.

Figure 6: Program participation by structural gains



Notes: Figure documents the distribution of structural gains and the relationship between structural gains and program participation on June 1, 2012 (the start of the experiment) for both CPP and TOU time-varying pricing treatments. Bottom panels: distributions of structural gains. Top panels: points are the proportion of households participating at the start of the program in each bin, lines and confidence intervals are the fitted values and confidence intervals for the prediction of a regression of participation on structural gains.

Table 7: Returns on attention (CPP)

	Opt-in	Opt-out
Participation	20%	96%
Passive customers	76%	
	Returns on attention ($)	
Switching cost c = $10		
Uninformed prior	$\mu = 3.53, \sigma = 7.73$	
No adjustment	13.51	3.76
With adjustment	31.03	2.70
Switching cost c = $20		
Uninformed prior	$\mu = 7.05, \sigma = 15.45$	
No adjustment	11.57	2.92
With adjustment	24.37	3.00

Notes: This table summarizes our estimates of the distribution of uninformed priors and the associated returns on attention for customers in the CPP group. Participation indicates the observed initial participation percentages in the time-varying pricing program. In the second panel, uninformed priors are the means and standard deviations of the normal distribution that rationalizes the observed participation in the opt-in and opt-out groups, given the assumed switching costs. We simulate returns on attention, or the average value of becoming informed about their structural gains (and possibly changing their enrollment choice) across all customers. The"No adjustment" assumes that customers can become informed about their structural gains under time-varying pricing. "With adjustment" assumes that customers both become informed about their structural gains and anticipate their own changes in energy consumption in response to time-varying pricing. Under both heuristics, we assume a discount rate of 5%.

Table 8: Cost-effectiveness

	Benefits		Costs				Benefits - Costs
	Avoided Capacity	Avoided Energy	One-time Fixed Costs	One-time Variable Costs	Recurring Annual Total Costs	10-year NPV	
CPP opt-in	44.0	0.9	1.4	31.0	0.9	36.5	8.4
CPP opt-out	92.1	2.1	1.4	21.0	3.1	38.8	55.4
TOU opt-in	27.0	5.0	0.8	30.0	0.5	32.5	-0.5
TOU opt-out	41.8	7.3	0.8	18.5	1.3	26.1	23.0

Notes: This table presents the estimates of the cost-effectiveness for each treatment group. All figures are in millions of dollars and assume the program is scaled to SMUD's whole residential customer base and run for 10 years. See Appendix 6 for details.

References

Abadie, Alberto, and Sebastien Gay. 2006. "The impact of presumed consent legislation on cadaveric organ donation: A cross-country study." *Journal of Health Economics* 25 (4): 599–620.

Allcott, Hunt, and Judd B. Kessler. 2019. "The Welfare Effects of Nudges: A Case Study of Energy Use Social Comparisons." *American Economic Journal: Applied Economics* 11 (1): 236–276.

Attari, Shahzeen Z., Michael L. DeKay, Cliff I. Davidson, and Wändi Bruine de Bruin. 2010. "Public perceptions of energy consumption and savings." *Proceedings of the National Academy of Sciences* 107 (37): 16054–16059. eprint: https://www.pnas.org/content/107/37/16054.full.pdf.

Bernheim, B. Douglas, Andrey Fradkin, and Igor Popov. 2015. "The Welfare Economics of Default Options in 401 (k) Plans." *The American Economic Review* 105 (9): 2798–2837.

Blumenstock, Joshua, Michal Callen, and Tarek Ghani. 2018. "Why Do Defaults Affect Behavior? Experimental Evidence from Afghanistan." *American Economic Review* 108:2868–2901.

Boiteux, Marcel. 1964a. "Marginal Cost Pricing." In *Marginal Cost Pricing in Practice,* edited by J. R. Nelson, 51–58. Englewood, NJ: Prentice-Hall.

———. 1964b. "The Choice of Plant and Equipment for the Production of Electricity." In *Marginal Cost Pricing in Practice,* edited by J. R. Nelson, 199–214. Englewood, NJ: Prentice-Hall.

Borenstein, Severin, and Stephen Holland. 2005. "On the Efficiency of Competitive Markets with Time-Invariant Retail Prices." *RAND Journal of Economics* 36 (3): 469–93.

Brown, Jeffrey R., Anne M. Farrell, and Scott J. Weisbenner. 2016. "Decision-making Approaches and the Propensity to Default: Evidence and Implications." *Journal of Financial Economics* 121 (3): 477–495.

Cappers, Peter, and Steven Sheer. 2016. *American Recovery and Reinvestment Act of 2009: Final Report on Customer Acceptance, Retention, and Response to Time-Based Rates from Consumer Behavior Studies.* LBNL-1007279. LBNL.

Carroll, Gabriel D., James J. Choi, David Laibson, Brigitte C. Madrian, and Andrew Metrick. 2009. "Optimal Defaults and Active Decisions." *Quarterly Journal of Economics* (November): 1639–1674.

Chetty, Raj, John N. Friedman, Søren Leth-Petersen, Torben Heien Nielsen, and Tore Olsen. 2014. "Active vs. passive decisions and crowd-out in retirement savings accounts: Evidence from Denmark." *The Quarterly Journal of Economics* 129 (3): 1141–1219.

Choi, James J., David Laibson, Brigitte C. Madrian, and Andrew Metrick. 2002. "Defined contribution pensions: Plan rules, participant choices, and the path of least resistance." In *Tax Policy and the Economy, Volume 16,* edited by James M. Poterba, 67–114. Cambridge, MA: MIT Press.

———. 2004. "For Better or for Worse: Default Effects and 401 (K) Savings Behavior." In *Perspectives on the Economics of Aging,* 81–126. University of Chicago Press.

Choukhmane, Taha. 2018. "Default Options and Retirement Saving Dynamics."

Cooper, Adam, and Mike Shuster. 2019. *Electric Company Smart Meter Deployments: Foundation for a Smart Grid.* Technical report. The Edison Foundation, Institute for Electric Innovation.

DellaVigna, Stefano. 2009. "Psychology and Economics: Evidence from the Field." *Journal of Economic Literature* 47:315–372.

Department of Energy. 2012. *Smart Grid Investment Grant Program.* Staff Report. United States Department of Energy, July.

EIA. 2018. *Annual Electric Power Industry Report.* Data retrieved from https://www.eia.gov/electricity/data/eia861/.

EPRI. 2012. *Understanding Electric Utility Consumers - Summary Report: What We Know and What We Need to Know.* Final Report. Electric Power Research Institution (EPRI), October.

Frederick, Shane, George Loewenstein, and Ted O'Donoghue. 2002. "Time discounting and time preference: A critical review." *Journal of Economic Literature* 40 (2): 351–401.

Goldin, Jacob, and Daniel Reck. 2019. "Revealed Preference Analysis with Framing Effects." *Journal of Political Economy:* forthcoming.

Gottlieb, Daniel, and Kent Smetters. 2019. *Lapse-Based Insurance.*

Handel, Benjamin R. 2013. "Adverse selection and inertia in health insurance markets: When nudging hurts." *The American Economic Review* 103 (7): 2643–2682.

Handel, Benjamin R., and Jonathan T. Kolstad. 2015. "Health insurance for "humans": Information frictions, plan choice, and consumer welfare." *The American Economic Review* 105 (8): 2449–2500.

Jimenez, Lupe, Jennifer Potter, and Stephen George. 2013. *SmartPricing Options Interim Evaluation.* https://www.smartgrid.gov/files/MASTER_SMUD_CBS_Interim_Evaluation_Final_SUBMITTED_TO_TAG_20131023.pdf, accessed February 2020. U.S. Department of Energy and Lawrence Berkeley National Laboratory.

Johnson, Eric J., Steven Bellman, and Gerald L. Lohse. 2002. "Defaults, Framing and Privacy: Why Opting In-Opting Out." *Marketing Letters* 13, no. 1 (February): 5–15.

Johnson, Eric J., and Daniel Goldstein. 2003. "Do Defaults Save Lives?" *Science* 302, no. 5649 (November): 1338–1339.

Johnson, Eric J., John Hershey, Jacqueline Meszaros, and Howard Kunreuther. 1993. "Framing, probability distortions, and insurance decisions." *Journal of Risk and Uncertainty* 7:35–51.

Ketcham, Jonathan D, Nicolai V Kuminoff, and Christopher A Powers. 2016. "Estimating the Heterogeneous Welfare Effects of Choice Architecture: An Application to the Medicare Prescription Drug Insurance Market." *NBER Working Paper.*

Kowalski, Amanda E. 2016. "Doing More When You're Running LATE: Applying Marginal Treatment Effect Methods to Examine Treatment Effect Heterogeneity in Experiments." *NBER Working Paper.*

Madrian, Brigitte C., and Dennis F. Shea. 2001. "The Power of Suggestion: Inertia in 401(k) Participation and Savings Behavior." *The Quarterly Journal of Economics* 116 (4): 1149–1187.

Myers, Erica, Steven L Puller, and Jeremy D West. 2019. *Effects of Mandatory Energy Efficiency Disclosure in Housing Markets.* Working Paper, Working Paper Series 26436. National Bureau of Economic Research, November.

Park, C. Whan, Sung Youl Jun, and Deborah J. MacInnis. 2000. "Choosing what I want versus rejecting what I do not want: An application of decision framing to product option choice decisions." *Journal of Marketing Research* 37 (2): 187–202.

Potter, Jennifer M., Stephen S. George, and Lupe R. Jimenez. 2014. *SmartPricing Options Final Evaluation.* Technical report.

Sallee, James M. 2014. "Rational Inattention and Energy Efficiency." *The Journal of Law and Economics* 57 (3): 781–820.

Samuelson, William, and Richard Zeckhauser. 1988. "Status quo bias in decision making." *Journal of Risk and Uncertainty* 1 (1): 7–59.

Sitzia, Stefania, Jiwei Zheng, and Daniel John Zizzo. 2015. "Inattentive consumers in markets for services." *Theory and Decision* 79 (2): 307–332.

Thaler, Richard H., and Cass R. Sunstein. 2009. *Nudge: Improving decisions about health, wealth, and happiness.* Penguin.

Todd-Blick, Annika, C. Anna Spurlock, Ling Jin, Peter Cappers, Sam Borgeson, Daniel Fredman, and Jarett Zuboy. 2020. "Winners are not keepers: Characterizing household engagement, gains, and energy patterns in demand response using machine learning in the United States." *Energy Research and Social Science* 70 (101595).

Wang, Wenjie, and Takanori Ida. 2017. "Default Effect Versus Active Decision: Evidence from a Field Experiment in Los Alamos." *Kyoto University Discussion Paper No. E-14-010.*

1 Appendix

DEFAULT EFFECTS AND FOLLOW-ON BEHAVIOR: EVIDENCE FROM AN ELECTRICITY PRICING PROGRAM

Meredith Fowlie
Catherine Wolfram
C. Anna Spurlock
Annika Todd-Blick
Patrick Baylis
Peter Cappers

Contents

1.1 Load Shape Balance across Treatment Groups

Table 1 in the main text discusses balance in covariates between control and treatment groups. Because we analyze consumption across hours of the day, we are also concerned about balance in hourly consumption profiles. Figure 1.1 plots each treatment group's hourly electricity consumption overlaid with control group consumption, obtained from a regression of electricity consumption on a set of indicator variables for each hour. The left side of the figure compares customers who were offered the opportunity to opt-in to either the CPP or TOU treatment to control customers, while the right side compares customers who were defaulted on to either the CPP or TOU plan to the same control customers. The graph highlights the variation in electricity consumption over the day, from a low below .75 kWh in the middle of the night to a peak nearly three times as high at 5PM. This consumption profile is typical across electricity consumers around the country, although SMUD customers' peak consumption tends to be slightly later than for customers of other utilities.

The graph also highlights that we cannot reject that both sets of treated households had statistically identical consumption profiles to the control households. The graphs in Figure 1.2 show the differences between treated and control, highlighting that these are well within the 95 percent confidence intervals for all hours. The standard errors for the CPP opt-out group are notably larger since that group had one tenth as many households.

1.2 Alternative Specifications

Table A1 reports heterogeneity in impacts of time-varying rates by customer type, including for structural winners, low-income customers and customers that had signed up for SMUD's online portal ("Low income" is a dummy variable indicating enrollment in the low-income rate and "My Account" is a dummy variable indicating whether or not the household had signed up to use SMUD's online portal prior to our experiment). Tables 1.3, 1.4, and 1.5 report results similar to those in Tables 3, 4 and 6 in the text using the log of hourly consumption as the dependent variable. The results are very consistent across specifications: the ITT estimate is about twice as large in the CPP opt-out treatment compared to the CPP opt-in.

Table 1.2 replicates Table 6 using data only from the balanced panel, i.e., customers who did not change their treatment status (either by opting in, opting out, or moving) during the treatment period. Table 1.6 reports results similar to those in Table 4 in the text using only post-treatment period data.

1.3 Assumptions Underlying the LATE Estimates

This section explains how we leverage our research design to estimate local average treatment effects in different sub-groups of our study sample. We use the randomly assigned encouragements (i.e., the opt-in offer and the opt-out offer, respectively) as instruments.

Let $D_i = 1$ if the individual participates in the dynamic pricing program. Let $D_i = 0$ if the individual remains in the standard pricing regime. Let $Z_i = 1$ if the individual was assigned to the opt-in encouragement treatment, let $Z_i = 2$ if the individual was assigned to the opt-out; otherwise $Z_i = 0$.

Conceptually, we define four sub-populations:

- Active leavers (AL): Do not opt in if $Z_i = 1$. Opt out if $Z_i = 2$.
- Passive consumers (PC): Do not opt in if $Z_i = 1$. Do not opt out if $Z_i = 2$.
- Active joiners (AJ): Opt in if $Z_i = 1$. Do not opt out if $Z_i = 2$.
- Defiers (D): Opt in if $Z_i = 1$. Opt out if $Z_i = 2$.

To identify the LATE separately for the opt-in and opt-out interventions, respectively, we make the following assumptions:

- **Unconfoundedness**: We assume that the assignment of the encouragement intervention Z_i is independent of/orthogonal to other observable and unobservable determinants of energy consumption. This assumption is satisfied (in expectation) by our experimental research design.
- **Stable unit treatment values:** Electricity consumption at household *i* is affected by the participation status of household *i* but not the participation decisions of other households.
- **Exclusion restriction:** Our encouragement intervention affects energy consumption only indirectly through the effect on pricing program participation.

- **Monotonicity**: Our encouragement intervention weakly increases (and never decreases) the likelihood of participation in the pricing program. This implies that there are no defiers.

Let π^{AL}, π^{PC}, and π^{AJ}, denote the population proportions of active leavers, passive consumers, and active joiners, respectively. Let $Y_i(D_i = 1)$ and $Y_i(D_i = 0)$ define the potential electricity consumption outcomes associated with consumer *i* conditioning on participation in the dynamic pricing program. Given the exclusion restriction, these potential outcomes need not condition on the encouragement intervention.

With the opt-in design, the average electricity consumption among households assigned to the control group ($Z_i = 0$) is:

$$E[Y_i|Z_i = 0] = \pi^{AL}E[Y_i(0)|AL] + \pi^{PC}E[Y_i(0)|PC] + \pi^{AJ}E[Y_i(0)|AJ].$$

The average consumption among households assigned to the opt-in encouragement:

$$E[Y_i|Z_i = 1] = \pi^{AL}E[Y_i(0)|AL] + \pi^{PC}E[Y_i(0)|PC] + \pi^{AJ}E[Y_i(1)|AJ].$$

Mechanically, it is straightforward to construct an estimate of the effect of the pricing program on average consumption among active joiners by taking the difference in these two expectations and dividing by π^{AJ}:

$$LATE^{AJ} = \frac{E[Y_i|Z_i = 0] - E[Y_i|Z_i = 1]}{\pi^{AJ}} = E[Y_i(0)|AJ] - E[Y_i(1)|AJ],$$

where $\pi^{AJ}$is estimated by the share of participants in the encouraged group. We take a similar approach using the opt-out design to construct an estimate of the local average treatment effect in the combined AJ and C groups:

To isolate the average treatment effect in the complacent population, we compare outcomes across the two groups assigned to $Z_i = 1$ and $Z_i = 2$, respectively. Taking the difference across these two groups and dividing by π^{PC} yields:

$$LATE^{PC} = \frac{E[Y_i|Z_i = 1] - E[Y_i|Z_i = 2]}{\pi^{PC}} = E[Y_i(0)|PC] - E[Y_i(1)|PC].$$

The estimate of π^{PC} is obtained by taking the difference in program participation across the opt-in and opt-out treatments.

If our encouragement intervention affects electricity consumption directly, this will violate the exclusion restriction and confound our ability to identify these local average treatment effects. The exclusion restriction would be violated, for example, if the encouragement (i.e., the dynamic price offers) increased the salience of energy use in a way that impacts energy consumption. In this scenario, potential outcomes are more accurately represented by $Y_i(D_i, Z_i)$. Taking the opt-in design as an example, the local average treatment effect among active joiners is now more accurately estimated as:

$$LATE^{AJ} = \frac{E[Y_i(0,0)|AJ] - E[Y_i(0,1)|AJ]}{\pi^{AJ}} - \frac{\Delta_{PC}}{\pi^{AJ}} - \frac{\Delta_{AL}}{\pi^{AJ}},$$

where $\Delta_{PC} = E[Y_i(0,0)|PC] - E[Y_i(0,1)|PC]$ and $\Delta_{AL} = E[Y_i(0,0)|AL] - E[Y_i(0,1)|AL]$. If these encouragement-induced changes in electricity consumption among non-participants are not equal to zero, they will bias our LATE estimates.

We cannot estimate these Δ terms directly. However, we can estimate bounds on the bias from these terms by comparing consumption patterns at households that did not participate in the dynamic pricing program across encouraged and unencouraged groups. Differences in electricity consumption among non-participants across experimental groups are difficult to interpret as they compare electricity consumption across different subsets of the consumer population, but they do provide some sense of how large the bias from violating the exclusion restriction might be.

We re-estimate Equation (1) using only those households who did not participate in dynamic pricing. Table 1.7 summarizes these comparisons. For the opt-in experiments, these results represent the difference in average consumption among households assigned to the control group and the average consumption among all non-participants who received the opt-in offer (i.e., passive consumers and active leavers). For the opt-out experiments, we compare consumption across all households assigned to the control group and the always leavers in the encouraged group.

Some of these differences are statistically different from zero. For example, we estimate a statistically significant difference of -0.025 across encouraged non-participants and unencouraged in the opt-in TOU experiment. It seems likely that some of this difference is driven by differences in composition - we are comparing consumption across all households in the control group with consumption of always leavers and passive consumers in the encouraged group. However, if we interpret this difference as entirely caused by the opt-out intervention, this would imply that our local average treatment effect estimate of energy reduction by the always taker group overstates the true effect by $\frac{0.025}{0.19} = 0.13$.

Our estimates of average treatment effects for passive consumers (see Tables 4 to 6 and Figure 5) assume that active joiners who actively enroll in the pricing programs under the opt-in treatment do not behave differently than active joiners who are defaulted onto the programs through the opt-out treatment. In other words, we are assuming that $E[Y_i(1,1)|AJ] = E[Y_i(1,2)|AJ]$. Again, we cannot verify this assumption directly, but we can use the recruit-and-delay treatment group who were encouraged to opt-in to the TOU program but only placed on the pricing schedule in 2014 after our sampling frame (i.e., delayed), rather than in 2012. (This group is introduced in footnote 8 in the main text.) This allows us, in principle, to estimate $E[Y_i(0,0)] - E[Y_i(0,1)|AJ]$, and provides insight on customers who actively enrolled in the program (i.e., are active joiners) but did not immediately face time-varying prices.

We re-estimate Equation (2) using this group and find that the customers who opted-in but for whom time-based pricing was delayed reduced their usage by a statistically significant 0.09 kwh during event hours and 0.08 during non-event peak hours on average during the 2012 and 2013 summers, despite experiencing an identical price schedule to the control group (see Table 1.8). If we assume that this difference is driven entirely by the recruitment encouragement, then our exclusion restriction is violated. In this case, this means that we are underestimating the magnitude of the average reduction for passive consumers. To estimate the extent of this underestimation, we return to our estimate of $LATE^{PC}$, but now allow $E[Y_i(0,0)] \neq E[Y_i(0,1)|AJ]$. This yields:

$$\hat{LATE}^{PC} = \underbrace{E[Y_i(1)|PC] - E[Y_i(2)|PC]}_{LATE^{PC}} + \underbrace{\frac{\pi^{AJ}(E[Y_i(0,0)] - E[Y_i(0,1)|AJ])}{\pi^{PC}}}_{\text{bias}}$$

To compute the size of the bias, we use take the treatment effect in the recruit-and-deny group (row 1, columns (1) and (2) in Table 1.8) as $E[Y_i(0,0)] - E[Y_i(0,1)|AJ]$ and substitute in the endline participation rates in the TOU group for π^{AJ} and π^{PC}, which are 0.163 and 0.707, respectively. The final row in Table 1.8 estimates the implied bias from this calculation for event and non-event hours.

This gives a bias of -0.023 during event hours and -0.019 for non-event peak hours. This represents an upper bound on the degree to which our estimates in columns (3) and (6) in Table 4 could understate event and non-event peak hour reductions by passive consumers.

However, another likely explanation for our finding of a recruitment or encouragement effect is that some customers were not fully informed about the delay in their start date. In order to investigate this possibility, we conduct two tests. First, we examine whether the treatment effect declined more from the first to the second summer of treatment, which would indicate that households who were previously misinformed about their 2014 start date became aware by the second summer that they were not yet on time-varying prices and reduced their energy saving behaviors accordingly. We find that this is the case: Table 1.8, column (4) shows that there is about a 59% (0.065/0.11) reduction in savings between years 1 and 2, larger than the 18% (0.056/0.31) reduction in the comparable non-delayed group seen in Table 6, third panel, fourth column. Our second test of treatment start date confusion examines whether the TOU opt-in and opt-out groups reduced usage in the two months prior to the treatment period start date on June 1, 2012. Table 1.9 documents this test, which demonstrates that both opt-in and opt-out households did reduce usage relative to the control group even before the treatment began. The opt-in households reduced slightly more, although the point estimate for the opt-in effect is not statistically significant at conventional levels. Finally, in the survey, customers in the recruit and delay group were much more likely to think (wrongly) that they were on the time-of-use rate compared to the control group.

Overall, these results suggest the estimates in columns (1) and (2) of Table 1.8 are likely an overestimate of the extent to which actively enrolling influenced energy consumption. If we use the effect estimated for the second treatment year only in columns (3) and (4), the bias is roughly halved. In any case, and as discussed in the main text, this assumption only affects our estimates of the passive consumers' behavior, and, to the extent actively enrolling leads to reductions, our main estimates understate the true complacent response.

1.4 Modeling Attrition out of the Program

As reported in Table 2, approximately 6-7% of the customers on the dynamic pricing programs opted to leave the program at some point during the two-year study. Figure 1.3 reports Kaplan-Meier survival estimates for each of the four treatment groups. The vertical orange lines indicate critical event days and the vertical blue line indicates the date on which the second summer reminder letter was sent out to all study participants letting them know that the rate would start again. We see some attrition from all four groups before the event days started, slightly more attrition from the CPP groups throughout the first summer, and then a relatively big drop after the reminder.

To gain more insight into attrition timing, we model the propensity for customers to leave the dynamic pricing programs once enrolled using an accelerated failure time (AFT) model. We elected to use an AFT model instead of a proportional hazard model as it better accommodates the impact of specific events, such as the critical peak pricing days. In the AFT, the exponential of the estimated coefficient on a variable indicates the "acceleration factor" in the influence on that variable on the survival time. The results of the hazard analysis are presented in Table 1.12.

One might expect that customers who actively opted in to the new rates would be less likely to later change their minds and opt-out. In fact, the attrition rates are similar across opt-in and opt-out for the TOU rates, and the opt-in customers were even quicker to get out of the rates than the opt-out in the CPP case. In particular, the CPP opt-out group had a survival time (i.e., time remaining in treatment before dropping out) that was 40 percent higher than (calculated as exp(0.339)) the opt-in group, which is the omitted category, although the difference is not statistically significant. This could reflect the fact that opt-in customers are self-selected to have low switching costs.

As for other customer-level impacts, there is some evidence that low-income customers were less likely to drop out of the study quickly relative to non-EAPR customers. Structural winners tended to remain in the study longer than those that were not structural winners, although the difference is not statistically significant. Customers with "Your Account" were no more likely to drop out of the study more quickly.

In the case of effects over time, the second summer reminder had a strong effect that accelerated the rate of drop-outs (reduced the survival time) across all the treatment groups. The occurrence of CPP event days enters the model in the following way: there is an indicator variable included for CPP event days for the two CPP treatment groups ("CPP event date"). In addition, the variable "CPP event date count in each summer" is a variable that increases by one each occurrence of a CPP event date within each summer. So, it is equal to 1 on the first occurrence of a CPP event both in the first and second summer, and is equal to 2 for the second occurrence of a CPP event within each summer, etc. The results for CPP event days indicate that for the opt-in CPP treatment group, the experience of CPP event days reduced the survival time in the study by slightly less than the reminder. However, this effect was attenuated over the course of more CPP events within each summer. For the CPP opt-out treatment group, however, the effect of experiencing a CPP event at all is close to zero (the sum of the coefficient and the interaction), and the effect of CPP events appears to increases the rate of drop-outs slightly over multiple events. Finally, we tested whether there was any disproportional additional effect of experiencing a string of consecutive (two or three in a row) events. There does not appear to be a discernible effect of experiencing multiple CPP event beyond the baseline CPP event effect for either CPP treatment group.

The bottom rows of the table list the number of participants and the number of dropouts for each treatment group. As emphasized in the main text, we find the attrition results suggestive but are hesitant to put too much emphasis on them given the relatively small number of dropouts.

1.5 Evidence on Alternative Mechanisms

In this section we provide a more detailed discussion of the extent to which the participation choices we observe are consistent with alternative explanations for the default effect. In Section 1.5.1, we estimate a discrete choice model which rationalizes the default effect with switching costs or discount rates that can vary across households. Section 1.5.2 extends the model to account for time inconsistent preferences and documents empirical evidence which suggests that that this explanation cannot explain the significant default effect we document.

1.5.1 Heterogeneous switching costs

The baseline model assumes that well-informed and risk neutral consumers faced with the choice of opting into the time-varying rate will do so if the difference in utility net of switching costs is positive. For example, a consumer assigned to the opt-in group will switch if the following inequality holds:

$$B_i - s_i + \epsilon_i > 0.$$

We use household-specific estimates of discounted structural gains, a lower bound on participation benefits, to proxy for B_i. The s_i is a customer-specific switching cost. Our empirical objective is to estimate the parameters of the distribution of switching costs that are most consistent with the participation choices we observe.

Once the pilot began, non-participants could not switch into the time-varying pricing program, but participants could switch out. To the extent that customers value this option, estimated switching costs are net of option value for opt-in customers defaulted onto the standard rate. To accommodate the possibility that consumers account for this option value, we estimate cost distributions separately for the opt-in and opt-out group. If consumers see value in preserving the participation option, we should expect smaller cost estimates in the opt-in group. We will allow this cost parameter to be distributed differently across the opt-in and opt-out treatments because we cannot separate switching costs and option value which varies with the default assignment.

To identify the parameters of these switching cost distributions, we must invoke a series of assumptions. We assume that the error term ϵ_i is a mean zero, type I extreme-value random variable. We begin by assuming that switching costs are distributed normally and independent of consumer-specific benefits. We assume a discount rate (we will estimate the cost parameters under a range of discount rate assumptions). And finally, to pin down the level of the cost parameters, we implement a standard normalization that fixes the coefficient on discounted benefits to equal one. Thus, our switching cost estimates are identified relative to our measure of benefits. If households don't fully attend to benefits in their participation decision, our model specification will over-weight benefits, and this will inflate our switching cost estimates.

Table 1.14 summarizes the estimated parameters of the switching costs distribution across different choice contexts under a range of assumed discount rates. The first two rows report the estimated mean and variance of the implied switching cost distributions in the opt-in and opt-out groups, respectively. To put these estimates in perspective, recall that moving away from the default required a single phone call, text, or email. Switching instructions were clearly displayed on all marketing materials. Given the limited effort actually required to switch away from the default option, the as-if cost distributions we estimate are implausibly large in absolute value. In the case of the opt-out group, switching costs have the wrong sign. Taken literally, this would imply that the act of switching generates utility improvements. This result follows from the fact that a key assumption implicit in this participation choice model finds no empirical support in our data. Whereas the model predicts/assumes a strong positive correlation between gains and participation, in the CPP opt-out enrollment group we observe a negative relationship. To rationalize this negative correlation, the model estimates negative average switching costs (implying a love of switching). This is the only way this rational choice model can rationalize the participation choices we observe.

In the context of behavioral welfare analysis, it can be insightful to eliminate from consideration those choices that are most susceptible to misunderstanding or characterization failure (see, for example, Bernheim and Rangel (2009)). In our setting, it is difficult to identify those choices that are clearly mistakes. But we do have a way to isolate those households who have, in the past, paid closer attention to their electricity consumption. In the years prior to the pricing pilot, customers had the option of signing up for a "My Account" program which allows them to access detailed information about their electricity consumption. Tables 1.10 and 1.11 show how the customers who have historically engaged with these pre-existing information programs are more likely to take an active choice and either opt-in or opt-out. We re-estimate Equation (**??**) using only the choices made by these 'attentive' households. Even among these informed customers, implied switching costs (reported in Table 1.14) seem implausible given that the act of switching required a simple email, call, or text.

As we note in the paper, another way to generate a large default bias using this simple choice model is to assume a significant degree of myopia on the part of households. In our setting, consumers incur switching costs immediately, whereas benefits (in the form of lower electricity costs) accrue over the two subsequent treatment years. An alternative way to specify the model is to assume a value for switching costs and search for the discount rate values that best rationalizes observed choices. We continue to assume that that households use an exponential discount function. All of our aforementioned identifying assumptions about program benefits, the statistical properties of the error term are maintained. The key difference is that we assume switching cost values and identify the discount rates that best rationalize participation choices conditional on the maintained assumptions.

Estimated discount rates are reported in Table 1.15. These large discount rates are implausibly large in most cases. This is, again, an artifact of assuming structural gains are a significant determinant of participation decisions, and forcing the coefficient on these benefits to be one (consistent with full attention) when observed choices suggest otherwise.

1.5.2 Present-biased preferences

An alternative way to explain the significant default effect is to appeal to present-biased preferences, which could induce a procrastination effect, where households that might have intended to opt-out or opt-in did not get around to doing so. In our choice context, one can assume a household is choosing between switching today, planning to switch later, or never switching at all. In addition to the exponential discount rate δ, the household may also exhibit a present-bias, parameterized by β, which additionally discounts all future periods by a constant amount. This type of discounting is also referred to in the literature as hyperbolic discounting (e.g., Frederick, Loewenstein, and O'Donoghue 2002; DellaVigna 2009).

Our setting is slightly different from the more familiar present-bias behavioral contexts where benefits to a choice start accruing once the choice is made. In our situation as customers were presented with their choices several months ahead of the beginning of the dynamic pricing program, and any benefits they would accrue from their choices did not begin until a specific start date (June 1, 2012) no matter whether they made their decision right away or waited. Customers who were invited to opt-in faced a deadline of June 1, 2012 and if they had not opted in by that date, they were ineligible to opt in for the rest of the program. In this case, both procrastination and simple discounting in this simple model predict that customers would wait until the deadline to incur the switching cost. We modify the notation slightly so as to explicitly represent the discounting of per-period benefits b_i. Specifically, assuming the offer was made in period 0 and customers could opt in during periods 1 or 2 and the program began in period 3, opt-in customers compared:

Value of opting in during period 1: $\beta\delta^2 b_i - s_i$
Value, from the perspective of period 1, of opting in during period 2: $\beta\delta^2 b_i - \beta\delta s_i$
Value of not opting in: 0

Where s_i is the cost of switching away from the default choice and b_i is the benefit of having made that switch. The household will choose to delay the decision until later, although this could reflect present-bias ($0 < beta < 1$), but is also true for $\beta = 1$ and simply reflects the household's desire to put off incurring the switching cost. This pattern will continue up until there is some binding deadline (period 2 in the example), at which point the household no longer has the option of delaying their decision and must now choose between the following options:

Value of opting in during period 2: $\beta\delta b_i - s_i$
Value of not opting in: 0

At this point, households will switch if $\beta\delta b_i - s_i > 0$.

Customers who could opt out did not face a deadline and could continue to opt out as the program ran. At that point, they faced a more commonly modeled present-bias situation where their choice to opt-out would result in an immediate reversion back to the standard rate, so for this group, the fact that many people who would have been better off opting out (structural losers) did not could reflect procrastination. Specifically, during the program, opt-out customers compared:

Value of opting out today: $\beta\delta b_i - s_i$
Value, from the perspective of today, of opting out tomorrow: $\beta\delta^2 b_i - \beta\delta s_i$
Value of not switching: 0

As long as $\beta\delta^2 b_i - \beta\delta s_i > 0 \Rightarrow \delta b_i - s_i$ > 0 and $\beta_1 < 1$, the household will choose to delay the decision until later.

This model results would result in two testable hypotheses. First, opt-in households will wait until the last possible moment to switch while opt-out customers may continue to procrastinate. Second, households that face a deadline and have higher structural gains are more likely to switch, while households not faced with a deadline may never actively make a choice to switch or not, and therefore their choice to do so may not be correlated with structural gains. In our context, however, the recruitment strategy used by the utility limits our ability to examine the first of these predictions, as the weeks leading up to the deadline involved heavy phone-banking of the opt-in group (and not the defaulted group) trying to increase their participation in the program. These phone calls could be interpreted as a reduction in s_i. This makes it hard to assess the extent to which there is any "bunching" of opt-in households joining right around the deadline. However, the second testable prediction is still something we can examine in the data.

Specifically, we consider the extent to which opt-in households, who faced a deadline, are more likely to switch if they were structural winners, while opt-out households, who did not face a deadline, may never actively make a choice to switch or not, and therefore their choice to do so may not be correlated with structural gains. The results of this assessment are discussed in the body of the paper.

1.6 Cost-Benefit Analysis

This section describes the cost-benefit calculations reported in Section 7. Many of the assumptions used in our calculations are summarized in Potter, George, and Jimenez (2014), a consulting report that provided, among other things, a cost-benefit calculation of several components of the SMUD program. Other assumptions are based on personal communications with SMUD employees and their consultants.

1.6.1 Benefits

At a high level, reduced demand during CPP and TOU peak hours avoids two types of expenses – the energy associated with generating electricity during these hours and the expected cost of adding new capacity to meet peak demand, where the expectation is taken over the probability that demand in a particular hour would drive capacity expansion decisions. The components of the benefit calculations are summarized in Figure 1.4.

Consider the first row, reflecting capacity benefits. The first box represents assumptions on the cost of adding a new peaking plant. Our calculations are based on proprietary information provided by SMUD and summarized in Potter, George, and Jimenez (2014). As reported by Potter et al., the costs "range from roughly $50 to $80/kW-year in the first few forecast years and increase to around $125/kW-year by the end of the forecast period" (p. 112, Potter, George, and Jimenez 2014). These costs are slightly lower than other estimates of generation capacity costs from Northern California. For example, the California Public Utilities Commission (CPUC) publishes capacity values for assessing the cost effectiveness of demand response programs. The "Generation Capacity Values" range from $174 to $209/kW-year for 2012-14, considerably higher than the numbers SMUD uses. Notably, SMUD did not include the capacity costs associated with the transmission and distribution system. According to the CPUC model, those can account for approximately 25% of the capacity benefits of a peak demand reduction program, so SMUD's decision likely understates the benefits of the program. The values represented by the second box, "# of Enrolled Customers on Time-Variant Pricing Plans," reflect participation rates, summarized in Table 2, multiplied by 600,000, an estimate of the number of customers SMUD will have in 2018. We assumed a customer attrition rate of approximately 7% per year. As shown in Table 2, attrition rates over the 16 months the program operated were approximately 5.5 to 7 percent. We converted these to annual attrition rates and then added 2% to account for customers moving out of SMUD's service territory, assuming that customers who moved within the service territory would remain on the rate.

The values represented by the third box, "Average Reduction by Enrolled Customer by Hour and Month" are the LATE coefficients summarized in Table 4. Potter, George, and Jimenez (2014) estimated separate LATE effects for each hour of the program and provide suggestive evidence that customers reduce more when day are hotter. Hotter days also have higher "Capacity Risk Allocation" values, so this likely explains why the numbers in Potter, George, and Jimenez (2014) are slightly higher than ours.

The "Capacity Risk Allocation by Hour and Month" figures are based on proprietary values provided by SMUD. They are based on a simulation model which estimates the probability that demand exceeds supply on SMUD's system across any of the hours on representative weekend days and weekdays for each month of the year (called the "loss of load probability.") These values are then normalized to sum to one across all hours of the year. We use the sum of the normalized values in hours targeted by the CPP and TOU rates. Finally, following Potter, George, and Jimenez (2014), we assume a 7.1% nominal discount rate and a 4.5% real discount rate.

1.6.2 Costs

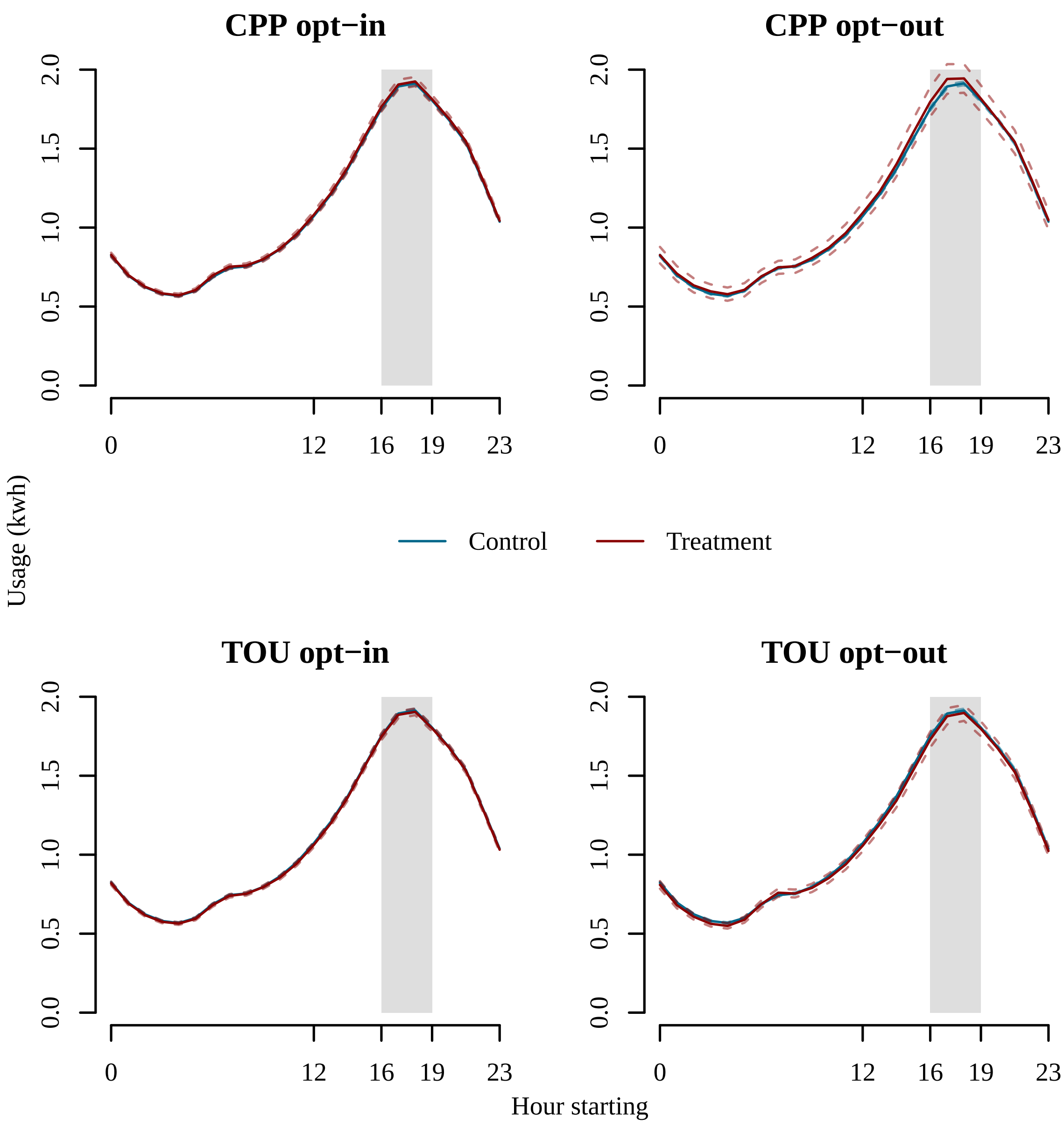
Table 8 summarizes one-time fixed costs, one-time variable costs and recurring fixed and variable costs. One-time fixed costs do not vary with enrollment and include items such as IT costs to adjust the billing system and initial market research costs. One-time variable costs primarily include the customer acquisition costs, including the in-home devices offered to customers as part of the recruitment. Note that Potter, George, and Jimenez (2014) model opt-in programs that do not include outbound calls to enroll customers, while we include the costs of the calls, as well as the customers recruited through them. Our objectives are different from theirs, as they were modeling a hypothetical program that SMUD might run in the future, while we are modeling the program that was actually run. Recurring annual fixed and variable costs include personnel costs required to administer the program and costs associate with customer support and equipment monitoring. They go down slightly over time with attrition from the program.

1.7 Customer losses from default assignment

To better understand customer incentives, here we offer a separate discussion in which we examine the number of and degree to which customers were defaulted into a program that was costly to them. To simplify the exposition, here we take observed usage during the experimental period as given and describe how the population of customers would have faired under the non-default rate (the time-varying rate and the flat rate for the opt-in and opt-out groups, respectively).

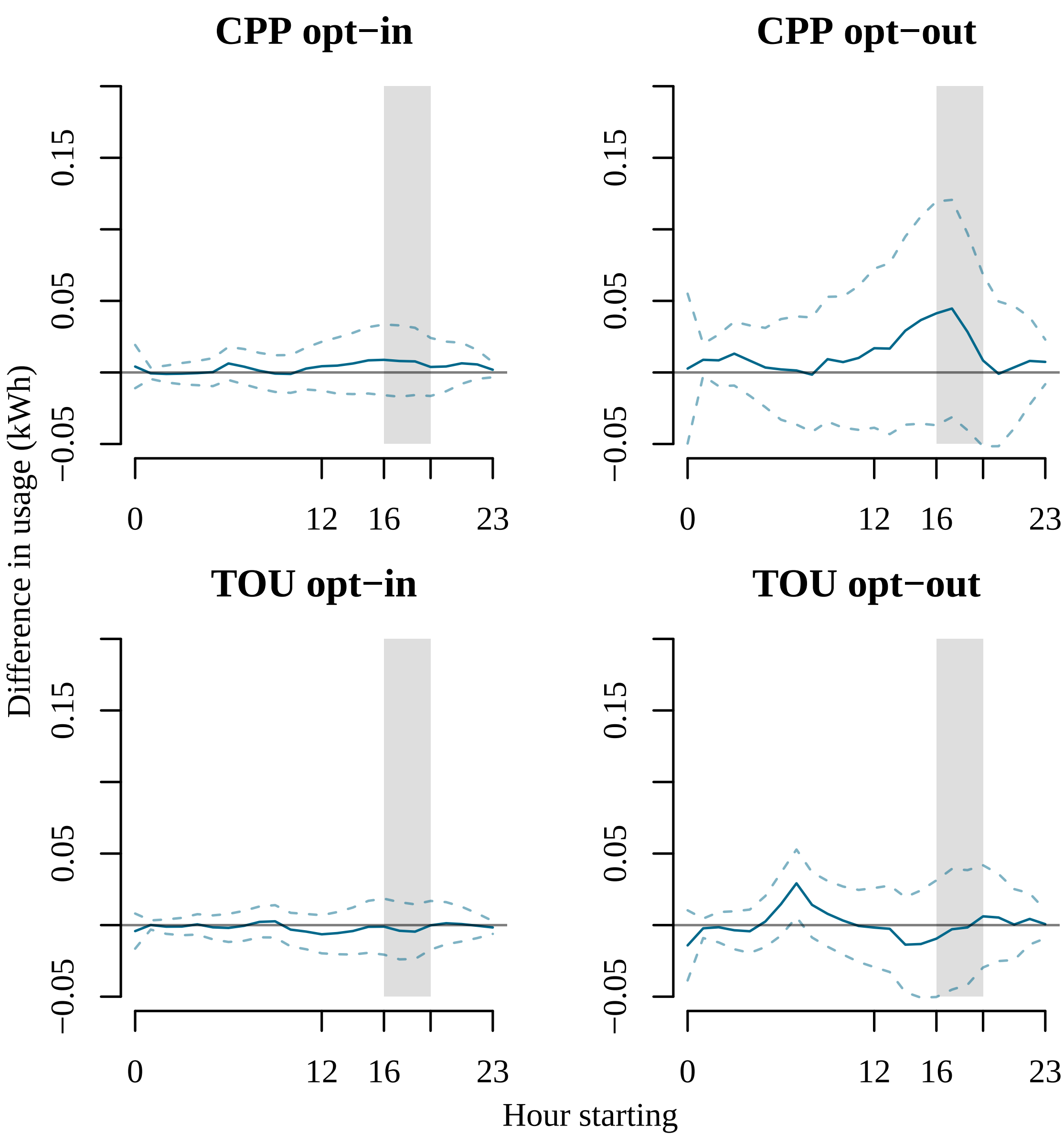
Table 1.18 summarizes these estimates. Under CPP, a higher proportion of customers lost money due to the default in the opt-in group than the opt-out group, while the opposite was the case for the TOU group. Average losses were higher on average than losses from the opt-out in both the CPP and TOU groups.

Figure 1.1: Pre-treatment electricity usage



Notes: Figure depicts average pre-treatment weekday electricity usage in kW. Panels plot average treatment group hourly electricity consumption overlaid with control group consumption, with coefficients and standard errors clustered by household obtained from a regression of electricity consumption on a set of indicator variables for each hour. Dashed lines indicate 95% confidence intervals.

Figure 1.2: Difference between treatment and control groups' electricity consumption prior to treatment



Notes: Figure depicts average difference in pre-treatment weekday electricity usage in kW between treatment and control groups. Lines represent regression coefficients from interactions between hourly indicator variables and a treatment indicator. Dashed lines indicate 95% confidence intervals, clustered by household. Vertical bars indicate peak period, between 4pm and 7pm.

Table 1.1: Usage impacts vary by customer characteristics

	Critical event hours			Non-event day peak hours		
	Opt-in (AJ)	Opt-out (AJ+PC)	Passive (PC)	Opt-in (AJ)	Opt-out (AJ+PC)	Passive (PC)
Structural winner						
Treatment (CPP)	−0.675***	−0.350***	−0.183***	−0.063	−0.058**	−0.036
	(0.071)	(0.054)	(0.057)	(0.042)	(0.027)	(0.028)
× Structural winner	0.036	0.039	−0.172	−0.172***	−0.086**	−0.153**
	(0.100)	(0.079)	(0.121)	(0.063)	(0.043)	(0.067)
Treatment (TOU)	−0.414***	−0.100***	−0.022	−0.252***	−0.085***	−0.044**
	(0.050)	(0.023)	(0.030)	(0.033)	(0.016)	(0.021)
× Structural winner	−0.190*	−0.108**	−0.087	−0.099	−0.061*	−0.048
	(0.098)	(0.047)	(0.062)	(0.065)	(0.032)	(0.042)
Low income						
Treatment (CPP)	−0.815***	−0.370***	−0.267***	−0.181***	−0.096***	−0.075**
	(0.066)	(0.047)	(0.060)	(0.040)	(0.025)	(0.032)
× Low income	0.543***	0.176**	0.104	0.122**	−0.023	−0.076
	(0.098)	(0.089)	(0.125)	(0.062)	(0.051)	(0.072)
Treatment (TOU)	−0.547***	−0.148***	−0.061**	−0.321***	−0.111***	−0.063***
	(0.056)	(0.024)	(0.031)	(0.037)	(0.017)	(0.021)
× Low income	0.227***	0.055	0.051	0.117**	0.026	0.020
	(0.086)	(0.043)	(0.061)	(0.057)	(0.030)	(0.042)
My Account						
Treatment (CPP)	−0.600***	−0.225***	−0.151***	−0.152***	−0.077***	−0.063**
	(0.080)	(0.045)	(0.056)	(0.049)	(0.026)	(0.032)
× My Account	−0.108	−0.251***	−0.238**	0.012	−0.057	−0.067
	(0.104)	(0.085)	(0.117)	(0.063)	(0.046)	(0.062)
Treatment (TOU)	−0.336***	−0.080***	−0.032	−0.204***	−0.065***	−0.039*
	(0.070)	(0.024)	(0.030)	(0.046)	(0.017)	(0.021)
× My Account	−0.274***	−0.143***	−0.055	−0.157***	−0.099***	−0.058
	(0.089)	(0.043)	(0.059)	(0.059)	(0.030)	(0.040)

* $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$. Standard errors in parentheses.

Notes: Table estimates treatment impacts separately for structural winners, low income customers and My Account holders. Structural winners are customers predicted to experience savings under the time-varying rate assuming their energy consumption during the treatment period is identical to their consumption in the pre-period. Low income is an indicator variable for customers enrolled in the low income rate. My Account indicates whether if the customer has enrolled in the online My Account program. For columns 1, 2, 4, and 5, regressors are instrumented with indicators for encouragement group and its interaction with the indicator variable for structural winners. Sample for columns 1, 2, 4, and 5 is composed of the control group and given treatment group. For columns 3 and 6, the instruments are enrollment into opt-out group and its interaction with the indicator variable for structural winners and sample includes only opt-in and opt-out treatment groups. Event hours include simulated critical peak events in 2011 and actual events in 2012 and 2013. Non-event peak day hours include all peak hours excluding critical event hours. All models include customer and hour of sample fixed effects, plus an interaction between the post-treatment period and given dimension of heterogeneity. Standard errors clustered by customer in parentheses.

Table 1.2: Usage impacts vary by year of program (balanced panel)

	Critical event hours			Non-event day peak hours		
	Opt-in (AJ)	Opt-out (AJ+PC)	Passive (PC)	Opt-in (AJ)	Opt-out (AJ+PC)	Passive (PC)
Treatment (CPP)	−0.775***	−0.346***	−0.238***	−0.163***	−0.092***	−0.075**
	(0.062)	(0.048)	(0.061)	(0.036)	(0.025)	(0.032)
× Year 2	0.144**	−0.051	−0.100**	0.038	−0.043*	−0.063**
	(0.056)	(0.037)	(0.048)	(0.037)	(0.022)	(0.029)
Treatment (TOU)	−0.605***	−0.168***	−0.069**	−0.351***	−0.118***	−0.065***
	(0.053)	(0.023)	(0.030)	(0.034)	(0.015)	(0.020)
× Year 2	0.161***	0.053***	0.028	0.061*	0.020	0.010
	(0.051)	(0.020)	(0.026)	(0.033)	(0.012)	(0.016)

* p < 0.1, ** p < 0.05, *** p < 0.01. Standard errors in parentheses.

Notes: Replicates Table 6 with a balanced panel, i.e., including only households who did not change their enrollment status (by opting in, opting out, or moving) during the treatment period.

Table 1.3: Intent to treat effects (logged outcome)

	Critical event		Non-event peak	
	Opt-in	Opt-out	Opt-in	Opt-out
Encouragement (CPP)	−0.083***	−0.173***	−0.021***	−0.055***
	(0.007)	(0.022)	(0.005)	(0.014)
Mean usage (kW)	2.5	2.5	1.8	1.8
Customers	55,024	46,680	55,028	46,684
Customer-hours	4,824,157	4,097,167	31,141,456	26,448,932
Encouragement (TOU)	−0.052***	−0.073***	−0.036***	−0.059***
	(0.005)	(0.012)	(0.004)	(0.010)
Mean usage (kW)	2.49	2.5	1.79	1.79
Customers	58,569	48,241	58,573	48,245
Customer-hours	5,133,166	4,232,869	33,137,047	27,326,082

* $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$. Standard errors in parentheses.

Notes: Replicates Table 3 with log(Usage) as outcome variable, coefficients are proportion change in consumption.

Table 1.4: Average treatment effects (logged outcome)

	Critical event hours			Non-event day peak hours		
	Opt-in (AJ)	Opt-out (AJ+PC)	Passive (PC)	Opt-in (AJ)	Opt-out (AJ+PC)	Passive (PC)
Treatment (CPP)	−0.424***	−0.187***	−0.124***	−0.106***	−0.059***	−0.046**
	(0.032)	(0.024)	(0.031)	(0.024)	(0.015)	(0.020)
Mean usage (kW)	2.50	2.50	2.44	1.80	1.80	1.79
Customers	55,024	46,680	10,036	55,028	46,684	10,036
Customer-hours	4,824,157	4,097,167	878,222	31,141,456	26,448,932	5,667,680
Treatment (TOU)	−0.275***	−0.077***	−0.028*	−0.190***	−0.062***	−0.030**
	(0.028)	(0.012)	(0.016)	(0.022)	(0.010)	(0.013)
Mean usage (kW)	2.49	2.50	2.44	1.79	1.79	1.75
Customers	58,569	48,241	15,142	58,573	48,245	15,142
Customer-hours	5,133,166	4,232,869	1,322,933	33,137,047	27,326,082	8,540,421

* $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$. Standard errors in parentheses.

Notes: Replicates Table 4 with log(Usage) as outcome variable, coefficients are proportion change in consumption.

Table 1.5: Usage impacts vary by customer observables and year of program (logged outcome)

	Critical event hours			Non-event day peak hours		
	Opt-in (AJ)	Opt-out (AJ+PC)	Passive (PC)	Opt-in (AJ)	Opt-out (AJ+PC)	Passive (PC)
Structural winner						
Treatment (CPP)	−0.425***	−0.227***	−0.124***	−0.043	−0.044**	−0.029
	(0.043)	(0.033)	(0.038)	(0.033)	(0.020)	(0.023)
× Structural winner	0.002	0.078*	0.002	−0.130***	−0.030	−0.049
	(0.063)	(0.046)	(0.066)	(0.048)	(0.030)	(0.044)
Treatment (TOU)	−0.250***	−0.066***	−0.020	−0.163***	−0.055***	−0.027*
	(0.035)	(0.015)	(0.020)	(0.028)	(0.012)	(0.016)
× Structural winner	−0.074	−0.031	−0.019	−0.076*	−0.020	−0.008
	(0.057)	(0.026)	(0.035)	(0.045)	(0.021)	(0.028)
Year 2						
Treatment (CPP)	−0.453***	−0.169***	−0.092***	−0.114***	−0.044***	−0.026
	(0.034)	(0.026)	(0.033)	(0.024)	(0.016)	(0.021)
× Year 2	0.065**	−0.041*	−0.071**	0.019	−0.034**	−0.049**
	(0.033)	(0.022)	(0.029)	(0.025)	(0.017)	(0.022)
Treatment (TOU)	−0.305***	−0.083***	−0.027	−0.206***	−0.065***	−0.030**
	(0.029)	(0.013)	(0.018)	(0.022)	(0.010)	(0.013)
× Year 2	0.066**	0.013	−0.001	0.040*	0.008	−0.001
	(0.031)	(0.013)	(0.017)	(0.024)	(0.010)	(0.013)
Low income						
Treatment (CPP)	−0.504***	−0.219***	−0.152***	−0.122***	−0.059***	−0.043**
	(0.040)	(0.028)	(0.035)	(0.030)	(0.017)	(0.022)
× Low income	0.275***	0.136***	0.129*	0.056	−0.003	−0.017
	(0.065)	(0.051)	(0.072)	(0.049)	(0.036)	(0.052)
Treatment (TOU)	−0.306***	−0.084***	−0.035*	−0.210***	−0.067***	−0.035**
	(0.035)	(0.014)	(0.018)	(0.027)	(0.012)	(0.015)
× Low income	0.102*	0.032	0.039	0.069	0.021	0.025
	(0.056)	(0.028)	(0.040)	(0.044)	(0.023)	(0.033)
My Account						
Treatment (CPP)	−0.386***	−0.139***	−0.089**	−0.124***	−0.053***	−0.039
	(0.052)	(0.028)	(0.035)	(0.039)	(0.019)	(0.024)
× My Account	−0.071	−0.117**	−0.090	0.032	−0.015	−0.019
	(0.065)	(0.049)	(0.067)	(0.049)	(0.031)	(0.042)
Treatment (TOU)	−0.200***	−0.050***	−0.021	−0.130***	−0.043***	−0.026*
	(0.044)	(0.015)	(0.019)	(0.034)	(0.012)	(0.015)
× My Account	−0.143**	−0.070***	−0.019	−0.113**	−0.047**	−0.011
	(0.056)	(0.026)	(0.036)	(0.044)	(0.022)	(0.029)

* $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$. Standard errors in parentheses.

Notes: Replicates Tables 6 and 1.1 with log(Usage) as outcome variable, coefficients are proportion change in consumption.

Table 1.6: Intent to treat effects (post-treatment period only)

	Critical event		Non-event peak	
	Opt-in	Opt-out	Opt-in	Opt-out
Encouragement (CPP)	−0.100***	−0.291***	−0.012	−0.073
	(0.023)	(0.061)	(0.017)	(0.047)
Mean usage (kW)	2.51	2.52	1.82	1.82
Customers	46,024	39,086	47,155	40,054
Customer-hours	2,855,231	2,426,418	18,751,449	15,935,568
Encouragement (TOU)	−0.089***	−0.193***	−0.061***	−0.143***
	(0.017)	(0.035)	(0.013)	(0.026)
Mean usage (kW)	2.51	2.52	1.81	1.82
Customers	48,971	40,383	50,188	41,387
Customer-hours	3,037,095	2,506,122	19,947,727	16,460,956

* $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$. Standard errors in parentheses.

Notes: Replicates Table 3 using only post-treatment period data. The estimating equation is identical, except that customer-specific fixed effects are no longer included due to the exclusion of pre-treatment period data.

Table 1.7: Average effects on non-participating households

	Critical event		Non-event peak	
	Opt-in	Opt-out	Opt-in	Opt-out
Encouragement (CPP)	−0.012	0.027	−0.003	−0.016
	(0.010)	(0.109)	(0.007)	(0.095)
Bound of bias	−0.06	0.00	−0.02	−0.00
Mean usage (kW)	2.52	2.52	1.80	1.79
Customers	53,381	45,867	53,381	45,867
Customer-hours	4,675,263	4,031,723	30,179,735	26,026,802
Encouragement (TOU)	−0.025***	0.035	−0.012**	−0.089
	(0.009)	(0.094)	(0.006)	(0.085)
Bound of bias	−0.13	0.01	−0.06	−0.01
Mean usage (kW)	2.52	2.52	1.79	1.79
Customers	56,378	45,881	56,378	45,881
Customer-hours	4,934,493	4,033,157	31,853,310	26,036,009

* $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$. Standard errors in parentheses.

Notes: Table estimates effect of encouragement on usage of households who did not enroll in treatment. Table specification similar to Table 3, but sample includes control customers and encouraged customers who did not enroll in the treatment by not opting in or opting out, depending on whether they were in the opt-in or opt-out treatments, respectively. Bound of bias rows calculate the potential bias $\frac{(1-P)}{P}\beta$ (where P is the proportion enrollment for that group) in Table 4 as a result of the estimated encouragement effects on non-enrolling customers under the assumption that selection does not bias the given estimates.

Table 1.8: Average effects on recruit-and-delay group

	Critical event	Non-event peak	Critical event	Non-event peak
Treatment (TOU)	−0.098**	−0.083***	−0.137***	−0.111***
	(0.041)	(0.028)	(0.044)	(0.028)
× 2013			0.085*	0.065**
			(0.047)	(0.031)
Bound of bias	0.023	0.019	0.012	0.011
Mean usage (kW)	2.50	1.80	2.50	1.80
Customers	58,532	58,532	58,532	58,532
Customer-hours	5,140,696	33,188,035	5,140,696	33,188,035

* $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$. Standard errors in parentheses.

Notes: Table estimates impact of treatment on usage for recruit-and-delay households (RITTD). Dependent variable is usage in kwh. Sampling frame is summer weekday CPP event hours and non-event peak hours from 2011-2013 and includes control group and TOU opt-in recruit-and-delay households. Regressions include household and hour of sample fixed effects, standard errors clustered by household.

Table 1.9: April-May LATE impacts

Treatment (TOU)	−0.060	−0.039**
	(0.039)	(0.016)
Mean usage (kW)	1.05	1.06
Customers	52,153	42,991
Customer-hours	6,748,730	5,564,183

* $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$. Standard errors in parentheses.

Notes: Table estimates effect of treatment on pre-treatment period usage. Dependent variable is usage in kwh. Sampling frame is April and May weekday peak hours in 2012 and includes control group and the given treatment group. Regressions include hour of sample fixed effects, standard errors clustered by household.

Table 1.10: Household characteristics by customer type (means)

	AJ	PC	AL
CPP customers			
Daily usage	26.75	26.97	26.90
Peak to off-peak	1.77	1.78	1.79
Bill amount	106.18	109.84	112.50
Structural winner (CPP)	0.50	0.52	0.49
Structural winner (TOU)	0.35	0.34	0.33
My Account	0.54	0.42	0.52
My Account logins	9.16	6.65	11.81
Paperless	0.24	0.19	0.18
Low income	0.29	0.19	0.15
TOU customers			
Daily usage	26.94	26.25	27.36
Peak to off-peak	1.74	1.78	1.73
Bill amount	107.32	107.99	114.93
Structural winner (CPP)	0.53	0.50	0.57
Structural winner (TOU)	0.35	0.33	0.39
My Account	0.53	0.39	0.48
My Account logins	8.25	5.91	10.79
Paperless	0.24	0.18	0.22
Low income	0.29	0.18	0.11

Notes: Mean customer characteristics for the three customer types: active joiners (AJ), passive consumers (PC), and active leavers (AL). Means for active joiners (μ^{AJ}) and active leavers (μ^{AL}) are computed as the average value for customers who enrolled in the opt-in groups or disenrolled in the opt-out groups, respectively. Means for passive consumers (μ^{PC}) are computed using the following formula: $\mu^{OO} = p^{AJ}\mu^{AJ} + p^{PC}\mu^{PC}$, where proportions p^{AJ} and p^{PC} are the relative proportions of active joiners and passive consumers who enroll in the opt-out group, which we compute from the difference in enrollments between opt-in and opt-out groups.

Table 1.11: Household characteristics by customer type (differences)

	AJ - PC	AJ - AL	PC - AL
CPP customers			
Daily usage	-0.22 (0.81)	-0.15 (0.95)	0.07 (0.98)
Peak to off-peak	-0.01 (0.62)	-0.02 (0.76)	-0.00 (0.99)
Bill amount	-3.66 (0.42)	-6.32 (0.59)	-2.66 (0.83)
Structural winner (CPP)	-0.02 (0.34)	0.01 (0.87)	0.03 (0.51)
Structural winner (TOU)	0.01 (0.73)	0.03 (0.54)	0.02 (0.70)
My Account	0.13 (0.00)	0.02 (0.64)	-0.11 (0.03)
My Account logins	2.51 (0.00)	-2.65 (0.30)	-5.17 (0.04)
Paperless	0.05 (0.02)	0.06 (0.12)	0.01 (0.80)
Low income	0.10 (0.00)	0.13 (0.00)	0.04 (0.32)
TOU customers			
Daily usage	0.69 (0.22)	-0.42 (0.70)	-1.11 (0.33)
Peak to off-peak	-0.04 (0.03)	0.01 (0.79)	0.05 (0.12)
Bill amount	-0.67 (0.81)	-7.62 (0.19)	-6.94 (0.25)
Structural winner (CPP)	0.03 (0.05)	-0.04 (0.14)	-0.08 (0.01)
Structural winner (TOU)	0.02 (0.17)	-0.04 (0.13)	-0.07 (0.02)
My Account	0.14 (0.00)	0.05 (0.07)	-0.08 (0.01)
My Account logins	2.34 (0.00)	-2.54 (0.05)	-4.89 (0.00)
Paperless	0.06 (0.00)	0.02 (0.52)	-0.04 (0.11)
Low income	0.12 (0.00)	0.18 (0.00)	0.07 (0.00)

Notes: Differences in means between the three customer types: active joiners (AJ), passive consumers (PC), and active leavers (AL). Means are computed following the notes in Table 1.10. The first column compares active joiners to passive consumers, the second compares active joiners to active leavers, and the third compares passive consumers to active leavers. Each cell gives the difference in means with p-value in parentheses for the two given customer types across the given household characteristic. P-values are computed using the following variance formula: $V(\mu^{OO}) = V(p^{AJ}\mu^{AJ} + p^{PC}\mu^{PC})$.

Table 1.12: Hazard Analysis - Accelerated Failure Time (AFT) Weibull Model

	Estimate	s.e.
Model Estimates		
TOU opt-in	0.340	(0.213)
TOU opt-out	0.561**	(0.226)
CPP opt-out	0.339	(0.301)
Low Income (EAPR)	0.514**	(0.202)
Structural winner	0.278	(0.172)
Your account	-0.0438	(0.162)
Second summer reminder date	-4.252***	(0.563)
CPP event date	-3.088***	(0.609)
CPP opt-out × CPP event date	2.406	(1.618)
CPP event date count in each summer	0.208**	(0.106)
CPP opt-out × CPP event date count in each summer	-0.352*	(0.210)
Final event in a string of consecutive event dates	-0.0937	(0.673)
Constant	9.869***	(0.292)
ln(p)	-0.328***	(0.0575)
Observations	2,690,168	

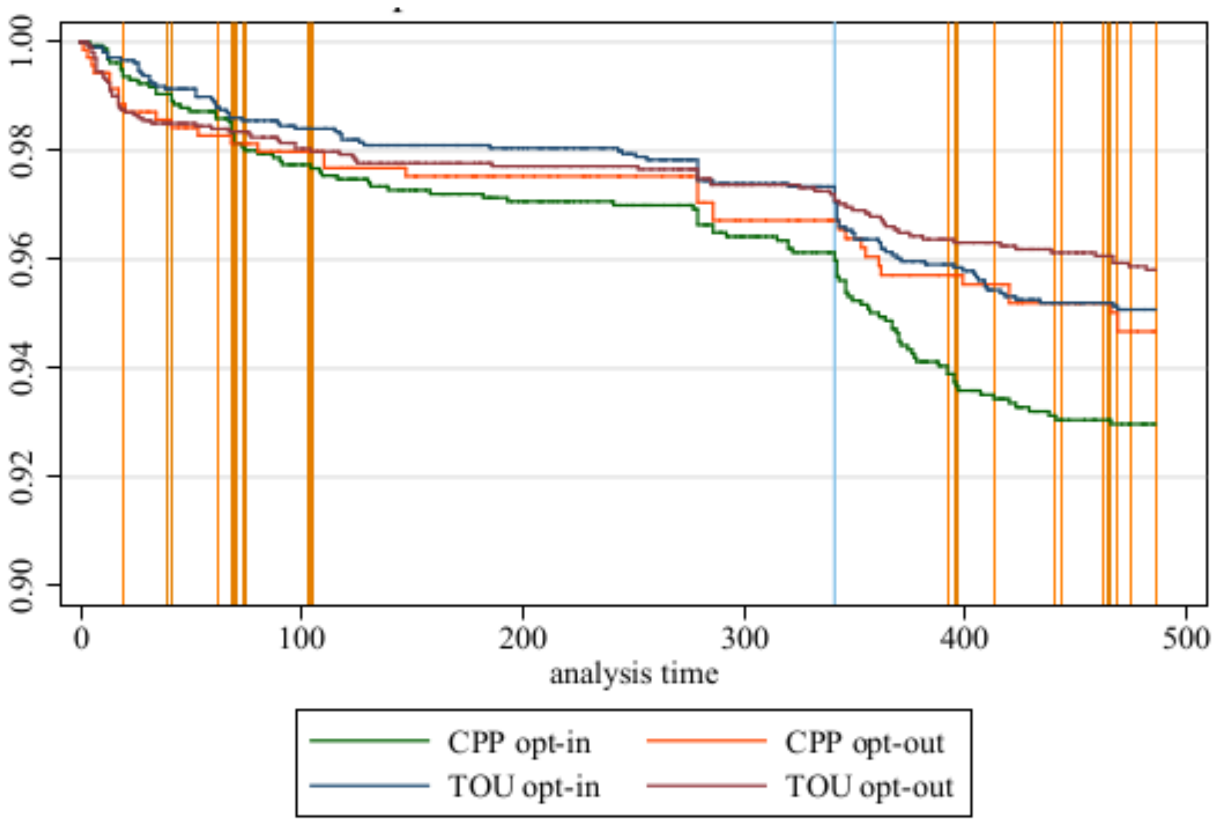
Drop out counts

	Number of households	Number of drop outs
TOU opt-in	2110	92
TOU opt-out	2019	77
CPP opt-in	1585	101
CPP opt-out	701	35

* $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$.

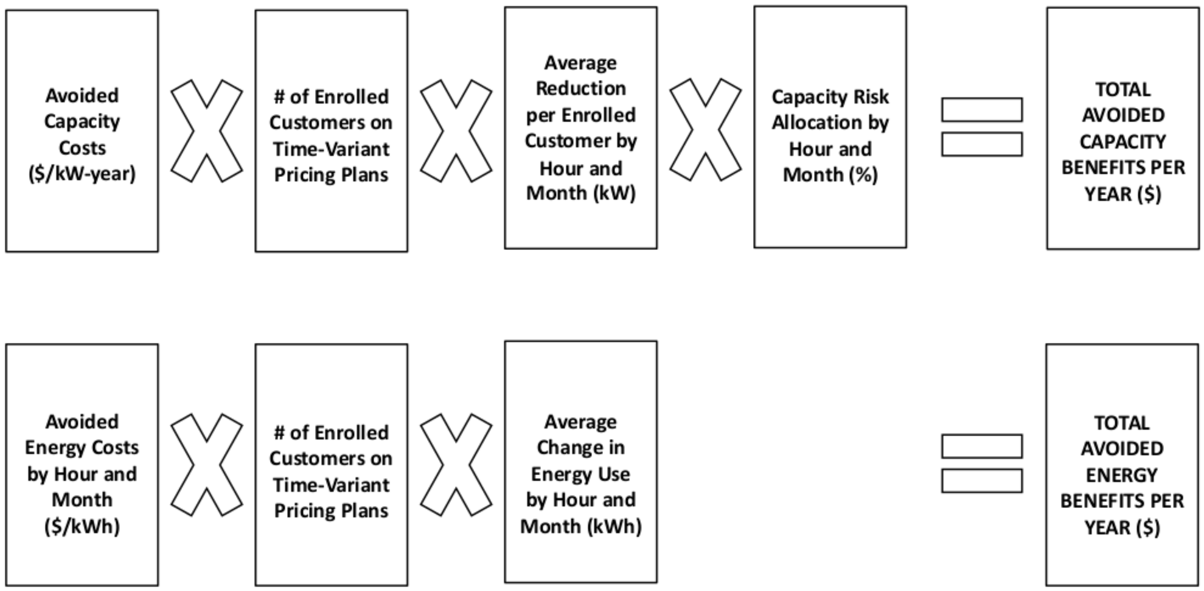
Notes: Top panel in table estimates predictors of time in treatment using an Accelerated Failure Time (AFT) specification, assuming a Weibull distribution parameterized by p. An estimate greater than zero indicates time in the program is extended (reduction in drop-out rate), while a number smaller than zero indicates that the time in the program is reduced (increase in drop-out rate). The omitted category is the CPP opt-in group. Bottom panel counts enrolled households and drop outs by treatment group.

Figure 1.3: Kaplan-Meier Survival Analysis



Notes: Kaplan-Meier survival estimates for each of the four treatment groups. Declining solid line is the proportion of households enrolled at the beginning of the treatment period who remain enrolled over time. Vertical orange lines indicate critical event days and the vertical blue line indicates the date on which the second summer reminder letter was sent out to all study participants letting them know that the rate would start again.

Figure 1.4: Measuring Benefits of Time-Varying Pricing



Notes: Schematic of estimated net benefits of time-varying pricing programs used in Table 8. Source is Potter et. al. (2014), Figure 10-1.

Table 1.13: Structural gains and participation

	CPP	TOU
Opt-in	0.1773***	0.1734***
	(0.0039)	(0.0033)
Opt-out	0.7448***	0.7443***
	(0.0134)	(0.0083)
Structural gains X Opt-in	−0.0001	0.0003***
	(0.0001)	(0.0001)
Structural gains X Opt-out	−0.0006*	−0.0003
	(0.0003)	(0.0002)

* $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$. Standard errors in parentheses.

Notes: Table estimates regressions of initial program participation on structural gains for each treatment group. Coefficients are equivalent to the slopes and intercepts of the fitted lines in the top panel of Figure 6.

/A

DUKE ENERGY CAROLINAS, LLC
Impact of Load Growth on Base Revenues
(Dollar Amounts in Thousands)

Line	Rate Class	Test-Year Adjusted Sales (MWh)	Projected Sales: 9/23-8/24 (MWh)	Increase (MWh)	Average Base Revenues ($/MWh)	Incremental Base Revenues Due to Sales Growth
		(1)	(2)	(3)	(4)	(5)
1	Residential	22,379,004	23,477,265	1,098,261	$107.73	$118,312
2	General Service/Lighting	23,421,227	24,077,007	655,780	$77.20	$50,626
3	Industrial	12,268,185	13,270,457	1,002,272	$58.77	$58,907
4	Total NC Retail	58,068,414	60,824,727	2,756,311		$227,840
Sources:		Page 2	Docket E-7, Sub 1282, Clark Revised Exhibit 2, Schedule 1	Col (2) - Col (1)	Page 2	Col (3) x Col (4)

DUKE ENERGY CAROLINAS, LLC
Average Base Revenues Per MWh Sold
(Dollar Amounts in Thousands)

Line	Rate Class	Base Revenues at Present Rates	MWh Sales	Base Revenues per MWh
		(1)	(2)	(3)
1	Residential	$2,410,826	22,379,004	$107.73
2	General Service/Lighting	$1,808,117	23,421,227	$77.20
3	Industrial	$721,040	12,268,185	$58.77
4	Total NC Retail	$4,939,983	58,068,413	
Sources:		DEC NC 2023 Rate Design Workbook VI RY 3		Col (1) ÷ Col (2)

DUKE ENERGY CAROLINAS, LLC
Typical Monthly Bills: Summer 2022

Line	Customer Class	Monthly Usage kWh	Monthly Usage kW	Typical Monthly Bill DEC	Typical Monthly Bill SE Avg.	DEC as a Percent of the SE Average
		(1)	(2)	(3)	(4)	(5)
1	Residential	1,000	N/A	$105.18	$134.24	78%
2	Commercial	1,500	N/A	$195.37	$208.50	94%
3		10,000	40	$836.99	$1,304.53	64%
4		14,000	40	$1,223.77	$1,654.93	74%
5		150,000	500	$11,159.52	$18,657.47	60%
6		180,000	500	$15,058.52	$20,700.55	73%
7	Industrial	200,000	1,000	$16,508.01	$27,009.68	61%
8		400,000	1,000	$26,730.31	$38,136.29	70%
9		650,000	1,000	$43,114.18	$50,876.14	85%
10		15,000,000	50,000	$1,186,980.45	$1,451,688.86	82%
11		25,000,000	50,000	$1,604,307.95	$1,933,242.21	83%
12		32,500,000	50,000	$1,917,303.58	$2,280,497.93	84%
13	Avg. Commercial					73%
14	Avg Industrial					77%

Source: Edison Electric Institute, Typical Bills and Average Rates Report, Summer 2022.

DUKE ENERGY CAROLINAS, LLC
Typical Monthly Bills: Winter 2022

Line	Customer Class	Monthly Usage kWh	Monthly Usage kW	Typical Monthly Bill DEC	Typical Monthly Bill SE Avg.	DEC as a Percent of the SE Average
		(1)	(2)	(3)	(4)	(5)
1	Residential	1,000	N/A	$105.34	$127.74	82%
2	Commercial	1,500	N/A	$195.48	$200.78	97%
3		10,000	40	$837.70	$1,238.56	68%
4		14,000	40	$946.21	$1,559.49	61%
5		150,000	500	$11,170.17	$17,822.86	63%
6		180,000	500	$11,584.05	$19,900.60	58%
7	Industrial	200,000	1,000	$16,519.01	$25,932.06	64%
8		400,000	1,000	$26,752.31	$36,819.32	73%
9		650,000	1,000	$35,929.11	$48,592.63	74%
10		15,000,000	50,000	$929,735.91	$1,398,273.48	66%
11		25,000,000	50,000	$1,337,252.72	$1,851,809.55	72%
12		32,500,000	50,000	$1,642,890.33	$2,193,036.53	75%
13	Avg. Commercial					69%
14	Avg Industrial					71%

Source: Edison Electric Institute, Typical Bills and Average Rates Report, Winter 2022.

DUKE ENERGY CAROLINAS, LLC
Proposed Rate Year 3 Base Revenue Increase
Measured as a Percent of Present Base Revenues
Adjusted Test Year Ended December 31, 2021
(Dollar Amounts in Thousands)

Line	Rate Class	Base Revenues at Present Rates	Proposed Increase Amount	Proposed Increase Percent
		(1)	(2)	(3)
1	Residential	$2,410,826	$447,709	18.6%
	General Service:			
2	SGS	$477,787	$96,190	20.1%
3	LGS	$371,038	$59,485	16.0%
4	Total General Service	$848,825	$155,674	18.3%
5	Industrial	$152,657	$26,550	17.4%
6	Optional TOU	$1,369,947	$158,682	11.6%
7	Lighting	$143,430	$50,526	35.2%
8	Total Before HP	$4,925,686	$839,142	17.0%
9	Schedule HP	$14,298	$570	4.0%
10	Total NC Retail	$4,939,984	$839,712	17.0%

Source: DEC NC 2023 Rate Design Workbook V1 RY3, Exhibit 2.

DUKE ENERGY CAROLINAS, LLC
Proposed Rate Year 3 Base Revenue Increase
Measured as a Percent of Present Base Revenues
Adjusted Test Year Ended December 31, 2021
(Dollar Amounts in Thousands)

Line	Rate Class	Base Revenues at Present Rates	Embedded Fuel Revenue	Non-Fuel Revenues at Present Rates	Proposed Increase Amount	Proposed Increase Percent
		(1)	(2)	(3)	(4)	(5)
1	Residential	$2,410,826	$447,772	$1,963,055	$447,709	22.8%
	General Service:					
2	SGS	$477,787	$80,277	$397,510	$96,190	24.2%
3	LGS	$371,038	$87,938	$283,101	$59,485	21.0%
4	Total General Service	$848,825	$168,215	$680,610	$155,674	22.9%
5	Industrial	$152,657	$38,273	$114,384	$26,550	23.2%
6	Optional TOU	$1,369,947	$430,036	$939,912	$158,682	16.9%
7	Lighting	$143,430	$10,675	$132,756	$50,526	38.1%
8	Total Before HP	$4,925,686	$1,094,970	$3,830,716	$839,142	21.9%
9	Schedule HP	$14,298	$5,203	$9,095	$570	6.3%
10	Total NC Retail	$4,939,984	$1,100,173	$3,839,811	$839,712	21.9%

Sources: DEC NC 2023 Rate Design Workbook V1 RY3, Exhibit 2 and Fuel Cost Adjustment Rider (NC) Base Fuel Costs and Base Fuel Adjustment.

Exhibit JP-4 Updated
Docket No. E-7, Sub 1276
Direct Testimony of Jeffry Pollock

DUKE ENERGY CAROLINAS, LLC
CUCA Derived Rate Year 3 Base Revenue Increase
To Reduce the Interclass Subsidies By Up To 50%
Adjusted Test Year Ended December 31, 2021
(Dollar Amounts in Thousands)

Line	Rate Class	Base Revenues at Present Rates	Base Revenues at CUCA Rates	Amount	
				Amount	Percent
		(1)	(2)	(3)	(4)
1	Residential	$2,410,826	$2,886,082	$475,255	19.7%
	General Service:				
2	SGS	$477,787	$555,063	$77,276	16.2%
3	LGS	$371,038	$422,892	$51,854	14.0%
4	Total General Service	$848,825	$977,955	$129,130	15.2%
5	Industrial	$152,657	$180,854	$28,197	18.5%
6	Optional TOU	$1,369,947	$1,526,287	$156,340	11.4%
7	Lighting	$143,430	$193,956	$50,526	35.2%
8	Total Before HP	$4,925,686	$5,765,134	$839,448	17.0%
9	Schedule HP	$14,298	$14,562	$264	1.8%
10	Total NC Retail	$4,939,984	$5,779,696	$839,712	17.0%

S&P Global
Market Intelligence

Feb 02, 2021
spglobal.com/marketintelligence
/A

RRA Regulatory Focus

Major Rate Case Decisions - January - December 2020

With the U.S. economy challenged in 2020 by the fallout from the COVID-19 pandemic, the equity returns authorized electric and gas utilities nationwide fell to its worst year on record.

Based on data gathered by Regulatory Research Associates, a group within S&P Global Market Intelligence, the average return on equity authorized electric utilities was 9.44% in all rate cases decided in 2020, below the 9.66% average for cases in 2019. There were 55 electric ROE determinations in 2020, versus 47 in 2019.

The average ROE authorized gas utilities was 9.46% in cases decided in 2020 versus 9.71% in 2019. There were 34 gas cases that included an ROE determination in 2020 versus 32 in 2019.

Included in the electric ROE average is a decision by the Maine Public Utilities Commission in which the commission reduced Central Maine Power Co.'s ROE by 100 basis points to 8.25% due to imprudence associated with a new billing system. The adjustment is to be lifted when the utility meets all performance benchmarks for all service quality metrics for at least 18 consecutive months after March 1, 2020, and formally demonstrates to the commission that the problems have been resolved.

In addition, the electric ROE average in 2020 was also weighed down by an 8.20% ROE authorized Green Mountain Power, as calculated under the company's multiyear regulation plan which employs a formulaic approach tied to U.S. Treasuries.

This data includes several limited-issue rider cases. Excluding these cases, the average authorized ROE was 9.39% in electric rate cases decided in 2020, versus 9.65% observed in 2019. The difference between the ROE averages including rider cases and those excluding the rider cases is driven by ROE premiums allowed in Virginia for riders that address recovery of specific generation projects.

In 2020, the median ROE authorized in all electric utility rate cases was 9.45%, versus 9.65% in 2019; for gas utilities, the metric was 9.42% in 2020, versus 9.70% in 2019.

Lisa Fontanella, CFA
Research Director

Sales & subscriptions
Sales_NorthAm@spglobal.com

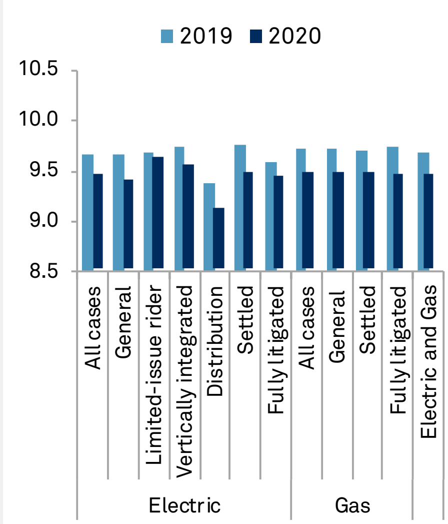
Enquiries
support.mi@spglobal.com

For Detailed Data

Click here to see supporting data tables.

Average authorized return on equity (%)

Dashboard



Electric average	2019	2020	
All cases	9.66	9.44	▼
General rate cases	9.65	9.39	▼
Limited-issue rider cases	9.68	9.62	▼
Vertically integrated cases	9.74	9.55	▼
Distribution cases	9.37	9.10	▼
Settled cases	9.76	9.46	▼
Fully litigated cases	9.58	9.43	▼
Gas average	**2019**	**2020**	
All cases	9.71	9.46	▼
General rate cases	9.72	9.46	▼
Settled cases	9.70	9.47	▼
Fully litigated cases	9.74	9.44	▼
Composite electric and gas averages	**2019**	**2020**	
Electric and Gas	9.68	9.45	▼
U.S. Treasury	**2019**	**2020**	
30-year bond yield	2.58	1.56	▼

Data compiled Jan. 27, 2021.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Executive Summary

Introduction

The average authorized return on equity for electric utilities approved in cases decided during 2022 rebounded from 2021, which was the lowest annual average in RRA's rate case database comprising all major rate cases decided since 1980. Despite the rise, however, the average authorized ROE for electric utilities in 2022 remained near historic lows and was the third-lowest annual average on record.

For gas utilities, the average authorized ROE in 2022 fell to the second-lowest annual average on record.

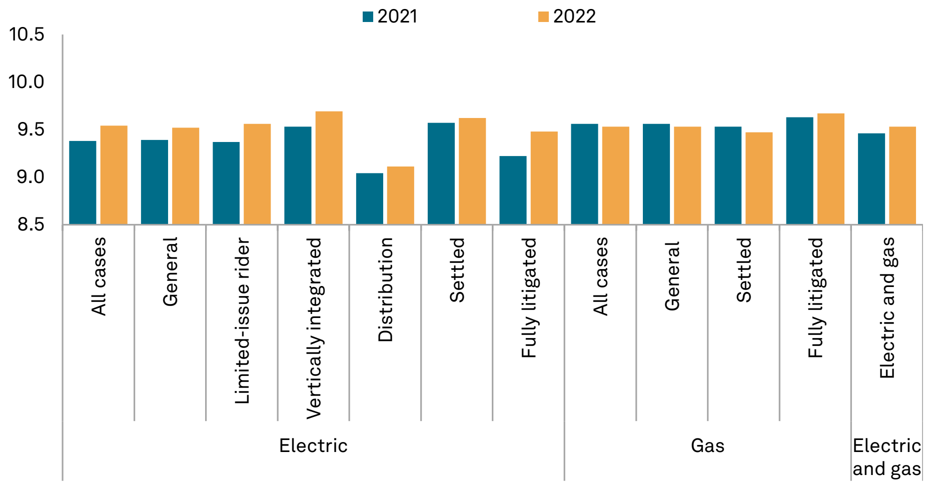
The average ROE authorized for electric utilities was 9.54% for rate cases decided in 2022 as compared to the 9.38% average for cases decided in 2021. There were 53 electric ROE determinations reflected in the calculations for 2022 versus 55 in 2021.

The average ROE authorized for gas utilities was 9.53% for cases decided during 2022 versus the 9.56% average observed in 2021. RRA's calculations relied on 33 gas rate case decisions that included an ROE determination during 2022 versus 43 in 2021.

Rate case activity remained elevated with about 136 decisions issued by state public utility commissions in 2022. This level of activity, however, is down from 2021 — a record year with 151 decisions rendered in electric and gas rate cases across the U.S.

While the reasons for a rate case filing are numerous, the main driver continues to be recovery of capital expenditures. Energy utilities are investing in infrastructure to modernize transmission and distribution systems; build new natural gas, solar and wind generation; and deploy new technologies to accommodate the expansion of electric vehicles, battery storage and advanced metering infrastructure that facilitate the transition toward decarbonization. Other reasons for rate filings include rising expenses, revised cost of capital parameters, the impact of broader economic and sector-wide forces on operations, the need to address rate treatment to be accorded generation facilities that are being retired prior to the end of their planned service lives due to the energy transition, recovery of storm and severe-weather related costs and regulatory approval for alternative regulatory mechanisms.

Average authorized ROE (%)



	2021	2022
Electric averages		
All cases	9.38	9.54
General rate cases	9.39	9.52
Limited-issue rider cases	9.37	9.56
Vertically integrated cases	9.53	9.69
Distribution cases	9.04	9.11
Settled cases	9.57	9.62
Fully litigated cases	9.22	9.48
Gas averages		
All cases	9.56	9.53
General rate cases	9.56	9.53
Settled cases	9.53	9.47
Fully litigated cases	9.63	9.67
Composite electric and gas averages		
Electric and gas	9.46	9.53
US Treasury		
30-year bond yield	2.06	3.11

Data compiled Jan. 27, 2023.
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; U.S. Department of the Treasury.

ERRATA - Clean
Exhibit BSL-2
Docket No. E-7, Sub 1276
Direct Testimony of Billie LaConte

DUKE ENERGY CAROLINA

Impact of Reducing ROE to National Average Authorized ROE

Line	Component	Ratio	Cost	Wtd Cost	Tax Mult.	Pre-tax Wtd. Cost	Ratio	Cost	Wtd Cost	Tax Mult.	Pre-tax Wtd. Cost
1	Debt[1]	47.0%	4.56%	2.143%		2.1%	47.0%	4.56%	2.143%		2.1%
2	Equity	53.0%	10.40%	5.512%	1.3046	7.2%	53.0%	9.69%	5.136%	1.3046	6.7%
3						9.33%					8.84%
4	Rate Base[2]	19,543					Change in Revenue Requirement				(95.9)

Source: Taylor Exhibit 4 Workpaper 9
S&P Global Major Energy Rate Case Decisions January - March 2023
Bowman Third Supplemental Direct at 3, Exhibit 2 at 2.

1. The debt cost is updated based on DEC's 3rd supplemental filing.

2. The original rate base represented the incremental rate base in the first year of the MYRP.
The corrected amount is the total rate base in the test year, from DEC's 3rd supplemental filing.

Request:

4. Provide DEC's actual earned return on equity for the period 2017 – 2022. Provide the derivation of the earned ROE in Excel format with all formulas and links intact.

Response:

DEC objects to this request, as it would require the Company to perform original work in the context of discovery, which the Company is not obligated to perform.

Notwithstanding this objection, and without waiver thereof, DEC is providing data from its "ES-1" quarterly surveillance reports for the time period requested. See attached file CUCA DR 4-4 NC ROEs.xlxs

These return on equity percentages are per book calculations and exclude any rate making adjustments. Methodologies used in arriving at the Income for Return and Rate Base components for ratemaking purposes in a general rate case proceeding are different than those used in the quarterly surveillance reports which produces these figures. For example, rate base in the quarterly report is based on a thirteen month average balance, where in a rate case it is a test period end balance plus any adjustment for known and measurable changes. In addition, these return on equity percentages were calculated using composite allocation factors from the various prior years Cost of Service studies.

NCUC Form E.S.-1 | **N.C. Rate Base Method**
Rate of Return Calculations | **Schedule 1**
Duke Energy Carolinas, LLC | **($000s)**
Twelve Months Ended 31-Dec-2017
CUCA DR 4-4

Line No.	Item		Average Capital (a)	Average Capital Ratio (b)		Rate Base (c)	Average Embedded Cost (d)		Overall Cost/ Rate % (e)		Total Company Earnings (f)
					North Carolina Retail Electric Jurisdiction						
9	Long-term Debt	$	9,662,306	46.62%	$	5,812,653	4.80%		2.24%	$	279,007
10	Preferred Stock		-	0.00%		-	0.00%		0.00%		-
11	Members' Equity		11,063,578	53.38%		6,655,630	11.56%	[A]	6.17%		769,264
12	Total Capitalization	$	20,725,884	100.00%	$	12,468,283			8.41%	$	1,048,271

NCUC Form E.S.-1 | **N.C. Rate Base Method**
Rate of Return Calculations | **Schedule 1**
Duke Energy Carolinas, LLC | **($000s)**
Twelve Months Ended 31-Dec-2018

Line No.	Item		Average Capital (a)	Average Capital Ratio (b)		Rate Base (c)	Average Embedded Cost (d)		Overall Cost/ Rate % (e)		Total Company Earnings (f)
					North Carolina Retail Electric Jurisdiction						
9	Long-term Debt	$	10,422,596	47.46%	$	6,496,832	4.76%		2.26%	$	309,249
10	Preferred Stock		-	0.00%		-	0.00%		0.00%		-
11	Members' Equity		11,537,106	52.54%		7,191,551	10.69%	[A]	5.61%		768,447
12	Total Capitalization	$	21,959,702	100.00%	$	13,688,383			7.87%	$	1,077,696

NCUC Form E.S.-1 | **N.C. Rate Base Method**
Rate of Return Calculations | **Schedule 1**
Duke Energy Carolinas, LLC | **($000s)**
Twelve Months Ended 31-Dec-2019

Line No.	Item		Average Capital (a)	Average Capital Ratio (b)		Rate Base (c)	Average Embedded Cost (d)		Overall Cost/ Rate % (e)		Total Company Earnings (f)
					North Carolina Retail Electric Jurisdiction						
9	Long-term Debt	$	11,328,362	47.96%	$	7,178,589	4.55%		2.18%	$	326,626
10	Preferred Stock		-	0.00%		-	0.00%		0.00%		-
11	Members' Equity		12,289,960	52.04%		7,787,937	11.49%	[A]	5.98%		895,138
12	Total Capitalization	$	23,618,322	100.00%	$	14,966,526			8.16%	$	1,221,764

NCUC Form E.S.-1 | **N.C. Rate Base Method**

Rate of Return Calculations — **Schedule 1**
Duke Energy Carolinas, LLC — **($000s)**
Twelve Months Ended 31-Dec-2020

North Carolina Retail Electric Jurisdiction

Line No.	Item	Average Capital (a)	Average Capital Ratio (b)	Rate Base (c)	Average Embedded Cost (d)		Overall Cost/ Rate % (e)	Total Company Earnings (f)
9	Long-term Debt	$ 12,612,143	49.05%	$ 7,758,573	4.29%		2.10%	$ 332,843
10	Preferred Stock	-	0.00%	-	0.00%		0.00%	-
11	Members' Equity	13,102,911	50.95%	8,060,478	10.77%	[A]	5.49%	868,406
12	Total Capitalization	$ 25,715,054	100.00%	$ 15,819,051			7.59%	$ 1,201,249

NCUC Form E.S.-1 — **N.C. Rate Base Method**
Rate of Return Calculations — **Schedule 1**
Duke Energy Carolinas, LLC — **($000s)**
Twelve Months Ended 31-Dec-2021

North Carolina Retail Electric Jurisdiction

Line No.	Item	Average Capital (a)	Average Capital Ratio (b)	Rate Base (c)	Average Embedded Cost (d)		Overall Cost/ Rate % (e)	Total Company Earnings (f)
9	Long-term Debt	$ 12,878,126	48.79%	$ 8,325,108	4.18%		2.04%	$ 347,990
10	Preferred Stock	-	0.00%	-	0.00%		0.00%	-
11	Members' Equity	13,519,197	51.21%	8,739,530	10.64%	[A]	5.45%	929,937
12	Total Capitalization	$ 26,397,324	100.00%	$ 17,064,638			7.49%	$ 1,277,926

NCUC Form E.S.-1 — **N.C. Rate Base Method**
Rate of Return Calculations — **Schedule 1**
Duke Energy Carolinas, LLC — **($000s)**
Twelve Months Ended 31-Dec-2022

North Carolina Retail Electric Jurisdiction

Line No.	Item	Average Capital (a)	Average Capital Ratio (b)	Rate Base (c)	Average Embedded Cost (d)		Overall Cost/ Rate % (e)	Total Company Earnings (f)
9	Long-term Debt	$ 13,863,273	48.65%	$ 8,640,995	4.24%		2.06%	$ 366,378
10	Preferred Stock	-	0.00%	-	0.00%		0.00%	-
11	Members' Equity	14,630,015	51.35%	9,119,753	11.60%	[A]	5.96%	1,057,879
12	Total Capitalization	$ 28,493,288	100.00%	$ 17,761,551			8.02%	$ 1,424,257

[A] The provided return on equity percentages were filed quarterly in docket M-100 Sub 157 Pursuant to the North Carolina Utilities Commission's ("Commission") January 30, 2010 Order Requiring Electronic Filing of Quarterly Financial and Operational Data.

These return on equity percentages are per book calculations and exclude any rate making adjustments. Methodologies used in arriving at the Income for Return and Rate Base components for ratemaking purposes in a general rate case proceeding are different than those used in the quarterly surveillance reports which produces these figures. For example, rate base in the quarterly report is based on a thirteen month average balance, where in a rate case it is a test period end balance plus any adjustment for known and measurable changes. In addition, these return on equity percentages were calculated using composite allocation factors from the various prior years Cost of Service studies.

Exhibit BSL-4
Docket No. E-7, Sub 1276
Direct Testimony of Billie LaConte

DUKE ENERGY CAROLINAS

Proxy Group Alternative Regulation

			Alternative Regulation					
Line	Utility		Formula Based Rate (1)	MYRP (2)	Rate Freeze Stay Out (3)	Earnings Sharing (4)	Formulaic ROE (5)	Incentive ROE (6)
1	Alliant Energy	LNT						
2	Interstate Power and Light							1
3	Wisconsin Power and Light			1	1	1		
4	Ameren Corporation	AEE						
5	Union Electric Company							
6	American Electric Power	AEP						
7	Southwestern Electric Power		1					
8	Indiana Michigan Power			1				
9	Kentucky Power							
10	Ohio Power			1	1			
11	Public Service Company of Oklahoma							
12	Kingsport Power							
13	AEP Texas							
14	Appalachian Power Company				1	1		
15	Avista Corporation	AVA						
16	Alaska Electric Light and Power Company							
17	Avista Corporation							
18	CMS Energy Corporation	CMS						
19	Consumers Energy							
20	Dominion Energy *	D						
21	Virginia Electric and Power Company				1	1	1	1
22	Dominion Energy South Carolina							
23	DTE Energy Company	DTE						
24	DTE Energy							
25	Entergy Corporation	ETR						
26	Entergy Arkansas		1			1		
27	Entergy New Orleans		1	1		1		
28	Entergy Louisiana		1			1		
29	Entergy Mississippi		1			1	1	1
30	Entergy Texas							
31	Evergy, Incorporated	EVRG						
32	Evergy Kansas Central				1	1		
33	Evergy Kansas South				1	1		
34	Evergy Metro				1	1		
35	Evergy Missouri West							
36	IDACORP, Incorporated	IDA						
37	Idaho Power Company					1		
38	Northwestern Corporation	NEW						
39	Northwestern Corporation				1			
40	Otter Tail Corporation*	OTTR						
41	Otter Tail Power					1		
42	Portland General	POR						
43	Portland General Electric Company							
44	Southern Company	SO						
45	Alabama Power Company		1			1		
46	Georgia Power Company		1	1		1		
47	Mississippi Power Company		1			1	1	1
48	WEC Energy Group, Incorporated	WEC						
49	Wisconsin Electric Power Conmpany			1		1		
50	Wisconsin Public Service Corporation							
51	Xcel Energy, Incorporated	XEL						
52	Public Service Company of Colorado							
53	Northern States Power Company Minnesota		1	1		1		
54	Northern States Power Company Wisconsin				1			
55	Southwestern Public Service Company							
56	Total			7		17		

DUKE ENERGY CAROLINAS
Discounted Cash Flow Analysis

Line	Company	Ticker	Avg of 30-day Closing $	Last Qtrly Dividend Payment	Current Annual Div (D0)	Current Dividend Yield	Value Line	Yahoo Finance	Zack's	Expected Average Growth Rate	Expected Dividend Yield	Low Analyst ROE	Mean Analyst ROE	High Analyst ROE
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	Alliant Energy	LNT	52.80	0.45	1.81	3.43%	6.5%	6.1%	6.4%	6.3%	3.54%	9.64%	9.88%	10.04%
2	Ameren Corporation	AEE	116.00	0.63	2.52	2.17%	6.5%	6.9%	7.0%	6.8%	2.25%	8.75%	9.04%	9.22%
3	American Electric Power	AEP	86.35	0.83	3.32	3.84%	6.0%	5.4%	5.7%	5.7%	3.95%	9.30%	9.65%	9.95%
4	Avista Corporation	AVA	42.23	0.46	1.84	4.36%	6.5%	6.3%	6.4%	6.4%	4.50%	10.80%	10.88%	11.00%
5	CMS Energy Corporation	CMS	59.23	0.49	1.95	3.30%	6.5%	7.5%	7.5%	7.2%	3.41%	9.91%	10.58%	10.91%
6	Dominion Energy *	D	51.99	0.67	2.67	5.14%	4.5%	9.0%		6.8%	5.31%	9.81%	12.06%	14.31%
7	DTE Energy Company	DTE	109.86	0.95	3.81	3.47%	4.5%	7.4%	6.0%	6.0%	3.57%	8.07%	9.54%	10.97%
8	Entergy Corporation	ETR	101.50	1.07	4.28	4.22%	0.5%	6.6%	5.7%	4.3%	4.31%	4.81%	8.57%	10.91%
9	Evergy, Incorporated	EVRG	59.31	0.61	2.45	4.13%	7.5%	2.7%	5.2%	5.1%	4.24%	6.91%	9.36%	11.74%
10	IDACORP, Incorporated	IDA	106.21	0.79	3.16	2.98%	4.5%	3.7%	3.7%	4.0%	3.03%	6.71%	6.99%	7.53%
11	Northwestern Corporation	NEW	59.98	0.64	2.56	4.27%	3.5%	4.5%	6.8%	4.9%	4.37%	7.87%	9.29%	11.13%
12	Otter Tail Corporation*	OTTR	76.14	0.44	1.75	2.30%	4.5%	9.0%		6.8%	2.38%	6.88%	9.13%	11.38%
13	Portland General	POR	46.69	0.45	1.81	3.88%	5.0%	4.2%	5.8%	5.0%	3.97%	8.15%	8.96%	9.76%
14	Southern Company	SO	71.20	0.70	2.80	3.93%	6.5%	7.3%	4.0%	5.9%	4.05%	8.05%	9.98%	11.35%
15	WEC Energy Group, Incorporated	WEC	89.71	0.78	3.12	3.48%	6.0%	5.5%	5.8%	5.8%	3.58%	9.08%	9.33%	9.58%
16	Xcel Energy, Incorporated	XEL	65.94	0.52	2.08	3.15%	6.0%	6.1%	6.3%	6.1%	3.25%	9.25%	9.38%	9.55%
17	Average											8.37%	9.54%	10.58%
18	Median											8.45%	9.37%	10.91%
19	Minimum											4.81%	6.99%	7.53%
20	Maximum											10.80%	12.06%	14.31%

Sources:
Column 2: Yahoo! Finance
Column 3: Value Line Investment Survey
* Zacks' projected earnings growth not available.

Exhibit BSL-6
Docket No. E-7, Sub 1276
Direct Testimony of Billie LaConte

DUKE ENERGY CAROLINAS
Capital Asset Pricing Model

Line	Company	Ticker	Current Beta (B)	Projected Risk-Free Rate (R_f)	Historical Risk Premium (R_p)	Historical CAPM ROE	Projected Market Return	Projected Risk Premium (R_p)	Projected Risk Premium CAPM ROE
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Alliant Energy	LNT	0.85	4.30%	5.50%	8.98%	9.90%	5.60%	9.06%
2	Ameren	AEE	0.85	4.30%	5.50%	8.98%	9.90%	5.60%	9.06%
3	American Electric Power	AEP	0.75	4.30%	5.50%	8.43%	9.90%	5.60%	8.50%
4	Avista Corporation	AVA	0.90	4.30%	5.50%	9.25%	9.90%	5.60%	9.34%
5	CMS Energy Corporation	CMS	0.80	4.30%	5.50%	8.70%	9.90%	5.60%	8.78%
6	Dominion Energy	D	0.85	4.30%	5.50%	8.98%	9.90%	5.60%	9.06%
7	DTE Energy Company	DTE	0.95	4.30%	5.50%	9.53%	9.90%	5.60%	9.62%
8	Entergy Corporation	ETR	0.90	4.30%	5.50%	9.25%	9.90%	5.60%	9.34%
9	Evergy, Incorporated	EVRG	0.90	4.30%	5.50%	9.25%	9.90%	5.60%	9.34%
10	IDACORP, Incorporated	IDA	0.80	4.30%	5.50%	8.70%	9.90%	5.60%	8.78%
11	Northwestern	NEW	0.90	4.30%	5.50%	9.25%	9.90%	5.60%	9.34%
12	Otter Tail Corporation	OTTR	0.85	4.30%	5.50%	8.98%	9.90%	5.60%	9.06%
13	Portland General	POR	0.85	4.30%	5.50%	8.98%	9.90%	5.60%	9.06%
14	Southern Company	SO	0.90	4.30%	5.50%	9.25%	9.90%	5.60%	9.34%
15	WEC Energy Group	WEC	0.80	4.30%	5.50%	8.70%	9.90%	5.60%	8.78%
16	Xcel Energy	XEL	0.80	4.30%	5.50%	8.70%	9.90%	5.60%	8.78%
17	Average		0.85	4.30%	5.50%	8.99%	9.90%	5.60%	9.08%
18	Average					8.99%			9.08%
19	Median					8.98%			9.06%
20	Minimum					8.43%			8.50%
21	Maximum					9.53%			9.62%

Column 2: Value Line Investment Survey
Column 3: Exhibit RAM-4
Column 4: Exhibit RAM-8
Column 6: Projected S&P return less risk-free rate.

DUKE ENERGY CAROLINAS
Risk Premium Analysis

Line	Year	Average Authorized ROE	Annual 30-Year Bond Yield	Risk Premium
	(1)	(2)	(3)	(4)
1	1986	13.93%	7.80%	6.13%
2	1987	12.99%	8.58%	4.41%
3	1988	12.79%	8.96%	3.83%
4	1989	12.97%	8.45%	4.52%
5	1990	12.70%	8.61%	4.09%
6	1991	12.54%	8.14%	4.40%
7	1992	12.09%	7.67%	4.42%
8	1993	11.46%	6.60%	4.86%
9	1994	11.21%	7.37%	3.84%
10	1995	11.58%	6.88%	4.70%
11	1996	11.40%	6.70%	4.70%
12	1997	11.33%	6.61%	4.72%
13	1998	11.77%	5.58%	6.19%
14	1999	10.72%	5.87%	4.85%
15	2000	11.58%	5.94%	5.64%
16	2001	11.07%	5.49%	5.58%
17	2002	11.21%	5.42%	5.79%
18	2003	10.96%	5.02%	5.94%
19	2004	10.81%	5.05%	5.76%
20	2005	10.51%	4.65%	5.86%
21	2006	10.32%	4.88%	5.44%
22	2007	10.30%	4.83%	5.47%
23	2008	10.41%	4.28%	6.13%
24	2009	10.52%	4.07%	6.45%
25	2010	10.37%	4.25%	6.12%
26	2011	10.29%	3.91%	6.38%
27	2012	10.17%	2.92%	7.25%
28	2013	10.03%	3.45%	6.58%
29	2014	9.91%	3.34%	6.57%
30	2015	9.84%	2.84%	7.00%
31	2016	9.77%	2.60%	7.17%
32	2017	9.74%	2.90%	6.84%
33	2018	9.60%	3.11%	6.49%
34	2019	9.66%	2.58%	7.08%
35	2020	9.44%	1.56%	7.88%
36	2021	9.38%	2.06%	7.32%
37	Average	10.98%	5.25%	5.73%
38	Projected Risk Free Rate			4.30%
39	Risk Premium ROE			10.03%

SOURCES:
Exhibit RAM-9

DUKE ENERGY CAROLINA

Impact of Reducing ROE to 9.4%

Line	Component	Ratio	Cost	Wtd Cost	Tax Mult.	Pre-tax Wtd. Cost	Ratio	Cost	Wtd Cost	Tax Mult.	Pre-tax Wtd. Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Debt[1]	47.0%	4.6%	2.1%		2.1%	47.0%	4.6%	2.1%		2.1%
2	Equity	53.0%	10.4%	5.5%	1.3046	7.2%	53.0%	9.4%	5.0%	1.3046	6.5%
3						9.33%					8.64%
4	Rate Base[2]	19,543					Change in Revenue Requirement				(135.1)

Source: Taylor Exhibit 4 Workpaper 9
Bowman Third Supplemental Direct at 3, Exhibit 2 at 2.

1. The debt cost is updated based on DEC's 3rd supplemental filing.

2. The original rate base represented the incremental rate base in the first year of the MYRP.
The corrected amount is the total rate base in the test year, from DEC's 3rd supplemental filing.

ERRATA - Clean
Exhibit BSL-9
Docket No. E-7, Sub 1276
Direct Testimony of Billie LaConte

DUKE ENERGY CAROLINA

Impact of Reducing ROE from 9.4% to 9.2%

Line	Component	Ratio	Cost	Wtd Cost	Tax Mult.	Pre-tax Wtd. Cost	Ratio	Cost	Wtd Cost	Tax Mult.	Pre-tax Wtd. Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Debt[1]	47.0%	4.56%	2.1%		2.14%	47.0%	4.56%	2.1%		2.1%
2	Equity	53.0%	9.40%	5.0%	1.3046	6.50%	53.0%	9.20%	4.9%	1.3046	6.4%
3						8.64%					8.50%
4	Rate Base[2]	19,543					Change in Revenue Requirement				(27.0)

Source: Taylor Exhibit 4 Workpaper 9
Bowman Third Supplemental Direct at 3, Exhibit 2 at 2.

1. The debt cost is updated based on DEC's 3rd supplemental filing.

2. The original rate base represented the incremental rate base in the first year of the MYRP.
The corrected amount is the total rate base in the test year, from DEC's 3rd supplemental filing.

Request:

2. Is DEC's parent company planning on issuing stock during the term of the MYRP? If yes, identify when the stock issuance will occur, the amount of the issuance, and the estimated flotation costs.

Response:

Duke Energy Corp currently has no planned equity issuances in the financial plan through 2027, outside of stock-based compensation awards to employees and outside directors. However, in November 2022, Duke Energy filed a prospectus supplement and executed an EDA under which it may sell up to $1.5 billion of its common stock through a new ATM offering program, including an equity forward sales component. Under the terms of the EDA, Duke Energy may issue and sell shares of common stock through September 2025.

DUKE ENERGY CAROLINAS

Revised Capital Asset Pricing Model

Line	Company Name	Risk-Free Rate (1)	Beta (2)	MRP (3)	CAPM Cost of Equity (4)
1	Alliant Energy	4.30%	0.85	6.40%	9.74%
2	Amer. Elec. Power	4.30%	0.75	6.40%	9.10%
3	Ameren Corp.	4.30%	0.85	6.40%	9.74%
4	Avista Corp.	4.30%	0.90	6.40%	10.06%
5	Black Hills	4.30%	0.95	6.40%	10.38%
6	CenterPoint Energy	4.30%	1.15	6.40%	11.66%
7	CMS Energy Corp.	4.30%	0.80	6.40%	9.42%
8	Dominion Energy	4.30%	0.85	6.40%	9.74%
9	DTE Energy	4.30%	0.95	6.40%	10.38%
10	Edison Int'l	4.30%	0.95	6.40%	10.38%
11	Entergy Corp.	4.30%	0.95	6.40%	10.38%
12	Evergy Inc.	4.30%	0.90	6.40%	10.06%
13	Eversource Energy	4.30%	0.90	6.40%	10.06%
14	FirstEnergy Corp.	4.30%	0.85	6.40%	9.74%
15	IDACORP Inc.	4.30%	0.80	6.40%	9.42%
16	NorthWestern Corp.	4.30%	0.90	6.40%	10.06%
17	OGE Energy	4.30%	1.05	6.40%	11.02%
18	Otter Tail Corp.	4.30%	0.85	6.40%	9.74%
19	Portland General	4.30%	0.85	6.40%	9.74%
20	Sempra Energy	4.30%	0.95	6.40%	10.38%
21	Southern Co.	4.30%	0.95	6.40%	10.38%
22	WEC Energy Group	4.30%	0.80	6.40%	9.42%
23	Xcel Energy Inc.	4.30%	0.80	6.40%	9.42%
25	**AVERAGE**				**10.02%**

Notes: Column (1): Risk-free rate
Column (2): see Exhibit RAM-5
Column (3): Market Risk Premium
Column (4): Column (1) + Column (2) x Column (3)

Exhibit BSL-12
Docket No. E-7, Sub 1276
Direct Testimony of Billlie LaConte

DUKE ENERGY CAROLINAS

Proxy Group Authorized Return on Equity and Equity Ratio

Line	Utility	Authorized ROE	Authorized Equity Ratio	Weighted Cost of Equity
	(1)	(2)	(3)	(4)
1	Georgia Power	10.50%	56.00%	5.880%
2	IDACORP	9.40%	50.00%	4.700%
3	Kentucky Power	9.30%	43.25%	4.022%
4	Consumers Energy	9.90%	50.75%	5.024%
6	Entergy Arkansas	9.65%	47.00%	4.536%
7	SWEPCO	9.50%	47.00%	4.465%
8	Public Service Colorado Xcel		55.69%	
8	Indiana Michigan IN	9.70%	49.46%	4.798%
10	Northern States Power MN	9.25%	52.50%	4.856%
10	Otter Tail	9.48%	52.50%	4.977%
11	Southwestern Public Service NM	9.35%	54.72%	5.116%
12	AEP Ohio	9.70%	54.43%	5.280%
14	DTE	9.90%		
14	Portland General	9.50%	50.00%	4.750%
15	Northern States Power ND	9.50%	52.50%	4.988%
16	Kingsport TN		48.90%	
17	TX Southwestern AEP	9.25%	49.37%	4.567%
18	VA Electric Power	9.35%	51.92%	4.855%
19	Northern States Power WI	10.00%	52.50%	5.250%
20	Wisconsin Electric WEC	9.80%	58.22%	5.706%
21	Wisconsin Electric and Light	10.00%	52.50%	5.250%
22	Wisconsin Public Service	9.80%	53.40%	5.233%
23	Average	9.64%	51.55%	4.961%
24	Duke Energy Carolinas	10.40%	53.00%	5.512%
25	CUCA	9.40%	51.55%	4.846%

DUKE ENERGY CAROLINA

Impact of Reducing Equity Ratio

Line	Component	Ratio	Cost	Wtd Cost	Tax Mult.	Pre-tax Wtd. Cost	Ratio	Cost	Wtd Cost	Tax Mult.	Pre-tax Wtd. Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Debt[1]	47.00%	4.56%	2.14%		2.14%	48.45%	4.56%	2.21%		2.21%
2	Equity	53.00%	10.40%	5.51%	1.3046	7.19%	51.55%	10.40%	5.36%	1.3046	6.99%
3						9.33%					9.20%
4	Rate Base[2]	19,543					Change in Revenue Requirement				(25.5)

Source: Taylor Exhibit 4 Workpaper 9
Bowman Third Supplemental Direct at 3, Exhibit 2 at 2.

1. The debt cost is updated based on DEC's 3rd supplemental filing.

2. The original rate base represented the incremental rate base in the first year of the MYRP.
The corrected amount is the total rate base in the test year, from DEC's 3rd supplemental filing.

MARK E. ELLIS

La Jolla, CA | mark.edward.ellis@gmail.com | 619-507-8892 | https://www.linkedin.com/in/mark-edward-ellis

Mark E. Ellis is a former utility executive now working as an independent consultant and testifying expert in finance and economics in utility regulatory proceedings.

Before establishing his own consultancy, Mark led the strategy function at Sempra Energy (parent of SDG&E and SoCalGas) for fifteen years. Previously, he worked as a consultant in McKinsey's energy practice, in international project development for ExxonMobil, and in industrial demand-side management for Southern California Edison. He has an MS from MIT's Technology and Policy Program, where he focused on utility policy and conducted research in the MIT Energy Lab, and a BS in mechanical engineering from Harvard.

EXPERT TESTIMONY

Client	State	Utility	Description	Docket	Date
North Carolina Justice Center et al.	NC	Duke Energy Carolinas	Cost of capital	E-7, Sub 1276	1/23-ongoing
North Carolina Justice Center et al.	NC	Duke Energy Progress	Cost of capital	E-2, Sub 1300	1/23-ongoing
The Utility Reform Network	CA	San Diego Gas & Electric, Southern California Gas	Wildfire liability insurance	A.22-05-015 & 016	1/23-ongoing
The Utility Reform Network	CA	Southern California Edison	Wildfire liability self-insurance	A.19-08-013	1/23-ongoing
Georgia Interfaith Power & Light	GA	Georgia Power	Cost of capital	44280	8/22-12/22
Clean Wisconsin	WI	Wisconsin Electric Power, Wisconsin Gas	Cost of capital	5-UR-110	8/22-12/22
The Protect Our Communities Foundation	CA	San Diego Gas & Electric, Southern California Gas	Cost of capital	A.22-04-008, et seq.	4/22-ongoing
The Utility Reform Network	CA	Pacific Gas & Electric	Wildfire liability self-insurance	A.21-06-021	11/21-ongoing
The Protect Our Communities Foundation	CA	Pacific Gas & Electric, San Diego Gas & Electric, Southern California Edison	Cost of capital	A.21-08-013, et seq.	11/21-ongoing
New Hampshire Department of Energy	NH	Aquarion Water Company of New Hampshire	Cost of capital	DW 20-184	6/21-2/22
The Utility Reform Network	CA	Pacific Gas & Electric	$7.5-billion wildfire cost securitization	A.20-04-023	6/20-2/21

EMPLOYMENT

Company	Title	Location	Date
Self-employed	Independent consultant and testifying expert	La Jolla, CA	2019-present
Sempra Energy	Chief of Corporate Strategy	San Diego, CA	2004-19
McKinsey & Company	Engagement Manager	Houston, TX	2000-03
ExxonMobil	Venture Development Advisor	Houston, TX	1996-2000
MIT Energy Laboratory	Research Assistant	Cambridge, MA	1994-96
Southern California Edison	Staff Engineer	Irwindale, CA	1994
Sanyo Electric Company	Research Engineer	Osaka, Japan	1992-93
Los Angeles Department of Water & Power	Seasonal Waterworks Laborer	Chatsworth, CA	1988

EDUCATION

Institution	Degree	Date
Massachusetts Institute of Technology	MS, Technology and Policy	1996
Harvard University	BS, *magna cum laude,* Mechanical and Materials Sciences and Engineering	1992

UC Berkeley

UC Berkeley Electronic Theses and Dissertations

Title
Essays on Energy and Environmental Economics

Permalink
https://escholarship.org/uc/item/8qr72677

Author
Dunkle Werner, Karl W

Publication Date
2021

Peer reviewed|Thesis/dissertation

Essays on Energy and Environmental Economics

by

Karl W. Dunkle Werner

A dissertation submitted in partial satisfaction of the

requirements for the degree of

Doctor of Philosophy

in

Agricultural and Resource Economics

in the

Graduate Division

of the

University of California, Berkeley

Committee in charge:

Associate Professor James Sallee, Chair
Professor Severin Borenstein
Associate Professor Meredith Fowlie

Spring 2021

Essays on Energy and Environmental Economics

by
Karl Dunkle Werner

Abstract

Essays on Energy and Environmental Economics

by

Karl W. Dunkle Werner

Doctor of Philosophy in Agricultural and Resource Economics

University of California, Berkeley

Associate Professor James Sallee, Chair

Over the past decades, two things have become increasingly apparent: first, climate change and associated environmental impacts are pressing issues, and second, despite this growing threat, existing policies still fall far short. The goal of my research, and what I hope for the field more broadly, is to achieve effective, efficient, and equitable policy. My dissertation research covers a wide range of topics, focusing on three different areas of energy and environmental economics: methane emissions from oil and gas production; flooding on agricultural land; and energy utility regulatory rates of return. The common thread is using applied economic tools and answering policy-relevant questions with data and analysis. Often, the data that are available are far from the ideal dataset, or the policies that are on the table are far from the first best. Here, my coauthors and I adopt the "economist as plumber" mindset, using the tools that are available to address the challenges at hand (Duflo 2017).

In my first chapter, my coauthor Wenfeng Qiu and I study emissions of methane, a powerful greenhouse gas, from oil and gas wells in the US. These emissions contribute significantly to climate change—they are approximately as large as the emissions of all fuel burned in the western US electricity grid. Methane emissions are rarely priced and lightly regulated—in part because they are hard to measure—leading to a large climate externality. However, measurement technology is improving, with remote sensing and other techniques opening the door for policy innovation. We present a theoretical model of emissions abatement at the well level and a range of feasible policy options, then use data constructed from cross-sectional scientific studies to estimate abatement costs. We simulate audit policies under realistic constraints, varying the information the regulator uses in choosing wells to audit. These policies become more effective when they can target on well covariates, detect leaks remotely, and charge higher fees for leaks. We estimate that a policy that audits 1% of wells with uniform probability achieves less than 1% of the gains of the infeasible first best. Using the same number of audits targeted on remotely sensed emissions data achieves gains of 30–60% of the first best. These results demonstrate that, because leaks are rare

events, targeting is essential for achieving welfare gains and emissions reductions. Auditing a small fraction of wells can have a large impact when properly targeted. Our approach highlights the value of information in designing policy, centering the regulatory innovation that is possible when additional information becomes available.

My second chapter is coauthored with Oliver Browne, Alyssa Neidhart, and Dave Sunding. We study high-frequency flood risk on agricultural land. Floods destroy crops and lower the value of agricultural land. Economic theory implies that the hedonic discount on the value of a parcel of flood-prone land should scale with the expected probability flooding. Most empirical studies of the impact of flood risk on property values in the United States focus on the relatively small risk posed by the 100-year or 500-year floodplains, as reported in maps produced by the Federal Emergency Management Agency (FEMA). These studies consequently find a relatively small corresponding discount in property values. However, a significant amount of agricultural bottom-land lies in floodplains that flood more frequently. We estimate the hedonic discounts on with agricultural land that floods at these higher frequencies along the Missouri River. As flood risk increases, the value of flood-prone land decreases, with a hedonic discount ranging from close to zero in the 500-year floodplain to approximately 17% in the 10-year floodplain. To illustrate the importance of characterizing these higher frequency flood risks, we consider a climate change scenario, where properties that already face some flood risk are expected to flood more frequently.

My third chapter, coauthored with Stephen Jarvis, examines the regulated rate of return on equity utility companies are allowed to collect from their customers. Utilities recover their capital costs through regulator-approved rates of return on debt and equity. The US costs of risky and risk-free capital have fallen dramatically in the past 40 years, but these utility rates of return have not. We estimate the gap between what utilities are paid now, and what they would have been paid if their rate of return had followed capital markets, using a comprehensive database of utility rate cases dating back to the 1980s. We estimate that the current average return on equity is 0.5–4 percentage points higher than historical relationships would suggest, and consumers pay an average of $2–8 billion per year more than they would otherwise. We then revisit the effect posited by Averch and Johnson (1962), estimating the consequences of this incentive to own more capital: a 1 percentage point increase in the return on equity increases new capital investment by about 5% in our preferred estimate.

REFERENCES

Averch, Harvey, and Leland L Johnson. 1962. "Behavior of the firm under regulatory constraint." *The American Economic Review* 52 (5): 1052–1069. (Cited on page 2).

Duflo, Esther. 2017. "The Economist as Plumber." *American Economic Review* 107, no. 5 (May): 1–26. https://doi.org/10.1257/aer.p20171153. (Cited on page 1).

Chapters

Transition

The next chapter focuses on state policies governing electricity and natural gas utility companies. These state-level decisions determine how utilities are paid for their investments, and how much utility customers have to pay for their service. Capital investments, from pipelines to solar farms, play an enormous role in shaping future US greenhouse gas emissions. While chapter 2 considered future changes in flood risk due to climate shifts, chapter 3 considers these very important capital investments. We focus on how much utilities are paid for their capital, the incentives utilities have to own more, and the effect of these incentives on capital ownership.

Chapter Three

Rate of Return Regulation Revisited

Coauthor: Stephen Jarvis

1 INTRODUCTION

In the two decades from 1997 to 2017, real annual capital spending on electricity distribution infrastructure by major utilities in the United States has doubled (EIA 2018a). Over the same time period annual capital spending on electricity transmission infrastructure increased by a factor of seven (EIA 2018b). The combined total is now more than $50 billion per year. This trend is expected to continue. Bloomberg New Energy Finance predicts that between 2020 and 2050, North and Central American investments in electricity transmission and distribution will likely amount to $1.6 trillion, with a further $1.7 trillion for electricity generation and storage (Henbest et al. 2020).[1]

These large capital investments could be due to the prudent actions of utility companies modernizing an aging grid. However, it is noteworthy that over this time period, utilities have earned sizeable regulated rates of return on their capital assets, particularly when set against the unprecedented low interest rate environment post-2008. As the economy-wide cost of capital has fallen, utilities' regulated rates of return have not fallen nearly as much. The exact drivers for this divergence are unclear, though we rule out large changes in riskiness in section 3. Whatever the underlying cause, the prospect of utilities earning excess regulated returns raises an age-old concern in the sector: the Averch–Johnson effect. When utilities are allowed to earn excess returns on capital, they will be incentivized to over-invest in capital assets. The resulting costs from "gold plating" are then passed on to consumers in the form of higher bills. Capital markets and the utility industry have undergone significant changes over the past 50 years since the early studies of utility capital ownership (Joskow 1972, 1974). In this paper we use new data to revisit these issues. We do so by exploring two main research questions. First, what can we say about the return on equity utilities are allowed by their regulators? Second, how has this return on equity affected utilities' capital investment decisions?

To answer our research questions, we use data on the utility rate cases of all major electricity and natural gas utilities in the United States spanning the past four decades (Regulatory Research Associates 2021). We combine this with a range of financial information on credit ratings, corporate borrowing and market returns. To examine possible sources of over-investment in more detail we also incorporate data from annual regulatory filings on

1. North and Central American generation/storage are reported directly. Grid investments are only reported globally, so we assume the ratio of North and Central America to global is the same for generation/storage as for grid investments.

individual utility capital spending.

We start our analysis by estimating the size of the gap between the allowed rate of return that utilities earn and the correct return on equity. A central challenge here, both for the regulator and for the econometrician, is estimating the correct cost of equity. We proceed by considering a range of approaches to simulating the correct cost of equity based on the observed rates of return and available measures of capital market returns. For the most part, our simulations ask "if approved RoE rates hadn't changed relative to some benchmark index since some baseline year, what would they be today?" We examine a number of benchmark indexes. None of these are perfect comparisons; the world changes over time, and different benchmarks may be more or less appropriate. Taken together, our various estimation approaches result in a consistent trend of excess rates of return. We find that the weighted median of the approved return on equity is 0.5–4 percentage points too high.[2] Applying these additional returns to the existing capital base we estimate excess costs to US customers of $2–8 billion per year. The majority of these excess costs are from the electricity sector, though natural gas contributes as well.[3]

However, excess regulated returns on equity will also distort the incentives to invest in capital. To consider the change in the capital base, we turn to a regression analysis. Here we aim to identify how a larger RoE gap translates into over investment in capital. Identification is challenging in this setting, so we again employ several different approaches, with different identifying assumptions. In addition to a fixed effects approach, we examine an instrumental variables strategy. We draw on the intuition that when a rate case is decided a utility's RoE is *fixed* at a particular nominal percentage for several years. The cost of capital in the rest of the economy, and therefore the true RoE, will shift over time. We use these shifts in the timing and duration of rate cases as an instrument for changes in the RoE gap. We argue that the instrument is valid, after controlling for an appropriate set of fixed effects. Across the range of specifications used, we find a broadly consistent picture. In our preferred specification we find that an additional percentage point increase in the RoE gap leads to the allowed increase in capital rate base to be about 5 percent higher.

2. Here we weight by the utilities' ratebase, so our results are not over-represented by very small utilities.

3. For comparison, total 2019 electricity sales by investor owned utilities were $204 billion, on 1.89 PWh of electricity (US Energy Information Administration 2020a). Natural gas sales to consumers are $146 billion on 28.3 trillion cubic feet of gas (These gas figures include sales to residential, commercial, industrial, and electric power, but not vehicle fuel. They include including all sales, not just those by investor owned utilities. US Energy Information Administration 2020b.)

2 BACKGROUND

Electricity and natural gas utility companies are regulated by government utility commissions, which allow the companies a geographic monopoly and, in exchange, regulate the rates the companies charge. These utility commissions are state-level regulators in the US. They set consumer rates and other policies to allow investor owned utilitys (IOUs) a designated rate of return on their capital investments, as well as recovery of non-capital costs. This rate of return on capital is almost always set as a nominal percentage of the installed capital base. For instance, with an installed capital base worth $10 billion and a rate of return of 8%, the utility is allowed to collect $800 million per year from customers for debt service and to provide a return on equity to shareholders. State utility commissions typically update these nominal rates every 3–6 years.

Utilities own physical capital (power plants, gas pipelines, repair trucks, office buildings, etc.). The capital depreciates over time, and the set of all capital the utility owns is called the ratebase (the base of capital that rates are calculated on). Properly accounting for depreciation is far from straightforward, but we will not focus on that challenge in this paper. This capital ratebase has an opportunity cost of ownership: instead of buying capital, that money could have been invested elsewhere. IOUs fund their operations through issuing debt and equity, typically about 50%/50%. (For this paper, we focus on common stocks. Utilities issue preferred stocks as well, but those form a very small fraction of utility financing.) The weighted average cost of capital is the weighted average of the cost of debt and the cost of equity.

Utilities are allowed to set rates to recover all of their costs, including this cost of capital. For some expenses, like fuel purchases, it's easy to calculate the companies' costs. For others, like capital, the state public utilities commissions are left trying to approximate the capital allocation at a cost competitive capital markets would provide, if the utility was a competitive company, rather than a regulated monopoly. The types of capital utilities own, and their opportunities to add capital to their books, vary across states and time. Utilities in vertically integrated states might own a large majority of their own generation, the transmission lines, and the distribution infrastructure. Other utilities are "wires only," buying power from independent power producers and transporting it over their lines. Natural gas utilities are typically pipeline only – the utility doesn't own the gas well or processing plant.

In the 1960s and 70s, state public utilities commissions (PUCs) began adopting automatic fuel price adjustment clauses. Rather than opening a new rate case, utilities used an established formula to change their customer rates when fuel prices changed. The same automatic adjustment has not happened for capital costs, despite large swings in the nominal cost of capital over the past 50 years. We're aware of one state (Vermont) that has an automatic update rule; we'll discuss that rule in more detail in section 4.1, where we consider various approaches of estimating the RoE gap.[4]

The cost of debt financing is by no means simple, particularly for a forward-looking decision-maker who isn't allowed to index to benchmark values, but is easier to estimate than the cost of equity financing. The cost of debt is the cost of servicing historical debt, and expected costs of new debt that will be issued before the next rate case. The historical cost is known, and can serve a direct basis for future expectations. In our data, we see both the utilities' requested and approved return on debt. It's notable that the requested and approved amounts are very close for debt, and much farther apart for equity.

The cost of equity financing is more challenging. Theoretically, it's the return shareholders require on their investment in order to invest in the first place. The Pennsylvania Public Utility Commission's ratemaking guide notes this difficulty (Cawley and Kennard 2018):

> Regulators have always struggled with the best and most accurate method to use in applying the [*Federal Power Commission v. Hope Natural Gas Company* (1944)] criteria. There are two main conceptual approaches to determine a proper rate of return on common equity: "cost" and "the return necessary to attract capital." It must be stressed, however,

4. At least one other state, California, had an automatic adjustment mechanism that has since been abandoned. Regulators at the California PUC feel that the rule, called the cost of capital mechanism (CCM), performed poorly. "The backward looking characteristic of CCM might have contributed to failure of ROEs in California to adjust to changes in financial environment after the financial crisis. The stickiness of ROE in California during this period, in the face of declining trend in nationwide average, calls for reassessment of CCM." (Ghadessi and Zafar 2017)

> that no single one can be considered the only correct method and that a proper return on equity can only be determined by the exercise of regulatory judgment that takes all evidence into consideration.

Unlike debt, where a large fraction of the cost is observable and tied to past issuance, the cost of equity is the ongoing, forward-looking cost of holding shareholders' money. Put differently, the RoE is applied to the entire ratebase – unlike debt, there's typically no notion of paying a specific RoE for specific stock issues.

Regulators employ a mixture of models and subjective judgment. Typically, these formal models, as well as the more subjective evaluations, benchmark against other US utilities (and often utilities in the same geographic region). There are advantages to narrow benchmarking, but when market conditions change and everyone is looking at their neighbors, rates will update very slowly.

In figure 1 we plot the approved return on equity over 40 years, with various risky and risk-free rates for comparison. The two panels show nominal and real rates. Consistent with a story where regulators adjust slowly, approved RoE has fallen slightly (in both real and nominal terms), but much less than other costs of capital. This price stickiness by regulators also manifests in peculiarities of the rates regulators approve. Rode and Fischbeck (2019) notes the fact that regulators seem reluctant to set RoE below a nominal 10%.

That paper, Rode and Fischbeck (2019), is the closest to ours in the existing literature. The authors use the same rate case dataset we do, and note a similar widening of the spread between the approved return on equity and 10-year Treasury rates. That paper, unlike ours, dives into the financial modeling, using the standard capital asset pricing model (CAPM) to examine potential causes of the increase the RoE spread. In contrast, we consider a wider range of financial benchmarks (beyond 10-year Treasuries) and ask more pointed questions about "what should rates be today if past relationships held?" and "how much has this RoE gap incentivized utilities to own more capital?"

Using CAPM, Rode and Fischbeck (2019) rule out a number of financial reasons we might see increasing RoE spreads. Possible reasons include utilities' debt/equity ratio, the asset-specific risk (CAPM's β), or the market's overall risk premium. None of these are supported by the data. A pattern of steadily increasing debt/equity could explain an increasing gap, but debt/equity has fallen over time. Increasing asset-specific risk could explain an increasing gap, but asset risk has (largely) fallen over time. (They use the Dow Jones Utility Average as a measure of utility asset risk.) An increasing market risk premium has could explain an increased spread between RoE and riskless Treasuries, but the market risk premium has fallen over time. Appendix figure 8, reproduced from Rode and Fischbeck (2019), shows the evolution of asset risk and the market risk premium over time.

Prior research has highlighted the importance of macroeconomic changes, and that these often aren't fully accounted for in utility commission ratemaking (Salvino 1967; Strunk 2014). Because rates of return are typically set in fixed nominal percentages, rapid changes in inflation can dramatically shift a utility's real return. This pattern is visible in figure 1 in the early 1980s. Inflation has lower and much more stable in recent years,

Many authors have written a great deal about modifying the current system of investor-owned utilities. Those range from questions of who pays for fixed grid costs to the role of government ownership or securitization (Borenstein, Fowlie, and Sallee 2021; Farrell 2019). For this project, we assume the current structure of investor-owned utilities, leaving aside other questions of how to set rates across different groups of customers or who owns the capital.

Finally, we note that a utility's approved rate of return or return on equity might differ from the realized return. In this paper, we focus on approved values. Other recent work, e.g. Hausman (2019), highlights important differences between approved costs and realized prices that customers face.

3 DATA

To answer our research questions, we use a database of resolved utility rate cases from 1980 to 2021 for every electricity and natural gas utility that either requested a nominal-dollar ratebase change of $5 million or had a ratebase change of $3 million authorized (Regulatory Research Associates 2021). Summary statistics on these rate cases can be seen in table 1.

We transform this panel of rate case events into an unbalanced utility-by-month panel, filling in the rate base and rate of return variables in between each rate case. There are some mergers and splits in our sample, but our SNL Financial (SNL) data provider lists each company by its present-day (2021) company name, or the company's last operating name before ceased to exist. With this limitation in mind, we construct our panel by (1) not filling data for a company before its first rate case in a state, and (2) dropping companies five years after their last rate case. In contexts where a historical comparison is necessary, but the utility didn't exist in the benchmark year, we use average of utilities that did exist in that state, weighted by ratebase size.

We match with data on S&P credit ratings, drawn from SNL's *Companies (Classic) Screener* (2021) and Wharton Research Data Services (WRDS)' *Compustat S&P legacy credit ratings* (2019). Most investor-owned utilities are subsidiaries of publicly traded firms. We use the former data to match as specifically as possible, first same-firm, then parent-firm, then same-ticker. We match the latter data by ticker only. Then, for a relatively small number of firms, we fill forward.[5] Between these two sources, we have ratings data are available from December 1985 onward. Approximately 80% of our utility–month observations are matched to a rating. Match quality improves over time: approximately 89% of observations after 2000 are matched.

These credit ratings have changed little over 35 years. In figure 2 we plot the median (in black) and various percentile bands (in shades of blue) of the credit rating for utilities active in each month. We note that the median credit rating has not changed much over time. The distribution of ratings is somewhat more compressed in 2021 than in the 1990s. While credit ratings are imperfect, we would expect rating agencies to be aware of large changes in riskiness.[6] Instead, the median credit rating for electricity utilities is A−, as it was for all of the 1990s. The median credit rating for natural gas utilities is also A−, down from a historical value of A.

Beyond credit ratings, we also use various market rates pulled from Federal Reserve Economic Data (FRED). These include 1-, 10-, and 30-year treasury yields, the core CPI, bond yield indexes for corporate bonds rated by Moody's as Aaa or Baa, as well as those rated by S&P as AAA, AA, A, BBB, BB, B, and CCC or lower.[7]

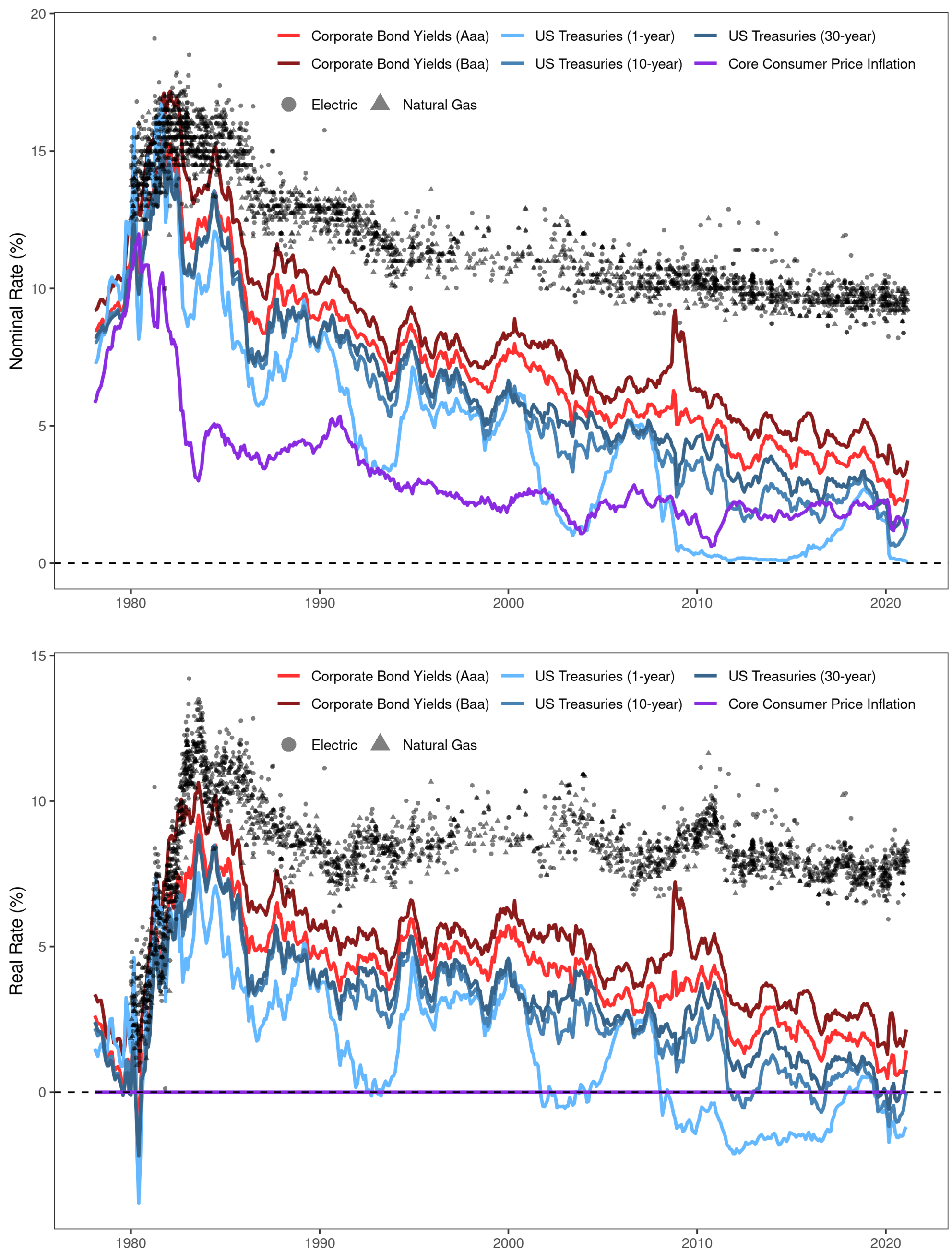
Matching these two datasets – rate cases and macroeconomic indicators – we construct the

5. When multiple different ratings are available, e.g. different ratings for subsidiaries trading under the same ticker, we take the median rating. We round down in the case of an even number of ratings, both here and in figure 2.

6. For utility risk to drive up the firms' cost of equity but not affect credit ratings, one would need to tell a very unusual story about information transmission or the credit rating process.

7. Board of Governors of the Federal Reserve System (2021a, 2021b, 2021c), US Bureau of Labor Statistics (2021), Moody's (2021a, 2021b), and Ice Data Indices, LLC (2021b, 2021a, 2021f, 2021d, 2021c, 2021g, 2021e).

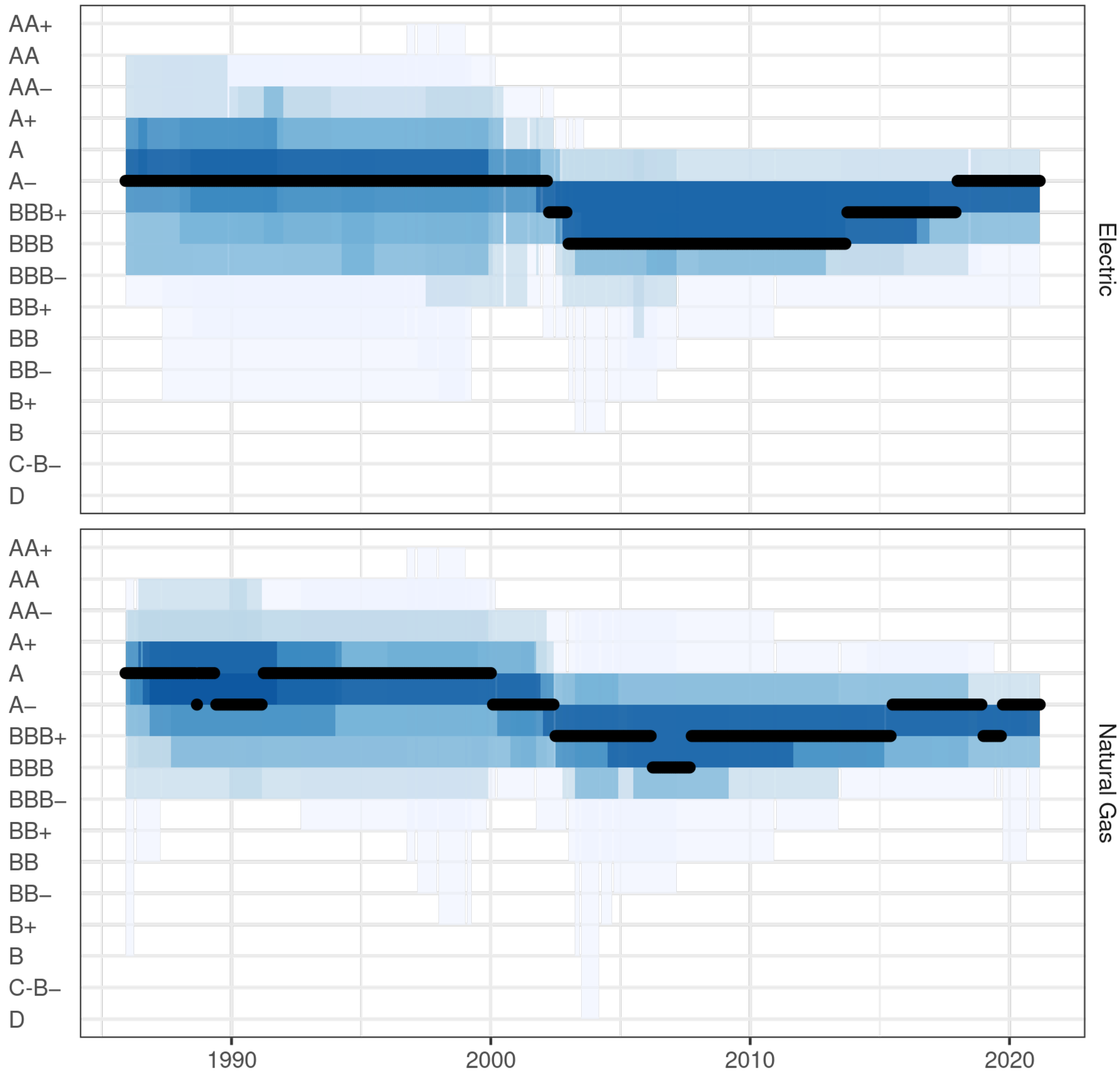
Figure 1: Return on Equity and Financial Indicators: Nominal and Real



Notes: These figures show the approved return on equity for investor-owned US electric and natural gas utilities. Each dot represents the resolution of one rate case. Real rates are calculated by subtracting consumer price index (CPI). Between March 2002 and March 2006 30-year Treasury rates are interpolated from 1- and 10-year rates.

Sources: Regulatory Research Associates (2021), Moody's (2021a, 2021b), Board of Governors of the Federal Reserve System (2021a, 2021b, 2021c), and US Bureau of Labor Statistics (2021).

Figure 2: Credit ratings have changed little in 35 years



Note: Black lines represent the median rating of the utilities active in a given month. We also show bands, in different shades of blue, that cover the 40–60 percentile, 30–70 percentile, 20–80 percentile, 10–90 percentile, and 2.5–97.5 percentile ranges. (Unlike later plots, these *are not* weighted by ratebase.) Ratings from C to B– are collapsed to save space.
Source: *Companies (Classic) Screener* (2021) and *Compustat S&P legacy credit ratings* (2019).

Table 1: Summary Statistics

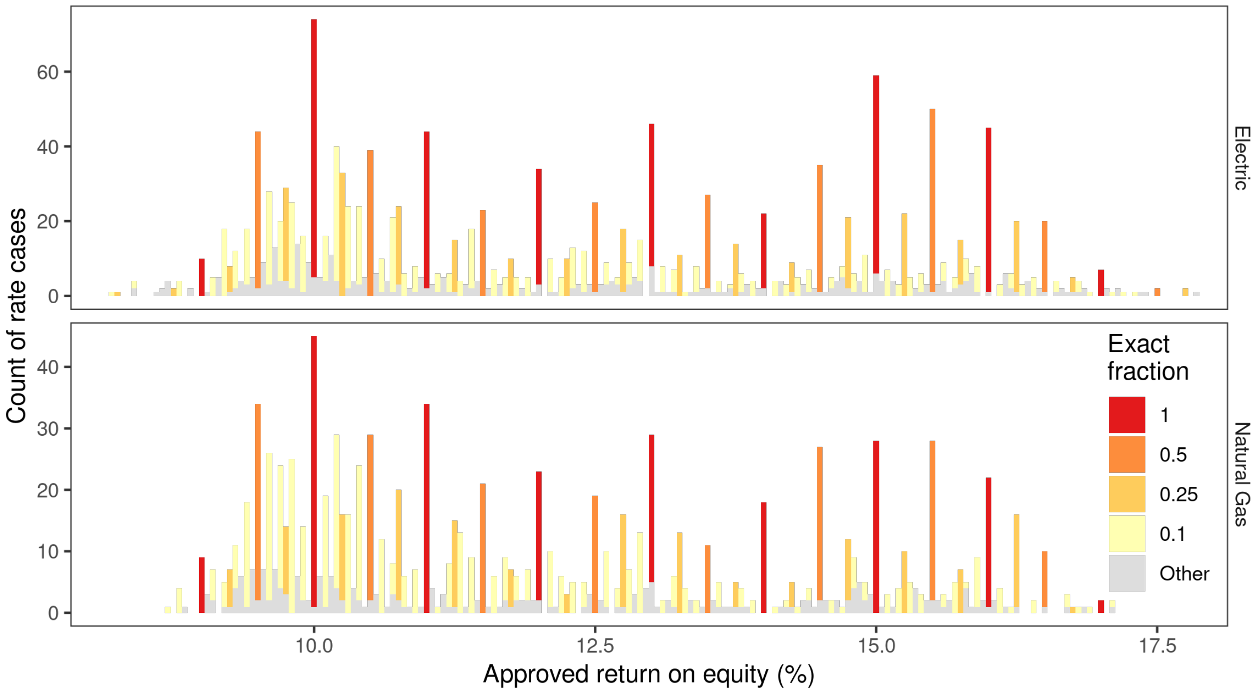
Characteristic	N	Electric	Natural Gas
Rate of Return Proposed (%)	3,324	9.95 (1.98)	10.07 (2.07)
Rate of Return Approved (%)	2,813	9.59 (1.91)	9.53 (1.95)
Return on Equity Proposed (%)	3,350	13.22 (2.69)	13.06 (2.50)
Return on Equity Approved (%)	2,852	12.38 (2.40)	12.05 (2.24)
Return on Equity Proposed Spread (%)	3,350	6.72 (2.18)	6.95 (1.99)
Return on Equity Approved Spread (%)	2,852	5.62 (2.27)	5.68 (2.10)
Return on Debt Proposed (%)	3,247	7.48 (2.11)	7.47 (2.16)
Return on Debt Approved (%)	2,633	7.54 (2.06)	7.44 (2.16)
Equity Funding Proposed (%)	3,338	45 (7)	48 (7)
Equity Funding Approved (%)	2,726	44 (7)	47 (7)
Rate Case Duration (mo)	3,713	9.1 (5.1)	8.1 (4.3)
Rate Base Increase Proposed ($ mn)	3,686	84 (132)	24 (41)
Rate Base Increase Approved ($ mn)	3,672	40 (84)	12 (25)
Rate Base Proposed ($ mn)	2,366	2,239 (3,152)	602 (888)
Rate Base Approved ($ mn)	1,992	2,122 (2,991)	583 (843)

NOTES: This table shows the rate case variables in our rate case dataset. Values in the Electric and Natural Gas columns are means, with standard deviations in parenthesis.
Approved values are approved in the final determination, and are the values we use in our analysis. Some variables are missing, particularly the approved rate base. The RoE spread in this table is calculated relative to the 10-year Treasury rate.
SOURCE: Regulatory Research Associates (2021) and author calculations.

timeseries shown in figure 1. A couple of features jump out, as we mentioned in the introduction. The gap between the approved return on equity and other measures of the cost of capital have increased substantially over time. At the same time, the return on equity has decreased over time, but much more slowly than other indicators. We quantify these observations in section 5.

We note that there are other distortions or ad-hoc evaluations in the PUC process. Rode and Fischbeck (2019) note a hesitancy for PUCs to set RoE below a nominal 10% level. We replicate this finding. In addition, we also note a bias toward round numbers, where regulators tend to approve RoE values at integers, halves, quarters, and tenths of percentage points. This finding is demonstrated in figure 3. We believe the true, unknown, cost of equity is smoothly distributed. If for instance, a PUC rounds in a way that changes the allowed RoE by 10 basis points (0.1%), the allowed revenue on the existing ratebase for the average electric utility in 2019 would change by $114 million. (The median is lower, at $52 million.) Small deviations have large implications for utility revenues and customer payments, though we don't know if rounding has a systematic bias toward higher or lower RoE. Of course, RoE values that aren't set at round numbers might not be any closer to the correct RoE. We leave this round number bias, as well as the above-10% stickiness, for future research.

Figure 3: Return on equity is often approved at round numbers



Colors highlight values of the nominal approved RoE that fall exactly on round numbers. More precisely, values in red are integers. Values in dark orange are integers plus 50 basis points (bp). Lighter orange are integers plus 25 or 75 bp. Yellow are integers plus one of {10, 20, 30, 40, 60, 70, 70, 80, 90} bp. All other values are gray.
Histogram bin widths are 5 bp. Non-round values remain gray if they fall in the same histogram bin as a round value. In that case, the bars are stacked.

Source: Regulatory Research Associates (2021).

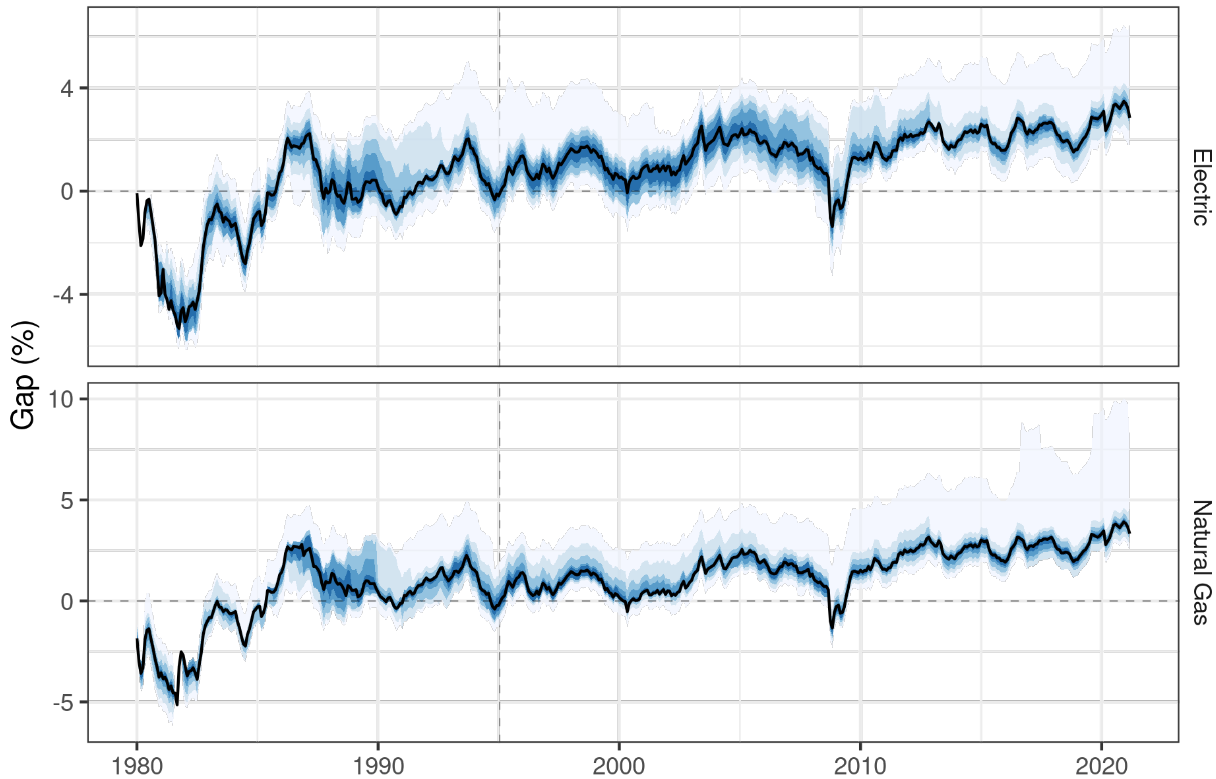
4 EMPIRICAL STRATEGY

4.1 RETURN ON EQUITY GAP

Knowing the return on equity (RoE) gap size is a challenge, and we take a couple of different approaches. None are perfect, but collectively, they shed light on the question. For each of the strategies we outline below (in sections 4.1.1, 4.1.2, 4.1.3, and 4.1.4) we plot the timeseries of the RoE gap. These are plotted in figures 4, 5, 6, and 7. Many of these strategies pick a specific time period as a benchmark. For all of these, we use January 1995. For the most part, our RoE gap results are flat over time (in the case of CPI) or steadily upward sloping (in the case of corporate bonds). The choice of baseline date determines where zero is, so changing the baseline date will shift the overall magnitude of the gap. As long as the baseline date isn't in the middle of a recession, our qualitative results don't depend strongly on the choice.

In each plot, we present the median of our RoE gap estimates, weighting by the utility's ratebase (in 2019 dollars). Our goal is to show the median of ratebase dollar value, rather than the median of utility companies, as the former is more relevant for understanding the impact of the RoE gap. We also show bands, in different shades of blue, that cover the 40–60 percentile, 30–70 percentile, 20–80 percentile, 10–90 percentile, and 2.5–97.5 percentile (all weighted by ratebase).

Figure 4: Return on equity gap, benchmarking to Baa-rates corporate bonds



Base year is 1995. Line represents median; shading represents ranges that cover the central 20, 40, 60, 80, and 95% of total IOU ratebase. See calculation details in section 4.1.1.

4.1.1 *Indexed to Corporate Bonds*

We first consider a benchmark index of corporate bond yields, rated Baa by Moody's.[8] The idea here is to ask if the *average* spread against the Baa rating hadn't changed since the baseline, what would the RoE be today? The results are plotted in figure 4. Moody's Baa is approximately equivalent to S&P's BBB, which is at or slightly below our most of the utilities in our data. We use January 1995 as our baseline. Our findings are qualitatively the same for other dates, though the magnitude differs.

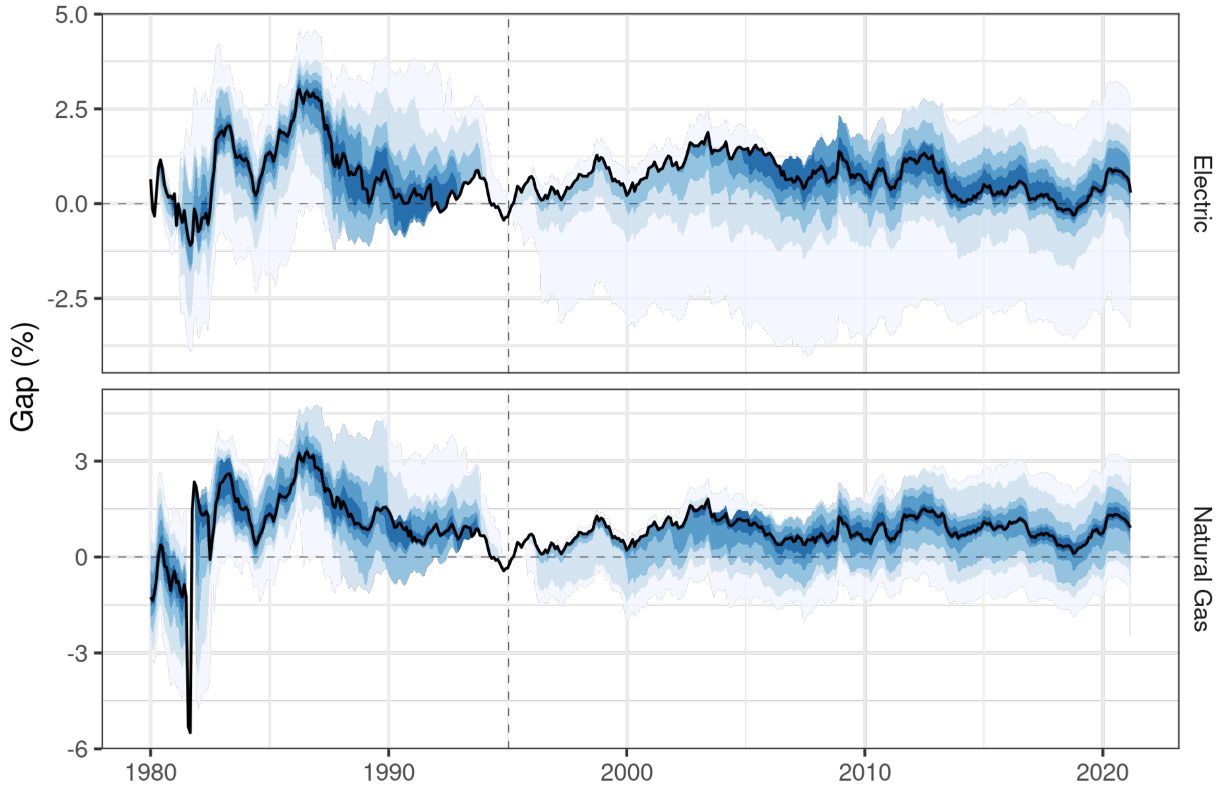
Making comparisons to debt instruments in this way, rather than benchmarking to some economy-wide cost of equity, means the measure of the RoE gap likely understates the gap. Rode and Fischbeck (2019) points out that (1) the market-wide equity risk premium has declined over the period and (2) the same is true for the utility sector.[9] Therefore, we would expect the mean spread against Baa bond yields to have declined, but instead, the spread has increased.

To calculate these results we first find the spread between the approved return on equity and the Moody's Baa rate for each utility in each state in each month. We then take the average at our baseline and simulate what that spread would be if the overall average

8. This index is one of two rating-specific corporate bonds indexes that's available for our entire study period. The other is Moody's Aaa.

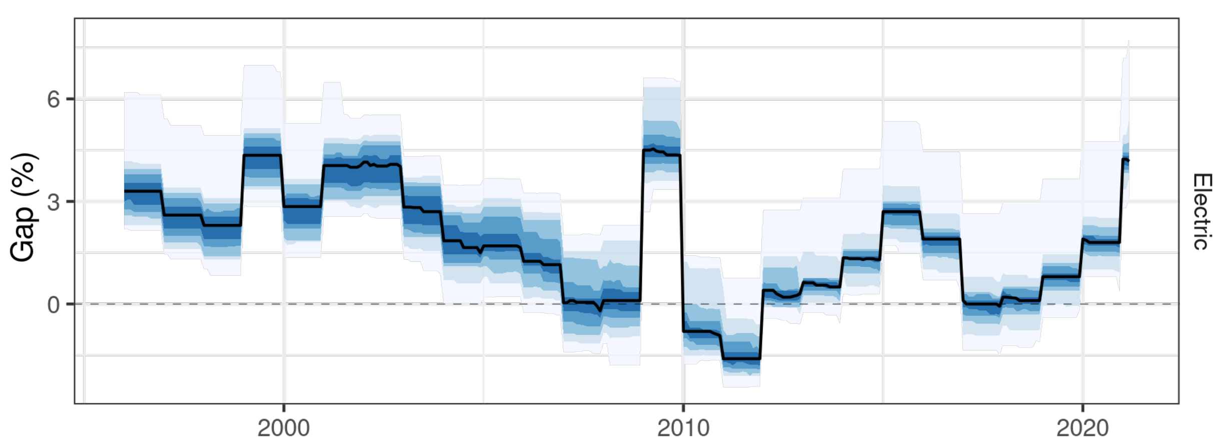
9. To the extent that observed utility stock returns are endogenous to the approved RoE, point #2 might be biased (Werth 1980).

Figure 5: Return on equity gap, using Vermont's update rule



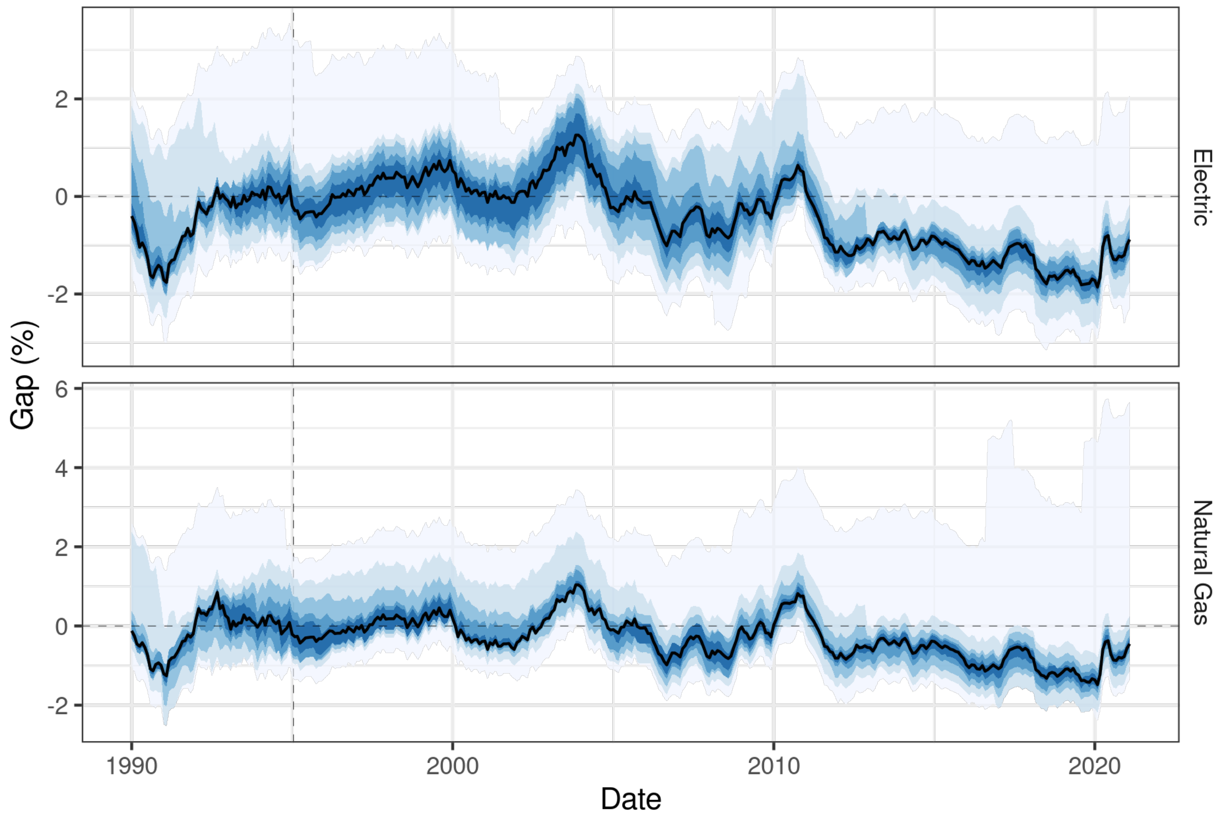
Line represents median; shading represents ranges that cover the central 20, 40, 60, 80, and 95% of total IOU ratebase. See calculation details in section 4.1.2.

Figure 6: Return on equity gap, compared to UK utilities



Base year is 1995. Line represents median; shading represents ranges that cover the central 20, 40, 60, 80, and 95% of total IOU ratebase. See calculation details in section 4.1.3.

Figure 7: Return on equity gap, benchmarking to CPI



Base year is 1995. Line represents median; shading represents ranges that cover the central 20, 40, 60, 80, and 95% of total IOU ratebase. See calculation details in section 4.1.4. Dates before 1990 are omitted for better axis scaling.

spread hadn't changed. One advantage of this approach is that we can still allow utilities to move around in their relative rankings and RoE. For example if a particular utility gets riskier and has correspondingly high RoE, our measure allows for that change in individual riskiness.

4.1.2 *Indexed to Treasuries*

Our next measure uses the RoE update rule recently implemented by the Vermont PUC. This rule is the only one we're aware of, from any PUC, that currently does automatic updating. Define R' as the baseline RoE, B' as the baseline 10-year Treasury bond yield, and B_t as the 10-year Treasury bond yield in year t. The update rule says the RoE in year t is then:

$$R_t = R' + \frac{B_t - B'}{2}$$

In the graph, we set the baseline to January 1995. In reality the commission set the baseline period as December 2018, for their plan published in June 2019. (*Green Mountain Power: Multi-Year Regulation Plan 2020–2022* 2020). We simulate the gap between approved RoE and what RoE would have been if every state's utilities commission followed this rule from 1995 onward. (Pre-1995 values are not particularly meaningful, but we can calculate them with the same formula.) We plot results in figure 5.

4.1.3 International Benchmark

We also consider an international benchmark. Here we ask, "what if US utilities faced a return on equity that was the same as return on equity in the UK?" Unlike the previous cases, we're not considering some benchmark year. Instead, we're considering the contemporaneous gap between the US and UK. Of course many things are different between these countries, and it's not fair to say all US utilities should adopt UK rate making, but we've think this benchmark provides an interesting comparison. Our results are in figure 6.

4.1.4 Indexed to Inflation

We also consider a calculation where we benchmark against core CPI. The mechanics of this calculation are identical to the Baa comparison above, where we calculate the gap between approved RoE and what the RoE would be if the mean spread against core CPI were unchanged. In this analysis, we find a small negative gap: real approved values RoE have declined, but by less than other costs of capital.

4.2 RATE BASE IMPACTS

Next, we turn to the ratebase the utilities own. A utility with a positive RoE gap will have a too-strong incentive to have capital on their books. In this section, we investigate the change in ratebase utilities request and receive. For our purposes, change in ratebase is more relevant than the total ratebase, as the change is a flow variable that changes from rate case to rate case, while the total ratebase is the partially-depreciated stock of all previous ratebase changes. We consider both the requested change and the approved change, though the approved value is our preferred specification. We estimate $\hat{\beta}$ from the following:

$$\log(RBI_{i,t}) = \beta RoE^{gap}_{i,t} + \gamma X_{i,t}\theta_i + \lambda_t + \epsilon_{i,t} \quad (3.1)$$

where an observation is a utility rate case for utility i in year-of-sample t. The dependent variable, $RBI_{i,t}$, is the increase in the rate base, and we take logs. (Cases where the ratebase shrinks are rare, but do happen. We drop these cases.) The independent variable of interest, $RoE^{gap}_{i,t}$, is the gap between the allowed return on equity and the true return on equity over the length of the rate case, where each rate case has a duration of D years.

$$RoE^{gap}_{i,t} = RoE^{allowed}_{i,t} - \frac{1}{D}\sum_{t}^{t+D} RoE^{correct}_{i,t} \quad (3.2)$$

Unlike section 4.1, for this analysis we care about differences in the gap between utilities or over time, but do not care about the overall magnitude of the gap. For ease of implementation, we begin by considering the gap as the spread between the approved rate of return and the 10-year Treasury bond yield. We do not expect the correct return on equity to be equal to the 10-year Treasury yield, but our fixed effects account for any constant differences. Future research will consider a richer range of gap calculations.

4.2.1 Fixed Effects Specifications

Our goal is to make causal claims about $\hat{\beta}$, so we are concerned about omitted variables that are correlated with both the estimated RoE gap and the change in ratebase. We begin with a fixed-effects version of the analysis. Our preferred version includes time fixed effects, λ_t, at the year-of-sample level and the unit fixed effects, θ_i, are at the utility company and state level.[10] Here, the identifying assumption is that after controlling for state and year effects, there are no omitted variables that would be correlated with both our estimate of the RoE gap and the utility's change in ratebase. The identifying variation is the differences in the RoE gap within the range of rate case decisions

10. Many utilities operate within only on state, but some span multiple. These company and state fixed effects are only partially nested.

Table 2: RoE gap, by different benchmarks

A: Electric		Baa yield	VT rule	UK	CPI
Gap (%)	2000	0.796	0.21	3.17	0.531
	2020	3.26	0.485	2.03	−1.06
Excess payment ($bn)	2000	0.581	0.23	4.54	0.142
	2020	6.54	1.43	3.92	−2.61
B: Natural Gas					
Gap (%)	2000	0.969	0.142		0.704
	2020	3.9	1.15	1.89	−0.421
Excess payment ($bn)	2000	0.0896	0.0183		0.0212
	2020	2.14	0.658	0.975	−0.361

NOTE: Gap percentage figures are an unweighted average across utilities. Excess payments are totals for all IOUS in the US, in billions of 2019 dollars per year, *for the observed ratebase*.
For cases where it's relevant (Baa yield, VT rule, and CPI), the benchmark date is January 1995. See text for details of each benchmark calculation.

for a given utility, relative to the annual average across all utilities. These fixed effects handle some of the most critical threats to identification, such as macroeconomic trends, technology-driven shifts in electrical consumption, or static differences in state PUC behavior. In columns 1–3 of our results tables (3 and 4), we consider different specifications for our fixed effects.

In this case the identification hinges on looking at variation in the RoE gap within the range of rate case decisions for a given utility, relative to the annual average across all utilities. The identifying assumption is that after controlling for state, year, and company effects, there are no omitted variables that would be correlated with both our estimate of the RoE gap and the utility's change in ratebase. These fixed effects handle many of the stories one could tell, such as macroeconomic trends, technological shifts in electrical consumption, or static differences in state PUC behavior. However, there are certainly other avenues for omitted variables bias to creep in, so next we turn to an instrumental variables strategy.

4.2.2 Instrumenting with Rate Case Timing and Duration

To try and further deal with concerns regarding identification, we examine an instrumental variables approach based on the timing and duration of rate cases.

Our IV analysis takes the idea that rates move around in ways that aren't always easy for the regulator to anticipate. So for instance if the allowed return on equity is set in year 0 and financial conditions change in year 2 such that the real allowed return on equity increases, then we would expect the utility to increase their capital investments in ways that

Table 3: Relationship Between Proposed Rate of Return and Proposed Rate Base

	Fixed effects specs.			IV
Model:	(1)	(2)	(3)	(4)
Variables				
RoE gap (%)	0.0670***	0.0436*	0.0672***	0.0353
	(0.0134)	(0.0217)	(0.0151)	(0.0215)
Fixed-effects				
State	Yes	Yes	Yes	Yes
Year		Yes	Yes	Yes
Company			Yes	Yes
Fit statistics				
Observations	3,210	3,210	3,210	3,210
R^2	0.37	0.39	0.73	0.73
Within R^2	0.24	0.23	0.29	0.29
Wald (1st stage)				50.9
Dep. var. mean	63.69	63.69	63.69	63.69

Two-way (Year & Company) standard-errors in parentheses
*Signif. Codes: ***: 0.01, **: 0.05, *: 0.1*

NOTES: The dependent variable in the first panel is log of the utility's proposed rate base increase. Columns 1–3 show varying levels of fixed effects. Column 4 is the IV discussed in section 4.2. Our preferred specification is column 4 of table 4. First-stage *F*-statistic is Kleibergen–Paap robust Wald test. All regressions control for an indicator of electricity or natural gas.

are unrelated to other aspects of the capital investment decision. For this instrument to work, it needs to be the case that these movements in bond markets or the like are conditionally independent of decisions that the utility is making, except via this return on equity channel. We control for common year fixed effects, and then the variation that drives our estimate is that different utilities will come up for their rate case at different points in time.

5 RESULTS

Beginning with the RoE gap analysis from section 4.1, table 2 summarizes the graphs, using 2000 and 2020 as example points in time. The table highlights the RoE gap and the excess payment on the existing ratebase. Our results on the RoE gap can largely be guessed from a close inspection of figure 1. Approved RoE has not changed much in real terms (i.e. relative to core CPI), but the gap has increased between RoE and various financial benchmarks. Of our various imperfect estimates of the gap, we believe the Baa benchmark is the most credible.

Table 4: Relationship Between Approved Rate of Return and Approved Rate Base

	Fixed effects specs.			IV
Model:	(1)	(2)	(3)	(4)
Variables				
RoE gap (%)	0.0551***	0.0752***	0.0867***	0.0523**
	(0.0200)	(0.0240)	(0.0225)	(0.0252)
Fixed-effects				
State	Yes	Yes	Yes	Yes
Year		Yes	Yes	Yes
Company			Yes	Yes
Fit statistics				
Observations	2,491	2,491	2,491	2,491
R^2	0.33	0.36	0.69	0.69
Within R^2	0.21	0.20	0.22	0.22
Wald (1st stage)				69.1
Dep. var. mean	38.63	38.63	38.63	38.63

Two-way (Year & Company) standard-errors in parentheses
*Signif. Codes: ***: 0.01, **: 0.05, *: 0.1*

NOTES: The dependent variable in the first panel is log of the utility's approved rate base increase. Columns 1–3 show varying levels of fixed effects. Column 4 is the IV discussed in section 4.2. Our preferred specification is column 4. First-stage *F*-statistic is Kleibergen–Paap robust Wald test. All regressions control for an indicator of electricity or natural gas.

Totalling up the 2020 excess payments gives us $8.7 billion in the Baa benchmark, or $2.1 billion in the Vermont benchmark. The UK benchmark falls between these, at $4.9 billion.

We also consider how the RoE gap affects capital ownership. Tables 3 and 4 show our regression results for proposed and approved values, respectively. Our preferred specification is column 4, the IV specification, in table 4. These results find that a 1 percentage point increase in the approved RoE gap leads to a 5.2% increase in the increase in approved rate base. These results have a strong first stage (Kleibergen–Paap *F*-stat of 69).

As a caveat, we note that an IOU can increase their capital holdings in two distinct ways. One option is to reshuffle capital ownership, either between subsidiaries or across firms, so that the IOU ends up with more capital on its books, but the total amount of capital is unchanged. The second option is to actually buy and own more capital, increasing the total amount of capital that exists in the state's utility sector. We do not differentiate between these two cases. Because we don't differentiate, we consider excess payments by utility customers, but we remain agnostic about the socially optimal level of capital investment.

6 CONCLUSION

Utilities invest a great deal in capital, and need to be compensated for the opportunity cost of their investments. Getting this rate of return, particularly the return on equity, correct is challenging, but is a first-order important task for state PUCs.

Our analysis shows that the RoE that utilities are allowed to earn has changed dramatically relative to various financial benchmarks in the economy. Across relevant benchmarks, we found that current rates are perhaps 0.5–4 percentage points too high, resulting in $2–8 billion in excess rate collected per year, given the existing ratebase.

We then turned to the Averch–Johnson effect, and estimated the additional capital this RoE gap generates. In our preferred specification, we estimate that an additional percentage point in the RoE gap leads to 5% higher rate base increases.

We hope that policymakers and regulators consider these changes and these benchmarks in future rate making and the role that a wider variety of metrics benchmarks and adjustments can play in utility rate cases. We close by echoing Rode and Fischbeck (2019) and the Vermont PUC. Just as PUCs adopted fuel adjustment clauses in the 1960s and 1970s, RoE adjustment clauses are a tool that would allow rates to automatically adjust to changing market conditions. It would, of course, be possible to change the formula from time to time, but by default, the PUC wouldn't need to, even as the cost of raising capital changes. If such a scheme was implemented, it would be necessary to think hard about the baseline rate. As we demonstrated, the approved RoE has grown over time, so the choice of baseline period is crucial.

Figure 8: Figures 8 and 9 from Rode and Fischbeck (2019), showing CAPM β and market risk premium

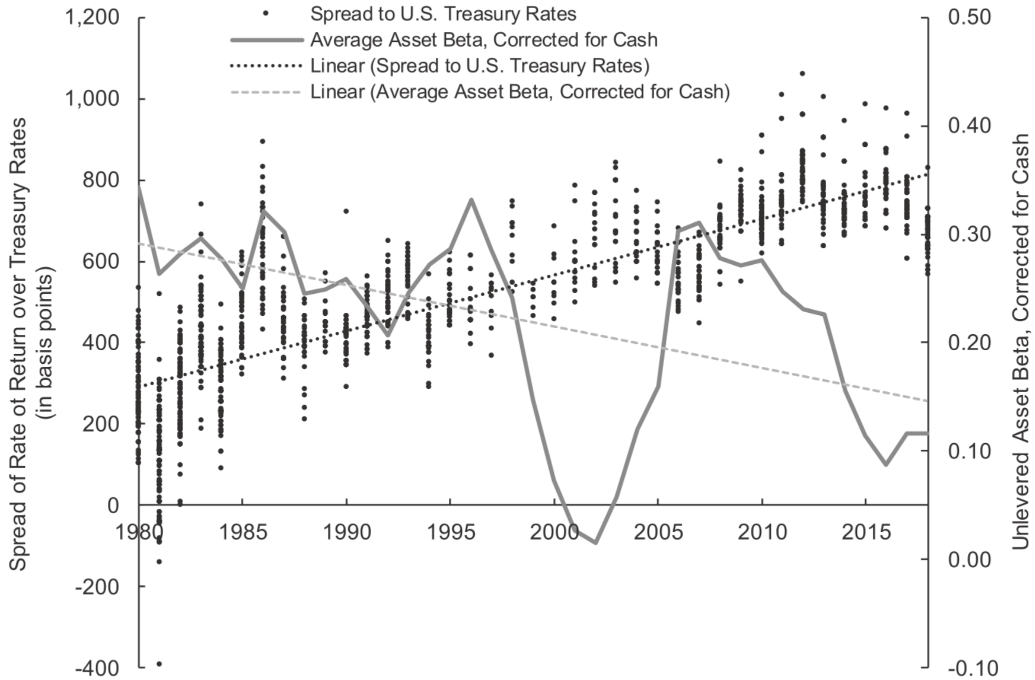


Fig. 8. Authorized return on equity premium vs. industry average asset beta.

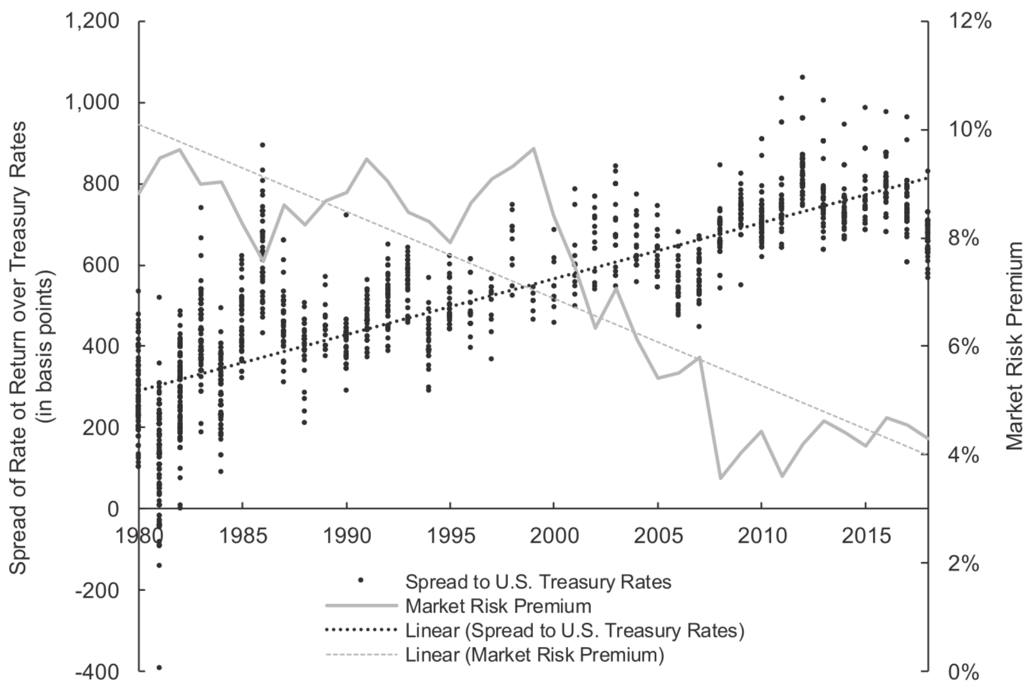


Fig. 9. Authorized rate-of-return premium vs. *ex ante* estimated market risk premium.

Bibliography

Borenstein, Severin, Meredith Fowlie, and James Sallee. 2021. *Designing Electricity Rates for An Equitable Energy Transition.* Technical report 314. February. https://haas.berkeley.edu/wp-content/uploads/WP314.pdf. (Cited on page 73).

Cawley, James H, and Norman J Kennard. 2018. *A Guide to Utility Ratemaking.* Technical report. Pennsylvania Public Utility Commission. https://www.puc.pa.gov/General/publications_reports/pdf/Ratemaking_Guide2018.pdf. (Cited on page 72).

EIA. 2018a. *Major utilities continue to increase spending on U.S. electric distribution systems.* Report, Today In Energy. Energy Information Administration. https://www.eia.gov/todayinenergy/detail.php?id=36675. (Cited on page 70).

———. 2018b. *Utilities continue to increase spending on transmission infrastructure.* Report, Today In Energy. Energy Information Administration. https://www.eia.gov/todayinenergy/detail.php?id=34892. (Cited on page 70).

Farrell, John. 2019. "Power Plant Securitization: Coming to a State Capitol Near You." *Institute for Local Self-Reliance* (May 13, 2019). https://ilsr.org/power-plant-securitization-coming-to-a-state-capitol-near-you/. (Cited on page 73).

Ghadessi, Maryam, and Marzia Zafar. 2017. *An Introduction to Utility Cost of Capital.* Technical report. April 18, 2017. https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Policy_and_Planning/PPD_Work/PPD_Work_Products_(2014_forward)/PPD-An-Introduction-to-Utility-Cost-of-Capital.pdf. (Cited on page 72).

Green Mountain Power: Multi-Year Regulation Plan 2020–2022. 2020. Technical report. September 3, 2020. Accessed March 17, 2021. https://puc.vermont.gov/sites/psbnew/files/doc_library/green-mountain-power-multi-year-regulation-plan.pdf. (Cited on page 81).

Hausman, Catherine. 2019. "Shock Value: Bill Smoothing and Energy Price Pass-Through." *The Journal of Industrial Economics* 67, no. 2 (December 4, 2019): 242–278. https://doi.org/10.1111/joie.12200. (Cited on page 74).

Henbest, Seb, Matthias Kimmel, Jef Callens, Tifenn Brandily, Meredith Annex, Julia Attwood, Melina Bartels, et al. 2020. *New Energy Outlook 2020 Executive Summary.* Technical report. October. Accessed April 1, 2021. https://assets.bbhub.io/professional/sites/24/928908_NEO2020-Executive-Summary.pdf. (Cited on page 70).

Joskow, Paul L. 1972. "The Determination of the Allowed Rate of Return in a Formal Regulatory Hearing." *The Bell Journal of Economics and Management Science* 3 (2): 632–644. https://doi.org/10.2307/3003042. (Cited on page 70).

———. 1974. "Inflation and Environmental Concern: Structural Change in the Process of Public Utility Price Regulation." *The Journal of Law and Economics* 17, no. 2 (October): 291–327. https://doi.org/10.1086/466794. (Cited on page 70).

Rode, David C., and Paul S. Fischbeck. 2019. "Regulated equity returns: A puzzle." *Energy Policy* 133 (October): 110891. https://doi.org/10.1016/j.enpol.2019.110891. (Cited on pages 73, 77, 79, 86, 87).

Salvino, S. M. 1967. "Rate of Return Dilemma of Public Utilities under Rising Cost of Money Conditions." *Financial Analysts Journal* 23 (6): 45–49. http://www.jstor.org/stable/4470243. (Cited on page 73).

Strunk, Kurt G. 2014. *The Decoupling of Treasury Yields and the Cost of Equity for Public Utilities.* Technical report. June 13, 2014. https://www.nera.com/content/dam/nera/publications/archive2/PUB_Equity_Risk_Premium_Utilities_0614(1).pdf. (Cited on page 73).

Werth, Alix Elaine. 1980. "The effects of regulatory policy on the cost of equity capital and the value of equity in the electric utility industry." PhD diss., Massachusetts Institute of Technology. (Cited on page 79).

DATA CITATIONS

Board of Governors of the Federal Reserve System. 2021a. *1-Year Treasury Constant Maturity Rate.* FRED, Federal Reserve Bank of St. Louis, April 1, 2021. Accessed April 7, 2021. https://fred.stlouisfed.org/series/GS1. (Cited on pages 74, 75).

———. 2021b. *10-Year Treasury Constant Maturity Rate.* FRED, Federal Reserve Bank of St. Louis, April 1, 2021. Accessed April 7, 2021. https://fred.stlouisfed.org/series/GS10. (Cited on pages 74, 75).

———. 2021c. *30-Year Treasury Constant Maturity Rate.* FRED, Federal Reserve Bank of St. Louis, April 1, 2021. Accessed April 7, 2021. https://fred.stlouisfed.org/series/GS30. (Cited on pages 74, 75).

Companies (Classic) Screener. 2021. S&P Global Market Intelligence, January. Accessed March 17, 2021. https://platform.marketintelligence.spglobal.com/web/client?auth=inherit#office/screener. (Cited on pages 74, 76).

Compustat S&P legacy credit ratings. 2019. Wharton Research Data Service, October 18, 2019. Accessed March 12, 2021. (Cited on pages 74, 76).

Ice Data Indices, LLC. 2021a. *ICE BofA AA US Corporate Index Effective Yield.* FRED, Federal Reserve Bank of St. Louis, April 6, 2021. Accessed April 7, 2021. https://fred.stlouisfed.org/series/BAMLC0A2CAAEY. (Cited on page 74).

———. 2021b. *ICE BofA AAA US Corporate Index Effective Yield.* FRED, Federal Reserve Bank of St. Louis, April 6, 2021. Accessed April 7, 2021. https://fred.stlouisfed.org/series/BAMLC0A1CAAAEY. (Cited on page 74).

———. 2021c. *ICE BofA BB US High Yield Index Effective Yield.* FRED, Federal Reserve Bank of St. Louis, April 6, 2021. Accessed April 7, 2021. https://fred.stlouisfed.org/series/BAMLH0A1HYBBEY. (Cited on page 74).

———. 2021d. *ICE BofA BBB US Corporate Index Effective Yield.* FRED, Federal Reserve Bank of St. Louis, April 6, 2021. Accessed April 7, 2021. https://fred.stlouisfed.org/series/BAMLC0A4CBBBEY. (Cited on page 74).

———. 2021e. *ICE BofA CCC & Lower US High Yield Index Effective Yield.* FRED, Federal Reserve Bank of St. Louis, April 6, 2021. Accessed April 7, 2021. https://fred.stlouisfed.org/series/BAMLH0A3HYCEY. (Cited on page 74).

———. 2021f. *ICE BofA Single-A US Corporate Index Effective Yield.* FRED, Federal Reserve Bank of St. Louis, April 6, 2021. Accessed April 7, 2021. https://fred.stlouisfed.org/series/BAMLC0A3CAEY. (Cited on page 74).

Ice Data Indices, LLC. 2021g. *ICE BofA Single-B US High Yield Index Effective Yield.* FRED, Federal Reserve Bank of St. Louis, April 6, 2021. Accessed April 7, 2021. https://fred.stlouisfed.org/series/BAMLH0A2HYBEY. (Cited on page 74).

Moody's. 2021a. *Moody's Seasoned Aaa Corporate Bond Yield.* FRED, Federal Reserve Bank of St. Louis, April 1, 2021. Accessed April 7, 2021. https://fred.stlouisfed.org/series/AAA. (Cited on pages 74, 75).

———. 2021b. *Moody's Seasoned Baa Corporate Bond Yield.* FRED, Federal Reserve Bank of St. Louis, April 1, 2021. Accessed April 7, 2021. https://fred.stlouisfed.org/series/BAA. (Cited on pages 74, 75).

Regulatory Research Associates. 2021. *Rate Case History.* S&P Global Market Intelligence, March. Accessed March 18, 2021. https://platform.marketintelligence.spglobal.com/web/client?auth=inherit#industry/pastRateCases?Type=1. (Cited on pages 70, 74, 75, 77, 78).

US Bureau of Labor Statistics. 2021. *Consumer Price Index for All Urban Consumers: All Items in U.S. City Average.* FRED, Federal Reserve Bank of St. Louis, March 10, 2021. Accessed April 7, 2021. https://fred.stlouisfed.org/series/CPIAUCSL. (Cited on pages 74, 75).

US Energy Information Administration. 2020a. *2019 Utility Bundled Retail Sales – Total.* October 2, 2020. Accessed April 28, 2021. https://www.eia.gov/electricity/sales_revenue_price/xls/table10.xlsx. (Cited on page 71).

———. 2020b. *Summary Statistics for Natural Gas in the United States, 2015–2019.* September 30, 2020. Accessed April 28, 2020. https://www.eia.gov/naturalgas/annual/csv/t2019_01.csv. (Cited on page 71).

SOFTWARE CITATIONS

Bache, Stefan Milton, and Hadley Wickham. 2020. *magrittr: A Forward-Pipe Operator for R.* 2.0.1. https://cran.r-project.org/package=magrittr.

Dowle, Matt, and Arun Srinivasan. 2021. *data.table: Extension of 'data.frame'.* 1.14.0. https://cran.r-project.org/package=data.table.

Fabri, Antoine. 2020. *safejoin: Join safely and Deal with Conflicting Columns.* 0.1.0. August 19, 2020.

François, Romain, Jeroen Ooms, Neal Richardson, and Apache Arrow. 2021. *arrow: Integration to 'Apache' 'Arrow'.* 3.0.0. https://cran.r-project.org/package=arrow.

Gaure, Simen. 2013. "lfe: Linear group fixed effects." User documentation of the 'lfe' package, *The R Journal* 5, no. 2 (December): 104–117. https://journal.r-project.org/archive/2013/RJ-2013-031/RJ-2013-031.pdf.

Grolemund, Garrett, and Hadley Wickham. 2011. "Dates and Times Made Easy with lubridate." *Journal of Statistical Software* 40 (3): 1–25. https://www.jstatsoft.org/v40/i03/.

Henry, Lionel, and Hadley Wickham. 2020a. *purrr: Functional Programming Tools.* 0.3.4. https://cran.r-project.org/package=purrr.

———. 2020b. *rlang: Functions for Base Types and Core R and 'Tidyverse' Features.* 0.4.10. https://cran.r-project.org/package=rlang.

———. 2020c. *tidyselect: Select from a Set of Strings.* 1.1.0. https://cran.r-project.org/package=tidyselect.

Hester, Jim. 2020. *glue: Interpreted String Literals.* 1.4.2. https://cran.r-project.org/package=glue.

Iannone, Richard, Joe Cheng, and Barret Schloerke. 2020. *gt: Easily Create Presentation-Ready Display Tables.* 0.2.2. https://cran.r-project.org/package=gt.

Köster, Johannes, and Sven Rahmann. 2018. "Snakemake—a scalable bioinformatics workflow engine." *Bioinformatics* 34, no. 20 (May): 3600–3600. https://doi.org/10.1093/bioinformatics/bty350.

Kuhn, Max. 2020. *caret: Classification and Regression Training.* 6.0-86. https://cran.r-project.org/package=caret.

Microsoft Corporation and Steve Weston. 2020. *doParallel: Foreach Parallel Adaptor for the 'parallel' Package.* 1.0.16. https://cran.r-project.org/package=doParallel.

Müller, Kirill. 2020. *here: A Simpler Way to Find Your Files.* 1.0.1. https://cran.r-project.org/package=here.

Müller, Kirill, and Hadley Wickham. 2021. *tibble: Simple Data Frames.* 3.1.0. https://cran.r-project.org/package=tibble.

Neuwirth, Erich. 2014. *RColorBrewer: ColorBrewer Palettes.* 1.1-2. https://cran.r-project.org/package=RColorBrewer.

Ooms, Jeroen. 2019. *curl: A Modern and Flexible Web Client for R.* 4.3. https://cran.r-project.org/package=curl.

Pebesma, Edzer. 2018. "Simple Features for R: Standardized Support for Spatial Vector Data." *The R Journal* 10 (1): 439–446. https://doi.org/10.32614/RJ-2018-009. https://doi.org/10.32614/RJ-2018-009.

R Core Team. 2020. *R: A Language and Environment for Statistical Computing.* 4.0.3. Vienna, Austria: R Foundation for Statistical Computing. https://www.r-project.org/.

Robinson, David, Alex Hayes, and Simon Couch. 2021. *broom: Convert Statistical Objects into Tidy Tibbles.* 0.7.5. https://cran.r-project.org/package=broom.

Teetor, Nathan. 2018. *zeallot: Multiple, Unpacking, and Destructuring Assignment.* 0.1.0. https://cran.r-project.org/package=zeallot.

Ushey, Kevin. 2021. *renv: Project Environments.* 0.13.0. https://cran.r-project.org/package=renv.

Wickham, Hadley. 2016. *ggplot2: Elegant Graphics for Data Analysis.* Springer-Verlag New York. https://ggplot2.tidyverse.org.

———. 2019. *stringr: Simple, Consistent Wrappers for Common String Operations.* 1.4.0. https://cran.r-project.org/package=stringr.

———. 2020. *tidyr: Tidy Messy Data.* 1.1.2. https://cran.r-project.org/package=tidyr.

Wickham, Hadley, Mara Averick, Jennifer Bryan, Winston Chang, Lucy D'Agostino McGowan, Romain François, Garrett Grolemund, et al. 2019. "Welcome to the tidyverse." *Journal of Open Source Software* 4 (43): 1686. https://doi.org/10.21105/joss.01686.

Wickham, Hadley, and Jennifer Bryan. 2019. *readxl: Read Excel Files.* 1.3.1. https://cran.r-project.org/package=readxl.

Wickham, Hadley, Romain François, Lionel Henry, and Kirill Müller. 2021. *dplyr: A Grammar of Data Manipulation.* 1.0.4. https://cran.r-project.org/package=dplyr.

Wickham, Hadley, and Jim Hester. 2020. *readr: Read Rectangular Text Data.* 1.4.0. https://cran.r-project.org/package=readr.

Wickham, Hadley, Jim Hester, Winston Chang, Kirill Müller, and Daniel Cook. 2021. *memoise: Memoisation of Functions.* 2.0.0. https://cran.r-project.org/package=memoise.

Zeileis, Achim, and Gabor Grothendieck. 2005. "zoo: S3 Infrastructure for Regular and Irregular Time Series." *Journal of Statistical Software* 14 (6): 1–27. https://doi.org/10.18637/jss.v014.i06.

Conclusion

These three papers cover a variety of topics in applied environmental economics. The first chapter addresses methane emissions from oil and gas wells, and considers the potential gains from policies that target these emissions. These gains could be large, but depend a great deal on the information the regulator has available and the details of the policy they enact. The second chapter considers the loss in value caused by flooding on agricultural land, examining losses over a wide range of flood frequencies. We contextualize these results in a world with changing climate, as properties that now flood occasionally are expected to flood more frequently in the future. The third chapter focuses on the rates of return utility companies are allowed to earn. These rates determine the profitability of investing in capital, the rates customers pay, and the amount of capital the utilities end up owning. All three of these chapters investigate policy-relevant economic topics, and all three use applied econometric tools to bring data to the question.

Energy Policy 133 (2019) 110891

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

Regulated equity returns: A puzzle

David C. Rode[a,*], Paul S. Fischbeck[a,b]

[a] Department of Social and Decision Sciences, Carnegie Mellon University, Pittsburgh, PA, 15213, USA
[b] Department of Engineering and Public Policy, Carnegie Mellon University, Pittsburgh, PA, 15213, USA

ARTICLE INFO

Keywords:
Discount rate
Electric utility
Rate of return regulation
Valuation

ABSTRACT

Based on a database of U.S. electric utility rate cases spanning nearly four decades, the returns on equity authorized by regulators have exhibited a large and growing premium over the riskless rate of return. This growing premium does not appear to be explained by traditional asset-pricing models, often in direct contrast to regulators' stated intent. We suggest possible alternative explanations drawn from finance, public policy, public choice, and the behavioral economics literature. However, absent some normative justification for this premium, it would appear that regulators are authorizing excessive returns on equity to utility investors and that these excess returns translate into tangible profits for utility firms.

1. Introduction

In economics, the equity-premium puzzle refers to the empirical phenomenon that returns on a diversified equity portfolio have exceeded the riskless rate of return on average by more than can be explained by traditional models of compensation for bearing risk. Since Mehra and Prescott's (1985) initial paper on the subject, a large body of research has attempted to explain away the puzzle, but without much success (Mehra and Prescott, 2003). The most likely explanations for the premium appear to reside outside of classical equilibrium models. We call the reader's attention to the Mehra-Prescott puzzle as a means of introducing our instant problem, of which it may be considered an applied case. Simply put: why are the equity returns authorized by electric utility regulators so high, given that riskless rates are so low?

Our scope is as follows. We employ a much larger dataset than has previously been examined in the literature and seek to explain the rates of return *authorized* by state electric utility regulators. We investigate the extent to which the actual returns authorized can be explained by the Capital Asset Pricing Model (CAPM), which regulators (and others) purport to use. We also examine whether the CAPM is capable of explaining the clear trend of rising risk premiums present over the last four decades in electric utility rate cases.

While previous studies have investigated rates of return for regulated electric utilities, the majority of this work has either examined *actual* rates of return to utility stockholders, relied on very limited samples of rate cases, or tested a variety of hypotheses connecting utility earnings to various structural and institutional factors. Table 1 summarizes the previous literature most similar to our study. By contrast, our study employs a far larger sample of rate cases (1,596) than previously examined in the literature. In addition, our focus on authorized rates of return highlights the impact of regulatory rate-setting on consumers, as opposed to stockholders, to the extent that authorized rates are used to set utility revenue requirements, while earned returns accrue to stockholders. This setting also enables us to analyze rate-setting in the context of regulatory decision-making. Actual rates of return earned by utilities can differ from the rates of return authorized by regulators due to factors such as the impact of weather on demand, but primarily due to the operational performance of a utility, including its ability to operate efficiently and control costs to those approved by regulators.

This regulated equity return puzzle is important not just from a theoretical asset-pricing perspective, but also for very practical reasons. The database used in this study reflects more than \$3.3 trillion (in 2018 dollars) in cumulative rate-base exposure.[1] An error or bias of merely one percentage point in the allowed return would imply tens of billions of dollars in additional cost for ratepayers in the form of higher retail power prices and could play a profound role in the allocation of investment capital. Coupled with utilities' tendencies toward excessive capital accumulation under rate regulation (Averch and Johnson, 1962; Spann, 1974; Courville, 1974; Hayashi and Trapani, 1976; Vitaliano

* Corresponding author.
E-mail addresses: rode@andrew.cmu.edu (D.C. Rode), fischbeck@cmu.edu (P.S. Fischbeck).

[1] This figure reflects the simple cumulative sum of authorized rate bases across all cases. Because rate-base decisions may remain in place for several years, this sum most likely underestimates the actual figure, which should be the authorized rate base in each year examined, whether or not a new case was decided. We cite this figure merely as evidence of the substantial magnitude of the costs at stake.

https://doi.org/10.1016/j.enpol.2019.110891
Received 22 January 2019; Received in revised form 18 July 2019; Accepted 19 July 2019
Available online 25 July 2019
0301-4215/

Table 1
Previous studies of the determinants of electric utility rates of return.

Study	Sample	Description
Joskow (1972)	20 cases in New York between 1960 and 1970	Only capital markets parameter included was cost of debt. Focused on the requested rate of return.
Joskow (1974)	174 cases between 1958 and 1972	No CAPM parameters tested. Regulators tended to ignoring overearning as long as prices were falling.
Hagerman and Ratchford (1978)	79 survey responses from utilities about their last rate case	Used authorized rates. Found positive coefficients related to beta and the debt/equity ratio.
Roberts et al. (1978)	59 cases from 4 Florida utilities between 1960 and 1976	No CAPM parameters tested. Only structural factors examined.
Roll and Ross (1983)	Utility stock returns between 1925 and 1980	No authorized returns used. CAPM underestimates returns relative to the APT.
Pettway and Jordan (1987)	58 electric service companies between 1969 and 1976	Used stockholder returns only.
Binder and Norton (1999)	92 firms	Used stockholder returns to estimate beta. Suggested that regulation causes cash flow "buffering" and that firms may be underearning.
PJM Interconnection (2016)	22 regulated firms between 2000 and 2015	Examined stockholder returns and found regulated firms had positive alpha.
Haug and Wieshammer (2019)	N/A	Regulators in continental Europe "uniformly adopt the [CAPM]" and courts have ruled that the authorized rates are too low. The opposite finding to our study.

and Stella, 2009), the magnitude of the problem makes it incumbent on the industry and regulators to get it right.

There are also policy implications for market design and regulation. A recent PJM Interconnection (2016) study compared and contrasted entry and exit decisions in competitive and regulated markets to evaluate the efficiency of competitive markets for power. One finding that emerged from the study was that regulated utilities appeared to be "overearning" and had generated positive alpha, while competitive firms had not generated positive alpha.[2] Although the study used a limited time window of rate case data and focused on utility stock returns, not returns authorized by regulators, its findings are consistent with those we explore in more detail here.

As an old joke goes, an economist is someone who sees something work in practice and asks whether it can work in theory. Undoubtedly, the utility sector has been successful in attracting capital over the past four decades. We cannot necessarily say, however, that had returns been consistent with the dominant theoretical model used (and thus lower), this would still have been the case. Accordingly, this article also raises the question of whether our theoretical models of required return and asset pricing must be refined. Or, at the very least, whether there are important considerations that must be accounted for in the application of those models to the regulated electric utility industry.

In this article, therefore, we examine the historical data on authorized rates of return on equity in U.S. electric utility rate cases. We compare these rates of return to several conventional benchmarks and the classical theoretical asset-pricing model. We demonstrate that the spread between authorized equity returns (and also earned equity returns) and the riskless rate has grown steadily over time. We investigate whether this growing spread can be explained by classical asset-pricing parameters and conclude that it cannot. We then evaluate possible explanations outside of classical finance to suggest fruitful paths for future research. Specifically, we investigate whether the addition of variables for commission selection and case adjudication contribute explanatory power, in line with existing theories in the pubic choice literature. We conclude with a discussion of the policy implications of the observed premiums and how regulatory rate-setting could be adjusted to mitigate higher premiums.

Section 2 reviews the legal, regulatory, and financial foundations of rate of return determination for utilities. Section 3 describes the data used in our analysis and defines the risk premium on which our analysis is based. Section 4 presents the results of our analysis and outlines the various factors explored, including both classical financial factors and factors outside of the classical paradigm. Section 5 highlights the policy implications of our research, suggests potential mitigating strategies, and concludes.

2. Regulated equity returns and the Capital Asset Pricing Model

At the outset, let us make clear that we are addressing only *regulated* rates of return on equity in this article. We draw no conclusions or inferences about the behavior of returns on non-regulated assets. Our focus is limited to regulated returns because in such cases it is regulators who are tasked with standing in for the discipline of a competitive market and ensuring that returns are just and reasonable. For more than a century, U.S. courts have ruled consistently in support of this objective, while recognizing that achieving it requires consideration of numerous factors that are subject to change over time. The task set to regulators, then, is to approximate what a competitive market would provide, *if one existed.*

Mindful of this mandate, two U.S. Supreme Court decisions are commonly thought to provide the conceptual foundation for utility rate-of-return regulation. In *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia* (262 U.S. 679 (1923)), the Court identified eight factors that were to be considered in determining a fair rate of return, ruling that "[t]he return should be reasonable, sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economic management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties." This position was made more concrete in *Federal Power Commission v. Hope Natural Gas Company* (320 U.S. 591 (1944)), wherein the Court ruled that the "return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."

In both *Bluefield* and *Hope*, the Court sought to balance the need for utilities to attract capital sufficient to discharge their duties with the need for regulators to protect ratepayers from what would otherwise be rent-seeking monopolists. These efforts in determining "just and reasonable" returns received significant assistance in the 1960s when groundbreaking advances in asset-pricing theory were made in finance. Specifically, the development of the Capital Asset Pricing Model (CAPM) (Sharpe, 1964; Lintner, 1965; Mossin, 1966) provided a rigorous framework within which the question of the appropriate rate of return could be addressed in an objective fashion. The security market line representation of the CAPM [1] set out the equilibrium rate of return on equity, r_E, as the sum of the rate of return on a riskless asset,

[2] In asset pricing models, positive alpha is evidence of non-equilibrium returns, meaning that investors are receiving compensation in excess of what would be required for bearing the risks they have assumed.

r_f, and a premium related to the level of risk being assumed that was defined in relation (through the factor β) to the expected excess rate of return on the overall market for capital, r_m.

$$r_E = r_f + \beta(r_m - r_f) \quad (1)$$

It is outside of the scope of this paper to delve too deeply into the foundations of asset pricing. We note, also, that the CAPM methodology is not the sole candidate for rate-of-return determination in utility rate cases. Morin (2006, p. 13) identifies four main approaches used in the determination of the "fair return to the equity holder of a public utility's common stock," of which the CAPM is but one.[3] Nevertheless, the concept of the appropriate rate of return on equity being a combination of a riskless rate of return and a premium for risk-bearing has since become widely accepted as a means of determining the appropriate authorized return on equity in state-level utility rate cases (Phillips, 1993, pp. 394–400). In contrast, the Federal Energy Regulatory Commission relies exclusively on the DCF approach, which is also common with natural gas utilities. For electric utilities, however, the CAPM in particular is seen as the "preferred" (Myers, 1972; Roll and Ross, 1983, p.22) and "most widely used" (Villadsen et al., 2017, p. 51) method in regulatory proceedings. Multi-factor approaches such as Arbitrage Pricing Theory (APT) (Ross, 1976) and the Fama and French (1993) framework are used with significantly less frequency in practice (Villadsen et al., 2017, p. 206). In other words, our focus on the CAPM is not solely because of its perceived normative status, but also because it is the method most regulators *say they are using.*

In *Hope,* however, the Court also advocated the "end results doctrine," acknowledging that regulatory methods were (legally) immaterial so long as the end result was reasonable to the consumer and investor. In other words, there was no single formula for determining rates. A typical example of the latitude granted by the doctrine is found in Pennsylvania Public Utility Commission (2016, p. 17): "The Commission determines the [return on equity] based on the range of reasonableness from the DCF barometer group data, CAPM data, recent [returns on equity] adjudicated by the Commission, and **informed judgment** [emphasis added]." Rate determination in practice is often not simply a matter of arithmetic; rather, it is an act of judgment performed by regulators. As a result, our investigation examines not just the relation of authorized rates to those implied by the CAPM, but also the potential for that relationship to be influenced by regulator judgment.

Before we turn to the data, however, let us dispense with an alternate formulation of the underlying question. In questioning the size of the premium and why equity returns are so high, one might also ask instead why the riskless rate is so low. Indeed, Mehra and Prescott (1985) ask this very question, before dismissing it on theoretical grounds. We revisit this question in light of recent data and ask whether the premium during the period in question is more a function of riskless rates being forced down by the Federal Reserve's intervention, than of equity premiums increasing (since the manifest intent of quantitative easing was to lower riskless rates).[4] Our historical data, as Section 3 indicates, do not support that hypothesis. The premium growth has persisted since the beginning of our data series in 1980 and has persisted across a variety of monetary and fiscal policy regimes.

3. Regulated electric utility returns on equity, 1980–2018

3.1. Historical authorized return on equity data

The data used in this study were collected and maintained by Regulatory Research Associates (RRA), a unit of S&P Global. The RRA database is comprehensive. It contains every electric utility rate case in the United States since 1980 in which the utility has requested a rate change of at least \$5 million or a regulator has authorized a rate change of at least \$3 million. Our study comprises the period from 1980 through 2018. Table 2 illustrates the bridge from the RRA rate-case population to the rate-case sample used in our analyses. We examined the returns on equity authorized by the regulatory agencies, *not* the returns requested by the utilities.[5] The sample we use in this paper contains 79% of the RRA universe, but 97% of the rate cases in which a rate of return on equity was authorized by a state regulator.

Nearly all fifty states and Washington D.C. are represented in the data set.[6] Thirty-two electric utility rate cases satisfying the qualifications listed above were filed in the average state over the past thirty-eight years, with the most being filed in Wisconsin (120) and the fewest being filed in Tennessee (3), Alaska (2), and Alabama (1). The frequency of filing in a state does not appear to have any relationship to premium growth. The average risk premium has grown in both the ten states that completed the most rate cases and the ten states that completed the fewest rate cases and has grown at very similar rates (see Fig. 1). In fact, as Fig. 2 illustrates, the general trend across all states is similar.

In the early 1980s there were over 100 rate cases filed each year. By the late 1990s, in the midst of widespread deregulation of the electric power industry, the number of filings reached its lowest point (with six in 1999). Since then, filing frequency has increased to an average of forty-eight per year over the last three years (see Fig. 3). The decline in rate case activity in many instances was the direct result of rate moratoria related to the transition to competitive markets in the late 1990s, as well as to moratorium-like concessions made to regulators related to merger approvals over the last decade. Many of these moratoria will expire over the next two years, suggesting a new increase in rate case activity is likely. Finally, no individual utility had an outsized influence on the sample. One hundred forty-four different companies filed rate cases, but many have since merged or otherwise stopped filing.[7] The average firm filed eleven rate cases in our sample. Within our sample the most frequently-filing entity was PacifiCorp, which filed seventy-three rate cases, or less than 5% of the sample.

3.2. Calculating the regulated equity premium

Regulated equity returns are generally equal to the sum of the riskless rate of return and a premium for risk-bearing. In the CAPM, the premium for risk-bearing is given by $\beta(r_m - r_f)$, where β is the utility's

[3] The other three approaches identified by Morin (2006) are: Risk Premium (which is an attempt to estimate empirically what the CAPM derives theoretically), Discounted Cash Flows (or "DCF," which is a dividend capitalization model), and Comparable Earnings (which is an empirical approach to deriving cost of capital from market comparables based on *Hope*).

[4] This has also been an ongoing issue of contention in recent regulatory proceedings. In Opinion 531-B (Federal Energy Regulatory Commission, March 3, 2015, 150 FERC 61,165), the Federal Energy Regulatory Commission (FERC) found that "anomalous capital market conditions" caused the traditional discount rate determination methods not to satisfy the *Hope* and *Bluefield* requirements (150 FERC 61,165 at 7). But in a related decision only eighteen months later (Federal Energy Regulatory Commission, September 20, 2016, 156 FERC 61,198), FERC acknowledged that expert witnesses disagreed as to whether any market conditions were, in fact, "anomalous" (156 FERC 61,198 at 10).

[5] To be clear, we refer to the rates set by regulators as the "authorized" rates. These may be contrasted with utilities' "requested" rates and also with the "earned" rates of return actually realized by utilities. Regulatory *authorization* of a rate is not a guarantee that a utility will actually *earn* such a rate. We address this issue in further detail in Section 4.5.

[6] Only Nebraska did not have a reported rate case meeting the parameters of the data set. Nebraska is unique in that it is the only state served entirely by consumer-owned entities (e.g., cooperatives, municipal power districts) and therefore absent a profit motive it does not have the same adversarial regulatory system as all other states.

[7] The level of analysis is at the regulated utility level. We recognize that many holding companies have multiple ring-fenced regulated utility subsidiaries.

Table 2
Bridge illustrating how our sample is constructed from the RRA electric utility rate case population data.

Number of cases	Percent of cases	Description
2033	100.0%	All electric utility rate cases 1980–2018 in which utility has requested a rate change of at least $5 million or a regulator has authorized a rate change of at least $3 million.
−19	−0.9%	Rate cases with final adjudication (i.e., fully-litigated or settled) still pending as of December 31, 2018, are excluded
−369	−18.2%	Rate cases with no return on equity determination are excluded
−30	−1.5%	Rate cases with no capital structure determination are excluded
−19	−0.9%	Rate cases with authorized rates lower than the then-prevailing riskless rate are excluded
1596	79.0%	Rate cases used in our analysis

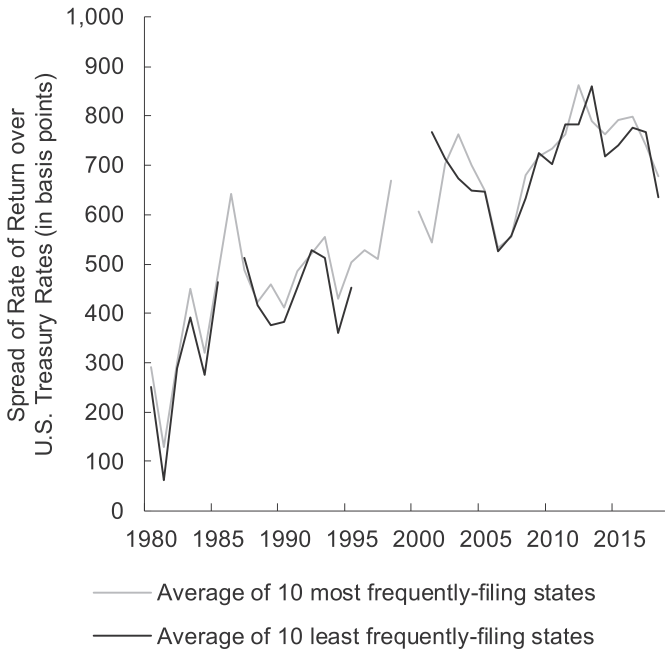


Fig. 1. Risk-premium growth by frequency of case filing. Gaps in the series reflect years in which no rate cases were filed for the subject group. The risk premium is calculated as $r_E - r_f$, or the excess of the authorized return on equity over the then-current riskless rate.

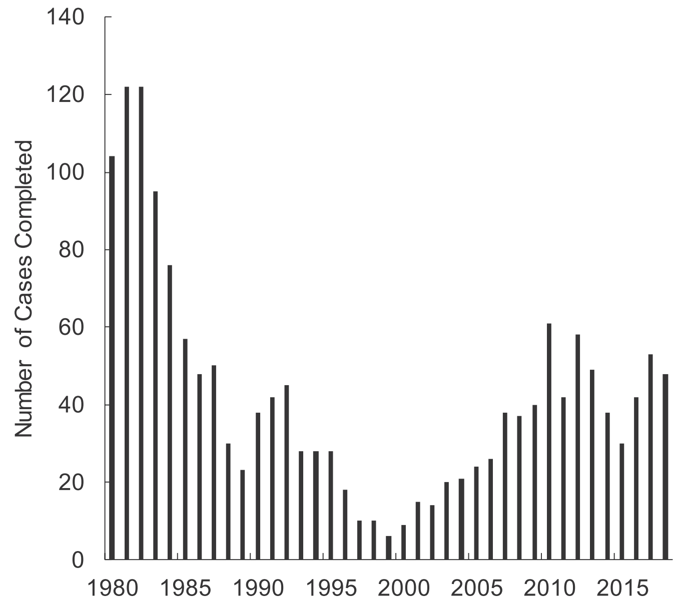


Fig. 3. Number of electric utility rate cases finalized by year.

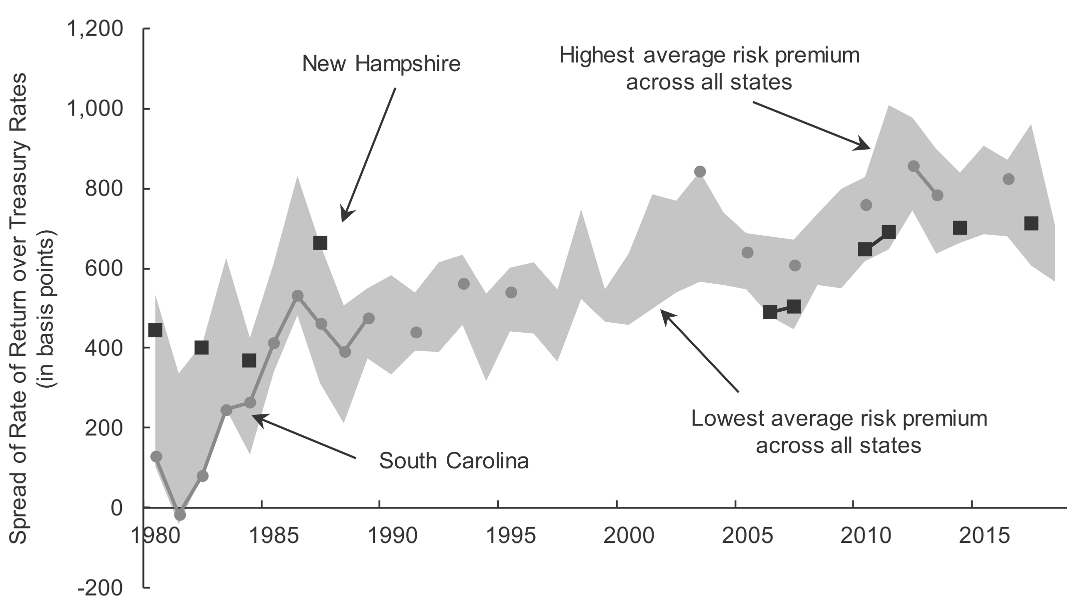


Fig. 2. Range of risk-premium growth across states. States with highest (New Hampshire) and lowest (South Carolina) rates of risk-premium growth over the period (among states with at least five rate cases) are highlighted.

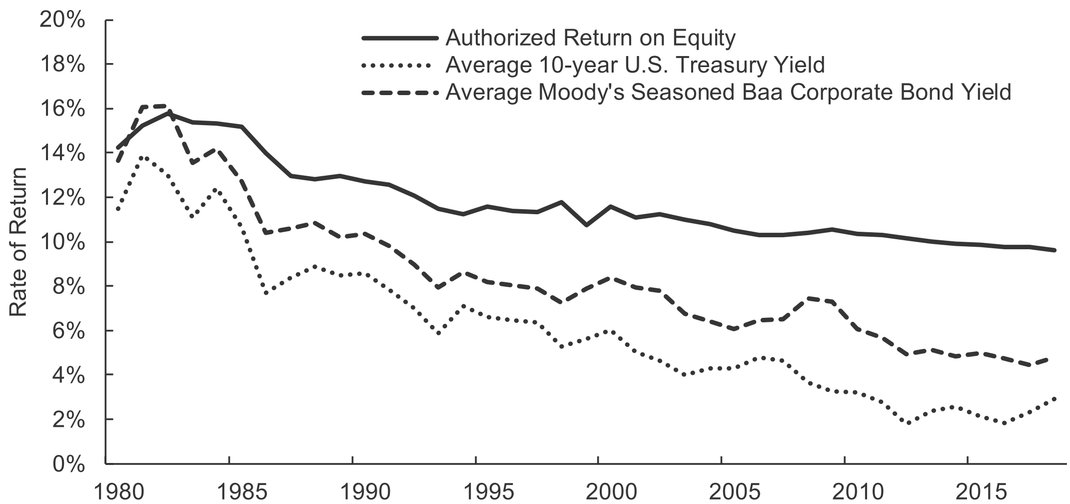


Fig. 4. Annual average authorized return on equity vs. U.S. Treasury and investment grade corporate bond rates.

equity beta. Rearranging the security market line equation [1], we define the regulated equity premium as $r_E - r_f = \beta(r_m - r_f)$. Presented thus, we first note that the existence of a (positive) regulated equity premium is not, by itself, evidence of irrational investor behavior or model failure. Neither is the existence of a growing regulated equity premium. We take no position here on what the "correct" premium should be in any instance. Rather, we shall be content in this article simply to determine whether or not the behavior of the risk premium in practice is consistent with financial theory.

On average, the authorized return on equity is 5.1% (standard deviation = 2.2%) higher than the riskless rate. Fig. 4 illustrates the average authorized return on equity over the period against the average annual riskless rate and investment-grade corporate bond rate.[8] For avoidance of doubt, we note that only the U.S. Treasury note rate should be considered the riskless rate. We include corporate bond rates solely to assess whether the trend in riskless rates is materially different from the trend in risky debt.

While the regulated equity premium has averaged 510 basis points across the entire time period, in 1980 the average premium was only 277 basis points, whereas in 2018 it averaged 668 basis points. Fig. 5 shows the difference between the authorized return on equity and the riskless rate for each case in the data over the past thirty-eight years. Although the premium is determined against the riskless rate of return (represented here as the yield on a 10-year U.S. Treasury note), we also present for comparison the spreads determined against the yield on the Moody's Seasoned Baa Corporate Bond Index to illustrate that the effect is not an artifact of recent monetary policy on Treasury rates. The trends of the two series are quite similar (and both have statistically-significant positive slopes); accordingly, we shall present only the Treasury rate-determined premiums throughout the remainder of this paper.

Given that a large and growing regulated equity premium exists, our question is whether or not it can be explained within an equilibrium asset-pricing framework such as the CAPM. If β were to have increased during the time period in question, for example, the growth of the regulated equity premium may well be explained by the increasing (relative) riskiness of utility equity. As Section 4 demonstrates, however, in fact it cannot.

[8] We used the 10-year constant maturity U.S. Treasury note yield as a proxy for the riskless rate and the yield on the Moody's Seasoned Baa Corporate Bond Index as a proxy for investment-grade corporate bond rates. Both series were obtained from the Federal Reserve's FRED database (Board of Governors of the Federal Reserve System, n.d.-a; n.d.-b).

4. Potential explanations for the premium

Having demonstrated the existence of a large and growing regulated equity premium, we investigate various potential explanations. As we indicated above, we proceed with our investigation of explanations for the premium via the Capital Asset Pricing Model. The CAPM allows three basic mechanisms of action for a change in the risk premium: (i) the manner in which the underlying assets are financed has changed, (ii) the risk of the underlying assets themselves has changed, and/or (iii) the rate at which the market in general prices risk has changed. We explore each in turn and formally test whether the trend in the data can be explained by the CAPM. Finding that it cannot, we then turn to theoretical explanations outside of the CAPM. The potential alternative explanations in Sections 4.5 through 4.7 all represent viable paths for further research.

4.1. Capital structure effects

As corporate leverage increases, the underlying equity becomes riskier and thus deserving of higher expected returns. In finance, the Hamada equation decomposes the CAPM equity beta (β) into an underlying asset beta (β_A) and the impact of capital structure (Hamada, 1969, 1972). Specifically, the Hamada equation states that $\beta = \beta_A\left[1 + (1-\tau)\frac{D}{E}\right]$, where τ is the tax rate and D and E are the debt and equity in the firm's capital structure, respectively. We use the marginal corporate federal income tax rate for the highest bracket, as provided in Internal Revenue Service (n.d.).

One explanation for a growing risk premium would be steadily increasing leverage among regulated utilities. However, regulators also generally approve of specific capital structures as part of the rate-making process. As a result, our database also contains the authorized capital structures for each utility.[9] In fact, utilities are *less* leveraged today than they were in 1980. The average debt-to-equity ratio in the first five years of the data set (1980–1984) was 1.74; in 2014–2018 it was 1.05. More generally, we can observe the impact of leverage

[9] To be clear, the authorized capital structures evaluated here apply to the regulated utility subsidiaries, and not necessarily to any holding companies to which they belong. The holding companies themselves may utilize more or less leverage, but typically the regulated utility subsidiaries are "ring-fenced" so as to isolate them from holding company-level risks. Similarly, rate-of-return regulation would apply only to the regulated subsidiaries, not to the parent holding company. As a result, the capitalization of the regulated entity (studied here) is often different from the capitalization of the publicly-traded entity that owns it.

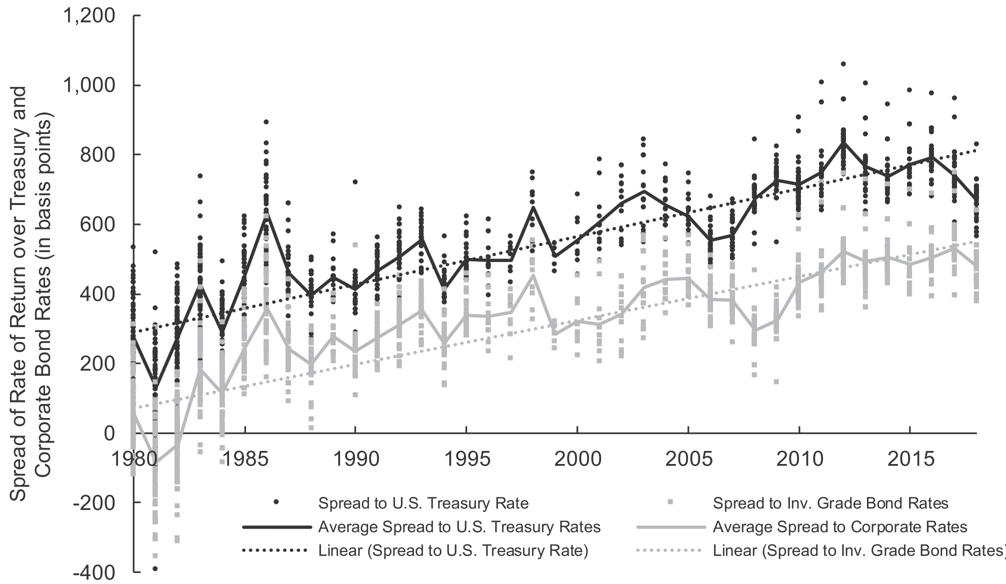


Fig. 5. Authorized return on equity premium, 1980–2018.

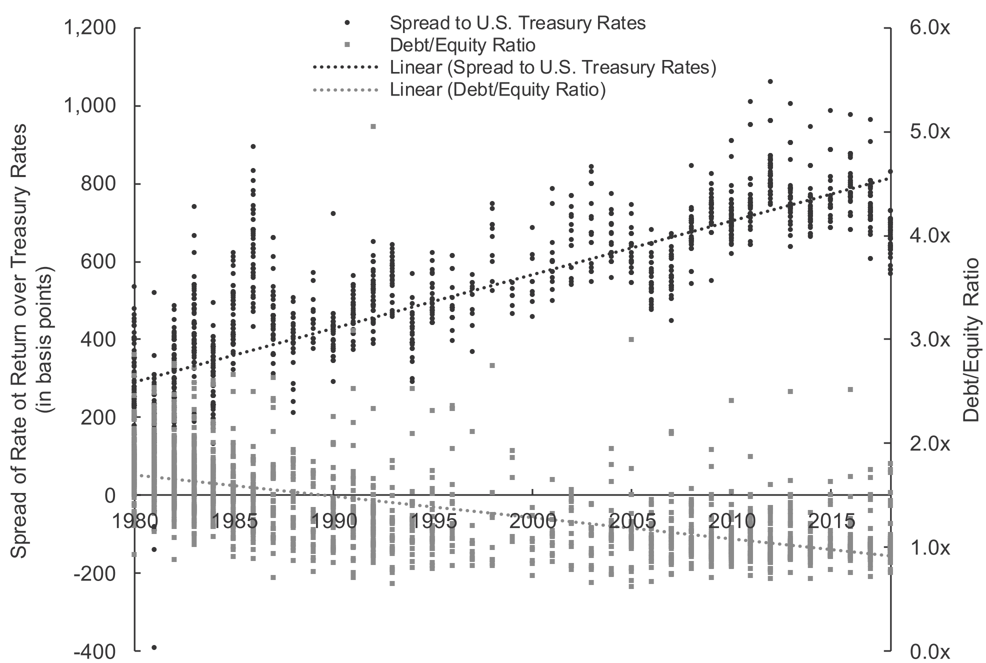


Fig. 6. Authorized return on equity premium vs. utility leverage.

moving in the opposite direction of what one may expect, whether we examine the debt-to-equity ratio exclusively or the Hamada capital structure parameter (i.e., the portion of the Hamada equation multiplied by β_A, or $\left[1 + (1 - \tau)\frac{D}{E}\right]$) in its entirety. Figs. 6 and 7 illustrate these results. As a result, it does not appear as if capital structure itself can explain the behavior of the risk premium.

4.2. Asset-specific risk

As noted above, the Hamada equation decomposes returns into compensation for bearing asset-specific risks and for bearing capital structure-specific risks. Even if a firm's capital structure remains unchanged, the riskiness of its underlying assets may change. This risk is represented by the unlevered asset beta, β_A. An increase in the asset beta applicable to such investments would, all else held equal, justify an increase in the risk premium.

To examine such a hypothesis, we used the fifteen members of the Dow Jones Utility Average between 1980 and 2018 as a proxy for "utility asset risk." We estimated five-year equity betas for each firm by regression of their monthly total returns against the total return on the S&P 500 index.[10] The equity betas calculated were then converted to

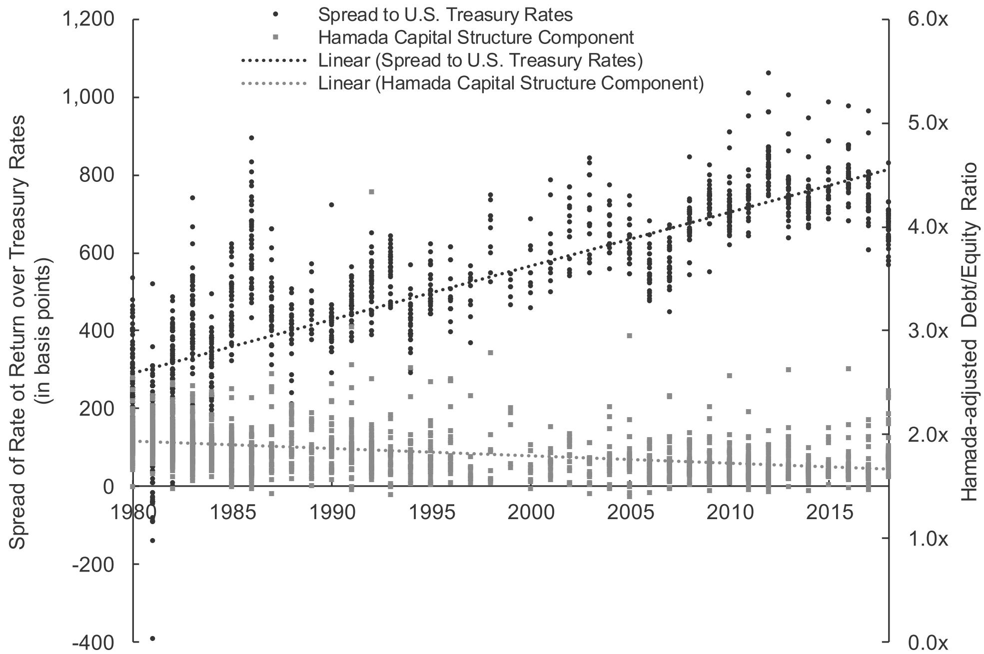


Fig. 7. Authorized return on equity premium vs. the Hamada capital structure parameter.

asset betas using Hamada's equation and corrected for firm cash holdings using firm-specific balance sheet information. We then averaged the fifteen asset betas calculated in each year as our proxy for utility asset risk.[11] The results remain substantively unchanged whether an equal-weighted or a capitalization-weighted average is used.

Although there is, of course, variation in the industry average asset beta across the thirty-eight years, the general trend is down. Fig. 8 presents the risk premium in comparison to the industry average asset beta. As a result, the asset beta is moving in the opposite direction from what one might expect, given a steadily-increasing risk premium, and therefore does not appear to explain the observed behavior of the risk premium.

4.3. The market risk premium

The last CAPM-derived explanation for a changing risk premium relates to the pricing of risk assets in general. If investors require greater compensation for bearing the systematic risk of the market in general, then the risk premium across all assets would increase as well (all else held equal) as a result of the average risk aversion coefficient of investors increasing. The market risk premium reflects this risk-bearing cost in the CAPM.

Although we can observe the *ex post* market risk premium, investors' assessment of the *ex ante* market risk premium is generally based on assuming that historical experience provides a meaningful guide to future experience.[12] It is customary to examine the actual market risk premium over some historical time period and base one's estimate of the *expected* future market risk premium on that historical experience (Sears and Trennepohl, 1993; Villadsen et al., 2017, p. 59). While the size of the historical window is subjective, it is sufficient for our purposes to note that the slope of the market risk premium over time has been negative irrespective of the historical window used.[13] Most sources advocate for using the longest time window available (Villadsen et al., 2017, p. 61); we use a fifty-year historical window for calculation purposes. As Fig. 9 illustrates, that declining trend in the market risk premium appears to be inconsistent with the increasing risk premium exhibited by the rates of return authorized by regulators.

4.4. Testing a theoretical model of the risk premium

Although we have illustrated that each component of the CAPM risk premium appears at odds with the risk premium derived from rates of return authorized by regulators, we now turn to a formal exploration of these relationships. By combining the security market line representation of the CAPM [1] and the Hamada equation, we can define the risk premium, $r_E - r_f$.

$$r_E - r_f = \beta_A \times \left[1 + (1-\tau)\frac{D}{E}\right] \times MRP \tag{2}$$

In [2], $r_E - r_f$ is the risk premium, or the difference between the authorized rate of return on equity for a given firm in a given rate case and the then-prevailing riskless rate. The asset beta, β_A, is calculated as described in Section 4.2. The middle component is taken from the Hamada equation and reflects the marginal corporate income tax rate (τ) in effect in the year in which the equity return was authorized and the authorized debt-to-equity ratio reflected in the regulators' decision for each case. Lastly, *MRP* is the *ex ante* estimate of the market risk

[10] We determined the composition of the Dow Jones Utility Average index at the end of each year and used a rolling five-year window to perform the regressions. For example, the 1980 regression betas were estimated based on monthly returns from 1975 to 1979, the 1981 regression betas were estimated based on monthly returns from 1976 to 1980, and so on.

[11] The balance sheet and total return data are taken from Standard & Poor's COMPUSTAT database. We calculate $\beta'_A = \beta / \left[1 + (1-\tau)\frac{D}{E}\right]$ and $\beta_A = \beta'_A / \left[1 - \frac{C}{D+E}\right]$, where C equals the amount of cash and cash equivalents held by each firm and D and E represent, respectively, the debt and equity of each firm. We measure D as the sum of Current Liabilities, Long-Term Debt, and Liabilities–Other in the COMPUSTAT data. Because final firm accounting information was not available for 2018 at the time of writing, we maintained the capital structures calculated using 2017 data.

[12] We do not dwell here on the issue of the "observability" of the market portfolio as it relates to testability of the CAPM. We shall assume that the S&P 500 index is a reasonable proxy for the market portfolio.

[13] The market risk premium data used here are taken from data on the S&P 500 and 10-year U.S. Treasury notes collected from the Federal Reserve (Damodaran, n.d.).

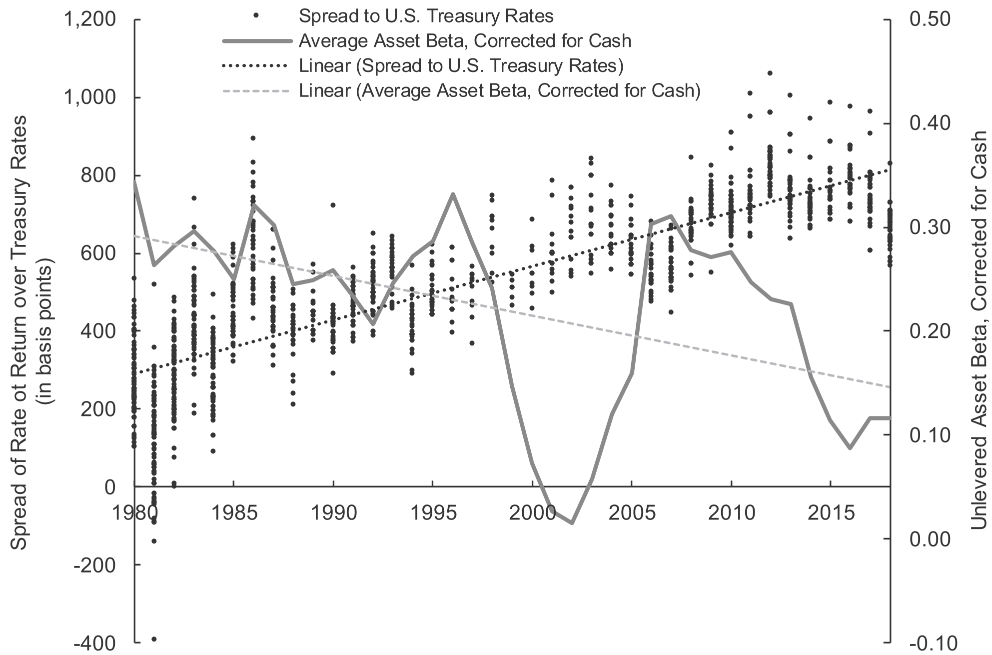


Fig. 8. Authorized return on equity premium vs. industry average asset beta.

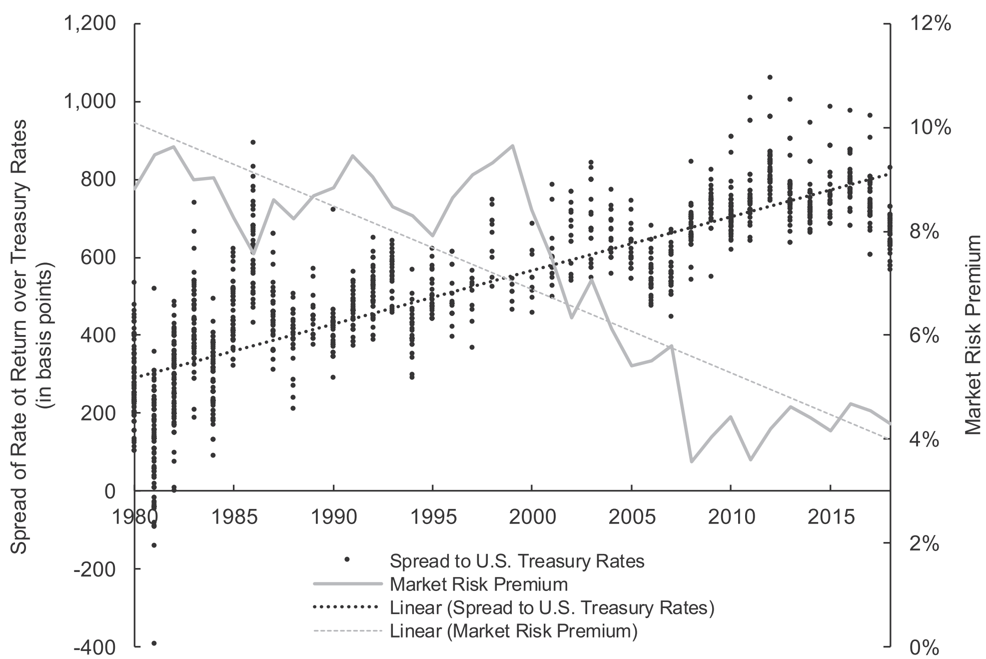


Fig. 9. Authorized rate-of-return premium vs. *ex ante* estimated market risk premium.

premium based on a fifty-year historical window as of the year in which each equity return was authorized.

Let $i = 1, \ldots, N$ index firms and $t = 1, \ldots, T$ index years. Not every firm files a rate case in every year. In addition, firms enter and exit over time due to merger or bankruptcy. Because regulators must have an evidentiary record to support their determinations, we assume that each rate case is evaluated independently in an adversarial hearing across time.

By using a logarithmic transform of [2], we arrive at equation [3].

$$ln(r_{E,it} - r_{f,t}) = \gamma_0 + \gamma_1 ln(\beta_{A,t}) + \gamma_2 ln\left[1 + (1 - \tau_t)\frac{D_{it}}{E_{it}}\right] + \gamma_3 ln(MRP_t) \tag{3}$$

In a traditional ordinary least squares (OLS) regression setting, the CAPM would hypothesize that γ_0 should be zero (or not significant) and γ_1, γ_2, and γ_3 should be positive and significant. What we find, however, is exactly the opposite of that (Table 3). The coefficients are negative and strongly significant. Further, a comparison of the observed risk premium to the risk premium estimated by our regression model reveals a good fit (Fig. 10). The negative coefficients are problematic for the CAPM, but also suggest rather counterintuitive effects at an applied

Table 3
Regression results for CAPM-based risk premium model. Coefficients for both the OLS regression model and a model controlling for utility-level fixed effects are shown.

	OLS	Controlling for utility-level fixed effects
	$ln(r_E - r_f)$	$ln(r_E - r_f)$
γ_0, Constant	3.641****	
	(0.130)	
γ_1, Asset beta, $ln(\beta_A)$	−0.158****	−0.156****
	(0.022)	(0.023)
γ_2, Capital structure, $ln\left[1 + (1-\tau)\frac{D}{E}\right]$	−0.492****	−0.967****
	(0.103)	(0.142)
γ_3, Market risk premium, $ln(MRP)$	−0.947****	−0.898****
	(0.035)	(0.039)
R-squared	46.4%	46.6%
Adjusted R-squared	46.3%	41.2%
F statistic	458.8****	420.9****
No. of observations	1596	1596

Standard errors are reported in parentheses.
*, **, ***, and **** indicate significance at the 90%, 95%, 99%, and 99.9% levels, respectively.

level. Regulators use CAPM prescriptively in rate cases; they are determining what utilities *should* earn. A negative capital structure coefficient suggests, for example, that investors in firms with high leverage *should* be compensated with *lower* returns. Similarly, negative coefficients imply that investors in firms with riskier assets (higher asset betas) and during periods of higher risk aversion (higher market risk premiums) should also be compensated with *lower* returns. These results would be difficult for regulators to justify on normative grounds.

It may be the case, however, that common cross-sectional variation is biasing the results for this data by creating endogeneity issues for the OLS-estimated coefficients. For example, the repeated presence of the same utilities over time could introduce entity-level fixed effects into the analysis. Accordingly, we performed an F-test to evaluate the presence of individual-level effects in the data (Judge et al., 1985: p. 521). The test strongly supports the presence of individual (utility-level) effects ($F_{143,1449} = 1.5$, $p < 0.001$). In addition, the Hausman test (Hausman, 1978; Hausman and Taylor, 1981) supports the fixed-effect specification in lieu of random effects ($\chi^2(3) = 24.0$, $p < 0.001$). As a result, Table 3 also provides the regression coefficients controlling for utility-level fixed effects. These coefficients, while numerically different than the OLS results, are nevertheless still negative and strongly significant, in conflict with both financial theory and regulator intent.

Fig. 10 also reveals a distinct shift in the predicted trend of the risk premium beginning in 1999. This is notable because for many parts of the U.S., 1999 represented the year that implementation of electric market reform and restructuring began, with wholesale markets such as ISO-New England opening and several divestiture transactions of formerly-regulated generating assets occurring, establishing market valuations for formerly regulated assets (Borenstein and Bushnell, 2015). In addition, FERC issued its landmark Order 2000 encouraging the creation of Regional Transmission Organizations. To examine this point in time, we divided the data into two sets, 1980–1998 and 1999–2018, and estimated separate regression models for each subset using both OLS and controlling for utility-level fixed effects (Table 4). As before, the F (pre-1999 $F_{129,805} = 1.6$, $p < 0.001$; post-1998 $F_{129,525} = 3.2$, $p < 0.001$) and Hausman (pre-1999 $\chi^2(3) = 15.5$, $p < 0.01$; post-1998 $\chi^2(3) = 23.8$, $p < 0.001$) tests both strongly support the model controlling for utility-level fixed effects over OLS.

Although the results in both cases are consistent with our earlier finding that the standard finance model appears at odds with the empirical data, the two regression models are noticeably different from one another and appear to better represent the data (Fig. 11). We performed the Chow (1960) test and confirmed the presence of a structural break in the data in 1999 ($F_{4,1588} = 91.6$, $p < 0.001$).[14] We find this result suggestive that deregulatory activity may have an influence even on still-regulated utilities—a point to which we shall return in Section 5.2.

4.5. Potential finance explanations other than the CAPM

In Mehra and Prescott's (2003) review of the equity premium puzzle literature, the authors acknowledge that uncertainty about changes in the prevailing tax and regulatory regimes may explain the premium. Such forces may also be at work with regard to regulated rates of return. To the extent that investors require higher current rates of return because they are concerned about future shocks to the tax or regulatory structure of investments in regulated electric utilities (e.g., EPA's promulgation of the Clean Power Plan, the U.S. Supreme Court's stay of the Clean Power Plan, expiration of tax credits), such concern may be manifest in a higher degree of risk aversion that is unique to investors in the electric utility sector, and therefore a higher "market" risk premium on the assumption that capital markets are segmented for electric utilities.

A separate line of inquiry concerns a criticism of the Hamada equation in the presence of risky debt (Hamada (1972) excluded default from consideration). Conine (1980) extended the Hamada equation to accommodate risky debt by applying a debt beta. Subsequently, Cohen (2008) sought to extend the Hamada equation by adjusting the debt-to-equity parameter to incorporate risky debt in the calculation of the equity beta [4].

$$\beta = \beta_A\left[1 + (1-\tau)\frac{r_D}{r_f}\frac{D}{E}\right] \tag{4}$$

We view neither of these proposed solutions as entirely satisfying, and note that they tend to be material only for high leverage, which is not common to regulated utilities. Nevertheless, we acknowledge that adjustments to the capital structure may influence the risk premium. However, applying the Cohen (2008) modification and using the Moody's Seasoned Baa Corporate Bond Yield as a proxy for the cost of risky debt (r_D), we note that our regression results are substantively unchanged. As Table 5 illustrates, use of the Cohen betas still results in highly significant, but negative coefficients, which is contrary to theory. These results are maintained when controlling for utility-level fixed effects, and the F (Hamada $F_{143,1449} = 1.5$, $p < 0.001$; Cohen $F_{143,1449} = 1.3$, $p < 0.01$) and Hausman (Hamada $\chi^2(3) = 24.0$, $p < 0.001$; Cohen $\chi^2(3) = 6.3$, $p < 0.1$) tests are significant in support of the fixed effects model.

In lieu of modifying the CAPM parameters, some researchers have suggested that Ross's (1976) Arbitrage Pricing Theory (APT) is preferable to the CAPM because the CAPM produces a "shortfall" in estimated returns (Roll and Ross, 1983) and "underestimates" actual returns in utility settings (Pettway and Jordan, 1987). While the works of these authors are suggestively similar to the analysis contained in this paper, we note that those authors were examining the *actual* returns on utility common stocks, rather than the rates of return *authorized* by regulators for assets held in utility rate bases. The distinction is important. In the case of the former, it is a question of asset pricing models and efficient capital markets. In the case of the latter, it is an issue of regulator judgment. We note specifically that regulators are making decisions that set these rates, and in many cases are doing so explicitly stating that they are relying in whole or in part on the CAPM. Our question concerns not just whether the CAPM is a better asset pricing model (than the APT, for example), but whether regulators' own judgment can

[14] Additional testing using the Andrews (1993) approach supports the presence of structural breaks during the transitional regulatory period identified by Borenstein and Bushnell (2015), confirming the appropriateness of our selection of 1999 as a year with strong historical motivation for a structural break.

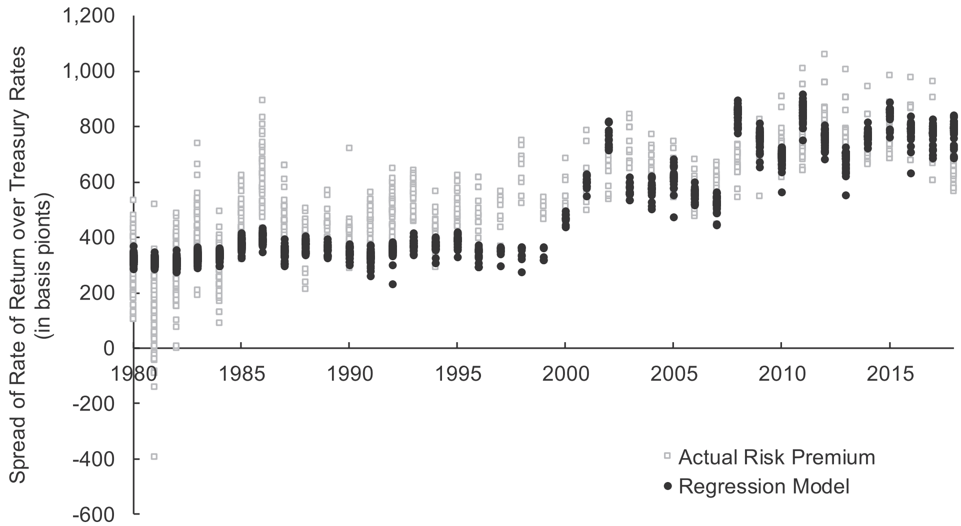


Fig. 10. Actual vs. OLS regression-model risk premium.

Table 4
Regression results for a two-period CAPM-based risk premium model. For purposes of the Chow test, the combined sum of squared residuals was 272.5. Coefficients for both the OLS regression model and a model controlling for utility-level fixed effects are shown.

	OLS		Controlling for utility-level fixed effects	
	1980–1998	1999–2018	1980–1998	1999–2018
	$ln(r_E - r_f)$	$ln(r_E - r_f)$	$ln(r_E - r_f)$	$ln(r_E - r_f)$
γ_0, Constant	−6.259****	5.159****		
	(0.718)	(0.093)		
γ_1, Asset beta, $ln(\beta_A)$	−0.940****	−0.071****	−0.972****	−0.065****
	(0.131)	(0.008)	(0.135)	(0.008)
γ_2, Capital structure, $ln\left[1 + (1-\tau)\frac{D}{E}\right]$	−0.140	−0.325****	−0.865****	−0.636****
	(0.150)	(0.049)	(0.224)	(0.075)
γ_3, Market risk premium, $ln(MRP)$	−4.529****	−0.471****	−4.326****	−0.432****
	(0.261)	(0.026)	(0.267)	(0.025)
R-squared	26.7%	36.9%	30.2%	44.9%
Adjusted R-squared	26.4%	36.6%	18.8%	31.0%
F statistic	113.3****	127.3****	116.0****	142.5****
Sum of squared residuals	214.4	8.4	170.8	4.7
No. of observations	938	658	938	658

Standard errors are reported in parentheses.
*, **, ***, and **** indicate significance at the 90%, 95%, 99%, and 99.9% levels, respectively.

be explained by the model on which they claim to rely.

Lastly, to address a related point, we also examined the actual earned rates of return on equity for the 15 utilities in the Dow Jones Utility Average over our historical window. We used each firm's actual return on equity, calculated annually as Net Income divided by Total Equity, as reported in the COMPUSTAT database. This measure of firm profitability examines how successful the firms were at converting their *authorized* returns into *earned* returns. In general, the earned returns closely tracked the authorized returns, suggesting that the decisions of regulators are significantly influencing the actual earnings of regulated utilities. Fig. 12 compares the spread of *authorized* rates of return over riskless rates to the spread of *earned* rates of return over riskless rates and to the median net income of utilities in constant 2018 dollars.[15] The steadily increasing risk premium we have identified is present in both series. The series are correlated at 0.77 (authorized vs. earned), 0.59 (authorized vs. median net income), and 0.75 (earned vs. median net income), all of which are significantly greater than zero ($p < 0.001$). Further, the "capture rate" (the percentage of authorized rates actually earned by the utilities) averaged 96% over the entire time period. As a result, we conclude that the trend of increasing risk premiums is not an abstract anomaly occurring in a regulatory vacuum, but rather a direct contributor to the earnings of regulated utilities.

However, these measures of firm performance must be interpreted with caution. The authorized rates of return apply to jurisdictional utilities, while the earned rates of return are calculated based on holding company performance, which in many cases are not strictly equivalent. Further, increasing net income may be due to industry consolidation producing larger firms (with income increasing only proportionally to size), rather than an increase in profitability itself. In fact, the average income-to-sales ratio of the Dow Jones Utility Average members remained remarkably stable across the period of our study,

[15] We used the median earned rate of return over the 15 Dow Jones utilities. The results are substantively equivalent if the average earned rate of return is used but are more volatile due to the impact on earnings of the California energy crisis of 2000–2001 and the collapse of Enron in 2001.

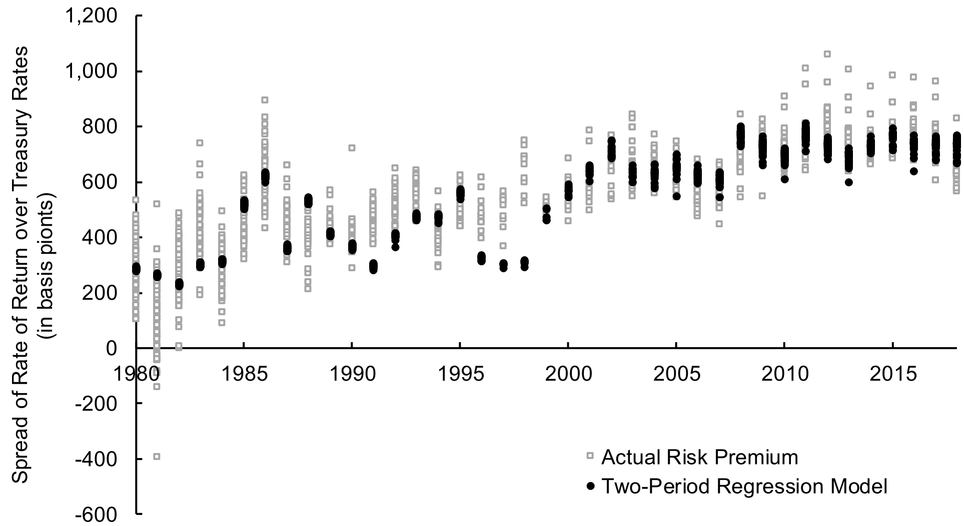


Fig. 11. Actual vs. two-period OLS model-predicted risk premium.

Table 5
Regression results for the standard Hamada capital structure model and Cohen (2008) capital structure model that incorporates risky debt. Coefficients for both the OLS regression model and a model controlling for utility-level fixed effects are shown.

	OLS		Controlling for utility-level fixed effects	
	Hamada	Cohen	Hamada	Cohen
	$ln(r_E - r_f)$	$ln(r_E - r_f)$	$ln(r_E - r_f)$	$ln(r_E - r_f)$
γ_0, Constant	3.641****	3.191****		
	(0.130)	(0.085)		
γ_1, Asset beta, $ln(\beta_A)$	−0.158****	−0.169****	−0.156****	−0.175****
	(0.022)	(0.022)	(0.023)	(0.023)
γ_2, Capital structure, $ln\left[1 + (1 - \tau)\frac{D}{E}\right]$	−0.492****		−0.967****	
	(0.103)		(0.142)	
γ_2', Capital structure, $ln\left[1 + (1 - \tau)\frac{r_D}{r_f}\frac{D}{E}\right]$		−0.156*		−0.275***
		(0.081)		(0.040)
γ_3, Market risk premium, $ln(MRP)$	−0.947****	−1.046****	−0.898****	−1.087****
	(0.035)	(0.036)	(0.039)	(0.040)
R-squared	46.4%	45.7%	46.6%	45.1%
Adjusted R-squared	46.3%	45.6%	41.2%	39.6%
F statistic	458.8****	447.1****	420.9****	396.9****
No. of observations	1596	1596	1596	1596

Standard errors are reported in parentheses.
*, **, ***, and **** indicate significance at the 90%, 95%, 99%, and 99.9% levels, respectively.

and actually slightly declined, suggesting that gains in net income came from growing revenue, rather than increasing margins (although revenue growth may itself be a function of rising authorized rates of return). Nevertheless, the results are suggestive.

We have not repeated the analysis of Roll and Ross (1983) and Pettway and Jordan (1987) and examined the relationship between firm performance and stock performance. Their findings, however, suggest that regulated utilities have realized *higher* stock returns than can be explained by the CAPM—a finding congruent with our work and suggestive of other factors being priced by the market. This does not entirely explain the judgment issue, however: why regulators appearing to use a CAPM approach provide utilities with returns that also appear to be excessive.

4.6. Potential public choice explanations

Another category of potential explanations emerges from the public choice literature on the role of institutional factors. Regulators may be deliberately or inadvertently providing a "windfall" of sorts to electric utilities. Stigler (1971), among others in the literature on regulatory capture, noted that firms may seek out regulation as a means of protection and self-benefit. This is particularly true when the circumstances are present for a collective action problem (Olson, 1965) of concentrated benefits (excess profits to utilities may be significant) and diffuse costs (the impact of those excess profits on each individual ratepayer may be small). Close relationships between regulators and the industries that they regulate have been observed repeatedly, and one possible explanation for the size and growth of the risk premium is the electric utility industry's increasing "capture" of regulatory power.

We are somewhat skeptical of this explanation, however, both because of the degree of intervention in most utility rate cases by non-utility parties, and because the data do not suggest that regulators have become progressively laxer over time. Fig. 13 compares the rates of return on equity *requested* by utilities in our data set against the rates of return ultimately authorized. As the trend line illustrates, this ratio has remained remarkably stable (within a few percent) over the thirty-eight

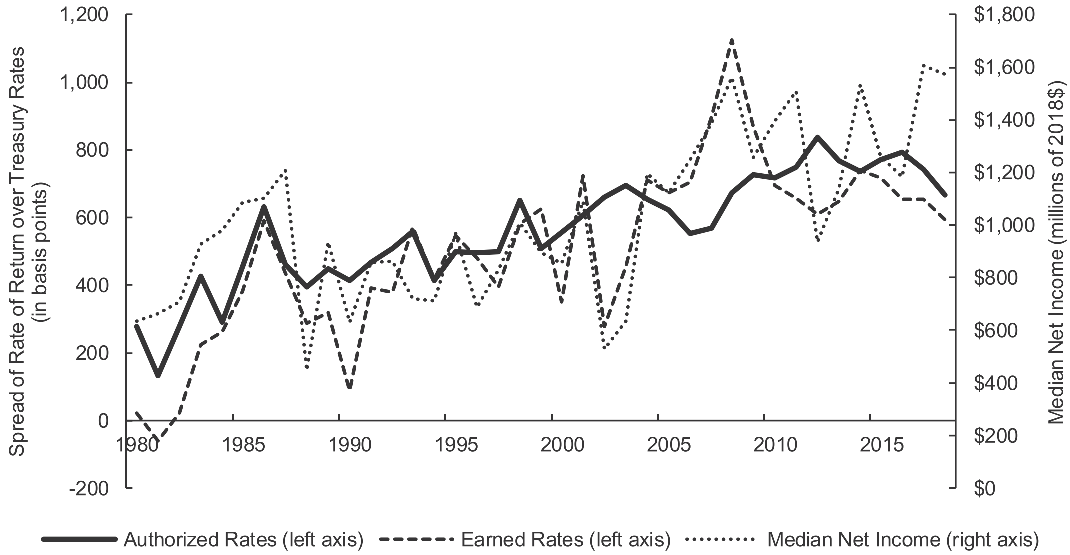


Fig. 12. Comparability of spreads measured with authorized and earned rates of return and utility net income.

years of data, even as the risk premium itself has steadily increased. As a result, the data do not suggest in general an obvious, growing permissiveness on the part of regulators. However, the last nine years are *suggestive* of an increasing level of accommodation among regulators. We propose a possible explanation for this particular pattern in Section 4.7.

To examine the public choice issues further, we investigated whether the risk premiums were related to the selection method of public utility commissioners and whether or not the rate cases in question were settled or fully litigated. The traditional hypothesis has been that elected (instead of appointed) commissioners were less susceptible to capture, more "responsive" to the public, and therefore more pro-consumer. Further, that cases that were settled were more likely to be accommodating to utilities (as money was "left on the table") and therefore would result in higher rates.

A sizable body of literature, however, has largely rejected the selection method hypothesis. Hagerman and Ratchford (1978) and Primeaux and Mann (1986) concluded that the selection method had no impact on returns or electricity prices respectively. Others have agreed that the selection method alone doesn't matter; it is how closely the regulators selected are monitored that matters (Boyes and McDowell, 1989). In addition, whatever evidence of an effect that may exist is likely due to selection method being a proxy for states with different intrinsic structural conditions (Harris and Navarro, 1983). Lastly, while states with elected utility commissioners (Kwoka, 2002) or commissioners whose appointment by the executive requires approval by the legislature (Boyes and McDowell, 1989) tend to have lower electricity prices, those low prices may create the perception of an "unfavorable" investment climate and may therefore lead to a higher cost of capital (Navarro, 1982). Alternatively, if lower prices are observed, it then remains unclear who actually pays (utility shareholders in foregone profits or consumers in higher costs of capital) for the lower observed prices (Besley and Coate, 2003).

To examine the impact of commission selection method and means of case resolution on risk premium, we categorized each state as having an elected or appointed utility commission based on data in Costello (1984), Besley and Coate (2003), and Advanced Energy Economy (2018). In addition, each rate case was reported as being either fully litigated or settled. The literature has hypothesized (but largely not found) that elected commissions are more "responsive" and therefore more pro-consumer. As a result, the expectation would be that the risk premiums implicit in authorized rates were higher for appointed commissions. Similarly, for means of case resolution, risk premiums would be higher for settled, rather than fully litigated rate cases.

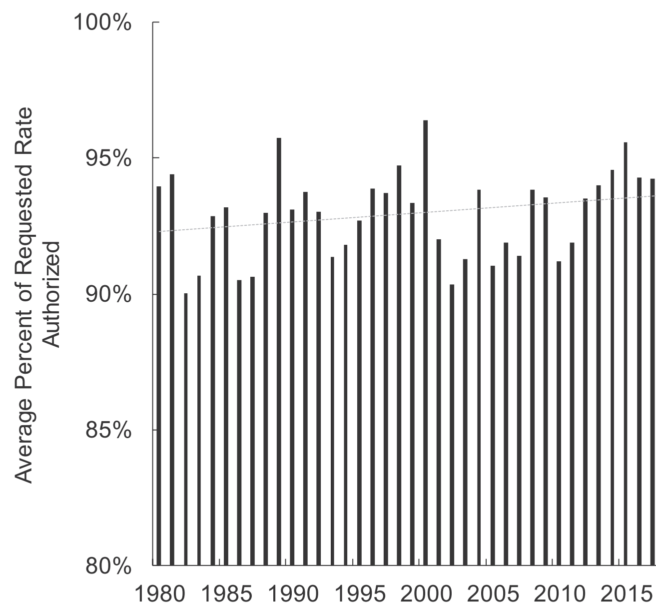


Fig. 13. Rate of return authorized as a percent of rate of return requested.

Table 6
Average risk premium in basis points by commission selection method and means of case resolution. The number of cases in each group is provided in parentheses.

	Appointed Commissions	Elected Commissions	Subtotals
Settled Cases	612 (367)	697 (89)	629 (456)
Fully Litigated Cases	460 (1008)	488 (181)	464 (1189)
Subtotals	500 (1375)	557 (270)	510 (1645)

Like other authors, we found no significant effect *overall* for selection method, but a very significant effect for whether cases were settled or fully litigated. In addition, there appears to be a significant *interaction* between selection method and means of case resolution, suggesting that the lack of evidence of an effect in the literature may be related to its interaction with the means of case resolution, which has not been examined in this depth before. Table 6 illustrates the average risk

Table 7
Regression results for the standard CAPM model and the CAPM model plus two public choice variables (commission selection method and means of case resolution). Coefficients for both the OLS regression model and a model controlling for utility-level fixed effects are shown.

	OLS		Controlling for utility-level fixed effects	
	CAPM	CAPM + Public Choice	CAPM	CAPM + Public Choice
	$ln(r_E - r_f)$	$ln(r_E - r_f)$	$ln(r_E - r_f)$	$ln(r_E - r_f)$
γ_0, Constant	3.641****	3.519****		
	(0.130)	(0.137)		
γ_1, Asset beta, $ln(\beta_A)$	−0.158****	−0.159****	−0.156****	−0.154****
	(0.022)	(0.022)	(0.023)	(0.023)
γ_2, Capital structure, $ln\left[1 + (1 - \tau)\frac{D}{E}\right]$	−0.492****	−0.463****	−0.967****	−0.917****
	(0.103)	(0.102)	(0.142)	(0.141)
γ_3, Market risk premium, $ln(MRP)$	−0.947****	−0.927****	−0.898****	−0.858****
	(0.035)	(0.036)	(0.039)	(0.041)
γ_4, Settle = 1		0.223***		0.249****
		(0.057)		(0.060)
γ_5, Appointed = 1		0.159****		0.132**
		(0.034)		(0.058)
γ_6, Settle = 1 × Appointed = 1		−0.182***		−0.197***
		(-0.061)		(-0.065)
R-squared	46.4%	47.4%	46.6%	47.3%
Adjusted R-squared	46.3%	47.2%	41.2%	41.9%
F statistic	458.8****	238.5****	420.9****	216.5****
AIC	−2809	−2810		
No. of observations	1596	1596	1596	1596

Standard errors are reported in parentheses.
*, **, ***, and **** indicate significance at the 90%, 95%, 99%, and 99.9% levels, respectively.

premium observed in each group. The average risk premium for settled cases is significantly higher than for fully litigated cases ($p < 0.001$). Further, while the average risk premium for settled cases and appointed commissions is significantly greater than for fully litigated cases and elected commissions ($p < 0.001$), there is an interaction effect suggesting that the impact of selection method on risk premium depends on the means of case resolution ($p < 0.05$).

Notwithstanding these differences, the incremental explanatory value of these public choice variables is minimal (but significant). Table 7 compares the standard CAPM model with an OLS model that incorporates selection method and means of case resolution. The Akaike Information Criterion (AIC) indicates that incorporation of the public choice variables has only slight incremental value. We estimate that the marginal impact is only approximately 8 basis points—much less than the observed increase over time.[16] As before, the F (CAPM $F_{143,1449} = 1.5$, $p < 0.001$; CAPM + Public Choice $F_{143,1446} = 1.4$, $p < 0.001$) and Hausman (CAPM $\chi^2(3) = 24.0$, $p < 0.001$; CAPM + Public Choice $\chi^2(6) = 24.1$, $p < 0.001$) tests strongly support controlling for utility-level fixed effects in the model. Table 7 also includes coefficients incorporating such controls.

4.7. Potential behavioral economics explanations

To this point, we have examined a number of factors related to economic and institutional influences. At the outset, however, we noted the potential for rate determination to be influenced by regulator judgment. In many cases there is evidence that regulators are not behaving in accordance with the method they in fact purport to be using (i.e., CAPM). As we cannot escape the fact that ultimately the authorized return on equity is a product of regulator decision-making, we now consider possible explanations for the risk premium based on insights from behavioral economics.

First, we note that regulator attachment to rate decisions from the recent past may be coloring their forward-looking decisions. Earlier we referenced a report from Pennsylvania regulators about their stated reliance on (*inter alia*) "recent [returns on equity] adjudicated by the Commission" (Pennsylvania Public Utility Commission, 2016, p. 17). The legal weight attached to precedent may give rise here to a recency bias, where regulators anchor on recent rate decisions and insufficiently adjust them for new information. While stability in regulatory decision-making is seen as useful in assuring investors, to the extent that it results in a slowing of regulatory response when market conditions change, regulators should be encouraged to weigh the benefits of stability against the costs of distortionary responses to authorized returns that lag market conditions.

Our second insight from behavioral economics involves a curious observation in the empirical data: the average rate of return on regulated equity appears to have "converged" to 10% over time. Although the underlying riskless rate has continued to drop, authorized equity returns have generally remained fixed in the neighborhood of 10%, only dropping below (on average) over the last few years. Anecdotally, we have observed a reluctance among potential electric power investors to accept equity returns on power investments of less than 10%—even though those same investors readily acknowledge that *debt* costs have fallen. To that extent, then, a behavioral bias may be at work.

The finance literature has noted a similar effect related to crossing index threshold points (e.g., every thousand points for the Dow Jones Industrial Average). These focal points, which have no normative import, appear to influence investor behavior. Trading is reduced near major crossings (Donaldson and Kim, 1993; Koedijk and Stork, 1994; Aragon and Dieckmann, 2011), with some asserting that the behavior of investors in clienteles may produce this behavior (Balduzzi et al., 1997). We propose a related theory.

In economics, "money illusion" refers to the misperception of nominal price changes as real price changes (Fisher, 1928). Shafir et al. (1997) proposed that this type of choice anomaly arises from framing effects, in that individuals give improper influence to the nominal representation of a choice due to the convenience and salience of the nominal representation. The experimental results have been upheld in several subsequent studies in the behavioral economics literature (Fehr and Tyran, 2001; Svedsäter et al., 2007).

The effect here may be similar: investors and regulators may conflate "nominal" rates of return (the authorized rates) with the risk

[16] For example, the marginal impact of a settled vs. fully-litigated case would be $exp(3.513 + 0.223) - exp(3.513) = 8.4$ using the OLS coefficients.

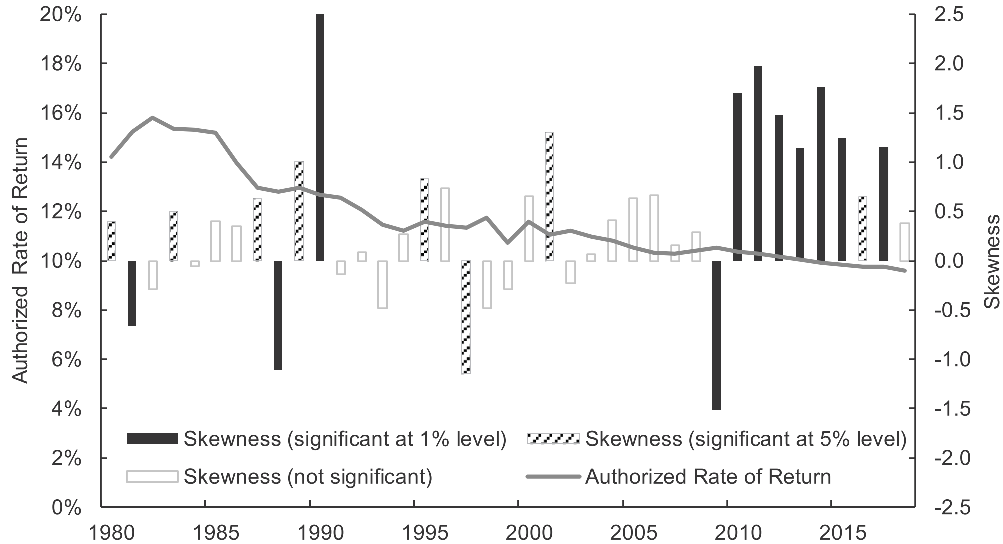


Fig. 14. Authorized rates of return on equity and skewness.

premium underlying the authorized rate. The apparent "stickiness" of rates of return on equity around 10% is similar to the "price stickiness" common in the money illusion (and, indeed, the rate of return is the price of capital). If there was in fact a tendency (intentional or otherwise) to respect a 10% "floor," one might expect that the distribution of authorized returns within each year may "bunch up" in the left tail at 10%, where absent such a floor one may expect them to be distributed symmetrically around a mean. As Fig. 14 illustrates, we see precisely such behavior. As average authorized returns decline to 10% (between 2010 and 2015), the skewness of the within-year distributions of returns becomes persistently and statistically significantly positive, suggesting a longer right-hand tail to the distributions, consistent with a lack of symmetry below the 10% threshold.[17] We note also that this period of statistically significant positive skewness coincides precisely with what appeared to be a period of increased regulator accommodation in Fig. 13. Further, once the threshold is definitively crossed, skewness appears to moderate and the distribution of returns appears to revert toward symmetry.

A related finding has been reported by Fernandez and colleagues (Fernandez et al., 2015, 2017, 2018), where respondents to a large survey of finance and economics professors, analysts, and corporate managers tended, on average, to overestimate the riskless rate of return. In addition, their estimates exhibited substantial positive skew, in that overestimates of the riskless rate far exceed underestimates.[18] The authors found similar results not just in the U.S., but also in Germany, Spain, and the U.K. In the U.S., the average response during the high skewness period exceeded the contemporaneous 10-year U.S. Treasury rate by 20–40 basis points, before declining as skewness moderated in 2018. It may be that overestimating the riskless rate is simply one way for participants in regulatory proceedings to "rationalize" maintaining the authorized return in excess of 10%. Alternatively, it may be an additional bias in the determination of authorized rates of return.

If such biases exist, there are clear implications for the regulatory function itself. For example, this apparent 10% "floor" was even recognized recently in a U.S. Federal Energy Regulatory Commission proceeding (Initial Decision, Martha Coakley, et al. v. Bangor Hydro-Electric Co., et al., 2013, 144 FERC 63,012 at 576): "if [return on equity] is set substantially below 10% for long periods […], it could negatively impact future investment in the (New England Transmission Owners)." Our findings here draw us back to Joskow's (1972) characterization of regulator decision-making as a sort of meta-analysis. That is, commissioners do not merely directly evaluate the CAPM equations. Rather, they look at the nature of the evidence *as presented to them*. Accordingly, their judgments are based not just on capital market conditions in a vacuum, but on the format, detail, and context of the information contained within the evidentiary record of a rate case. As a result, regulators are susceptible to biases in judgment, and calibration of regulatory decision-making during the rate-setting process should be a required step.

5. Conclusions and policy implications

In this paper, we have examined a database of electric utility rates of return authorized by U.S. state regulatory agencies over a thirty-eight-year period. These rates have demonstrated a growing spread over the riskless rate of return across the time horizon studied. The size and growth of this spread—the risk premium—does not appear to be consistent with classical finance theory, as expressed by the CAPM. In fact, regression analysis of the data suggests the *opposite* of what would be predicted if the CAPM holds. This is particularly perplexing given that regulators often *claim* to be using the CAPM. In addition to the traditional finance factors, our work examined the influence of institutional, structural, and behavioral factors on the determination of authorized rates of return. We find support for many of these factors, although most cannot be justified on traditional normative grounds.

The pattern of large and growing risk premiums illustrated in this paper has significant implications for both utility and infrastructure investment and regulation and market design in environments where both regulated and restructured firms compete for capital. In particular, if rate case activity increases over the next several years as rate moratoria expire, the implications for retail rate escalation and capital investment may be significant. We discuss each in turn before offering some thoughts on possible mitigating factors.

[17] Formally, we test the hypothesis that the observed skewness is equal to zero (a symmetric, normal distribution). The test statistic is equal to the skewness divided by its standard error $\sqrt{6n(n-1)/(n-2)(n+1)(n+3)}$, where n is the sample size. The test statistic has an approximately normal distribution (Cramer and Howitt, 2004).

[18] At the time of the 2015 survey, for example, the 10-year U.S. Treasury rate was 2.0%. The average riskless rate reported by the 1983 U.S. survey respondents was 2.4% (median 2.3%), but responses ranged from 0.0% to 8.0%.

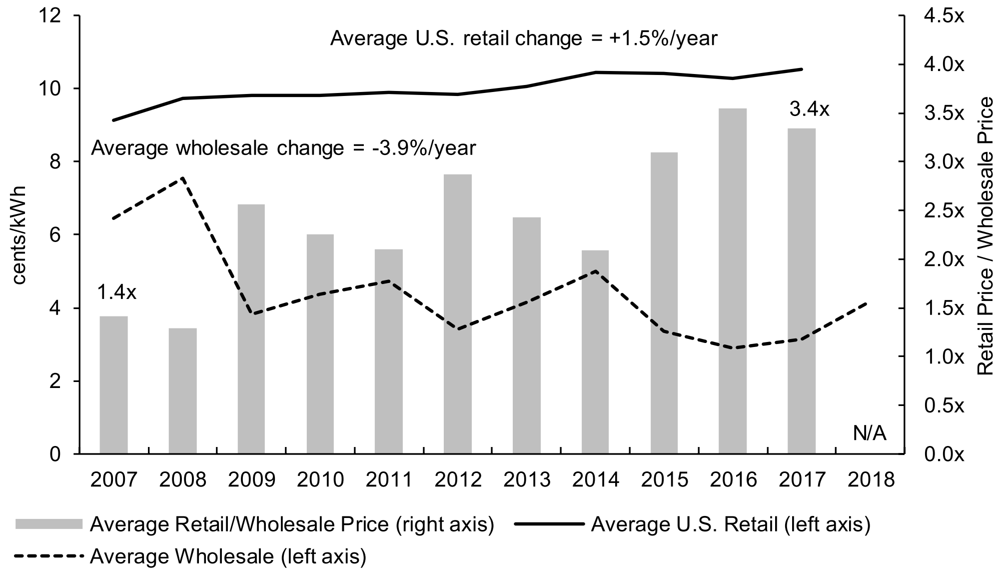


Fig. 15. Peak wholesale (2007–2018) vs. retail (2007–2017) power prices. Wholesale prices represent the average annual peak electricity price in MISO-IN, ISO-NE Mass Hub, Mid-C, Palo Verde, PJM-West, SP-15, and ERCOT-North. Retail prices collected from U.S. Energy Information Administration (https://www.eia.gov/electricity/data/state/avgprice_annual.xlsx). The retail price is the average for the entire country (using only the 7 states with wholesale markets included does not change the result).

5.1. Wholesale and retail electricity price divergence

A growing divergence has emerged over the last decade. Although fuel costs and wholesale power prices have declined since 2007, the *retail* price of power has increased over the same period (see Fig. 15). One explanation for this divergence in wholesale and retail rates may be the presence of a growing premium attached to regulated equity returns and therefore embedded into rates. To be sure, other forces may also be at work (for example, recovery of transmission and distribution system investments is consuming a greater portion of retail bills—a circumstance potentially exacerbated by excessive risk premiums). Further, even if the growing divergence between wholesale and retail rates is related to a growing risk premium, it does not necessarily follow that such growth is inappropriate or inconsistent with economic theory. Nevertheless, the potential for embedding of such quasi-fixed costs into the cost structure of electricity production may be significant for end users, as efficiency gains on the wholesale side are more than offset by excess costs of equity capital on the retail side.

5.2. Regulation itself as a source of risk

Public policy, or regulation itself, may be a causal factor in the observed behavior of the risk premium. The U.S. Supreme Court acknowledged, in *Duquesne Light Company* et al. *v. David M. Barasch* et al. (488 U.S. 299 (1989), p. 315) that "the risks a utility faces are in large part defined by the rate methodology, because utilities are virtually always public monopolies dealing in an essential service, and so relatively immune to the usual market risks." The recognition that the very act of regulating utilities subjects them to a unique class of risks may influence their cost of capital determination. And yet, if the *purpose* (or at least *a* purpose) of regulating electric utilities is to prevent these quasi-monopolists from charging excessive prices, but the *practice* of regulating them results in a higher cost of equity capital than might otherwise apply, it calls into question the role of such regulation in the first place.

Similarly, we may also question whether the hybrid regulated and non-regulated nature of the electric power sector in the U.S. plays a role as well. Has deregulation caused risk to "leak" into the regulated world because both regulated and non-regulated firms must compete for the same pool of capital? Has the presence of non-regulated market participants raised the marginal price of capital to all firms? In Section 4.4 we illustrated a shift in the trend of risk premium growth in 1999, as several U.S. markets were switching to deregulation, but further study of this question is needed.

The trajectory of public policy during the entire time period studied has been toward deregulation (beginning before 1980 with Public Utility Regulatory Policy Act, through the Natural Gas Policy Act in the 1980s, and electric industry deregulation in the 1990s) and "today's investments face market, political and regulatory risks, many of which have no historical antecedent that might serve as a starting point for modeling risk." (PJM Interconnection, 2016) The general unobservability of the *ex ante* expected returns on deregulated assets complicates determining if the progressive deregulation of the industry has caused a convergence in regulated and non-regulated returns over that time period. While the data do not suggest that utilities in states that have never undertaken deregulation have meaningfully different risk premiums, there are many ways to evaluate the "degree" of deregulatory activity that could be explored.

Another public policy-related factor could be a change in the nature of the rate base or of rate-making itself. Toward the beginning of our study period, most of the electric utilities were vertically integrated (i.e., in the business of both generation and transmission of power). Over time, generation became increasingly exposed to deregulation, while transmission and distribution of power have tended to remain regulated. To the extent that the portion of the rate base comprised of transmission and distribution assets has increased at the expense of generation assets, it may suggest a shift in the underlying risk profile of the assets being recognized by regulators. We note, for example, that public policy has tended to favor transmission investments with "incentive rates" in recent years in order to address a perceived relative lack of investment in transmission within the electric power sector. Our data, however, reveal the opposite. Based on data since 2000, there have been 172 transmission and distribution-only cases, out of 653 total cases. The average rate of return authorized in the transmission and distribution cases is approximately 60 basis points *lower* than those in vertically-integrated cases from the same period. These have been *state-*

level cases however. We note as deserving of further study that (interstate) electric transmission is regulated by FERC using a well-defined DCF approach instead of CAPM. The impact of having differing regulatory frameworks to set rates for assets that are functionally substantially identical remains an open question.

As for a change in the nature of rate-making itself, we note that the industry has tended to move from cost-of-service rate-making to performance-based ratemaking. If this shift, in an attempt to increase utility operating efficiency, has inadvertently raised the cost of equity capital through the use of incentive rates, it would be important to ascertain if the net cost-benefit balance has been positive. In general, there has been a lack of attention to the impact of regulatory changes on discount rates. The data on authorized returns on equity provides a unique dataset for such investigations.

5.3. Strategies for mitigating the growing premium

Our research does not necessarily imply that the rates of return authorized by regulators are too high, or otherwise necessarily inappropriate for utilities. An evaluation of whether these non-normative factors constitute a legitimate basis of rate of return determination deserves separate study. But if institutional or behavioral factors lead to departures from normative outcomes in setting rates of return on equity, then perhaps like Ulysses and the Sirens, regulators' hands should be "tied to the mast."

One notable jurisdictional difference in regulatory practice is between formulaic and judgment-based approaches to setting the cost of capital. In Canada, for example, formulaic approaches are more prevalent than in the United States (Villadsen and Brown, 2012). California also adjusts returns on equity for variations in bond yields beyond a "dead band," and the performance-based regulatory approaches in Mississippi and Alabama rely on formulaic cost of capital determination (Villadsen et al., 2017).

By pre-committing to a set formula (e.g., government bond rates plus *n* basis points) in lieu of holding adversarial hearings, regulators could minimize the potential for deviation from outcomes consistent with finance theory. Villadsen and Brown (2012) noted, for example, that then-recent rates set by Canadian regulators tended to be lower than those set by U.S. regulators despite nearly equivalent riskless rates of return. An intermediate approach would be to require regulators to calculate and present a formulaic result, but then allow them the discretion to authorize deviations from such a result when circumstances justify such departures. In such cases, regulators could avoid anchoring on past results, and instead anchor on a theoretically-justifiable return, before adjusting for any mitigating factors. If regulator judgment is impaired or subject to bias, then minimizing the influence of judgment by deferring to models may be prudent. In the end, we may observe simply that what regulators *should* do, what regulators *say* they're doing, and what regulators *actually* do may be three very different things.

Conflicts of interest

The authors declare that they have no conflict of interest.

Funding

This research did not receive any specific grant from funding agencies in the public, commercial, or not-for-profit sectors.

Acknowledgements

This paper is based on a portion of the first author's doctoral dissertation. The authors gratefully acknowledge the thoughtful comments and assistance received from Jay Apt, Tony Páez, Thomas Yu, Chad Schafer, participants at the Carnegie Mellon Electricity Industry Center's 2017 Advisory Committee Meeting, and two anonymous reviewers. All responsibility for any errors remains with the authors.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.enpol.2019.110891.

References

Advanced Energy Economy, 2018. PowerPortal. https://powersuite.aee.net/portal, Accessed date: 2 January 2019.
Andrews, D., 1993. Tests for parameter instability and structural change with unknown change point. Econometrica 61, 821–856. https://doi.org/10.2307/2951764.
Aragon, G., Dieckmann, S., 2011. Stock market trading activity and returns around milestones. J. Empir. Financ. 18, 570–584. https://doi.org/10.1016/j.jempfin.2011.05.010.
Averch, H., Johnson, L., 1962. Behavior of the firm under regulatory constraint. Am. Econ. Rev. 52, 1052–1069.
Balduzzi, P., Foresi, S., Hait, D., 1997. Price barriers and the dynamics of asset prices in equilibrium. J. Financ. Quant. Anal. 32, 137–159. https://doi.org/10.2307/2331170.
Besley, T., Coate, S., 2003. Elected versus appointed regulators: theory and evidence. J. Eur. Econ. Assoc. 1, 1176–1206. https://doi.org/10.1162/154247603770383424.
Binder, J., Norton, S., 1999. Regulation, profit variability and beta. J. Regul. Econ. 15, 249–265. https://doi.org/10.1023/A:1008078230272.
Board of Governors of the Federal Reserve System (US), n.d.-a. 10-Year Treasury Constant Maturity Rate [DGS10], Retrieved from FRED, Federal Reserve Bank of St. Louis. https://research.stlouisfed.org/fred2/series/DGS10 (accessed 2 January 2019).
Board of Governors of the Federal Reserve System (US), n.d.-b. Moody's Seasoned Baa Corporate Bond Yield [BAA], Retrieved from FRED, Federal Reserve Bank of St. Louis. https://research.stlouisfed.org/fred2/series/BAA (accessed 2 January 2019).
Borenstein, S., Bushnell, J., 2015. The U.S. electricity industry after 20 years of restructuring. Annu. Rev. of Econ. 7, 437–463. https://doi.org/10.1146/annurev-economics-080614-115630.
Boyes, W., McDowell, J., 1989. The selection of public utility commissioners: a reexamination of the importance of institutional setting. Public Choice 61, 1–13. https://doi.org/10.1007/BF00116759.
Chow, G., 1960. Tests of equality between sets of coefficients in two linear regressions. Econometrica 28, 591–605. https://doi.org/10.2307/1910133.
Cohen, R., 2008. Incorporating default risk into Hamada's equation for application to capital structure. Wilmott Mag. March/April 62–68.
Conine Jr., T., 1980. Corporate debt and corporate taxes: an extension. J. Financ. 35, 1033–1037. https://doi.org/10.1111/j.1540-6261.1980.tb03519.x.
Costello, K., 1984. Electing regulators: the case of public utility commissioners. Yale J. Regul. 2, 83–105.
Courville, L., 1974. Regulation and efficiency in the electric utility industry. Bell J. Econ. Manag. Sci. 5, 53–74. https://doi.org/10.2307/3003092.
Cramer, D., Howitt, D., 2004. The SAGE Dictionary of Statistics. SAGE Publications, Thousand Oaks, pp. 159. https://doi.org/10.4135/9780857020123.
Damodaran, A., n.d. Annual Returns on Stock, T-Bonds and T-Bills: 1928-Current. http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/histretSP.html (accessed 2 January 2019).
Donaldson, R., Kim, H., 1993. Price barriers in the Dow Jones industrial average. J. Financ. Quant. Anal. 28, 313–330. https://doi.org/10.2307/2331416.
Fama, E., French, K., 1993. Common risk factors in the returns on stocks and bonds. J. Financ. Econ. 33, 3–56. https://doi.org/10.1016/0304-405X(93)90023-5.
Fehr, E., Tyran, J., 2001. Does money illusion matter? Am. Econ. Rev. 91, 1239–1262. https://doi.org/10.1257/aer.91.5.1239.
Fernandez, P., Ortiz, A., Acín, I., 2015. Discount Rate (Risk-free Rate and Market Risk Premium) Used for 41 Countries in 2015: A Survey. http://ssrn.com/abstract=2598104, Accessed date: 2 January 2019.
Fernandez, P., Pershin, V., Acín, I., 2017. Discount Rate (Risk-free Rate and Market Risk Premium) Used for 41 Countries in 2017: A Survey. http://ssrn.com/abstract=2954142, Accessed date: 2 January 2019.
Fernandez, P., Pershin, V., Acín, I., 2018. Market Risk Premium and Risk-free Rate Used for 59 Countries in 2018: A Survey. http://ssrn.com/abstract=3155709, Accessed date: 2 January 2019.
Fisher, I., 1928. The Money Illusion. Adelphi, New York.
Hagerman, R., Ratchford, B., 1978. Some determinants of allowed rates of return on equity to electric utilities. Bell J. Econ. 9, 46–55. https://doi.org/10.2307/3003611.
Hamada, R., 1969. Portfolio analysis, market equilibrium and corporation finance. J. Financ. 24, 13–31. https://doi.org/10.1111/j.1540-6261.1969.tb00339.x.
Hamada, R., 1972. The effect of the firm's capital structure on the systematic risk of common stocks. J. Financ. 27, 435–452. https://doi.org/10.1111/j.1540-6261.1972.tb00971.x.
Harris, M., Navarro, P., 1983. Does electing public utility commissioners bring lower electric rates? Public Util. Fortn. 112, 23–27.
Haug, T., Wieshammer, L., 2019. Cost of equity for regulated networks: recent developments in continental Europe. Electr. J. 32, 1–3. https://doi.org/10.1016/j.tej.2019.02.001.
Hausman, J., 1978. Specification tests in econometrics. Econometrica 46, 1251–1272. https://doi.org/10.2307/1913827.
Hausman, J., Taylor, W., 1981. Panel data and unobservable individual effects.

Econometrica 49, 1377–1398. https://doi.org/10.2307/1911406.
Internal Revenue Service, n.d. SOI Tax Stats, Historical Table 24. https://www.irs.gov/pub/irs-soi/histabb.xls (accessed 2 January 2019).
Joskow, P., 1974. Inflation and environmental concern: structural change in the process of public utility price regulation. J. Law Econ. 17, 291–327. https://doi.org/10.1086/466794.
Hayashi, P., Trapani, J., 1976. Rate of return regulation and the regulated firm's choice of capital-labor ratio: further empirical evidence on the Averch-Johnson model. South. Econ. J. 42, 384–398.
Joskow, P., 1972. The determination of the allowed rate of return in a formal regulatory hearing. Bell J. Econ. Manag. Sci. 3, 632–644. https://doi.org/10.2307/3003042.
Judge, G., Griffiths, W., Hill, R., Lütkepohl, H., Lee, T., 1985. The Theory and Practice of Econometrics, second ed. John Wiley, New York.
Koedijk, K., Stork, P., 1994. Should we care? Psychological barriers in stock markets. Econ. Lett. 44, 427–432. https://doi.org/10.1016/0165-1765(94)90116-3.
Kwoka, J., 2002. Governance alternatives and pricing in the U.S. electric power industry. J. Law Econ. Organ. 18, 278–294. https://doi.org/10.1093/jleo/18.1.278.
Lintner, J., 1965. Security prices, risk, and maximal gains from diversification. J. Financ. 20, 79–96. https://doi.org/10.1111/j.1540-6261.1965.tb02930.x.
Mehra, R., Prescott, E., 1985. The equity premium: a puzzle. J. Monet. Econ. 15, 145–161. https://doi.org/10.1016/0304-3932(85)90061-3.
Mehra, R., Prescott, E., 2003. The equity premium in retrospect. In: Constantinides, G., Harris, M., Stulz, R. (Eds.), Handbook of the Economics of Finance. Elsevier, Amsterdam, pp. 889–938.
Morin, R., 2006. New Regulatory Finance. Public Utilities Reports, Vienna.
Mossin, J., 1966. Equilibrium in a capital asset market. Econometrica 34, 768–783. https://doi.org/10.2307/1910098.
Myers, S., 1972. The application of finance theory to public utility rate cases. Bell J. Econ. Manag. Sci. 3, 58–97. https://doi.org/10.2307/3003071.
Navarro, P., 1982. Public utility commission regulation: performance, determinants, and energy policy impacts. Energy J. 3, 119–139. https://doi.org/10.5547/ISSN0195-6574-EJ-Vol3-No2-7.
Olson, M., 1965. The Logic of Collective Action. Harvard University Press, Cambridge.
Pennsylvania Public Utility Commission, 2016. Bureau of Technical Utility Services Report on the Quarterly Earnings of Jurisdictional Utilities for the Year Ended June 30, 2016. Docket M-2016-2570997. . http://www.puc.state.pa.us/pcdocs/1483248.docx, Accessed date: 2 January 2019.
Pettway, R., Jordan, B., 1987. APT vs. CAPM estimates of the return-generating function parameters for regulated public utilities. J. Financ. Res. 10, 227–238. https://doi.org/10.1111/j.1475-6803.1987.tb00493.x.
Phillips Jr., C., 1993. The Regulation of Public Utilities. Public Utilities Reports, Arlington.
PJM Interconnection, 2016. Resource Investment in Competitive Markets. http://pjm.com/~/media/documents/reports/20160505-resource-investment-in-competitive-markets-paper.ashx, Accessed date: 2 January 2019.
Primeaux, W., Mann, P., 1986. Regulator selection methods and electricity prices. Land Econ. 62, 1–13. https://doi.org/10.2307/3146558.
Roberts, R., Maddala, G., Enholm, G., 1978. Determinants of the requested rate of return and the rate of return granted in a formal regulatory process. Bell J. Econ. 9, 611–621. https://doi.org/10.2307/3003601.
Roll, R., Ross, S., 1983. Regulation, the capital asset pricing model, and the arbitrage pricing model. Public Util. Fortn., May 26 (1983), 22–28.
Ross, S., 1976. The arbitrage theory of capital asset pricing. J. Econ. Theory 13, 341–360. https://doi.org/10.1016/0022-0531(76)90046-6.
Sears, R., Trennepohl, G., 1993. Investment Management. Dryden Press, Ft. Worth, pp. 516–517.
Shafir, E., Diamond, P., Tversky, A., 1997. Money illusion. Q. J. Econ. 112, 341–374. https://doi.org/10.1162/003355397555208.
Sharpe, W., 1964. Capital asset prices: a theory of market equilibrium under conditions of risk. J. Financ. 19, 425–442. https://doi.org/10.1111/j.1540-6261.1964.tb02865.x.
Spann, R., 1974. Rate of return regulation and efficiency in production: an empirical test of the Averch-Johnson thesis. Bell J. Econ. Manag. Sci. 5, 38–52. https://doi.org/10.2307/3003091.
Stigler, G., 1971. The theory of economic regulation. Bell J. Econ. Manag. Sci. 2, 3–21. https://doi.org/10.2307/3003160.
Svedsäter, H., Gamble, A., Gärling, T., 2007. Money illusion in intuitive financial judgments: influences of nominal representation of share prices. J. Socio Econ. 36, 698–712. https://doi.org/10.1016/j.socec.2007.01.006.
Villadsen, B., Brown, T., 2012. International innovations in rate of return determination. In: Presentation at the 2012 Society of Utility and Regulatory Financial Analysts Forum, April 26, 2012.
Villadsen, B., Vilbert, M., Harris, D., Kolbe, A.L., 2017. Risk and Return for Regulated Industries. Academic Press, Cambridge.
Vitaliano, D., Stella, G., 2009. A frontier approach to testing the Averch-Johnson hypothesis. Int. J. Econ. Bus. 16, 347–363. https://doi.org/10.1080/13571510903227031.

Gmail

Mark Ellis <mark.edward.ellis@gmail.com>

RE: Inquiry: How Value Line calculates beta
1 message

vlsoft@valueline.com <vlsoft@valueline.com> Wed, Oct 6, 2021 at 9:03 AM
To: mark.edward.ellis@gmail.com

Dear Mr. Ellis,

Value Line's Estimation of Beta

The return on security I is regressed against the return on the New York Stock Exchange

Composite Index in the following form:

$$\mathrm{Ln}\,(p^{I}_{t} / p^{I}_{t-1}) = a_{I} + B_{I} * \mathrm{Ln}\,(p^{m}_{t} / p^{m}_{t-1})$$

Where:

p^{I}_{t} - The price of security I at time t

p^{I}_{t-1} - The price of security I one week before time t

p^{m}_{t} and p^{m}_{t-1} are the corresponding values of the NYSE Composite Index.

The natural log of the price ratio is used as an approximation of the return and no adjustment is made for dividends paid during the week.

The regression estimate of beta, B_I, is computed from data over the past five years, so that 259 observations of weekly price changes are used.

Value Line adjusts its estimate of beta for regression bind described by Blume (1971). The reported beta is the adjusted beta computed as:

$$\text{Adjusted } B_I = 0.35 + .67 * B_I$$

M. Blume, "On the assessment of risk," Journal of Finance, March 1971

There is nothing more recent.

Thanks,

Cheryl Dhanraj | **Technical Support** | 212.907.1500 | vlsoft@valueline.com

Connect with us: Facebook | Google+ | LinkedIn | Twitter

Complimentary Value Line® Reports on Dow 30 Stocks

Value Line—*The Most Trusted Name in Investment Research®*

From: Mark Ellis [mailto:mark.edward.ellis@gmail.com]
Sent: Wednesday, October 06, 2021 10:48 AM
To: VLsoft <vlsoft@valueline.com>
Subject: Inquiry: How Value Line calculates beta

I am researching how different market data providers calculate beta. I could not find any details on your website but came across the attached, from a regulatory filing, which looks dated. Could you please provide an update of Value Line's beta calculation methodology or confirm that the method described in the attached is correct?

Thank you!

Mark Ellis

619 507 8892

Gmail

Mark Ellis <mark.edward.ellis@gmail.com>

Fwd: Chat Question: Case 11968851 [ref:_00D30aXa._5006f1hy0ed:ref]

1 message

From: **Support - Primary Email Address** <support.capiqpro@spglobal.com>
Date: Wed, Nov 17, 2021 at 5:57 PM
Subject: Chat Question: Case 11968851 [ref:_00D30aXa._5006f1hy0ed:ref]

S&P Global
Market Intelligence

Thank you for your response. Yes, you are correct about all your questions related to beta; likewise, you are using CIQ Pro and are pulling 1 and 3-year betas from using this platform.

I hope this is helpful, and please let me know if you have any other questions. Thanks and have a great rest of your day!

Best,

Paul Cordle
Associate, Client Support

Please "Reply All" to this email to ensure you receive a timely response.

S&P Global Market Intelligence
212 7th St NE
Charlottesville, VA 22902
T: +1.434.529.2097 | Support: 1.888.275.2822
paul.cordle@spglobal.com | support.MI@spglobal.com
www.spglobal.com
LinkedIn | Twitter | Facebook | YouTube | Instagram

--------------- Original Message ---------------
Sent: 11/17/2021 4:16 PM
To: support.capiqpro@spglobal.com
Subject: Re: Chat Question: Case 11968851 [ref:_00D30aXa._5006f1hy0ed:ref]
Sorry for the delay in getting back to you, Paul.

Just to confirm:

- I am using CIQ Pro
- When I download betas, they are "SNL" 1- and 3-year betas
- Regarding SNL betas --
    - They use daily returns
    - Returns are:
        - Price-only (not total return)
        - Absolute (not relative to the risk-free rate)
        - Simple (not logarithmic)
    - The S&P 500 is the proxy for the market
    - The betas are raw, not adjusted toward 1.0

Thanks for your patience and help!

Docket E-7, Sub 1276
Exhibit MEE-6

Richard A. Michelfelder *is Clinical Associate Professor of Finance at Rutgers University, School of Business, Camden, New Jersey. He earlier held a number of entrepreneurial and executive positions in the public utility industry, some of them involving the application of renewable and energy efficiency resources in utility planning and regulation. He was CEO and chairperson of the board of Quantum Consulting, Inc., a national energy efficiency and utility consulting firm, and Quantum Energy Services and Technologies, LLC, an energy services company that he co-founded. He also helped to co-found and build Comverge, Inc., currently one of the largest demand-response firms in the world, which went public in 2006 on the NASDAQ exchange. He was also an executive at Atlantic Energy, Inc. and Chief Economist at Associated Utilities Services, where he testified on the cost of capital for public utilities in a number of state jurisdictions and before the Federal Energy Regulatory Commission. He holds a Ph.D. in Economics from Fordham University.*

Panayiotis Theodossiou *is Professor and Dean of Faculty of Management at the Cyprus University of Technology. Previously he was Professor of Finance at Rutgers University, School of Business, Camden. Dr. Thedossiou has also held a number of other faculty positions in finance at Catholic University and Clarkson University. He has also provided consulting advice to national governments. He holds a Ph.D. in Finance from the City University of New York.*

This article has benefitted from participant comments at the Rutgers University Center for Research in Regulated Industries Eastern Conference in May 2011. The authors would also acknowledge the Whitcomb Center for Financial Research for funding the data acquisition from the WRDS database.

Public Utility Beta Adjustment and Biased Costs of Capital in Public Utility Rate Proceedings

The Capital Asset Pricing Model (CAPM) is commonly used in public utility rate proceedings to estimate the cost of capital and allowed rate of return. The beta in the CAPM associates risk with estimated return. However, an empirical analysis suggests that the commonly used Blume CAPM beta adjustment is not appropriate for electric and electric and gas public utility betas, and may bias the cost of common equity capital in public utility rate proceedings.

Richard A. Michelfelder and Panayiotis Theodossiou

I. Introduction

Regulators, public utilities, and other financial practitioners of utility rate setting in the United States and other countries often use the Capital Asset Pricing Model (CAPM) to estimate the rate of return on common equity (cost of common equity).[1] Typically, the ordinary least squares method (OLS) is the preferred estimation method for the CAPM betas of public utilities. Although the CAPM model has been widely criticized regarding its validity and predictability in the literature, as summarized by Professors Fama and French in 2005,[2] many firms and practitioners extensively use it to obtain cost of common equity estimates; e.g., such as shown by Bruser et al. in 1998, Graham and Harvey in 2001, and Gray, et al. in 2005.[3] Michelfelder, et al. in 2013[4] in this

 1040-6190/$–see front matter http://dx.doi.org/10.1016/j.tej.2013.09.017

journal presents a new model, i.e., the Predictive Risk Premium Model, to estimate the cost of common equity capital and compare and contrast the poor results of the CAPM to that model and the discounted cash flow model.

Major vendors of betas include, but are not limited to, Merrill Lynch, Value Line Investment Services (Value Line), and Bloomberg. These companies use Blume's 1971 and 1975[5] beta adjustment equation to adjust OLS betas to be used in the estimation of the cost of common equity for public utilities and other companies.

The premise behind the Blume adjustment is that estimated betas exhibit mean reversion toward one over time; that is, betas greater or less than 1 are expected to revert to 1. There are various explanations for the phenomenon first discussed in Blume's pioneering papers. One explanation is that the tendency of betas toward one is a by-product of management's efforts to keep the level of firm's systematic risk close to that of the market. Another explanation relates to the diversification effect of projects undertaken by a firm.[6]

While this may be the case for non-regulated stocks, regulation affects the risk of public utility stocks and therefore the risk reflected in beta may not follow a time path toward one as suggested by Peltzman in 1976, Binder and Norton in 1999, Kolbe and Tye in 1990, Davidson, Rangan, and Rosenstein in 1997, and Nwaeze in 2000.[7] Being natural monopolies in their own geographic areas, public utilities have more influence on the prices of their product (gas and electricity) than other firms. The rate setting process provides public utilities with the opportunity to adjust prices of gas and electricity to recover the rising costs of fuel and other materials used in the transmission and distribution of electricity and gas. Companies operating in competitive markets do not have this ability. In this respect, the perceived systematic risk associated with the common stock of a public utility may be lower than that of a non-public utility. Therefore, forcing the beta of a utility stock toward one may not be appropriate, at least on a conceptual basis.

The premise behind the Blume adjustment is that estimated betas exhibit mean reversion toward one over time.

The explanations provided by Blume and others to justify the latter tendency are hardly applicable to public utilities. Unlike other companies, utilities can and do possess monopolistic power over the markets for their products. This power impacts the ''negotiation process'' for setting electric and gas prices. Furthermore, it provides them with the opportunity to raise prices to recover increases in operating costs without regard to competitive market pressure. Such price influence is rarely available to companies operating in competitive market environments for their products. In that respect, macroeconomic factors will have a greater impact on the earnings and stock prices of the non-utility companies resulting in larger systematic risk or betas.

The application of Blume's equation to public utility stocks generally results in larger betas, since most raw utility betas are less than 1. Therefore, applications of these betas to estimate the cost of capital and an allowed rate of return on common equity possibly biases the required rate of return or cost of common equity, leading to an over-investment of capital as predicted by Averch and Johnson in 1962,[8] which preceded the trend in prudency reviews that began to occur in the 1980s. Although reported public utility betas may have been biased upward by the vendors of beta that applied Blume's adjustment to public utility betas, ex post prudency reviews of ''used and useful'' assets defined and supported by the Duquesne 1989 US Supreme Court decision[9] resulted in an underinvestment of capital in generation and transmission assets, leading to electric brownouts and blackouts. This article examines the behavior of the betas of the population of publicly traded U.S. energy utilities. In addition to evaluating the stability of these betas over the period from the January 1962 to December 2007, we also test whether or not public utility betas are stationary or mean reverting toward 1 or perhaps a different level.

II. Background

Investor-owned public utility regulatory proceedings to change rates for service almost always involve contentious litigation on the fair rate of return or cost of common equity. Since the cost of common equity is not observable, it must be inferred from market valuation models of common equity. The differences in the recommended allowed rates of return resulting from necessary subjective judgments in the application of cost of common equity models can easily mean 500 basis points or more in the estimate. Therefore, both the impact on customer rates for utility service and the profits of the utilities are very sensitive to the methods used to estimate the cost of common equity and allowed rate of return. The two most commonly used models are the Dividend Discount Model (DDM) and the CAPM. We discuss the use of CAPM for estimating the cost of common equity for public utilities. Our focus is on the use of market-influential betas from the major vendors of betas: Merrill Lynch, Value Line, and Bloomberg. These vendors apply Blume's adjustment to raw betas to estimate forward-looking betas. Blume[10] performed an empirical investigation, finding that beta is non-stationary and has a tendency to converge to 1. Bey in 1983 and Gombola and Kahl in 1990[11] found that utility betas are non-stationary and concluded that each utility beta's non-stationarity must be viewed on an individual stock basis, unlike the recommendation of Blume which adjusts all betas for their tendency to approach 1. Similarly with

Investor-owned public utility regulatory proceedings to change rates for service almost always involve contentious litigation on the fair rate of return or cost of common equity.

Gombola and Kahl, we find that public utility betas have a tendency to be less than 1. They investigated the time series properties of public utility betas for their ability to be forecasted whereas we are concerned with the institutional reasons for the trends in beta, the bias instilled in cost of capital estimates assuming that utility betas converge to one and the widespread use and applicability of the Blume adjustment to public utility betas. McDonald, Michelfelder and Theodossiou in 2010[12] show that use of OLS is problematic itself for estimating betas as the nonnormal nature of stock returns result in beta estimates that are statistically inefficient and possibly biased.

Blume's equation is:

$$\beta_{t+1} = 0.343 + 0.677\beta_t \qquad (1)$$

where β_{t+1} is the foreasted or projected beta for stock *i* based on the most recent OLS estimate of firm's beta β_t. For example if β_t is estimated using historical returns from the most recent five years, then the projected β_{t+1} may be viewed as a forecast of the beta to prevail during the next five years. As mentioned earlier, Blume's equation implies a long-run mean reversion of betas toward 1. The long-run tendency of betas implied by Blume's equation can be computed using the equation:

$$\overline{\beta} = \frac{0.343}{1-0.677} = 1.0619 \approx 1 \qquad (2)$$

The same result can be obtained by recursively predicting beta until it converges to a final value. This can only be appropriate for stocks with average betas, as a group, close to one. This is, however, hardly the case for public utility betas that are generally less than 1 (as discussed in detail below).

The magnitude of adjustment for Blume's beta equation is initially large and declines dramatically as the adjusted beta approaches 1 either from below (for betas lower than 1) or from above (for betas greater than 1). In this respect, the beta adjustment step (size) will be larger for betas further away from 1.

As we will see in the next section, the median beta of the public utilities studied ranges between 0.08 and 0.74 over time,

  http://dx.doi.org/10.1016/j.tej.2013.09.017

depending upon the period used. Under the assumption that betas for public utilities are consistent with Blume's equation, the next period beta for a stock with a current beta of 0.5, will be $\beta_{t+1} = 0.343 + 0.677\ (0.5) = 0.6815$, implying a 36.3 percent (0.6815/0.5) upward adjustment. On the other hand a beta of 0.4 will be adjusted to $\beta_{t+1} = 0.343 + 0.677\ (0.4) = 0.6138$ which constitutes a 53.5 percent upward adjustment and a beta of 0.3 will be adjusted to 0.5461 or by 82.0 percent.

The beta adjustment method most widely disseminated by the major beta vendors is the Blume adjustment. Therefore, our focus is on the Blume adjustment for public utility betas and the public utility cost of common equity capital. Occasionally, an expert witness in a public utility rate case estimates their own betas, but they are quickly repudiated in rate proceedings since these betas are not disseminated by influential stock analysts and presumed not to be reflected in the stock price. Section III discusses the data and empirical analysis of the Blume adjustment and its impact on the cost of common equity for public utilities.

III. Data and Empirical Analysis

The data include monthly holding period total returns for 57 publicly traded U.S. public utilities for the period from January 1962 to December 2007 obtained from the University of Chicago's Center for Research in Security Prices (CRSP) database. The sample includes all publicly traded electric and electric and gas combination public utilities with SIC codes 4911 and 4931 listed in the CRSP database. All non-U.S. public utilities traded in the U.S. and non-utility stocks were not included in the dataset. The monthly holding period total returns for each stock as calculated in the CRSP database were used for estimating betas of varying periods. The monthly market total return is the CRSP value-weighted total return.

Occasionally, an expert witness in a public utility rate case estimates their own betas, but they are quickly repudiated in rate proceedings.

The computation of the betas is based on the single index model, also used in Blume:

$$R_{i,t} = \alpha_i + \beta_i R_{m,t} + e_{i,t}, \tag{3}$$

where $R_{i,t}$ and $R_{m,t}$ are total returns for stock i and the market during month t, α_i, and β_i are the intercept and beta for stock i and $e_{i,t}$ is a regression error term for stock i. As previously mentioned, OLS is the typical estimation method used by many vendors of beta and is used in this investigation.

Table 1 presents the mean and median OLS beta estimates for the 57 utilities using 60, 84, 96, and 108 monthly returns respectively over five different non-lapping periods between December 1962 and December 2007. We also performed the same empirical analysis for periods of 4, 6, 10, 11, 12 and 13 years and the results were similar; the results are not shown for brevity but available upon request. We used non-overlapping periods to avoid serial correlation and unit roots. If we take, for example, 360 months of time series of returns for a stock and estimate 60-month rolling betas moving one month forward for each beta, this would result in 300 betas. Since only two of 60 observations would be unique due to overlapping periods, the error term would be highly serially correlated. A Blume-type regression of these betas would have a unit root, a coefficient of one and an intercept near 0, and therefore appear to follow a random walk. Therefore, the empirical nature of beta requires that lags in the Blume equation involve no overlapping time periods.

The mean and median betas in Table 1 not only do not rise toward 1 as the time period moves forward; the betas generally decline. Table 2 includes OLS regressions of the Blume equation for the 5-, 7-, 8-, and 9-year betas. We estimated five sets of 4- through 13-year betas inclusively for each public utility then

Table 1: Mean and Median Betas for Varying Time Periods.

9-Year Periods	12/62–12/71	12/71–12/80	12/80–12/89	12/89–12/98	12/98–12/07
Mean	0.69	0.60	0.41	0.40	0.27
Median	0.68	0.57	0.40	0.36	0.22
8-Year Periods	**12/67–12/75**	**12/75–12/83**	**12/83–12/91**	**12/91–12/99**	**12/99–12/07**
Mean	0.76	0.39	0.45	0.27	0.33
Median	0.74	0.37	0.43	0.23	0.27
7-Year Periods	**12/72–12/79**	**12/79–12/86**	**12/86–12/93**	**12/93–12/00**	**12/00–12/07**
Mean	0.68	0.40	0.40	0.09	0.50
Median	0.65	0.39	0.38	0.06	0.47
5-Year Periods	**12/77–12/82**	**12/82–12/87**	**12/87–12/92**	**12/92–12/97**	**12/97–12/02**
Mean	0.36	0.38	0.53	0.49	0.12
Median	0.35	0.38	0.50	0.45	0.08

The following model was estimated for the sample of public utility stocks for five 60-, 84-, 96-, and 108-month non-overlapping periods. The ordinary least squares method was used to estimate the parameters of the single index model: $R_{i,t} = \alpha_i + \beta_i R_{m,t} + e_{i,t}$
where $R_{i,t}$ and $R_{m,t}$ are total returns for stock i and the market during month t, α_i, and β_i is the intercept and capital asset pricing model beta for stock i, respectively, and $e_{i,t}$ is a regression error term for stock i. The entire data series ranges from December 1962 to December 2007. The stock returns are the monthly holding period total returns from the CRSP database. The market returns are the CRSP market value-weighted total returns.

regressed the latter beta on the previous period betas. The 5-, 7-, 8-, and 9-year equations are shown for brevity. The diagnostic statistics strongly refute the validity of the Blume equation for public utility stocks. Most of the R^2's are equal to or close to 0.00 and the largest is 0.09. Only one F-statistic (tests the significance of the equation estimation) is significant and all but two slopes are insignificant. Also shown is the long-run beta implied from each Blume model as shown in equation (2). They range from 0.08 to 0.59. Only one estimate, the first-period 9-year Blume equation, includes a positive and statistically significant slope and intercept. The implied long-term beta of that equation is 0.59, which is substantially below one and the largest value of all estimates. As a final and visual review of the trends in betas, we developed and plotted probability distribution box plots developed by Tukey in 1977[13] for the 4- through 13-year public utility betas. We have shown only the 4- and 5-year beta box plots as shown in Figures 1 and 2 for brevity (the 6- to 13-year plots are available upon request). Tukey box plots show the 25th and 75th percentiles (the box height), the 10th and 90th percentiles (the whiskers), the median (the line inside the box), and the dispersion of the outlying betas. The box plots should be viewed as looking down on the distributions of the betas. We developed 4- through 13-year beta box plots to review the trend in shorter-term versus longer-term betas. None of the 51 beta probability distributions display any tendency for betas to drift toward one. The 5-, 6- and 7-year betas have higher variances in the last period relative to all other periods. A few outlying betas are greater than 2.0. This pattern is consistent with the notion that utility holding companies are investing in risky ventures of affiliates that can retain excess returns should they be realized. Note that the mean beta in Figures 1 and 2 show the cyclical nature of short-term utility betas with a severe downturn in the late 1990s and a severe upswing in the early 2000s. Generally, the box plots show a long-term downward trend in public utility betas.

It is interesting to note that the drop in beta occurred just after

 1040-6190/$–see front matter , http://dx.doi.org/10.1016/j.tej.2013.09.017

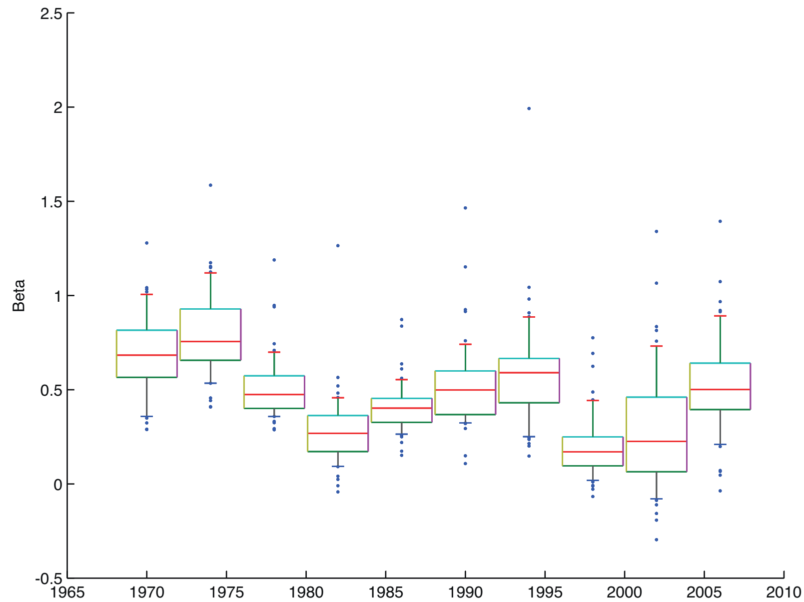
Table 2: Public Utility Blume Equation Estimates.

9-Year Betas	$\beta_2 = f(\beta_1)$	$\beta_3 = f(\beta_2)$	$\beta_4 = f(\beta_3)$	$\beta_5 = f(\beta_4)$
γ_0	0.463***	0.318***	0.480***	0.235***
	(0.074)	(0.062)	(0.096)	(0.080)
γ_1	0.214**	0.153	−0.186	0.800
	(0.102)	(0.099)	(0.227)	(0.179)
Long Run β	0.59	0.38	0.41	0.26
R^2	0.09	0.04	0.01	0.00
F-Statistic	4.43**	2.36	0.67	0.20
p-Value	0.04	0.13	0.42	0.65
8-Year Betas	$\beta_2 = f(\beta_1)$	$\beta_3 = f(\beta_2)$	$\beta_4 = f(\beta_3)$	$\beta_5 = f(\beta_4)$
γ_0	0.341***	0.464***	0.184**	0.321***
	(0.083)	(0.047)	(0.088)	(0.070)
γ_1	0.058	−0.034	0.193	0.035
	(0.106)	(0.115)	(0.189)	(0.220)
Long Run β	0.36	0.45	0.23	0.33
R^2	0.01	0.00	0.02	0.00
F-Statistic	0.30	0.09	1.04	0.02
p-Value	0.58	0.76	0.31	0.88
7-Year Betas	$\beta_2 = f(\beta_1)$	$\beta_3 = f(\beta_2)$	$\beta_4 = f(\beta_3)$	$\beta_5 = f(\beta_4)$
γ_0	0.370***	0.375***	0.074	0.491***
	(0.081)	(0.052)	(0.075)	(0.049)
γ_1	0.048	0.059	0.036	0.128
	(0.115)	(0.122)	(0.179)	(0.259)
Long Run β	0.39	0.40	0.08	0.56
R^2	0.00	0.00	0.00	0.00
F-Statistic	0.17	0.23	0.04	0.24
p-Value	0.68	0.63	0.84	0.62
5-Year Betas	$\beta_2 = f(\beta_1)$	$\beta_3 = f(\beta_2)$	$\beta_4 = f(\beta_3)$	$\beta_5 = f(\beta_4)$
γ_0	0.329***	0.474***	0.321***	0.106*
	(0.047)	(0.086)	(0.088)	(0.061)
γ_1	0.151	0.137	0.316**	0.019
	(0.119)	(0.213)	(0.157)	(0.111)
Long Run β	0.39	0.55	0.47	0.11
R^2	0.03	0.01	0.07	0.00
F-Statistic				
p-Value	1.62	0.41	4.07	0.03
	0.21	0.52	0.05	0.87

The following Blume equation was estimated using the betas of public utility stocks for five 60-, 84-, 96-, and 108-month non-overlapping periods. The ordinary least squares method was used to estimate the parameters of the following model: $\beta_{i,t+1} = \gamma_0 + \gamma_1\beta_{i,t} + \varepsilon_{i,t}$.
where $\beta_{i,t+1}$ is the OLS estimated CAPM beta for stock i, $\beta_{i,t}$ is the previous period beta for stock i, γ_0 and γ_1 are the intercept and slope of the Blume equation, and ε_t is the regression error term. The time subscripts on the betas refer to the time periods of estimation from Table 1. For example, β_5 in the 9 year panel refers to the beta estimated for each stock using the returns data from December 1998 to December 2007. The long-run $\beta = \gamma_0/(1 - \gamma_1)$; it can also be found by solving recursively for the next period beta until it converges on a final value. Newey-West autocorrelation and heteroskedasticity consistent standard errors are in parentheses.

* Significance at 0.10 level.
** Significance at 0.05 level.
*** Significance at 0.01 level.

deregulation of the wholesale electricity market in April 1996. This is inconsistent with the buffering theory of Peltzman and Binder and Norton[14] who found that regulation buffers the volatility of cash flows of public utilities from the vicissitudes of competition and business cycles and therefore reduces their systematic risk. However, this is consistent with Koble and Tye's 1990[15] theory of asymmetric regulation and the empirical findings of Michelfelder and Theodossiou in 2008,[16] who found that asymmetric regulation is associated with down-market public utility betas greater than their up-market betas. Adverse asymmetric regulation began in the 1980s and resulted in an upper boundary for public utilities' allowed rates of return equal to the cost of capital. If public utilities were granted an opportunity to earn their cost of common equity, regulators frequently would disallow specific investments *ex post* from earning the allowed rate of return if they were deemed ''not used and useful,'' even though they were deemed to be prudent when the decision was made to make these investments. The result was that utilities were not truly granted the opportunity to earn their allowed rate of return. If they happened to over-earn their allowed rate of return due to higher than anticipated demand forecasts, ''excess'' returns were taken away. This became known as regulatory risk, quantified as a risk premium in the cost of



Boxes give the 25th and 75th percentiles; line in the boxes is for the median; whiskers give the 10th and 90th Percentiles

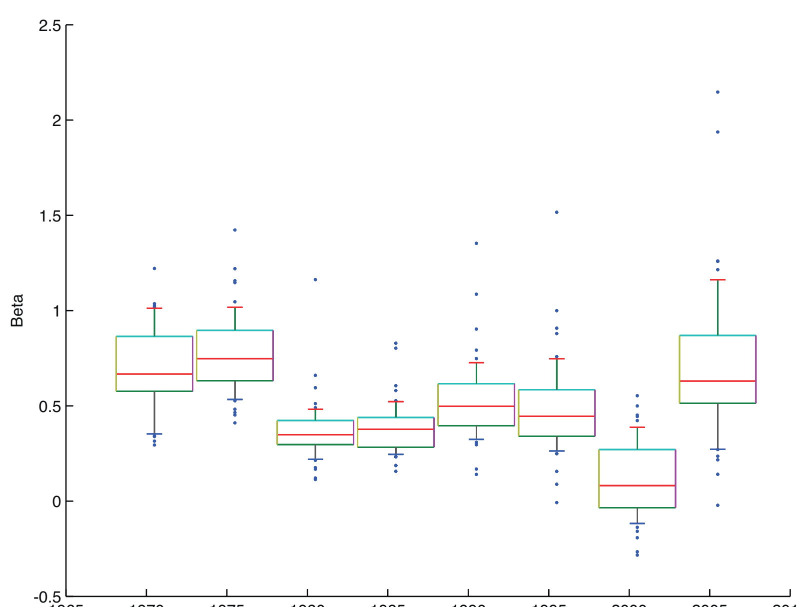
Figure 1: Boxplots of Utility Stock Betas Using 4 Year Periods Data

common equity. Michelfelder and Theodossiou in 2008[17] also concluded that public utility stocks are no longer defensive stocks dampening the downward behavior of otherwise less diversified portfolio returns in down markets.

Therefore, some suggest that *de*regulation may have ''buffered'' utility cash flows from regulatory risk, i.e., the chance that regulation would impose disappointing allowed rates of return in the manner described above. The advent of generation deregulation caused electric utilities with generating plants to no longer face regulatory risk on over 50 percent of their asset base. This is consistent with falling betas after deregulation of electric generation. The Brattle Group in 2004[18] found the same result in a research project for the Edison Electric Institute, an electric utility trade and lobbying organization. They found that electric utility betas fell after deregulation.

We suggest that it may be due to the relief of deregulation from asymmetric regulation. In any case, we find that the Blume adjustment toward 1 is not supported by our empirical results. This adjustment suggests that in the long run, all public utilities (and all firms) would gravitate toward the same risk and return. Our results herein suggest that the Blume adjustment is inappropriate for public utilities as it assumes that public utility betas are moving toward one in the long run as are non-utility company betas.

We perform a simple calculation to show the impact of a biased beta on public utility revenues. We calculate the common equity risk premium on the market as the annual total return for the CRSP market return from 1926 to 2007 to be approximately 12 percent and the average return on a three-month T-Bill to be about 4 percent. The long-term common equity risk premium is 8 percent. The difference between a beta of 0.50 and a Blume adjusted beta of .67 would result in a difference in cost of common equity



Boxes give the 25th and 75th percentiles; line in the boxes is for the median; whiskers give the 10th and 90th Percentiles.

Figure 2: Boxplots of Utility Stock Betas Using 5 Year Periods Data

 1040-6190/$–see front matter http://dx.doi.org/10.1016/j.tej.2013.09.017

of 136 basis points. Using a common equity ratio of 0.50, this would impact the weighted average rate of return by 68 points. Assuming a rate base of $5 billion (the level for a moderately large electric utility), the difference in ''allowed'' net income would be 0.0068 × $5 billion, or, $34 million. Assuming a 37.5 percent income tax rate, the increase in revenues required to earn the additional $34 million would be $54 million. This is obviously a substantial difference. It is important for us to stress in this example that we do not necessarily advocate these inputs for the recommended cost of common equity for a utility with a raw beta of 0.50. The deliberation in recommending the cost of common equity is performed with a careful and detailed analysis of the company and stock, referral to more than one valuation model of the cost of common equity estimation and expert judgment.

IV. Conclusion

Major vendors of CAPM betas such as Merrill Lynch, Value Line, and Bloomberg distribute Blume-adjusted betas to investors. We have shown empirically that public utility betas do not have a tendency to converge to 1. Short-term betas of public utilities follow a cyclical pattern with recent downward trends, then upward structural breaks with long-term betas following a downward trend. We estimate the Blume equation for electric and gas public utilities, finding that all but one equation is statistically insignificant. The single significant equation implies a long-term convergence of beta to approximately 0.59. During our nearly 45-year study period, the median beta ranged from 0.08 to 0.74. Therefore the Blume equation overpredicts utility betas and Blume-adjustments

of utility betas are not appropriate.

We are not suggesting that betas should not be adjusted for prediction. Rather, the measurement period and subjective adjustment to beta should be based upon the likely future trend in peer group or *public utility betas*, or the specific utility's beta, not the trend in betas for all stocks in general. The time pattern of utility betas is obviously more complex than a smooth curvilinear adjustment, or for that matter, any adjustment toward one. Nor do we suggest as an alternative the use of raw or unadjusted betas in an application of the CAPM to estimate a public utility's cost of common equity.■

Endnotes:

1. D.R. Harrington, *The Changing Use of The Capital Asset Pricing Model in Utility Regulation*, PUB. UTIL. FORTNIGHTLY 105 (1980), at 28.

2. E. Fama and K. French, *The Capital Asset Pricing Model: Theory and Evidence*, J. ECON. PERSPECTIVES, 18 (2005), at 25–46.

3. R.F. Bruner, K. Eades, R. Harris and R. Higgins, *Best Practices in Estimating the Cost of Capital: Survey and Synthesis*, FIN. PRACTICE & EDUCATION, 8 (1998), at 13–28. Also, J.R. Graham and C.R. Harvey, *The Theory and Practice of Corporate Finance: Evidence from the Field*, J. FIN. ECON., 60 (2001), at 187–243. And, S. Gray, J. Hall, J. Bowman, T. Brailsford, R. Faff and B. Officer, The Performance of Alternative Techniques for Estimating Equity Betas of Australian Firms, unpublished paper, Frontier Economics Network, 2005.

4. R.A. Michelfelder, P.M. Ahern, D. D'Ascendis and F.J. Hanley, *Comparative Evaluation of the Predictive Risk Premium Model, the Discounted Cash Flow Model and the Capital Asset Pricing Model for Estimating the Cost of Common Equity Capital*, ELEC. J., May 2013, at 84–89.

5. M. Blume, *On the Assessment of Risk*, J. FIN. 26 (1971), at 1–10, and M. Blume, *Betas and Their Regression Tendencies*, J. FIN. 30 (1975), at 785–795.

6. Id.

7. S. Peltzman, *Towards a More General Theory of Regulation*, J. LAW & ECON., 19 (1976), at 211–241. J.J. Binder and S.W. Norton, *Regulation, Profit Variability and Beta*, J. REGULATORY ECON., 15 (1999), at 249–265. And, A. Kolbe and W. Tye, *The Duquesne Opinion: How Much 'Hope' Is There for Investors in Regulated Firms*, YALEJ. ON REG., 8 (1990), at 113–158. W.N. Davidson, N. Rangan and S. Rosenstein, *Regulation and Systematic Risk in the Electric Utility Industry: A Test of the Buffering Hypothesis''*, FIN.REV. 23 (1997), at 163–184. And, E. Nwaeze, *Deregulation of the Electric Power Industry: The Earnings, Risk, and Returns Effects*, J. REG.ECON.17 (2000), at 49–67.

8. H. Averch and L. Johnson, *Behavior of the Firm Under Regulatory Constraint*, AM. ECON. REV. 52 (1962), at 1052–1069.

9. Kolbe and Tye, supra note 7.

10. Blume, supra note 5.

11. R. Bey, *Market Model Stationarity of Individual Public Utilities*, J. FIN. & QUANTITATIVE ANAL. 18 (1983), at 67–85. M. Gombola and D. Kahl, *Time-Series Processes for Utility Betas: Implications for Forecasting Systematic Risk*, FIN. MGMT.(1990), 84–93.

12. J.B. McDonald, R.A. Michelfelder and P. Theodossiou, *Robust Estimation with Flexible Parametric Distributions: Estimation of Utility Stock Betas*, QUANTITATIVE FIN. 10 (2010), at 375–387.

13. J. Tukey, EXPLORATORY DATA ANALYSIS (Reading, MA: Addison Wesley, 1977) at 39–43.

14. Peltzman, supra note 7, and Binder and Norton, supra note 7.

15. Kolbe and Tye, supra note 7.

16. R.A. Michelfelder and P. Theodossiou, Asymmetric Response of Public Utility Stocks to Up and Down Markets, Unpublished manuscript, Rutgers Univ., 2008.

17. Id.

18. Brattle Group, Issues for Cost of Capital Estimation, Presentation to Edison Electrical Institute Members, Chicago, Feb. 4, 2004.

Major vendors of CAPM betas such as Merrill Lynch, Value Line, and Bloomberg distribute Blume adjusted betas to investors.

  http://dx.doi.org/10.1016/j.tej.2013.09.017

Secular Mean Reversion and Long-Run Predictability of the Stock Market*

Valeriy Zakamulin†

This revision: December 18, 2015

Abstract

Empirical financial literature documents the evidence of mean reversion in stock prices and the absence of out-of-sample return predictability over periods shorter than 10 years. The goal of this paper is to test the random walk hypothesis in stock prices and return predictability over periods longer than 10 years. Specifically, using 141 years of data, this paper begins by performing formal tests of the random walk hypothesis in the prices of the real S&P Composite Index over increasing time horizons up to 40 years. Even though our results cannot support the conventional wisdom which says that the stock market is safer for long-term investors, our findings speak in favor of the mean reversion hypothesis. In particular, we find statistically significant in-sample evidence that past 15-17 year returns are able to predict future 15-17 year returns. This finding is robust to the choice of data source, deflator, and test statistic. The paper continues by investigating the out-of-sample performance of long-horizon return forecast based on the mean-reverting model. These latter tests demonstrate that the forecast accuracy provided by the mean-reverting model is statistically significantly better than the forecast accuracy provided by the naive historical-mean model. Moreover, we show that the predictive ability of the mean-reverting model is economically significant and translates into substantial performance gains.

Key words: predictability, stock returns, long-run, random walk, mean reversion, bootstrap simulation

JEL classification: C12, C14, C22, G12, G14, G17.

*The author is grateful to the following individuals for their helpful comments and suggestions regarding previous drafts of this paper: two anonymous referees; Brian Berry; Ed Easterling; Jochen Jungeilges; Ole Gjølberg; Steen Koekebakker; and the participants at the 2011 Computational and Financial Econometrics Conference (London, UK), the 2013 Fagkonferansen i Bedriftsøkonomiske Emner (FIBE Conference, Bergen, Norway), and the 2013 Forecasting Financial Markets Conference (Hannover, Germany). Any remaining errors in the manuscript are the author's responsibility.

†a.k.a. Valeri Zakamouline, School of Business and Law, University of Agder, Service Box 422, 4604 Kristiansand, Norway, Tel.: (+47) 38 14 10 39, Fax: (+47) 38 14 10 27, Valeri.Zakamouline@uia.no

1 Introduction

Until the late 1980s there was a widespread agreement in the academic community that stock prices follow a random walk. Indeed, a large body of empirical literature seemed to support this point of view (see Fama (1970) and Leroy (1982) for surveys). The efficient market hypothesis is strongly associated with the idea of a random walk in stock prices and loosely says that stock returns are unpredictable. However, during the late 1980s there appeared a series of papers where the authors challenged the random walk hypothesis (see, for example, Summers (1986), Campbell and Mankiw (1987), Fama and French (1988b), Lo and MacKinlay (1988), and Poterba and Summers (1988)). In particular, these authors considered the time series properties of stock returns over increasing time horizons up to 10 years and found the indications of mean reversion[1] and return predictability. For example, Fama and French (1988b) discovered a substantial negative autocorrelation in returns over periods of 3-5 years and concluded that past 3-5 year returns are able to predict future 3-5 year returns. Poterba and Summers (1988) found that stock returns exhibit positive and statistically significant autocorrelation in returns over periods shorter than one year and negative, though not statistically significant at conventional levels (1% or 5%), autocorrelations over longer periods.

However, the conclusions reached in these earlier papers were strongly criticized on statistical grounds. For example, Kim, Nelson, and Startz (1991) demonstrated that due to the small-sample bias the statistical significance of the test statistics in Fama and French (1988b) and Poterba and Summers (1988) was overstated and there was no predictability of future 3-5 year returns on the basis of past 3-5 year returns. Similarly, Richardson and Stock (1989) and Richardson (1993) showed that correcting for the small-sample bias may reverse the results obtained by Fama and French (1988b) and Poterba and Summers (1988).

[1] Mean reversion is an ambiguous concept and exists in several different forms. Most often, the concept of mean reversion can be expressed by the common investment wisdom which says that "over time markets tend to return to the mean". For example, when stocks go too far in one direction, they will eventually come back. Another type of mean reversion, which is studied in this paper, implies that the reversion is much more than just returning back to the mean. In reality the movement is far greater. This type of mean reversion incorporates another common investment wisdom which says that "an excess in one direction will lead to an excess in the opposite direction". That is, when stocks go too far in one direction, they will not just come back to the mean, but overshoot in the opposite direction. For example, a period of above average returns tends to be followed by a period of below average returns and vice versa. Throughout the paper, the term "period" is used to denote the period of mean reversion. The term "horizon" is mainly used to denote the average length of a complete cycle of reversion which consists of two periods: a period of higher than average returns and a period of lower than average returns (or vice versa).

Apparently, the statistical power of earlier tests was insufficient to reject the random walk hypothesis. Jegadeesh (1991) suggested a new more powerful test and detected statistically significant evidence of mean reversion in stock prices (over periods of 4-8 years). In addition, Jegadeesh found evidence of mean reversion not only for the US stock market, but also for the UK stock market. Later on based on a panel approach Balvers, Yangru, and Gilliland (2000) found statistically significant evidence of mean-reverting behavior (over periods of 3-3.5 years) in many international stock indices. Thus, mean reversion in stock prices seems to be an international phenomenon. Using the same technique as in Balvers et al. (2000), Gropp (2003) and Gropp (2004) found statistically significant evidence of mean reversion in the prices of portfolios of small cap stocks (over periods of 3.5 years) and industry-sorted portfolios (over periods of 4.5-8 years). Moreover, Balvers et al. (2000), Gropp (2003), and Gropp (2004) showed that parametric contrarian investment strategies that exploit mean reversion outperform buy-and-hold and standard contrarian strategies. This provides further support for the mean reversion findings in these papers.

Thus, nowadays the evidence of mean reversion in the prices of some stock portfolios over periods of 3-8 years seems to have been manifested. In contrast, the predictability of stock returns is still a source of heated debate within the academic community. Earlier papers, that demonstrated the existence of in-sample stock return predictability, include, among others, Fama (1981), Campbell (1987), Fama and French (1988b), Fama and French (1988a), Campbell and Shiller (1988), and Fama and French (1989). Again, the conclusions reached in these earlier papers were strongly criticized on statistical grounds. For example, Richardson and Stock (1989) and Nelson and Kim (1993) pointed to the small-sample bias problem, whereas Cavanagh, Elliott, and Stock (1995), Stambaugh (1999), and Lanne (2002) pointed to a neglected near unit root problem. Responding to the critique, Torous, Valkanov, and Yan (2004), Lewellen (2004), Rapach and Wohar (2005), and Campbell and Yogo (2006) developed new tests, that are free from the discovered flaws in the earlier tests, and again found some evidence of in-sample predictability. Yet, Bossaerts and Hillion (1999), Goyal and Welch (2003), and Welch and Goyal (2008) demonstrated that, despite evidence of in-sample predictability, the predictive models have no out-of-sample forecasting power. These authors therefore argued that in-sample predictability appears as a result of data mining. It should be noted, however, that in all these tests the longest forecast horizon was 10 years. Consequently, the results of these tests imply that the predictive models fail to demonstrate statistically significant predictive ability over short-term and medium-term horizons.

To the best knowledge of the author, no one has ever tested the random walk hypothesis in stock prices over periods longer than 10 years. Yet, anecdotal evidence suggests the presence of mean reversion in stock prices over very long horizons. Probably the best known evidence is presented by Siegel (2002) in his famous book "Stocks for the Long Run". In particular, using a historical sample that covers nearly 200 years, Siegel computed the standard deviation of average real annual returns on a broad US stock market index over increasing horizons up to 30 years. Siegel found that the standard deviation declines far faster than predicted by the random walk hypothesis. This led many to conclude that stocks are less risky in the long run. However, so far there have been no studies conducted on whether the decline in the standard deviation over very long horizons is statistically significant.

Another well-known anecdotal evidence, explicitly related to the mean reversion in stock prices over very long horizons, suggests the existence of long-lasting alternating periods of bull and bear markets. These long-lasting bull and bear markets are often termed as "secular" bull and bear markets. Alexander (2000), Easterling (2005), Rogers (2005), Katsenelson (2007), and Hirsch (2012), among others, analyzed the dynamics of the real S&P Composite Index since 1870 and found the indications of existence of secular stock market trends that last from 5 to 25 years, with average duration of about 15 years. Motivated by the seeming regularity in the reversion of secular trends, some authors made quite successful forecasts for the long-run US stock market outlook. For example, Alexander (2000) predicted that during the period from 2000 to 2020 the stock market will not beat the money market. So far, this forecast seems to come true. This anecdotal evidence suggests, among other things, that a price change over a given long-run period may be able to predict the price change over the subsequent long-run period. This idea motivates to re-examine the predictive performance of the model introduced by Fama and French (1988b). Even though Kim et al. (1991) demonstrated that this model has no predictive power on increasing periods up to 10 years, as far as the author knows, no one has ever tested this model on periods longer than 10 years. This paper aims to fill these gaps in scientific knowledge about the stock market dynamics over very long horizons.

The first contribution of this paper is to provide, for the first time, statistically significant evidence against the random walk hypothesis over periods longer than 10 years. Even though our results cannot support the anecdotal evidence which says that the stock market is safer for long-term investors, our findings do speak in favor of mean reversion in stock prices over periods of 15-17 years. In particular, using the whole sample of data, we find statistically significant evidence that a given change in price over 15-17 years tends to be reversed over the next 15-17 years by a predictable change in the opposite direction. This implies the existence of in-sample long-horizon predictability. Since the conventional wisdom says that in-sample evidence of stock return predictability might be a result of data mining, we investigate the performance of out-of-sample long-horizon return forecast. Besides the mean-reverting model, we investigate the out-of-sample forecast accuracy of a few other competing models which employ, as a predictor for long-horizon returns, the cyclically adjusted price-to-earnings ratio, the price-to-dividends ratio, and the long-term bond yield.

The second contribution of this paper is to demonstrate that the out-of-sample long-horizon forecasts provided by the mean-reverting model and the models that employ the price-to-earnings and price-to-dividends ratios are statistically significantly better than the forecast provided by the historical-mean model. It is worth emphasizing that Welch and Goyal (2008) also used the price-to-earnings and price-to-dividends ratios in their study and found that these models have no predictive ability over forecast horizons up to 5 years. Our results therefore advocate that these models do have predictive ability, but over forecast horizons longer than 10 years. We also demonstrate that the advantages of the models, that show the predictive ability, translate into significant performance gains. For example, we estimate that risk-averse investors would be willing to pay from 30 to 77 basis points fees per year to switch from the historical-mean model to a model with a superior forecast accuracy. Moreover, our tests suggest that over the recent past the out-of-sample forecast accuracy provided by the mean-reverting model was substantially better than that provided by the competing models. In addition, we find that the mean-reverting model delivers the highest performance gains when investors have to make long-term allocation decisions.

The rest of the paper is organized as follows. Section 2 presents the data for our study, namely, the returns on the real Standard and Poor's Composite Stock Price Index over the period from 1871 to 2011. In Section 3 we perform the tests of the random walk hypothesis using the S&P Composite Index. In Section 4 we study the out-of-sample predictability of multi-year returns on the S&P Composite Index. Finally, Section 5 summarizes and concludes the paper.

2 The Data

The data for the study in this paper are the annual log real returns on a broad US stock market index for the period from 1871 to 2011. The returns are adjusted for dividends and computed using the real (i.e., inflation-corrected) Standard and Poor's Composite Stock Price Index data and corresponding dividend data. The inflation adjustment is done using the Consumer Price Index (CPI) for the US. All the data are provided by Robert Shiller.[2] The Standard and Poor's Composite Stock Price index is a value-weighted stock index. The index for the period from 1871 to 1925 is constructed using the Cowles Commission Common Stock Index series. From 1926 to the present, the index data come from various reports of the Standard and Poor's. From 1957 this index is identical to the Standard and Poor's 500 Index which is intended to be a representative sample of leading companies in leading industries within the US economy. Stocks in the index are chosen for market size, liquidity, and industry group representation. For more details about the construction of the index and its dividend series see Shiller (1989), Chapter 26. Formally, let $(p_0, p_1, \ldots, p_n)$ be observations of the natural log of an inflation-corrected stock index price over $n+1$ years. Denote the one-year log return during year t, $1 \leq t \leq n$, by

$$r_t = p_t - p_{t-1}.$$

The resulting sample of n return observations is $(r_1, r_2, \ldots, r_n)$. The probability distribution of r_t is unknown, yet it is well-documented that stock returns are non-normal and heteroscedastic.

In order to check the robustness of findings, in particular, to see whether the results of

[2] See `http://www.econ.yale.edu/~shiller/data.htm`. The real dividend adjusted annual return series on the index are readily available in the file `chapt26.xls`. Robert Shiller stopped maintaining his database in 2012.

the testing the random walk hypothesis depend on a specific historical period, we divide the total sample period from 1871 to 2011 (141 annual observations) in two equal overlapping sub-samples, the first one is from 1871 to 1956 and the second one is from 1926 to 2011.[3] Both of these sub-samples cover a span of 86 years. Table 1 presents the descriptive statistics for the annual stock index returns, r_t, for the total sample and both sub-samples. Table 2 reports the results of the t-test on difference in mean returns and F-test on difference in standard deviations between the first and the second sub-sample. The descriptive statistics and the results of the tests suggest that the mean and variance of returns on the index were more or less stable during the total sample. Specifically, using a t-test for equal means we cannot reject the hypotheses that the mean returns are alike in both sub-samples. Similarly, using an F-test for equal variances we cannot reject the hypotheses that the variances are alike in both sub-samples. All the series exhibit negative skewness and positive excess kurtosis which indicates a deviation from normality. Observe also that the return series during the overall sample period exhibits a statistically significant negative autocorrelation at lag 2 (at the 5% level). There are no other indications of serial dependence in the return series.

3 Testing the Random Walk Hypothesis

3.1 Methodology

One of the main questions we want to study in this paper is whether the log of the real S&P Composite Stock Price Index follows a random walk. To answer this question we perform two well-known tests. The first test is based on the examination of the first-order autocorrelation function of k-year returns. This test is used by, for example, Fama and French (1988b), Fama and French (1989), and Fama (1990) and based on the computation of the following test statistic

$$AC1(k) = \frac{Cov(r_{t,t+k}, r_{t-k,t})}{\sqrt{Var(r_{t,t+k})Var(r_{t-k,t})}}, \tag{1}$$

[3] The reasons for using overlapping sub-samples are as follows. First, in order to perform statistical tests on the presence of long-run mean reversion we need longer time series. Second, the starting point of our second sub-sample coincides with the starting point of the database of historical stock market data provided by the Center for Research in Security Prices. Therefore the data on the stock market returns over the second sub-sample is much more accurate than that over the first sub-sample.

Statistics	Sample period		
	1871-2011	**1871-1956**	**1926-2011**
Mean, %	6.28	6.91	6.24
Std. dev., %	17.14	17.76	18.77
Skewness	-0.57	-0.48	-0.59
Kurtosis	3.41	3.32	3.24
ρ_1	0.02	0.04	0.04
ρ_2	**-0.19**	-0.20	-0.18
ρ_3	0.09	0.07	0.02
ρ_4	-0.08	-0.18	-0.14
ρ_5	-0.11	-0.10	-0.07
ρ_6	0.10	0.12	0.11
ρ_7	0.10	0.06	0.16
ρ_8	-0.08	-0.15	-0.02
ρ_9	-0.06	-0.04	0.04
ρ_{10}	0.02	0.06	0.06
ρ_{11}	0.02	0.06	-0.07
ρ_{12}	-0.08	-0.04	-0.10
ρ_{13}	-0.09	-0.15	-0.19
ρ_{14}	0.03	0.03	-0.14
ρ_{15}	-0.09	-0.07	-0.02
ρ_{16}	-0.09	-0.09	0.06
ρ_{17}	0.06	0.16	-0.02
ρ_{18}	-0.08	-0.06	-0.13
ρ_{19}	-0.17	-0.11	-0.21
ρ_{20}	0.06	0.09	-0.07

Table 1: Descriptive statistics of the annual log real returns on the Standard and Poor's Composite Stock Price Index. ρ_k denotes the autocorrelation between r_t and r_{t+k}. For each ρ_k we test the hypothesis $H_0 : \rho_k = 0$. Bold text indicates values that are statistically significant at the 5% level.

	Test statistic	**P-value**
t-test on difference in mean returns	0.24	0.81
F-test on difference in standard deviations	0.89	0.61

Table 2: Results of the t-test on difference in mean returns and F-test on difference in standard deviations between the first and the second sub-sample.

where $r_{i,j}$ is the compounded return from year i to year j, $r_{i,j} = p_j - p_i$, $Cov(\cdot,\cdot)$ and $Var(\cdot)$ denote the covariance and variance respectively, and $AC1(k)$ stands for the first-order autocorrelation function of k-year returns. The second test is based on the examination of the variance ratio. This test is very popular and used by Cochrane (1988), Lo and MacKinlay (1988), Poterba and Summers (1988), and many other afterwards. The test is based on the computation of the following test statistic

$$VR(k) = \frac{Var(r_{t,t+k})}{k \times Var(r_t)}. \tag{2}$$

Both the tests are motivated by the notion that if the stock returns are independent and identically distributed, then the first-order autocorrelation function is zero and the variance ratio is unity irrespective of the number of years k. In other words, without serial dependence in data, the variance of k-year returns equals k times the variance of one-year returns and there is no correlation between two successive non-overlapping k-year returns. The null hypothesis of a random walk is rejected if the first-order autocorrelation is significantly different from zero or the variance ratio is significantly different from unity.

We want to compute the variance ratio $VR(k)$ for return horizons k from 20 to 40 years and the first-order autocorrelation $AC1(k)$ for periods from 10 to 20 years (note that in the latter case we also study serial dependence in data over time horizons from 20 to 40 years). The fundamental problem with these computations is that we have only a few non-overlapping intervals of length 20-40 years. Therefore in the computations of the two test statistics we employ overlapping intervals (rolling k-year periods). To compute $AC1(k)$ we regress k-year returns $r_{t,t+k}$ on lagged k-year returns $r_{t-k,t}$. That is, we run the following regression

$$r_{t,t+k} = a(k) + b(k)\, r_{t-k,t} + \varepsilon_{t,t+k}. \tag{3}$$

Observe that the slopes of the regression, $b(k)$, $k \in [10, 20]$, are the estimated autocorrelations of k-year returns, $AC1(k)$. The variance of k-year returns is computed as

$$Var(r_{t,t+k}) = E\left[(r_{t,t+k} - E[r_{t,t+k}])^2\right].$$

The use of overlapping returns leads to some potentially very serious econometric issues which are commonly termed as "small-sample bias". In particular, when it comes to the estimation of regression (3), there are two econometric problems. First, the estimates for the slope coefficients are biased. The sources of this bias in the estimation of autocorrelation are described in details by Orcutt and Irwin (1948) and Marriott and Pope (1954). More specifically, these authors show that an estimate of autocorrelation obtained using overlapping blocks of data is downward biased. Therefore, the estimates must be corrected for the bias. The second problem is that the standard errors of estimation using overlapping blocks of data are also downward biased, see, for example, Nelson and Kim (1993). Both biases work in the direction of making the values of t-statistic too large so that standard inference may indicate dependence in return series even if none is present.[4]

Similarly, the estimate for the variance of multi-year returns, $Var(r_{t,t+k})$, is downward biased when one uses overlapping blocks of data.[5] As an immediate consequence, the estimate for the variance ratio $VR(k)$ becomes also downward biased. Therefore, the estimates for $VR(k)$ must be corrected for the bias. In addition, since the estimate for $VR(k)$ is a random variable, for the purpose of statistical inference we need to know the probability distribution of $VR(k)$. This is necessary in order to be able to estimate standard errors and confidence intervals for $VR(k)$. This is also necessary for performing hypothesis tests about the value of $VR(k)$.

When the nature of the data generating process is unknown, it is generally not possible to tackle the econometric problems described above. However, in the context of the null hypothesis our goal is primarily to test whether or not stock returns are distributed independently of their ordering in time. Since under the null there is no dependence in return series, in order to estimate the significance level and perform the bias correction of the test statistics, we follow closely Kim et al. (1991) and Nelson and Kim (1993) where the authors employ the randomization method. The randomization method is introduced by Fisher

[4]Specifically, in case where returns are independent, using overlapping blocks of data produces a negative value of the estimated slope coefficient in regression (3). In addition, the standard error of estimation of the slope coefficient using overlapping blocks of data is downward biased. That is, the estimated standard error is smaller than it is in reality. The higher the overlap, the more negative the slope coefficient and the smaller the estimated standard error. As a result, the values of t-statistic may falsely indicate the presence of dependence in return series when none is present.

[5]Note that this is also related to the second econometric problem in the estimation of regression (3). That is, the standard errors of estimation of slope coefficients using overlapping blocks of data are downward biased, because the estimates for variance using overlapping blocks of data are downward biased. For the sake of motivation, consider what happens to the estimate for $Var(r_{t,t+k})$ when $k \to n$. Obviously in the limit, when the length k converges to the sample length, there is only one available block of data to estimate $Var(r_{t,t+k})$. Therefore, regardless of the nature of the data generating process, $Var(r_{t,t+k}) \to 0$ as $k \to n$.

(1935) and provides a very general and robust approach for computing the probability of obtaining some specific value for an estimator under the null hypothesis of no dependence. We refer the interested readers to Noreen (1989) and Manly (1997) for extensive discussion of the randomization tests. In a nutshell, randomization consists of reshuffling the data to destroy any dependence and then recalculating the test statistics for each reshuffling in order to estimate its distribution under the null hypothesis of no dependence. The great advantage of the randomization method is that it is very simple and no assumptions are made about the actual distribution of stock returns.

To be more specific, consider the estimation of the significance level and the bias correction of the estimate for the autocorrelation of k-year returns $AC1(k)$. First, we run regression (3) using the original series $(r_1, r_2, \ldots, r_n)$ to obtain the actual historical estimates for $AC1(k)$. Then we randomize the original series to get a permutation $(r_1^*, r_2^*, \ldots, r_n^*)$. This is repeated 10,000 times, each time running regression (3) and obtaining an estimate for $AC1^*(k)$. In this manner we estimate the sampling distribution of $AC1(k)$ under the null hypothesis. Finally, to estimate the significance level for some particular k, we count how many times the computed value for $AC1^*(k)$ after randomization falls below the value of the actual historical estimate for $AC1(k)$. In other words, under the null hypothesis we compute the probability of obtaining a more extreme value for the autocorrelation of k-year returns than the actual historical estimate. Note that in this manner we compute p-values of one-tailed test. The estimation bias is defined as the difference between the expected and the true value of $AC1^*(k)$. Since the true value is zero under the null hypothesis, the bias correction is done by subtracting the expected value of $AC1^*(k)$ from the actual historical estimate for $AC1(k)$. That is, the bias adjusted values of the first-order autocorrelation of k-year returns are computed as $AC1(k) - E[AC1^*(k)]$.

The estimation of the significance level and the bias correction of the estimate for the variance ratio $VR(k)$ is done in a similar manner. First, we use the original series to obtain the actual historical estimates for $VR(k)$. Then we randomize the series and compute $VR^*(k)$ to obtain the sample distribution under the null hypothesis. Finally, to estimate the significance level for some particular k, we count how many times the computed value for $VR^*(k)$ after randomization falls below the value of the actual historical estimate of $VR(k)$. The estimation bias in this case is given by $E[VR^*(k)] - 1$ since the true value is unity under the null hypothesis. Finally, the bias adjusted values of the variance ratio are computed as $VR(k) - E[VR^*(k)] + 1$.

There is ample evidence that the series of stock returns is heteroscedastic, see, for example, Officer (1973) and Schwert (1989). In particular, many researchers document that the variance of stock returns is not constant, but time-varying. To see whether a change in the variance of returns might affect the sampling distribution of a test statistic, we follow closely Kim et al. (1991) and Nelson and Kim (1993) and use the stratified randomization. In the stratified randomization method the total sample (or a sub-sample) is divided into several separate bins (urns) and the randomization is performed within each bin. Such a stratified randomization allows us to see whether the sampling distribution of a test statistic is sensitive to the particular pattern of heteroscedasticity that occurred historically.

3.2 Empirical Results

Figure 1 plots the sample first-order autocorrelations and variance ratios of the k-year returns on the Standard and Poor's Composite Stock Price Index. The first-order autocorrelations and variance ratios are computed according to formulas (1) and (2) respectively using overlapping blocks of data. Apparently, for the total sample and both the sub-samples the first-order autocorrelations and variance ratios generally decline with increasing k. The indications against the null hypothesis on very long horizons are stronger (i.e., the declines in the first-order autocorrelations and variance ratios are larger) for the second sub-sample (1926 to 2011) than for the total sample or the first sub-sample (1871 to 1956).

Recall, however, that the estimates for both the first-order autocorrelations and the variance ratios presented in Figure 1 are downward biased. As a matter of fact, under the null hypothesis of no serial dependence in return series we expect to see declining first-order autocorrelations and variance ratios with increasing k. In order to find out whether the observed declines are statistically significantly different from the expected declines under the null hypothesis, and in order to correct for the estimation bias under the null, we perform the randomization method with and without the stratification. These results are reported in Tables 3 and 4 which show the estimates for the bias-adjusted first-order autocorrelations and variance ratios, respectively, with corresponding p-values. The estimates are based on 10,000 reshuffles and computed using different numbers of bins in the stratification. The

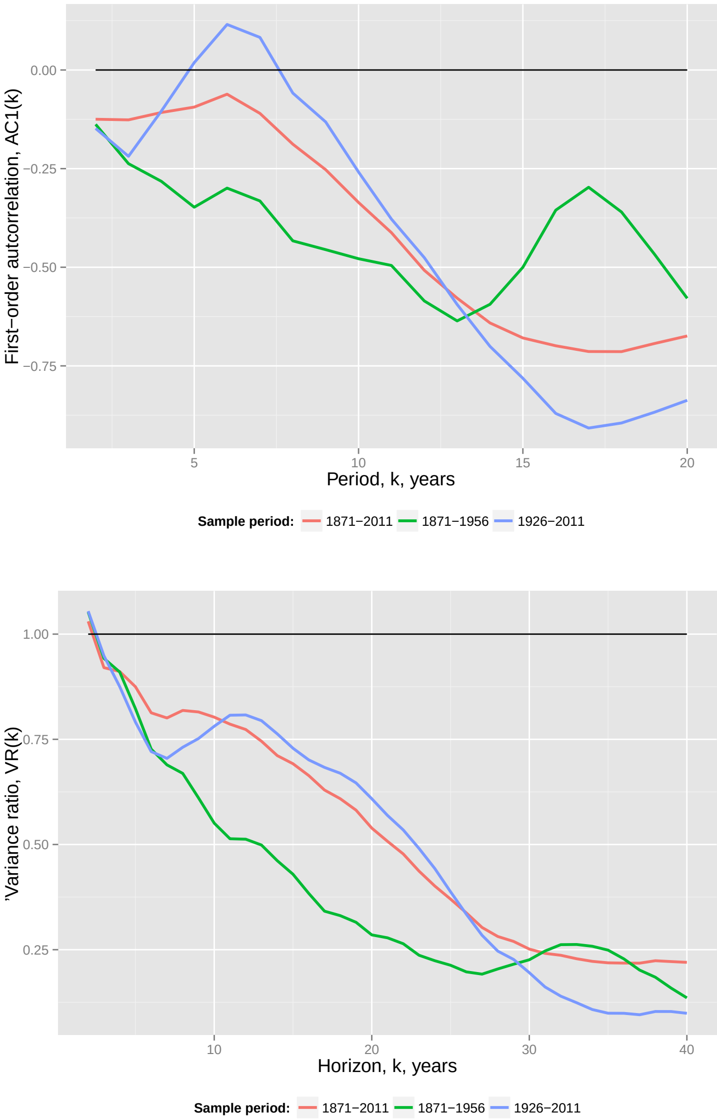


Figure 1: The sample first-order autocorrelations (top panel) and variance ratios (bottom panel) for the k-year log real returns on the Standard and Poor's Composite Stock Price Index. Neither the first-order autocorrelations nor the variance ratios are adjusted for the estimation bias.

number of bins varies from 1 (no stratification) to 5.

Without the stratification (that is, when the number of bins equals to one) both the test statistics suggest that the return series over the total sample (1871 to 2011) and the second sub-sample (1926 to 2011) exhibit clear evidence against the random walk on horizons of about 30-40 years. In particular, for the overall sample the values of the first-order autocorrelation are statistically significantly negative at the 5% level at periods 12-20 years (which indicates dependence over 24-40 year horizons). In addition, the values of the variance ratio are statistically significantly below unity at the 5% level at horizons 30-34 years. Thus, both the test statistics present evidence against the null hypothesis over horizons of 30-34 years. For the second sub-sample the values of the first-order autocorrelation are statistically significantly negative at the 5% level at periods 15-18 years (which indicates dependence over 30-36 year horizons), and the values of the variance ratio are statistically significantly below unity at horizons 34-36 years. For the first sub-sample the evidence against the random walk is weaker. Yet, if we use the 10% significance level, then we can reject the null hypothesis of no dependence in return series at several horizons.

Further, our results suggest that accounting for heteroscedasticity in stock returns does not influence the outcomes of the randomization tests on the first-order autocorrelations of k-year returns. Regardless of the number of bins in the stratified randomization, the first-order autocorrelation of k-year returns remains statistically significantly different from zero at the 5% level over periods of 15-17 years for the total sample and the second sub-sample. In contrast, stratification of the sample weakens the evidence against the null hypothesis for the value of the variance ratio. In particular, for the total sample and the stratification with either 2, 4, or 5 bins, the variance ratio is not statistically significantly below unity at conventional levels. Similarly, for the second sub-sample and the stratification with either 3 or 5 bins the variance ratio is not significantly below unity at conventional levels. For the first sub-sample the variance ratio is not significantly below unity regardless of the number of bins in the stratified randomization.

Consequently, we do not have strong enough evidence to claim that the variance ratio decreases with increasing investment horizon. Even though without stratification the variance ratio over horizons of 30-34 years is statistically significantly below unity, stratification of the sample suggests that this effect can be attributed to the historical pattern

Period, years	Number of bins 1	2	3	4	5
Panel A : Total sample 1871 to 2011					
10	-0.23 (0.14)	-0.15 (0.22)	-0.19 (0.16)	-0.10 (0.29)	-0.06 (0.36)
11	-0.29 (0.09)	-0.21 (0.15)	-0.25 (0.10)	-0.15 (0.20)	-0.11 (0.26)
12	**-0.38** (0.04)	-0.29 (0.08)	**-0.34** (0.05)	-0.23 (0.10)	-0.18 (0.13)
13	**-0.43** (0.03)	**-0.34** (0.04)	**-0.39** (0.03)	-0.28 (0.06)	-0.23 (0.07)
14	**-0.48** (0.02)	**-0.38** (0.03)	**-0.44** (0.02)	**-0.32** (0.03)	**-0.27** (0.04)
15	**-0.50** (0.01)	**-0.40** (0.02)	**-0.46** (0.01)	**-0.34** (0.03)	**-0.29** (0.03)
16	**-0.51** (0.01)	**-0.40** (0.02)	**-0.47** (0.01)	**-0.34** (0.02)	**-0.28** (0.03)
17	**-0.51** (0.02)	**-0.40** (0.02)	**-0.46** (0.01)	**-0.34** (0.02)	**-0.27** (0.02)
18	**-0.50** (0.02)	**-0.38** (0.03)	**-0.45** (0.02)	**-0.33** (0.03)	**-0.25** (0.03)
19	**-0.47** (0.03)	**-0.34** (0.04)	**-0.41** (0.03)	**-0.29** (0.04)	**-0.21** (0.05)
20	**-0.43** (0.05)	-0.30 (0.07)	**-0.37** (0.05)	-0.26 (0.06)	-0.17 (0.09)
Panel B : First sub-sample 1871 to 1956					
10	-0.25 (0.17)	-0.11 (0.32)	-0.10 (0.33)	-0.06 (0.39)	-0.26 (0.18)
11	-0.28 (0.15)	-0.13 (0.29)	-0.12 (0.31)	-0.10 (0.33)	-0.31 (0.14)
12	-0.36 (0.09)	-0.20 (0.21)	-0.20 (0.22)	-0.19 (0.20)	-0.41 (0.08)
13	-0.31 (0.13)	-0.13 (0.29)	-0.15 (0.29)	-0.15 (0.26)	-0.37 (0.09)
14	-0.22 (0.23)	-0.03 (0.46)	-0.06 (0.41)	-0.08 (0.37)	-0.27 (0.12)
15	-0.13 (0.32)	0.07 (0.60)	0.01 (0.52)	-0.01 (0.48)	-0.16 (0.20)
16	-0.03 (0.47)	0.19 (0.77)	0.11 (0.68)	0.10 (0.66)	-0.01 (0.47)
17	0.02 (0.52)	0.25 (0.83)	0.15 (0.74)	0.14 (0.72)	0.09 (0.74)
18	-0.07 (0.41)	0.19 (0.75)	0.06 (0.60)	0.06 (0.59)	0.07 (0.68)
19	-0.16 (0.32)	0.14 (0.66)	-0.03 (0.46)	-0.03 (0.46)	0.05 (0.62)
20	-0.17 (0.32)	0.16 (0.66)	-0.03 (0.45)	-0.03 (0.46)	0.11 (0.70)
Panel C : Second sub-sample 1926 to 2011					
10	-0.06 (0.41)	-0.05 (0.41)	0.09 (0.67)	-0.03 (0.45)	0.06 (0.64)
11	-0.16 (0.28)	-0.15 (0.27)	-0.00 (0.49)	-0.14 (0.27)	-0.02 (0.45)
12	-0.23 (0.20)	-0.23 (0.17)	-0.07 (0.35)	-0.22 (0.17)	-0.08 (0.33)
13	-0.32 (0.11)	-0.33 (0.09)	-0.17 (0.19)	-0.33 (0.08)	-0.16 (0.18)
14	-0.41 (0.06)	**-0.42** (0.05)	-0.27 (0.08)	**-0.42** (0.03)	-0.23 (0.07)
15	**-0.46** (0.04)	**-0.47** (0.03)	**-0.34** (0.05)	**-0.48** (0.02)	**-0.29** (0.03)
16	**-0.53** (0.03)	**-0.54** (0.01)	**-0.42** (0.03)	**-0.54** (0.01)	**-0.37** (0.01)
17	**-0.53** (0.04)	**-0.54** (0.02)	**-0.45** (0.03)	**-0.55** (0.01)	**-0.41** (0.01)
18	-0.50 (0.06)	**-0.51** (0.03)	**-0.43** (0.04)	**-0.51** (0.01)	**-0.42** (0.01)
19	-0.45 (0.09)	**-0.46** (0.05)	-0.40 (0.06)	**-0.46** (0.01)	**-0.43** (0.01)
20	-0.40 (0.13)	-0.43 (0.08)	-0.36 (0.09)	**-0.41** (0.03)	**-0.42** (0.02)

Table 3: First-order autocorrelations of the k-year log real returns on the Standard and Poor's Composite Stock Price Index ($AC1(k)$). These estimates are obtained using the randomization method with stratification (when the number of bins is greater than one). The estimates are corrected for the bias under the null hypothesis. The values in the brackets report the p-values of one-tailed test for the hypothesis $H_0 : AC1(k) = 0$. Bold text indicates values that are statistically significant at the 5% level.

Horizon, years	Number of bins 1	2	3	4	5
Panel A : Total sample 1871 to 2011					
20	0.75 (0.21)	0.87 (0.32)	0.80 (0.22)	0.93 (0.39)	1.00 (0.50)
22	0.71 (0.17)	0.84 (0.28)	0.77 (0.17)	0.90 (0.34)	0.97 (0.45)
24	0.66 (0.12)	0.79 (0.21)	0.71 (0.11)	0.86 (0.25)	0.93 (0.35)
26	0.62 (0.09)	0.76 (0.16)	0.67 (0.07)	0.83 (0.18)	0.90 (0.26)
28	0.58 (0.06)	0.73 (0.12)	**0.64** (0.04)	0.80 (0.12)	0.87 (0.19)
30	**0.58** (0.05)	0.73 (0.11)	**0.63** (0.03)	0.80 (0.10)	0.87 (0.16)
32	**0.59** (0.05)	0.75 (0.11)	**0.64** (0.03)	0.81 (0.11)	0.88 (0.17)
34	**0.60** (0.05)	0.76 (0.11)	**0.65** (0.03)	0.82 (0.11)	0.89 (0.17)
36	0.62 (0.06)	0.78 (0.13)	**0.67** (0.03)	0.83 (0.13)	0.91 (0.21)
38	0.65 (0.08)	0.81 (0.16)	**0.70** (0.04)	0.86 (0.18)	0.93 (0.28)
40	0.67 (0.09)	0.84 (0.18)	**0.72** (0.05)	0.87 (0.20)	0.95 (0.32)
Panel B : First sub-sample 1871 to 1956					
20	0.66 (0.11)	0.82 (0.21)	0.84 (0.18)	0.91 (0.30)	0.71 (0.07)
22	0.67 (0.10)	0.82 (0.20)	0.84 (0.16)	0.90 (0.27)	**0.69** (0.05)
24	0.65 (0.06)	0.81 (0.13)	0.82 (0.09)	0.87 (0.17)	**0.66** (0.02)
26	0.70 (0.09)	0.85 (0.18)	0.86 (0.14)	0.90 (0.25)	**0.69** (0.03)
28	0.74 (0.13)	0.89 (0.25)	0.90 (0.23)	0.94 (0.33)	**0.73** (0.04)
30	0.79 (0.18)	0.94 (0.34)	0.93 (0.31)	0.97 (0.40)	0.77 (0.06)
32	0.84 (0.26)	0.99 (0.46)	0.97 (0.43)	1.01 (0.53)	0.84 (0.12)
34	0.86 (0.26)	0.99 (0.48)	0.98 (0.43)	1.01 (0.53)	0.87 (0.13)
36	0.85 (0.21)	0.97 (0.40)	0.95 (0.34)	0.98 (0.42)	0.87 (0.08)
38	0.84 (0.16)	0.96 (0.33)	0.94 (0.27)	0.97 (0.33)	0.89 (0.08)
40	0.85 (0.14)	0.96 (0.31)	0.94 (0.24)	0.97 (0.30)	0.92 (0.11)
Panel C : Second sub-sample 1926 to 2011					
20	0.98 (0.48)	1.01 (0.51)	1.20 (0.79)	1.10 (0.67)	1.18 (0.81)
22	0.94 (0.44)	0.97 (0.46)	1.17 (0.76)	1.05 (0.59)	1.15 (0.77)
24	0.90 (0.38)	0.91 (0.38)	1.12 (0.71)	0.98 (0.47)	1.10 (0.69)
26	0.83 (0.28)	0.84 (0.26)	1.04 (0.59)	0.89 (0.30)	1.03 (0.56)
28	0.78 (0.19)	0.78 (0.15)	0.98 (0.44)	0.82 (0.18)	0.97 (0.42)
30	0.76 (0.14)	0.77 (0.10)	0.94 (0.32)	0.79 (0.13)	0.95 (0.34)
32	0.74 (0.07)	**0.74** (0.04)	0.90 (0.17)	0.76 (0.07)	0.92 (0.19)
34	**0.74** (0.04)	**0.74** (0.02)	0.88 (0.09)	**0.76** (0.04)	0.91 (0.11)
36	**0.76** (0.04)	**0.76** (0.01)	0.89 (0.09)	**0.78** (0.03)	0.92 (0.12)
38	0.79 (0.07)	**0.79** (0.02)	0.91 (0.14)	**0.81** (0.04)	0.93 (0.16)
40	0.82 (0.07)	**0.81** (0.02)	0.92 (0.15)	**0.84** (0.03)	0.93 (0.17)

Table 4: Variance ratios of the k-year log real returns on the Standard and Poor's Composite Stock Price Index ($VR(k)$). These estimates are obtained using the randomization method with stratification (when the number of bins is greater than one). The estimates are corrected for the bias under the null hypothesis. The values in the brackets report the p-values of one-tailed test for the hypothesis $H_0 : VR(k) = 1$. Bold text indicates values that are statistically significant at the 5% level.

of heteroscedasticity (that is, existence of periods of high and low variance). Thus, our results cannot support the anecdotal evidence which says that the stock market is safer for long-term investors. Nevertheless, we do have strong enough evidence that allows us to reject the random walk hypothesis in stock prices over periods of about 15-17 years. This evidence is based on the first-order autocorrelation of multi-year returns. Yet, our results suggest that the departure from the random walk on very long horizons has been primarily a phenomenon of the post-1926 period.

3.3 Robustness Tests

In order to check the robustness of our findings regarding the statistical significance of the secular mean reversion, we conducted a series of robustness checks which results are not reported in this paper in order to save the space. These additional robustness tests are described below.

First, the results reported in this section are obtained using the annual data provided by Robert Shiller. More specifically, these data are annual series of (average) January values of the real Standard and Poor Composite Stock Price Index. Hence, the results obtained in this section might be affected by seasonality.[6] To test the seasonality problem, we used the monthly data instead and obtained virtually the same levels of statistical significance of the mean-reverting behavior over very long horizons.

Second, Robert Shiller uses the CPI to adjust the nominal returns for inflation. We tested whether our evidence of mean reversion depends on the choice of deflator used to construct real stock returns.[7] For this purpose we constructed the real stock returns using the GDP deflator and value of the Consumer bundle.[8] We found that regardless of the choice of a deflator the evidence on mean reversion remains intact.

Third, since Kim et al. (1991) demonstrated that the mean-reversion in the study by Fama and French (1988b) is primarily a phenomenon of pre World War II period which is presented in both our sub-samples, we tested whether there is evidence of mean-reversion in the post 1940 period.[9] We found that the evidence is weaker (which is naturally to expect

[6] We thank Ole Gjølberg for pointing this.

[7] We thank an anonymous referee for pointing this.

[8] The data on the GDP deflator and the Consumer bundle are downloaded from `www.measuringworth.com`. The value of the consumer bundle is defined as the average annual expenditures of consumer units.

[9] We thank an anonymous referee for pointing this.

since the sample length becomes shorter), but is still statistically significant at the 10% level.

Fourth, instead of the first-order autocorrelation of multi-year returns test statistic, suggested by Fama and French (1988b), we used the test statistic suggested by Jegadeesh (1991). In particular, instead of regression (3), we used the following regression

$$r_t = a(k) + b(k)\, r_{t-k,t} + \varepsilon_{t,t+k}. \tag{4}$$

Note that in this regression the stock market return at year t is predicted using the aggregated return over the preceding k years. Using this regression we could also reject the random walk hypothesis in stock prices over very long horizons in the post-1926 period.

Finally, instead of using the data provided by Robert Shiller, we used the real annual returns on the large cap stocks provided by Kenneth French[10] over the period from 1927 to 2012. Again we found that the values of the first-order autocorrelation of multi-year returns are statistically significantly negative over periods of 15-18 years.

Thus, on the basis of the results from numerous robustness tests, we conclude that our evidence on the secular mean reversion is robust to the choice of data, deflator, sample period, and test statistics.

4 Testing the Long-Horizon Return Predictability

4.1 Motivation

The results of the tests performed in the preceding section allow us to reject the hypothesis that the S&P Composite Stock Price Index follows a random walk. Rather surprisingly, considering a seemingly insufficient span of available historical observations of the returns on the stock index, convincing evidence against the random walk is present over long-lasting periods of about 15-17 years. That is, our tests support the alternative hypothesis that there is serial dependence in stock returns. The question arises: what kind of serial dependence? In other words, what is the alternative hypothesis? Usually a statistically significant decrease in the variance ratio with increasing investment horizon (this effect is sometimes

[10] See `http://mba.tuck.dartmouth.edu/pages/faculty/ken.french/data_library.html`. We use the large-cap stocks because the S&P Composite is a large-cap index.

termed as the "variance compression") is interpreted as evidence of mean reversion. Unfortunately, the evidence of mean reversion based on the variance ratio test appears to be not strong enough under stratified randomization of data. However, variance compression seems to be the sufficient, but probably not necessary condition for mean reversion. Luckily, besides the variance ratio we have another test statistic, namely, the first-order autocorrelation of multi-year returns. The significance of this test statistic is unaffected by the choice of a randomization method. The presence of the values of the autocorrelation of k-year returns that are statistically significantly below zero suggests mean reverting behavior in stock prices. Specifically, a given change in price over first k years tends to be reversed over the next k years by a predictable change in the opposite direction. For the full sample period, evidence for mean reversion comes from the negative and statistically significant values of the first-order autocorrelations at periods of 15, 16, and 17 years particularly.

Considering the above mentioned, the results reported in the previous section suggest the presence of long-term mean reversion over periods of about 15-17 years in the real Standard and Poor's Composite Stock Price Index. In this case, if the pattern of the first-order autocorrelation of multi-year returns suggests the presence of mean reversion over the horizon of $2k$ years, there should be some degree of predictability of multi-year returns over a half-part of this horizon, that is, over a period of k years. Indeed, regression (3) is a predictive regression. To demonstrate the predictability of multi-year returns, Figure 2 presents a scatter plot of $r_{t,t+15}$ versus $r_{t-15,t}$ for the returns on the real Standard and Poor's Composite Stock Price Index for the total sample period from 1871 to 2011. In addition, a regression line is fitted through these data points. The scatter plot clearly suggests a tendency for the past 15-year returns to predict future 15-year returns. The regression line has a strongly negative slope, and R^2 statistic is 42%.

However, if we use the full sample period to estimate the first-order autocorrelation of multi-year returns, our estimate measures the degree of in-sample (IS) predictability. Yet it is known that in-sample predictability might be spurious (for example, it appears as a result of data mining) and not hold out-of-sample (OOS) (see, for example, Bossaerts and Hillion (1999), Goyal and Welch (2003), and Welch and Goyal (2008)). In order to guard against data mining, in this section we assess the performance of the OOS forecast based on the mean-revering model given by regression (3). Besides the mean-reverting model, we use

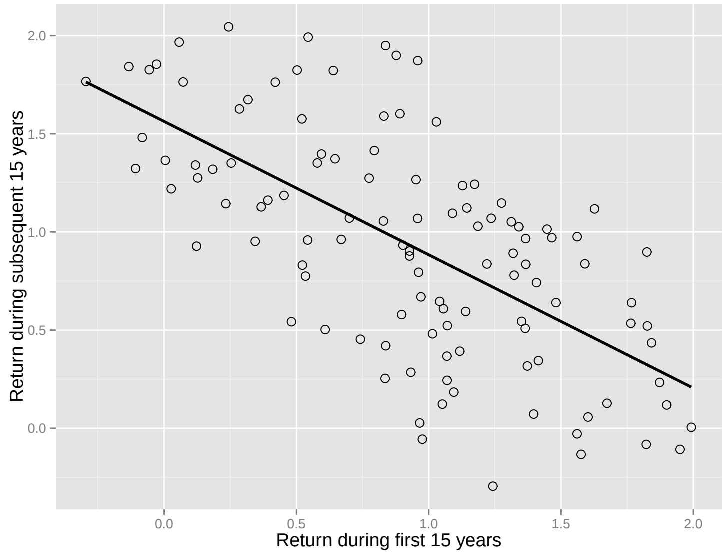


Figure 2: This figure shows a scatter plot of $r_{t,t+15}$ versus $r_{t-15,t}$ for the log real Standard and Poor's Composite Stock Price Index for the period from 1871 to 2011. In addition, a regression line is fit through these data points. The goodness of fit, as measured by R^2, amounts to 42%.

several other competing predictive models. We demonstrate that in the OOS tests the mean-reverting model and a few other predictive models perform statistically significantly better than the naive historical-mean model. In addition, we demonstrate that the advantages of the predictive models translate into significant utility gains.

4.2 Methodology of Assessing the Performance of OOS Forecasts

Our OOS recursive forecasting procedure is as follows. The initial IS period $[1, m]$, $m < n$, is used to estimate regression (3) for different period lengths $k \in [10, 20]$ years. In this manner we estimate a number of autocorrelations of k-year returns, $AC1(k)$. Then we perform the bias adjustment of $AC1(k)$. Next we select the value of $k = k_1$ which produces the lowest estimate of the bias-adjusted autocorrelation. That is,

$$k_1 = \arg \min_{k \in [10,20]} AC1(k).$$

Presumable, over the initial IS period the evidence of mean reversion is strongest over the period of k_1 years. Subsequently, the estimated coefficients from regression (3) with k_1 are used to compute the first k_1-year ahead return forecast for the period $[m+1, m+k_1]$. We then expand our IS period by one year (it becomes $[1, m+1]$), perform the selection of k_2 at which the evidence of mean reversion is strongest over the second IS period, and compute the OOS forecast for the period $[m+2, m+k_2+1]$. We repeat the procedure, increasing every time our IS window by one year, until we compute the last k_l-year ahead return for the period $[n-k_l+1, n]$.

Observe that our OOS forecasting procedure is free from look-ahead bias, since to forecast the return for the period $[m+j, m+k_j+j-1]$, $j \geq 1$, we use only information that is available at time $m+j-1$. It is worth noting that since we are dealing with a long-horizon forecast, in performing the recursive forecasting procedure we need not just to update the estimates for the coefficients of regression (3), but first of all we need to update the optimal length of the prediction period k. Observe that, in order to avoid the look-ahead bias, the optimal length of the prediction period k is determined using only information that is available at the end of each IS period as well. Thus, our OOS recursive forecasting procedure updates all the values of the model parameters and is able to adapt to changing conditions in the time series. For example, it can accommodate the possibility that the period of mean reversion is monotonically changing over time.[11]

To assess the performance of OOS forecast, a common approach in the empirical literature is to run a "horse-race" among several competing predictive models. A standard criterion by which to compare two alternative predictive models is to compare their mean squared prediction errors (MSPE). As a matter of fact, the comparison of the mean squared prediction errors of two alternative models has a long tradition in evaluating which of the two models has a better ability to forecast, see McCracken (2007) and references therein. In our study, we run OOS horse races involving the mean-reverting model (MR), the historical-mean model (HM), Robert Shiller's model (PE10) that uses the cyclically adjusted price-to-earnings ratio as a predictor for long-horizon returns, the model that uses the price-to-dividends ratio (PD) as a predictor, and the model that uses the long-term bond yield

[11]Recall that the results presented in the previous section indicate that the period of the long-term mean reversion seems to have been increasing over time. In particular, during the first sub-sample the evidence of mean reversion is strongest over horizons of about 24-26 years (judging by the values of the most statistically significant first-order autocorrelation and variance ratio). In contrast, during the second sub-sample the evidence of mean reversion is strongest over horizons of about 34-36 years. Apparently this results in the fact that over the total sample period the evidence of mean reversion is strongest over horizons of about 30-34 years.

(LTY) as a predictor. These models are given by

$$\text{MR}: r_{t,t+k} = a(k) + b(k)\, r_{t-k,t} + \varepsilon_{t,t+k}, \tag{5}$$

$$\text{PE10}: r_{t,t+k} = a(k) + b(k)\, pe10_t + \varepsilon_{t,t+k}, \tag{6}$$

$$\text{PD}: r_{t,t+k} = a(k) + b(k)\, pd_t + \varepsilon_{t,t+k}, \tag{7}$$

$$\text{LTY}: r_{t,t+k} = a(k) + b(k)\, lty_t + \varepsilon_{t,t+k}, \tag{8}$$

$$\text{HM}: r_{t,t+k} = a(k) + \varepsilon_{t,t+k}, \tag{9}$$

where $pe10$ is the natural log of the ratio of price to 10-year moving average of earnings (this ratio is usually denoted as CAPE or PE10), pd is the natural log of the price-to-dividends ratio, and lty is the natural log of the long-term bond yield. The data for the price-to-earnings ratio, price-to-dividends ratio, and the long-term bond yield are also provided by Robert Shiller.

Robert Shiller's model was introduced by Campbell and Shiller (1998) and further popularized and developed by Shiller (2000) and Campbell and Shiller (2001). Shiller's model is based on a simple mean reversion theory which says that when stock prices are very high relative to recent earnings, then prices will eventually fall in the future to bring the price-to-earnings ratio back to a more normal historical level. Using this model Campbell and Shiller (1998) predicted the stock market crash of 2000 on the basis of an unreasonably high PE10 ratio. Since that time, Shiller's model has been extremely popular among practitioners. Originally, Campbell and Shiller (1998), Shiller (2000), and Campbell and Shiller (2001) used this model to forecast future 10-year returns. Yet, Asness (2003) demonstrated that the PE10 ratio is a good predictor of the future returns over periods from 10 to 20 years.[12] Thus, Shiller's model represents a natural competitor to our long-term mean-reverting model.

The model that uses the price-to-dividends ratio as a predictor for future returns was presented by Fama and French (1988a). This model is also based on a simple mean reversion theory which says that if the price-to-dividends ratio is unusually high or low, then this ratio tends to return to its long-run historical mean. The motivation for the model that

[12]This conclusion is made on the basis of studying R^2 of the predictive regression for different forecasting horizons. It should be noted, however, that in estimating the coefficient in front of the predictor and its significance level, Asness (2003) does not account for the estimation biases discovered by Cavanagh et al. (1995) and Stambaugh (1999).

uses the long-term bond yield as a predictor is based on a simple idea that stocks and long-term bonds are two major competing assets. Therefore simple logic suggests that the changes in the long-term bond yield must be highly correlated with the changes in the stock market earnings yield (earnings-to-price ratio). If, for example, the bond yield increases, stock prices should decrease and the stock market earnings yield increase. The so-called "Fed model" postulates that the stock's earnings yield should be approximately equal to the long-term bond yield. Empirical support for this model is found in the studies by Lander, Orphanides, and Douvogiannis (1997), Koivu, Pennanen, and Ziemba (2005), Berge, Consigli, and Ziemba (2008), and Maio (2013).

The historical-mean model can be interpreted as a reduced version of any other predictive model. This model uses the historical average of k-year returns to predict the return for the next k years. It is worth emphasizing that Welch and Goyal (2008) also employed in their study the predictive models that use the price-to-earnings ratio, price-to-dividends ratio, and the long-term bond yield. They found that in out-of-sample tests these models perform worse than the historical-mean model. However, these authors used an increasing forecast horizon up to 5 years only. In our study the goal is to compare the out-of-sample forecast accuracy from these models on horizons longer than 10 years.

Now we turn to the formal presentation of our test statistic that is employed to assess the performance of OOS forecasts provided by two competing models. Let $r^{AC}_{t,t+k}$, $t > m$, be the actual k-year returns and $r^{mod_1}_{t,t+k}$ and $r^{mod_2}_{t,t+k}$ be the OOS forecast of the k-year returns provided by models 1 and 2. To compute the test statistic, we first compute the OOS prediction errors of the two competing models

$$\varepsilon^{mod_1}_{t,t+k} = r^{mod_1}_{t,t+k} - r^{AC}_{t,t+k}, \quad \varepsilon^{mod_2}_{t,t+k} = r^{mod_2}_{t,t+k} - r^{AC}_{t,t+k}.$$

Our test statistic is the ratio of the MSPE of model 1 to the MSPE of model 2

$$\text{MSPE-R} = \frac{\frac{1}{T-m}\sum_{t=m+1}^{T}\left(\varepsilon^{mod_1}_{t,t+k}\right)^2}{\frac{1}{T-m}\sum_{t=m+1}^{T}\left(\varepsilon^{mod_2}_{t,t+k}\right)^2},$$

where $T-m$ is the number of OOS forecasted k-year returns.[13] The null hypothesis in this

[13]Note that k is not constant, but a variable which is exogenously determined by our recursive forecasting procedure. We suppress its dependence on time in order to simplify the notation.

test is that the forecast provided by model 2 is not better than the forecast provided by model 1. Formally, under the null hypothesis the MSPE of model 1 is less than or equal to the MSPE of model 2. Formally, H_0 : MSPE-R ≤ 1. Consequently, we reject the null hypothesis when the actual estimate for the MSPE ratio is significantly above unity. In our tests, the model 1 is always the historical-mean model. Therefore the outcome of our tests is whether a predictive model can "beat" the historical-mean model (a similar approach is used by Goyal and Welch (2003), Welch and Goyal (2008), and many others).

If two alternative prediction errors are assumed to be Gaussian, serially uncorrelated, and contemporaneously uncorrelated, then an MSPE-R statistic under the null hypothesis has the usual F-distribution.[14] However, in our case the assumptions listed above are not met. First, because of using overlapping multi-year returns, the prediction errors of all our models are serially correlated. Second, since the historical-mean model is the reduced version of any other predictive model, the prediction errors of the historical-mean models and any other predictive model are contemporaneously correlated. Finally, the assumption of Gaussian errors also seems to be unpalatable. One potential possibility to obtain correct statistical inference in this case is to perform asymptotically valid tests in the spirit of the seminal tests by Diebold and Mariano (1995). However, because we use relatively small samples, and because of the variable length k of the prediction horizon in our forecasting procedure, in order to compute the p-value of the MSPE ratio we employ a bootstrap method.

Our bootstrap method follows closely Welch and Goyal (2008). In this method we assume that the returns are serially independent, whereas the log of the PE10, the log of the PD, and the log of LTY follow the first-order autoregressive (AR(1)) process. Therefore the data generating process is assumed to be

$$\begin{aligned} r_t &= \mu + u_t, \\ pe10_t &= \alpha_1 + \beta_1\, pe10_{t-1} + w_t, \\ pd_t &= \alpha_2 + \beta_2\, pd_{t-1} + z_t, \\ lty_t &= \alpha_3 + \beta_3\, lty_{t-1} + e_t. \end{aligned} \tag{10}$$

[14]In this case testing the null hypothesis largely corresponds to the standard F-test of equal forecast error variances.

In this case the return series r_t follows the random walk[15] and a bootstrapped resample is generated using the nonparametric bootstrap method. In particular, a random resample $(r_1^*, r_2^*, \ldots, r_n^*)$ is generated by drawing with replacement from the original series $(r_1, r_2, \ldots, r_n)$. In contrast, a bootstrapped resample of any other predictive variable is generated using the semi-parametric bootstrap method. The construction of a bootstrapped resample for the log of the PE10 series, $pe10_t$, is performed as follows. First of all, the parameters α_1 and β_1 are estimated by OLS using the full sample of observations, with the residuals stored for resampling. Afterwards, to generate a random resample $(pe10_1^*, pe10_2^*, \ldots, pe10_n^*)$ we pick up an initial observation $pe10_1^*$ from the actual data at random. Then a series is generated using the AR(1) model and by drawing w_t^* with replacement from the residuals.[16] The construction of a bootstrapped resample for the log of the PD and the LTY series is done in a similar manner.

Now we turn to the description of how we compute the MSPE-R statistic and its p-value. First, using the original series $(r_1, r_2, \ldots, r_n)$ we employ the recursive forecasting procedure described above to obtain the OOS forecasts of the mean-reverting model. Note that one of the outcomes of our recursive forecasting procedure is a sequence of lengths of prediction periods $(k_1, k_2, \ldots, k_l)$. Second, using the same sequence of lengths of prediction periods we obtain the OOS forecasts of all the other models. Afterwards we compute the mean squared prediction errors, and after that the MSPE-R statistic. Then we bootstrap the original series to get random resamples. The next crucial step is to generate a sequence of lengths of prediction periods $(k_1^*, k_2^*, \ldots, k_l^*)$. All this is repeated 10,000 times, each time running the recursive forecasting procedures[17] and obtaining an estimate for MSPE-R*. In this manner we estimate the sampling distribution of the MSPE-R statistic under the null hypothesis. Finally, to estimate the significance level, we count how many times the computed value for the MSPE-R* after bootstrapping happens to be above the value of the actual estimate for the MSPE-R. In other words, under the null hypothesis we compute

[15]Note that is this case the historical-mean model is a version of the random walk hypothesis.

[16]It should be noted, however, that our data generating process assumes no contemporaneous correlation between the stock return and a predictive variable. In the actual data there is a small but statistically significant correlation between the returns and the price-to-earnings (as well as the price-to-dividends) ratio. To check the robustness of our findings, we also implemented another bootstrap method which retains the historical correlations between the data series. We found that both the bootstrap methods deliver similar p-values of our test statistic.

[17]Note that this time the recursive forecasting procedures for all the models use the exogenously determined sequence of lengths of prediction periods.

the probability of obtaining a more extreme value for the MSPE ratio than the actual estimate.[18]

It is not clear what method should be used to generate a sequence of lengths of prediction periods for each bootstrap simulation. To the best of the author's knowledge, there are no similar forecasting procedures in the relevant scientific literature. Therefore we entertain four different methods listed below. In the first method we always use the original sequence of lengths of prediction periods $(k_1, k_2, \ldots, k_l)$. In the second and third methods a generated sequence $(k_1^*, k_2^*, \ldots, k_l^*)$ is a bootstrapped version of the original sequence. Whereas in the second method we use the nonparametric bootstrap, in the third method we use the semi-parametric bootstrap. In the semi-parametric bootstrap we assume that the length of a prediction period is a linear function of time.[19] In the fourth method a sequence of lengths of prediction periods is endogenously determined by the recursive forecasting procedure on the basis of the bootstrapped series $(r_1^*, r_2^*, \ldots, r_n^*)$. We find that the first three methods produce virtually similar p-values, whereas the fourth method produces notably lower p-values. Therefore when we report the p-values of the MSPE-R statistic we use the highest p-values. Thus, our statistical inference is based on the "worst case scenario" for the rejection of the null hypothesis. In other words, if we can reject the null in the "worst case scenario", we would reject it for any other case.

4.3 Empirical Results on Performance of OOS Forecasts

Our OOS forecast begins 50 years after the data are available, that is, in 1921, and ends in 1997 with the last forecast for the 15-year period from 1997 to 2011. To check the robustness of findings, we split the total OOS period in two equal OOS subperiods, the first one from 1921 to 1959, and the second one from 1959 to 1997. As in Goyal and Welch (2003), we employ a simple graphical diagnostic tool that makes it easy to understand the relative performance of two competing forecasting models. In particular, in order to monitor the predictive power of the unrestricted model relative to the predictive power of

[18]Note again that in this manner we compute p-values of one-tailed test.

[19]Indeed, for our OOS period from 1921 to 1997 the length of a prediction period is almost monotonically stepwise increasing from 10 to 15 years. The goodness of fit to the linear function, as measured by R^2, amounts to 73%. To perform the semi-parametric bootstrap, first of all we estimate the simple linear trend model for the original sequence of lengths of prediction periods $(k_1, k_2, \ldots, k_l)$ with the residuals stored for resampling. Afterwards, to generate a random resample of the sequence of lengths of prediction periods, we pick up the original initial prediction period k_1. The rest of the sequence is generated using the estimated linear trend model by drawing the error terms from the residuals with replacement.

the restricted model, Goyal and Welch (2003) suggested using the cumulative difference between the MSPE of the restricted model (the HM model in our case) and the MSPE of the unrestricted model:

$$CUDIF_t = \sum_{i=m}^{t} \left(\varepsilon_{i,i+k}^{mod_1}\right)^2 - \left(\varepsilon_{i,i+k}^{mod_2}\right)^2.$$

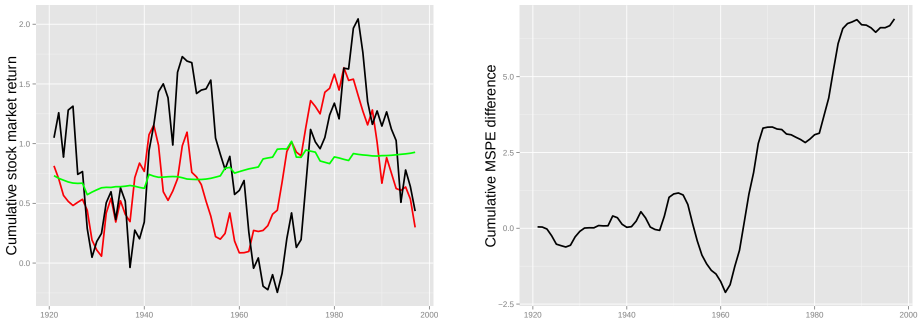
By visual examination of the graph of $CUDIF_t$ it is easy to understand in which periods the unrestricted model predicts better than the restricted model. Specifically, in periods when the cumulative MSPE difference increases, the unrestricted model predicts better, in periods when it decreases, the unrestricted model predicts worse than the restricted model.

Figure 3 shows the performance of the unrestricted models versus the performance of the restricted (historical-mean) model. Specifically, left panels in the figure plot the actual k-year ahead returns versus the OOS forecasted k-year ahead returns produced by the unrestricted and restricted models. Right panels in the figure plot the cumulative difference between the MSPE of the restricted model and the MSPE of the unrestricted model. The results of the estimations of the MSPE-R test statistic with corresponding p-values are reported in Table 5.

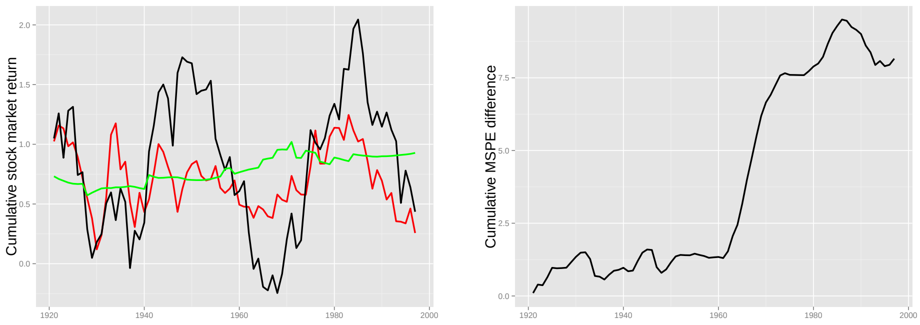
The p-values of the MSPE-R statistic demonstrate that over the total OOS period 3 out of 4 unrestricted models performed statistically significantly better (at the 5% level) than the restricted model. These unrestricted models are: the mean-reverting model, the price-earnings model, and the price-dividends model. However, over the first OOS subperiod only the price-dividends model performed statistically significantly better than the historical-mean model. In contrast, over the second OOS subperiod only the mean-revering and the price-earnings models showed the evidence of superior forecasting accuracy as compared to that of the historical-mean model. Our results advocate that the model, which uses the long-term bond yield as predictor, performed substantially worse than all the other competing models. Our results on the predictive ability of the long-term bond yield support the conclusions reached in the studies by Estrada (2006) and Estrada (2009). Specifically, Estrada argued that the predictive ability of the long-term bond yield is supported by data in the post 1960 period only.[20] Prior to 1960, there is no empirical support for the model

[20]In all empirical studies that demonstrate the predictive ability of the long-term bond yield the sample period starts after 1960. In this case if, for example, the initial IS period is chosen to be 1960-1980, then over the OOS period 1980-2010 one finds the evidence of OOS predictability of stock return using the long-term

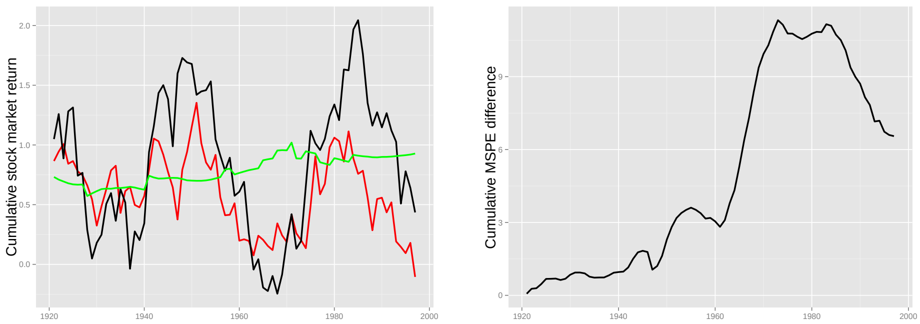
Performance of the Mean-Reverting model



Performance of the Price-Earnings model



Performance of the Price-Dividends model



Performance of the Bond Yield model

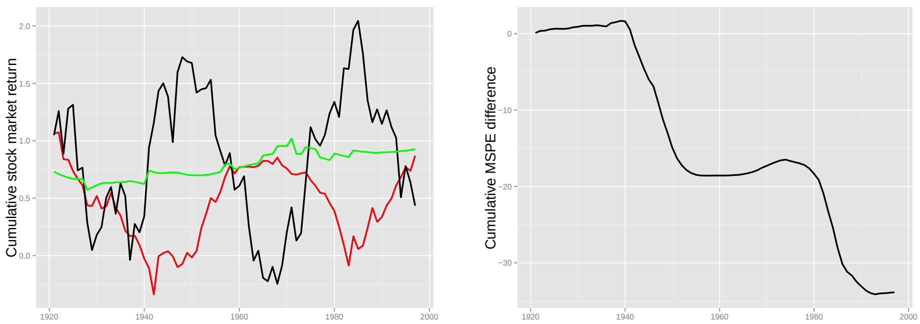


Figure 3: Performance of the unrestricted models versus the performance of the restricted (historical-mean) model. Left panels plot the actual k-year ahead returns (black line) versus the k-year ahead returns forecasted OOS by the unrestricted (red line) and restricted (green line) models. The initial IS period is from 1871 to 1920 which covers a span of 50 years. The OOS forecast begins in 1921 and ends in 1997 with the last forecast for the 15-year period from 1997 to 2011. Right panels plot the cumulative difference between the MSPE of the restricted model and the MSPE of the unrestricted model.

OOS period	HM to MR	HM to PE10	HM to PD	HM to LTY
1921-1997	**1.35** (0.01)	**1.44** (0.01)	**1.33** (0.03)	0.44 (0.98)
1921-1959	0.86 (0.38)	1.14 (0.10)	**1.38** (0.04)	0.37 (0.97)
1959-1997	**2.14** (0.01)	**1.78** (0.01)	1.28 (0.09)	0.50 (0.92)

Table 5: The values of the MSPE-R statistic with corresponding p-values (in brackets). A MSPE-R statistic is a ratio of the mean squared prediction error of the restricted (historical-mean) model to the mean squared prediction error of an unrestricted model. The four competing unrestricted models are: the mean-reverting (MR) model, the price to 10-year moving average of earnings (PE10) model, the price-dividends (PD) model, and the long-term bond yield model (LTY). For example, the column **HM to MR** reports the values of the ratio of the MSPE of the historical-mean model to the MSPE of the mean-reverting model. The estimated p-values of the MSPE ratios are based on performing 10,000 bootstraps. Bold text indicates values that are statistically significantly above unity at the 5% level.

that uses the long-term bond yield as a predictor for stock returns.

The graphs of the cumulative difference between the MSPE of the restricted (historical-mean) model and the unrestricted model allow us to see in which historical periods one model performed better than the other. Visual monitoring of these graphs reveals the following observations. The price-dividends model performed relatively well until about 1970 only. After that, the accuracy of the forecast provided by the price-dividends model was substantially worse than that of the historical-mean model. Both the mean-reverting and price-earnings models performed significantly better than the historical-mean model over 1960-1990. From about 1990 the price-earnings model lost its advantage over the historical-mean model. Starting from about 1980 the mean-revering model performed substantially better than all the other competing models. Only over the decade of 1950s the mean-reverting model performed notably worse than the historical-mean model.

4.4 Economic Significance of Return Predictability

In the preceding subsection we found a statistically significant evidence of long-term predictability of stock returns. This evidence was obtained by comparing the MSPE of the predictive model with the MSPE of the historical-mean model. However, over the total OOS period the ratios of the MSPE of the restricted model to the MSPE of the unrestricted model are not substantially above unity. This raises the important question of whether they are economically meaningful. Put it differently, statistical significance is not the same thing as economic significance.

bond yield.

To estimate the economic significance of return predictability, we follow closely the methodology employed in the studies by Fleming, Kirby, and Ostdiek (2001), Campbell and Thompson (2008), and Kirby and Ostdiek (2012). We consider an investor who, at time t, allocates the proportion y_t of his wealth to the stock market index and the proportion $(1 - y_t)$ to the risk-free asset. The investor revises the composition of his portfolio at time $t + q$; that is, after q years, $q \geq 1$. The investor's return over period $(t, t + q)$ is given by

$$R_{t,t+q} = y_t r_{t,t+q} + (1 - y_t) r^{free}_{t,t+q},$$

where $r_{t,t+q}$ and $r^{free}_{t,t+q}$ are the stock market return and the risk-free rate of return over period $(t, t + q)$.

We assume that the investor is equipped with the mean-variance utility function which can be considered as a second-order approximation to the investor's true utility function. As a result, the investor's *realized* utility over period $(t, t + q)$ can be written as

$$u(R_{t,t+q}) = y_t \left(r_{t,t+q} - r^{free}_{t,t+q} \right) - \frac{1}{2} \gamma y_t^2 \sigma^2_{t,t+q},$$

where $\sigma_{t,t+k}$ is the volatility of the stock market index over period $(t, t + q)$ and γ is the investor's coefficient of risk aversion. The total investor's realized utility is found as the sum of single-period utilities

$$U(R) = \sum_{i=1}^{n} u(R_{t,t+q}), \quad t = (i - 1) \times q,$$

where $n = \frac{T}{q}$ is the number of periods of length q from time 0 to time T (the end of the investment horizon).

The investor's optimal proportion y_t, which maximizes the expected utility, is given by (see Bodie, Kane, and Marcus (2007), Chapter 7)

$$y_t = \frac{1}{\gamma} \left(\frac{E[r_{t,t+q}] - r^{free}_{t,t+q}}{\sigma^2_{t,t+q}} \right),$$

where $E[r_{t,t+q}]$ and $\sigma_{t,t+q}$ are the expected return and volatility over $(t, t + q)$ that need to be forecasted at time t. The forecasting of expected returns is done using two competing models, 1 and 2. Specifically, $\hat{r}^{mod_1}_{t,t+q}$ and $\hat{r}^{mod_2}_{t,t+q}$ denote the return forecasts provided by models 1 and 2 respectively. Since we do not have a specific predictive model to forecast the volatility, the volatility over $(t, t+q)$ is forecasted using the historical-mean model for volatility. Formally,

$$y_t^{mod_1} = \frac{1}{\gamma}\left(\frac{\hat{r}_{t,t+q}^{mod_1} - r_{t,t+q}^{free}}{\hat{\sigma}_{t,t+q}^2}\right), \quad y_t^{mod_2} = \frac{1}{\gamma}\left(\frac{\hat{r}_{t,t+q}^{mod_2} - r_{t,t+q}^{free}}{\hat{\sigma}_{t,t+q}^2}\right),$$

where $\hat{\sigma}_{t,t+q}$ denotes the forecasted volatility.

It is important to observe that our predictive models forecast the stock market returns for a period of $k \geq 10$ years. Since generally $q \neq k$ (most often $q < k$), the q-year forecasted returns for model $i \in \{1, 2\}$ are computed as

$$\hat{r}_{t,t+q}^{mod_i} = \hat{r}_{t,t+k}^{mod_i} \times \frac{q}{k},$$

where $\hat{r}_{t,t+k}^{mod_i}$ is the k-year return forecast provided by model i.

As before, the model 1 in our study is the historical-mean model. The economic significance of return predictability is measured by equating to total realized utilities associated with two alternative forecasting models

$$\sum_{i=1}^{n} u\left(R_{t,t+q}^{mod_1}\right) = \sum_{i=1}^{n} u\left(R_{t,t+q}^{mod_2} - q \times \Delta\right),$$

where Δ denotes the annual fees the investor is willing to pay to switch from predictive model 1 to predictive model 2. Whereas Fleming et al. (2001) and Kirby and Ostdiek (2012) used the equation above to compute the annual fees, Campbell and Thompson (2008) demonstrated that the total realized investor's mean-variance utility can alternatively be measured by means of the Sharpe ratio. That is, the computation of the annual fees can be done using

$$SR\left(R_{t,t+q}^{mod_1}\right) = SR\left(R_{t,t+q}^{mod_2} - q \times \Delta\right),$$

where $SR(\cdot)$ denotes the Sharpe ratio.

In our computations we assume that the investor's risk aversion $\gamma = 5$ (as in Kirby and Ostdiek (2012)). Since we do not have data for the real risk-free rate of return, to perform the computations we assume that the nominal annual risk-free rate of return equals the annual inflation rate. Therefore, in real terms, $r_{t,t+p}^{free} = 0$. We measure the annual

Forecasting model	Sharpe ratio	Basis point fees
Panel A : Portfolio rebalancing once a year		
Historical-Mean	0.35	0
Mean-Reverting	0.42	46
Price-Earnings	0.45	77
Price-Dividends	0.39	30
Bond Yield	0.32	-20
Panel B : Portfolio rebalancing once in 15 years		
Historical-Mean	0.35	0
Mean-Reverting	0.40	47
Price-Earnings	0.35	1
Price-Dividends	0.39	37
Bond Yield	0.21	-129

Table 6: The table reports the performance of alternative predictive models and the annual fees the investor is willing to pay to switch from the historical-mean model to another predictive model. The performance is measured by means of the Sharpe ratio. The annual fees are measured in basis points.

performance fees over our total OOS period 1921-2011. Table 6 reports the Sharpe ratios associated with each predictive model and the estimated annual fees measured in basis points. The results are reported for two values of q: $q = 1$ and $q = 15$. In the first case the investor rebalances his portfolio once a year, in the second case the investor rebalances his portfolio once in 15 years.

First we consider the case where the investor rebalances his portfolio once a year. In this case the Sharpe ratios of all predictive models, which perform statistically significantly better than the historical-mean model, are higher than the Sharpe ratio of the historical-mean model. The advantages of these predictive models translate into significant utility gains. Specifically, risk-averse investors would be willing to pay from 30 to 77 basis points fees per year to switch from the historical-mean model to a model with a superior forecast accuracy. In contrast to these models, our results indicate that the model that uses the long-term bond yield as a predictor demonstrates an inferior forecast accuracy as compared with that of the historical-mean model. As a result, not only the Sharpe ratio of this model is lower than that of the historical-mean model, but also the investor would require to be paid 20 basis points fees per year to switch from the historical-mean model to the bond yield model.

When the investor can rebalance his portfolio once a year, the price-earnings model performs best while the mean-reverting model performs second best. However, when the investor decreases the portfolio revision frequency, the performance gains delivered by the price-earnings model diminish whereas the performance gains provided by the mean-reverting model remains rather stable. When the investor rebalances his portfolio once in 15 years, the performance gains of the price-earnings model virtually disappear. In contrast, the performance gains of the mean-reverting model (as measured in annual fees) remain virtually intact. Therefore in cases where the investor has to make long-term allocation decisions, the mean-reverting model delivers the highest performance gains.

5 Summary and Conclusions

We started the paper by performing two tests of the random walk hypothesis using the real Standard and Poor's Composite Stock Price Index data for the period from 1871 to 2011. In particular, we investigated the time series properties of the index returns at increasing horizons up to 40 years. In our tests of the random walk hypothesis we used two well-known test statistics: the autocorrelation of multi-year returns and the variance ratio. In the context of the null hypothesis our goal was to test whether the index returns are distributed independently of their ordering in time. In order to estimate the significance level of the test statistics under the null hypothesis, we employed the randomization methods which are free of distributional assumptions.

Rather surprisingly, considering a seemingly insufficient span of available historical observations of the returns on the stock index, either of the test statistic allowed us to reject the random walk hypothesis at conventional statistical levels over very long horizons of about 30-34 years. By studying the impact of sample period on the test statistics we concluded that mean reversion seems to be an extraordinary strong phenomenon of the post-1926 period. Having performed the same randomization tests with stratification we found that the results based on the use of the variance ratio are sensitive to the particular pattern of heteroscedasticity that occurred historically,[21] while the results based on the use of the autocorrelation of multi-year returns are not.

[21] A similar conclusion is drawn by Nelson and Kim (1993).

Consequently, we do not have strong enough evidence to claim that the variance ratio decreases with increasing investment horizons. In other words, our results cannot support the conventional belief that the stock market is safer for long-term investors. In contrast, we do have convincing evidence that suggests that a given change in price over 15-17 years tends to be reversed over the next 15-17 years by a predictable change in the opposite direction. Overall, our findings support the mean reversion hypothesis as the alternative to the random walk hypothesis. Our evidence of secular mean reversion in stock prices is robust to the choice of data source, deflator used to compute the real prices and returns, sample period, and test statistic.

The results of our tests demonstrated the evidence of in-sample predictability. However, conventional wisdom says that in-sample evidence of stock return predictability might be a result of data mining. In order to guard against data mining, we investigated the performance of out-of-sample forecast of multi-year returns. We demonstrated that the out-of-sample forecast provided by the mean-reverting model is statistically significantly better than the forecast provided by the historical-mean model. Moreover, the out-of-sample forecast accuracy of the mean-reverting model is comparable to that of very popular (among practitioners) Robert Shiller's model that uses the cyclically adjusted price-earnings ratio as a predictor for long-horizon returns, and of the model that uses the price-dividends ratio as a predictor for long-horizon returns. In addition, we demonstrated that the advantages of these three predictive models translate into significant utility gains. We found that in cases where the investor has to make long-term allocation decisions, the mean-reverting model delivers the highest performance gains. Besides, in the post-1960 period the mean-reverting model showed the best forecast accuracy among all competing model.

Given the main result of our study, it is natural to ask the following question. What causes this long-lasting mean reversion in the stock market prices? Put it differently, what is the economic intuition behind this result? One possible answer is suggested by previous research on the link between the demography and stock market returns and on the long-term variations in the birth rates and population growth in the US. In particular, on the one hand, Bakshi and Chen (1994), Dent (1998), Geanakoplos, Magill, and Quinzii (2004), and Arnott and Chaves (2012) observe the interrelationship between the demography and the US stock market returns and argue that the demography determines the stock market returns. On the other hand, the evidence presented by Kuznets (1958), Dent (1998), Berry (1999), and Geanakoplos et al. (2004) suggests the presence of secular trends in birth rates in the US that last from 10 to 20 years. Thus, if the population growth goes through long-term alternating periods of above-average and below-average rates, and it is the demography that determines the stock market returns, then it is naturally to expect that the stock market also goes through long-term alternating periods of above-average and below-average returns.

A more elaborate model of cyclical dynamics of economic activity, interrelated with similar movements in other elements, is presented by Schlesinger (1949), Schlesinger (1986), Berry (1991), Berry, Elliot, Harpham, and Kim (1998), and Alexander (2004). These authors argue that the dynamics of economic activity in the US has a long-term rhythm (with a period of 12-18 years) of accelerated and retarded secular growth. This cyclical fluctuation in economic activity, in particular the alternation of long-term periods of good and bad economic times, gives rise to similar long-term fluctuations in social and political activities. In brief, a long-term period of rapid economic growth and technological development coincides with a conservative political wave (era). The conservative politics reduces the scope and the role of government in the life of the nation and frees up business and capital. Such a period is also characterized by a higher population growth, increase in inequality, and deflationary conditions. Yet inevitably a long-term period of economic growth comes to a long-term stagflationary crisis. During such a crisis conservative leaders are replaced by liberal leaders committed to business regulation, social innovation, equity, and redistribution via an enhanced role of government. A liberal era is usually characterized by a lower population growth, decrease in inequality, and inflationary conditions. In our opinion, the secular mean-reverting behavior of the stock market fits nicely into this model of socioeconomic dynamics. It seems to be possible to demonstrate that the conservative political waves are usually associated with above average stock market returns, whereas during the liberal political waves the stock market returns are below average.

References

Alexander, M. A. (2000). *Stock Cycles: Why Stocks Won't Beat Money Market Over the Next Twenty Years*. iUniverse Star.

Alexander, M. A. (2004). *Cycles in American Politics*. iUniverse Star.

Arnott, R. D. and Chaves, D. B. (2012). "Demographic Changes, Financial Markets, and the Economy", *Financial Analysts Journal*, *68*(1), 23–46.

Asness, C. S. (2003). "Fight the Fed Model", *Journal of Portfolio Management*, *30*(1), 11–24.

Bakshi, G. S. and Chen, Z. (1994). "Baby Boom, Population Aging, and Capital Markets", *Journal of Business*, *67*(2), 165–202.

Balvers, R., Yangru, W., and Gilliland, E. (2000). "Mean Reversion Across National Stock Markets and Parametric Contrarian Investment Strategies", *Journal of Finance*, *55*(2), 745–772.

Berge, K., Consigli, G., and Ziemba, W. T. (2008). "The Predictive Ability of the Bond-Stock Earnings Yield Differential Model", *Journal of Portfolio Management*, *34*(3), 53 – 80.

Berry, B. J. L. (1991). *Long-Wave Rhythms in Economic Development and Political Behavior*. Johns Hopkins University Press.

Berry, B. J. L. (1999). "Fertility Cycles: A Note on Onset and Periodicity", *Population and Environment*, *21*(2), 149–154.

Berry, B. J. L., Elliot, E., Harpham, E. J., and Kim, H. (1998). *The Rhythms of American Politics*. University Press of America.

Bodie, Z., Kane, A., and Marcus, A. J. (2007). *Investments*. McGraw Hill.

Bossaerts, P. and Hillion, P. (1999). "Implementing Statistical Criteria to Select Return Forecasting Models: What Do We Learn?", *Review of Financial Studies*, *12*(2), 405–428.

Campbell, J. Y. (1987). "Stock Returns and the Term Structure", *Journal of Financial Economics*, *18*(2), 373–399.

Campbell, J. Y. and Mankiw, N. G. (1987). "Are Output Fluctuations Transitory?", *Quarterly Journal of Economics*, *102*(4), 857–880.

Campbell, J. Y. and Shiller, R. J. (1988). "The Dividend-Price Ratio and Expectations of Future Dividends and Discount Factors", *Review of Financial Studies*, *1*(3), 195–227.

Campbell, J. Y. and Shiller, R. J. (1998). "Valuation Ratios and the Long-Run Stock Market Outlook", *Journal of Portfolio Management*, *24*(4), 11–26.

Campbell, J. Y. and Shiller, R. J. (2001). "Valuation Ratios and the Long-Run Stock Market Outlook: An Update", Working paper, Harvard University and Yale University.

Campbell, J. Y. and Thompson, S. B. (2008). "Predicting Excess Stock Returns out of Sample: Can Anything Beat the Historical Average?", *The Review of Financial Studies*, *21*(4), 1509–1531.

Campbell, J. Y. and Yogo, M. (2006). "Efficient Tests of Stock Return Predictability", *Journal of Financial Economics*, *81*(1), 27–60.

Cavanagh, C. L., Elliott, G., and Stock, J. H. (1995). "Inference in Models with Nearly Integrated Regressors", *Econometric Theory*, *11*(5), 1131–1147.

Cochrane, J. H. (1988). "How Big Is the Random Walk in GNP?", *Journal of Political Economy*, *96*(5), 893–920.

Dent, H. (1998). *The Roaring 2000s.* Simon and Shuster, New York.

Diebold, F. X. and Mariano, R. S. (1995). "Comparing Predictive Accuracy", *Journal of Business and Economic Statistics*, *13*(3), 253–263.

Easterling, E. (2005). *Unexpected Returns: Understanding Secular Stock Market Cycles.* Cypress House.

Estrada, J. (2006). "The Fed Model: A Note", *Finance Research Letters*, *3*(1), 14 – 22.

Estrada, J. (2009). "The Fed Model: The Bad, the Worse, and the Ugly", *The Quarterly Review of Economics and Finance*, *49*(2), 214 – 238.

Fama, E. F. (1970). "Efficient Capital Markets: A Review of Theory and Empirical Work", *Journal of Finance*, *25*(2), 383–416.

Fama, E. F. (1981). "Stock Returns, Real Activity, Inflation, and Money", *American Economic Review*, *71*(4), 545–565.

Fama, E. F. (1990). "Term-Structure Forecasts of Interest Rates, Inflation, and Real Returns", *Journal of Monetary Economics*, *25*(1), 59–76.

Fama, E. F. and French, K. R. (1988a). "Dividend Yields and Expected Stock Returns", *Journal of Financial Economy*, *22*, 3–25.

Fama, E. F. and French, K. R. (1988b). "Permanent and Temporary Components of Stock Prices", *Journal of Political Economy*, *96*(2), 246–273.

Fama, E. F. and French, K. R. (1989). "Business Conditions and Expected Returns on Stocks and Bonds", *Journal of Financial Economics*, *25*(1), 23–49.

Fisher, R. A. (1935). *The Design of Experiments.* Oliver and Boyd, Edinburgh.

Fleming, J., Kirby, C., and Ostdiek, B. (2001). "The Economic Value of Volatility Timing", *Journal of Finance*, *56*(1), 329–352.

Geanakoplos, J., Magill, M., and Quinzii, M. (2004). "Demography and the Long-Run Predictability of the Stock Market", *Brookings Papers on Economic Activity*, *1*, 241–325.

Goyal, A. and Welch, I. (2003). "Predicting the Equity Premium with Dividend Ratios", *Management Science*, *49*(5), 639–654.

Gropp, J. (2003). "Mean Reversion of Size-Sorted Portfolios and Parametric Contrarian Strategies", *Managerial Finance*, *29*, 5–21.

Gropp, J. (2004). "Mean Reversion of Industry Stock Returns in the U.S., 1926-1998", *Journal of Empirical Finance*, *11*, 537–551.

Hirsch, J. A. (2012). *The Little Book of Stock Market Cycles.* John Wiley and Sons, New Jersey.

Jegadeesh, N. (1991). "Seasonality in Stock Price Mean Reversion: Evidence from the U.S. and the U.K.", *Journal of Finance*, *46*(4), 1427–1444.

Katsenelson, V. N. (2007). *Active Value Investing: Making Money in Range-Bound Markets.* Wiley Finance.

Kim, M. J., Nelson, C. R., and Startz, R. (1991). "Mean Reversion in Stock Prices? A Reappraisal of the Empirical Evidence", *Review of Economic Studies*, *58*(3), 515–528.

Kirby, C. and Ostdiek, B. (2012). "It's All in the Timing: Simple Active Portfolio Strategies that Outperform Naive Diversification", *Journal of Financial and Quantitative Analysis*, *47*, 437–467.

Koivu, M., Pennanen, T., and Ziemba, W. T. (2005). "Cointegration Analysis of the Fed Model", *Finance Research Letters*, *2*(4), 248 – 259.

Kuznets, S. (1958). "Long Swings in the Growth of Population and in Related Economic Variables", *Proceedings of the American Philosophical Society*, *102*(1), 25–52.

Lander, J., Orphanides, A., and Douvogiannis, M. (1997). "Earnings Forecasts and the Predictability of Stock Returns: Evidence from Trading the S&P", *Journal of Portfolio Management*, *23*(4), 24 – 35.

Lanne, M. (2002). "Testing the Predictability of Stock Returns", *Review of Economics and Statistics*, *84*(3), 407–415.

Leroy, S. F. (1982). "Expectations Models of Asset Prices: A Survey of Theory", *Journal of Finance*, *37*(1), 185–217.

Lewellen, J. (2004). “Predicting Returns with Financial Ratios”, *Journal of Financial Economics*, *74*(2), 209–235.

Lo, A. W. and MacKinlay, A. G. (1988). “Stock Market Prices do not Follow Random Walks: Evidence from a Simple Specification Test”, *Review of Financial Studies*, *1*(1), 41–66.

Maio, P. (2013). “The Fed Model and the Predictability of Stock Returns”, *Review of Finance*, *17*(4), 1489–1533.

Manly, B. F. J. (1997). *Randomization, Bootstrap and Monte Carlo Methods in Biology.* Chapman and Hall/CRC.

Marriott, F. H. C. and Pope, J. A. (1954). “Bias in the Estimation of Autocorrelations”, *Biometrika*, *41*(3/4), 390–402.

McCracken, M. W. (2007). “Asymptotics for Out of Sample Tests of Granger Causality”, *Journal of Econometrics*, *140*(2), 719–752.

Nelson, C. R. and Kim, M. J. (1993). “Predictable Stock Returns: The Role of Small Sample Bias”, *Journal of Finance*, *48*(2), 641–661.

Noreen, E. W. (1989). *Computer-Intensive Methods for Testing Hypotheses: An Introduction.* John Wiley and Sons, New York.

Officer, R. R. (1973). “The Variability of the Market Factor of the New York Stock Exchange”, *Journal of Business*, *46*(3), 434–453.

Orcutt, G. H. and Irwin, J. O. (1948). “A Study of the Autoregressive Nature of the Time Series Used for Tinbergen’s Model of the Economic System of the United States”, *Journal of the Royal Statistical Society. Series B*, *10*(1), 1–53.

Poterba, J. M. and Summers, L. H. (1988). “Mean Reversion in Stock Prices: Evidence and Implications”, *Journal of Financial Economics*, *22*, 27–59.

Rapach, D. E. and Wohar, M. E. (2005). “Valuation Ratios and Long-Horizon Stock Price Predictability”, *Journal of Applied Econometrics*, *20*(3), 327–344.

Richardson, M. (1993). “Temporary Component of Stock Prices: A Skeptic’s View”, *Journal of Business and Economic Statistics*, *11*(2), 199–207.

Richardson, M. and Stock, J. (1989). “Drawing Inferences From Statistics Based on Multi-Year Asset Returns”, *Journal of Financial Economics*, *25*, 323–348.

Rogers, J. (2005). *Hot Commodities: How Anyone Can Invest Profitably in the World’s Best Market.* Random House Publishing Group.

Schlesinger, Jr., A. M. (1986). *The Cycles of American History.* Boston: Houghton Mifflin.

Schlesinger, Sr., A. M. (1949). *Paths to the Present.* New York: Macmillian Co.

Schwert, G. W. (1989). "Why Does Stock Market Volatility Change Over Time?", *Journal of Finance*, *44*(5), 1115–1153.

Shiller, R. J. (1989). *Market Volatility.* The MIT Press.

Shiller, R. J. (2000). *Irrational Exuberance.* Princeton University Press.

Siegel, J. (2002). *Stocks for the Long Run.* McGraw-Hill Companies.

Stambaugh, R. F. (1999). "Predictive Regressions", *Journal of Financial Economics*, *54*(3), 375–421.

Summers, L. H. (1986). "Does the Stock Market Rationally Reflect Fundamental Values?", *Journal of Finance*, *41*(3), 591–601.

Torous, W., Valkanov, R., and Yan, S. (2004). "On Predicting Stock Returns with Nearly Integrated Explanatory Variables", *Journal of Business*, *77*(4), 937–966.

Welch, I. and Goyal, A. (2008). "A Comprehensive Look at The Empirical Performance of Equity Premium Prediction", *Review of Financial Studies*, *21*(4), 1455–1508.

Duke Energy Carolinas
Response to NCJC, et al.
Data Request No. 5

Docket No. E-7, Sub 1276

Date of Request: June 2, 2023
Date of Response: June 12, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NCJC, et al. Data Request No. 5-2, was provided to me by the following individual(s): Spencer Heuer, Treasury Manager, and was provided to NCJC, et al. under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

Request:

5-2. On page 7 of witness Roger A. Morin's Direct Testimony, he asserts that "low allowed ROEs can increase the future cost of capital and ratepayer costs." Is witness Morin aware of any empirical data, academic studies (conducted by witness Morin or others), or other evidence that supports this claim with respect to utilities specifically? If so, please provide any and all such supporting evidence.

Response:

The underlying premise of the referenced question and answer is that if a utility is authorized a ROE below the level required by equity investors, the result is a decrease in the utility's market price per share of common stock, thus increasing the cost of procuring common equity capital. As a result, the utility has to rely more on debt financing to meet its capital needs, its capital structure becomes more leveraged, hence increasing financial risk, and the cost of debt increases as well. The final result is an increase in the cost to the utility for both debt and equity financing, and by extension, the rates charged to consumers. This raises the broader issue of regulatory risk.

Several empirical studies have documented the impact of regulatory climate on utility cost of capital and de facto on revenue requirements. These empirical studies are summarized in Chapter 4 of Dr. Morin's regulatory finance textbook Modern Regulatory Finance. Not surprisingly, the preponderance of the empirical evidence supports the notion that a favorable regulatory climate decreases a utility's risk and capital costs and ratepayer burden. High ratings result in low capital costs (lower ratepayer costs) and low ratings in high capital costs (high ratepayer costs).

The bottom line is that capital suppliers, both debt and equity, will require a higher rate of return in the presence of low regulatory quality which in turn is highly dependent on the reasonableness of allowed ROEs. Low regulatory quality leads to an increase in the cost of capital and, by extension, the rates charged to consumers, and conversely.

To illustrate, a typical instance of the impact of regulatory decisions on capital costs, hence on ratepayers, occurred on 11/9/21 as a result of a negative ROE decision rendered by the Arizona Public Service Commission in an Arizona Public Service (APS) docket. (Docket No. E-01345A-22-0144). Moody's and S&P both downgraded Pinnacle West and APS from A- to BBB+, with a Negative outlook.

In summarizing its decision to downgrade, S&P explained: "The downgrade and negative outlook reflects higher regulatory risk in Arizona. The downgrade on PWCC and its subsidiary reflects the ACC's final order, including lower authorized ROE to 8.7%......". (Standard & Poors Ratings Direct, Pinnacle West Capital Corp. Downgraded To 'BBB+', Outlook Negative, On Arizona Rate Reduction, Nov. 9, 2021).

In summarizing its decision to downgrade, Moody's explained: "The rate case decision will result in a base rate decrease of $119.8 million and a substantive decline in the authorized ROE to 8.7% from 10%, which is well below the national average of 9.5%. (Moody's

Investor Services Credit Opinion, Rating Action: Moody's downgrades Pinnacle West to Baa1 and Arizona Public Service to A3; outlook negative, Nov. 17, 2021).
A downgrade of a company's bonds and subsequent negative stock price reaction inexorably leads to higher debt costs and equity costs and perforce to higher ratepayer burdens.