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Part 4 of 4

INFORMATION SHEET

PRESIDING: Commissioner Duffley, Presiding; Chair Mitchell, and Commissioners Brown-Bland, Clodfelter, Hughes, McKissick, Jr., and Kemerait
PLACE: Raleigh, NC
DATE: Thursday, August 31, 2023
TIME: 9:34 p.m. to 12:55 p.m.
DOCKET NO.: E-7, Sub 1134 and E-7 Sub 1276
COMPANY: Duke Energy Carolinas, LLC
DESCRIPTION: In the Matter of Duke Energy Carolinas, LLC Application for Approval to Construct a 402 MW Natural Gas-Fired Combustion Turbine Electric Generating Facility in Lincoln County, and for an Application for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and for Performance-Based Regulation

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VOLUME NUMBER: 12

APPEARANCES
See attached

WITNESSES
See attached

EXHIBITS

None attached

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| | |
|---|---|
| REPORTED BY: Renee Habrack | TRANSCRIPT PAGES: 158 |
| TRANSCRIBED BY: Renee Habrack | PREFILED PAGES 908 |
| DATE FILED: September 8, 2023 | TOTAL PAGES 1066 |

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PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Thursday, August 31, 2023

TIME: 9:34 a.m. - 12:55 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 12

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# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

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

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

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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)**

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# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

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

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Associate General Counsel

FIRM NAME: Duke Energy

ADDRESS:

CITY: STATE: ZIP CODE:

APPEARANCE ON BEHALF OF: Duke Energy Carolinas LLC

APPLICANT: X COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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

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# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

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PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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# NORTH CAROLINA UTILITIES COMMISSION

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CITY: Raleigh STATE: NC ZIP CODE: 27601

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APPLICANT: X COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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# NORTH CAROLINA UTILITIES COMMISSION

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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.

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# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

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

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**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.

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# NORTH CAROLINA UTILITIES COMMISSION

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FIRM NAME: Troutman Pepper Hamilton Sanders LLP

ADDRESS: 600 Peachtreet St. NE Suite 3000

CITY: Atlanta STATE: GA ZIP CODE: 30308

APPEARANCE ON BEHALF OF: Duke Energy Carolinas, LLC

APPLICANT: X COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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

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# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

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

ATTORNEY NAME and TITLE: Joshua Warren Combs, Associate Attorney

FIRM NAME: Troutman Pepper Hamilton Sanders LLP

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CITY: Atlanta STATE: GA ZIP CODE: 30308

APPEARANCE ON BEHALF OF: Duke Energy Carolinas, LLC

APPLICANT: X COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

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

ATTORNEY NAME and TITLE: Kiran H. Mehta, Partner

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CITY: Charlotte STATE: NC ZIP CODE: 28202

APPEARANCE ON BEHALF OF: Duke Energy Carolinas, LLC

APPLICANT: X COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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

Email: kiran.mehta@troutman.com

SIGNATURE: [signature]

**(Signature Required for distribution of CONFIDENTIAL information)**

OFFICIAL COPY

Oct 02 2023

# 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 Digitally signed by Molly M. Jagannathan DN: CN = Molly M. Jagannathan, email = molly.jagannathan@troutman.com, C = US Date: 2023.08.22 10:14:33 -04'00'

**(Signature Required for distribution of CONFIDENTIAL information)**

OFFICIAL COPY

Oct 02 2023

# 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)**

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Oct 02 2023

# 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)**

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Oct 02 2023

# 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)**

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Oct 02 2023

# 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)**

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Oct 02 2023

# 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)**

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Oct 02 2023

# 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)**

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Oct 02 2023

# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

**DATE:** 8-28-23 **DOCKET NO.:** G-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)**

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May 26 2023
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Oct 02 2023

# 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)**

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Oct 02 2023

# 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:

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Oct 02 2023

# 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)**

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Oct 02 2023

# 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: Andrea Bonvecchio

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Oct 02 2023

# 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.

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

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

Email: dneal@selcnc.org

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

**(Signature Required for distribution of CONFIDENTIAL information)**

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Oct 02 2023

# 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.

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

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

Email: mmagarira@selcnc.org

SIGNATURE: Digitally signed by Munaashe Magarira Date: 2023.09.22 09:28:18 -04'00'

**(Signature Required for distribution of CONFIDENTIAL information)**

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Oct 02 2023

# 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.

---

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

Email: tgooding@selcnc.org

SIGNATURE: Thomas Gooding Digitally signed by Thomas Gooding Date: 2023.04.28 12:46:36 -04'00'

**(Signature Required for distribution of CONFIDENTIAL information)**

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Oct 02 2023

# 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.

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Email: _____

SIGNATURE: _____

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Oct 02 2023

# 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

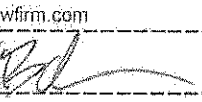
PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

**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: 

**(Signature Required for distribution of CONFIDENTIAL information)**

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Oct 02 2023

# 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.

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

Email: _____

SIGNATURE: _____

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Oct 02 2023

# 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.

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

Email: _____

SIGNATURE: _____

**(Signature Required for distribution of CONFIDENTIAL information)**

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Oct 02 2023

# 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)**

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Oct 02 2023

# 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)**

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Oct 02 2023

# 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)**

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Oct 02 2023

# 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

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Oct 02 2023

# NORTH CAROLINA
# PUBLIC STAFF
# UTILITIES COMMISSION

September 20, 2022

Mr. Stephen G. De May
North Carolina President
Duke Energy Corporation
410 S. Wilmington Street
12th Floor
Raleigh, North Carolina 27601

Dear Stephen:

As we anticipate the multi-year rate plan ("MYRP") filings of Duke Energy Progress and Duke Energy Carolinas (collectively, "Duke Energy") over the coming months, I want to express the Public Staff's expectations with respect to timing and process. The next year will be incredibly demanding as the Public Staff simultaneously investigates both Duke Energy MYRP rate cases. In addition to these MYRP cases, we are simultaneously investigating MYRPs for the two largest water companies in the State, electric utility annual riders, a New River Light and Power general rate case, the Carbon Plan, the transfer application of the Bald Head Island Ferry, and numerous other matters for Duke Energy and the other regulated utilities. This is an unprecedented workload, and like other employers, we are facing staffing shortages, turnover, and loss of experienced employees.

The MYRP will involve significantly more investigatory work as compared to historical general rate cases due in large part to the projection of three years of capital spend and development of performance-based mechanisms. As the MYRP statute allows no additional investigation time than that allowed for a traditional general rate case, it is crucial that Duke Energy be prepared to provide requested information to us within the deadlines and that responses be complete. In past rate cases, Duke Energy has requested multiple extensions to discovery requests, provided non-responsive information to discovery requests, and lacked sufficient staff to timely and completely respond to Public Staff data requests. As a result, the Public Staff's receipt of information was delayed and our ability to fully investigate the cases was impeded.

**Christopher J. Ayers, Executive Director**
**4326 Mail Service Center, Raleigh, North Carolina 27699-4326 • 919/733-2435 • Fax 919/733-9565**
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The Public Staff expects Duke Energy to provide us all data, documentation, and workpapers used to prepare the MYRP application contemporaneous with the application's filing at the Commission. Such data, documentation, and workpapers should be readily available as they serve as the underlying basis for the filing. The Public Staff further expects Duke Energy to promptly respond to all Public Staff discovery requests with relevant information and documents that directly address the questions asked. To the extent there is a question or confusion concerning a data request, our expectation is that Duke Energy will promptly and proactively contact the Public Staff for resolution rather than providing a non-responsive answer or waiting until the deadline to seek clarification. We expect Duke Energy to have sufficient technical staff available throughout the entire case to respond to discovery requests or other questions. As critical parts of the Duke Energy Progress rate case investigation will occur during the holiday season, the Public Staff will be unable to grant extensions during that period.

During rate case hearings, utilities frequently comment on the number of Public Staff data requests they answer. It should be noted that the volume of data requests can be due, in part, to a utility's failure to provide complete and responsive information, which necessitates repeated follow-up questions until the requested information has been received. The volume of data requests is also dependent upon the complexity of the matter under investigation. With the advent of MYRPs, the Companies should expect more data requests than in prior cases as we investigate three years of projected capital spend and performance-based metrics in addition to the utilities' historical spend.

We are committed to carrying out the mandates of House Bill 951 for MYRPs and obtaining the best possible outcome for consumers in a time of increasing cost pressures. I know Duke Energy is invested in ensuring that MYRPs live up to their promise in reducing regulatory lag and reducing rate case frequency. To achieve these goals, it is vital that we work together to ensure that the Public Staff can conduct a thorough investigation of Duke Energy's applications. We would be happy to meet to discuss how we can work together to ensure that information flows most efficiently. We look forward to receiving previews of the cases.

Sincerely,

Christopher J. Ayers
Executive Director

| PSDR No. | Title | Date Sent | Date Due | Subitems | Date Completed | No. Days Late | Notes |
|---|---|---|---|---|---|---|---|
| PSDR 2 | Fuel and Fuel-Related Topics | 1/19/2023 | 1/30/2023 | | | | |
| | | | | 2-2 | 2/7/2023 | 8 days | The Public Staff granted an extension to February 6. |
| PSDR 9 | Inventory Levels | 2/8/2023 | 2/20/2023 | | | | |
| | | | | 9-2 | 2/27/2023 | 7 days | |
| | | | | 9-10 | 2/27/2023 | 7 days | |
| | | | | 9-13 | 2/27/2023 | 7 days | |
| | | | | 9-17 | 2/27/2023 | 7 days | The Public Staff granted an extension to February 27. |
| PSDR 10 | Plant & Accumulated Depreciation | 2/9/2023 | 2/20/2023 | | | | |
| | | | | 10-1 | 2/21/2023 | 1 day | |
| | | | | 10-2 | 3/2/2023 | 10 days | |
| | | | | 10-3 | 2/21/2023 | 1 day | |
| | | | | 10-5 | 2/21/2023 | 1 day | |
| | | | | 10-6 | 2/27/2023 | 7 days | |
| PSDR 11 | Coal Combustion Residuals (CCR) Management | 2/14/2023 | 2/24/2023 | | | | |
| | | | | 11-2 | 2/27/2023 | 3 days | |
| | | | | 11-4 | 2/27/2023 | 3 days | |
| | | | | 11-5 | 2/25/2023 | 1 day | |
| | | | | 11-7 | 3/31/2023 | 35 days | |
| | | | | 11-8 | 3/31/2023 | 35 days | |
| | | | | 11-9 | 3/31/2023 | 35 days | |
| | | | | 11-10 | 3/31/2023 | 35 days | |
| | | | | 11-11 | 3/31/2023 | 35 days | |
| | | | | 11-12 | 3/31/2023 | 35 days | |
| | | | | 11-13 | 3/31/2023 | 35 days | |
| | | | | 11-14 | 3/31/2023 | 35 days | |
| | | | | 11-15 | 3/31/2023 | 35 days | |
| | | | | 11-16 | 3/31/2023 | 35 days | |
| | | | | 11-17 | 3/31/2023 | 35 days | |
| | | | | 11-18 | 3/31/2023 | 35 days | |
| PSDR 15 | Customer Connect | 3/1/2023 | 3/13/2023 | | | | |
| | | | | 15-7 | 3/14/2023 | 1 day | |
| | | | | 15-8 | 3/14/2023 | 1 day | |
| | | | | 15-9 | 3/14/2023 | 1 day | |
| PSDR 18 | Distribution Sample Costs - List A | 3/13/2023 | 3/23/2023 | | | | |
| | | | | 18-1 | 3/24/2023 | 1 day | |
| PSDR 21 | CPRE Facilities (CONFIDENTIAL) | 3/16/2023 | 3/27/2023 | | | | |
| | | | | 21-6 | 4/3/2023 | 7 days | The Public Staff granted an extension to 3/31/2023. |
| PSDR 29 | Detailed Sample Costs - Nuclear Plant 1 | 3/22/2023 | 4/3/2023 | | | | |
| | | | | 29-1 | 4/20/2023 | 17 days | The Public Staff granted an extension to provide the first 10 items on April 3, and the remainder on April 5. |
| PSDR 31 | Adjust for COVID Impacts | 3/22/2023 | 4/3/2023 | | | | |
| | | | | 31-16 | 4/5/2023 | 2 days | |
| | | | | 31-17 | 4/5/2023 | 2 days | |
| | | | | 31-23 | 4/4/2023 | 1 day | |
| PSDR 36 | Insurance | 3/23/2023 | 4/2/2023 | | | | |
| | | | | 36-1 | 4/3/2023 | 1 day | |
| | | | | 36-2 | 4/4/2023 | 2 days | |
| | | | | 36-3 | 4/3/2023 | 1 day | |
| | | | | 36-4 | 4/3/2023 | 1 day | |
| | | | | 36-5 | 4/3/2023 | 1 day | |
| | | | | 36-6 | 4/3/2023 | 1 day | |
| PSDR 37 | Aviation Expense - NC-2090 | 3/23/2023 | 4/2/2023 | | | | |
| | | | | 37-1 | 4/3/2023 | 1 day | |
| | | | | 37-2 | 4/3/2023 | 1 day | |
| | | | | 37-3 | 4/3/2023 | 1 day | |
| | | | | 37-5 | 4/3/2023 | 1 day | |
| | | | | 37-7 | 4/3/2023 | 1 day | |
| | | | | 37-9 | 4/3/2023 | 1 day | |

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| PSDR No. | Title | Date Sent | Date Due | Subitems | Date Completed | No. Days Late | Notes |
|---|---|---|---|---|---|---|---|
| | | | | 37-10 | 4/3/2023 | 1 day | |
| | | | | 37-12 | 4/3/2023 | 1 day | |
| | | | | 37-15 | 4/3/2023 | 1 day | |
| PSDR 38 | Severance | 3/23/2023 | 4/2/2023 | | | | |
| | | | | 38-1 | 4/3/2023 | 1 day | |
| | | | | 38-2 | 4/3/2023 | 1 day | |
| PSDR 41 | DEC-Owned Solar Facilities | 3/23/2023 | 4/3/2023 | | | 3 days | |
| | | | | 41-1 | 4/6/2023 | 3 days | |
| | | | | 41-2 | 4/12/2023 | 9 days | The Public Staff granted an extension to 4/6/2023 for 41-2. |
| | | | | 41-3 | 4/6/2023 | 3 days | |
| PSDR 51 | Non-Fuel O&M Expenses | 3/27/2023 | 4/6/2023 | | | | |
| | | | | 51-2 | 4/10/2023 | 4 days | |
| | | | | 51-3 | 4/11/2023 | 5 days | |
| PSDR 52 | Detailed Sample Costs - Intan. Plant 2 | 3/28/2023 | 4/7/2023 | | | | |
| | | | | 52-1 | 4/10/2023 | 3 days | |
| PSDR 53 | Detailed Sample Costs - Nuclear Plant 2 | 3/28/2023 | 4/7/2023 | | | | |
| | | | | 53-1 | 4/11/2023 | 4 days | |
| PSDR 54 | Detailed Sample Costs - Trans. 2 | 3/28/2023 | 4/7/2023 | | | | |
| | | | | 54-1 | 4/10/2023 | 3 days | |
| PSDR 55 | Detailed Sample Costs - Dist. List C | 3/28/2023 | 4/7/2023 | | | | |
| | | | | 55-1 | 4/11/2023 | 4 days | |
| PSDR 56 | Transmission and Distribution Spending | 3/28/2023 | 4/7/2023 | | | | |
| | | | | 56-1 | 4/10/2023 | 3 days | |
| | | | | 56-2 | 4/10/2023 | 3 days | |
| | | | | 56-3 | 4/10/2023 | 3 days | |
| | | | | 56-4 | 4/10/2023 | 3 days | |
| | | | | 56-5 | 4/10/2023 | 3 days | |
| | | | | 56-6 | 4/10/2023 | 3 days | |
| PSDR 57 | CPRE Intercon./Upgrade Costs (CONFIDENTIAL) | 3/28/2023 | 4/7/2023 | | | | |
| | | | | 57-1 | 4/14/2023 | 7 days | |
| | | | | 57-2 | 4/11/2023 | 4 days | The Public Staff granted an extension to April 11. |
| PSDR 58 | MYRP Other Production Plant, Nat. Gas | 3/29/2023 | 4/10/2023 | | | | |
| | | | | 58-1 | 4/13/2023 | 3 days | |
| | | | | 58-2 | 4/13/2023 | 3 days | |
| | | | | 58-3 | 4/13/2023 | 3 days | |
| | | | | 58-4 | 4/16/2023 | 6 days | |
| | | | | 58-5 | 4/13/2023 | 3 days | |
| | | | | 58-6 | 4/13/2023 | 3 days | |
| | | | | 58-7 | 4/13/2023 | 3 days | |
| | | | | 58-8 | 4/13/2023 | 3 days | |
| | | | | 58-9 | 4/14/2023 | 4 days | |
| | | | | 58-10 | 4/13/2023 | 3 days | |
| PSDR 59 | MYRP General Plant | 3/29/2023 | 4/10/2023 | | | | |
| | | | | 59-1 | 4/13/2023 | 3 days | |
| | | | | 59-2 | 4/13/2023 | 3 days | |
| | | | | 59-3 | 4/13/2023 | 3 days | |
| PSDR 64 | Detailed Sample Costs - Dist. List D | 3/30/2023 | 4/10/2023 | | | | |
| | | | | 64-1 | 4/11/2023 | 1 day | |
| PSDR 67 | Detailed Sample Costs - General Plant 3 | 3/31/2023 | 4/10/2023 | | | | |
| | | | | 67-1 | 4/13/2023 | 3 days | |
| PSDR 68 | Transmission Project Discovery | 3/31/2023 | 4/10/2023 | | | | |
| | | | | 68-26 | 4/11/2023 | 1 day | |
| | | | | 68-29 | 4/13/2023 | 3 days | |
| | | | | 68-34 | 4/13/2023 | 3 days | |
| | | | | 68-39 | 4/11/2023 | 1 day | |
| | | | | 68-40 | 4/24/2023 | 14 days | |
| PSDR 69 | Lincoln County Unit 17 (CONFIDENTIAL) | 3/31/2023 | 4/10/2023 | | | | |
| | | | | 69-8 | 4/11/2023 | 1 day | |

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| PSDR No. | Title | Date Sent | Date Due | Subitems | Date Completed | No. Days Late | Notes |
|---|---|---|---|---|---|---|---|
| | | | | 69-9 | 4/18/2023 | 8 days | |
| PSDR 70 | Detailed Sample Costs - Nuclear Plant 3 | 4/3/2023 | 4/13/2023 | | | | |
| | | | | 70-1 | 4/17/2023 | 4 days | |
| PSDR 71 | Detailed Sample Dist. Costs; Follow-Up to DR 10; List E | 4/3/2023 | 4/13/2023 | | | | |
| | | | | 71-1 | 4/14/2023 | 1 day | |
| PSDR 73 | Coal MYRP Projects | 4/5/2023 | 4/17/2023 | | | | |
| | | | | 73-5 | 5/1/2023 | 14 days | The Public Staff granted DEC an extension, with 1/3 of the responses due on April 17, 1/3 due on April 20, and the final 1/3 due on April 24. |
| PSDR 76 | Detailed Sample Costs - Distribution List F | 4/6/2023 | 4/17/2023 | | | | |
| | | | | 76-1 | 4/21/2023 | 4 days | |
| PSDR 77 | DR 18 Follow-Up | 4/6/2023 | 4/17/2023 | | | | |
| | | | | 77-1 | 4/18/2023 | 1 day | |
| | | | | 77-2 | 4/18/2023 | 1 day | |
| | | | | 77-3 | 4/18/2023 | 1 day | |
| PSDR 85 | Rent Expense | 4/10/2023 | 4/20/2023 | | | | |
| | | | | 85-25 | 4/21/2023 | 1 day | |
| | | | | 85-26 | 4/21/2023 | 1 day | |
| PSDR 86 | Detailed Sample Costs - List G | 4/10/2023 | 4/20/2023 | | | | |
| | | | | 86-1 | 4/24/2023 | 4 days | |
| PSDR 89 | Residential Revenue Decoupling | 4/11/2023 | 4/21/2023 | | | | |
| | | | | 89-1 | 4/25/2023 | 4 days | |
| | | | | 89-2 | 4/25/2023 | 4 days | |
| | | | | 89-3 | 4/25/2023 | 4 days | |
| | | | | 89-4 | 4/25/2023 | 4 days | |
| | | | | 89-5 | 4/25/2023 | 4 days | |
| | | | | 89-6 | 4/25/2023 | 4 days | |
| | | | | 89-7 | 4/25/2023 | 4 days | |
| | | | | 89-8 | 4/25/2023 | 4 days | |
| | | | | 89-9 | 4/25/2023 | 4 days | |
| | | | | 89-10 | 4/25/2023 | 4 days | |
| | | | | 89-11 | 4/24/2023 | 3 days | |
| | | | | 89-12 | 4/24/2023 | 3 days | |
| | | | | 89-13 | 4/24/2023 | 3 days | |
| PSDR 94 | Payroll & Incentives NC2050 & NC2040 | 4/12/2023 | 4/24/2023 | | | | |
| | | | | 94-1 | 4/25/2023 | 1 day | |
| | | | | 94-3 | 4/25/2023 | 1 day | |
| | | | | 94-4 | 4/25/2023 | 1 day | |
| | | | | 94-5 | 4/25/2023 | 1 day | |
| | | | | 94-6 | 4/25/2023 | 1 day | |
| | | | | 94-8 | 4/25/2023 | 1 day | |
| | | | | 94-9 | 4/25/2023 | 1 day | |
| | | | | 94-10 | 4/25/2023 | 1 day | |
| | | | | 94-13 | 4/25/2023 | 1 day | |
| PSDR 97 | Decommissioning Study | 4/25/2023 | 5/5/2023 | | | | |
| | | | | 97-1 | 5/10/2023 | 5 days | |
| | | | | 97-2 | 5/10/2023 | 5 days | |
| | | | | 97-3 | 5/10/2023 | 5 days | |
| | | | | 97-4 | 5/10/2023 | 5 days | |
| | | | | 97-5 | 5/10/2023 | 5 days | |
| | | | | 97-6 | 5/10/2023 | 5 days | |
| | | | | 97-9 | 5/10/2023 | 5 days | |
| | | | | 97-10 | 5/10/2023 | 5 days | |
| | | | | 97-11 | 5/10/2023 | 5 days | |
| | | | | 97-12 | 5/10/2023 | 5 days | |
| | | | | 97-13 | 5/10/2023 | 5 days | |
| | | | | 97-14 | 5/10/2023 | 5 days | |
| | | | | 97-15 | 5/10/2023 | 5 days | |

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| PSDR No. | Title | Date Sent | Date Due | Subitems | Date Completed | No. Days Late | Notes |
|---|---|---|---|---|---|---|---|
| | | | | 97-16 | 5/10/2023 | 5 days | |
| PSDR 98 | Follow-Up to DR 6 (Spanos Testimony) | 4/25/2023 | 5/5/2023 | | | | |
| | | | | 98-1 | 5/10/2023 | 5 days | |
| PSDR 103 | Detailed Sample Coal/Steam; Follow-Up to PSDR 10, 26, 33, & 47 | 5/3/2023 | 5/15/2023 | | | | |
| | | | | 103-1 | 5/16/2023 | 1 day | |
| | | | | 103-2 | 5/16/2023 | 1 day | |
| | | | | 103-3 | 5/16/2023 | 1 day | |
| PSDR 105 | General Plant Follow-Up to PSDR 27 (CONFIDENTIAL) | 5/4/2023 | 5/15/2023 | | | | |
| | | | | 105-2 | 5/16/2023 | 1 day | |
| | | | | 105-3 | 5/17/2023 | 2 days | |
| PSDR 107 | Questions related to Beveridge's Testimony | 5/4/2023 | 5/15/2023 | | | | |
| | | | | 107-15 | 5/16/2023 | 1 day | |
| | | | | 107-18 | 5/16/2023 | 1 day | |
| | | | | 107-21 | 5/16/2023 | 1 day | |
| | | | | 107-22 | 5/16/2023 | 1 day | |
| | | | | 107-23 | 5/16/2023 | 1 day | |
| PSDR 108 | Follow-Up #1 to PSDR 20 and MYRP Hydro Projects | 5/4/2023 | 5/15/2023 | | | | |
| | | | | 108-1 | 5/17/2023 | 2 days | |
| | | | | 108-2 | 5/16/2023 | 1 day | |
| | | | | 108-3 | 5/16/2023 | 1 day | |
| | | | | 108-4 | 5/16/2023 | 1 day | |
| | | | | 108-5 | 5/16/2023 | 1 day | |
| PSDR 109 | Follow-Up to PSDR 57 | 5/4/2023 | 5/15/2023 | | | | |
| | | | | 109-1 | 5/16/2023 | 1 day | |
| | | | | 109-2 | 5/16/2023 | 1 day | |
| | | | | 109-3 | 5/16/2023 | 1 day | |
| | | | | 109-5 | 5/16/2023 | 1 day | |
| PSDR 111 | NC5040 and GIP Deferral | 5/5/2023 | 5/15/2023 | | | | |
| | | | | 111-2 | 5/16/2023 | 1 day | |
| | | | | 111-3 | 5/17/2023 | 2 days | |
| | | | | 111-4 | 5/17/2023 | 2 days | |
| | | | | 111-5 | 5/17/2023 | 2 days | |
| | | | | 111-6 | 5/17/2023 | 2 days | |
| | | | | 111-7 | 5/19/2023 | 4 days | |
| | | | | 111-8 | 5/17/2023 | 2 days | |
| PSDR 112 | Outside Services | 5/8/2023 | 5/18/2023 | | | | |
| | | | | 112-1 | 5/19/2023 | 1 day | |
| | | | | 112-2 | 5/19/2023 | 1 day | |
| PSDR 113 | Affiliates | 5/8/2023 | 5/18/2023 | | | | |
| | | | | 113-10 | 5/19/2023 | 1 day | |
| | | | | 113-11 | 5/19/2023 | 1 day | |
| | | | | 113-13 | 5/19/2023 | 1 day | |
| | | | | 113-14 | 5/19/2023 | 1 day | |
| | | | | 113-15 | 5/19/2023 | 1 day | |
| | | | | 113-16 | 5/19/2023 | 1 day | |
| | | | | 113-23 | 5/19/2023 | 1 day | |
| | | | | 113-24 | 5/19/2023 | 1 day | |
| | | | | 113-25 | 6/2/2023 | 15 days | |
| | | | | 113-26 | 5/22/2023 | 4 days | |
| | | | | 113-27 | 5/22/2023 | 4 days | |
| | | | | 113-28 | 6/2/2023 | 15 days | |
| | | | | 113-29 | 5/19/2023 | 1 day | |
| | | | | 113-30 | 5/25/2023 | 7 days | |
| PSDR 115 | Follow-Up to DR 20 and MYRP Hydro Projects (CONFIDENTIAL) | 5/9/2023 | 5/19/2023 | | | | |
| | | | | 115-1 | 5/22/2023 | 3 days | |
| | | | | 115-3 | 5/24/2023 | 5 days | |
| | | | | 115-4 | 5/22/2023 | 3 days | |
| PSDR 118 | Clemson Hydrogen Project - MYRP | 5/11/2023 | 5/22/2023 | | | | |

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| PSDR No. | Title | Date Sent | Date Due | Subitems | Date Completed | No. Days Late | Notes |
|---|---|---|---|---|---|---|---|
| | | | | 118-1 | 5/24/2023 | 2 days | |
| | | | | 118-2 | 5/24/2023 | 2 days | |
| | | | | 118-3 | 5/24/2023 | 2 days | |
| | | | | 118-4 | 5/24/2023 | 2 days | |
| | | | | 118-5 | 5/24/2023 | 2 days | |
| | | | | 118-6 | 5/24/2023 | 2 days | |
| | | | | 118-7 | 5/24/2023 | 2 days | |
| | | | | 118-8 | 5/24/2023 | 2 days | |
| | | | | 118-9 | 5/24/2023 | 2 days | |
| | | | | 118-10 | 5/24/2023 | 2 days | |
| | | | | 118-11 | 5/24/2023 | 2 days | |
| | | | | 118-12 | 5/24/2023 | 2 days | |
| | | | | 118-13 | 5/24/2023 | 2 days | |
| | | | | 118-14 | 5/24/2023 | 2 days | |
| | | | | 118-15 | 5/24/2023 | 2 days | |
| | | | | 118-16 | 5/24/2023 | 2 days | |
| | | | | 118-17 | 5/24/2023 | 2 days | |
| | | | | 118-18 | 5/24/2023 | 2 days | |
| | | | | 118-19 | 5/24/2023 | 2 days | |
| | | | | 118-20 | 5/24/2023 | 2 days | |
| PSDR 121 | Distribution Plant - PSDR 34 Follow-Up Number 1 | 5/15/2023 | 5/25/2023 | | | | |
| | | | | 121-1 | 6/1/2023 | 7 days | |
| | | | | 121-2 | 6/1/2023 | 7 days | |
| | | | | 121-3 | 6/1/2023 | 7 days | DEC email on 5/25/2023 stated that responses to this DR would be |
| | | | | 121-4 | 6/1/2023 | 7 days | late" as a result of an internal mix-up about who was responsible |
| | | | | 121-5 | 6/1/2023 | 7 days | for these requests." |
| PSDR 125 | Plant and Accumulated Depreciation Follow-Up to PSDR 10 | 5/17/2023 | 5/29/2023 | | | | |
| | | | | 125-1 | 5/30/2023 | 1 day | |
| | | | | 125-2 | 5/30/2023 | 1 day | |
| | | | | 125-3 | 5/30/2023 | 1 day | |
| | | | | 125-4 | 5/31/2023 | 2 days | |
| | | | | 125-5 | 5/31/2023 | 2 days | |
| | | | | 125-6 | 5/30/2023 | 1 day | |
| | | | | 125-7 | 5/30/2023 | 1 day | |
| | | | | 125-8 | 5/31/2023 | 2 days | |
| | | | | 125-9 | 5/31/2023 | 2 days | |
| PSDR 126 | Financial Statements & Tax Returns, Follow-Up to DR 24 | 5/17/2023 | 5/29/2023 | | | | |
| | | | | 126-1 | 5/31/2023 | 2 days | |
| | | | | 126-2 | 6/2/2023 | 4 days | |
| | | | | 126-3 | 5/31/2023 | 2 days | |
| | | | | 126-4 | 5/31/2023 | 2 days | |
| PSDR 127 | Follow-Up to Adjust for Covid Impacts, PSDR 31 | 5/17/2023 | 5/29/2023 | | | | |
| | | | | 127-1 | 6/1/2023 | 3 days | |
| | | | | 127-2 | 6/1/2023 | 3 days | |
| | | | | 127-3 | 6/1/2023 | 3 days | |
| | | | | 127-4 | 6/2/2023 | 4 days | |
| PSDR 128 | Follow-Up #3 to PSDR 20 and MYRP Hydro Projects | 5/17/2023 | 5/30/2023 | | | | |
| | | | | 128-1 | 6/7/2023 | 8 days | |
| | | | | 128-2 | 6/1/2023 | 2 days | |
| | | | | 128-3 | 6/1/2023 | 2 days | |
| | | | | 128-4 | 6/7/2023 | 8 days | |
| | | | | 128-5 | 6/7/2023 | 8 days | |
| | | | | 128-6 | 6/7/2023 | 8 days | |
| | | | | 128-7 | 6/8/2023 | 9 days | |
| | | | | 128-8 | 6/5/2023 | 6 days | |
| | | | | 128-12 | 5/31/2023 | 1 day | |
| | | | | 128-13 | 6/5/2023 | 6 days | |
| | | | | 128-14 | 6/5/2023 | 6 days | |

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| PSDR No. | Title | Date Sent | Date Due | Subitems | Date Completed | No. Days Late | Notes |
|---|---|---|---|---|---|---|---|
| | | | | 128-15 | 6/7/2023 | 8 days | |
| | | | | 128-17 | 6/7/2023 | 8 days | |
| | | | | 128-18 | 6/12/2023 | 13 days | |
| PSDR 130 | Other Production Plant Detailed Follow-Up to DR 39 | 5/18/2023 | 5/30/2023 | | | | |
| | | | | 130-1 | 6/2/2023 | 3 days | |
| | | | | 130-2 | 6/2/2023 | 3 days | |
| | | | | 130-3 | 6/9/2023 | 10 days | |
| | | | | 130-4 | 6/6/2023 | 7 days | |
| | | | | 130-5 | 6/8/2023 | 9 days | |
| | | | | 130-6 | 6/6/2023 | 7 days | |
| | | | | 130-7 | 6/19/2023 | 20 days | |
| | | | | 130-8 | 6/14/2023 | 15 days | |
| | | | | 130-9 | 6/5/2023 | 6 days | |
| PSDR 132 | General Plant Closed to Plant, Follow-Up to PSDR 49 | 5/19/2023 | 5/30/2023 | | | | |
| | | | | 132-1 | 5/31/2023 | 1 day | |
| | | | | 132-2 | 6/8/2023 | 9 days | |
| | | | | 132-3 | 6/5/2023 | 6 days | |
| | | | | 132-4 | 5/31/2023 | 1 day | |
| | | | | 132-5 | 5/31/2023 | 1 day | |
| | | | | 132-6 | 6/7/2023 | 8 days | |
| | | | | 132-7 | 5/31/2023 | 1 day | |
| | | | | 132-8 | 6/13/2023 | 14 days | |
| PSDR 134 | Intangible Plant Follow-Up to DR 52 | 5/22/2023 | 6/1/2023 | | | | |
| | | | | 134-1 | 6/6/2023 | 5 days | |
| | | | | 134-2 | 6/5/2023 | 4 days | |
| | | | | 134-3 | 6/5/2023 | 4 days | |
| PSDR 135 | Joint Use Utility Facilities Work Requests | 5/22/2023 | 6/1/2023 | | | | |
| | | | | 135-1 | 6/2/2023 | 1 day | |
| | | | | 135-2 | 6/2/2023 | 1 day | |
| PSDR 136 | Electric Vehicle Purchases and Infrastructure | 5/23/2023 | 6/2/2023 | | | | |
| | | | | 136-1 | 6/5/2023 | 3 days | |
| | | | | 136-6 | 6/7/2023 | 5 days | |
| | | | | 136-7 | 6/7/2023 | 5 days | |
| | | | | 136-9 | 6/5/2023 | 3 days | |
| PSDR 140 | Quality of Service | 5/24/2023 | 6/5/2023 | | | | |
| | | | | 140-15 | 6/6/2023 | 1 day | |
| PSDR 141 | Other Plant Follow-Up to PSDR 60 | 5/23/2023 | 6/5/2023 | | | | |
| | | | | 141-1 | 6/13/2023 | 8 days | |
| | | | | 141-2 | 6/8/2023 | 3 days | |
| | | | | 141-3 | 6/15/2023 | 10 days | |
| | | | | 141-4 | 6/9/2023 | 4 days | |
| PSDR 142 | NC 2150 Duke Energy Plaza Follow-Up | 5/25/2023 | 6/5/2023 | | | | |
| | | | | 142-1 | 6/6/2023 | 1 day | |
| | | | | 142-2 | 6/6/2023 | 1 day | |
| | | | | 142-3 | 6/6/2023 | 1 day | |
| | | | | 142-4 | 6/6/2023 | 1 day | |
| PSDR 143 | Vegetation Management Proforma NC 2070 | 5/29/2023 | 6/8/2023 | | | | |
| | | | | 143-1 | 6/9/2023 | 1 day | |
| | | | | 143-2 | 6/9/2023 | 1 day | |
| | | | | 143-3 | 6/9/2023 | 1 day | |
| | | | | 143-4 | 6/9/2023 | 1 day | |
| | | | | 143-5 | 6/9/2023 | 1 day | |
| | | | | 143-6 | 6/9/2023 | 1 day | |
| | | | | 143-7 | 6/9/2023 | 1 day | |
| | | | | 143-8 | 6/9/2023 | 1 day | |
| PSDR 146 | Fuel Rate Calculations | 5/30/2023 | 6/9/2023 | | | | |
| | | | | 146-3 | 6/12/2023 | 3 days | |
| | | | | 146-4 | 6/12/2023 | 3 days | |

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| PSDR No. | Title | Date Sent | Date Due | Subitems | Date Completed | No. Days Late | Notes |
|---|---|---|---|---|---|---|---|
| | | | | 146-5 | 6/12/2023 | 3 days | |
| PSDR 147 | Coal Plant Retirement & Securitization | 5/30/2023 | 6/9/2023 | | | | |
| | | | | 147-2 | 6/12/2023 | 3 days | |
| PSDR 151 | Reliability Metrics | 6/1/2023 | 6/12/2023 | | | | |
| | | | | 151-5 | 6/19/2023 | 7 days | |
| | | | | 151-8 | 6/19/2023 | 7 days | |
| | | | | 151-11 | 6/19/2023 | 7 days | |
| | | | | 151-16 | 6/13/2023 | 1 day | |
| | | | | 151-17 | 6/13/2023 | 1 day | |
| PSDR 156 | Follow-Up to PSDR 113 | 6/2/2023 | 6/12/2023 | | | | |
| | | | | 156-1 | 6/13/2023 | 1 day | |
| | | | | 156-2 | 6/15/2023 | 3 days | |
| PSDR 162 | Interconnection and CIAC | 6/6/2023 | 6/16/2023 | | | | |
| | | | | 162-6 | 6/20/2023 | 4 days | The Public Staff granted an extension to June 20. |
| PSDR 163 | Follow-Up to DR 48 (CONFIDENTIAL) | 6/7/2023 | 6/19/2023 | | | | |
| | | | | 163-6 | 6/20/2023 | 1 day | |
| | | | | 163-7 | 6/20/2023 | 1 day | |
| | | | | 163-8 | 6/20/2023 | 1 day | |
| PSDR 166 | Follow-Up to Adjust for Covid Impacts, PSDR 127 | 6/7/2023 | 6/19/2023 | | | | |
| | | | | 166-1 | 6/21/2023 | 2 days | |
| | | | | 166-2 | 6/20/2023 | 1 day | |
| PSDR 168 | MYRP Project Estimates & Classification; Historic Review | 6/7/2023 | 6/19/2023 | | | | |
| | | | | 168-1 | 6/20/2023 | 1 day | |
| | | | | 168-5 | 6/30/2023 | 11 days | |
| | | | | 168-6 | 6/30/2023 | 11 days | |
| | | | | 168-7 | 6/30/2023 | 11 days | |
| | | | | 168-8 | 6/30/2023 | 11 days | |
| | | | | 168-9 | 6/30/2023 | 11 days | |
| | | | | 168-10 | 6/30/2023 | 11 days | |
| | | | | 168-11 | 6/30/2023 | 11 days | |
| PSDR 170 | Distribution MYRP 2 (direct and supplemental) | 6/8/2023 | 6/19/2023 | | | | |
| | | | | 170-7 | 7/9/2023 | 20 days | |
| | | | | 170-10 | 6/20/2023 | 1 day | |
| PSDR 172 | House Power Panel Program | 6/8/2023 | 6/19/2023 | | | | |
| | | | | 172-2 | 6/20/2023 | 1 day | |
| | | | | 172-4 | 6/20/2023 | 1 day | |
| PSDR 177 | NC 5130 Pro Forma Adjustment | 6/9/2023 | 6/19/2023 | | | | |
| | | | | 177-2 | 6/26/2023 | 7 days | Discussed providing supplemental info with the public staff |
| PSDR 178 | IIJA/IRA | 6/9/2023 | 6/19/2023 | | | | |
| | | | | 178-1 | 6/20/2023 | 1 day | |
| | | | | 178-6 | 6/20/2023 | 1 day | |
| | | | | 178-8 | 6/21/2023 | 2 days | |
| | | | | 178-9 | 6/20/2023 | 1 day | |
| | | | | 178-10 | 6/20/2023 | 1 day | |
| PSDR 181 | RRE MYRP Supplemental Projects | 6/13/2023 | 6/23/2023 | | | | |
| | | | | 181-1 | 6/30/2023 | 7 days | |
| PSDR 184 | | 6/13/2023 | 6/23/2023 | | | | |
| | | | | 184-1 | 6/26/2023 | 3 days | |
| | | | | 184-2 | 6/26/2023 | 3 days | |
| PSDR 185 | Distribution MYRP 3 (direct and supplemental) | 6/13/2023 | 6/23/2023 | | | | |
| | | | | 185-3 | 6/26/2023 | 3 days | |
| | | | | 185-10 | 6/26/2023 | 3 days | |
| | | | | 185-21 | 6/26/2023 | 3 days | |
| PSDR 186 | Distribution MYRP 4 (direct and supplemental) | 6/13/2023 | 6/23/2023 | | | | |
| | | | | 186-7 | 6/26/2023 | 3 days | |
| | | | | 186-8 | 6/26/2023 | 3 days | |
| | | | | 186-9 | 6/26/2023 | 3 days | |

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| PSDR No. | Title | Date Sent | Date Due | Subitems | Date Completed | No. Days Late | Notes |
|---|---|---|---|---|---|---|---|
| | | | | 186-10 | 6/26/2023 | 3 days | |
| PSDR 190 | Follow-Up to DR 146 Fuel Rate Calculations (CONFIDENTIAL) | 6/15/2023 | 6/26/2023 | | | | |
| | | | | 190-2 | 6/28/2023 | 2 days | |
| PSDR 191 | Follow-Up to PSDR 111 | 6/15/2023 | 6/26/2023 | | | | |
| | | | | 191-1 | 6/29/2023 | 3 days | |
| PSDR 194 | Distribution; IVVC, TRP, SOG | 6/16/2023 | 6/26/2023 | | | | |
| | | | | 194-1 | 6/28/2023 | 2 days | |
| | | | | 194-4 | 6/28/2023 | 2 days | |
| PSDR 199 | Storm Normalization & Tracker | 6/20/2023 | 6/30/2023 | | | | |
| | | | | 199-1 | 7/5/2023 | 5 days | |
| | | | | 199-2 | 7/5/2023 | 5 days | DEC email on 6/30/2023 stated that this DR response would be late "due to personnel unavailability." |
| | | | | 199-4 | 7/3/2023 | 3 days | |
| PSDR 204 | Follow-Up to PSDR 166-3 and 127-4; Adjust for Covid Impacts | 6/21/2023 | 6/27/2023 | | | | |
| | | | | 204-1 | 7/10/2023 | 13 days | |
| PSDR 205 | Hydro (Follow-Up to PSDR 128) | 6/21/2023 | 6/26/2023 | | | | |
| | | | | 205-1 | 7/3/2023 | 7 days | |
| | | | | 205-2 | 7/3/2023 | 7 days | |
| PSDR 209 | Hydroelectric Incentives (Follow-Up to DR 178) (CONFIDENTIAL) | 6/26/2023 | 7/3/2023 | | | | |
| | | | | 209-2 | 7/6/2023 | 3 days | |
| | | | | 209-3 | 7/6/2023 | 3 days | |
| | | | | 209-4 | 7/5/2023 | 2 days | |
| PSDR 210 | Follow-Up to DR 31 & 180; Adjust for Covid Impacts | 6/27/2023 | 7/5/2023 | | | | |
| | | | | 210-1 | 7/6/2023 | 1 day | |
| PSDR 217 | Follow-Up to PSDR 159 - Duke Energy Plaza - Facility Study | 6/30/2023 | 7/10/2023 | | | | |
| | | | | 217-2 | 7/11/2023 | 1 day | |
| | | | | 217-3 | 7/11/2023 | 1 day | |
| | | | | 217-4 | 7/11/2023 | 1 day | |

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| Funding Pro ect | Location Name | MYRP Project | Project Authorizat on File Name | Schedule File Name | R sk Register | PSR (Project Status Report, available once in initiate Gate) | Change Log | Risk-informed information (if assigned) - PMCost R sk Regis ter tool |
|---|---|---|---|---|---|---|---|---|
| 24VEGDEC | Haza d T ee Removal | Vegetat on Management | NA | NA | NA | NA | NA | NA |
| 24WOODPOLEDEC | Tx geted Wood Poles Upg ades | T L ne H&R | NA | NA | NA | NA | NA | NA |
| 25VEGDEC | Haza d T ee Removal | Vegetat on Management | NA | NA | NA | NA | NA | NA |
| 25WOODPOLEDEC | Tx geted Wood Poles Upg ades | T L ne H&R | NA | NA | NA | NA | NA | NA |
| 26VEGDEC | Haza d T ee Removal | Vegetat on Management | NA | NA | NA | NA | NA | NA |
| 26WOODPOLEDEC | Tx geted Wood Poles Upg ades | T L ne H&R | NA | NA | NA | NA | NA | NA |
| CP17TRC | T ansfo rma Bush ng Replacement - CP17TRC | T ansfo rma s | Document not p oduced | Document not p oduced | NA | NA | NA | NA |
| NP09100 | Hard ns 44kV - L ne Rebu ld | T L ne H&R | Hard ns 44kV - L ne Rebu ld-NP09100-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| NP09175 | W lkes T e 230kV Casac tv Exoens on | Casac tv & Custome Plan | W lkes T e 230kV Casac tv Exoens on-NP09175--P esentat on.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | | W lkes T e 230kV Casac tv Exoens on-NP09175-PSR.xlsm | W lkes T e 230kV Casac tv Exoens on-NP09175-Change Log.xlsx | W lkes T e 230kV Casac tv Exoens on-NP09175-R sk Info med.pdf |
| NP09177 | Du ham Ma n - Rel ab l ty Upg ade | Substat on H&R | Du ham Ma n - Rel ab l ty Upg ade-NP09177-Fund ng P esentat on.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | Du ham Ma n - Rel ab l ty Upg ade-NP09177 -R sk Reg ste .xlsx | Du ham Ma n - Rel ab l ty Upg ade-NP09177-PSR.xlsm | Du ham Ma n - Rel ab l ty Upg ade-NP09177-Change Log.xlsm | Du ham Ma n - Rel ab l ty Upg ade-NP09177-R sk Info med.pdf |
| W170015 | Stamey T e - Add Redundant Bus P otect on | Capacity & Custome Plan | Stamey T e - Add Redundant Bus P otect on-W170015-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170053 | Shady G ove T e - Add Redundant Bus P otect on | Capacity & Custome Plan | Shady Gl ove T e-AddRedundantBusP otect on-W170053-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170054 | Sunset Reta l - Replace T ansfo rme | T ansfo rma s | Sunset Reta l - Replace T ansfo rme -W170054-Cove Sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170080 | N neb N ne Island Hvd o TO L B eake s | B eake s | N neb N ne Island Hvd o TOIL B eake s-W170080-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170085 | Tu ne Shoals Sw tch ng Stat on TOIL B eake s | B eake s | Tu ne Shoals Sw tch ng Stat on TO L B eake s-W170085-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170089 | G eenv lle Ma n - Sw tch Upg ade | Substat on H&R | G eenv lle Ma n - Sw tch Upg ade-W170089 Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170090 | Pecolet T e TOIL B eake s | B eake s | Pecolet T e TOIL B eake s-W170090-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170091 | E G eenv lle Sw tch ng Stat on TOIL B eake s | B eake s | E G eenv lle Sw tch ng Stat on TOIL B eake s-W170091-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170092 | Glen Raven Ma n TOIL & DOIL B eake s | B eake s | Glen Raven Ma n TOIL & DOIL B eake s-W170092-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170093 | G eenlawn Sw tch ng Stat on TOIL B eake s | B eake s | G eenlawn Sw tch ng Stat on TOIL B eake s-W170093-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170095 | Shelby T e TOIL B eake s | B eake s | Shelby T e TOIL B eake s-W170095-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170102 | Wamsutta TOIL B eake s | B eake s | Wamsutta TO L B eake s-W170102-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170115 | Hende sonv lle T e TOIL B eake s | B eake s | Hende sonv lle T e TOIL B eake s- W170115-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170116 | Newton T e - Rel ab l ty Upg ade | Substat on H&R | Newton T e - Rel ab l ty Upg ade-W170116-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170117 | Stouts Reta l - Replace T ansfo rme | T ansfo rma s | Stouts Reta l - Replace T ansfo rme -W170117-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170129 | Sp ndale 44kV - L ne Rebu ld | T L ne H&R | Sp ndale 44kV - L ne Rebu ld-W170129-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170139 | B oad R ve EC Del 2 TOIL B eake s | B eake s | B oad R ve EC Del 2 TOIL B eake s-W170139-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170145 | Pa kdale Ame ca LLC TOI L B eake s | B eake s | Pa kdale Ame ca LLC TO L B eake s-W170145-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170153 | P nn cle T e - Rel ab l ty Upg ade | Substat on H&R | P nn cle T e - Rel ab l ty Upg ade-W170153-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170154 | N Kernapol s Reta l - Relay Upg ades | System Intell gence | N Kernapol s Reta l - Relay Upg ades-W170154-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170155 | Ha sbu g T e TOI L B eake s | B eake s | Ha sbu g T e TOIL B eake s-W170155-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | Document not ava lable, st l n Development | Document not ava lable, st ll n Development | Document not ava lable, st l n Development | Document not ava lable, st ll n Development |
| W170156 | Hawtho ne Road Reta l - Rel ab l ty Upg ade | Substat on H&R | Hawtho ne Road Reta l - Rel ab l ty Upg ade-W170156-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170157 | Campobello T e TOIL B eake s | B eake s | Campobe llo T e TOIL B eake s-W170157-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170159 | Cl ffs de Sw tch ne Stat on TO L B eake s | B eake s | Cl ffs de Sw tch ne Stat on TOIL B eake s-W170159-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170166 | Ogden Reta l - Reley Upg ades | System Intell gence | Ogden Reta l - Reley Upg ades-W170116-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170168 | Mockov lle Ma n - Replace T ansfo rme | T ansfo rma s | Mockov lle Ma n - Replace T ansfo rme -W170168-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170171 | Bu l ngton Ma n TOIL B eake s | B eake s | Bu l ngton Ma n TOIL B eake s-W170171-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170176 | Ho seshoe T e TOI L B eake s | B eake s | Ho seshoe T e TOIL B eake s-W170176-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170177 | N neb S x Reta l - Remote Ope ated Sw tch | System Intell gence | N neb S x Reta l - Remote Ope ated Sw tch-W170177-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170180 | P gah T e TOIL B eake s | B eake s | P gah T e TOIL B eake s-W170180-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | Document not ava lable, st l n Development | Document not ava lable, st ll n Development | Document not ava lable, st l n Development | Document not ava lable, st ll n Development |
| W170194 | P ne Needle LNG Co LLC - Replace T ansfo rme | T ansfo rma s | P ne Needle LNG Co LLC - Replace T ansfo rme -W170194-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170195 | Peacock T e TOIL B eake s | B eake s | Peacock T e TOIL B eake s-W170195-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170200 | Blue R dge EC Del 14 TOI L B eake s | B eake s | Blue R dge EC Del 14 TO L B eake s-W170200-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170206 | Seneca Place - Reley Upg ades | System Intell gence | Seneca Place - Reley Upg ades-W170206-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170207 | Coleman Reta l - Rel ab l ty Upg ade | Substat on H&R | Coleman Reta l - Rel ab l ty Upg ade-W170207-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170208 | Eastgate TOIL B eake s | B eake s | Eastgate TOIL B eake s-W170208-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170209 | Mt Tabo TOIL B eake s | B eake s | Mt Tabo TOIL B eake s-W70209-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170211 | GE A c eft - Reley Upg ades | System Intell gence | GE A c eft - Reley Upg ades-W170211-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170214 | Mebane T e - Rel ab l ty Upg ade | Substat on H&R | Mebane T e - Rel ab l ty Upg ade-W170214 Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170218 | Nantahala Hyd ro - Reley Upg ades | system ntell gence | Nantahala Hyd ro - Reley Upg ades-W170218-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170222 | E Spence - Reley Upg ades | System Intell gence | E Spence - Reley Upg ades-W170222-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170223 | Beech St eet Reta l - Reley Upg ades | System Intell gence | Beech St eet Reta l - Reley Upg ades-W170223-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170241 | W necoff T e - Ove duty B eake s | Capacity & Custome Plan | W necoff T e - Ove duty B eake s-W170241-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W170306 | N G eenv lle T e - Bus Junct on B eake s | Casac tv & Custome Plan | N G eenv lle T e - Bus Junct on B eake s-W170306-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180045 | Robe t Bosch - Reley Upg ades | system ntell gence | Robe t Bosch - Reley Upg ades-W180045-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180049 | W nston T e - Rel ab l ty Upg ade | Substat on H&R | W nston T e - Rel ab l ty Upg ade-W180049-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180082 | ONS 525kV Sw tch Ya d - Bus Upg ades | Substat on H&R | ONS 525kV Sw tch Ya d - Bus Upg ades-W180082-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180084 | R pp Sw tch ng Stat on - Ove duty B eake s | Capacity & Custome Plan | R pp Sw tch ng Stat on - Ove duty B eake s-W180084-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180088 | Camo C oft Reta l - Replace T ansfo rme | T ansfo rma s | Camo C oft Reta l - Replace T ansfo rme -W180088-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180226 | Mon oe Road Reta l - Replace T ansfo rme | T ansfo rma s | Mon oe Road Reta l - Replace T ansfo rme -W180226-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180227 | Conco d Ma n - Replace T ansfo rme | T ansfo rma s | Conco d Ma n - Replace T ansfo rme -W180227-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180229 | Lancaste Reta l - Replace T ansfo rme | T ansfo rma s | Lancaste Reta l - Replace T ansfo rme -W180229-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180230 | Pa kdale Ame - Replace T ansfo rme | T ansfo rma s | Pa kdale Ame - Replace T ansfo rme -W180230-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180231 | A owood Reta l - Replace T ansfo rme | T ansfo rma s | A owood Reta l - Replace T ansfo rme -W180231-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180235 | Vendel a Reta l - Replace T ansfo rme - W180235 | T ansfo rma s | Document not p oduced | Document not p oduced | NA | NA | NA | NA |
| W180237 | Wh tehall Reta l - Replace T ansfo rme | T ansfo rma s | Wh tehall Reta l - Replace T ansfo rme -W180237-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180239 | Augusta Road Reta l - Replace T ansfo rme | T ansfo rma s | Augusta Road Reta l - Replace T ansfo rme -W180239-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180240 | Kno lwood Reta l - Replace T ansfo rme | T ansfo rma s | Knollwood Reta l - Replace T ansfo rme -W180240-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180241 | Una Reta l - Replace T ansfo rme | T ansfo rma s | Una Reta l - Replace T ansfo rme -W180241-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180244 | JP Stevens 44kV - L ne Rebu ld | T L ne H&R | JP Stevens 44kV - L ne Rebu ld-W180244-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180247 | Leakov lle Reta l - Replace T ansfo rme | T ansfo rma s | Leakov lle Reta l - Replace T ansfo rme -W180247-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180266 | Oconee 230kV Sw tchya d TOIL B eake s | B eake s | Oconee 230kV Sw tchya d TOIL B eake s-W180266-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180280 | S gobee A&B 44kV - L ne Rebu ld | T L ne H&R | S gobee A&B 44kV - L ne Rebu ld-W180280-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180288 | Camobe lo A&B 44kV - L ne Rebu ld | T L ne H&R | Camobello A&B 44kV - L ne Rebu ld-W180288-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180293 | L be ty 44kV - L ne Rebu ld | T L ne H&R | L be ty 44kV - L ne Rebu ld-W180293-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180294 | Ha mony 44kV - L ne Rebu ld | T L ne H&R | Ha mony 44kV - L ne Rebu ld-W180294-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | Ha mony 44kV - L ne Rebu ld-W180294-R sk. Reg ste .pdf | Ha mony 44kV - L ne Rebu ld-W180294-PSR.pdf | Ha mony 44kV - L ne Rebu ld-W180294-Change Log.pdf | Ha mony 44kV L ne Rebu ld-W180294-R sk Info med.xlsx |
| W180296 | It on - A B eak Sw tch Upg ade | Substat on H&R | It on - A B eak Sw tch Upg ade_Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180297 | Koyo Bea ngs USA LLC - C ou t Sw tche Upg ade | Substat on H&R | Koyo Bea ngs USA LLC - C ou t Sw tche Upg ade-W180297-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180298 | Pleasant Ga den T e - Add Redundant Bus P otect on | Capacity & Custome Plan | Pleasant Ga den T e - Add Redundant Bus P otect on-W180298-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180307 | A l Po nts T uck ng - A B eak Sw tch Upg ade | Substat on H&R | All Po nts T uck ng - A B eak Sw tch Upg ade-W180307-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180326 | G eenf eld Reta l - A B eak Sw tch Upg ade | Substat on H&R | G eenf eld Reta l - A B eak Sw tch Upg ade-W180326-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180327 | Med son T e TOIL B eake s | B eake s | Med son T e TOIL B eake s-W180327-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180328 | Pancle Sw tch ng Stat on - A B eak Sw tch Upg ade | Substat on H&R | Pancle Sw tch ng Stat on - A B eak Sw tch Upg ade-W180328-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180330 | M l ken & Co Ge sh M l - A B eak Sw tch Upg ade | Substat on H&R | M l ken & Co Ge sh M l - A B eak Sw tch Upg ade-W180330-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180331 | GTP G eenv lle Inc - A B eak Sw tch Upg ade | Substat on H&R | Document not p oduced | Document not p oduced | NA | NA | NA | NA |
| W180332 | Bethlehem Sw tch ng Stat on - Replace DOIL B eake s | B eake s | Bethlehem Sw tch ng Stat on - Replace DOIL B eake s-W180332-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180333 | JPS Glass Slate Pl - A B eak Sw tch Upg ade | Substat on H&R | JPS Glass Slate Pl - A B eak Sw tch Upg ade-W180333-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180337 | Cle ermont Reta l - Replace DOI L B eake s | B eake s | Cle ermont Reta l - Replace DO L B eake s-W180337-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180338 | Denton Reta l - Replace DOIL B eake s | B eake s | Denton Reta l - Replace DOIL B eake s-W180338-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180339 | Gaston s Ma n - Replace DOIL B eake s | B eake s | Gaston s Ma n - Replace DOIL B eake s-W180339-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180340 | Be nb dge Reta l - Replace DOIL B eake s | B eake s | Be nb dge Reta l - Replace DOIL B eake s-W180340-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180343 | IVA Sw tch ng Stat on - Replace DOI L B eake s | B eake s | IVA Sw tch ng Stat on - Replace DO L B eake s-W180343-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180349 | T ge v lle Reta l - Replace DOI L B eake s | B eake s | T ge v lle Reta l - Replace DO L B eake s-W180349-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180351 | Mawsden Reta l - C ou t Sw tche Upg ade | Substat on H&R | Mawsden Reta l - C ou t Sw tche Upg ade-W180351-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180358 | McAdenv lle Reta l - Reley Upg ades | system ntell gence | McAdenv lle Reta l - Reley Upg ades-W180358-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180368 | Beckw d te T e - Replace TOIL B eake s | B eake s | Beckw d te T e - Replace TOIL B eake s-W180368-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180369 | Cl ffs de Steem Sw tch ng Stat on - An mal M t gat on | Substat on H&R | Cl ffs de Steem Sw tch ng Stat on - An mal M t gat on-W180369-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180370 | Bethwe a Reta l - Remote Ope ated Sw tch | System Intell gence | Bethwe a Reta l - Remote Ope ated Sw tch-W180370-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180371 | Flav Reta l - Remote Ope ated Sw tch | System Intell gence | Flav Reta l - Remote Ope ated Sw tch-W180371 Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180372 | Yo k EC Del ve y 20 - Remote Ope ated Sw tch | System Intell gence | Yo k EC Del ve y 20 - Remote Ope ated Sw tch-W180372-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180374 | Sexm ll 1&2 44kV - L ne Rebu ld | T L ne H&R | Sexm ll 1&2 44kV - L ne Rebu ld-W180374-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | Sexm ll 1&2 44kV - L ne Rebu ld-W180374-R sk Reg ste .pdf | Sexm ll 1&2 44kV - L ne Rebu ld-W180374-PSR.pdf | Sexm ll 1&2 44kV - L ne Rebu ld-W180374-Change Log.pdf | Sexm ll 1&2 44kV L ne Rebu ld_R sk Info med.xlsx |
| W180379 | Lowe 44kV - L ne Rebu ld | T L ne H&R | Lowe 44kV - L ne Rebu ld-W180379-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180385 | Cent al T e - Replace TOIL B eake s | B eake s | Cent al T e - Replace TOIL B eake s-W180385-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180393 | C est St Reta l - Replace TOIL B eake s | B eake s | C est St Reta l - Replace TOIL B eake s-W180393-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180400 | Oconee 230kV Sw tchya d - Relay Cont ol House Upg ade | System Intell gence | Oconee 230kV Sw tchya d - Relay Cont ol House Upg ade-W180400-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | Oconee 230kV Sw tchya d - Relay Cont ol House Upg ade-W180400--R sk Reg ste .pdf | Oconee 230kV Sw tchya d - Relay Cont ol House Upg ade-W180400-PSR.pdf | Oconee 230kV Sw tchya d - Relay Cont ol House Upg ade-W180400-Change Log.pdf | Oconee 230kV Sw tchya d - Relay Cont ol House Upg ade-W180400-R sk Info med.pdf |
| W180416 | Ma on Ma n - Replace DOIL B eake s | B eake s | Ma on Ma n - Replace DOIL B eake s-W180416-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180455 | C eto T e - Capac to Upg ade | Substat on H&R | C eto T e - Capac to Upg ade-W180455-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180471 | B assf eld Reta l - Replace DOIL B eake s | B eake s | B assf eld Reta l - Replace DOIL B eake s-W180471-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180506 | Mulbe v C eek - Replace TOI L & DOI L B eake s | B eake s | Mulbe v C eek - Replace TOIL & DOIL B eake s-W180506-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W180527 | T ansfo rme Bush ng Replacement - W180527 | T ansfo rma s | Document not p oduced | Document not p oduced | NA | NA | NA | NA |
| W180552 | W llow C eek Reta l - Replace DOI L B eake s | B eake s | W llow C eek Reta l - Replace DOIL B eake s-W180552-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W190010 | H cko y T e - Reley Cont ol House Upg ade | system ntell gence | H cko y T e - Reley Cont ol House Upg ade-W190010-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | Document not ava lable, st l n Development | Document not ava lable, st ll n Development | Document not ava lable, st l n Development | Document not ava lable, st ll n Development |
| W190075 | Pebble C eek Reta l - Replace TOIL & DOIL B eake s | B eake s | Pebble C eek Reta l - Replace TOIL & DOIL B eake s-W190075 Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W190110 | G eenv lle Ma n - An mal M t eat on | Substat on H&R | G eenv lle Ma n - An mal M t eat on-W190110-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W190120 | K vett D Reta l - Replace TOIL B eake s | B eake s | K vett D Reta l - Replace TOIL B eake s-W190120-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W190136 | T ansfo rme Cond t on Based Mon to ng | System Intell gence | T ansfo rme Cond t on Based Mon to ng-W190136-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W190145 | Oconee Nucles Sw tch ng Stat on Fent L nes - A eake s | Substat on H&R | Document not p oduced | Document not p oduced | NA | NA | NA | NA |
| W190149 | H ghland Reta l - Reley Upg ade | system ntell gence | H ghland Reta l - Reley Upg ade-W190149-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |

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|---|---|---|---|---|---|---|---|---|
| W190152 | D lwo th - Reley Upg ade | System Intell gence | D lwo th - Reley Upg ade-W190152-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W190159 | Depot St Reta l - Reley Upg ade | system ntell gence | Depot St Reta l - Reley Upg ade-W190159-Cove sheet .pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W190160 | Bed n Reta l - Reley Upg ade | system ntell gence | Bed n Reta l - Reley Upg ade-W190160-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W190161 | Howe d St Reta l - Reley Upg ade | system ntell gence | Howe d St Reta l - Reley Upg ade-W190161-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W190163 | Alberna le Sw tch ne Stat on - Relev Use ade | system ntell gence | Alberna le Sw tch ne Stat on - Relev Use ade-W190163-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W190165 | Shuman Ave - Reley Upg ade | system ntell gence | Shuman Ave - Reley Upg ade-W190165-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W190178 | W No wood Reta l - Reley Upg ade | system ntell gence | W No wood Reta l - Reley Upg ade-W190178-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W190183 | Condense Stat on Reta l - Reley Upg ade | system ntell gence | Condense Stat on Reta l - Reley Upg ade-W190183-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W190189 | Campobello T e - Reley Upg ade | system ntell gence | Campobe lo T e - Reley Upg ade-W190189-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W190192 | Walhalla Reta l - Relev Use ade | System Intell gence | Walha la Reta l - Relev Use ade-W190192-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W190193 | D ape Reta l - Reley Upg ade | system ntell gence | D ape Reta l - Reley Upg ade-W190193-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W190195 | Stonee le Reta l - Reley Upg ade | system ntell gence | Stonee le Reta l - Reley Upg ade-W190195-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W190199 | Conco d Me n - Reley Upg ade | system ntell gence | Conco d Me n - Reley Upg ade-W190199-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W190221 | McGu e Nuclea Sw tch ng Stat on-Rock Sp ngs A este s | Substat on H&R | McGu e Nuclea Sw tch ng Stat on-Rock Sp ngs A este s-W190221-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W190224 | Lonav ew T e - Reolace TO L B eake s | B eake s | Lonav ew T e - Reolace TOIL B eake s-W190224-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W190242 | Colesbu y 100kV - L ne Rebu ld | Capac ty & Custome Plan | Colesbu y 100kV - L ne Rebu ld-W190242-Cove sheet .xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W190279 | Sh loh Sw tch ng Stat on - Reley Upg ade | System Intell gence | Sh loh Sw tch ng Stat on - Reley Upg ade-W190279-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W190306 | Eno T e 230kV - Bus Junct on B eake s | Capac ty & Custome Plan | Eno T e 230kV - Bus Junct on B eake s-W190306-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W190320 | Quebec 44kV - L ne Rebu ld | T L ne H&R | Quebec 44kV - L ne Rebu ld-W190320-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W190322 | Duke Un ve s ty Stat on 1&2 - Relev Use ake | system ntell gence | Duke Un ve s ty Stat on 1&2 - Relev Use ake-W190322-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W190356 | Rhodh ss T e Stat on - Replace TOIL B eake s | B eake s | Rhodh ss T e Stat on - Replace TOIL B eake s-W190356-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W190383 | Ru al Hall T e - Ove duty B eake s | Capac ty & Custome Plan | Ru al Hall T e - Ove duty B eake s-W190383-Cove sheet .pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W192022 | Fou Seasons - Replace DOIL B eake s | B eake s | Fou Seasons - Replace DOIL B eake s-W192022-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W192043 | McGu e Nuclea Sw tch ng Stat on-Mecklenbu g Wh te - A este s | Substat on H&R | McGu e Nuclea Sw tch ng Stat on-Mecklenbu g Wh te - A este s-W192043-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W192053 | McGu e Nuclea Sw tch ne Stat on-Cowens Fo d Black - A este s | Substat on H&R | McGu e Nuclea Sw tch ne Stat on-Cowens Fo d Black - A este s-W192053-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W192064 | Oconee Nuclea Sw tch ng Stat on-Dacus Black - A este s | Substat on H&R | Oconee Nuclea Sw tch ng Stat on-Dacus Black - A este s-W192064-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W192066 | Oconee Nuclea Sw tch ng Stat on-Jocassee Black - A este s | Substat on H&R | Oconee Nuclea Sw tch ng Stat on-Jocassee Black - A este s-W192066-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W192080 | Oconee Nuclea Sw tch ng Stat on-AT1 - A este s | Substat on H&R | Oconee Nuclea Sw tch ng Stat on-AT1 - A este s-W192080 Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W192082 | Oconee Nuclea Sw tch ng Stat on - A este s | Substat on H&R | Oconee Nuclea Sw tch ng Stat on - A este s-W192082-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200008 | Hollv H ll Tao 100kV - L ne Rebu ld | T L ne H&R | Hollv H ll Tao 100kV - L ne Rebu ld-W200008-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200017 | F st Quel ty T ssue - Reley Upg ade | System Intell gence | F st Quel ty T ssue - Reley Upg ade-W200017-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200029 | S las 100kV - L ne Rebu ld | T L ne H&R | S las 100kV - L ne Rebu ld-W200029-P esentat on.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200031 | Mon oe 100kV - L ne Rebu ld | Capac ty & Custome Plan | Mon oe 100kV - L ne Rebu ld-W200031-Stage Gate Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | Mon oe 100kV - L ne Rebu ld-W200031-R skReg ste .pdf | Mon oe 100kV - L ne Rebu ld-W200031-PSR.pdf | Mon oe 100kV - L ne Rebu ld-W200031-Change Log.pdf | Mon oe 100kV - L ne Rebu ld-W200031-R sk Info med.xlsx |
| W200039 | Co onaca 100kV L ne - Add 2nd C cu t | Capac ty & Custome Plan | Co onaca 100kV L ne - Add 2nd C cu t-W200039-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200042 | Sev e 100kV - L ne Rebu ld | Capac ty & Custome Plan | Sev e 100kV - L ne Rebu ld-W200042-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200060 | Ma ble T e - Reley Upg ade | System Intell gence | Ma ble T e - Reley Upg ade-W200060-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200061 | Page and Gu lfo d 100kV - L ne Rebu ld | Capac ty & Custome Plan | Page and Gu lfo d 100kV - L ne Rebu ld-W200061_Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | Document not ava lable, st l n Development | Document not ava lable, st ll n Development | Document not ava lable, st l n Development | Document not ava lable, st ll n Development |
| W200090 | T ansm ss on L ne Fault Detect on - W200090 | System Intell gence | T ansm ss on L ne Fault Detect on - W200090-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200108 | T ansm ss on L ne Fault Detect on - W200108 | System Intell gence | T ansm ss on L ne Fault Detect on - W200108-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200109 | T ansm ss on L ne Fault Detect on - W200109 | System Intell gence | T ansm ss on L ne Fault Detect on - W200109-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200110 | T ansm ss on L ne Fault Detect on - W200110 | System Intell gence | T ansm ss on L ne Fault Detect on - W200110-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200126 | A len Steam Stat on - Relocate Sw tchya d & L ne | Substat on H&R | Allen Steam Stat on - Relocate Sw tchya d & L new-W200126-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | Allen Steam Stat on - Relocate Sw tchya d & L new-W200126-R sk Reg ste .pdf | Allen Steam Stat on - Relocate Sw tchya d & L new-W200126-PSR.xlsm | Document not p oduced | Allen Steam Stat on - Relocate Sw tchya d & L new-W200126-R skInfo med.pdf |
| W200128 | G eenwood Pack ng Del 1 - A B eak Sw tch Upg ade | Substat on H&R | G eenwood Pack ng Del 1 - A B eak Sw tch Upg ade-W200128-Cove sheet xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200131 | Lancaste Ma n - Replace TOIL B eake s | B eake s | Lancaste Ma n - Replace TOIL B eake s-W200131-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200143 | Gaffney T e - Replace TO L B eake s | B eake s | Gaffney T e - Replace TOIL B eake s - W200143-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200157 | fi dger ew Reta l - Replace DOIL B eake s | B eake s | fi dger ew Reta l - Replace DOIL B eake s-W200157-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200169 | Lee and F edmont 100kV - L ne Us ate fo Casac tv | Capac ty & Custome Plan | Lee and F edmont 100kV - L ne Us ate fo Casac tv-W200169-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | Lee and F edmont 100kV - L ne Us ate fo Casac tv-W200169-R sk Rea ste .pdf | Document not ava lable, st ll n Develoomnt | Document not ava lable, st l n Develoomnt | Document not ava lable, st ll n Develoomnt |
| W200177 | P ysm an Powe Cables - Replace T ansfo me | T ansfo me s | P ysm an Powe Cables - Replace T ansfo me - W200177-Cove sheet pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200182 | Esto-P cians T e 100kV - L ne Rebu ld | T L ne H&R | Esto-P cians T e 100kV - L ne Rebu ld-W200182-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200193 | E Ma ket St - Replace T ansfo me | T ansfo me s | E Ma ket St - Replace T ansfo me -W200193-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200197 | Campobello T e - L ne Insulato Upg ade | T L ne H&R | Campobe lo T e - L ne Insulato Upg ade-W200197-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200210 | P nk Ha ll - Replace T ansfo me | T ansfo me s | P nk Ha ll - Replace T ansfo me -W200210-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200212 | Hu cane C eek - Replace T ansfo me | T ansfo me s | Hu cane C eek - Replace T ansfo me -W200212-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200213 | Easley Ma n - Replace T ansfo me | T ansfo me s | Easley Ma n - Replace T ansfo me -W200213-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200215 | Ind anland Reta l Tap - L ne Rebu ld | Capac ty & Custome Plan | Ind anland Reta l Tap - L ne Rebu ld-W200215-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200221 | Cl nton T e - Replace T ansfo me | T ansfo me s | Cl nton T e - Replace T ansfo me -W200221-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200222 | Oelbu n - Reolace T ansfo me | T ansfo me s | Oelbu n - Reolace T ansfo me -W200222 Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200225 | T ed Pa k Reta l - Replace T ansfo me | T ansfo me s | T ed Pa k Reta l - Replace T ansfo me -W200225-Cove sheet xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200230 | Ac e ock T e - Replace T ansfo me | T ansfo me s | Ac e ock T e - Replace T ansfo me -W200230-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200233 | B dgewate Hyd o Plant - Replace T ansfo me | T ansfo me s | B dgewate Hyd o Plant - Replace T ansfo me -W200233-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200235 | Vandal e Reta l - Replace T ansfo me - W200235 | T ansfo me s | Vandal e Reta l - Replace T ansfo me -W200235-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200237 | Revnolds Tob - Reolace T ansfo me | T ansfo me s | Revnolds Tob - Reolace T ansfo me -W200237-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200239 | Tuxedo Reta l - Replace T ansfo me | T ansfo me s | Tuxedo Reta l - Replace T ansfo me -W200239-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200244 | Cel-R ve to Ind anland 44kV - New L ne | Capac ty & Custome Plan | Cel-R ve to Ind anland 44kV - New L ne_W200244-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200245 | P ngah T e - Bus Junct on B eake s | Capac ty & Custome Plan | P ngah T e - Bus Junct on B eake s-W200245-Cove sheet .pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200246 | Ch ne G ove Reta l - Replace T ansfo me | T ansfo me s | Document not p oduced | Document not p oduced | NA | NA | NA | NA |
| W200248 | El zabeth Ave Reta l - Replace T ansfo me | T ansfo me s | El zabeth Ave Reta l - Replace T ansfo me -W200248-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200249 | T plett Reta l - Replace T ansfo me | T ansfo me s | T plett Reta l - Replace T ansfo me -W200249-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200260 | McDowell T e - Replace T ansfo me | T ansfo me s | McDowell T e - Replace T ansfo me -W200260-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200261 | Rosman Sw tch ng Stat on - Replace T ansfo me | T ansfo me s | Rosman Sw tch ng Stat on - Replace T ansfo me -W200261 Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200265 | Newpo t T e - Rel eb l ty Upg ade | Capac ty & Custome Plan | Document not p oduced | Document not p oduced | NA | NA | NA | NA |
| W200285 | Tavlo sv lle T e - Reolace TOIL B eake s | B eake s | Tavlo sv lle T e - Reolace TOIL B eake s-W200285-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200295 | Rockfo d 44kV - L ne Rebu ld | T L ne H&R | Rockfo d 44kV - L ne Rebu ld-W200295-Cove sheet .pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200305 | McGu e Nuclea Stat on - Reley Upg ade | System Intell gence | McGu e Nuclea Stat on - Reley Upg ade-W200305-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200312 | Reedy R ve T e - Replace TOIL B eake s | B eake s | Reedy R ve T e - Replace TOIL B eake s-W200312-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200321 | Oconee Nuclea Stat on - Remote Ope ated Sw tches | System Intell gence | Oconee Nuclea Stat on - Remote Ope ated Sw tches-W200321-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200342 | Clemmons Reta l - Reolace DOIL B eake s | B eake s | Clemmons Reta l - Reolace DOIL B eake s-W200342-Cove sheet xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200344 | Oxfo d Road Reta l - Replace DOIL B eake s | B eake s | Oxfo d Road Reta l - Replace DOIL B eake s-W200344-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200379 | Oelbo o T e - Rel eb l ty Upg ade | Capac ty & Custome Plan | Oelbo o T e - Rel eb l ty Upg ade-W200379-Cove sheet xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200393 | Swepsonv lle T e - Replace TOIL B eake s | B eake s | Swepsonv lle T e - Replace TOIL B eake s-W200393-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200396 | Ene gy Un ted EMC Del ve y 32 - Replace TOIL B eake s | B eake s | Ene gy Un ted EMC Del ve y 32 - Replace TOIL B eake s-W200396-Cove sheet xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200399 | F nnacle T e - Reolace TOIL B eake s | B eake s | Document not p oduced | Document not p oduced | NA | NA | NA | NA |
| W200400 | Toast Reta l - Replace TOIL B eake s | B eake s | Toast Ret TO I B eake _W200400_Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200401 | Banne town T e - Replace TOIL B eake s | B eake s | Banne town T e - Replace TOIL B eake s-W200401-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200403 | L nden St eet Sw tch Stat on - Replace TOIL B eake s | B eake s | L nden St eet Sw tch Stat on - Replace TOIL B eake s-W200403-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | Document not ava lable, st l n Development | Document not ava lable, st ll n Development | Document not ava lable, st l n Development | Document not ava lable, st ll n Development |
| W200416 | Ioa d Reta l - Replace T ansfo me | T ansfo me s | Ioa d Reta l - Replace T ansfo me -W200416-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200504 | Lookout T e - Rel eb l ty Use ade | Substat on H&R | Lookout T e - Rel eb l ty Use ade-W200504-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200534 | E Du hem T e - Reley Upg ade | System Intell gence | E Du hem T e - Reley Upg ade-W200534-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200626 | T ansfo me Bush ng Replacement - W200626 | T ansfo me s | Document not p oduced | Document not p oduced | NA | NA | NA | NA |
| W200662 | Mob le T ansfo me Upg ade - W200662 | T ansfo me s | Mob le T ansfo me Upg ade - W200662-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200664 | Mob le T ansfo me Upg ade - W200664 | T ansfo me s | Mob le T ansfo me Upg ade - W200664-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200665 | Mob le T ansfo me Upg ade - W200665 | T ansfo me s | Mob le T ansfo me Upg ade - W200665-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200666 | Mob le T ansfo me Upg ade - W200666 | T ansfo me s | Mob le T ansfo me Upg ade - W200666-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200669 | Mob le T ansfo me Upg ade - W200669 | T ansfo me s | Mob le T ansfo me Upg ade - W200669-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200670 | Mob le T ansfo me Upg ade - W200670 | T ansfo me s | Mob le T ansfo me Upg ade - W200670-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200671 | Mob le T ansfo me Upg ade - W200671 | T ansfo me s | Mob le T ansfo me Upg ade - W200671-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200672 | Mob le T ansfo me Use ade - W200672 | T ansfo me s | Mob le T ansfo me Use ade - W200672-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200674 | Mob le T ansfo me Upg ade - W200674 | T ansfo me s | Mob le T ansfo me Upg ade - W200674-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W200675 | Mob le T ansfo me Upg ade - W200675 | T ansfo me s | Mob le T ansfo me Upg ade - W200675-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W210027 | G eat Fa ls Sw tch ng Stat on - Replace TOIL B eake s | B eake s | G eat Falls Sw tch ng Stat on - Replace TOIL B eake s-W210027-Cove sheet.pdf | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W210058 | N G eenv le T e - Cond t on Based Mon to ng | System Intell gence | N G eenv le T e - CBM-W210058-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W210059 | Ande son T e - Cond t on Based Mon to ng | System Intell gence | Ande son T e - CBM-W210059-Cove sheet xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W210061 | H cko ty T e - Cond t on Based Mon to ng | System Intell gence | H cko ty T e - CBM-W210061-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W210063 | Peach Va ley T e - Cond t on Based Mon to ng | System Intell gence | Peach Valley T e - CBM-W210063-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W210065 | W neoff T e - Cond t on Based Mon to ng | System Intell gence | W neoff T e - CBM-W210065-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W210066 | Starney T e - Cond t on Based Mon to ng | System Intell gence | Starney T e - CBM-W210066-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W210067 | Tuckaseee T e - Cond t on Based Mon to ne | System Intell gence | Tuckaseee T e - CBM-W210067 Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W210068 | Eno T e - Cond t on Based Mon to ng | System Intell gence | Eno T e - CBM-W210068-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W210069 | Bush R ve T e - Cond t on Based Mon to ng | System Intell gence | Bush R ve T e - CBM-W210069-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W210070 | Mo n ng Ste T e - Cond t on Based Mon to ng | System Intell gence | Mo n ng Ste T e - CBM-W210070-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W210071 | Oelbo o T e - Cond t on Based Mon to ng | System Intell gence | Oelbo o T e - CBM-W210071-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W210072 | M tchell R ve T e - Cond t on Based Mon to ne | System Intell gence | M tchell R ve T e - CBM-W210072-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W210073 | M le H l T e - Cond t on Based Mon to ng | System Intell gence | M le H l T e - CBM-W210073-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W210074 | Ma shal Steam Stat on - Cond t on Based Mon to ng | System Intell gence | Ma shall Steam Stat on - CBM-W210074-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W210075 | Shelby T e - Cond t on Based Mon to ng | System Intell gence | Shelby T e - CBM-W210075-Cove sheet xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W210076 | Buck T e - Cond t on Based Mon to ng | System Intell gence | Buck T e - CBM-W210076-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W210077 | A len Steam Plant Substat on - Cond t on Based Mon to ne | System Intell gence | Allen Steam Plant Substat on - CBM-W210077-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W210078 | P ngah T e - Cond t on Based Mon to ng | System Intell gence | P ngah T e - CBM-W210078-Cove sheet xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |
| W210079 | Ru al Hall T e - Cond t on Based Mon to ng | System Intell gence | Ru al Hall T e - CBM-W210079-Cove sheet xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | NA | NA | NA | NA |

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|---|---|---|---|---|---|---|---|---|
| W210080 | E Du ham T e - Cond t on Based Mon to ng | System Intell gence | E Du ham T e - CBM-W210080-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W210122 | McAdenv lle Junct on Substat on - Cond t on Based Mon to ng | System Intell gence | McAdenv lle Junct on Substat on - CBM-W210122-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W210189 | Ma etta L ne - Remote Ope ated Sw tch | System Intell gence | Ma etta L ne - Remote Ope ated Sw tch-W210189-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W210193 | B oyh l Fu n tu e - C cu t Sw tche Upg ade | Substat on H&R | B oyh l Fu n tu e -C cu t-W210193-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W210200 | W x F t at on Co p D xon - Batte y Bank Replacement | System Intell gence | W xF lt at onCo pD xon-Batte yBankRplc-W210200-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W210205 | Kobew eland Coppe - Batte y Bank Replacement | System Intell gence | Kobew eland Coppe - Batte y Bank Replacement-W210205-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W210206 | T mken Co Spec alty - Batte y Bank Replacement | System Intell gence | T mken Co Spec alty - Batte y Bank Replacement-W210206-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W210275 | Un on Del ve y 16 Stat on - B eake Stat on | Capac ty & Custome Plan | Un on Del ve y 16 Stat on - B eake Stat on-W210275-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W210293 | RRB Beve age Ope at ons - New Custome Substat on | Capac ty & Custome Plan | RRB Beve age Ope at ons - NewCustome Sub-W210293-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W210349 | Pe fo mance F be s Tap - Batte y Bank Replacement | System Intell gence | Pe fo mance F be s Tap - Batte yBankRplc-W210349-Cove sheet xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W210356 | Toyota Batte y Manufactu ng - New Custome Substat on | Capac ty & Custome Plan | Toyota Batte y Manufactu ng - NewCustome Substat on-W210356-Cove sheet.xlsx | DEC-NC_T ansm ss on P ojects_Schedule.xlsx | Toyota Batte y Manufactu ng - New Custome Substat on-W210356 R sk Reg ste .xlsx | Toyota Batte y Manufactu ng - New Custome Substat on-W210356-PSR.xlsm | Toyota Batte y Manufactu ng - New Custome Substat on-W210356-Change Log.xlsm | Toyota Battery Manufacturing -W210356-Risk Informed.xlsx |
| W210363 | McGu e Nuclea Stat on 230kV SR - Gang Sw tch Replacement | Substat on H&R | McGu e Nuclea Stat on 230kV SR - Gang Sw tch Rplc-W210363-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W210365 | McGu e Nuclea Stat on 525kV 59Y - Gang Sw tch Replacement | Substat on H&R | McGu e Nuclea Stat on 525kV 59Y - Gang Sw tch Rplc-W210365-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W210367 | McGu e Nuclea Stat on 525kV 59R - Gang Sw tch Replacement | Substat on H&R | McGu e Nuclea Stat on 525kV 59R - Gang Sw tch Rplc-W210367-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W210369 | McGu e Nuclea Stat on 525kV 51R - Gang Sw tch Replacement | Substat on H&R | McGu e Nuclea Stat on 525kV 51R - Gang Sw tch Rplc-W210369-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W210371 | McGu e Nuclea Stat on 525kV 56R - Gang Sw tch Replacement | Substat on H&R | McGu e Nuclea Stat on 525kV 56R - Gang Sw tch Rplc-W210371-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W210373 | McGu e Nuclea Stat on 525kV 56Y - Gang Sw tch Replacement | Substat on H&R | McGu e Nuclea Stat on 525kV 56Y - Gang Sw tch Rplc-W210373-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W210374 | Cha lotte Wate Stowe WWTF - New Custome Substat on | Capac ty & Custome Plan | Cha lotte Wate Stowe WWTF - New Custome Substat on-W210374-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W210382 | Kennedy L nes - Remed al Act on Scheme (RAS) | Capac ty & Custome Plan | Kennedy L nes - Remed al Act on Scheme (RAS)-W210382-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W210428 | Walmsa t Cold Sto age - New Custome Substat on | Capac ty & Custome Plan | Walmsa t Cold Sto age - New Custome Substat on-W210428-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W210463 | Duke Unv Stat on 1 - Replace TOIL B eake s | B eake s | Duke Unv Stat on 1 - Replace TOIL B eake s-W210463-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W210464 | Duke Unv Stat on 5 - Replace TOIL B eake s | B eake s | Duke Unv Stat on 5 - Replace TOIL B eake s-W210464-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W210465 | Duke Unv Stat on 2 - Replace TOIL B eake s | B eake s | Duke Unv Stat on 2 - Replace TOIL B eake s-W210465-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220036 | Pa kwood T e - Replace T ansfo me s | T ansfo me s | Pa kwood T e - Replace T ansfo me -W220036-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220053 | Bethan a L nes - Remed al Act on Scheme (RAS) | Capac ty & Custome Plan | Bethan a L nes - Remed al Act on Scheme (RAS)-W220053-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220082 | Oconee Nuclea Stat on 525kV SBR - Gang Sw tch Replacement | Substat on H&R | Oconee Nuclea Stat on 525kV SBR - Gang Sw tch Rplc-W220082-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220122 | Cl nton 100kV - L ne Up ate fo Capac ty | Capac ty & Custome Plan | Cl nton 100kV - L ne Up ate fo Capac ty-W220122-Cove sheet xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | Cl nton 100kV - L ne Up ate fo Capac ty-W220122-R sk Reg ste .pdf | Document not ava lable, st ll n Development | Document not ava lable, st l n Development | Document not ava lable, st ll n Development |
| W220124 | Newbe y 115kV - L ne Up ate fo Capac ty | Capac ty & Custome Plan | Newbe y 115kV - L ne Up ate fo Capac ty-W220124-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220125 | Enb dge - New Custome Substat on | Capac ty & Custome Plan | Enb dge - New Custome Substat on-W220125-Cove sheet xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220176 | Che yv lle T e - Annuc ato | System Intell gence | Che yv lle T e - Annuc ato -W220176-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220192 | Becke d te T e - Annunc ato | System Intell gence | Becke d te T e - Annunc ato -W220192-Cove sheet xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220207 | Catawba Nuclea Stat on Roddey Black - Gang Sw tch Replacement | Substat on H&R | Catawba Nuclea Stat on Roddey Black - Gang Sw tch Replacement-W220207-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220213 | Cathod c P otect on - W220213 | T L ne H&R | Cathod c P otect on-W220213-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220220 | Oconee Nuclea Stat on PCB 54Y - Gang Sw tch Replacement | Substat on H&R | Oconee Nuclea Stat on PCB 54Y - Gang Sw tch Rplc-W220220-Cove sheet xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220224 | Buckho n 44kV P edmont EMC Tab L ne - L ne Rebu ld | Capac ty & Custome Plan | Buckho n 44kV P edmont EMC Tab L ne-L neRebu ld-W220224-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220228 | Oconee Nuclea Stat on PCB 57Y - Gang Sw tch Replacement | Substat on H&R | Oconee Nuclea Stat on PCB 57Y - Gang Sw tch Rplc-W220228-Cove sheet xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220232 | Oconee Nuclea Stat on PCB 55Y - Gang Sw tch Replacement | Substat on H&R | Oconee Nuclea Stat on PCB 55Y - Gang Sw tch Rplc-W220232-Cove sheet xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220253 | Mon oe Ma n - Commun cat ons Upg ade | System Intell gence | Mon oe Ma n - Commun cat ons Upg ade-W220253-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220255 | Newpo t T e - Replace T ansm ss on B eake s | B eake s | Newpo t T e - Replace T ansm ss on B eake s-W220255-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220257 | H cko y T e - Commun cat ons Upg ade | System Intell gence | H cko y T e - Commun cat ons Upg ade-W220257-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220259 | Peacock T e - Replace T ansm ss on B eake s | B eake s | Peacock T e - Replace T ansm ss on B eake s-W220259-Cove sheet xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220260 | Duke Un ve s ty Ma n - Annunc ato Upg ade | System Intell gence | Duke Un ve s ty Ma n - Annunc ato Upg ade-W220260-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220262 | E nest Sw tch ng Stat on - Annunc ato Upg ade | System Intell gence | E nest Sw tch ng Stat on - Annunc ato Upg ade-W220262-Cove sheet xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220263 | Ma sha l Steam - Replace T ansm ss on B eake s | B eake s | Ma shall Steam - Replace T ansm ss on B eake s-W220263-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220265 | Wadswo th Reta l - Annunc ato Upg ade | System Intell gence | Wadswo th Reta l - Annunc ato Upg ade-W220265-Cove sheet xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220266 | Woodlawn T e - Annunc ato Upg ade | System Intell gence | Woodlawn T e - Annunc ato Upg ade-W220266-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220273 | G eenv lle Ma n - Commun cat on Upg ade | System Intell gence | G eenv lle Ma n - Commun cat on Upg ade-W220273-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220274 | Lake Emo y T e - Commun cat on Upg ade | System Intell gence | Lake Emo y T e - Commun cat on Upg ade-W220274-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220275 | Lau ens E C Del ve y 25 Mauld n - Commun cat on Upg ade | System Intell gence | Lau ens E C Del ve y 25 Mauld n-CommUpg ade-W220275-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220277 | Resolute FP US Inc - Commun cat on Upg ade | System Intell gence | Resolute FP US Inc- Commun cat on Upg ade-W220277-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220278 | Woodlawn T e - Commun cat on Upg ade | System Intell gence | Woodlawn T e - Commun cat on Upg ade-W220278-Cove sheet xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220282 | Ac e ock T e - Capac to Replacement - W220282 | Substat on H&R | Ac e ock T e - Capac to Replacement-W220282-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220285 | Ac e ock T e - Capac to Replacement - W220285 | Substat on H&R | Ac e ock T e - Capac to Replacement-W220285-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220286 | H ltop T e - Capac to Replacement | Substat on H&R | H l top T e - Capac to Replacement-W220286-Cove sheet xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220288 | Albema le Sw tch ng Stat on - Commun cat on Upg ade | System Intell gence | Albema le Sw tch ng Stat on-CommUpg ade-W220288 Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220290 | FMC Co p L th um - A B eak Sw tch Upg ade | Substat on H&R | FMC Co p L th um - A B eak Sw tch Upg ade-W220290-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220291 | Cap tal Funds Inc - A B eak Sw tch Upg ade | Substat on H&R | Cap tal Funds Inc - A B eak Sw tch Upg ade-W220291-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220292 | Ilpea Inc - A B eak Sw tch Upg ade | Substat on H&R | Ilpea Inc - A B eak Sw tch Upg ade-W220292 Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220294 | G E Co Flat Rock - A B eak Sw tch Upg ade - W220294 | Substat on H&R | G E Co Flat Rock -ABSUpg ade-W220294-Cove sheet xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220295 | G E Co Flat Rock - A B eak Sw tch Upg ade - W220295 | Substat on H&R | G E Co Flat Rock - ABSUpg ade-W220295-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220296 | NC State Dept of Co ect on - A B eak Sw tch Upg ade | Substat on H&R | NC State Dept of Co ect on-ABSUpg ade-W220296-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220297 | Ame &EF d Gaston a Place - A B eak Sw tch Upg ade - W220297 | Substat on H&R | Ame &EF d Gaston a Place - A B eak Sw tch Upg ade - W220297-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220298 | B ad ngton-Young Inc - A B eak Sw tch Upg ade | Substat on H&R | B ad ngton-YoungInc-ABSUpg ade-W220298-Cove sheet xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220299 | Ame &EF d Gaston a Place - A B eak Sw tch Upg ade - W220299 | Substat on H&R | Ame &EF dGaston aPl-ABSUpg ade-W220299-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220300 | One Wo ld Tech Ande son - A B eak Sw tch Upg ade | Substat on H&R | OneWo ldTechAnde son-ABSUpg ade-W220300-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220301 | Toxaway T e - A B eak Sw tch Upg ade | Substat on H&R | Toxaway T e - A B eak Sw tch Upg ade-W220301-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220302 | Jantzen Inc Seneca Place - A B eak Sw tch Upg ade | Substat on H&R | JantzenIncSenecaPlace-ABSUpg ade-W220302-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220303 | Eaton Ae oqu p Fo est C ty - A B eak Sw tch Upg ade | Substat on H&R | EatonAe oqu pFo estC ty-ABSUpg ade-W220303-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220304 | Fo est Dale Sw tch ng Stat on - A B eak Sw tch Upg ade | Substat on H&R | Fo est Dale Sw tch ng Stat on - ABS Upg ade-W220304 Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220305 | G an te Falls C ty Del 2 - A B eak Sw tch Upg ade | Substat on H&R | G an te Fa ls C ty Del 2 - A B eak Sw tch Upg ade-W220305-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220306 | Ma den C ty Del 2 - A B eak Sw tch Upg ade | Substat on H&R | Ma denC tyDe 2-ABSUpg ade-W220306-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220307 | Longv ew T e - A B eak Sw tch Upg ade | Substat on H&R | Longv ew T e - A B eak Sw tch Upg ade-W220307-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220319 | Bush R ve T e - C cu t Sw tche Upg ade | Substat on H&R | Bush R ve T e - C cu t Sw tche Upg ade-W220319-Cove sheet xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220320 | Gaston a - C cu t Sw tche Upg ade | Substat on H&R | Gaston a - C cu t Sw tche Upg ade-W220320-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220324 | Cathod c P otect on - W220324 | T L ne H&R | Cathod c P otect on - W220324-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220325 | Cathod c P otect on - W220325 | T L ne H&R | Cathod c P otect on - W220325-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220327 | Cathod c P otect on - W220327 | T L ne H&R | Cathod c P otect on - W220327-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220328 | Cathod c P otect on - W220328 | T L ne H&R | Cathod c P otect on - W220328-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220329 | Cathod c P otect on - W220329 | T L ne H&R | Cathod c P otect on - W220329-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220332 | Cathod c P otect on - W220332 | T L ne H&R | Cathod c P otect on - W220332-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220333 | Hogback - Towe Replacement | T L ne H&R | Hogback - Towe Replacement-W220333-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220334 | Waco - Remote Ope ated Sw tch | System Intell gence | Waco - Remote Ope ated Sw tch-W220334-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220335 | Ruff n - Remote Ope ated Sw tch | System Intell gence | Ruff n - Remote Ope ated Sw tch-W220335-Cove sheet xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220336 | K ngs Mounta n - Remote Ope ated Sw tch | System Intell gence | K ngs Mounta n - Remote Ope ated Sw tch-W220336-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220337 | Shule - Insulato Replacement | T L ne H&R | Shule - Insulato Replacement-W220337-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220338 | Ba nb dge - Insulato Replacement | T L ne H&R | Ba nb dge - Insulato Replacement-W220338-Cove sheet.xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220339 | R pp - Insulato Replacement | T L ne H&R | R pp - Insulato Replacement-W220339-Cove sheet xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220340 | M tchel R ve - Insulato Replacement | T L ne H&R | M tchel R ve - Insulato Replacement Cove sheet xlsx | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |
| W220341 | O ange L ne - OHGW Replacement | T L ne H&R | O ange L ne - OHGW Replacement-W220341-Cove sheet.pdf | DEC-NC T ansm ss on P ojects Schedule.xlsx | NA | NA | NA | NA |

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| DEC MYRP Projects and Required Documentation | | | | | WHITE | | | | | GREEN or greater | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Plant/Unit** | **Funding#** | **Project#** | **Risk Rank** | **Project Desc** | Proj Auth Forms | Charter / Scope | Schedule | Estimate | Comm Docs if applicable (attached) | Alt Analysis/Bus Case | Risk Register | WBS | Proj Reports | Formal Change Cntrl | Ris-informed info | **Comments** |
| CN01 | 20048 CN004GJ | **CN004GJ** | Green | CNS Replace Unit 1 Zone A and B Protective Relays | Attached | Attached | Attached | Attached | # 03071719 03062161 03103278 | | Attached | Attached | Attached | Attached | | Most recent Project Monthly Report Attched |
| CN02 | 20048 CN004GK | **CN004GK** | Green | CNS Replace Unit 2 Zone A and B Protective Relays | Attached | Attached | Attached | Attached | 03119006 198120 178447 | | Attached | Attached | Attached | Attached | Attached | Most recent Project Monthly Report Attched |
| CN02 | 20048 CN004GK | **CN004GK** | Green | CNS Replace Unit 2 Zone A and B Protective Relays | Same project as above, but with 2 projected in-service dates based on Zones | | | | | | Attached | Attached | Attached | Attached | Attached | Most recent Project Monthly Report Attched |
| CN01 | 20048 CN006PZN | **CN006PZ** | White | CNS 1A Main Step-Up (MSU) Transformer Replacement | Attached | Attached | Attached | Attached | | | | | | | | Estimate, scope, and risk register is included in funding package |
| CN02 | 20048 CN00751 | **CN00751** | Green | CNS Unit 2 - Purchase and Install New High Pressure (HP) Turbine Diaphragm | Phase 1 Funding Attached | Attached | Attached | Attached | 03149759 3152719 | Attached | Attached | Attached | Attached | Not yet created | Attached | This project has not yet routed for final funding approval. |
| CN01 | 20048 CTURDIA1N | **CN00D0Z** | Green | CNS Unit 1 - Purchase and Install New High Pressure (HP) Turbine Diaphragm | Not final | Attached | Attached | Attached | 03149759 | Attached | Attached | Attached | Attached | Not yet created | Attached | This project has not yet routed for final funding approval. |
| CN01 | 20048 CN007LNBN | **CN007LN** | Green | CNS Reactor Coolant Pump (NCP) Motor 1B and 1C Replacement/Refurbishment | Attached | Attached | Attached | Attached | See proj CN007Z5 for applicable | Attached | Attached | Attached | Attached | Attached | Attached | |
| CN02 | 20048 CN007Z5CN | **CN007Z5** | Green | CNS Reactor Coolant Pump (NCP) Motor 2A and 2C Replacement/Refurbishment | 2A Attached | Attached | Attached | Attached | 03090950 03050091 | Attached | Attached | Attached | Attached | Not yet created | Attached | No PCR change log 2A funding Complete, 2C funding has not been routed |
| CN01 | 20048 CN0016924 | **CN00169** | Routine Work | CNS Unit 1 - Replace Reactor Coolant Pump (NCP) Seals | | | | | | | | | | | | Not yet started |
| CN01 | 20048 CN0016926 | **CN00169** | Routine Work | CNS Unit 1 - Replace Reactor Coolant Pump (NCP) Seals | | | | | | | | | | | | Not yet started |
| CN02 | 20048 CN0016D25 | **CN0016D** | Routine Work | CNS Unit 2 - Replace Reactor Coolant Pump (NCP) Seals | | | | | | | | | | | | Not yet started |
| CN02 | 20048 CNE126725 | **CNE1267** | Routine Work | CNS Unit 2 - Remove and Replace Nuclear Service Water (RN) Pumps | | | | | | | | | | | | Not yet started |
| MN01 | 20048 MC000V6N | **MC000V6** | White | MNS Unit 1 Polar Crane Motor and Controls Upgrade | Attached | Attached | Attached | TPC Attached | Contract 03132348 | | | | | | | |
| MN02 | 20048 MC00C7MN | **MC00C7M** | Green | MNS Unit 2 Moisture Separator Reheaters (MSRs) Replacement | Not yet created | Attached | Attached | TPC Attached | Not yet created | Attached | Attached | Attached | Not yet created | Not yet created | Attached | This project has not yet routed for funding approval. |
| MN01 | 20048 MC00C7NN | **MC00C7N** | Green | MNS Unit 1 Moisture Separator Reheaters (MSRs) Replacement | Not yet created | Attached | Attached | TPC Attached | Not yet created | Attached | Attached | Attached | Not yet created | Not yet created | Attached | This project has not yet routed for funding approval. |
| MN00 | 20048 MC00CWCN | **MC00CWC** | White | MNS Ice Condenser Refrigeration (NF) Chiller Replacements | Not yet created | Attached | Attached | Not yet created | Not yet created | | | | | | | This project has not yet routed for funding approval. |
| MN01 | 20048 M1ITEUPGC | **MC00C8M** | Green | MNS Unit 1 Turbine Controls Upgrade | Attached | Attached | Attached | TPC Attached | Not yet created | Attached | Attached | TPC Attached (See estimate) | Attached | Not yet created | Attached | |
| MN02 | 20048 MC00BWXN | **MC00BWX** | White | MNS Unit 2 Replace Lower Containment (VL) 2B and 2C Air Handling Unit (AHU) Coils | Not yet created | Not yet created | Not yet created | Not yet created | Not yet created | | | | | | | This project has not yet routed for funding approval. Anticipate to begin project in 2023. |
| MN02 | 20048 MC00BS8N | **MC00CXM** | White | MNS Unit 2 Replace Lower Containment (VL) 2D Air Handling Unit (AHU) Coils | Attached | Charter Only Attached | Attached | Advance and TPC Range Attached | Not yet created | | | | | | | |
| MN00 | 20048 MC008ZXN | **MC008ZX** | Routine Work | MNS Replace 2C Reactor Coolant Pump (RCP) Seal | | | | | | | | | | | | Not yet started |
| MN00 | 20048 MC00B6JN | **MC00B6J** | Routine Work | MNS Replace 1C Reactor Coolant Pump (RCP) Seal | | | | | | | | | | | | Not yet started |
| MN00 | 20048 MC00B6LN | **MC00B6L** | Routine Work | MNS Replace 1A Reactor Coolant Pump (RCP) Seal | | | | | | | | | | | | Not yet started |
| MN00 | 20048 MC00B6MN | **MC00B6M** | Routine Work | MNS Replace 2D Reactor Coolant Pump (RCP) Seal | | | | | | | | | | | | Not yet started |

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| DEC MYRP Projects and Required Documentation | | | | | WHITE | | | | | GREEN or greater | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Plant/Unit** | **Funding#** | **Project#** | **Risk Rank** | **Project Desc** | Proj Auth Forms | Charter / Scope | Schedule | Estimate | Comm Docs if applicable (attached) | Alt Analysis/Bus Case | Risk Register | WBS | Proj Reports | Formal Change Cntrl | Ris-informed info | **Comments** |
| MN02 | 20048 M2KC2B1N | **MCE1203** | White | MNS Unit 2 Component Cooling (KC) Motor Inspections and Replacement | Attached | Attached | Attached | TPC Attached | Not yet created | | | | | | | Original Advance created in 2020 with planned implementation in Spring 2023. Project implementation has been moved to Fall 2024. Revised funding planned for approval in early 2023. |
| MN01 | 20048 M1RN1BN | **MCE1206** | White | MNS Unit 1 Nuclear Service Water (RN) Motor Inspections and Replacement | Not yet created | Not yet created | Not yet created | Not yet created | Not yet created | | | | | | | This project has not yet routed for funding approval. Anticipate to begin project in 2023. |
| | 20048 NG00C6HN | **NG00C6H** | White | NGO Fleet Firewall ASA-5555x Replacement | | | | | | | | | | | | |
| | 20048 NG00C6JN | **NG00C6J** | White | NGO OSI PI Process Book Replacement | | | | | | | | | | | | |
| ON03 | 20048 OFWH3A1N | **ON0070L** | Green | ONS 3A1 and 3B2 Feedwater Heater Replacement | Attached | Attached | Attached | TPC Attached | | Attached | Attached | Part of schedule | Attached | N/A | Attached | |
| ON03 | 20048 O600RTE3N | **ON008P7** | White | ONS Unit 3 Alloy 600 Nozzles | | | | | | | | | | | | The project funding and associated documents have not been developed for this project. Expected Start Date is May 2023. |
| ON01 | 20048 OSAFEFM1N | **ON008P8** | White | ONS Unit 1 Alloy 600 Nozzles | | | | | | | | | | | | The project funding and associated documents have not been developed for this project. The expected start date is November 2023. |
| ON03 | 20048 ON00C4FN | **ON00C4F** | Routine Work | ONS Replace Unit 3 Reactor Coolant Pump (RCP) Motor | | | | | | | | | | | | Not yet started |
| ON01 | 20048 ON00C4GN | **ON00C4G** | Routine Work | ONS Replace Unit 1 Reactor Coolant Pump (RCP) Motor | | | | | | | | | | | | Not yet started |
| ON | 20048 ONSSLRN | **ONSSLRN** | Green | ONS Subsequent License Renewal | Attached | Attached | Attached | Attached | Attached | Attached | Attached | Attached | Attached | | Attached | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 | Bad Creek U1 Replace Control System | BA010091 | | x | | | | | | | | | | CBA/Evaluator |
| 1 | 2 | Bad Creek U2 Replace Control System | BA020027 | | x | | | | | | | | | | CBA/Evaluator |
| 1 | 3 | Bad Creek U3 Replace Control System | BA030016 | | x | | | | | | | | | | CBA/Evaluator |
| 3 | 4 | Bad Creek U4 MW Uprate | BA040005 | x | x | | | | | X | | | | | Funding Approval CBA/Evaluator Whitepaper |
| 1 | 5 | Bad Creek U4 Replace Control System | BA040009 | | x | | | | | | | | | | CBA/Evaluator |
| 1 | 6 | Bad Creek Unit Transformers Loadcenters | BA002992 | | x | | | | | | | | | | CBA/Evaluator |
| 1 | 7 | Belews Creek BC FGD Lighting Replacement | BC000951 | x | | | | | | | | | | | Funding Approval |
| 0 | 8 | Belews Creek BC01 SCR Catalyst Replacement | BC010717 | | | | | | | | | | | | No Data |
| 0 | 9 | Belews Creek Boiler Outage - Coal (2025) | BC00xxxx | | | | | | | | | | | | No Data |
| 0 | 10 | Belews Creek Boiler Outage - Coal (2024) | BC00xxxx | | | | | | | | | | | | No Data |
| 0 | 11 | Belews Creek Boiler Outage - Coal (2023) | BC00xxxx | | | | | | | | | | | | No Data |
| 1 | 12 | Bridgewater Replace 9070 to 3i Controls | BW000025 | | x | | | | | | | | | | CBA/Evaluator |
| 0 | 13 | Buck BK11 OpFlex Fast Start | BK1100XX | | | | | | | | | | | | No Data |
| 0 | 14 | Buck BK12 OpFlex Fast Start | BK1200XX | | | | | | | | | | | | No Data |
| 0 | 15 | Buck CC Oily Water Separator (OWS) Replacement | BKCC0186 | | | | | | | | | | | | No Data |
| 0 | 16 | BUCK CC Unit Flex Enhancement Prjts | BKCC0134 | | | | | | | | | | | | No Data |
| 0 | 17 | CC Cycling Project GMA | FHGC0086 | | | | | | | | | | | | No Data |
| 0 | 18 | CC Cycling Project GMA | FHGC0087 | | | | | | | | | | | | No Data |
| 1 | 19 | Cedar Cliff Civil Life Ext HeadTailra Gates | CE000023 | x | | | | | | | | | | | Funding Approval |
| 2 | 20 | Cedar Cliff Electrical Life Extension | CE000021 | x | x | | | | | | | | | | Funding Approval CBA/Evaluator |
| 0 | 21 | Cedar Cliff Generator Stator Rewind | CE000052 | | | | | | | | | | | | No Data |
| 1 | 22 | Cedar Cliff Install Turbine Inlet Valve | CE000043 | x | | | | | | | | | | | Funding Approval |
| 2 | 23 | Cedar Cliff Mechanical Life Extension | CE000048 | x | x | | | | | | | | | | Funding Approval CBA/Evaluator |
| 1 | 24 | Cedar Creek Replace 9070 to 3i Controls | CC001222 | | x | | | | | | | | | | CBA/Evaluator |
| 0 | 25 | Clemson Hydrogen Project (CHP) H2 Project | CUCH0083 | | | | | | | | | | | | No Data |
| 0 | 26 | Cliffside Boiler Outage - Coal (2024) | CS00xxxx | | | | | | | | | | | | No Data |
| 0 | 27 | Cliffside Boiler Outage - Coal (2025) | CS00xxxx | | | | | | | | | | | | No Data |
| 0 | 28 | Cliffside Boiler Outage - Coal (2023) | CS00xxxx | | | | | | | | | | | | No Data |
| 0 | 29 | Cliffside CS06 Template Turbine MajorValve | CS060059 | | | | | | | | | | | | No Data |
| 0 | 30 | Compressor Blade Replacement | MK050001 | | | | | | | | | | | | No Data |
| 2 | 31 | Cowans Ford Bank 2 GSU Replacement | CF000134 | x | x | | | | | | | | | | Funding Approval CBA/Evaluator |
| 1 | 32 | Dan River DR08 OpFlex Fast Start | DR080036 | | x | | | | | | | | | | CBA/Evaluator |
| 1 | 33 | Dan River DR09 OpFlex Fast Start | DR090041 | | x | | | | | | | | | | CBA/Evaluator |
| 0 | 34 | DRCC Unit Flex Enhancement Projects | DRCC0155 | | | | | | | | | | | | No Data |
| 0 | 35 | FERC Bridgewater Fonta Flora Access Area | BW001210 | | | | | | | | | | | | No Data |
| 0 | 36 | FERC Bridgewater Pocket Park At Dam LJ Loop | BW001211 | | | | | | | | | | | | No Data |
| 1 | 37 | FERC Cedar Cliff Dam IDF Spillway&Gate House | CE000012 | | | | | | | x | | | | | Whitepaper |
| 0 | 38 | FERC Cowans Ford Stumpy Creek Access Area | CF001208 | | | | | | | | | | | | No Data |
| 1 | 39 | FERC Fishing Creek Floodgate Life Exten Ph II | FC003677 | x | | | | | | | | | | | Funding Approval |
| 0 | 40 | FERC Great Falls Pedestrian Bridge | GF000058 | | | | | | | | | | | | No Data |
| 0 | 41 | FERC Linville Canoe Kayak Access Area | BW001212 | | | | | | | | | | | | No Data |
| 0 | 42 | FERC Lookout Shoals Upper Access Area | LK001205 | | | | | | | | | | | | No Data |
| 2 | 43 | FERC Mountain Island Dam Seismic | MI000028 | | | | | | | | x | x | | | Charter Funding Memo |
| 0 | 44 | FERC Moutain Island Riverbend Access Area | MI001205 | | | | | | | | | | | | No Data |
| 1 | 45 | FERC Oxford Gate Guides for Floodgates | OX000050 | x | | | | | | | | | | | Funding Approval |
| 1 | 46 | FERC Oxford Spillway Piers Bulkhead | OX000006 | x | | | | | | | | | | | Funding Approval |

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| 0 | 47 | FERC Thorpe Hydro Trout Crk Pipeline Coatings | TH000011 | | | | | | | | | | | | No Data |
| 1 | 48 | FERC WA Flood Management | WA001213 | x | | | | | | | | | | | Funding Approval |
| 0 | 49 | FERC Wateree Taylor Creek Bank Fishing | WA001206 | | | | | | | | | | | | No Data |
| 1 | 50 | Fishing Creek Replace 9070 to 3i Controls | FC001225 | | x | | | | | | | | | | CBA/Evaluator |
| 0 | 51 | Fishing Creek U2 Replace Turbine Gate Casing | FC020024 | | | | | | | | | | | | No Data |
| 0 | 52 | Fishing Creek U3 Headgate Replacement | FC030009 | | | | | | | | | | | | No Data |
| 0 | 53 | Fishing Creek U3 Replace Wear Rings | FC031204 | | | | | | | | | | | | No Data |
| 0 | 54 | Fishing Creek U4 Headgate Replacement | FC040010 | | | | | | | | | | | | No Data |
| 0 | 55 | Fishing Creek U5 Headgate Replacement | FC050008 | | | | | | | | | | | | No Data |
| 0 | 56 | Great Falls Replace Headworks Rake and Racks | GF000039 | | | | | | | | | | | | No Data |
| 0 | 57 | HCA Dust BC 6C7C6D7D Transfer | BC020315 | | | | | | | | | | | | No Data |
| 0 | 58 | HCA Dust BC23 Conv Trans Repl | BC001465 | | | | | | | | | | | | No Data |
| 0 | 59 | HCA DustBC 1 Head Chute Repl | BC000199 | | | | | | | | | | | | No Data |
| 0 | 60 | HCA DustBC 6A6D Vibratory Fdrs | BCCM0023 | | | | | | | | | | | | No Data |
| 1 | 61 | HCA Transfer House Wash Down | MS000747 | x | | | | | | | | | | | Funding Approval |
| 0 | 62 | Jocassee Replace 9070 Controls | JO001239 | | | | | | | | | | | | No Data |
| 0 | 63 | Jocassee DFSP Ramp Replacement | JO000204 | | | | | | | | | | | | No Data |
| 1 | 64 | Jocassee Exterior Life Extension | JO001249 | x | | | | | | | | | | | Funding Approval |
| 2 | 65 | Jocassee Station Motor Control Center | JO000095 | x | x | | | | | | | | | | Funding Approval CBA/Evaluator |
| 1 | 66 | Jocassee U1 U2 Motor Control Center | JO010055 | x | | | | | | | | | | | Funding Approval |
| 2 | 67 | Jocassee U3 U4 Motor Control Center | JO030016 | x | x | | | | | | | | | | Funding Approval CBA/Evaluator |
| 0 | 68 | Jocassee Warehouse Replace Siding Roof | JO000151 | | | | | | | | | | | | No Data |
| 1 | 69 | Lincoln CT 17 | LC170001 | | | | | | | x | | | | | Whitepaper |
| 1 | 70 | Lookout Shoals Repl Jr Generator Penstock Liner | LK001228 | | x | | | | | | | | | | CBA/Evaluator |
| 0 | 71 | Lookout Shoals Replace Jr Generator Headgate | LK000029 | | | | | | | | | | | | No Data |
| 0 | 72 | Marshall - Replace Fuel Handling Trnsfr 2024 | MS000745 | | | | | | | | | | | | No Data |
| 0 | 73 | Marshall - Replace Fuel Handling Trnsfr 2025 | MS000746 | | | | | | | | | | | | No Data |
| 1 | 74 | Marshall Aux Boiler | MSCM1242 | | x | | | | | | | | | | CBA/Evaluator |
| 1 | 75 | Marshall Coal Blending PLC Replacement | MS001315 | | x | | | | | | | | | | CBA/Evaluator |
| 0 | 76 | Marshall Common Boiler Outage - Coal (2025) | MS00xxxx | | | | | | | | | | | | No Data |
| 0 | 77 | Marshall Common Boiler Outage - Coal (2024) | MS00xxxx | | | | | | | | | | | | No Data |
| 0 | 78 | Marshall Common Boiler Outage - Coal (2023) | MS00xxxx | | | | | | | | | | | | No Data |
| 2 | 79 | Marshall Crusher Motor Chillers Alt Feed | MS000926 | x | x | | | | | | | | | | Funding Approval CBA/Evaluator |
| 1 | 80 | Marshall MS01 600V 1XS MCC Replacement | MS011378 | | x | | | | | | | | | | CBA/Evaluator |
| 1 | 81 | Marshall MS1 600V 1XD MCC Replacement | MS011394 | | x | | | | | | | | | | CBA/Evaluator |
| 1 | 82 | Marshall MS1 MSU Transf Cooler and Pump | MS010109 | | x | | | | | | | | | | CBA/Evaluator |
| 1 | 83 | Marshall MS2 4kV Relay System replacement | MS020111 | | x | | | | | | | | | | CBA/Evaluator |
| 1 | 84 | Marshall MS2 MSU Xfrmr Cooler and Pump | MS020064 | | x | | | | | | | | | | CBA/Evaluator |
| 1 | 85 | Marshall MS3 Blr SH Pend Pla Asbly | MS031264 | | x | | | | | | | | | | CBA/Evaluator |
| 1 | 86 | Marshall MS3 Centerwall Replacement | MS031310 | | x | | | | | | | | | | CBA/Evaluator |
| 1 | 87 | Marshall MS3 FD Fan Bearing Oil System | MS030130 | | x | | | | | | | | | | CBA/Evaluator |
| 1 | 88 | Marshall MS3 Retube Condenser | MS031304 | | x | | | | | | | | | | CBA/Evaluator |
| 1 | 89 | Marshall MS3 SH Division Panel Assembly | MS031266 | | x | | | | | | | | | | CBA/Evaluator |
| 0 | 90 | Marshall MS4 APH REPL | MS040197 | | | | | | | | | | | | No Data |
| 0 | 91 | Marshall MS4 BCP Valve Replacement | MS040111 | | | | | | | | | | | | No Data |
| 1 | 92 | Marshall MS4 Condenser Retube | MS041278 | | x | | | | | | | | | | CBA/Evaluator |

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| 1 | 93 | Marshall MS4 FD Fan Bearing Oil System | MS040117 | | x | | | | | | | | | | CBA/Evaluator |
| 2 | 94 | Marshall MS4 ID fan motor LCI replacement | MS040139 | x | x | | | | | | | | | | Funding Approval CBA/Evaluator |
| 1 | 95 | Marshall MS4 replace ME in absorber tank | MS040168 | | x | | | | | | | | | | CBA/Evaluator |
| 1 | 96 | Marshall Station - Replace #3 chiller and air handling unit (AHU). | MS001093 | | x | | | | | | | | | | CBA/Evaluator |
| 1 | 97 | Marshall Station - Replace #4,#5 chiller and air handling units (AHU). | MS001094 | | x | | | | | | | | | | CBA/Evaluator |
| 1 | 98 | Mill Creek CT - Replace U1-8 Turbine Controls | MKC00006 | | x | | | | | | | | | | CBA/Evaluator |
| 1 | 99 | Mountain Island Replace 9070 Controls | MI001215 | | x | | | | | | | | | | CBA/Evaluator |
| 1 | 100 | Mountain Island U3 Trash Racks Stop Logs System | MI030004 | x | | | | | | | | | | | Funding Approval |
| 1 | 101 | NA GSU Transformer Replacement | NA000643 | x | | | | | | | | | | | Funding Approval |
| 0 | 102 | Nantahala Hydro Tainter Gate Hoist Replacements | NA000498 | | | | | | | | | | | | No Data |
| 1 | 103 | Ninety Nine Island U4 Turbine Runner Replacement | NN040001 | | x | | | | | | | | | | CBA/Evaluator |
| 1 | 104 | OPTIM Combustion Turbine Hot Gas Path (HGP) Dan River Unit 8 | DR080050 | | | x | | | | | | | | | OEM data |
| 1 | 105 | OPTIM Combustion Turbine Hot Gas Path (HGP) Dan River Unit 9 | DR090055 | | | x | | | | | | | | | OEM data |
| 1 | 106 | OPTIM Exciter MJR U2HP | BC020271 | x | | | | | | | | | | | Funding Approval |
| 0 | 107 | OPTIM Exciter MJR U2LP | BC020275 | | | | | | | | | | | | No Data |
| 0 | 108 | OPTIM ST Valve CRV MS4 | MS040203 | | | | | | | | | | | | No Data |
| 0 | 109 | OPTIM ST Valve RHSVIVTVGV U2 | BC020371 | | | | | | | | | | | | No Data |
| 1 | 110 | OPTIM ST07 Valves 2023 | DR070023 | x | | | | | | | | | | | Funding Approval |
| 1 | 111 | Ovation Evergreen Upgrade | LCC00139 | | x | | | | | | | | | | CBA/Evaluator |
| 1 | 112 | Oxford OX Replace 9070 to 3i Controls | OX001222 | | x | | | | | | | | | | CBA/Evaluator |
| 1 | 113 | Oxford Replace Spillway Gantry Girders | OX000048 | x | | | | | | | | | | | Funding Approval |
| 1 | 114 | Oxford U2 Replace Mandoors | OX020008 | x | | | | | | | | | | | Funding Approval |
| 1 | 115 | Replace Filtered Water Riser - Marshall | MS000577 | | x | | | | | | | | | | CBA/Evaluator |
| 0 | 116 | Replace Marshall Coal Crusher Transfer Feeder Belts and Chutes 2026 | MS000480 | | | | | | | | | | | | No Data |
| 2 | 117 | Replace Marshall Unit 2 Air Preheater (APH) baskets | MS020175 | x | x | | | | | | | | | | Funding Approval CBA/Evaluator |
| 1 | 118 | Rhodhiss RH Replace 9070 to 3i Controls | RH000029 | | x | | | | | | | | | | CBA/Evaluator |
| 2 | 119 | Rhodhiss Spillway Debris Gate | RH000039 | x | x | | | | | | | | | | Funding Approval CBA/Evaluator |
| 1 | 120 | Rockingham CT RK00 Combustion Dynamics Monitoring System (CDMS) Autotune System | RK001265 | | x | | | | | | | | | | CBA/Evaluator |
| 0 | 121 | Rockingham CT RK01 Gen Stator and Rotor Rewind | RK010068 | | | | | | | | | | | | No Data |
| 0 | 122 | Rockingham CT RK02 Gen Stator and Rotor Rewind | RK020002 | | | | | | | | | | | | No Data |
| 0 | 123 | Rockingham CT RK03 Gen Stator and Rotor Rewind | RK030040 | | | | | | | | | | | | No Data |
| 0 | 124 | Rockingham CT RK04 Gen Stator and Rotor Rewind | RK040015 | | | | | | | | | | | | No Data |
| 0 | 125 | Rockingham CT RK05 Gen Stator and Rotor Rewind | RK050001 | | | | | | | | | | | | No Data |
| 1 | 126 | Thorpe Hydro Generator Replacement | TH000068 | x | | | | | | | | | | | Funding Approval |
| 0 | 127 | Thorpe Hydro GSU Replacement | TH000052 | | | | | | | | | | | | No Data |
| 0 | 128 | Wateree U1 Wear Ring Replacement | WA011203 | | | | | | | | | | | | No Data |
| 0 | 129 | Wateree U2 Wear Ring Replacement | WA021201 | | | | | | | | | | | | No Data |
| 1 | 130 | WS Lee CC Ammonia Tank Upgrade | LSCC0136 | | x | | | | | | | | | | CBA/Evaluator |
| 1 | 131 | WS Lee CC LS11 HRH and CRH Isolation Valves | LS110016 | | x | | | | | | | | | | CBA/Evaluator |
| 1 | 132 | WS Lee CC LS12 HRH and CRH Isolation Valves | LS120015 | | x | | | | | | | | | | CBA/Evaluator |
| 0 | 133 | WS Lee CC Spare GSU Containment | LSCC0146 | | | | | | | | | | | | No Data |
| 0 | 134 | WS Lee CC Unit Flex Enhancement Prjcts | LSCC0111 | | | | | | | | | | | | No Data |
| 1 | 135 | WS Lee CC WSL U11 OPTIM LTSA MAJOR | LS110035 | | | x | | | | | | | | | OEM data |
| 1 | 136 | WS Lee CC WSL U12 OPTIM LTSA MAJOR | LS120032 | | | x | | | | | | | | | OEM data |
| 1 | 137 | WS Lee CT 7C and 8C Spare GSU Containment | LSC00075 | | x | | | | | | | | | | CBA/Evaluator |
| 0 | 138 | WS Lee CTs 2024 Ovation Evergreen | LSC00100 | | | | | | | | | | | | No Data |

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**DUKE ENERGY CAROLINAS**
**RRE MYRP PROJECT LIST**
**DOCKET NO. E-2 Sub 1276**
Supplemental Response to PSDR 1-8

As of 2/8/23

| | | | | | | | Commercial documents | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total # of documents | Exhibit Line No. | MYRP Project Name | Funding Project | Funding Approval | CBA/Evaluator | OEM data | Purchase order | Change orders | Bid Evaluation | Whitepaper | Charter | Funding Memo | | Green indicates that some documentation exists | Doc List |
| 1 | 139 | WSL Unit 11 Siemens FX Upgrade | LS110040 | | x | | | | | | | | | | CBA/Evaluator |
| 1 | 140 | WSL Unit 12 Siemens FX Upgrade | LS120036 | | x | | | | | | | | | | CBA/Evaluator |
| 1 | 141 | Wylie Replace 9070 to 3i Controls | WY001223 | | x | | | | | | | | | | CBA/Evaluator |

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# Duke Energy Carolinas
# Response to
# NC Public Staff Data Request
# Data Request No. NCPS 5

## Docket No. E-7, Sub 1276

**Date of Request:** **January 19, 2023**
**Date of Response:** **January 30, 2023**

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***Confidential Responses are provided pursuant to Confidentiality Agreement***

The attached response to NC Public Staff Data Request No. 5-2, was provided to me by the following individual(s): Jennifer Edwards, Lead HR Consultant, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

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North Carolina Public Staff
Data Request No. 5
DEC Docket No. E-7, Sub 1276
Item No. 5-2
Page 1 of 2

**Request:**

2. Please provide a spreadsheet, in Excel format, of the planned staffing levels at each of the facilities listed below as of January 1, 2024, 2025, and 2026:
    a. Catawba;
    b. McGuire;
    c. Oconee;
    d. Nuclear Generation Division/Group;
    e. Belews Creek;
    f. Cliffside;
    g. Marshall;
    h. Allen;
    i. W.S. Lee CC;
    j. Dan River CC;
    k. Buck CC;
    l. Lincoln County CT 1-17
    m. Fossil Fuel Generation Division/Group
    n. Hydro Generation Division/Group
    o. Solar Generation Division/Group
    p. Customer Service/Support/Call Center;
    q. Transmission Group;
        i. Transmission Planning
        ii. Transmission Interconnection and Generation Interconnection Studies
    r. Distribution Group;
        i. Distribution Planning
        ii. Distribution Interconnection and Generation Interconnection Studies
    s. NERC Compliance
        i. CIP
        ii. Operations and Planning
    t. Enterprise Security
    u. Administrative Services
    v. Generation
    w. Information Technology

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

**Response:**

Planned staffing levels for 2024 – 2026 are not available as staffing plans are prepared for one year forward.

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# Duke Energy Carolinas
# Response to
# NC Public Staff Data Request
# Data Request No. NCPS 5

## Docket No. E-7, Sub 1276

**Date of Request:** **January 19, 2023**
**Date of Response:** **May 24, 2023**

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***Confidential Responses are provided pursuant to Confidentiality Agreement***

The attached supplemental response to NC Public Staff Data Request No. 5-2, was provided to me by the following individual(s): Jennifer Edwards, Lead HR Consultant, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

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North Carolina Public Staff
Data Request No. 5
DEC Docket No. E-7, Sub 1276
Item No. 5-2
Page 1 of 2

**Request:**

2. Please provide a spreadsheet, in Excel format, of the planned staffing levels at each of the facilities listed below as of January 1, 2024, 2025, and 2026:
    a. Catawba;
    b. McGuire;
    c. Oconee;
    d. Nuclear Generation Division/Group;
    e. Belews Creek;
    f. Cliffside;
    g. Marshall;
    h. Allen;
    i. W.S. Lee CC;
    j. Dan River CC;
    k. Buck CC;
    l. Lincoln County CT 1-17
    m. Fossil Fuel Generation Division/Group
    n. Hydro Generation Division/Group
    o. Solar Generation Division/Group
    p. Customer Service/Support/Call Center;
    q. Transmission Group;
        i. Transmission Planning
        ii. Transmission Interconnection and Generation Interconnection Studies
    r. Distribution Group;
        i. Distribution Planning
        ii. Distribution Interconnection and Generation Interconnection Studies
    s. NERC Compliance
        i. CIP
        ii. Operations and Planning
    t. Enterprise Security
    u. Administrative Services
    v. Generation
    w. Information Technology

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

**Supplemental Response (5/24/23):**

In our original response we stated that planned staffing levels for 2024 – 2026 are not available as staffing plans are prepared for one year forward. To clarify, planned staffing levels are entered into our budget tool in the current year for the next calendar year starting in August. Final data is not available for reporting from our budget tool until February.

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# Duke Energy Carolinas
# Response to
# NC Public Staff Data Request
# Data Request No. NCPS 5

## Docket No. E-7, Sub 1276

**Date of Request:** **January 19, 2023**
**Date of Response:** **January 30, 2023**

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***Confidential Responses are provided pursuant to Confidentiality Agreement***

The attached response to NC Public Staff Data Request No. 5-3, was provided to me by the following individual(s): Jennifer Edwards, Lead HR Consultant, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

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North Carolina Public Staff
Data Request No. 5
DEC Docket No. E-7, Sub 1276
Item No. 5-3
Page 1 of 2

**Request:**

3. Please provide the current organization chart for each of the following identified work areas and include any currently open or non-filled positions.

Note: For example, if the Maintenance Division at Oconee Plant has 32 technician openings and only 18 of those filled positions report to manager John Doe, the organization chart should include the reporting manager (John Doe) and a general reference to 18 of the 32 technician spots that are filled.

a. Catawba;
b. McGuire;
c. Oconee;
d. Nuclear Generation Division/Group;
e. Belews Creek;
f. Cliffside;
g. Marshall;
h. Allen;
i. W.S. Lee CC;
j. Dan River CC;
k. Buck CC;
l. Lincoln County CT 1-17
m. Fossil Fuel Generation Division/Group
n. Hydro Generation Division/Group
o. Solar Generation Division/Group
p. Customer Service/Support/Call Center;
q. Transmission Group;
    i. Transmission Planning
    ii. Transmission Interconnection and Generation Interconnection Studies
r. Distribution Group;
    i. Distribution Planning
    ii. Distribution Interconnection and Generation Interconnection Studies
s. NERC Compliance
    i. CIP
    ii. Operations and Planning
t. Enterprise Security

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u. Administrative Services
v. Generation
w. Information Technology

**Response:**

For current organizational structure in Excel format, see attachment DEC PS DR 5-3_Org Chart. Organization charts are not organized by work location or HR company but by department. Each work location or business group is on a separate tab and includes employees in HR Companies 100(DEC), 801(DEP), and 110(DEBS).
See attachment DEC PS DR 5-3_Open Positions for the number of open positions per work location or business group.

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# Duke Energy Carolinas
# Response to
# NC Public Staff Data Request
# Data Request No. NCPS 42

## Docket No. E-7, Sub 1276

**Date of Request:** **March 23, 2023**
**Date of Response:** **April 3, 2023**

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***Confidential Responses are provided pursuant to Confidentiality Agreement***

The attached response to NC Public Staff Data Request No. 42-5, was provided to me by the following individual(s): Maria L. Hernandez, Director Nuclear Finance and RGT Reporting, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

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North Carolina Public Staff
Data Request No. 42
DEC Docket No. E-7, Sub 1276
Item No. 42-5
Page 1 of 1

**Request:**

5. Catawba Unit 2 Total Deferred Costs, shown in the table above, is much larger (~40% larger) than previous projects. Please provide a narrative of this outage and why the total deferred costs are so much greater than previous deferrals. In part of the response, please provide the number of outage days in the outage in question as well as previous outages and any narrative that may expand upon if the outage in question is representative of ongoing and future outages.

**Response:**

This Catawba Unit 2 Outage, C2R24, was completed in 37 days, 8 hours. The original schedule was for 28 days. The primary driver of the outage extension and increased cost was an issue with the U2 reactor vessel head. This issue was found as part of performing the U2 reactor vessel head ultrasonic inspections of all penetrations in the head (performed every seven years.) This inspection validates structural integrity and no leakage paths through the penetrations. When testing was performed on nozzle #74 (one of five for the core exit thermocouples coming up through the head), we identified an area where we did not get a clear picture of structural material. We tried to remove its associated funnel to allow us to perform a different type of testing (eddy current) to validate there were no concerns with the structural integrity of the weld for nozzle #74. We were unable to remove the funnel initially. Westinghouse brought in a special machine that used electrical discharge machining (EDM) to cut and remove the funnel for nozzle #74. This enabled us to complete eddy current testing of the entire weld associated with nozzle #74. This testing identified an indication in the j-groove weld that was confirmed by dye-penetrant testing. Westinghouse then installed a three-layer weld overlay overtop of the j-groove weld to isolate the original weld from the reactor coolant system water. This overlay took approximately five days to install and validate integrity. The NRC approved a relief request for this weld overlay, which gave us approval to startup and operate Catawba U2.

The average duration of the 3 preceding Catawba U2 outages was 27 days. The average scheduled duration for the upcoming 4 outages, beginning with C2R26 in the spring of 2024, is also 27 days. C2R25, which occurred in the fall of 2022, had a duration of 42 days, due to increased outage scope (reactor vessel head peening project.)

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# Duke Energy Carolinas
# Response to
# NC Public Staff Data Request
# Data Request No. NCPS 42

## Docket No. E-7, Sub 1276

**Date of Request:** **March 23, 2023**
**Date of Response:** **April 3, 2023**

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***Confidential Responses are provided pursuant to Confidentiality Agreement***

The attached response to NC Public Staff Data Request No. 42-7, was provided to me by the following individual(s): Maria L.Hernandez, Director Nuclear Finance and RGT Reporting, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

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North Carolina Public Staff
Data Request No. 42
DEC Docket No. E-7, Sub 1276
Item No. 42-7
Page 1 of 1

**Request:**

7. The Company, or Duke, has delayed refueling outages to account for unit commitment, grid conditions, or emergent items. In some cases, the Company may have to pay incremental costs to labor crews and vendors for outage delays. If the deferred costs include costs associated with delayed refueling outage, please provide a list of those costs and a narrative of why those costs should be included in this proforma.

**Response:**

Oconee Unit 3 R31 was delayed 7 days due to grid availability and replacement costs being higher than the delay cost. The total gross delay costs were $4.7M, including $1.8M for turnkey contract services and $2.9 for contingent worker. These costs are specifically attributable to the refueling outage and therefore included as part of total actual outage costs.

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**Duke Energy Carolinas**
**Docket No. E-7, Sub 1276**
**Public Staff Data Request No. 52**
**Date Sent: March 28, 2023**
**Date Requested: April 7, 2023**

**Public Staff Technical Contact:** **Dustin Metz**
**Phone #: (919) 733-1513**
**Email: dustin.metz@psncuc.nc.gov**

**Public Staff Legal Contact:** **Nadia Luhr**
**Phone #: (919) 733-0975**
**Email: nadia.luhr@psncuc.nc.gov**

**Topic: Detailed Sample of Intangible Plant 2, Follow-Up to PS DR 10**

**Please provide any available responses electronically in a searchable native electronic format. If in Excel format, be sure to include all working formulas. In addition, please include (1) the name and title of the individual who has the responsibility for the subject matter addressed therein, and (2) the identity of the person making the response by name, occupation, and job title.**

1. For each of the projects identified in the below table, please provide the following:

    a. Narrative project description, including an overview of major equipment installed and number of devices and major contractors/vendors hired.

    b. Need for the project.

        i. Was the project initiated or triggered by a regulatory compliance issue? If so, please list each regulatory entity and each regulatory requirement that triggered the project need and provide a brief narrative describing the compliance requirement(s).

        ii. Was the project the result of any settlement agreements, stipulations, or any other legal requirements? If so, please provide a copy of each agreement. If the agreement contains privileged information, please provide a privilege log detailing the information claimed to be privileged.

        iii. If the project was to replace aged or end of life assets, please provide the average life of the pre-project equipment/plant and a brief narrative of how the Company calculated the average life.

        iv. For assets that were replaced prior to the end of life, please provide each individual retirement entry that was booked for the project.

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1. If replaced equipment did not have a retirement entry booked, please explain why not.

v. For new customer additions, please provide the number of new customers added and whether or not the new customers are currently drawing/consuming electricity from the Company's grid.

c. Whether the project or any subset of the project was part of a warranty or covered by insurance.

i. If so, please provide a narrative of what was covered and show the applicable costs that were covered and are removed from the current case.

d. Detailed WBS breakdown of all charges booked to the Project ID.

Note: The list provided is meant to indicate the project, not the cost. Please include all charges for the entire/total Project ID.

i. Was the project (or any part of the project) included for rate recovery during a previous proceeding? If so, please reconcile and provide all journal entries related to the project that were included in the prior proceeding(s) and in the current rate case (Sub 1276) and indicate the proceeding in which entries were included.

e. A list of any Contributions in Aid of Construction (CIAC) that were received associated with this project, including the amount, the contributing party, and confirmation and supporting journal entries demonstrating that the CIAC was used to reduce the costs that were closed to plant.

f. Date the project started (mm/yr).

g. Date the project was completed, and what criteria the Company used to establish that it was complete (mm/yr).

i. If the project is not yet completed, please identify whether the Company is seeking cost recovery for the project (or any part of the project) in this rate case, and whether the Company considers the project or portion of the project included to be "used and useful" or performing its intended function.

1. If the project is in an incomplete (not closed to plant) project state, but the Company is seeking cost recovery for all or parts of the project, please describe how and why each component for which cost recovery is sought in this case is considered "used and useful."

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h. All supporting cost/benefit analyses and supplemental analyses (or equivalent) used to support the project need and cost effectiveness as well as cost alternatives for alternative projects that would have addressed/resolved the project need.

   i. Provide the initial project funding authorization (or equivalent), along with the date of approval.

   ii. Provide the original cost estimate of the project.

   iii. Provide the project risk category designation.

i. Expected operable life of the new asset.

j. Where applicable, list the capacity rating of the new equipment (major equipment: transformers, main wires, etc.). For projects that are designed to increase the capacity of the Company's system, please provide the old capacity and the new capacity.

k. List the internal labor costs, external labor costs, and equipment costs.

l. List any incremental operation and maintenance expenses or savings that were projected for the project and indicate if and where those incremental savings are reflected in the current general rate case.

m. Provide a detailed narrative describing how the project and its respective costs are beneficial to rate payers.

DEC Intang Sample 2.xlsx (excel sheet shown below)

| Project ID | Funding Project | Project Description | Type of Plant | 2020 starting June | 2021 | 2022 | Grand Total | Total Estimate | Closing Option |
|---|---|---|---|---|---|---|---|---|---|
| CS2100004 | FPIT | Avaya License Purchase | Elec - Intangible Plant | | 573,774 | | 573,774 | | *Standard Close* |
| SG1094OTA | SG001094F | DEE Outage Timestamp Accuracy | Elec - Intangible Plant | | | 516,436 | 516,436 | | *Standard Close* |
| SG943MAIF | SG000943F | Advanced Reliability Metrics (MAIFI | Elec - Intangible Plant | | 470,531 | 4,379 | 474,910 | | *Standard Close* |
| ETORANK | RESBLDCW | Feeder Operational Controls | Elec - Intangible Plant | | 514,814 | | 514,814 | | *Standard Close* |
| ETOPRTL | RESBLDCW | MT Holly Simulation an Testing | Elec - Intangible Plant | | 330,240 | | 330,240 | | *Standard Close Auto* |
| 349472016 | FPIT | Autodesk Subscription Agreement | Elec - Intangible Plant | | | 318,419 | 318,419 | | *Standard Close Auto* |
| LTHMWSON | LTHMWSN48 | Lighthse Init - Nuclear Mobile Work | Elec - Intangible Plant | 212,532 | | 105,769 | 318,301 | | *External Close* |
| CS2100009 | FPIT | Avaya License Purchase #2 | Elec - Intangible Plant | | 283,246 | | 283,246 | | *Standard Close* |
| CS1900001 | FPIT | Voice of the Customer Engagement Pl | Elec - Intangible Plant | | | 277,741 | 277,741 | | *Standard Close* |
| ETOSIM | RESBLDCW | Mount Holly Simulation and Testing | Elec - Intangible Plant | 248,011 | | | 248,011 | | *Standard Close Auto* |
| LTHMWSCN | LTHMWSN48 | Lighthouse Init - Nuclear Mob Wrkr | Elec - Intangible Plant | 53,254 | 23,421 | 142,062 | 218,737 | | *External Close* |

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# Duke Energy Carolinas
# Response to
# NC Public Staff Data Request
# Data Request No. NCPS 59

## Docket No. E-7, Sub 1276

**Date of Request:** **March 29, 2023**
**Date of Response:** **April 12, 2023**

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***Confidential Responses are provided pursuant to Confidentiality Agreement***

The attached response to NC Public Staff Data Request No. 59-1, was provided to me by the following individual(s): Jacqueline D. Walker, Lead Ping & Regulatory Support Specialist, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

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North Carolina Public Staff
Data Request No. 59
DEC Docket No. E-7, Sub 1276
Item No. 59-1
Page 1 of 3

**Request:**

1. The Company listed ~13 projects under the MYRP Project Name "Land Mobile Radio Replacement Project." Please answer the following questions for each of the 13 projects:

    a. Describe the project need.

    b. Describe how these projects support general utility operations.

    c. Since these are listed as replacements, list the installation date for all equipment that will be replaced.

    d. For the equipment that is to be replaced, list the total amount of annual O&M and capital spent on the equipment/projects for the last five years.

    e. Describe why all the replacement projects occur in 2024.

        i. Could the replacement projects occur in 2025, 2026, or even 2027? If not, please describe why not.

    f. Provide a log of all communication issues for the last five years along with a narrative that explains the reason for the issue, the time duration, and corrective action taken.

    g. Provide a general narrative and support for why a project lease would qualify for a capital MYRP project.

    h. Provide detailed support for how the Company determined the one-time O&M cost.

    i. Provide a general narrative for how the Company calculated an approximate 8.4% contingency for 12 of the 13 projects.

**Response:**

a. The purpose of the Land Mobile Radio Program is the Enterprise-wide replacement and improvement of Duke Energy's Land Mobile Radio (LMR) systems.

Existing LMR systems in several jurisdictions are at or near end of life and no longer supported by the original equipment manufacturers.

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The replacement LMR system will provide reliable, interoperable, mission-critical communications across all jurisdictions for Transmission, Distribution, Nuclear, and RRE.

This program consists of eight projects: Cores, Consoles, DEM (includes DEI, DEO, DEK) Deployment, DEF Deployment, DEP Deployment, and DEC Deployment.

The new radio system will provide increased functionality and interoperability between regions, meaning field workers from one region can use the same radio system when supporting another region during major storms, emergencies, or widespread outages.
b. The LMR DEC projects support utility operations in three primary areas:
1. Mission Critical Voice: LMR provides a reliable, mission-critical communications solution that is available for operational purposes 24/7 among the Transmission, Distribution, Nuclear, and RRE business units in all jurisdictions.
2. Interoperability: LMR provides the capability for cross-jurisdictional communications during operational and event management activities (storm response or major event days).
3. Safety: LMR provides a radio system that is an integral part of safe work practices and worker safety.
c. The original Harris OpenSky system was installed between 2008-2010, with some system upgrades in 2016. Communications equipment is classified to account 397, and is not individually tracked, due to the volume of equipment the company has, therefore Communications Equipment is set to auto retire when it reaches its full depreciable life,
d. For the Harris OpenSky system, break/fix costs averaged $26,462 per year, net of labor. The L3 OpenSky annual maintenance cost is $80,000 per year.
e. To delay the project poses an operational risk, as the vendor has sunset system support on the OpenSky system in favor of moving to the P25 industry standard.
i. Further delays in implementation would also prevent operations from using the additional functionality of interoperability, redundancy, and other capabilities of the P25 system.
f. Duke's ticketing system carries a 12-month rolling period of records. The previous 12-month period rolling year recorded 136 incidents as noted in the attached spreadsheet (filename: PS-DR-59-2f - LMR Incident Log).
g. Leased towers were broken out into separate projects to mitigate the risk associated with additional teams and work involved with deploying the P25 system to towers not owned by Duke Energy. The leased projects for LMR includes capital expenditures for all labor and materials used in structural modifications, site shelters, P25 installation, and all other LMR assets installed in each zone, exclusive of tower lease payments which are O&M.

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North Carolina Public Staff
Data Request No. 59
DEC Docket No. E-7, Sub 1276
Item No. 59-1
Page 3 of 3

h. The project O&M costs are labor, obsolete inventory, and tower lease addendums. For labor, estimated O&M is a percentage of labor costs based on the type of work performed, such as upfront planning and analysis, and some training. Obsolete inventory is determined from remaining maintenance spares, and residual book value, if any. Tower lease addendum costs are based on quotes from the tower owners.
i. The contingency is based on the standard PMCoE cost estimating and risk identification processes, as previously described. The contingency percentage is a result of this PMCoE standard and not a targeted contingency percentage.

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# Duke Energy Carolinas
# Response to
# NC Public Staff Data Request
# Data Request No. NCPS 59

## Docket No. E-7, Sub 1276

**Date of Request:** **March 29, 2023**
**Date of Response:** **April 12, 2023**

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***Confidential Responses are provided pursuant to Confidentiality Agreement***

The attached response to NC Public Staff Data Request No. 59-3, was provided to me by the following individual(s): Jacqueline D. Walker, Lead Ping & Regulatory Support Specialist, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

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North Carolina Public Staff
Data Request No. 59
DEC Docket No. E-7, Sub 1276
Item No. 59-3
Page 1 of 3

**Request:**

3. The Company listed ~29 projects as Facilities for ~$120M. Please answer the following question for each of the 29 projects:
    a. Describe the project need.
    b. List the cost savings for ratepayers once these projects are complete. Include assumptions used in the analysis as well as the period in which the benefits were calculated.
    c. For new buildings/facilities, provide a detailed narrative of how day-to-day utility operations occur in that service area and if they are dependent on an existing building/facility.
    d. For buildings/facilities listed for renovation, please provide the date when the existing building/facility was built as well as an annual list of capital improvements and renovations completed over the last 10 years.
    e. Describe how and why each of the project renovations would be eligible for capital treatment versus traditional O&M.
    f. Describe why project renovations in the MYRP require contingency.
    g. Provide support for how the Company determined each of the project contingencies.
    h. Describe why these projects must be completed in the proposed year the Company has estimated.
    i. Describe why these projects could not be delayed one, two, or even three years.
    j. Provide a map/floor layout of the before and after for the new buildings and renovations.
        i. List the number of employees assigned annually to each building for the last five years.
        ii. Describe how teleworking has impacted the day-to-day staffing of each the buildings and whether it could delay the project need.
        iii. Explain the normal day-to-day function(s) of the staff.
    k. Provide detailed support for the one-time O&M.

**Response:**

a. Please refer to program summaries as noted in Guyton Direct Exhibit 7-Other Program Summaries.

b. Facilities projects are evaluated based on multiple benefits that aim to improve operations in order to provide a better service to our customers. These benefits include

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operational benefits, such as reduced travel time to customers, improved storm response cycle times, space allotment for new equipment and increased availability of resources.

c. The new facilities presented are Little Rock Operations Center, Matthews Operations Center, and Wentworth Operations Center.
Support for each is as follows:

- Little Rock- The current Little Rock Operation Center is located central to the service territory it supports. This center is the home base for line crews (including the Downtown Underground crew), metering, fleet, and engineers serving central and northwest Charlotte/Mecklenburg County. Without a facility in this location, drive times to serve the territory from surrounding centers would exceed 60 minutes. Centers that are in this greater Charlotte area around Little Rock Operations are Newell Operations Center, Fort Mill Operations Center, and Matthews Operations Center.
- Matthews- The Matthews Operations Center is on the outer eastern boundary of the central zone and close to the boundary of the upstate zone. This center is the home base for line crews and engineers serving southeast Charlotte and northwest Union County along the Highway 74 corridor. Centers that are in this area around Matthews are Little Rock Operations Center, Fort Mill Operations Center, and Lancaster Operations Center.
- Wentworth- Wentworth Operations Center will replace the current Madison Operations Center and Reidsville Operations center once completed. Placement of this center will centralize staff and material in order to allow a more efficient workflow for customer support, but there will be dependencies on Burlington Operations Center and Fairfax Operations Center for materials and training.

d. Please see attachment DEC PS DR 59-3d.xlsx.

e. Facility renovations are completed in line with guidance provided in the Duke Energy Capitalization Guideline, page 80.

f. Renovations of older facilities uncover conditions that preliminary site condition assessments cannot detect. Contingency is included to cover cost impacts from those unforeseen conditions.

g. Facilities project estimates included contingency that is based on a percentage averaging 9% of the project cost. As project planning progresses, each project's

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contingency will be informed by potential risks such as hazardous material abatement, unsuitable soils remediation, above roof leakage, etc.

h.The timing of facility investments is based on each zone operation's requirements.

i. Consideration for deferral of these facilities investments was incorporated into the prioritization of operational requirements.

j. New drawings have not been produced for the presented projects. Drawings for before and after will be provided at Commit Gate.

i. Please see attachment DEC PS DR 59-3j.i. Historical Headcount.xlsx
ii. Employees at operations centers have designated seat assignments due to the nature of the work. Deployment of a teleworking strategy does not apply to these teams.
iii. A typical operation center's primary employees are line workers, and they report to the site in the mornings for team huddles, work assignments, safety reviews, material gathering, and utility trucks. After they deploy for job assignments, the teammates that remain at the operations center site are work management, engineering, zone leaders, schedulers, and other support functions. Line workers return to the site as work is completed throughout the day and into the night.

k. Certain office components that are not fixed assets such as trash bins and movable whiteboards. All relocation management activities are considered O&M per the Duke Energy Capitalization Guideline on pages 42-46.

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**Duke Energy Carolinas, LLC**
**Docket No. E-7, Sub 127**
**Public Staff Data Request No. 118**
**Date Sent: May 11, 2023**
**Date Requested: May 22, 2023**

**Public Staff Technical Contacts:** **Dustin Metz**
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**Topic: Clemson Hydrogen Project - MYRP**

**Please provide any available responses electronically in a searchable native electronic format. If in Excel format, be sure to include all working formulas. In addition, please include (1) the name and title of the individual who has the responsibility for the subject matter addressed therein, and (2) the identity of the person making the response by name, occupation, and job title.**

1. Please provide a general description of the Company's proposed Clemson Hydrogen Project (CHP) and the project need.

**Note that the Company considers the "CHP" to be the combined heat and power system already in service at Clemson. The hydrogen project is referred to as the "H2 Orange Project." For purposes of this set and for clarity, the "Hydrogen Project," "Project," or "H2 Orange Project" will refer to the hydrogen project, and "CHP" or "Clemson CT" will refer to the existing combined heat and power unit.**

The proposed Hydrogen Project is a demonstration site with utility scale hydrogen production, storage, and combustion turbine co-firing located at the Clemson Combined Heat and Power Plant on the Clemson University Main Campus.

This operational demonstration will test the dispatchable operational capabilities of an integrated hydrogen production, compression, storage, and generation system and define the future development requirements and operational needs to reduce the technology introduction risk for a utility-scale system.

Learnings will include improved understanding of the required CAPEX, OPEX, operational procedures, safety practices, future workforce needs, and environmental and social impacts of this type of facility.

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This work supports the expected need to utilize hydrogen to meet the proposed EPA Clean Air Act emission limits as well as support future needs identified in the Companies' resource plans.

The Project Scope Includes:

- An 8 MW advanced Polymer Electrolyte Membrane (PEM) electrolyzer. This hydrogen production technology is one of the most promising hydrogen production technologies and has the capability to cycle and ramp quickly. These are important characteristics to enable effective hydrogen production from renewable generation.
- Gaseous hydrogen compressor – compress hydrogen to elevated pressures for storage.
- Hydrogen Storage – Rack mounted compressed gas storage pressure vessels.
- Evaporative cooling system – to provide required hydrogen production system cooling.
- Automated controls and advanced monitoring / trending.
- Hydrogen and natural gas blending system.
- Hydrogen and natural gas blended capable combustion turbine dry low emission (DLE) combustors and associated scope (upgradeable to 100% hydrogen capable DLE when developed).

The proposed Project system will produce hydrogen fuel that the existing CHP can use to produce electric power for the Company's electric system.

a. If the project need is based on HB 951 and carbon compliance, please describe how a South Carolina project will directly or indirectly help North Carolina meet carbon compliance.

The hydrogen produced from this Project will displace a portion of the natural gas used by the existing Clemson CT to produce electric power. While the impacts from the expected emission reductions resulting from the co-firing of hydrogen at the Clemson CHP for this demonstration have not been modeled as part of the emission reduction targets of HB 951, hydrogen firing in combustion turbines is one of the potential zero carbon technologies that can help meet the requirements of HB 951. Additionally, this technology can help stretch natural gas supplies farther in a fuel-constrained market and ultimately help support reliability.

The impacts of hydrogen blending and transition have been modeled for the fleet in the 2040s, with the transition from natural gas to hydrogen as a fuel source for CTs and combined cycles. Therefore, the advancement and development of the technology is

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needed not only for zero-carbon targets but also to prudently operate the Company's system in a fuel-constrained market with ever increasing federal regulations. This project will advance the technology and provide an understanding of how low carbon hydrogen production and generation can support a future decarbonized Carolinas system while also providing, as a practical matter, ways to continue to diversify fuel sources for the benefit of customers system wide.

Future cost-effective production of clean hydrogen will require agile production and storage technologies that can maximize the integration and availability of excess renewable generation. This demonstration will test the dispatchable operational abilities of an integrated hydrogen production, compression, storage, and generation system. The demonstration will be operated based on current grid profiles and volatility as well as simulate future Duke Energy projected grid conditions, all of which will allow the Company to gain valuable operational experience. This will help define the future development requirements and operational need, reducing the technology introduction risk for a utility-scale system.

2. Please describe the timing of the project and why it must be completed in the timeline proposed by the Company.

The proposed timeline provides numerous advantages including cost minimization, timely lessons learned, and advancement of technology. Further, these learnings will allow for sufficient time to adequately match with technology development and project development and deployment. The knowledge gained by this demonstration will also allow the Company to share this information with regulators, thus enabling more informed decisions in future resource plan updates. Finally, learning how to develop, construct, operate, and maintain an integrated hydrogen system will help inform what, if any, state and federal policy advancements would be needed to support hydrogen at scale. Although other utilities are exploring hydrogen and the Company routinely interfaces and shares lessons with other utilities, each region is unique, and the specific needs of the Carolinas may not be represented by a hydrogen project being deployed by another utility in a different state or region.

See also the Company's response to 2.b. below.

a. Describe why the project could not be completed and be commercially online in 2027, 2028, or even some other period than what the Company proposed in the MYRP application.

There are benefits that will be realized with the proposed schedule, as the timeline enables the Clemson Hydrogen Project to be a demonstration site. By delaying implementation, the project could fall behind others, lessening the benefits of the early learnings discussed above to the region and customers, industry, and Duke Energy. Siemens Energy is eager to support construction of this project by leveraging

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knowledge and relationships to help minimize the traditional costs associated with a conventional EPC process. Siemens is willing to act in this role to have state of the art cutting edge technologies operating in a demonstration scale in the US, and the Company will benefit from Siemens' expertise and involvement in the project. Should the project be delayed, these developmental synergies would likely be lost and the project would be completed in a traditional fashion with added costs. Additionally, a substantial amount of engineering, integration strategy, and analysis were completed as part of a Department of Energy (DOE) funded study in 2021-2022. This early work helps to save project costs. As is the case with more detailed engineering, this work can become less applicable over time as site conditions and technologies change

i. Provide all supporting analysis and workpapers that drive and/or require the Company's proposed in-service date.

The projected in-service date is tied to the benefits discussed above.

b. Provide supporting documentation and objective analysis that provides certainty that the Company will meet the proposed commercial operation date.

The current schedule includes significant critical path margin. Additionally, the project benefits from the engineering work already completed. Therefore, there is more certainty with the remaining schedule as the scope is well understood. There is also less risk associated with unknowns and potential schedule overruns.

| | |
|---|---|
| FNTP | 9/23/2023 |
| Equipment Purchase | 12/23/2023 |
| Silyzer Factory Acceptance Test / ExW / Site mobilization | 7/24/2024 |
| Completion of Civil Works | 9/23/2024 |
| Delivery of equipment | 11/22/2024 |
| Mechanical Completion | 1/22/2025 |
| Plant Substantial Completion (operational) | 7/24/2025 |
| Final Completion | 10/24/2025 |

c. Would the Company consider this proposed project to be a first of a kind, or at least a first of a kind for Duke Energy?

The individual project components are not considered first of a kind. The electrolyzer, hydrogen compressor, and hydrogen storage are established technologies. The uniqueness of this demonstration is in the operation of the components as a system and

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dispatching that system in simulated future Carolina grid conditions (with increasing amounts of variable renewables)

i. If not, please describe why not, along with a list of completed projects, their respective costs, and size of hydrogen generation/storage/blending.

The following are related Siemens Energy hydrogen projects. The Company does not possess cost information for these projects beyond what is provided below.

**Electrolyzer Projects**

- H2Future project (Voestalpine, Verbund, Austrian Power Grid) - 6MW – commissioned in 2019 – EUR 18 million
- Wunsiedel – Power to gas – 8.5MW – commissioned in 2021
- Trailblazer Project Oberhausen – Green H2 for hydrogen pipeline – 20MW – commissioning underway for 2023

**Combustion Turbine with H2 Co-firing Projects**

- Braskem / Brazil - SGT-600 CHP plant with DLE combustion system for up to 60% H2 co-firing at 25ppm NOx – commissioned in 2022
- Donaustadt / Austria - SGT5-4000F gas turbine in combined cycle operation ready to be tested with up 15 vol.% H2 co-firing in 2023

**Power-to-Hydrogen-to Power Project**

- HYFLEXPOWER / France
  - Decarbonized a papermill by modernizing Smurfit Kappa SGT-400 cogeneration plant in Saillat-sur-Vienne, France. World-first demonstration of a power to H2 to power path for CO2-free power generation pilot including an advanced H2 gas turbine.
  - 2022: Construction, commissioning and demonstration of industrial scale integrated power-to-H2-to-power plant completed. Demonstrated operation of SGT-400 with H2 blends up to 30% H2.
  - 2023: Demonstration of advanced H2 gas turbine SGT-400 up to 100% H2 for carbon-free energy production from stored excess renewable energy in preparation.

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Braskem

**60% Hydrogen, baseload at 25ppm NOx**

Customer: Braskem
Country: Brazil

January 2022

## Reference: Braskem (Brazil) for 60% $H_2$ cofiring in DLE mode

SIEMENS energy

**Challenge**

- Use of hydrogen as fuel gas to reduce use of natural gas, up to 60% not exceeding 25ppm NOx
- Reduced need for external grid supply
- High availability and reliability, low O&M costs

**Technology**

- 2x SGT-600 turnkey CHP plant with 3rd generation DLE system for up to 60% $H_2$ co-firing at 25ppm NOx

**Solution**

- Advanced Additive manufactured burners
- Complete plant delivery, Siemens Energy will build, own & operate the CHP, HRSG and gas compressor
- O&M contract based on delivery of steam and power

**Benefits**

- Fuel cost savings, operation on high levels of hydrogen with DLE, no need for water injection
- Lowest emissions using the latest DLE combustion <25ppm NOx
- Predictable operation and maintenance cost

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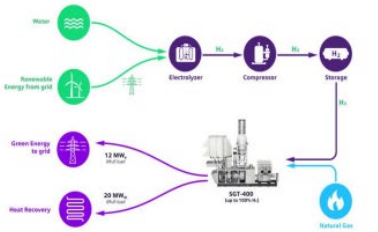
## HYFLEXPOWER Project - France (EU Funded)
## $CO_2$ free power-to-power path using 100% $H_2$ in DLE combustion

SIEMENS energy

**World-first** demonstration of a **power to $H_2$ to power path for $CO_2$-free** power generation pilot including an advanced **$H_2$ gas turbine**

- Decarbonizing papermill by modernizing combined heat and power plant in Saillat-sur-Vienne, France.




HYFLEXPOWER

SIEMENS energy · UCL · CENTRAX · DLR · ENGIE · ARTTIC

**Source:** http://www.hyflexpower.eu/

**$H_2$ Milestones**

**2021**
- Installation of the **$H_2$ production, storage** & supply facility at site

**2022**
- Initial demonstration of **advanced plant concept** with NG/ $H_2$ mixtures

**2023**
- Pilot up to **100% $H_2$ for carbon-free energy production** from stored excess renewable energy ($CO_2$ saving 65,000t/yr.)

March 2023

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6 MW
Power demand based on Silyzer 300

1,200 $Nm^3$
of green hydrogen per hour

April 2023

# H2FUTURE
## A European Flagship project for generation and use of green hydrogen

SIEMENS energy

### Project

| | |
|---|---|
| Partner: | VERBUND (coordination), voestalpine, Austrian Power Grid (APG), TNO, K1-MET |
| Country: | Austria |
| Installed: | 2019 |
| Product: | Silyzer 300 |

### Use cases

- Hydrogen for the steel making process
- Supply grid services

### Challenge

- Potential for "breakthrough" steelmaking technologies which replace carbon by green hydrogen as basis for further upscaling to industrial dimensions
- Installation and integration into an existing coke oven gas pipeline at the steel plant
- High electrolysis system efficiency of 80%

### Solutions

- Operation of a 12-stack array Silyzer 300
- Highly dynamic power consumption – enabling grid services
- State-of-the-art process control technology based on SIMATIC PCS 7

This project has received funding from the Fuel Cells and Hydrogen 2 Joint Undertaking under grant agreement No 735503. This Joint Undertaking receives support from the European Union's Horizon 2020 research and innovative program and Hydrogen Europe and NERGHY


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8.5 MW
Power demand based on Silyzer 300

1,835 $Nm^3$
of green hydrogen per hour

April 2023

# POWER-TO-GAS WUNSIEDEL
## Generation and use of green hydrogen

### Project

- Partner: Siemens AG, WUNH2, SWW Wunsiedel GmbH
- Country: Germany
- Installed: 2021
- Product: Silyzer 300

### Use cases

- Hydrogen for Industry
- Supply grid services
- Supply of green hydrogen for mobility applications

### Challenge

- Power supply only from renewable Energy, primarily solar and wind
- Potential to expand to supply up to 2,000 tons of green hydrogen

### Solutions

- Operation of a 12-stack array Silyzer 300
- Highly dynamic power consumption enabling grid services
- One of the largest Hydrogen production plants of Germany


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335 kg
of green hydrogen per hour

2,680 kg
of green oxygen per hour

April 2023

# TRAILBLAZER PROJECT OBERHAUSEN
## Green hydrogen for Air Liquide pipeline infrastructure

SIEMENS energy

### Project

Partners: Air Liquide
Country: Germany
Installation: 2023
Commissioning: 2023
Product: Silyzer 300

### Use cases

- Hydrogen for the Industry
- Hydrogen for mobility

### Potential

- Connect hydrogen production to both existing hydrogen and oxygen pipelines
- First step: up to 20 MW capacity
- Potential to expand to 30 MW total planned capacity

### Solutions

- Operation of a full 24-stack array Silyzer 300
- Electrolyzer will be integrated into existing local hydrogen and oxygen pipeline infrastructure of Air Liquide
- First electrolyzer to be built in the framework of the partnership between Air Liquide and Siemens Energy
- One of the largest renewable hydrogen and oxygen production plants of Germany


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3. Please provide a general narrative and support as to why Duke's existing Clemson combustion turbine was selected for the hydrogen project.

The Clemson Combined Heat Power site was selected for the project for several reasons.

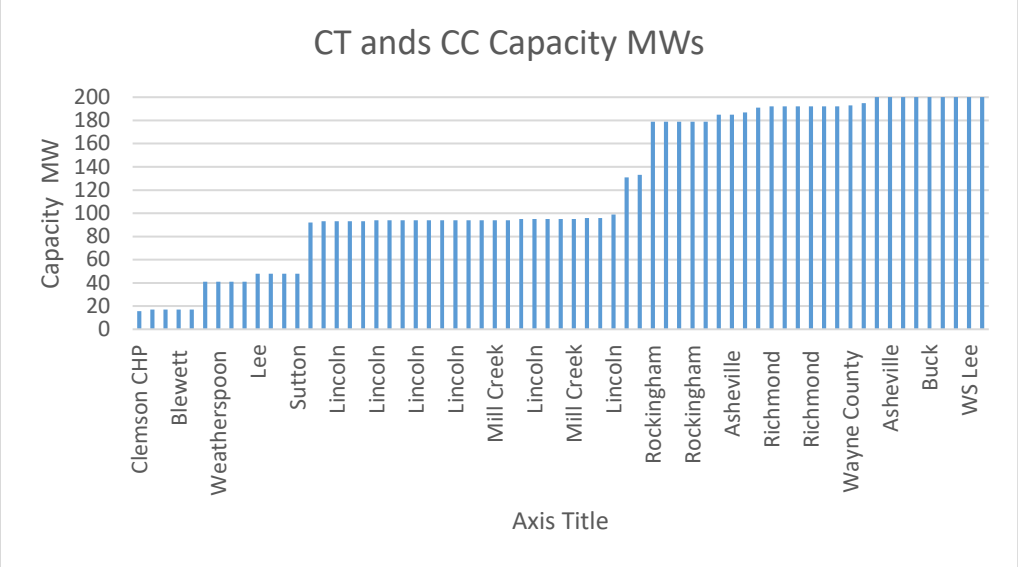
First, the Clemson combustion turbine capacity is orders of magnitude lower than other modern combustion turbines in the DEC or DEP fleet. This translates directly to lower fuel / hydrogen use and lower costs for hydrogen production, compression, storage, and combustion. This results in a much lower total project cost.

In addition, the combustion system of the SGT-400 combustion turbine at Clemson is of a similar design to larger combustion turbines. This similarity allows scaling of the demonstration results to larger units in the fleet.

Finally, co-siting the demonstration at Clemson allows university involvement in the demonstration. This involvement provides high quality and cost-effective modeling, evaluations, and technology enhancement research.

a. Provide supporting documentation that demonstrates the Company's evaluation and selection of the Clemson site.

The Clemson CT is the smallest CT in the DEC / DEP fleet. The next smallest modern unit is rated at 48 MW and is 3 times the size of the Clemson unit. (Note that there are some older CTs of similar size that DEC understands not to be supported for hydrogen firing due to their age.)



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b. Provide a general narrative as to why the hydrogen project was not proposed for a different location, including in Duke Energy Progress East given the excess energy from solar generation and related solar curtailments.

Duke Energy recognizes that excess solar energy and solar curtailments are more likely in the DEP East region. The Company plans to simulate high renewable penetration Carolina grid conditions as part of the demonstration at Clemson. These simulations will include current and future DEP East grid simulations. This will allow a cost-effective demonstration while also learning and evaluating the technology for use anywhere in the system. In addition, as discussed above, the Clemson CT is the smallest CT in the DEC / DEP fleet, with the next smallest modern unit rated at 48MWs and 3 times the size of the Clemson unit. The Clemson CT was therefore the best option from the list of available units in terms of size and cost as discussed above. Because this unit operates in a CHP environment, it gives the Company more operating hours, thereby allowing for flexibility and range of the types of operating scenarios that can be simulated, while maximizing the electrolyzer output, hydrogen production and potential hydrogen production tax credits.

4. Provide a general narrative of the main components of the overall CHP.

See response to Question no. 1, above.

a. Provide a general breakdown of the overall costs of each of the main components and any ancillary equipment/charges needed to complete the project.

A breakdown of the equipment costs associated with the hydrogen production island:

**[BEGIN CONFIDENTIAL]**

| **Clemson – HPI** | Cost<br>MUSD |
|---|---|
| Electrolyzer System | $ 9 |
| Electrical Distribution | $ 1 |
| BoP Equipment | $ 2 |
| H2 Gas Management | $ 4 |
| H2 Storage (short-term) | $ 1 |

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| | |
|---|---|
| TFA, Project Management and Engineering | $ 5 |
| Total | $ 22 |

**[END CONFIDENTIAL]**

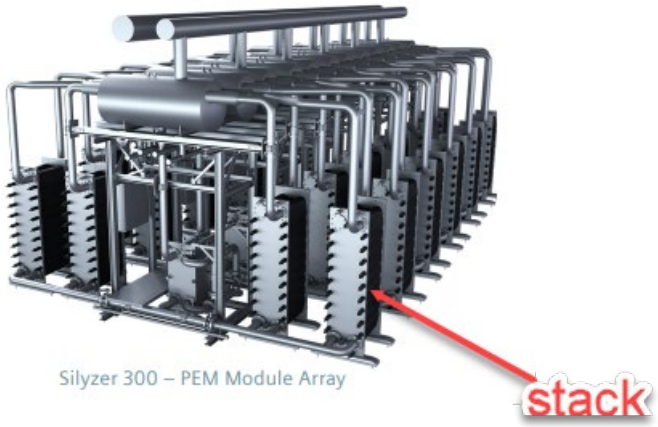
i. Identify and list the Company's internal labor charges that are included in the cost estimates and ultimately the project dollar value amount listed in the MYRP application.

**[BEGIN CONFIDENTIAL]**
The estimated Duke Energy internal labor costs are $2,700,000 plus labor loading and overhead.

**[END CONFIDENTIAL**

5. Please list the expected life of the overall proposed CHP project, with and without the electrolyzer (or equivalent) replacement.

The expected project life is 30 years. The body of the electrolyzer is expected to have a life of 30 years as well, however the internal stacks currently have a projected life of 10 years.



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6. Provide a general narrative that explains the Company's assumption of tax credits (ITC/PTC) for this project and list where the tax credits for the CHP are found in the MYRP revenue requirement.

At the time that the project was included in the MYRP the tax credits for hydrogen were still being written. Due to this uncertainty, the Company did not include any tax credits in the submitted MYRP revenue requirement. In order to provide an indication of the impact of tax credits (most of which have not been finalized) DEC has made a number of assumptions and is currently using those assumptions in CPIRP modeling that is currently in progress and should be completed within the next month.

7. Please provide the equivalent $/kW of the overall CHP, including supporting workpapers.

**[BEGIN CONFIDENTIAL]**

Since the Project is a hydrogen production project, the Company believes that costs should be provided on a kilogram of hydrogen basis. In the case of CAPEX that would be $16,607/kg/day ($59,386,417/3,576 kg/day).

**[END CONFIDENTIAL]**

a. If the CHP was built at the same time as the Clemson Combustion turbine, list the overall $/kW of both projects.

The Company does not have this analysis.

8. Please provide the equivalent $/MWh of the overall CHP, with and without the electrolyzer (or equivalent), including the supporting workpapers. The $/kWh metric should include both with and without the Company's assumptions for tax credits.

This information will be provided when the CPIRP modeling is complete.

9. Provide the LCOE ($/MWh) of the Clemson CT both with and without CHP on an ~90% annual capacity factor (or the capacity factor which the Company believes reflects the expected operations of the Clemson CT). Provide the supporting workpapers. The $/MWh metric should include both with and without the Company's assumptions on tax credits.

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This information will be provided when the CPIRP modeling is complete.

10. Please provide the equivalent $/MMBTU the CHP will generate, including the supporting workpapers.

See the response to question no. 6 above; equivalent $/mmBTU will be provided based on modeling currently underway for the CPIRP.

11. Please list the expected hydrogen blending percentage as well as the natural gas displacement that will occur with hydrogen injection. Provide supporting workpapers.

The expected hydrogen blending percentage capability of the combustion turbine will be greater than 85% by volume. The production system can support an average of 30% hydrogen blend with continuous operation displacing an estimated average of 20.23 mmBTU of natural gas per hour or approximately 11% of the natural gas burn. Estimated hydrogen combusted 151 kg/hour x hydrogen higher heating value 0.134 mmBTU/kg = 20.23 mmBTU/hr.

12. Please provide the cost benefit analysis and net present value cost analysis of the project. If a cost analysis was not completed, please explain why not.

Although a techno-economic analysis was completed as part of the DOE study, this analysis was not completed with methodology that can be used to correctly determine customer benefits and net present revenue requirements. This analysis will be provided once the CPIRP modeling is complete.

13. Provide the supporting workpapers and a general narrative of the contingency and how it was objectively calculated.

For generic unit screening cost studies, a 5% project contingency is typically used. Higher contingencies in the 10% range are also typically used for technologies that are less established. The Company targeted a 10% contingency for this project as DEC believed it best fit into the latter category.

14. Does the overall design or expected design of the CHP enable the ability to sell hydrogen? For example, will the design of the project enable a fuel handling

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truck/container to withdraw hydrogen from the CHP's on-site storage tanks?

Yes, the overall design planned will allow loading of a hydrogen tanker truck from the onsite hydrogen storage area.

a. If so, please provide a general description or expectation of how much hydrogen may be sold annually and list the potential annual revenue.

We have discussed, at a high level, the possibility of providing compressed gaseous hydrogen via tanker trucks to some local off takers. But at this time, we do not have estimated volumes or revenues.

b. If the Company were to sell hydrogen, hypothetically, would the Company treat the sale as revenue? If so, please describe how the Company may treat the revenue (i.e., would the Company consider it a revenue in a test year as an offset to the revenue requirement, or would the Company consider any sale to be an offset in the annual fuel rider).

We have not defined a proposal for any revenue generated from off takers.

15. Please provide a general description of whether the Company believes the CHP should or should not be a pilot project versus research and development or even a demonstration project. Provide an accompanying narrative of how the Company made such a determination and how other Duke projects were similarly treated or considered by the Company.

As stated above, the individual project components are not considered first of a kind and are not considered to be an "R&D" project. The electrolyzer, hydrogen compressor, and hydrogen storage are established technologies. The uniqueness of this demonstration is operating the components as a system and dispatching that system in simulated future Carolina grid conditions (with increasing amounts of variable renewable resources).

While some knowledge can be realized with shorter duration pilots, the longer duration project proposed allows expanded learnings that are crucial to understanding how a hydrogen production system will fit into a future HB951 based grid. Being able to dispatch, operate and maintain the system as it experiences real world conditions such as start-ups, load ramps, wear, ambient temperature variations, water supply variations, etc. will provide the deepest understanding of the CHP and hydrogen production, storage and firing. This is not an R&D project.

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16. Please describe why the Company believes the PEM fuel assemblies should be treated as capital versus a cost that could be recovered in the fuel clause. Note: The Public Staff would like to explore the potential or concept of cost recovery of the fuel assembly, not the balance of plant, recovery through the annual fuel rider.

The Company believes that the PEM fuel assemblies (which DEC takes to mean the electrolyzer stacks) qualify for capitalization as units of property pursuant to the Company's capital accounting guidelines.

a. Describe how the PEM fuel assembly is rated in relation to operable life. Is the PEM fuel assembly rated in total hours, equivalent energy conversion amount, "x" amount of kg of hydrogen (or equivalent metric) over the life of the fuel assembly, etc.?

For planning purposes, the Company is using a 10,000 hour-operating life of the fuel assemblies (stacks). DEC plans to monitor performance of the fuel assembles / stacks and replace them when the performance drops below preestablished targets

b. How many PEM fuel assemblies are proposed at the CHP.

1 electrolyzer = 12 fuel assemblies / stacks are proposed for the H2 Orange Project.

c. To the extent that it is known, list the expected cost of each fuel assembly.

**[BEGIN CONFIDENTIAL]**

It is anticipated that when the project stacks require replacement (which is estimated to occur in approximately 2036) the estimated cost in 2023$ would be approximately $3,600,000 for all 12 stacks or $300,000 per stack. This cost estimate is based on future PEM electrolyzer cost projections by the Department of Energy.

**[END CONFIDENTIAL]**

d. Please describe why or how the fuel assembly has an operable life and will need to be replaced.

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The specific AC-energy consumption is expected to increase by approximately 15% in 10 years at nominal operating point (100% load), if operated continuously. The service life of the electrolyzer stacks is dependent on the operational profile (load, ramp-up, part-load operation, etc.) as well as many other factors such as water quality and operating temperature.

Is a component of the fuel assembly being "consumed" and/or deteriorating over the life of the asset as hydrogen is created?

Note: This specific question seeks clarity on the composition and potential chemistry/reaction of the fuel assembly and how it decays/consumed/expires over a time or usage duration.

Fuel assembly / stack degradation can occur due to multiple factors and mechanisms. In addition to operational profile and water quality, academic research has indicated that other contributing factors include accumulation of sodium and iron in the catalyst, loss of Ruthenium from Iridium Ruthenium Oxide anode, degradation of the Titanium plats, and membrane thinning and restructuring. The stacks are not being "consumed" but will degrade like any other unit of property.

17. Please describe the dependency on a water source to generate hydrogen at the proposed CHP.

a. List the expected annual amount of water (gallons) needed in a typical year for hydrogen generation.

The expected water use at full production is approximately 6.5 gallons per minute. This is about 57,000 gallons per year.

b. Describe where the water will be sourced from and discharged to.

DEC plans to source the water from the existing combined heat power system demineralized water supply system. Similarly, any wastewater would be handled by the existing combined heat power system demineralized water supply system.

c. Please provide an analysis of the Company evaluation of drought or low-level water amounts in the southeast U.S. and the ability to produce hydrogen at the CHP in a drought condition.

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The Company is not aware of a recent such drought analysis or evaluation.

To the Company's knowledge, has the area in which Clemson CT operates had drought(s) or decreased amounts of rainfall and or ability to use water in an ancillary function over the last ten years?

In the past 10 years the Clemson University Water System has had no cases of extreme drought, two months of severe drought and fifteen months of moderate drought, as indicated from monthly Lake Hartwell elevations. In all the indicated drought conditions, we understand that the water supply to the Clemon Hydrogen Project would not have been interrupted.

| Hartwell Project Elevation in FT - MSL | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Avg |
| 2012 | 652.1 | 652.3 | 652.65 | 652.63 | 652.22 | 651.04 | 650.06 | 649.25 | 648.23 | 647.54 | 646.64 | 646.18 | 649.9 |
| 2013 | 648.04 | 652.55 | 655.32 | 656.86 | 659.65 | 661.47 | 663.08 | 661.7 | 660.55 | 660.12 | 659.02 | 660.46 | 658.23 |
| 2014 | 661.97 | 658.87 | 660.4 | 660.69 | 660.53 | 660.24 | 658.65 | 657.21 | 656.46 | 655.73 | 654.7 | 654.82 | 658.36 |
| 2015 | 655.74 | 656.46 | 657.89 | 659.47 | 660.22 | 659.83 | 658.85 | 656.91 | 655.57 | 657.28 | 660.1 | 658.52 | 658.07 |
| 2016 | 662.61 | 658.53 | 659.68 | 660.29 | 660.23 | 659.09 | 656.92 | 655.97 | 654.79 | 653.16 | 650.51 | 649.78 | 656.8 |
| 2017 | 649.76 | 650.5 | 650.09 | 651.24 | 652.94 | 653.62 | 653.63 | 652.66 | 652.09 | 651.75 | 652.86 | 651.83 | 651.91 |
| 2018 | 651.26 | 655.46 | 659.04 | 659.96 | 660.67 | 661.17 | 659.96 | 660.86 | 660.45 | 658.63 | 658.68 | 659.64 | 658.82 |
| 2019 | 659.59 | 659.24 | 661.39 | 660.79 | 660.59 | 660.72 | 659.97 | 658.49 | 657.31 | 655.81 | 655.99 | 655.66 | 658.8 |
| 2020 | 659.47 | 661.73 | 661.06 | 660.67 | 661.65 | 660.45 | 660.3 | 660.18 | 660.22 | 660.78 | 659.12 | 657.95 | 660.3 |
| 2021 | 658.61 | 658.1 | 659.94 | 661.01 | 661.29 | 661.16 | 660.42 | 660.28 | 659.61 | 660.93 | 659.23 | 656.69 | 659.77 |
| 2022 | 658.08 | 659.22 | 660.78 | 660.56 | 660.61 | 660.89 | 659.18 | 656.86 | 657.2 | 655.44 | 654.31 | 655.62 | 658.23 |
| 2023 | 657.56 | 657.87 | 659.74 | 660.83 | 661.52 | | | | | | | | |

Moderate Drought  Severe Drought  Extreme Drought

18. Describe how or when the Company is expecting to generate hydrogen at Clemson CHP.

The current schedule plans for hydrogen production commencing in July of 2025.

a. If not provided in prior response(s), please list the expected annual costs of electricity to charge/generate hydrogen. Provide both the energy and non-energy costs on an annual basis and provide supporting workpapers.

This cost will be an output of the current on-going modeling that reflect that latest CPIRP system portfolios and latest understanding of applicable tax credits. That modeling work is currently in progress and should be complete in the next few weeks.

b. For every equivalent MW of generation from the Clemson CT (using its specific heat rate and excluding any steam sale revenue) from 100%

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hydrogen, list the equivalent $/MWh to create the hydrogen. This analysis should include but not be limited to the electricity to charge/generate the hydrogen, water costs, other reagents, fixed costs and variable costs of the CHP, etc. Please provide supporting workpapers.

Similar to item a above, we will provide these values when the modeling work is complete in the next few weeks.

c. Does DEC have or expect to have excess solar generation subject to curtailment over the MYRP period? If so, please provide support and the amount of expected solar generation that will be curtailed.

See item a and b above, this will also be an output of the latest modeling.

19. Please include any additional information the Company believes would be beneficial to aid in the understanding of need for this project and the accompanying economics/costs and benefits for North Carolina rate payers.

In addition to the benefits described above (important hydrogen learnings, experience, and tax credits) the project also has the potential to support the broader hydrogen economy in the Carolinas including the DOE Hydrogen Hub.

20. Please provide a general summary of what permits and agency approvals would be needed to construct and operate the CHP.

The following permits and approvals are anticipated:

- Clemson Land Use Approval
- S.C. Department of Health and Environmental Control Air Permit Revision Land use/Lease agreement
- Land disturbance for construction site\Building code permit - Mainly for verification of electrical code compliance, fire & life safety, structural.

a. Provide a timeline of the permits/approvals.

The Company does not foresee any issues receiving approvals of the permits / approvals listing above to support the proposed schedule

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b. Does the CHP require or does Duke foresee any South Carolina Public Service Commission approval? If so, please describe.

Due to its size and correlation to the Clemson Combined Heat and Power project, the H2 Orange Project will not require a CEPCN in South Carolina to be constructed. However, the Company is evaluating whether other aspects of the H2 Orange Project will require PSCSC approval in advance of construction as it did for the Clemson CHP project. Once the project is constructed, the Company plans to seek recovery of the SC retail allocated share of the Project.

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# Duke Energy Carolinas
# Response to
# NC Public Staff Data Request
# Data Request No. NCPS 134

## Docket No. E-7, Sub 1276

**Date of Request:** **May 22, 2023**
**Date of Response:** **June 5, 2023**

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***Confidential Responses are provided pursuant to Confidentiality Agreement***

The attached response to NC Public Staff Data Request No. 134-2, 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

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North Carolina Public Staff
Data Request No. 134
DEC Docket No. E-7, Sub 1276
Item No. 134-2
Page 1 of 1

**Request:**

2. The Company has provided information about multiple projects at Mount Holly in response to PSDR 52-1, as well as in response to other discovery requests on samples of projects closed to Plant in the DEC rate case. Please provide details for each project sought for cost recovery in this rate case related to Mount Holly, including, but not limited to:
    a. Project id.
    b. Description of the project.
    c. A narrative of how the project will support DEC operations only, whether it can/will be used by other Duke Energy affiliates.
    d. The total cost of the project.
    e. The amount sought for cost recovery in Sub 1276.
    f. A summary of how each project resulted in a specific product for operational use by DEC and/or the larger utility system. Provide support for each end use application and the benefits experienced.

**Response:**

Based on the Company's review, DR 52-1 had one project with direct reference to "Mt Holly." That project is "ETOSIM".

The Company has already provided the detail requested on this project. This is grid device security for Mt Holly and is a DEC-only application. However, similar grid device security projects are being launched Company-wide; therefore, the same documentation applies for those projects across the Company. Based on this, it may appear that this particular item would be for more than just DEC. However, this item was recorded to DEC's books and is for DEC use only.

DEC PS DR 134-2 did not provide specificity as to the other discovery requests on samples of projects closed to Plant in the DEC rate case that refer to "Mount Holly." If Public Staff can provide the Company the referenced data responses and/or project IDs referenced in the question the Company can provide responses for the specific projects.

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# Duke Energy Carolinas
# Response to
# NC Public Staff Data Request
# Data Request No. NCPS 134

## Docket No. E-7, Sub 1276

**Date of Request:** **May 22, 2023**
**Date of Response:** **June 5, 2023**

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The attached response to NC Public Staff Data Request No. 134-3, was provided to me by the following individual(s): Denise Lepisto, Manager Accounting I, and was provided to NC Public Staff under my supervision.

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Deputy General Counsel
Duke Energy Carolinas

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North Carolina Public Staff
Data Request No. 134
DEC Docket No. E-7, Sub 1276
Item No. 134-3
Page 1 of 1

**Request:**

3. Discovery responses from the Company have listed “Duke Energy” and not specifically Duke Energy Carolinas. It is not clear whether the gains or the cost causation from Mount Holly are actual Mount Holly projects being proportionally paid for by DEC ratepayers commensurate with Duke Energy benefits. Please provide a detailed narrative on how costs of Mount Holly are or are not being paid for in whole or in part by other Duke Energy affiliates in this general rate case. Provide support for your answer.

**Response:**

Many grid security or IT security type projects are initiatives which are Company-wide, and the documentation describing these items may indicate "Duke Energy" to indicate the enterprise-wide initiative. However, the projects that were selected were recorded on DEC's books and serve DEC specifically. All other entities have costs recorded to their books separately from DEC. The costs are recorded at a project level to each individual business unit during the project, and would go into service on each individual business units books.

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# Duke Energy Carolinas
# Response to
# NC Public Staff Data Request
# Data Request No. NCPS 216

## Docket No. E-7, Sub 1276

**Date of Request:** **June 29, 2023**
**Date of Response:** **July 7, 2023**

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***Confidential Responses are provided pursuant to Confidentiality Agreement***

The attached response to NC Public Staff Data Request No. 216-1, was provided to me by the following individual(s): Brian Neiheisel, CW-Professional, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

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North Carolina Public Staff
Data Request No. 216
DEC Docket No. E-7, Sub 1276
Item No. 216-1
Page 1 of 3

**Request:**

1. The following questions are focused on the Inflation Reduction Act's creation of the Zero Emission Production Tax Credit under Section 45U.
    a. Please provide evaluations performed by DEC, Duke Energy Business Services (DEBS), other Duke Energy affiliates, or third parties to quantify the potential tax benefits available through Section 45U to DEC's Nuclear fleet.
    b. Please provide a narrative discussion addressing the ability of DEC to access the Section 45U Zero Emission Nuclear Power Production Tax Credits.
        i. If the Company does not believe it will be able to access the Section 45U benefits, please discuss what the specific impediments are to accessing the Section 45U benefits.
    c. Please discuss the ability of DEC to monetize any tax credits potentially available under Section 45U. This response should, at a minimum, address the potential to transfer the credits and whether they are subject to normalization.
        i. If the Company does not believe monetization is possible, please discuss the limitation and specifically delineate the items preventing DEC from monetizing potential tax credits under Section 45U.

**Response:**

DEC objects to this request (including all sub-parts) on the grounds that it is irrelevant to this case. Tax credits under Section 45U are not even calculable until after December 31, 2023. Further, DEC's request for an Accounting Order in this case includes any benefits from Nuclear PTC's, net of costs incurred. Accordingly, if DEC's request is approved, Nuclear PTC impacts (if any) will be deferred pending further action of the Commission with respect to the deferred benefits, net of costs. Notwithstanding this objection, DEC responds as follows to each subpart.

Response to DR 203-1.a:

DEC expects that its nuclear fleet will qualify for the Section 45U PTC; however, since the credit applies to electricity produced and sold after December 31, 2023, calculation of the amount that may ultimately be allowed as a credit against tax is not possible at this time. DEC is currently evaluating the potential credit amount, and since the passage of the IRA, Duke has engaged with the IRS and Treasury Department as they develop

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guidance implementing the IRA, with respect to the definition of "gross receipts" for purposes of determining the "reduction amount" (i.e., the mechanism through which the phase-down is effectuated). Uncertainty with respect to such forthcoming guidance impacts the potential credit amount available for DEC's nuclear fleet.

Response to DR 203-1.b:

DEC does expect that its existing nuclear generation fleet will qualify for the PTC enabled by Section 13105 of the IRA.

Section 13105 of the IRA added Section 45U to the Internal Revenue Code ("IRC"), which provides an income tax credit for electricity produced at a qualified nuclear power facility and sold by the taxpayer to an unrelated person in taxable years beginning after December 31, 2023, and before January 1, 2033 (the "Section 45U PTC"). Each of the seven reactors/units in DEC's existing nuclear fleet is a "qualified nuclear power facility" since each such reactor/unit is a facility owned by DEC that 1) uses nuclear energy to produce electricity, 2) is not an advanced nuclear power facility as defined in IRC Section 45J(d)(1) (a facility must be placed in service after August 8, 2005 and before January 1, 2021 in order to be an advanced nuclear power facility as defined in IRC Section 45J(d)(1)), and 3) was placed in service before August 16, 2022 (i.e., before the date of the enactment of IRC Section 45U). Therefore, DEC expects the electricity that it produces and sells from its existing nuclear generation fleet in 2024 through 2032 to be eligible for the Section 45U PTC. Depending on the average price at which each facility's annual output is sold, the amount of credit for any such year could be anywhere from $0 to $15/MWh (assuming prevailing wage requirements are met and without regard to any inflation adjustment). This is because the credit rate with respect to any such facility effectively starts to phase down, ratably, when the average price per MWh at which the facility's annual output is sold exceeds $25 (without regard to any inflation adjustment) and effectively reaches $0/MWh when such price per MWh reaches $43.75 (assuming no inflation adjustment to the credit rate or the price at which the credit rate effectively starts to phase down). The ultimate amount of the PTC earned by eligible facilities will be determined annually based upon the $/MWh at which production is sold.

Response to DR 203-1.c:

The IRA contains provisions that allow both PTC and ITC credits to be transferred. Under new IRC § 6418, an eligible taxpayer can elect to transfer all (or any portion specified in the election) of an eligible credit to an unrelated transferee taxpayer. The transfer may have the effect of accelerating monetization of these credits. The transfer, however, must be paid in cash, not be included in the income of the recipient taxpayer,

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and not be deducted by the paying taxpayer. Further, the transfer must be a one-time transfer (i.e., the transferee cannot make a subsequent election to further transfer any portion of the transferred credit). The taxpayer must elect to transfer the credits no later than the due date (including extensions) for the tax return for the tax year for which the credit is determined, and any election, once made, is irrevocable.

While a discount on the total credit value is expected upon the sale and transfer of the credit, the economics for these credit transfers is still uncertain as a market will need to develop. DEC believes that availing itself of the market for transferable credits may ultimately be beneficial to customers in that it would provide DEC with the opportunity to monetize the cash benefit of the credit more rapidly. However, until a stable market for transfer credits materializes the potential benefits of transfer (should they ultimately materialize) are too uncertain and speculative at this point to permit DEC to include potential impacts of transferability upon its revenue requirement in this case.

Irrespective of whether/how monetized, any credit under Section 45U would not be subject to normalization since it is not among the credits that make up the investment credit under Section 46.

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# Duke Energy Carolinas Resource Plans Stakeholder Meeting 4

## Virtual Meeting – May 31, 2023

**Please note, with the exception of the South Carolina-specific session, this meeting is being recorded. Presentations will be posted on the IRP website, and discussion portions will be kept for internal purposes only to ensure accuracy of meeting notes.*

Public Staff
Metz Exhibit 3
Page 63 of 153

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# Meeting Ground Rules

- **Respect each other:** Help us to collectively uphold respect for each other's experiences and opinions, even in difficult conversations. We need everyone's wisdom to achieve better understanding and develop robust solutions.

- **Focus on today's topics**: Please respect the scope of today's meeting to make the most use of our time. Pending legal issues are outside the scope of today's meeting.

- **Chatham House Rule**: Empower others to voice their perspective by respecting the "Chatham House Rule;" you are welcome to share information discussed, but not a participant's identity or affiliation (including unapproved recording of this session).

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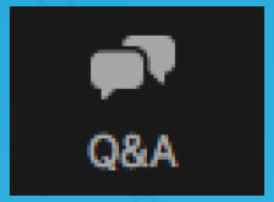
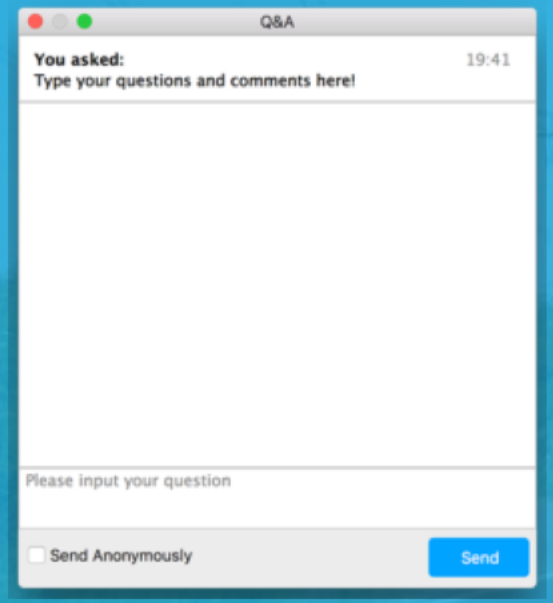
# Attendee Roles: Observers




- Please use the "Q&A" feature, on the menu at the bottom of your screen, to submit questions to presenters and Technical Representatives. Please be respectful and focus on issues, not people.
- Questions/comments submitted will be seen by **all participants.**
- We will address these questions as time permits, with deference given to discussion with Technical Representatives.
- A report of the submitted questions will be included in the meeting summary.
- The chat is also available for sharing information and resources (but please direct questions to the Q&A).

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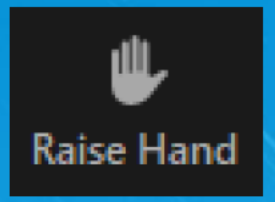
# Attendee Roles: Technical Representative




- May utilize the camera and unmute themselves.
- To manage participation, please use the “raise hand” feature to indicate you would like to join the conversation.

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# Additional Participation

Meeting materials/recordings will be uploaded to the website:

**www.duke-energy.com/carolinas-irp**

Information/feedback can be sent to:

**DukeCarolinas@gpisd.net**

**Meeting recordings (Q&A portions of meetings will be removed to adhere to the non-attribution rule) and meeting summaries will be uploaded to the website for participants to access.**

# 2023 Resource Planning Stakeholder Engagement Overview



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Feb | Mar | Apr | May | Jun | Jul | Aug | Sep

**Meeting 1**
Feb. 22

**Introduction & Process Overview**

**Technical Session:**
Load Forecast

**Meeting 2**
March 16

**Model Assumptions:**
- Solar
- Solar Plus Storage
- Standalone Storage

**Meeting 3**
March 22

**Model Assumptions:**
- Natural Gas Price Forecast Methodology
- Modeling Methodology for Coal Retirement Analysis

**Meeting 4**
May 31

**Model Assumptions:**
- Resource Adequacy Study
- Updated Load Forecast
- Inflation Reduction Act

**End of May:** modeling inputs finalized

**Meeting 5**
June 13

**Summary of Key Modeling Assumptions and Analytical Framework**

Final Modeling and Document Preparation

**IRP Filing**
(PSCSC)
Aug. 15

**CPIRP Filing**
(NCUC)
Due by Sept.1

## Other Related Stakeholder Engagement

- EE/DSM Collaborative
- FERC-Jurisdictional Transmission Planning Collaborative
- 2023 Solar/SPS Request for Proposals
- Integrated Systems & Operations Planning (ISOP)
- Rapid Prototyping

# Agenda



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| | |
|---|---|
| 9:00am – 9:15am: | **Introduction** |
| 9:15am – 10:00am: | **Load Forecast Update** |
| 10:00am – 10:15am: | **Break** |
| 10:15am – 11:15am: | **Resource Adequacy Study** |
| 11:15am – 12:00pm: | **Modeling IRA Impact** |
| 12:00pm – 12:30pm: | **Open for additional South Carolina comments/questions** |

# Introductions



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## Duke Energy Technical Representatives:

- **Tom Davis**
  Principal Planning Analyst– Carolinas IRP & Analytics
- **Nick Wintermantel**
  Utility and Energy Consultant – Astrapé Consulting
- **Justin Brooks**
  Lead Quantitative Analyst – Quantitative Analytics
- **Benjamin Passty**
  Principal Load Forecasting Analyst – Load Forecasting & Fundamentals
- **Jennifer Poppler**
  Principal Planning Analyst – Carolinas IRP & Analytics
- **Cooper Monroe**
  Vice President – Tax

## Support:

- **Glen Snider**
  Managing Director, IRP and Analyticsfff
- **Cole Benson**
  Consultant – Astrapé Consulting

## Stakeholder Technical Representatives:

- **Adam Helsel**
  Senior Utilities Engineer, Fujifilm Diosynth Biotechnologies
- **Bob Hinton**
  Director of Economic Research, NCUC Public Staff
- **Steve Levitas**
  Senior Vice President for Regulatory and Government Affairs, Pine Gate Renewables
- **David Posner**
  Utility Transition Finance Manager, RMI
- **Ben Manuel**
  Director of Development, Cypress Creek Renewables
- **Nick Phillips**
  Principal Advisor for Carolina Industrial Group for Fair Utility Rates (CIGFUR)

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# Load forecast update

Ben Passty – *Principal Load Forecasting Analyst*

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# 2023 Load Forecast Drivers



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## Short-term:

- Weather challenges
- Economic and population challenges

## Long-term:

- Population growth and the impact on residential customers
- Electric vehicle adoptions
- Significant economic development growth in the Carolinas

# Real GDP Growth



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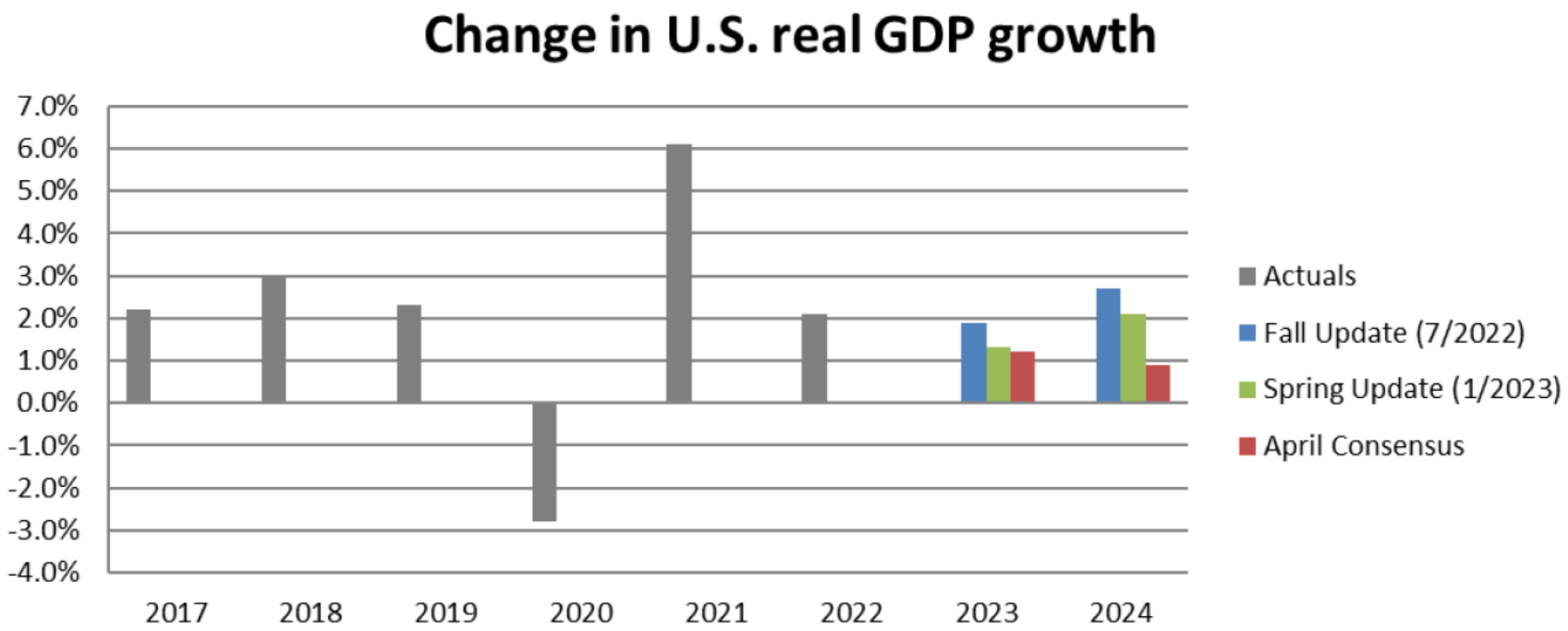


| Real GDP forecasted growth | 2023 | 2024 |
|---|---|---|
| Fall 2022 Update (July) | 1.9% | 2.7% |
| Spring 2023 Update (January) | 1.3% | 2.1% |
| April 2023 Consensus | 1.2% | 0.9% |

# Economic Trends



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Labor Market averaging more than 300,000 net new jobs per month

The median forecast calls for Real GDP growth of 1.0% during this calendar year

February 2023 data shows a Consumer Spending level 6.2% greater than a year earlier, a rate that is slowing but still indicates strong growth

Surveys of Industrial sentiment have turned toward business contraction

The strong jobs growth in the private sector has not spread to the public sector, where employment remains more than 1% *below* the winter 2020 high

Fiscal and Monetary policy is AVA contractionary

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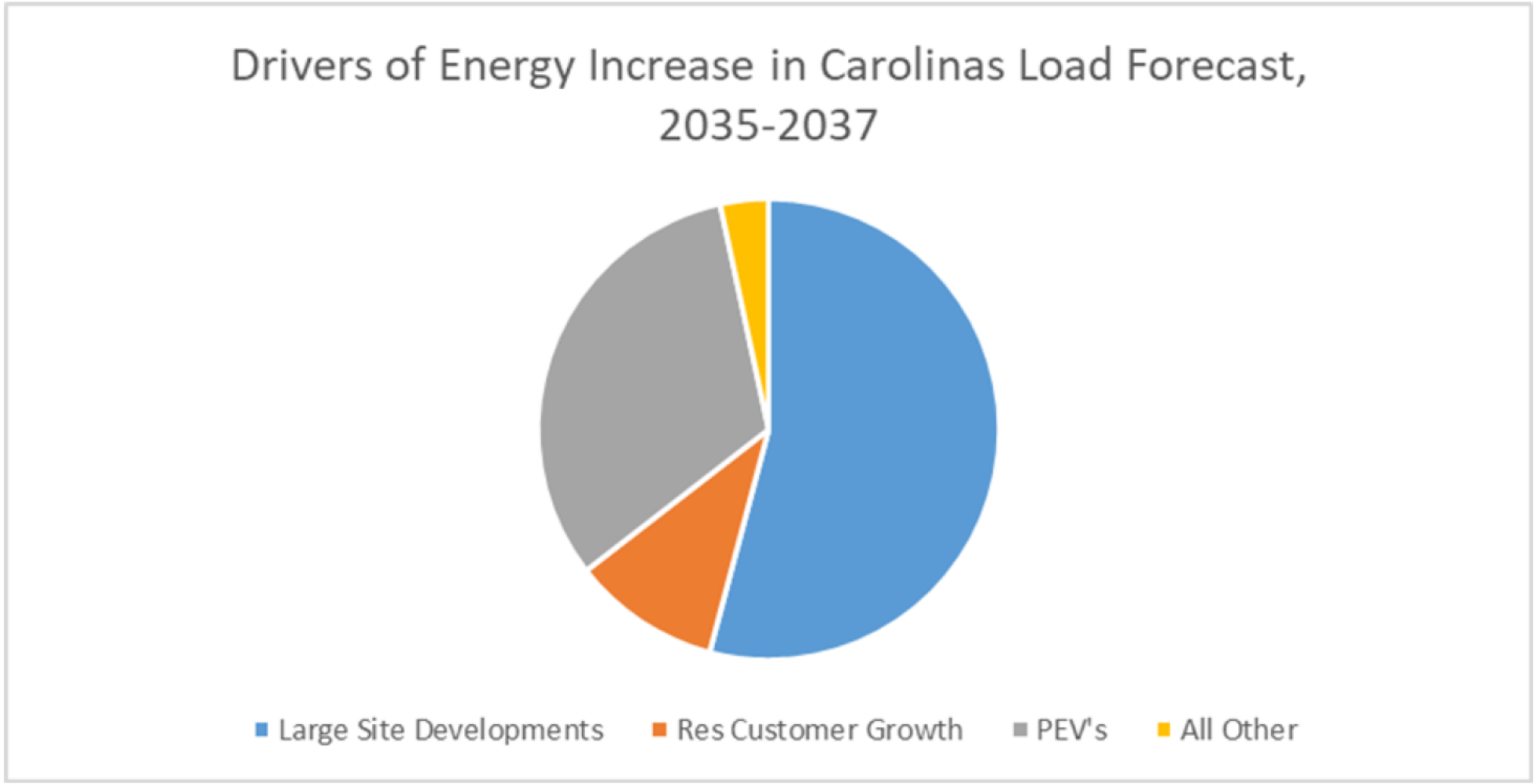
# Load Forecast Drivers from 2022 Resource Plans



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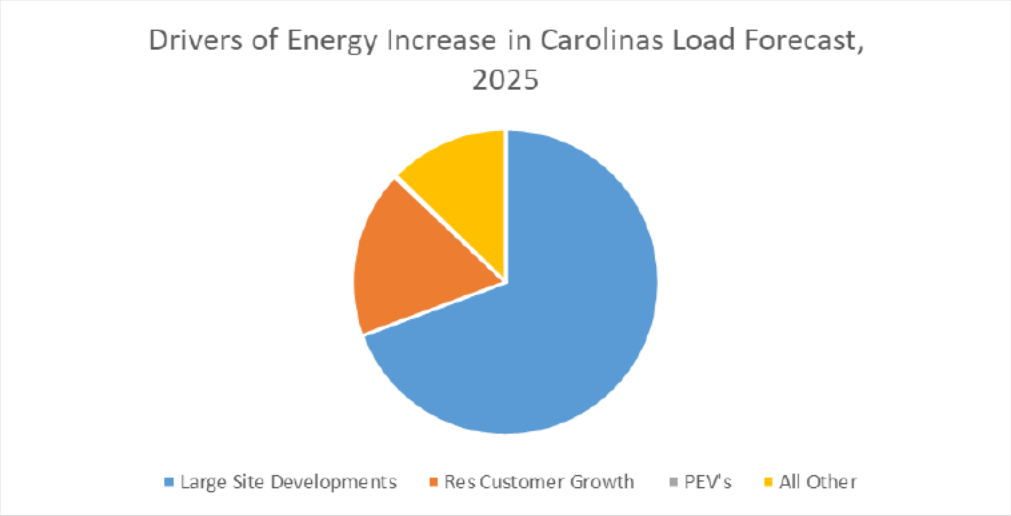
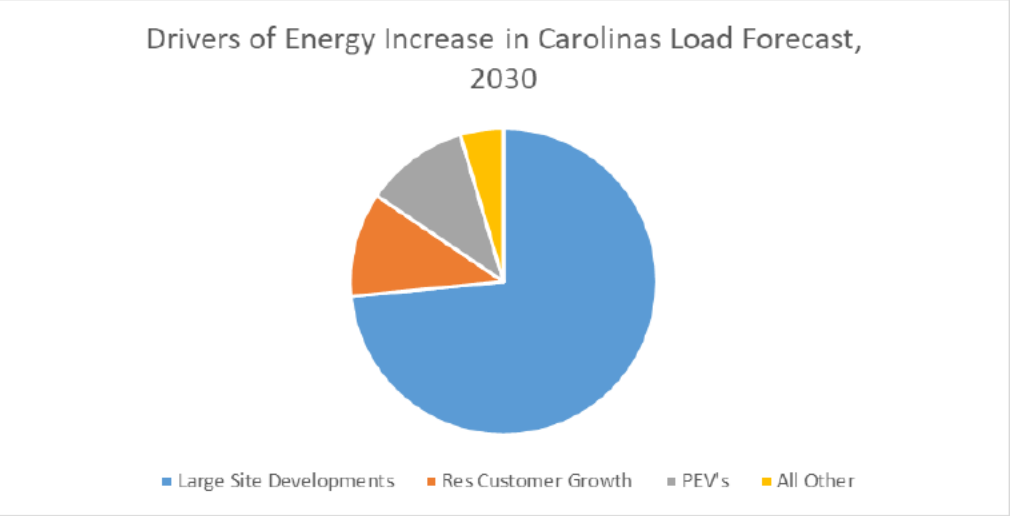
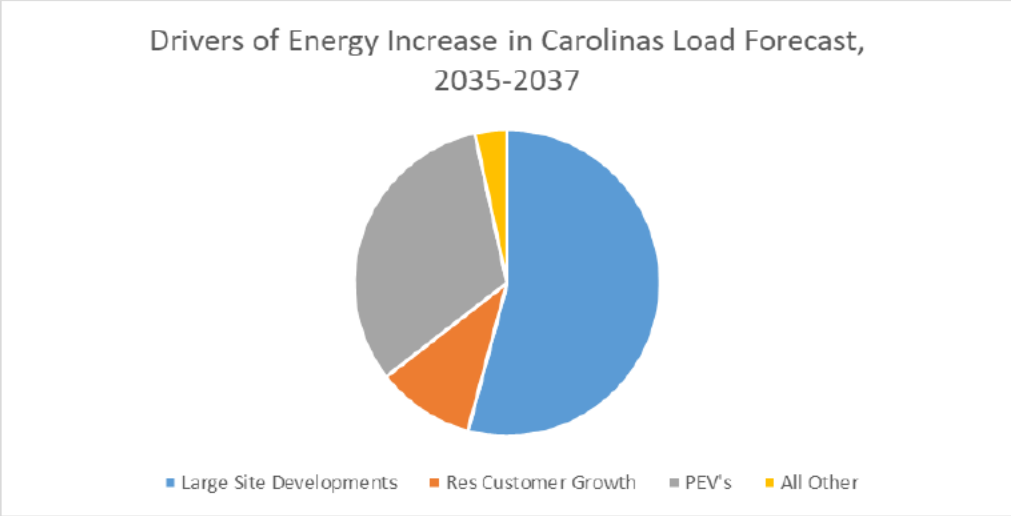
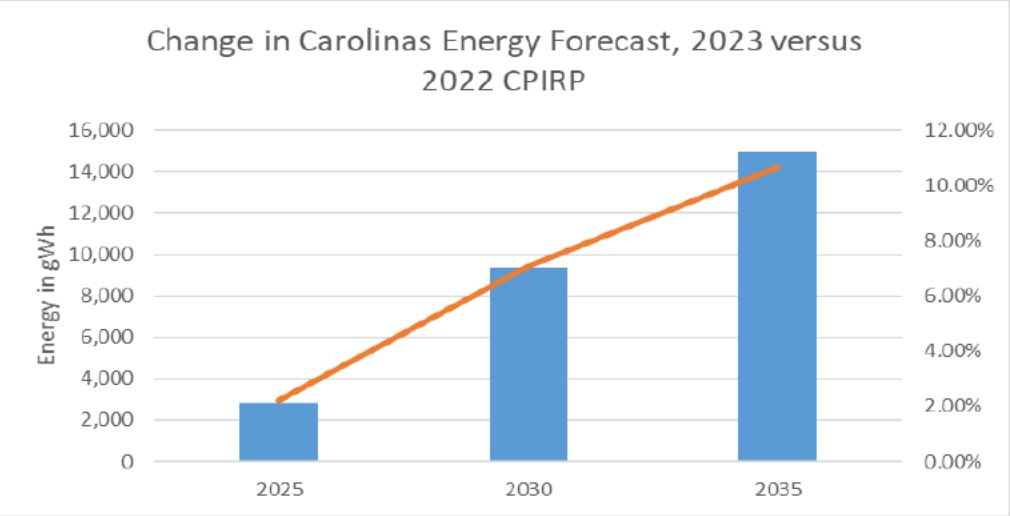
# Load Forecast Drivers from 2022 Resource Plans (Snapshots)



# Large Site Development



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- Economic Development has driven customers to DEC's and DEP's service territories
- Large Account Management tracks new customers that will potentially connect to the system
- Only Projects that have started construction are generally reflected in load forecast
- Currently reflecting a portion of the service territory's potential future economic development projects
- Large site development load tends to be high load factor additions to the energy forecast
- Dominion Energy Virginia's 2023 IRP also forecasts similar growth in large site development
- Both states have projects that are included in the adjustments

# EV Forecast - 2022 vs 2023 Resource Plans



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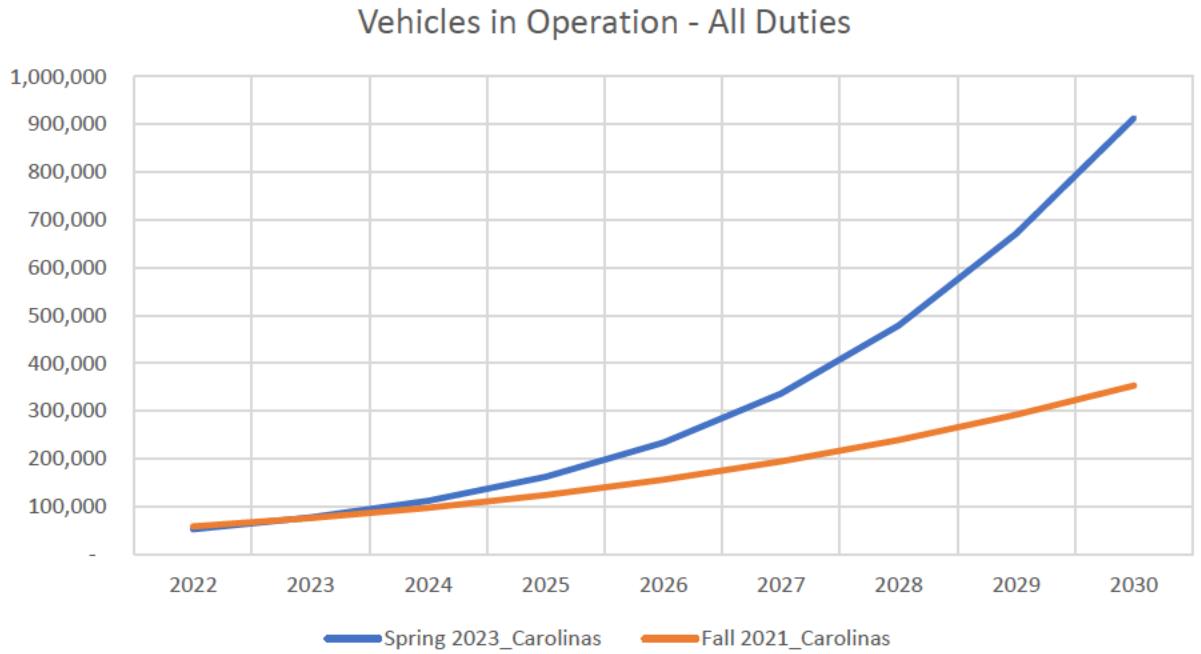


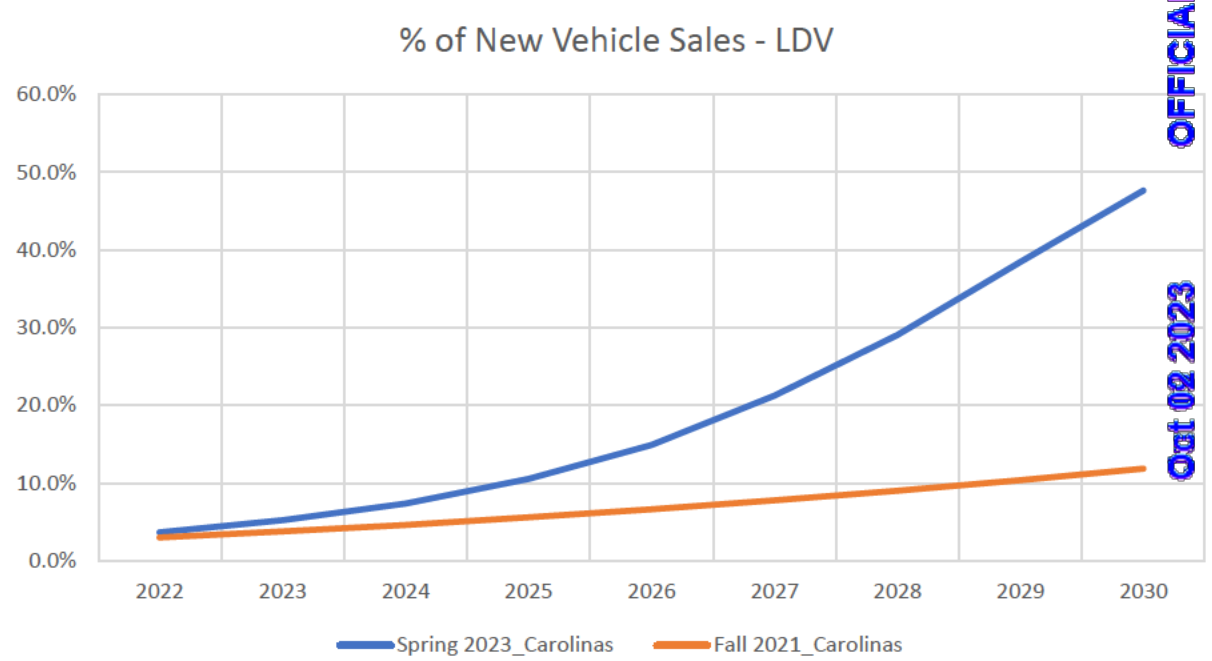


## Key Drivers:

18 months of updated data on all variables:

- Updated forecast includes IRA and IIJA and other legislative impacts
- Current vehicle registrations
- PEV model market availability driven by OEM announcements and manufacturing updates and pledges, ICEV bans in impactful states, policy updates, etc.
- Battery cost projections

# Customer Growth Rate Historical and Projected



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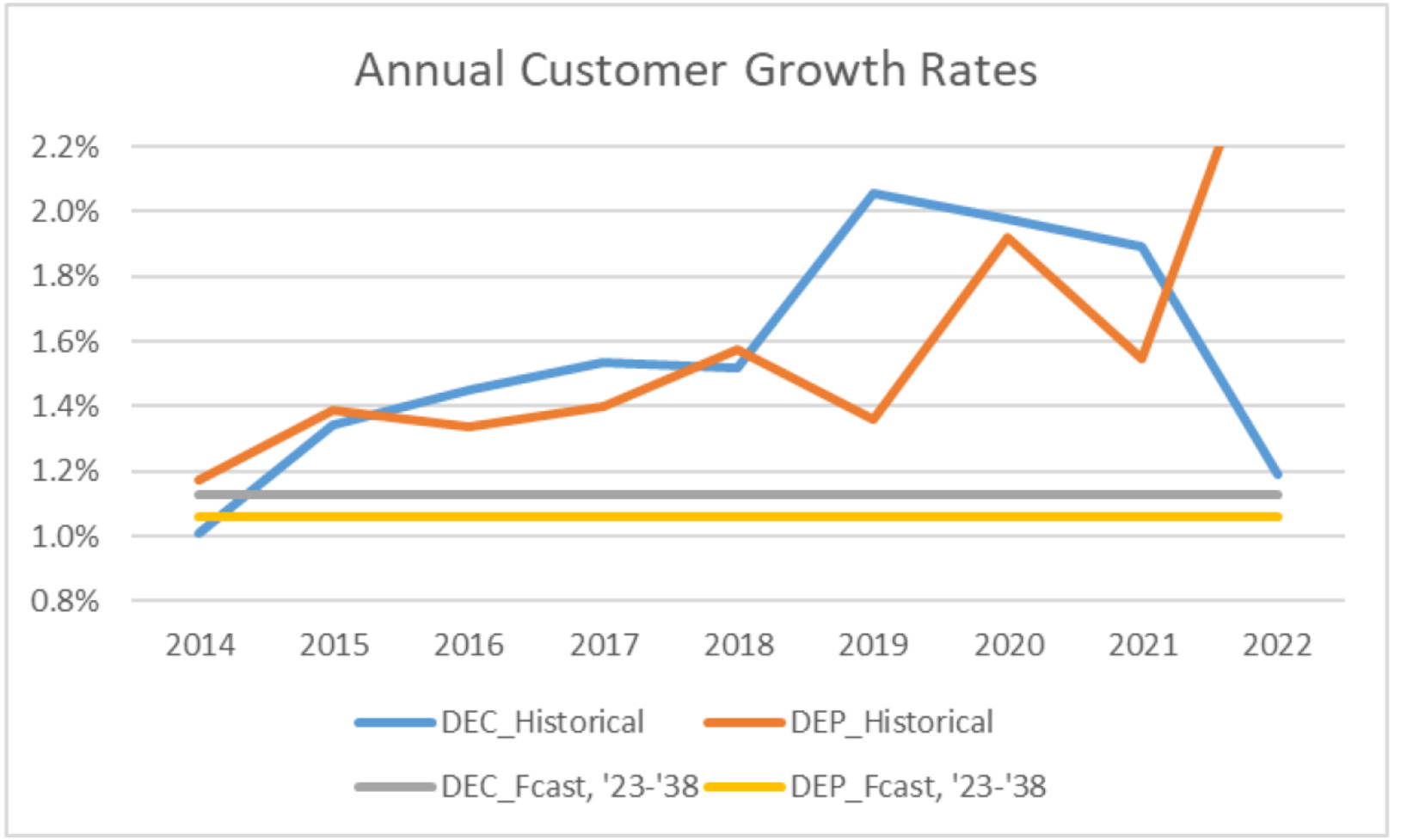

# 2023 Load Forecast Conclusion and Review



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**Short-term fragility of weather and economic conditions**

- Variability of the reading on the economy

**Measurement of long-term forces that will support the forecast has increased:**

- Significant economic development growth
- Population growth
- Electric vehicles

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# Break

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# Resource adequacy study

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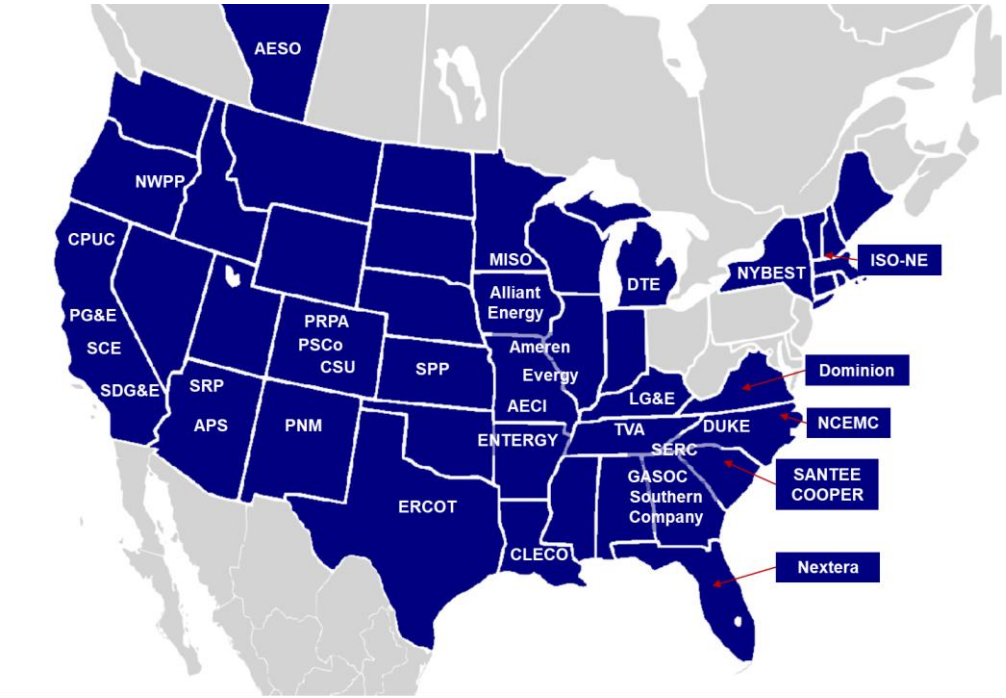
- **Owner and Exclusive Licensor of SERVM**
  - Nation's leading resource adequacy model
  - Full hourly economic commitment and dispatch for thousands of weather, unit performance, economic growth scenarios
- **Resource Adequacy Studies**
  - Planning Reserve Margin, ELCC, Demand Response Evaluations, Market Design Assessments, Probabilistic Risk Assessments
- **Renewable Integration, Expansion Planning, Energy and Capacity Resource Valuations**

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# PRM Study Methodology



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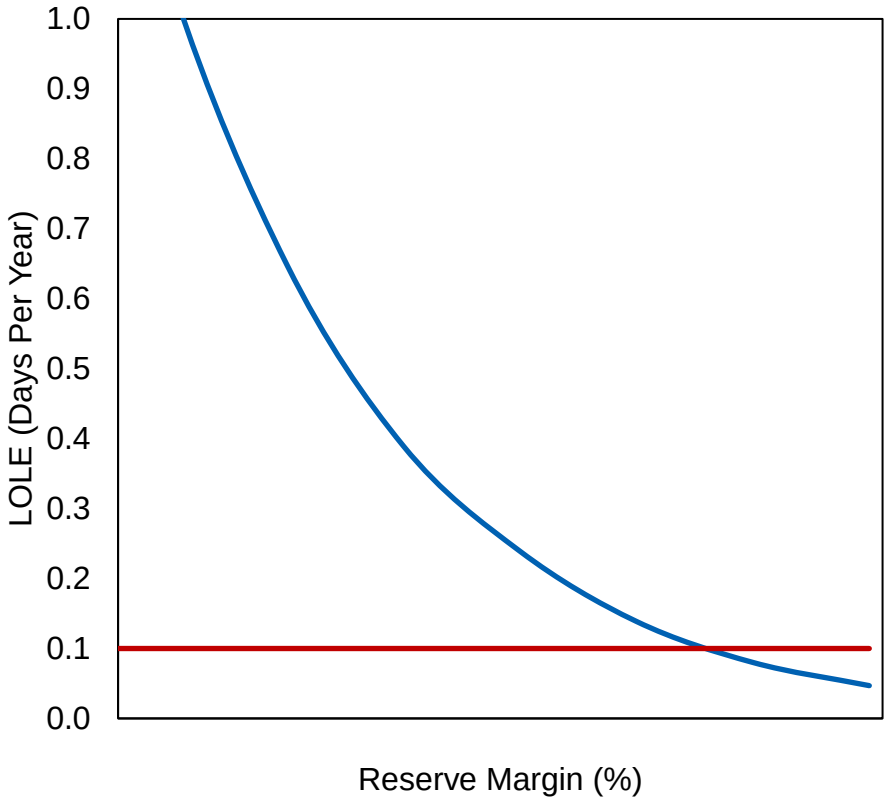
- Planning Reserve Margin (PRM) - defined as the percentage by which the total capacity of system resources exceeds the forecasted peak load
- Loss of Load Expectation (LOLE) – number of days in a year that customer load is shed
- Methodology - Determine the reserve margin that achieves LOLE of 0.1 days/year; Also known as the 1 day in 10-year standard across the electric industry

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# SERVM Framework



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- **Capture Uncertainty in the Following Variables for the 2027 Study Year**
  - Weather: 43 years of weather history (1980-2022) with equal probability of occurrence
    - Impact on Load and Resources (hydro, wind, PV, temp derates on thermal resources)
  - Economic Load Forecast Error: Distribution of 3 points with varying probabilities of occurrence
  - Unit Outage Modeling (40 iterations for each load scenario)
- **Multi-Area Modeling – Pipe and Bubble Representation**
- **Total Base Case Scenario Breakdown**

| | | | | |
|---|---|---|---|---|
| **43**<br>**Weather Years**<br>(Equal Probability) | x | **3**<br>**LFE Points**<br>(Associated Probabilities) | = | **129**<br>**Load Scenarios**<br>(Associated Probabilities) |
| **129**<br>**Load Scenarios** | x | **40**<br>**Unit Outage Draws** | = | **5,160**<br>**8760 Hour Simulations** |

- **Adjust capacity with peaking resources to reach the 1 day in 10 year standard = 0.1 Loss of Load Expectation (LOLE)**

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# 2023 Resource Adequacy Key Drivers



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- **Cold Weather Load Response and Long Term Economic Load Forecast Error**
- **Generating Availability Data System (GADS) Data for DEC and DEP (5-year period 2018-2022)**
- **Weather related forced outages for DEC and DEP**
- **Updates to Neighbor Resource Plans**

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# Load Modeling

# Approach for Incorporating Weather Uncertainty on Load



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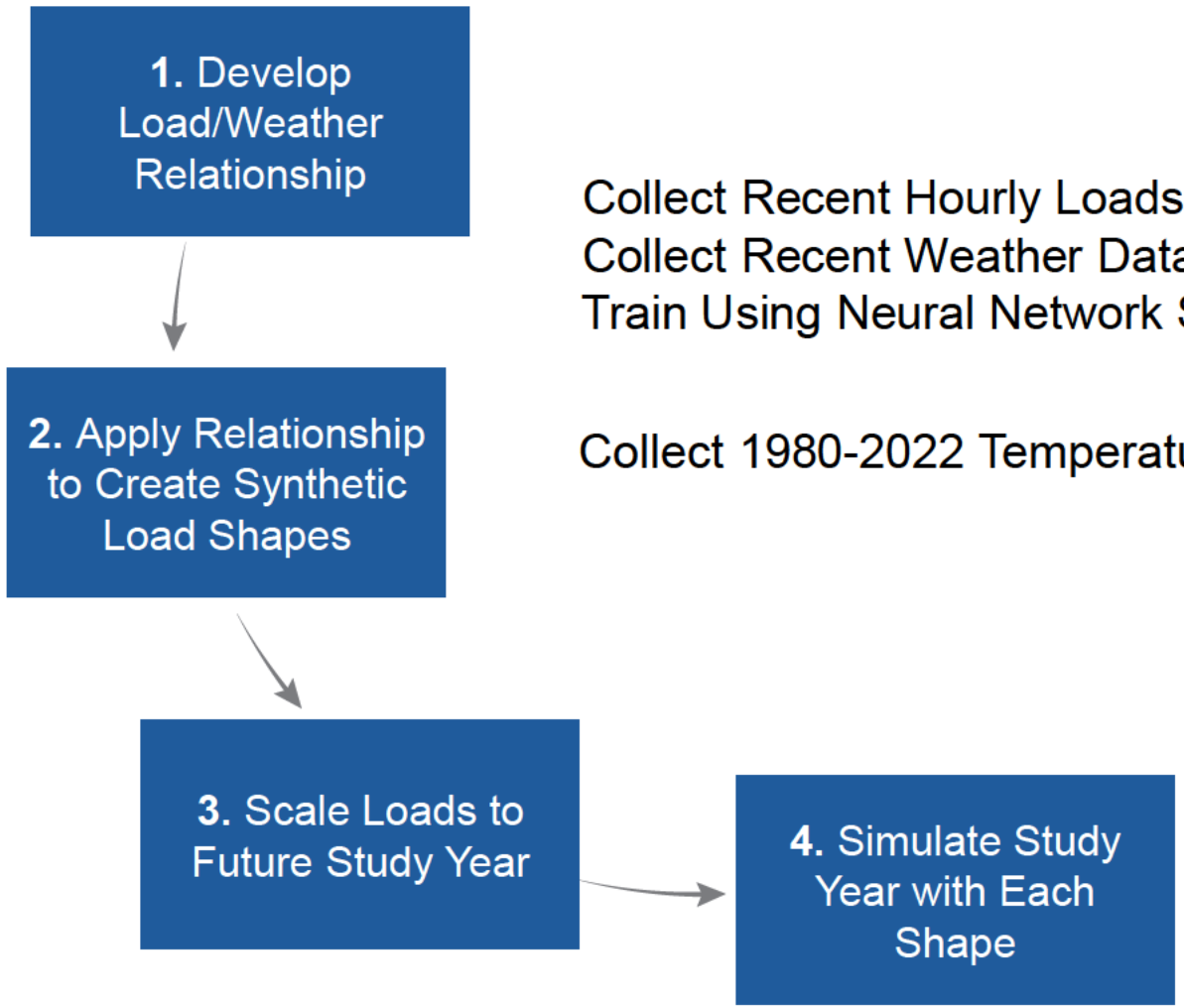


Collect Recent Hourly Loads (01/2018-12/2022)
Collect Recent Weather Data (01/2018-12/2022)
Train Using Neural Network Software

Collect 1980-2022 Temperature Data

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# Load/Weather Modeling



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- **Monthly Neural Net Training Data**
  - Weather Stations (2018-2022)
  - Hourly Temperature
  - 24, and 48 Hour Prior Temperature
  - Day of Week
  - Time of Day (1-24)
- **Actual Loads – 2018-2022**
  - Scaled to 2022 equivalent loads

| DEC | Weighting |
|---|---|
| Charlotte, NC | 33.3% |
| Greensboro, NC | 33.3% |
| Greenville, SC | 33.3% |

| DEP-E | Weighting |
|---|---|
| Columbia, SC | 10.0% |
| Raleigh, NC | 40.0% |
| Wilmington, NC | 30.0% |
| Fayetteville, NC | 20.0% |

| DEP-W | Weighting |
|---|---|
| Asheville, NC | 100.0% |

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# DEC Training Data All Hours 2018-2022



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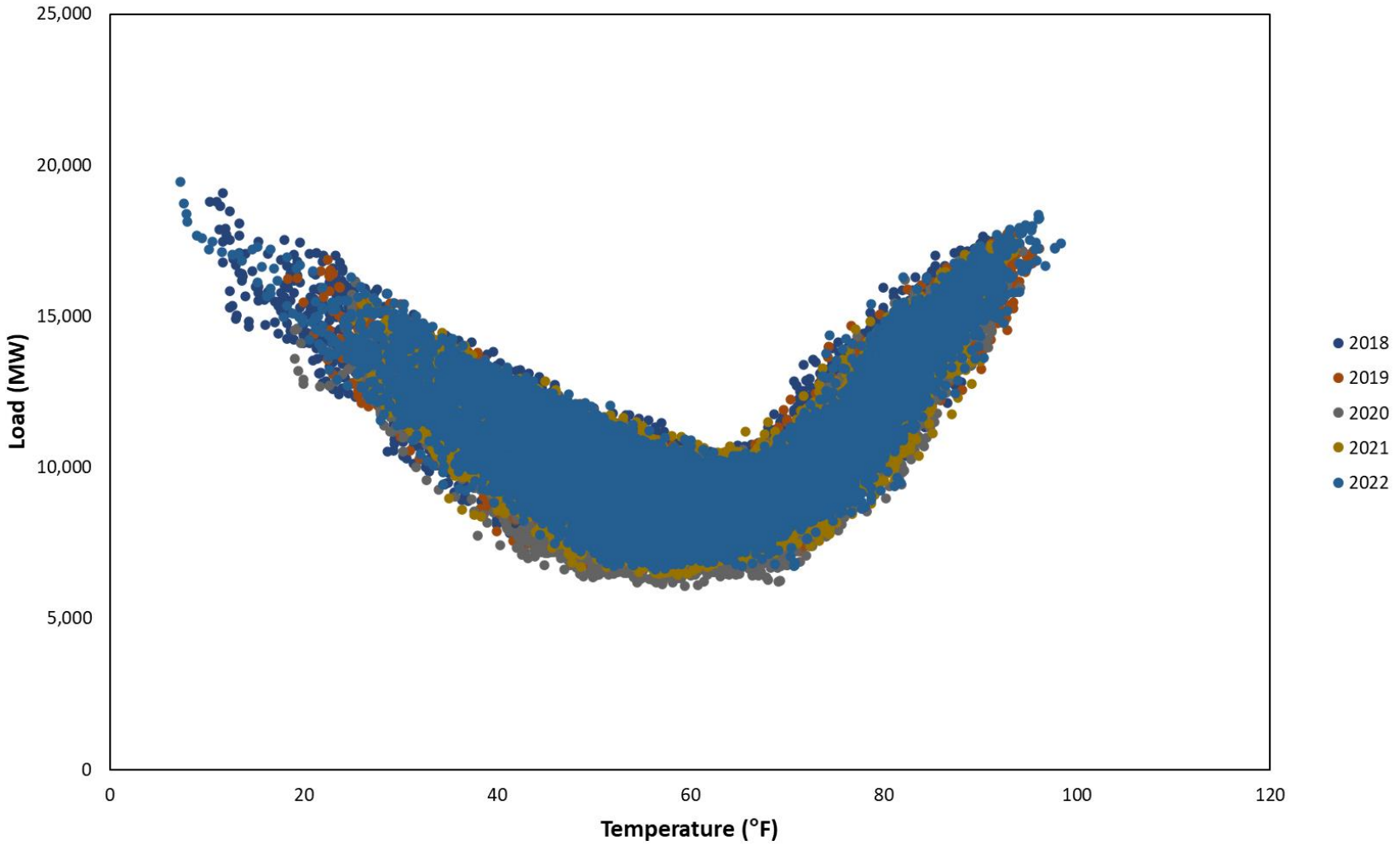


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# DEC Load Comparison- Winter Weekdays



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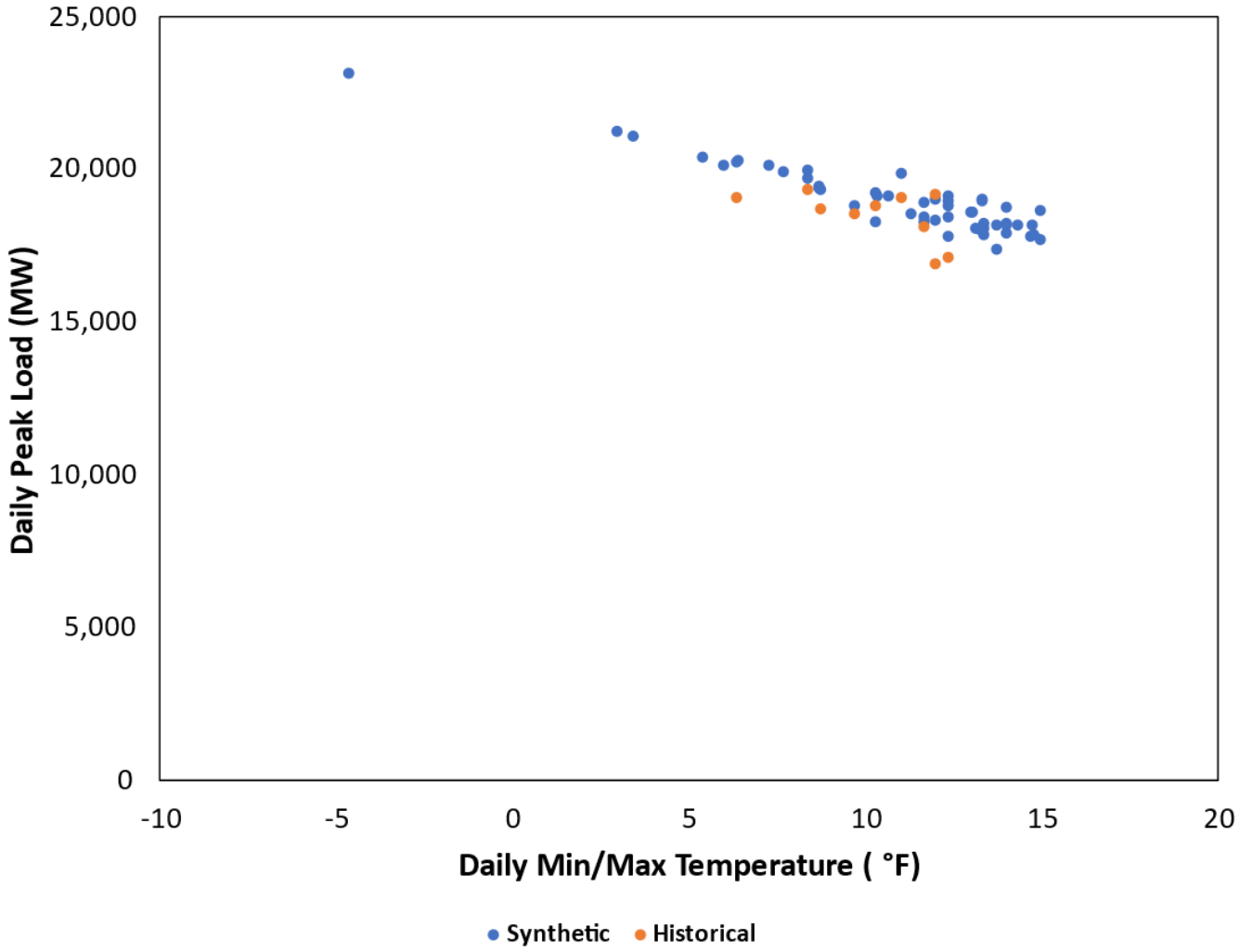


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# Updated Synthetic Loads DEC



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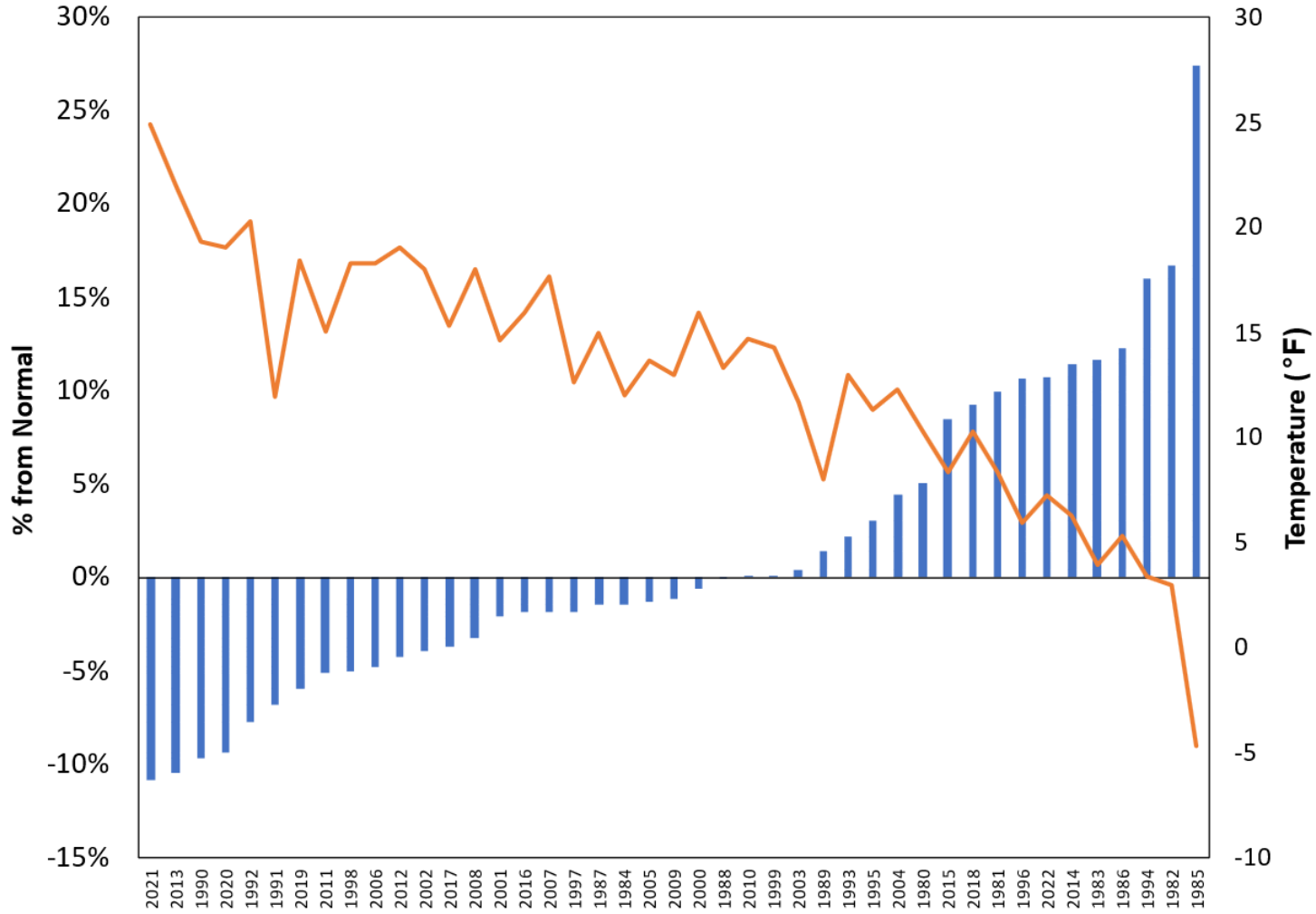


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# DEP-E Training Data All Hours 2018-2022



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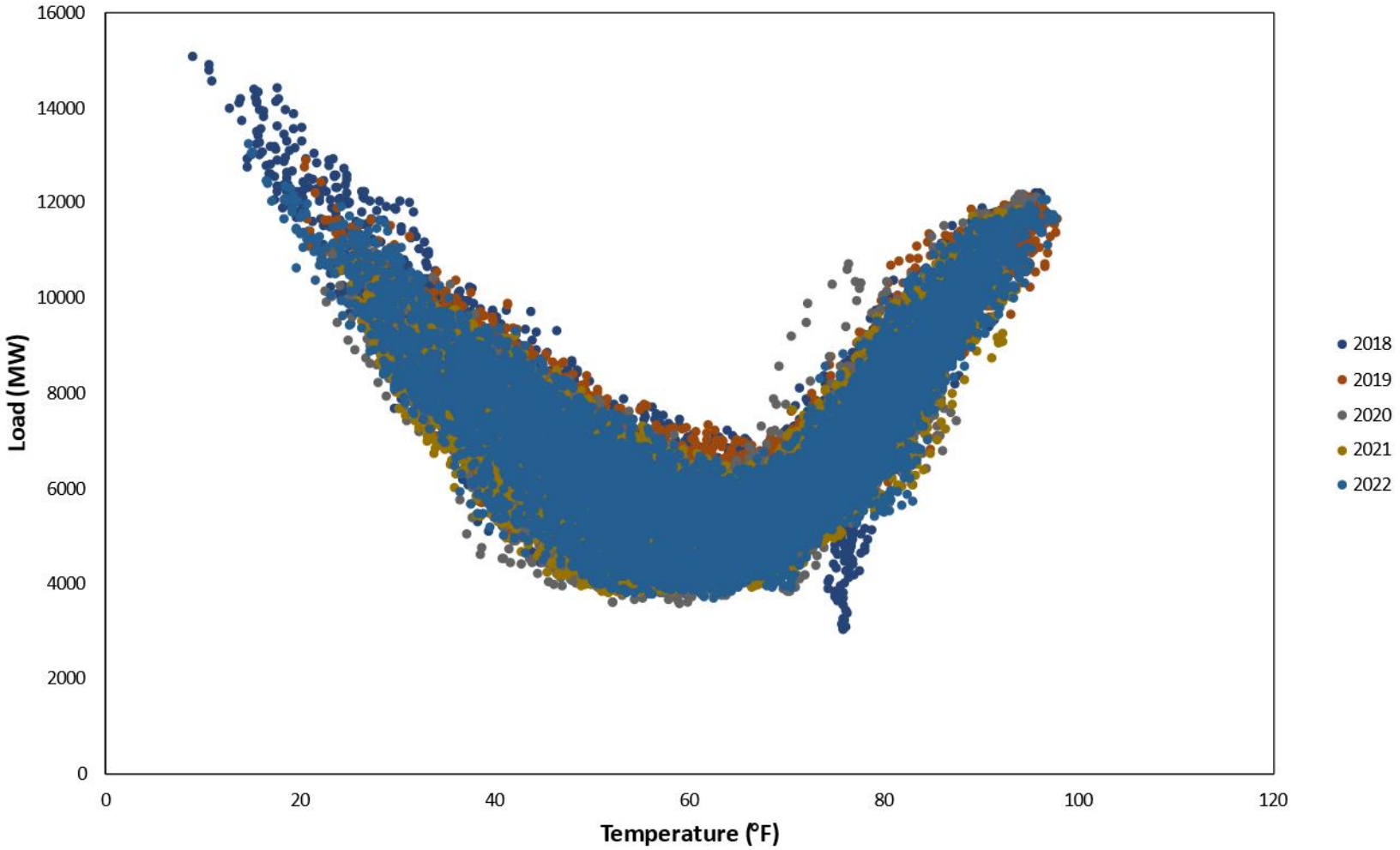


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# DEP-E Load Comparison- Winter Weekdays



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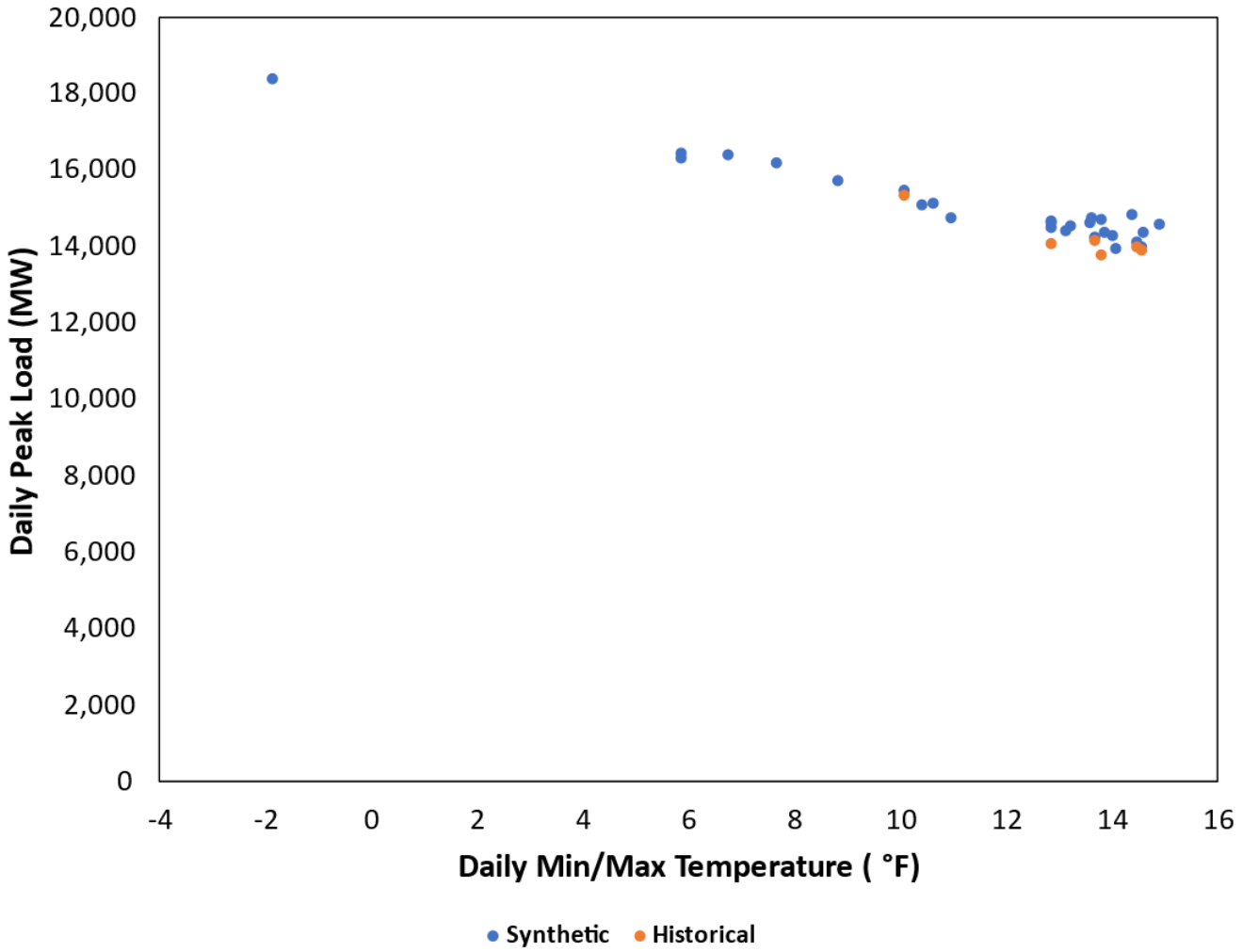


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# Updated Synthetic Loads DEP-E



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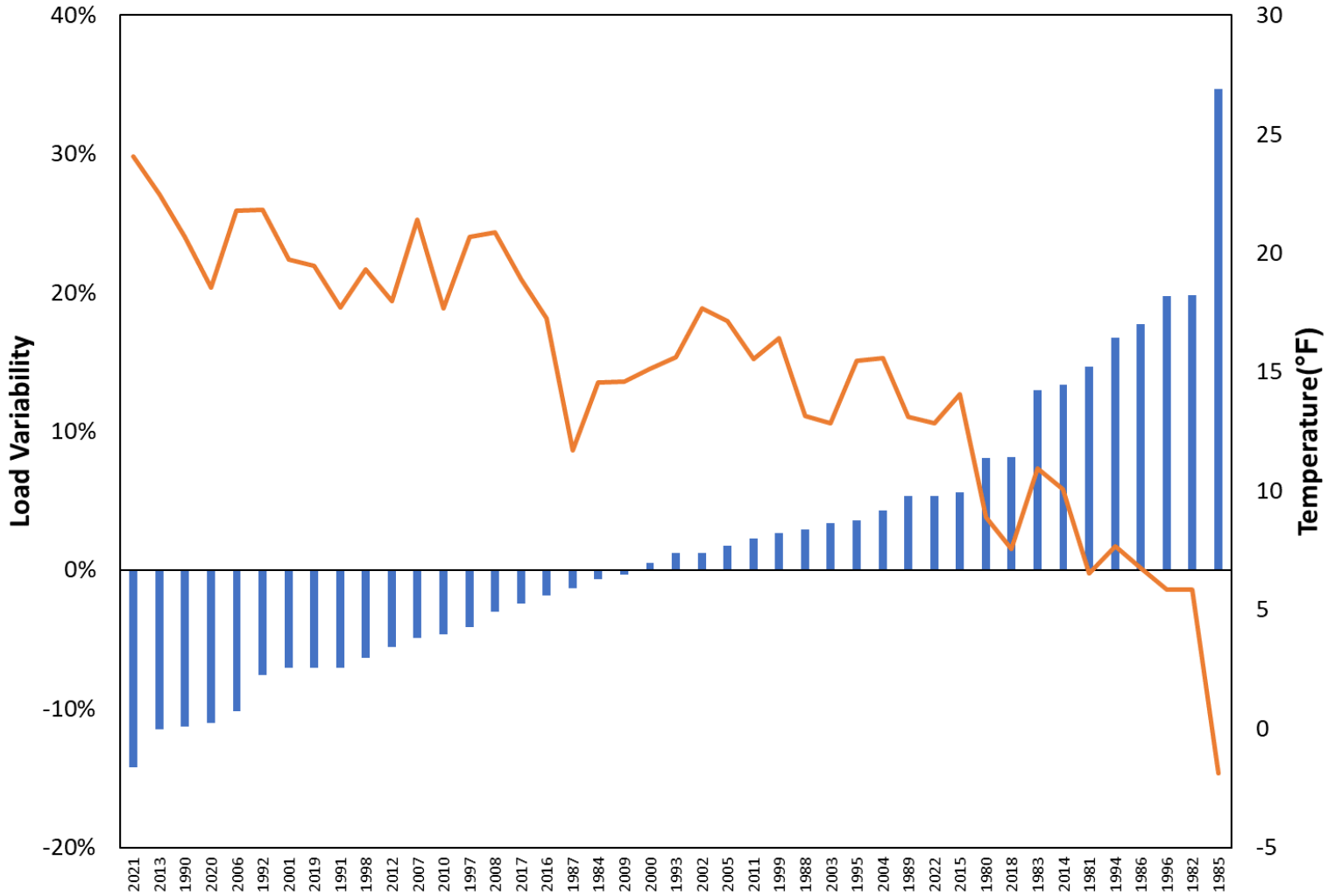


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# DEP-W Training Data All Hours 2018-2022



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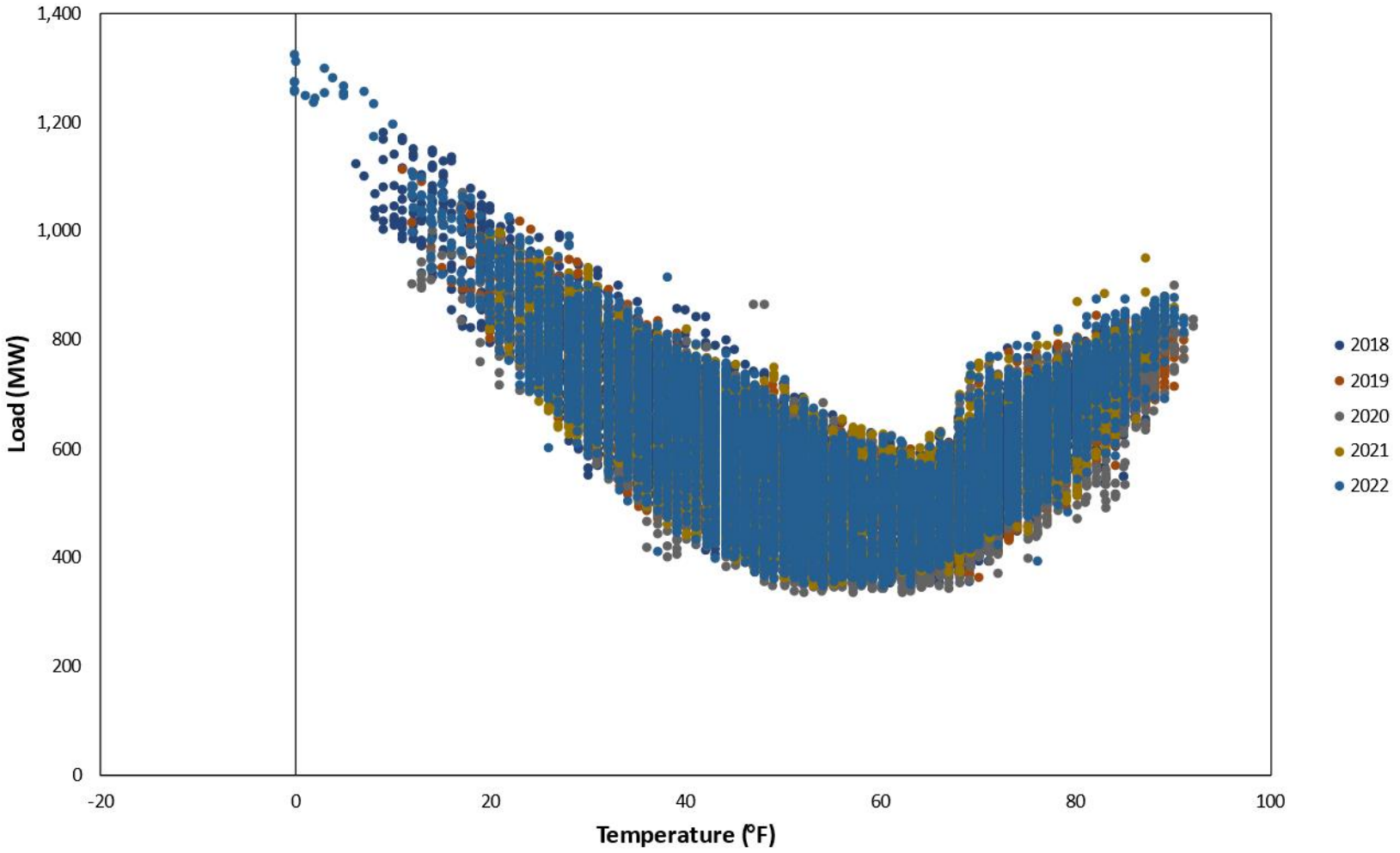


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# DEP-W Load Comparison- Winter Weekdays



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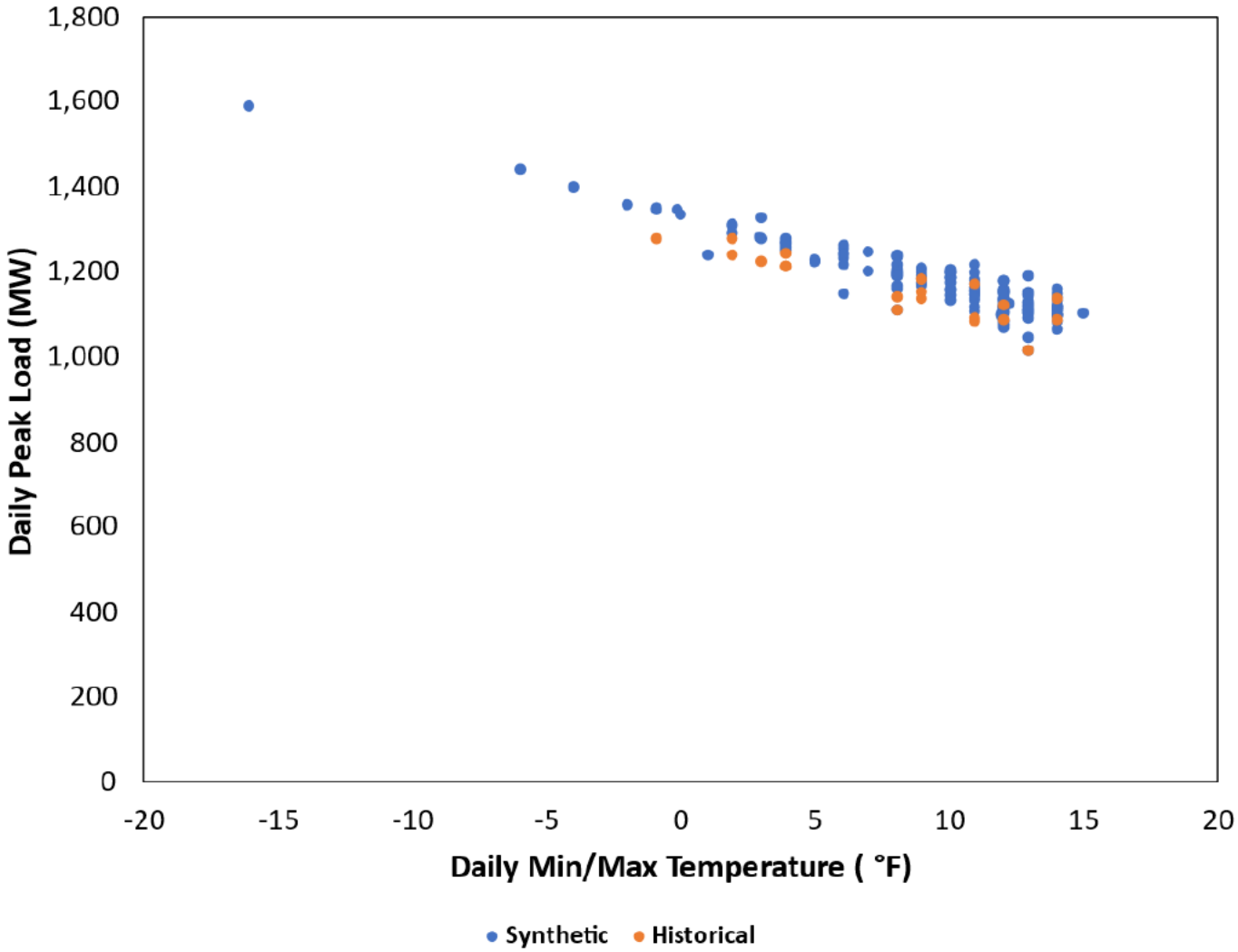


Draft: Preliminary findings.

# Updated Synthetic Loads DEP-W



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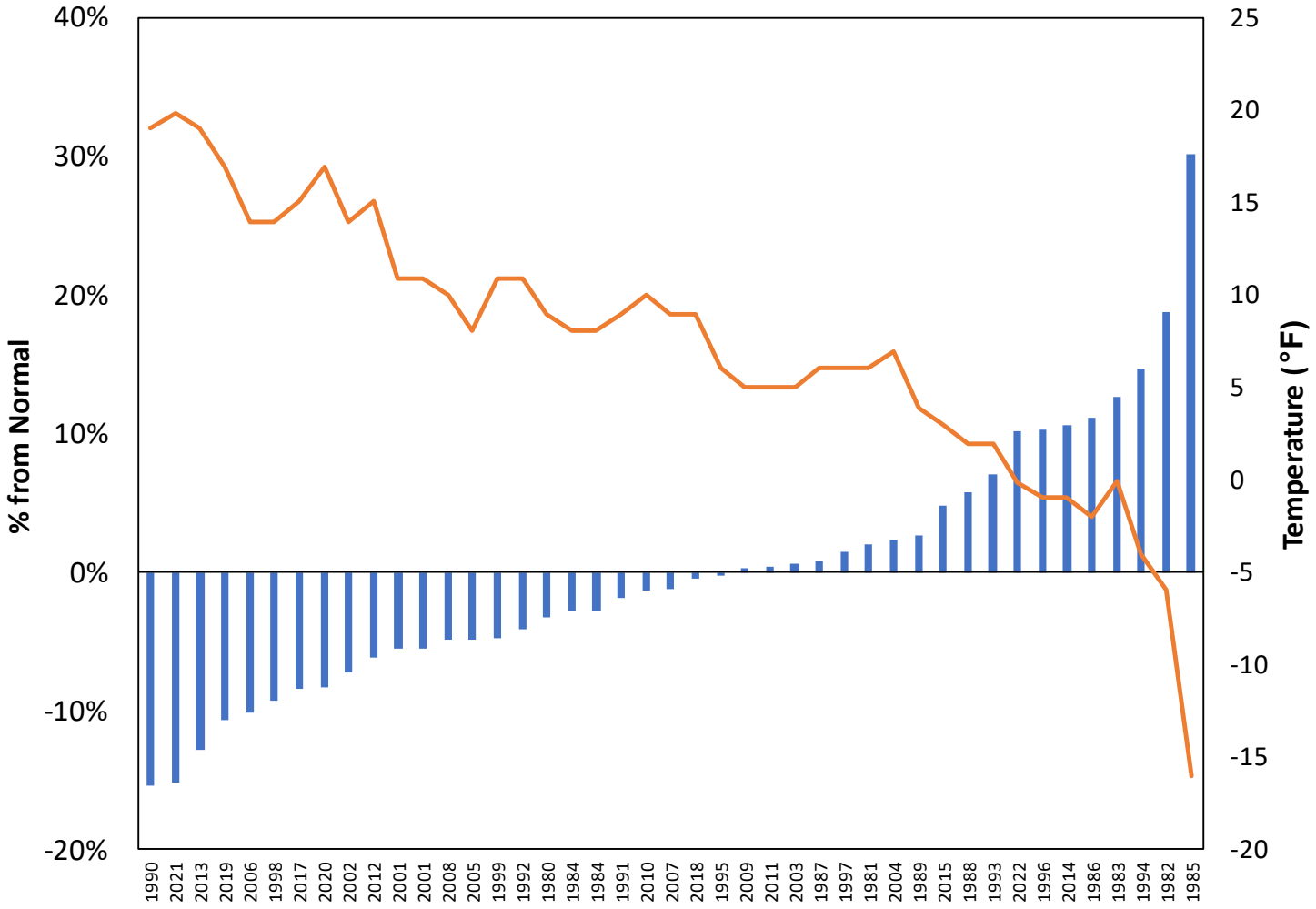


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# Updated Economic Load Forecast Error



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## 2023 Study

| Over/Under Load Forecast (Positive is Under Forecast) | Probability |
|---|---|
| -1.94% | 27% |
| 0.0% | 46% |
| 2.31% | 27% |

## 2020 Study - Asymmetrical

| Over/Under Load Forecast (Positive is Under Forecast) | Probability |
|---|---|
| -4.2% | 10% |
| -2.7% | 25% |
| 0% | 40% |
| 2.0% | 15% |
| 3.1% | 10% |

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# Outage Modeling

# Unit Outage Modeling



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- **Historical Data:  January 2018 - October 2022**
  - Full Outages
    - Time to Repair
    - Time to Failure
  - Partial Outages
    - Time to Repair
    - Time to Failure
    - Derate Percentage
  - Startup Failures
  - Maintenance Outages
- **Planned Outages based on projections**
- **Reviewed and Modeled Incremental Cold Weather Outages based on 5 Years of Data**

# Modeled Forced Outages as a Function Temperature
## Combined DEC and DEP



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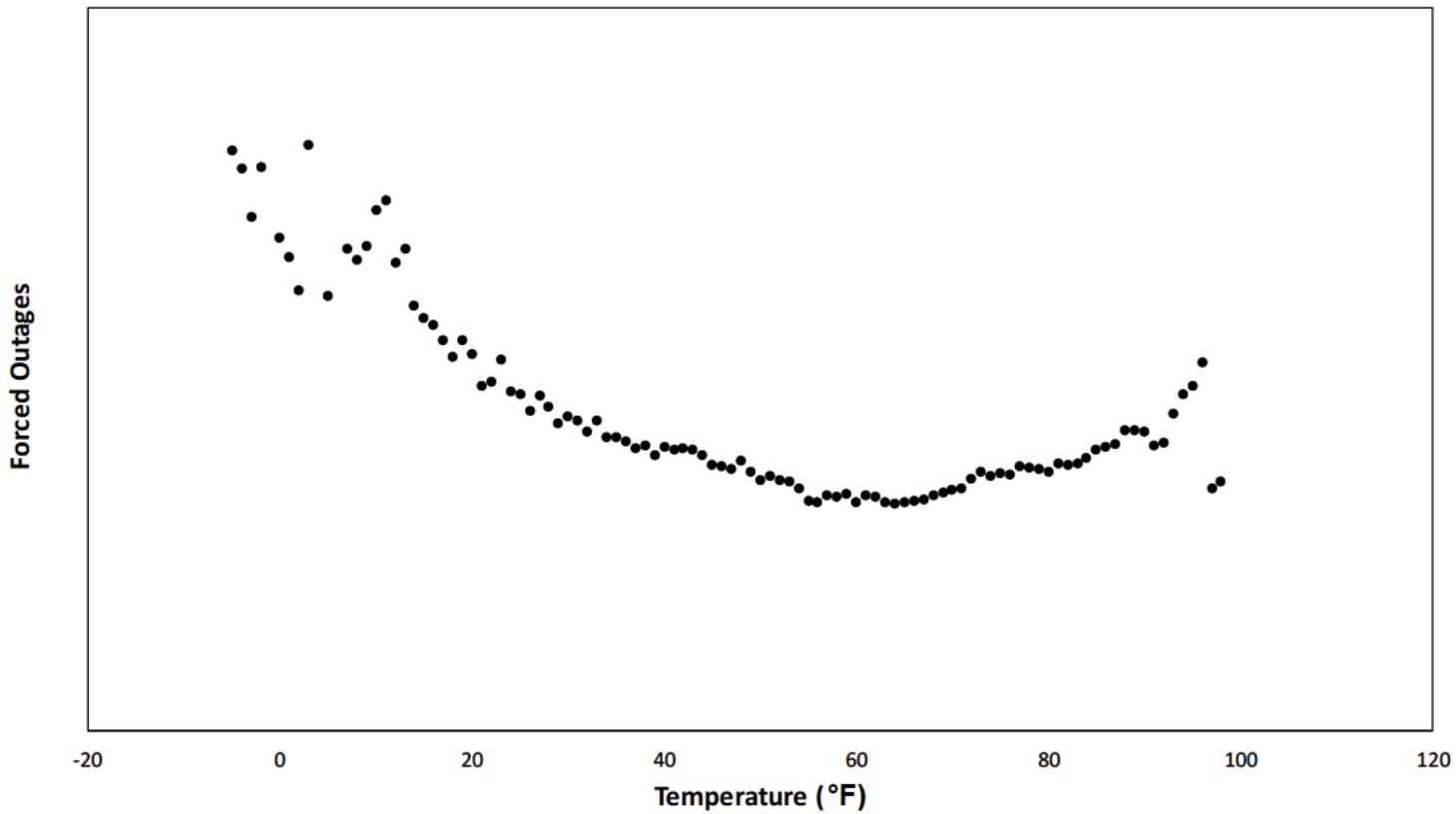


Modeled Outages based on 5 Years of Historical Data

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# Solar Modeling

# Solar Capacity Projections – 2027 Study Year



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| Solar Type | ILR | DEC Capacity (MW) | DEP Capacity (MW) |
|---|---|---|---|
| Fixed | 1.3 | 1,142 | 3,161 |
| Fixed | 1.6 | 121 | 239 |
| Tracking | 1.3 | 575 | 179 |
| Tracking | 1.6 | 258 | 164 |
| Bifacial | 1.4 | 809 | 765 |
| **Total** | | **2,905** | **4,507** |

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# Solar Profile Overview



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- **Solar profiles were created for each of the 102 locations on the following slide**
- **Solar irradiance data was downloaded from NREL NSRDB for 1998 – 2020 for each of the 102 locations**
- **Fixed tilt, monofacial single axis tracking, and bifacial single axis tracking profiles were developed using NREL SAM Software**
  - Profiles created with 1.0 inverter loading ratio
- **Weather years prior to 1998 and after 2020 were developed using daily peak load +/- 2 days matching methodology**
- **Profiles assigned inverter loading ratios (provided by Duke) within SERVM**

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# Solar Locations



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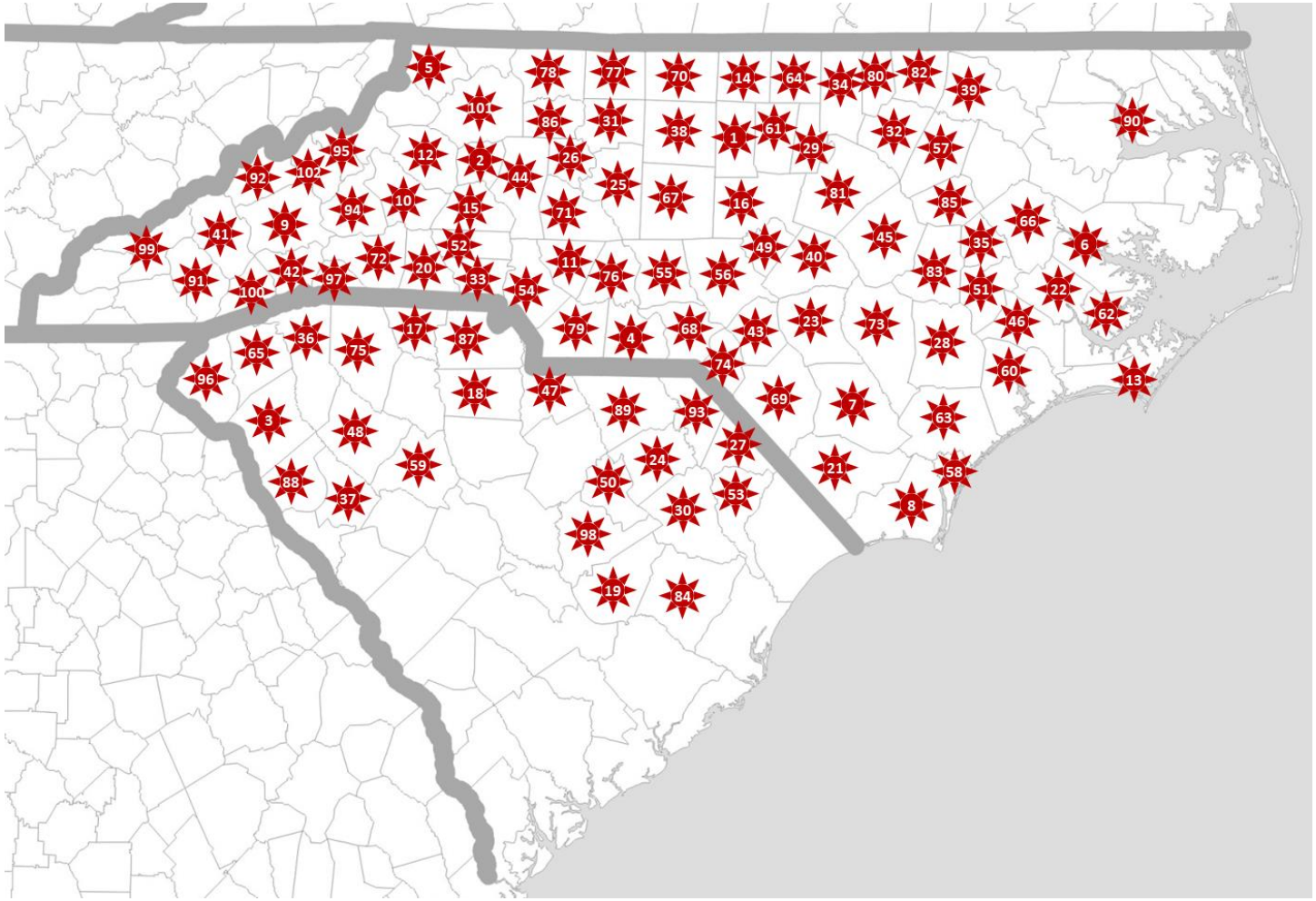


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# Yancey, NC Average August Daily Shape by Technology



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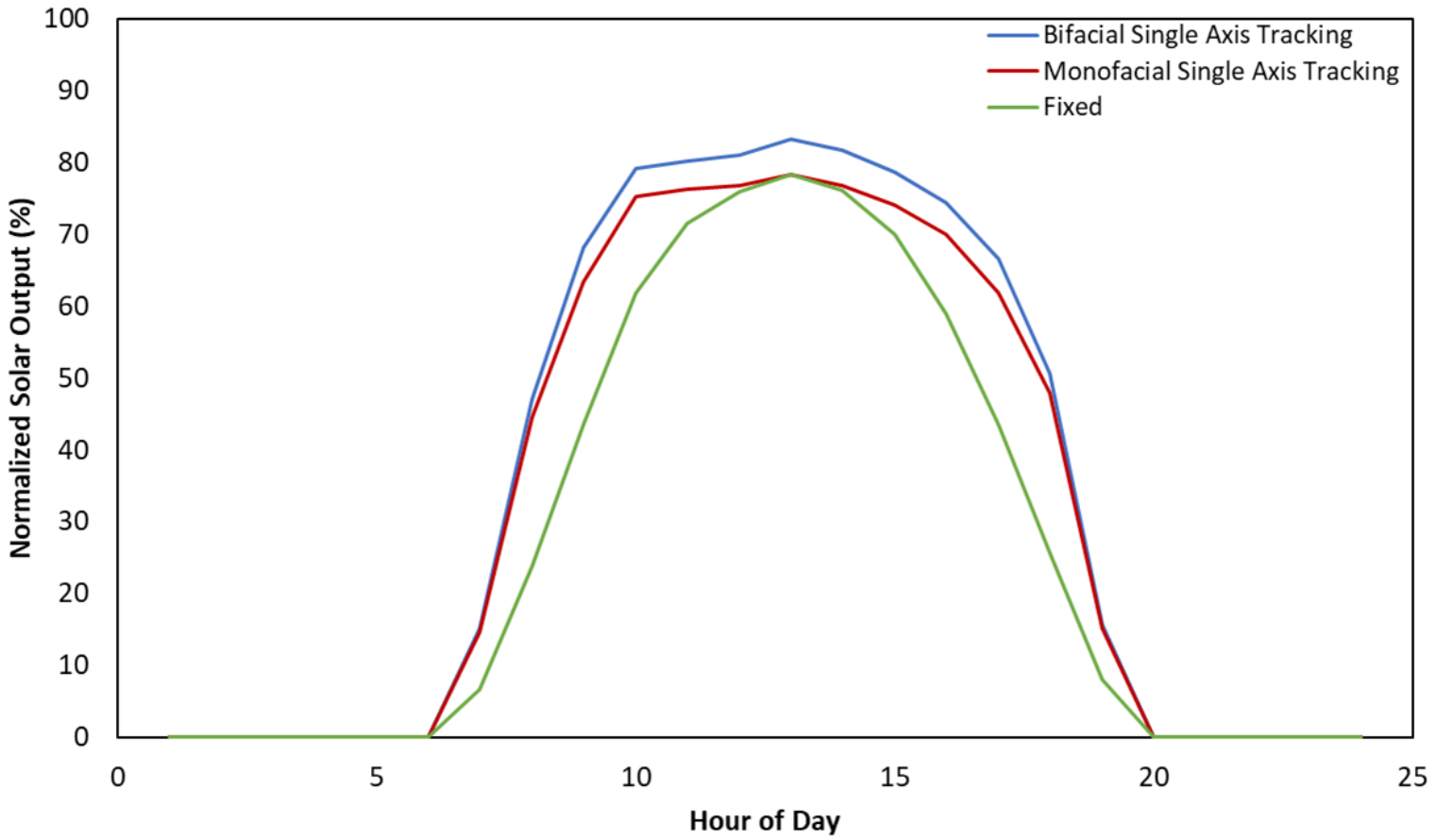


*Shown with a 1.3 ILR

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# Yancey, NC August Daily Shape Example



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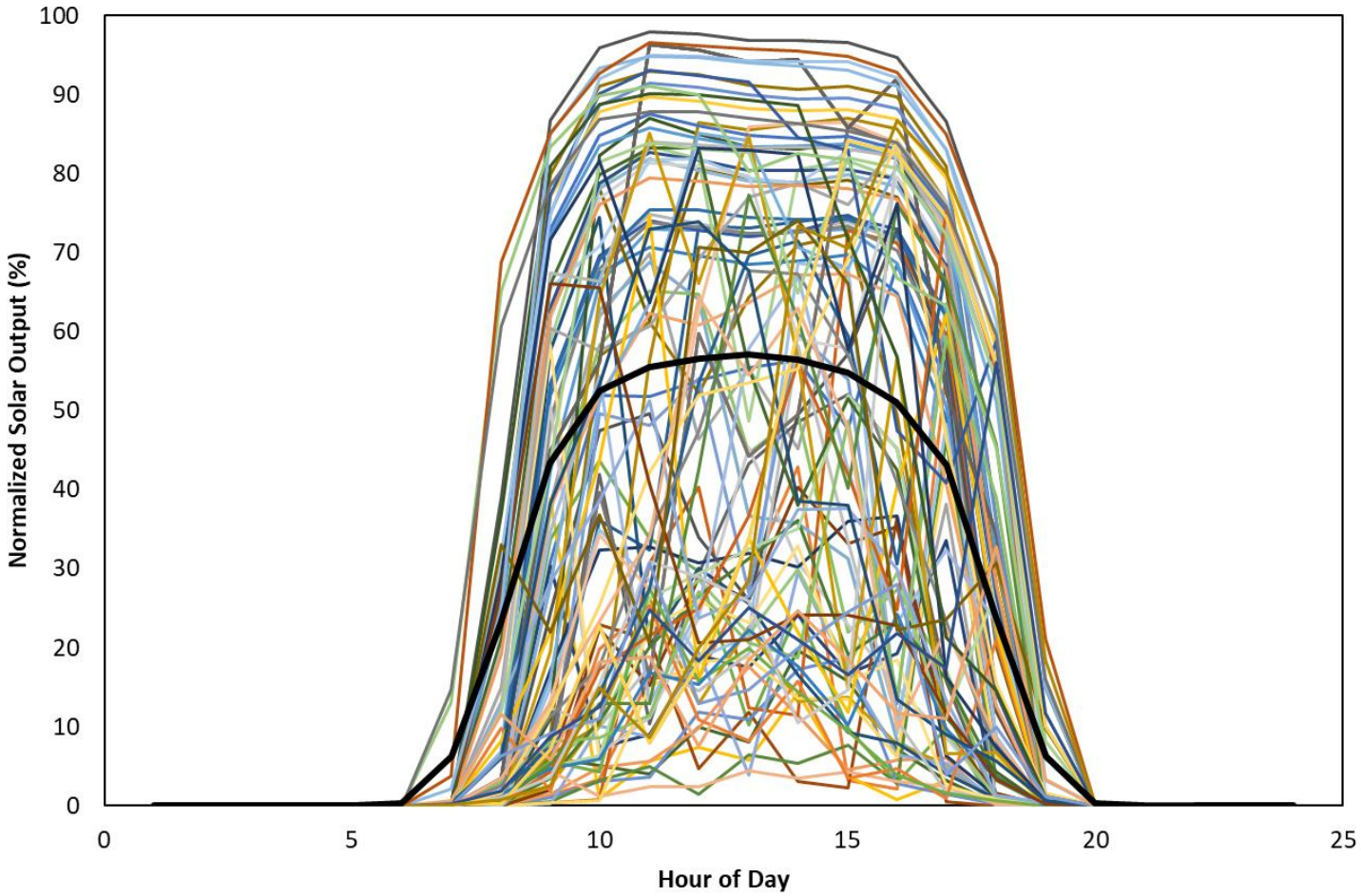


*Shown with a 1.0 ILR

** 100 August daily shapes selected at random as an example (1,333 total)

*** Bold black line is the average daily shape of all August shapes from 1980 – 2022

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# Demand Response Modeling

# DEC Demand Response Modeling



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| | Summer Capacity (MW) | Winter Capacity (MW) |
|---|---|---|
| DEC Energy Wise Business | 12 | 17 |
| Interruptible Service | 53 | 51 |
| Power Manager Residential | 658 | 125 |
| PowerShare Generator | 5 | 4 |
| PowerShare Mandatory | 468 | 435 |
| IVVC* | 190 | 190 |
| **Total** | **1,386** | **822** |

*Integrated Voltage/VAR Control

Draft: Preliminary findings.

# DEP Demand Response Modeling



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| | Summer Capacity (MW) | Winter Capacity (MW) |
|---|---|---|
| Demand Response Automation | 48 | 30 |
| IVVC* | 149 | 149 |
| Energy Wise Home | 497 | 77 |
| Energy Wise Business | 5 | 10 |
| Large Load Curtailable | 207 | 168 |
| **Total** | **906** | **434** |

*Integrated Voltage/VAR Control

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# Neighbor Modeling

# Regional Resource Mix Changes



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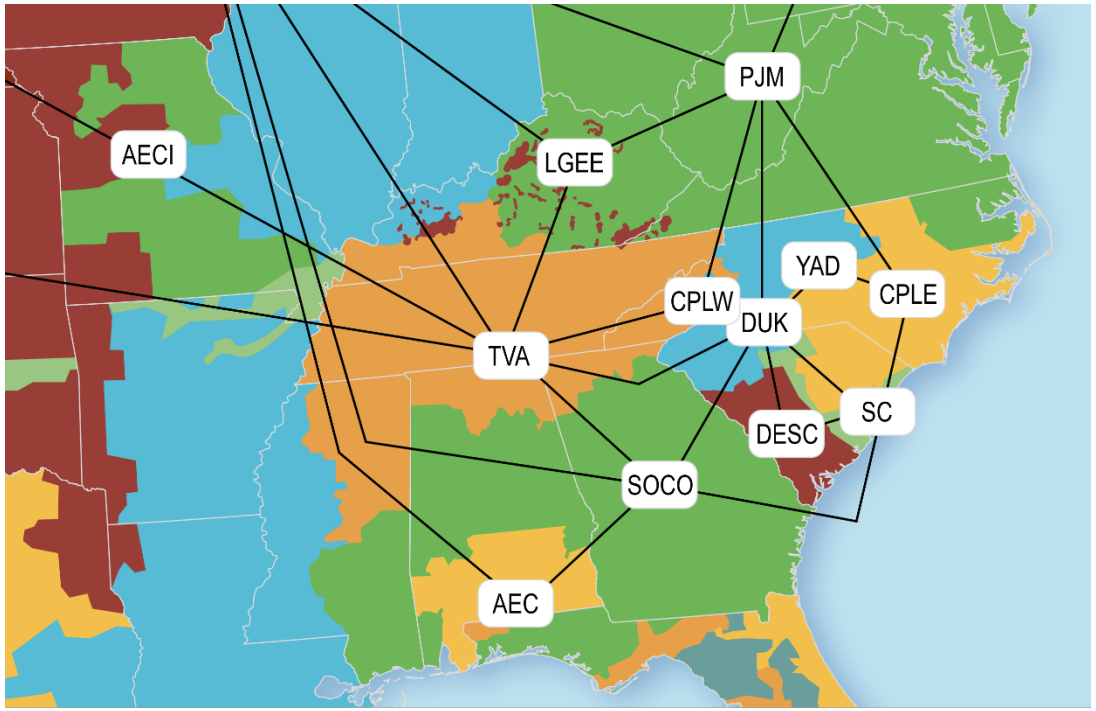
- **Updated surrounding region resource mix for the 2027 study year**
  - Coal Retirements
  - Increases in Solar, Wind, and Storage
  - Significant Cold Weather Load Response
  - Target 0.1 for each surrounding BA
- **Shifts resource adequacy risk to the winter providing less market assistance on extreme cold days.**

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# Results

# 2023 Resource Adequacy Results



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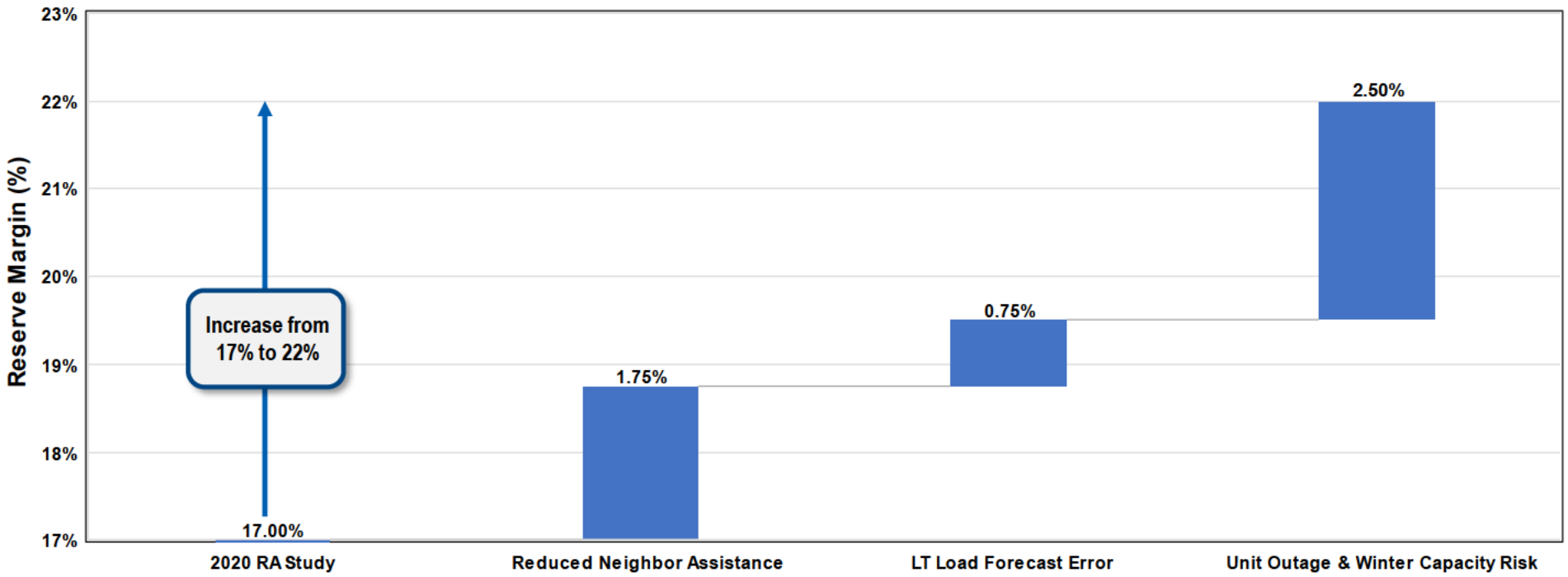


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# Base vs. Island Case Results



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| | DEC | DEP | Combined Case |
|---|---|---|---|
| **Base Case** | 20.75% | 23.25% | 22.00% |
| **Island Case** | 28.50% | 26.00% | 24.50% |

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# LOLE by Month – Combined Case



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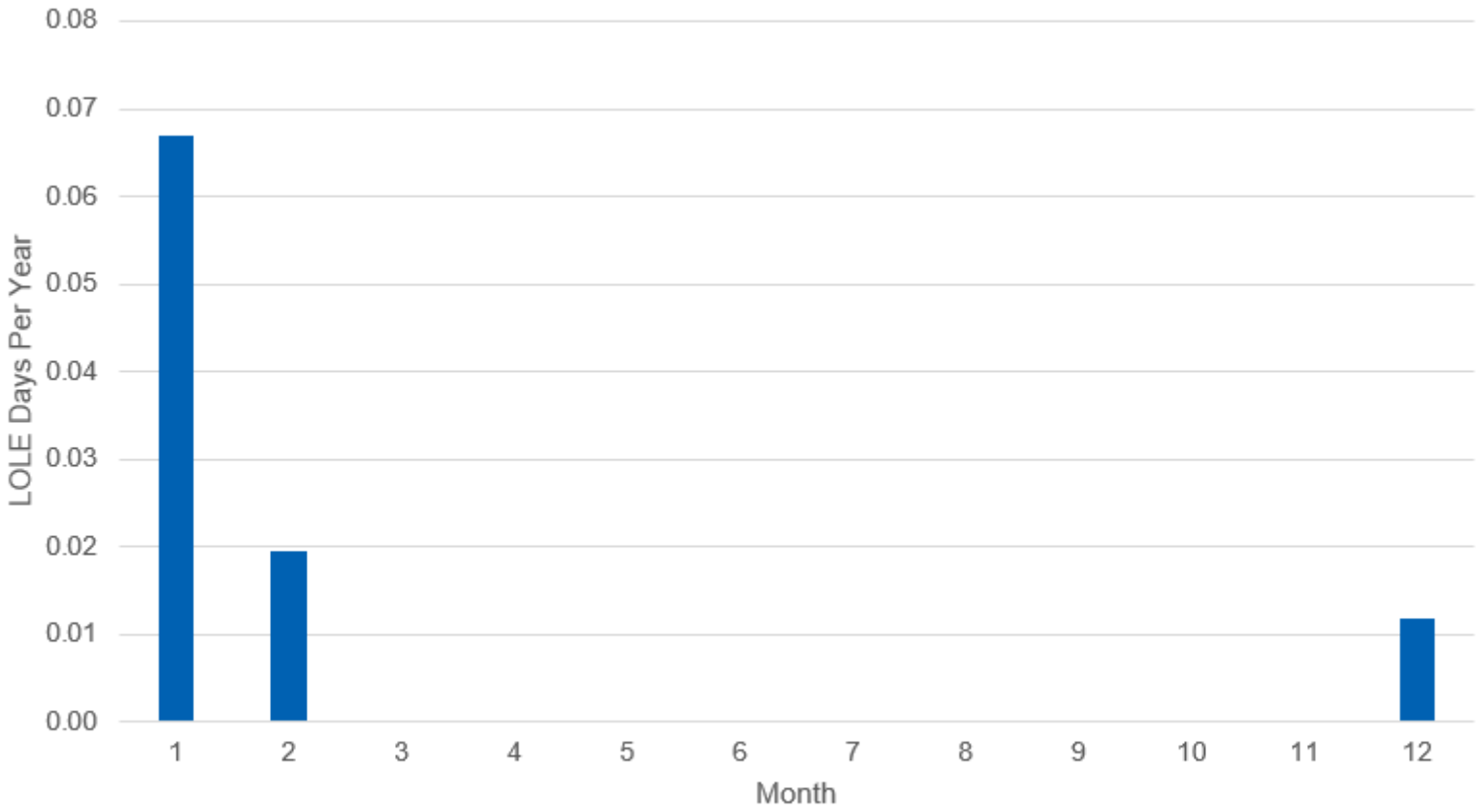


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# Modeling IRA Impact

DUKE ENERGY®

BUILDING A SMARTER ENERGY FUTURE®

# Inflation Reduction Act



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The Inflation Reduction Act (IRA) of 2022 makes the single largest investment in climate and energy in American history, enabling America to tackle the climate crisis, advancing environmental justice, securing America's position as a world leader in domestic clean energy manufacturing, and putting the United States on a pathway to achieving the Biden Administration's climate goals, including a net-zero economy by 2050.[1]

On August 16, 2022, President Biden signed the Inflation Reduction Act into law, marking the most significant action Congress has taken on clean energy and climate change in the nation's history.[2]

The DOE estimates that the Inflation Reduction Act, in combination with the IIJA and other actions, will lead to a reduction of 40% in economy wide greenhouse gas emission below 2005 levels by 2030.[2]

Source:
[1] Inflation Reduction Act of 2022, energy.gov
[2] Inflation Reduction Act Guidebook, whitehouse.gov

# Incentives for Modeling



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## Investment Tax Credit (48E)

- Investment Tax Credit (ITC) is a capital credit
- ITC is expressed in percentage – 30% ITC translates into about a 30% reduction in capital
- Applied as either normalized (over life of asset) or non-normalized (taken immediately)
- Utilities must normalize ITCs EXCEPT for storage
- ITC is chosen most often for high capital and/or low-capacity factor projects
- ITC is the only credit available for batteries and pumped storage

Section 48 – Applies to 2022-2024 in service

Section 48E – Applies to 2025 and beyond

## Production Tax Credit (45Y)

- Production Tax Credit (PTC) is an O&M type credit
- PTC is expressed as a cent/kWh or dollar/MWh and is based on production
- PTCs are available for first 10 years of operation and are inflation adjusted
- PTC is chosen most often for high-capacity factor projects
- PTCs can be riskier because production is not assured
- PTCs are also available for existing nuclear (45U)

Section 45 – Applies to 2022-2024 in service

Section 45Y – Applies to 2025 and beyond

# Potential Ranges of ITC/PTC



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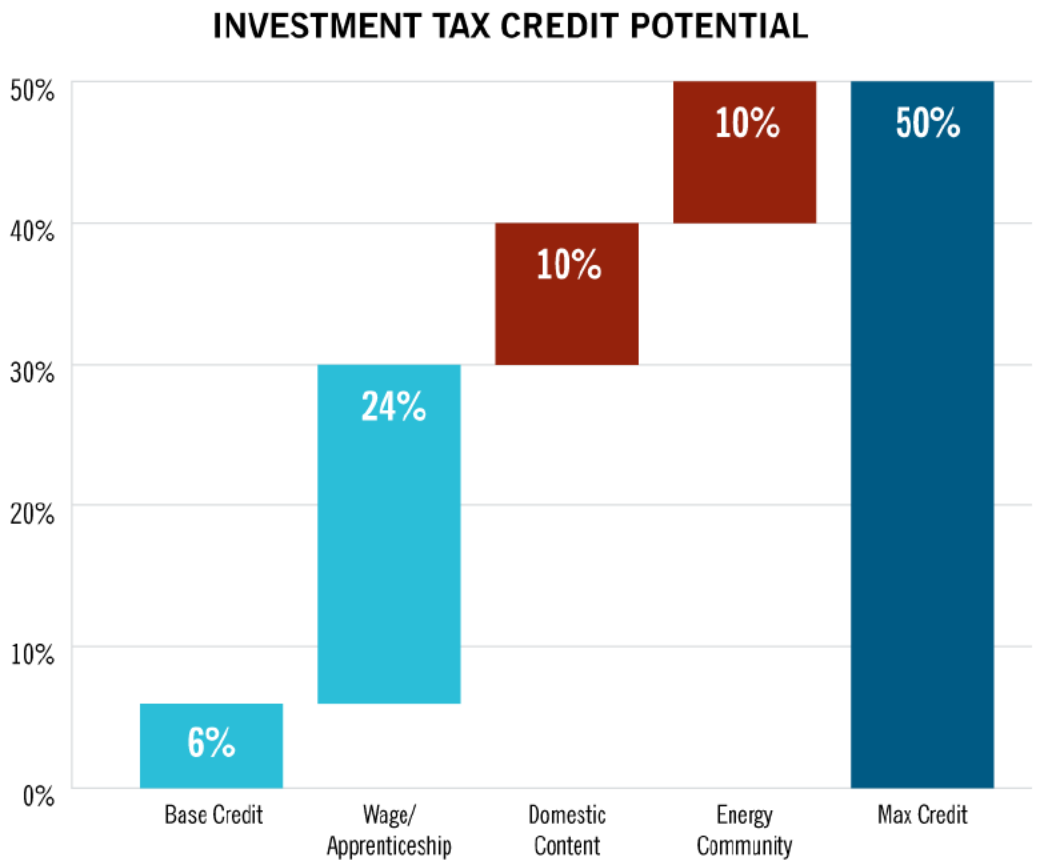


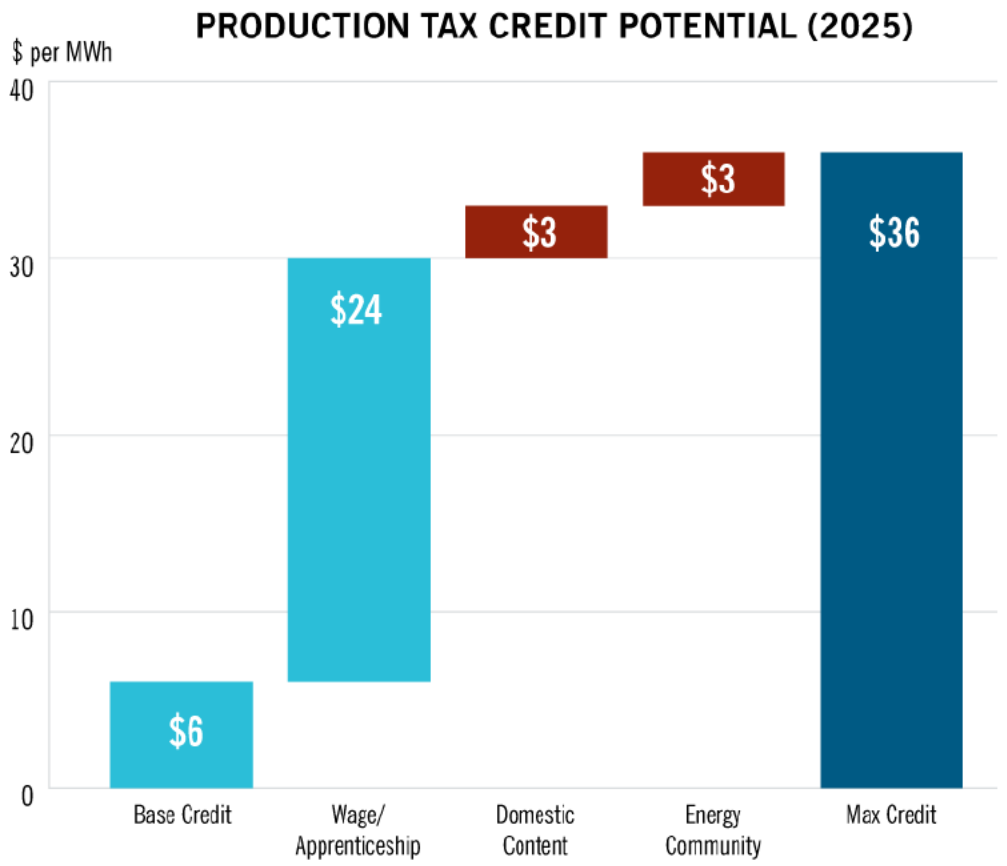


<5 MW solar, wind and associated storage can receive up to 70% ITC with statutory limits

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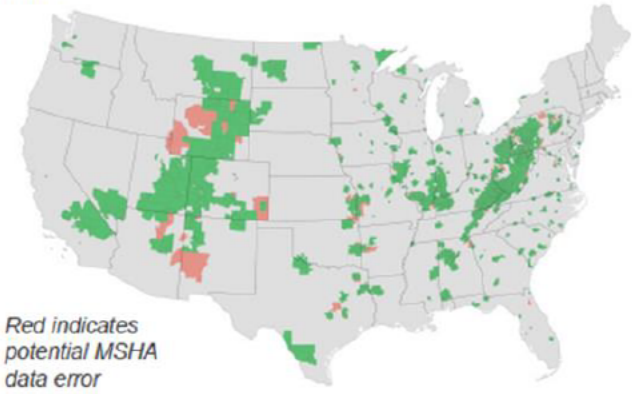
# Energy Communities

## Coal Closure Category

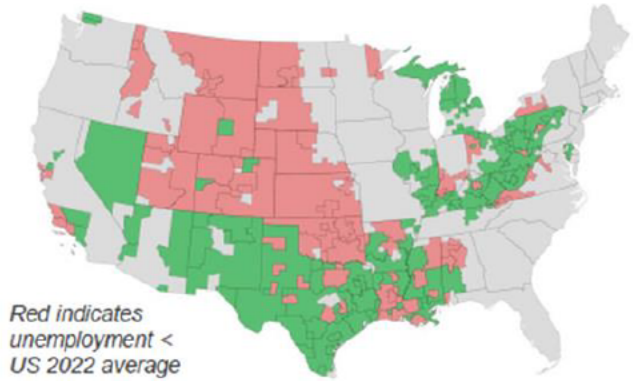
Census tracts neighboring retired coal mines or coal-fired electric generating units




DEC/DEP have several potential sites with coal already retired or coal retiring in the near term.

## Statistical Area Category

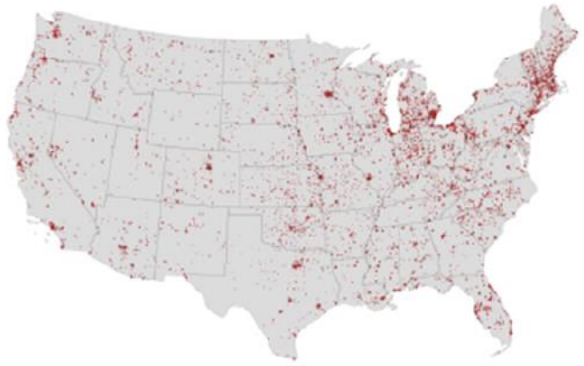
Metro / sub-state areas with historical employment in fossil industries **and** higher unemployment than US average




DEC/DEP are projected to have no sites in this category.

## Brownfield Category

Properties with the potential presence of hazardous substances, pollutants, or contaminants



DEC/DEP may have some potential small sites, but more study is warranted, and most sites will not be large enough for solar or wind.

Maps from CRA, Inflation Reduction Act Energy Communities, April 13, 2023 Presentation

# Domestic Content



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**Qualified Facility**

- 100% of all iron and steel components must be produced in the U.S.
- 40% of all “manufactured products” must be produced in the U.S.

**Manufactured Product that is a Component of the Qualified Facility**

- 100% of the manufacturing processes must occur in the U.S.
- 100% of the components must be of U.S. origin.

**Component parts of the Manufactured Product**

- 100% of the manufacturing processes must occur in the U.S.
- 0% of the subcomponents required to be of U.S. origin.

**Subcomponent parts of the Manufactured Product**

- 0% of Subcomponent parts, including raw materials, required to be of U.S. origin.

## An energy project satisfies the domestic-content requirement if it meets the two requirements below

- **Steel or Iron Requirement** – 100% of all of the steel and iron must be completely manufactured in the United States except for the "metallurgical processes involving refinement of steel additives." This requirement applies to construction materials made primarily of steel or iron that are "structural in function," but not to the steel and iron in manufactured product components or subcomponents (such as nuts, bolts, etc.).
- **Manufactured-Products Requirement** – To meet the Manufactured Product Requirement, the product must meet one of two tests:
  - (1) A manufactured product is produced in the US if all of the manufacturing processes take place in the United States and all of the product components are of US origin. Components include any articles, materials or supplies that are incorporated into the manufactured product and may be of US origin if manufactured in the United States regardless of the origin of subcomponents.
  - (2) The domestic cost percentage is found by dividing the domestic manufactured products and components cost by the total manufactured products cost; at least 40% of the total cost of the product must comply with the requirements (20% for offshore wind facilities). The percentage is gradually raised to 55% for projects that begin after 2026 (55% after 2027 for offshore wind facilities)

# Current PTC/ITC Supply Side Modeling Assumptions



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Assumption of no credit transfers or discount in modeling
Baseline of Wage and Apprenticeship for all credits; no domestic content assumed

| Generation Alternatives | IRA Incentives Modeled in Resource Plan | Incentive Phase Out |
|---|---|---|
| Standalone Solar (45Y) Off Shore Wind (45Y)<br>On Shore Wind (45Y) New Nuclear (45Y) | PTC for 10 Years<br>5 Year MACRs | No Credit Phase Out During Study Period |
| Standalone Storage (48E) | 40% of MW @ 30% ITC No Norm<br>60% of MW @ 40% ITC No Norm (EC)<br>98.5% Project Eligibility<br>5 Year MACRs | No Credit Phase Out During Study Period |
| Solar Plus Storage (45Y+48E)<br>Advanced Nuclear (45Y+48E) | PTC for 10 Years (Solar/Nuclear)<br>30% ITC No Norm (Storage)<br>98.5% Project Eligibility<br>5 Year MACRs | No Credit Phase Out During Study Period |
| Pumped Storage (48E) | 30% ITC No Norm<br>98.5% Project Eligibility<br>5 Year MACRs | No Credit Phase Out During Study Period |
| Existing Nuclear (45U) | PTC for 9 Years (if eligible) | 2024 - 2032 |
| Hydrogen (45V) | $3/kg PTC for 10 Years | Ends Year After 2032 if not yet under construction |

# IRA Customer Impacts



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The IRA will lower the cost of the energy transition for customers

Utility customers will receive the credits – every dollar will flow back to our customers

Duke Energy will continue to maximize customer benefits from the IRA as further guidance from Treasury is received

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South Carolina Session:

# Additional SC-specific Comments and Questions

- **Leigh Tondini**
  Utility Strategy Director (SC)

- **Sam Wellborn**
  Associate General Counsel (SC)

## Earlier Identified Technical Representatives

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# Additional Participation

Meeting materials/recordings will be uploaded to the website:

**www.duke-energy.com/carolinas-irp**

Information/feedback can be sent to:

**DukeCarolinas@gpisd.net**

**Meeting recordings (Q&A portions of meetings will be removed to adhere to the non-attribution rule) and meeting summaries will be uploaded to the website for participants to access.**

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# THANK YOU

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# Appendix

# Updated Synthetic Loads Combined



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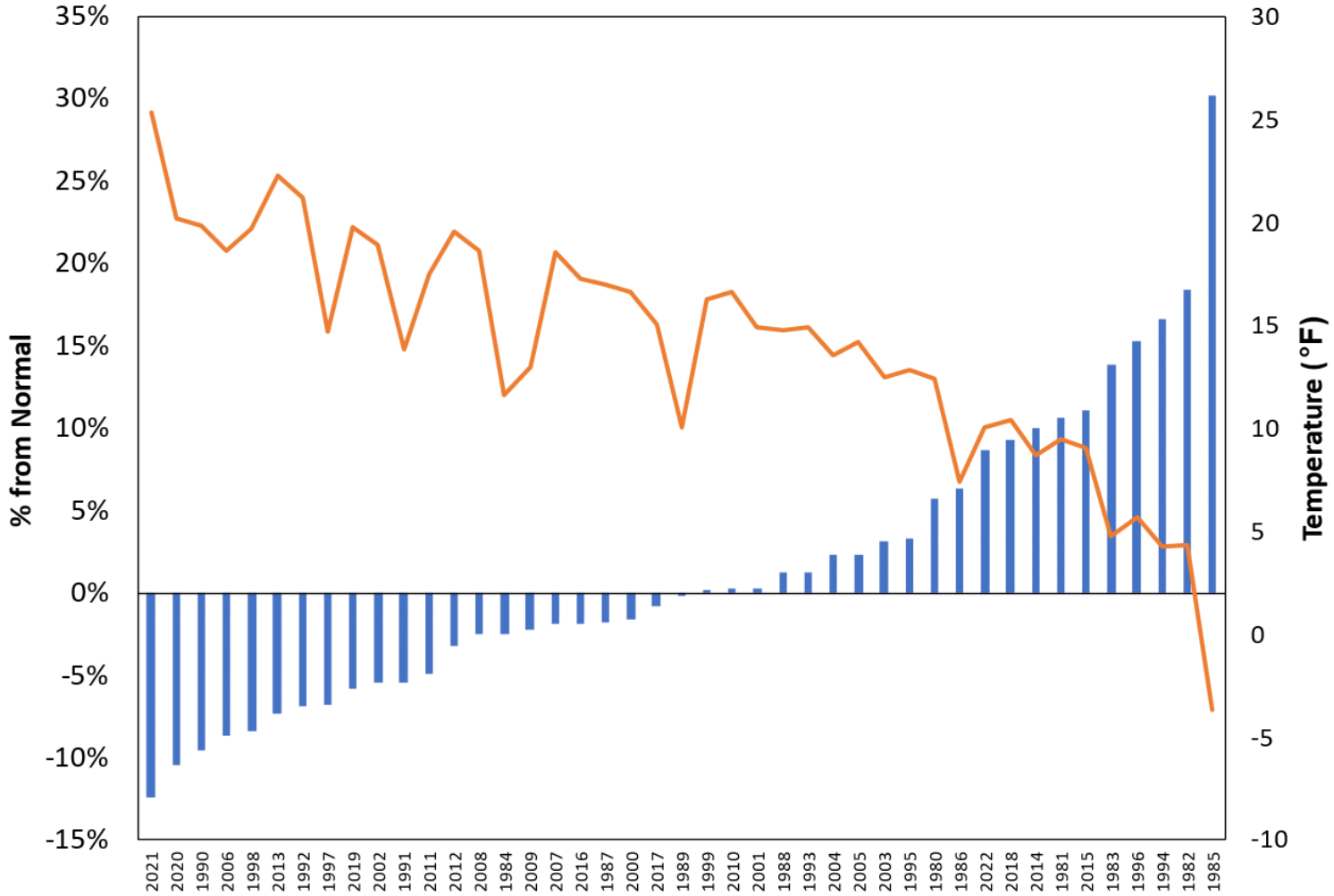


Draft: Preliminary findings.



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# DEC Winter Morning Regression



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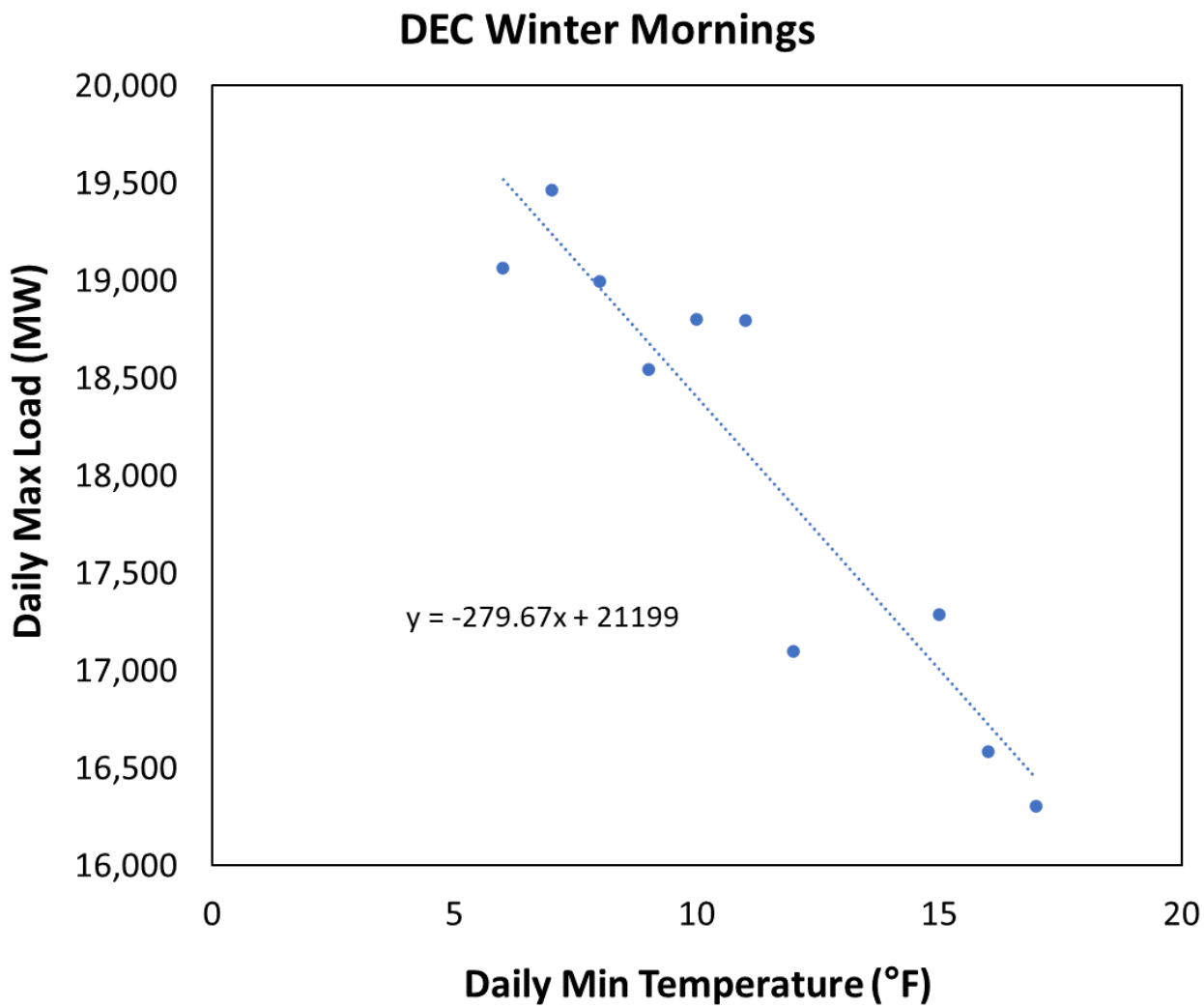


Draft: Preliminary findings.



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# Updated Synthetic Loads DEC



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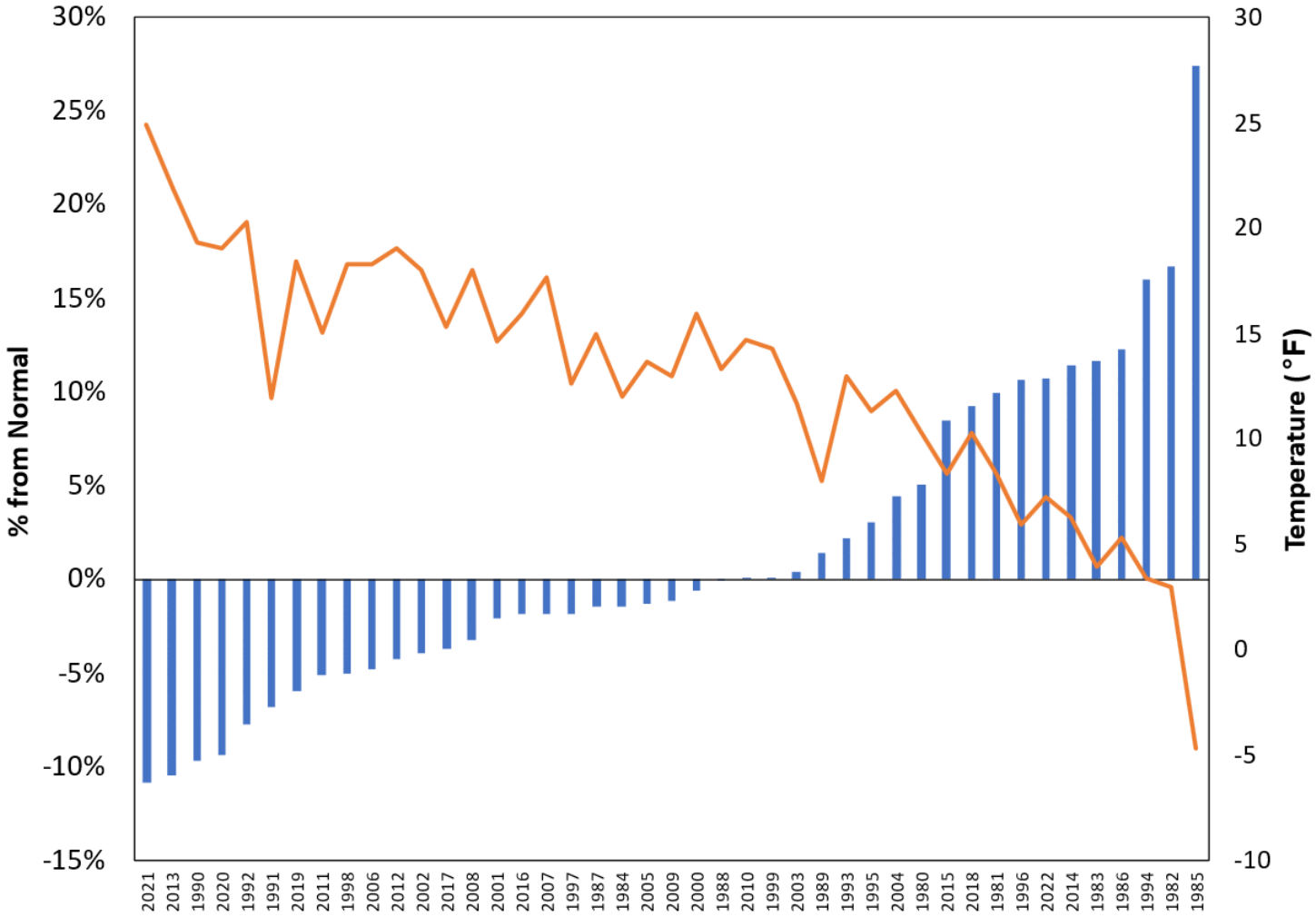


Draft: Preliminary findings.



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# Updated Synthetic Loads DEP-E



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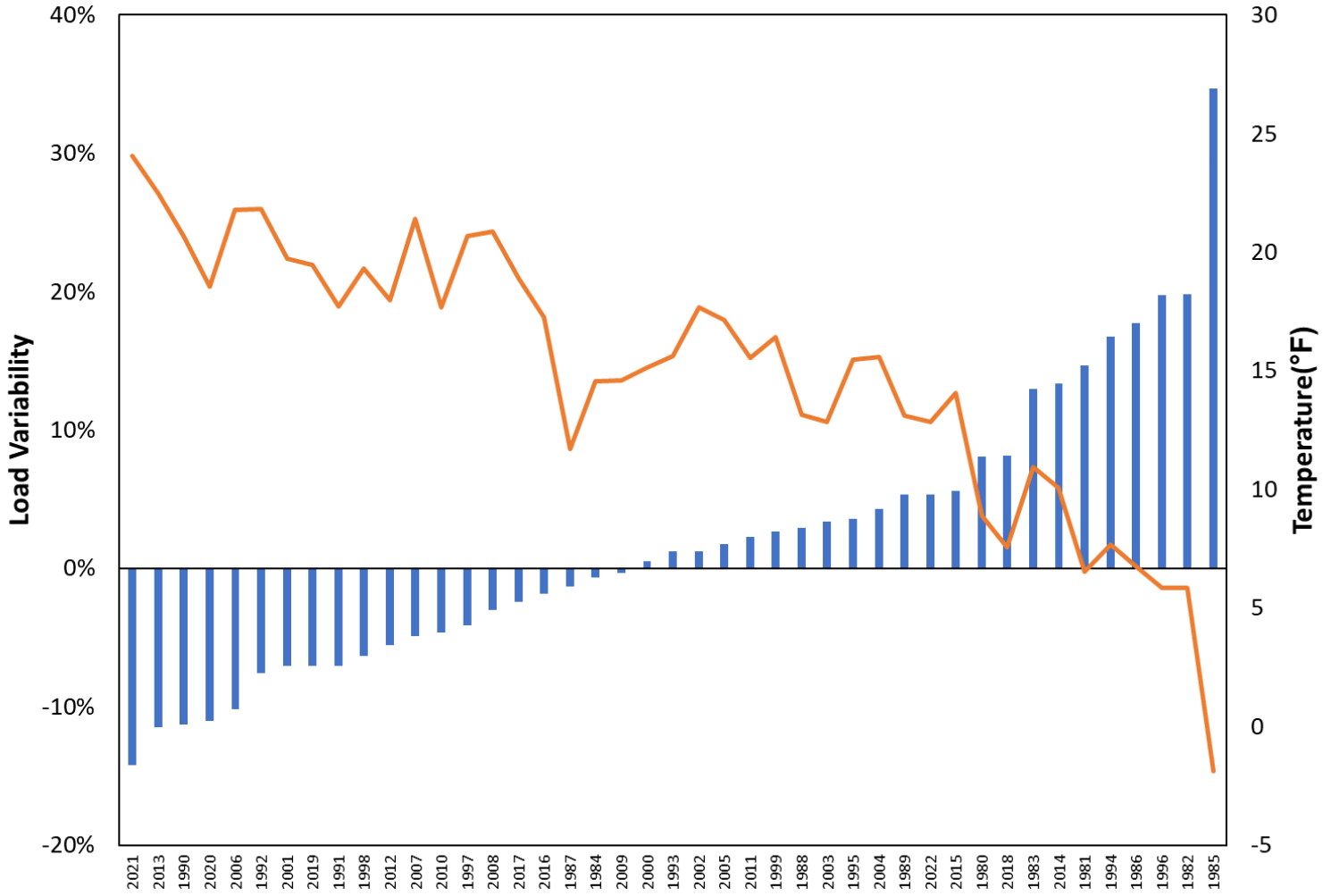


Draft: Preliminary findings.



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# DEP-E Winter Morning Regression



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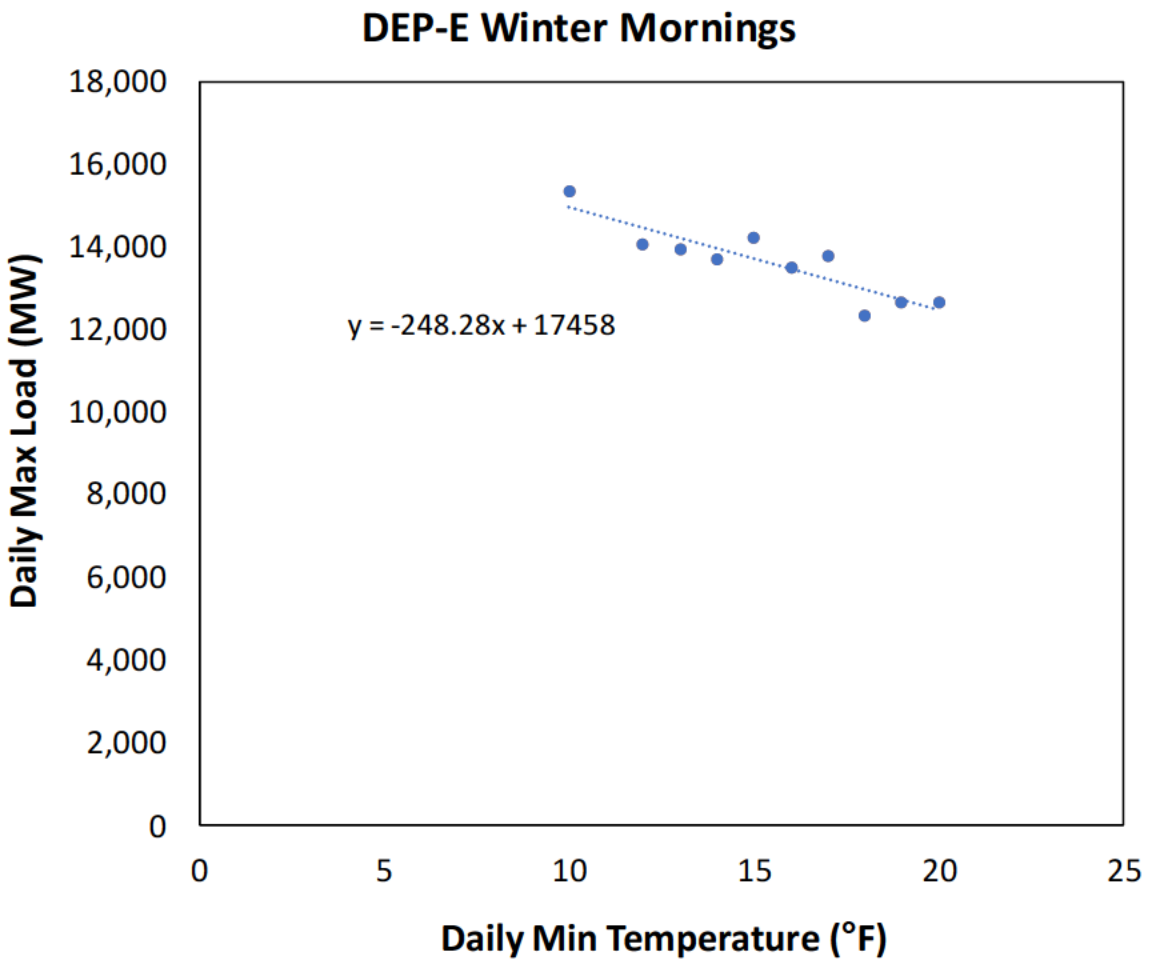


Draft: Preliminary findings.



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# Updated Synthetic Loads DEP-W



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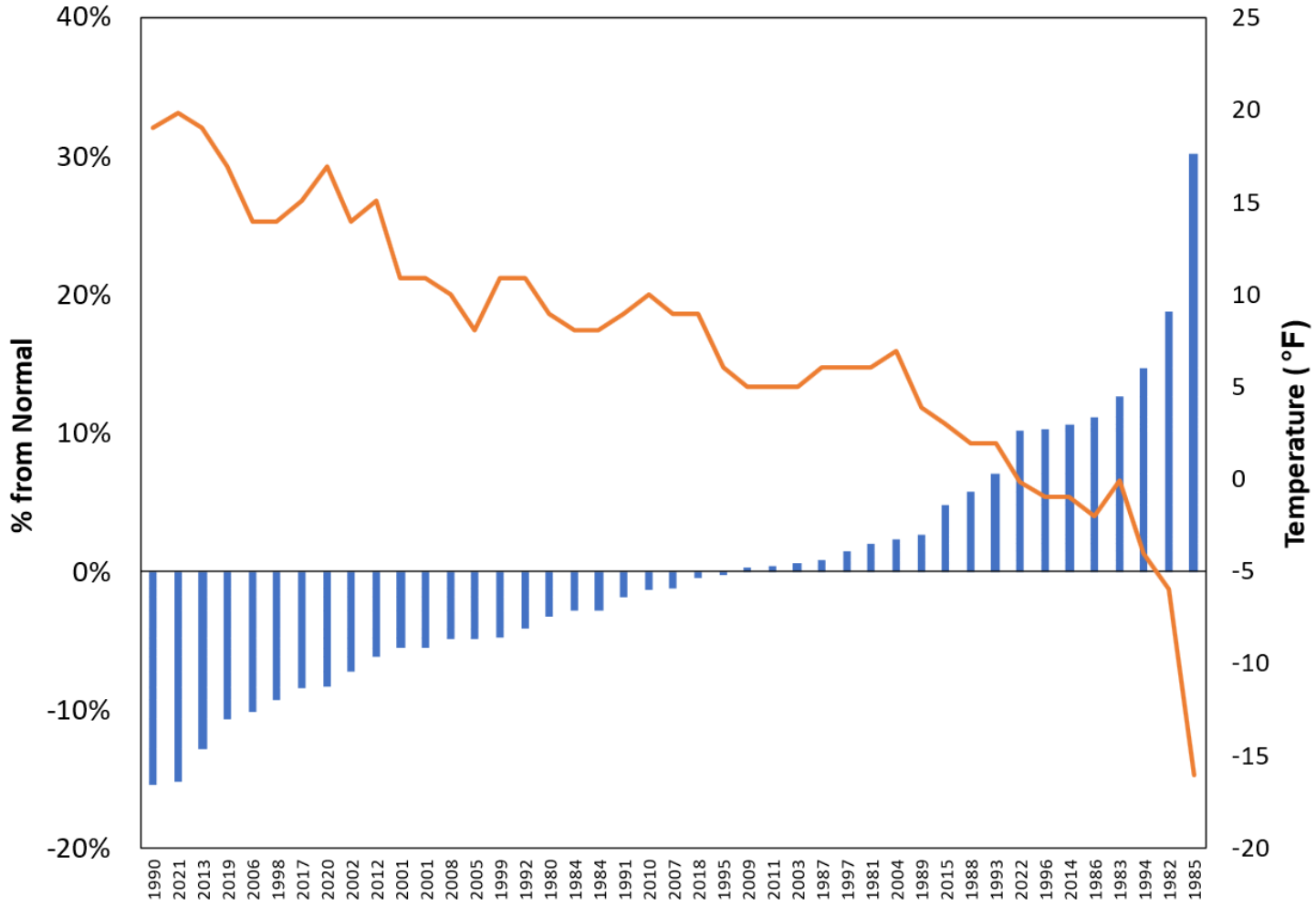


Draft: Preliminary findings.



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# DEP-W Winter Morning Regression



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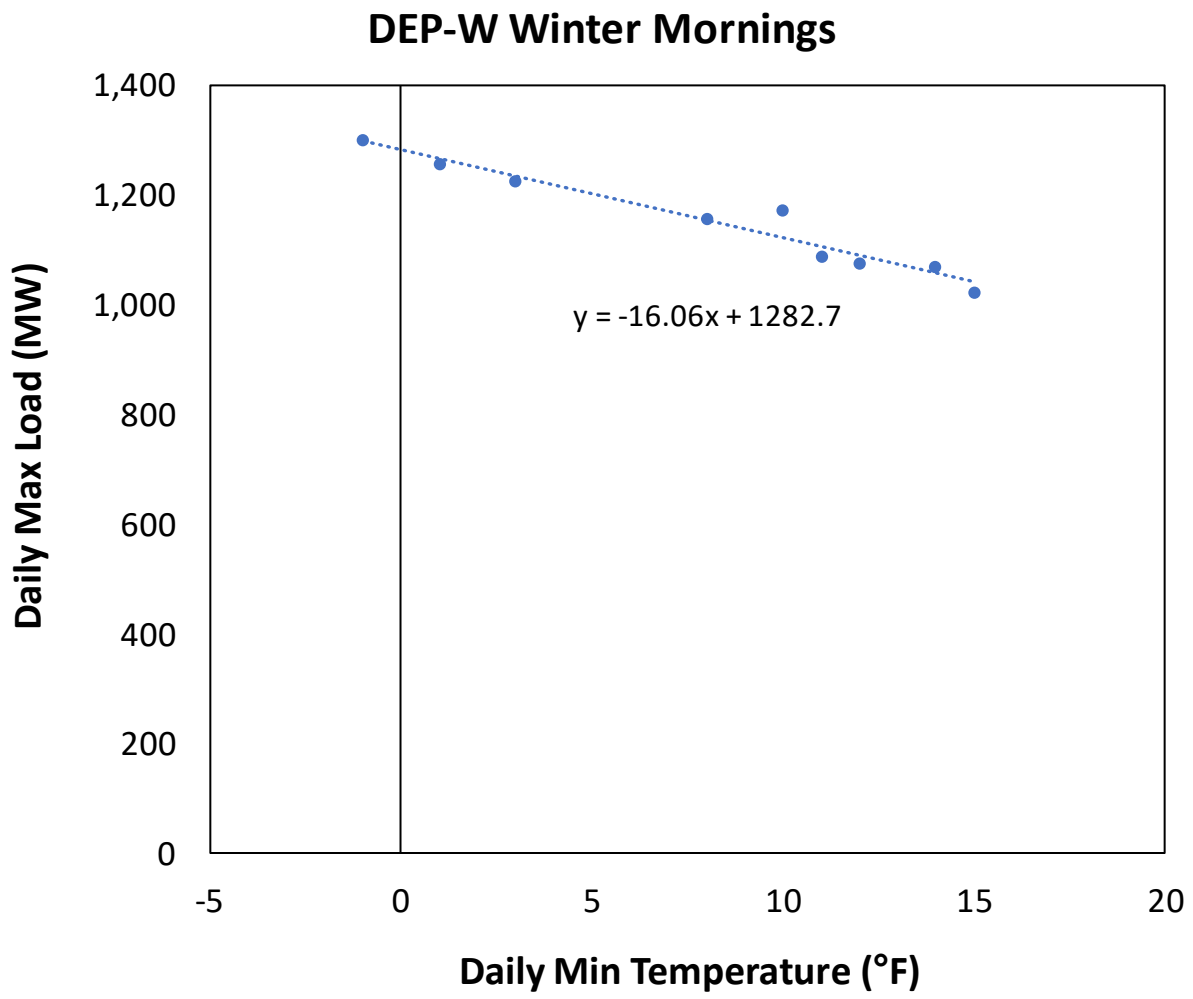


Draft: Preliminary findings.



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# Combined Base Case – 12 x 24 EUE



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| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 3 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 4 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 5 | 3% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 6 | 12% | 1% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 7 | 22% | 2% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 1% |
| 8 | 26% | 2% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 1% |
| 9 | 19% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 10 | 8% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 11 | 1% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 12 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 13 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 14 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 15 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 16 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 17 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 18 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 19 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 20 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 21 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 22 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 23 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 24 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |

Draft: Preliminary findings.



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# Neighbor Resource Portfolio Changes



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| | PJM_South | PJM_West | TVA | SC | SOCO | SCEG | DEC | Progress East | Progress West | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| **Coal-2020** | 4,121 | 34,007 | 5,999 | 3,215 | 12,167 | 1,704 | 5,666 | 3,166 | 0 | 70,046 |
| **Solar-2020** | 105 | 17 | 2,000 | 0 | 4,107 | 303 | 2,055 | 3,865 | 15 | 12,467 |
| **Wind-2020** | 0 | 858 | 2,675 | 0 | 0 | 0 | 0 | 0 | 0 | 3,533 |
| | | | | | | | | | | 0 |
| **Coal-2023** | 1,714 | 24,880 | 6,050 | 2,930 | 7,372 | 1,612 | 5,122 | 3,166 | 0 | 52,846 |
| **Solar-2023** | 8,927 | 2,437 | 3,600 | 1,000 | 6,397 | 1,522 | 2,905 | 4,451 | 56 | 31,295 |
| **Wind-2023** | 3,143 | 13,695 | 1,700 | 0 | 200 | 0 | 0 | 0 | 0 | 18,738 |
| | | | | | | | | | | 0 |
| **Coal Delta** | -2,407 | -9,127 | 51 | -285 | -4,795 | -92 | -544 | 0 | 0 | -17,200 |
| **Solar Delta** | 8,822 | 2,420 | 1,600 | 1,000 | 2,290 | 1,219 | 851 | 586 | 41 | 18,828 |
| **Wind Delta** | 3,143 | 12,837 | -975 | 0 | 200 | 0 | 0 | 0 | 0 | 15,205 |

Winter risk increasing in the region as solar is added

Draft: Preliminary findings.

# External Imports During EUE Hours



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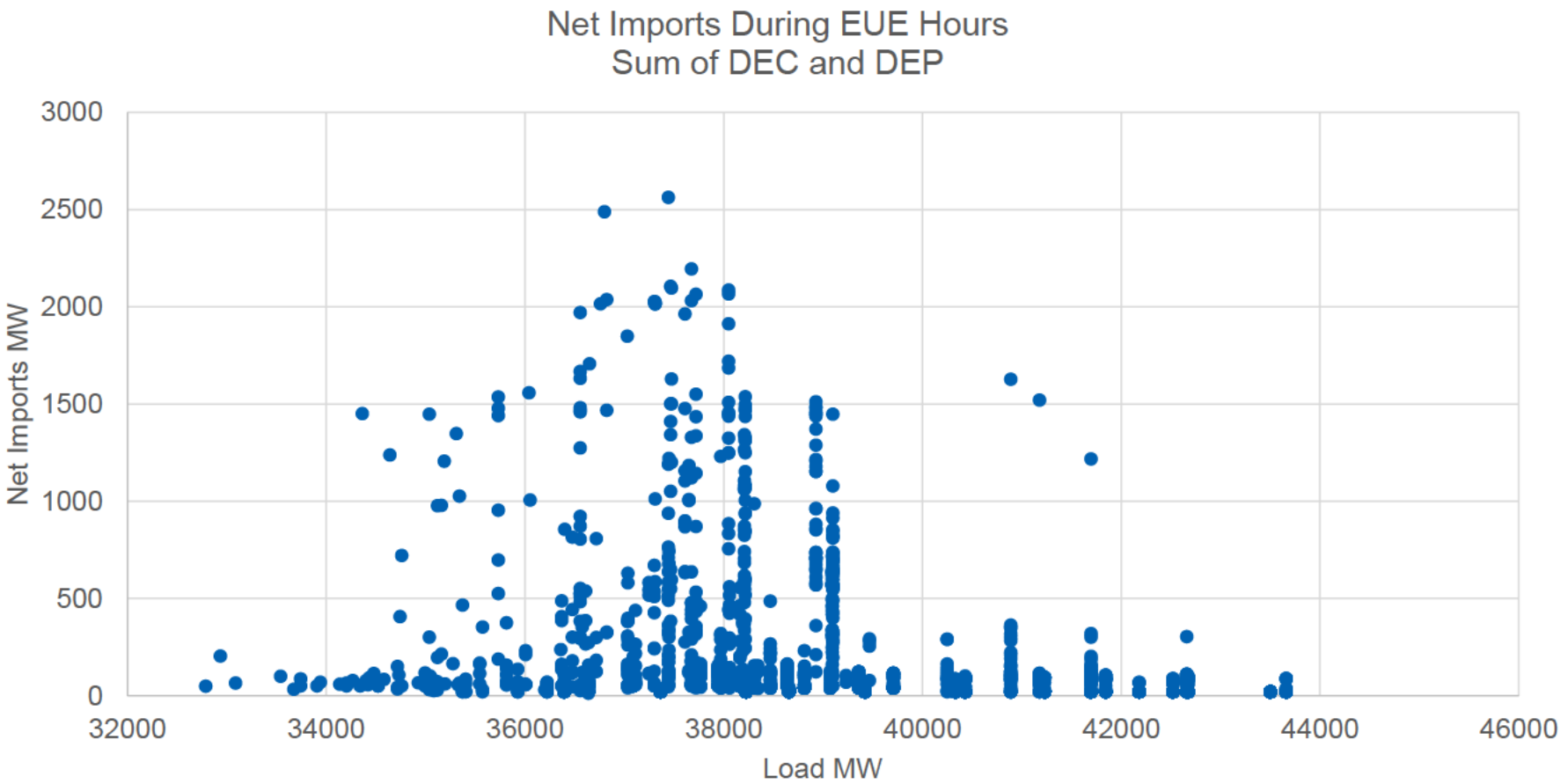


Average: 212 MW during EUE Hours

Draft: Preliminary findings.



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# Annual Capacity Factor Comparison – NC Sites



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| | Fixed | Monofacial Single Axis Tracking | Bifacial Single Axis Tracking |
|---|---|---|---|
| Alamance, NC | 23.4 | 28.4 | 30.0 |
| Alexander, NC | 23.4 | 28.4 | 29.9 |
| Anson, NC | 23.5 | 28.5 | 30.1 |
| Ashe, NC | 22.7 | 27.4 | 28.9 |
| Beaufort, NC | 23.5 | 28.5 | 30.1 |
| Bladen, NC | 23.7 | 28.7 | 30.3 |
| Brunswick, NC | 23.8 | 28.8 | 30.4 |
| Buncombe, NC | 23.6 | 28.5 | 30.0 |
| Burke, NC | 23.2 | 28.2 | 29.8 |
| Cabarrus, NC | 23.7 | 28.8 | 30.3 |
| Caldwell, NC | 23.2 | 28.1 | 29.7 |
| Carteret, NC | 23.6 | 28.4 | 30.0 |
| Caswell, NC | 23.4 | 28.4 | 29.9 |
| Catawba, NC | 23.7 | 28.8 | 30.3 |
| Chatham, NC | 23.4 | 28.4 | 30.0 |
| Chowan, NC | 23.6 | 28.7 | 30.2 |
| Cleveland, NC | 23.8 | 29.0 | 30.5 |
| Columbus, NC | 23.9 | 28.9 | 30.5 |
| Craven, NC | 23.5 | 28.6 | 30.1 |
| Cumberland, NC | 23.8 | 28.9 | 30.4 |
| Davidson, NC | 23.8 | 28.9 | 30.4 |
| Davie, NC | 23.6 | 28.6 | 30.1 |
| Duplin, NC | 23.7 | 28.7 | 30.2 |
| Durham, NC | 23.3 | 28.2 | 29.9 |
| Forsyth, NC | 23.5 | 28.5 | 30.0 |
| Franklin, NC | 23.4 | 28.5 | 30.0 |
| Gaston, NC | 23.8 | 28.9 | 30.4 |
| Granville, NC | 23.5 | 28.6 | 30.1 |
| Greene, NC | 23.8 | 28.9 | 30.4 |
| Guilford, NC | 23.5 | 28.5 | 30.0 |
| Halifax, NC | 23.4 | 28.4 | 30.0 |
| Harnett, NC | 23.7 | 28.7 | 30.2 |
| Haywood, NC | 23.4 | 28.2 | 29.7 |
| Henderson, NC | 23.7 | 28.8 | 30.3 |
| Hoke, NC | 23.7 | 28.7 | 30.3 |
| Iredell, NC | 23.7 | 28.7 | 30.2 |
| Jackson, NC | 23.4 | 28.3 | 29.8 |
| Johnston, NC | 23.8 | 28.9 | 30.4 |
| Jones, NC | 23.4 | 28.3 | 29.9 |
| Lee, NC | 23.6 | 28.6 | 30.2 |

| | Fixed | Monofacial Single Axis Tracking | Bifacial Single Axis Tracking |
|---|---|---|---|
| Lenoir Kinston, NC | 23.6 | 28.6 | 30.2 |
| Lincoln, NC | 23.7 | 28.9 | 30.4 |
| Madison, NC | 22.9 | 27.6 | 29.1 |
| McDowell, NC | 23.2 | 28.2 | 29.7 |
| Mecklenburg, NC | 23.5 | 28.6 | 30.2 |
| Mitchell, NC | 22.6 | 27.2 | 28.7 |
| Montgomery, NC | 23.7 | 28.7 | 30.3 |
| Moore, NC | 23.5 | 28.5 | 30.1 |
| Nash, NC | 23.6 | 28.7 | 30.2 |
| NewHanover, NC | 23.7 | 28.7 | 30.4 |
| Onslow, NC | 23.7 | 28.7 | 30.2 |
| Orange, NC | 23.5 | 28.4 | 30.0 |
| Pamlico, NC | 23.3 | 28.3 | 29.9 |
| Pender, NC | 23.4 | 28.3 | 30.0 |
| Person, NC | 23.5 | 28.4 | 30.0 |
| Pitt, NC | 23.6 | 28.7 | 30.2 |
| Polk, NC | 23.5 | 28.5 | 30.1 |
| Randolph, NC | 23.7 | 28.7 | 30.3 |
| Richmond, NC | 23.5 | 28.5 | 30.2 |
| Robeson, NC | 24.1 | 29.3 | 30.8 |
| Rockingham, NC | 23.3 | 28.3 | 29.8 |
| Rowan, NC | 23.7 | 28.8 | 30.3 |
| Rutherford, NC | 23.6 | 28.6 | 30.2 |
| Sampson, NC | 24.1 | 29.2 | 30.7 |
| Scotland, NC | 23.8 | 28.9 | 30.4 |
| Stanly, NC | 23.7 | 28.7 | 30.3 |
| Stokes, NC | 23.3 | 28.2 | 29.8 |
| Surry, NC | 23.1 | 27.9 | 29.4 |
| Swain, NC | 22.7 | 27.4 | 28.9 |
| Transylvania, NC | 23.5 | 28.6 | 30.1 |
| Union, NC | 23.7 | 28.8 | 30.5 |
| Vance, NC | 23.3 | 28.3 | 29.9 |
| Wake, NC | 23.5 | 28.6 | 30.2 |
| Warren, NC | 23.2 | 28.2 | 29.8 |
| Wayne, NC | 23.8 | 28.9 | 30.4 |
| Wilkes, NC | 22.9 | 27.7 | 29.3 |
| Wilson, NC | 23.7 | 28.7 | 30.2 |
| Yadkin, NC | 23.5 | 28.5 | 29.9 |
| Yancey, NC | 23.1 | 27.9 | 29.4 |

*Shown with a 1.3 ILR

# Annual Capacity Factor Comparison – SC Sites



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| | Fixed | Monofacial Single Axis Tracking | Bifacial Single Axis Tracking |
|---|---|---|---|
| Abbeville, SC | 23.8 | 29.0 | 30.6 |
| Anderson, SC | 24.0 | 29.2 | 30.8 |
| Cherokee, SC | 23.8 | 29.0 | 30.5 |
| Chester, SC | 23.6 | 28.8 | 30.4 |
| Chesterfield, SC | 23.7 | 28.7 | 30.3 |
| Clarendon, SC | 24.4 | 29.6 | 31.2 |
| Darlington, SC | 24.2 | 29.4 | 30.9 |
| Dillon, SC | 24.1 | 29.2 | 30.8 |
| Florence, SC | 24.2 | 29.3 | 30.8 |
| Greenville, SC | 23.8 | 29.0 | 30.6 |
| Greenwood, SC | 23.7 | 28.9 | 30.5 |
| Lancaster, SC | 23.8 | 28.9 | 30.6 |
| Laurens, SC | 23.8 | 28.9 | 30.5 |
| Lee, SC | 24.3 | 29.5 | 31.1 |
| Marion, SC | 24.2 | 29.3 | 30.8 |
| Marlboro, SC | 24.0 | 29.0 | 30.6 |
| Newberry, SC | 23.7 | 28.9 | 30.5 |
| Oconee, SC | 23.7 | 28.9 | 30.5 |
| Pickens, SC | 23.8 | 29.0 | 30.5 |
| Spartanburg, SC | 23.8 | 29.0 | 30.5 |
| Sumter, SC | 24.2 | 29.4 | 31.0 |
| Williamsburg, SC | 24.2 | 29.3 | 30.9 |
| York, SC | 23.8 | 29.0 | 30.6 |

*Shown with a 1.3 ILR

# Fixed – January Average Shape



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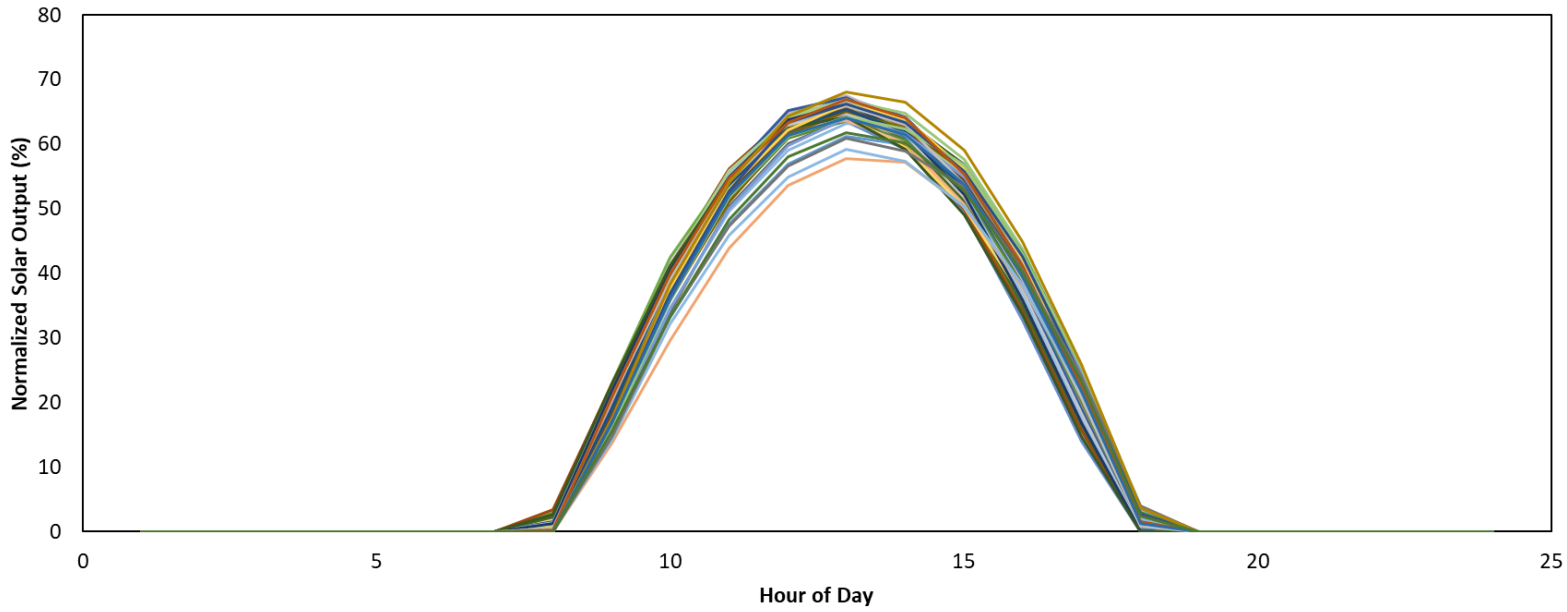


Alamance_NC, Alexander_NC, Anderson_SC, Anson_NC, Ashe_NC, Beaufort_NC, Bladen_NC, Brunswick_NC, Buncombe_NC
Burke_NC, Cabarrus_NC, Caldwell_NC, Carteret_NC, Caswell_NC, Catawba_NC, Chatham_NC, Cherokee_SC, Chester_SC
Clarendon_SC, Cleveland_NC, Columbus_NC, Craven_NC, Cumberland_NC, Darlington_SC, Davidson_NC, Davie_NC, Dillon_SC
Duplin_NC, Durham_NC, Florence_SC, Forsyth_NC, Franklin_NC, Gaston_NC, Granville_NC, Greene_NC, Greenville_SC
Greenwood_SC, Guilford_NC, Halifax_NC, Harnett_NC, Haywood_NC, Henderson_NC, Hoke_NC, Iredell_NC, Johnston_NC
Jones_NC, Lancaster_SC, Laurens_SC, Lee_NC, Lee_SC, LenoirKinston_NC, Lincoln_NC, Marion_SC, Mecklenburg_NC
Montgomery_NC, Moore_NC, Nash_NC, NewHanover_NC, Newberry_SC, Onslow_NC, Orange_NC, Pamlico_NC, Pender_NC
Person_NC, Pickens_SC, Pitt_NC, Randolph_NC, Richmond_NC, Robeson_NC, Rockingham_NC, Rowan_NC, Rutherford_NC
Sampson_NC, Scotland_NC, Spartanburg_SC, Stanly_NC, Stokes_NC, Surry_NC, Union_NC, Vance_NC, Wake_NC
Warren_NC, Wayne_NC, Williamsburg_SC, Wilson_NC, Yadkin_NC, York_SC, Abbeville_SC, Chesterfield_SC, Chowan_NC
Jackson_NC, Madison_NC, Marlboro_SC, McDowell_NC, Mitchell_NC, Oconee_SC, Polk_NC, Sumter_SC, Swain_NC
Transylvania_NC, Wilkes_NC, Yancey_NC

*Shown with a 1.3 ILR

Draft: Preliminary findings.



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# Fixed – August Average Shape



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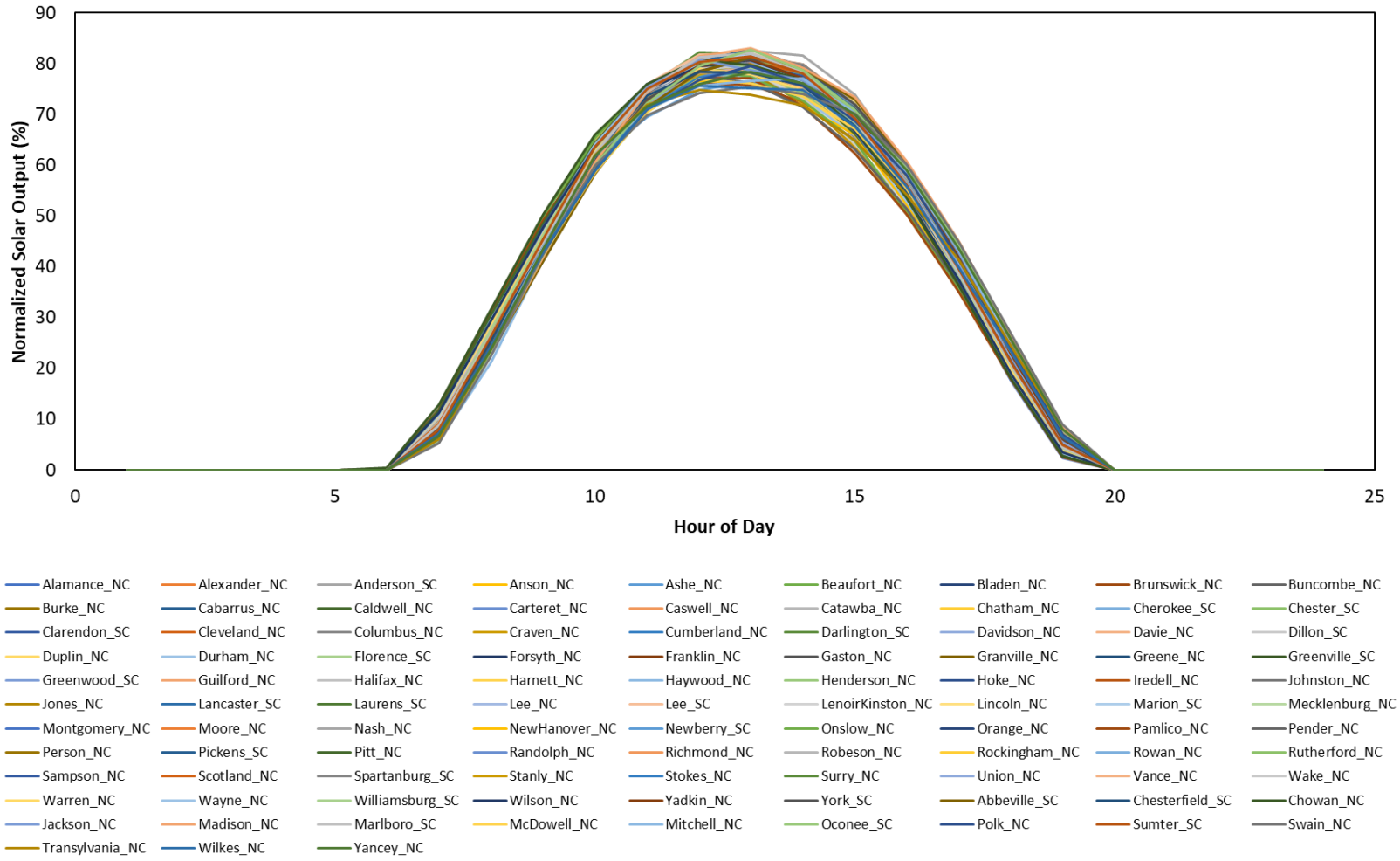


*Shown with a 1.3 ILR

Draft: Preliminary findings.

# Yancey, NC August Daily Shape Example



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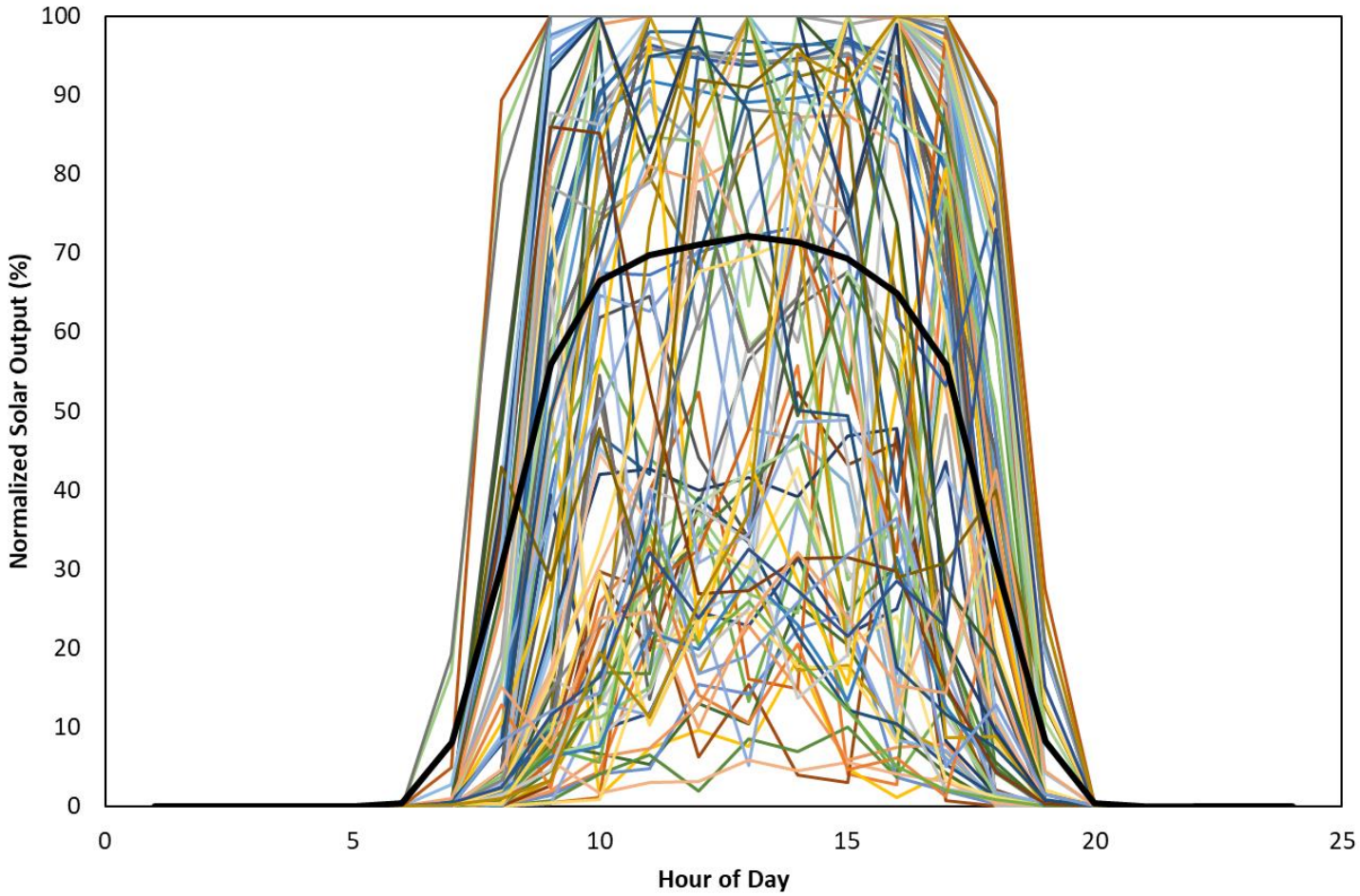


*Shown with a 1.3 ILR

** 100 August daily shapes selected at random as an example (1,333 total)

*** Bold black line is the average daily shape of all August shapes from 1980 – 2022

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# Monofacial Single Axis Tracking – January Average Shape



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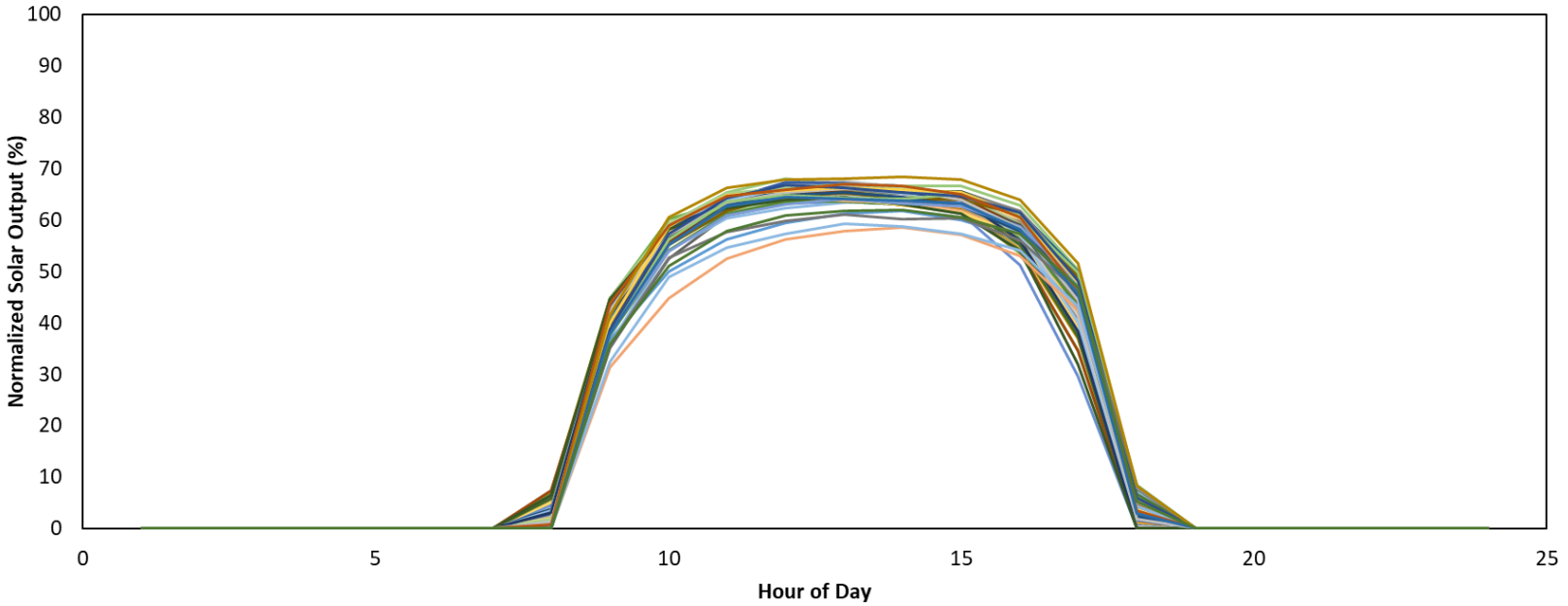


Alamance_NC, Alexander_NC, Anderson_SC, Anson_NC, Ashe_NC, Beaufort_NC, Bladen_NC, Brunswick_NC, Buncombe_NC
Burke_NC, Cabarrus_NC, Caldwell_NC, Carteret_NC, Caswell_NC, Catawba_NC, Chatham_NC, Cherokee_SC, Chester_SC
Clarendon_SC, Cleveland_NC, Columbus_NC, Craven_NC, Cumberland_NC, Darlington_SC, Davidson_NC, Davie_NC, Dillon_SC
Duplin_NC, Durham_NC, Florence_SC, Forsyth_NC, Franklin_NC, Gaston_NC, Granville_NC, Greene_NC, Greenville_SC
Greenwood_SC, Guilford_NC, Halifax_NC, Harnett_NC, Haywood_NC, Henderson_NC, Hoke_NC, Iredell_NC, Johnston_NC
Jones_NC, Lancaster_SC, Laurens_SC, Lee_NC, Lee_SC, LenoirKinston_NC, Lincoln_NC, Marion_SC, Mecklenburg_NC
Montgomery_NC, Moore_NC, Nash_NC, NewHanover_NC, Newberry_SC, Onslow_NC, Orange_NC, Pamlico_NC, Pender_NC
Person_NC, Pickens_SC, Pitt_NC, Randolph_NC, Richmond_NC, Robeson_NC, Rockingham_NC, Rowan_NC, Rutherford_NC
Sampson_NC, Scotland_NC, Spartanburg_SC, Stanly_NC, Stokes_NC, Surry_NC, Union_NC, Vance_NC, Wake_NC
Warren_NC, Wayne_NC, Williamsburg_SC, Wilson_NC, Yadkin_NC, York_SC, Abbeville_SC, Chesterfield_SC, Chowan_NC
Jackson_NC, Madison_NC, Marlboro_SC, McDowell_NC, Mitchell_NC, Oconee_SC, Polk_NC, Sumter_SC, Swain_NC
Transylvania_NC, Wilkes_NC, Yancey_NC

*Shown with a 1.3 ILR

Draft: Preliminary findings.

# Monofacial Single Axis Tracking – August Average Shape



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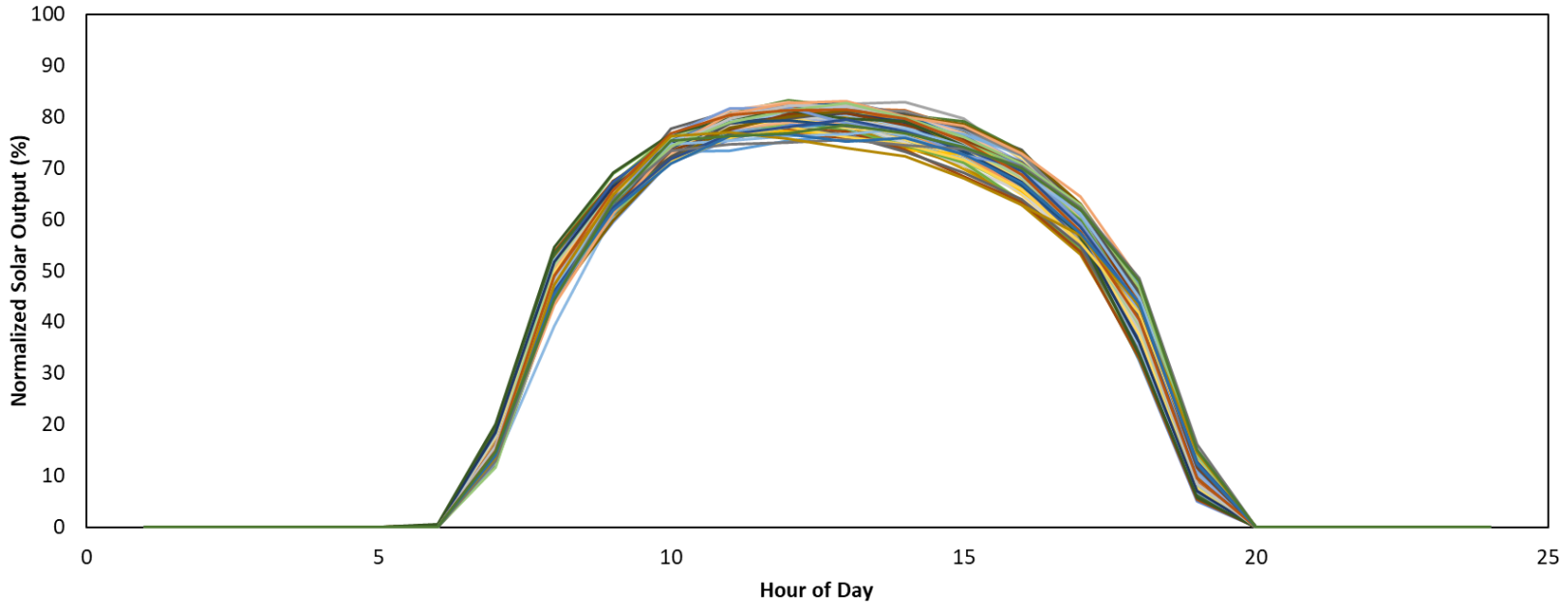


*Shown with a 1.3 ILR

Draft: Preliminary findings.

# Bifacial Single Axis Tracking – January Average Shape



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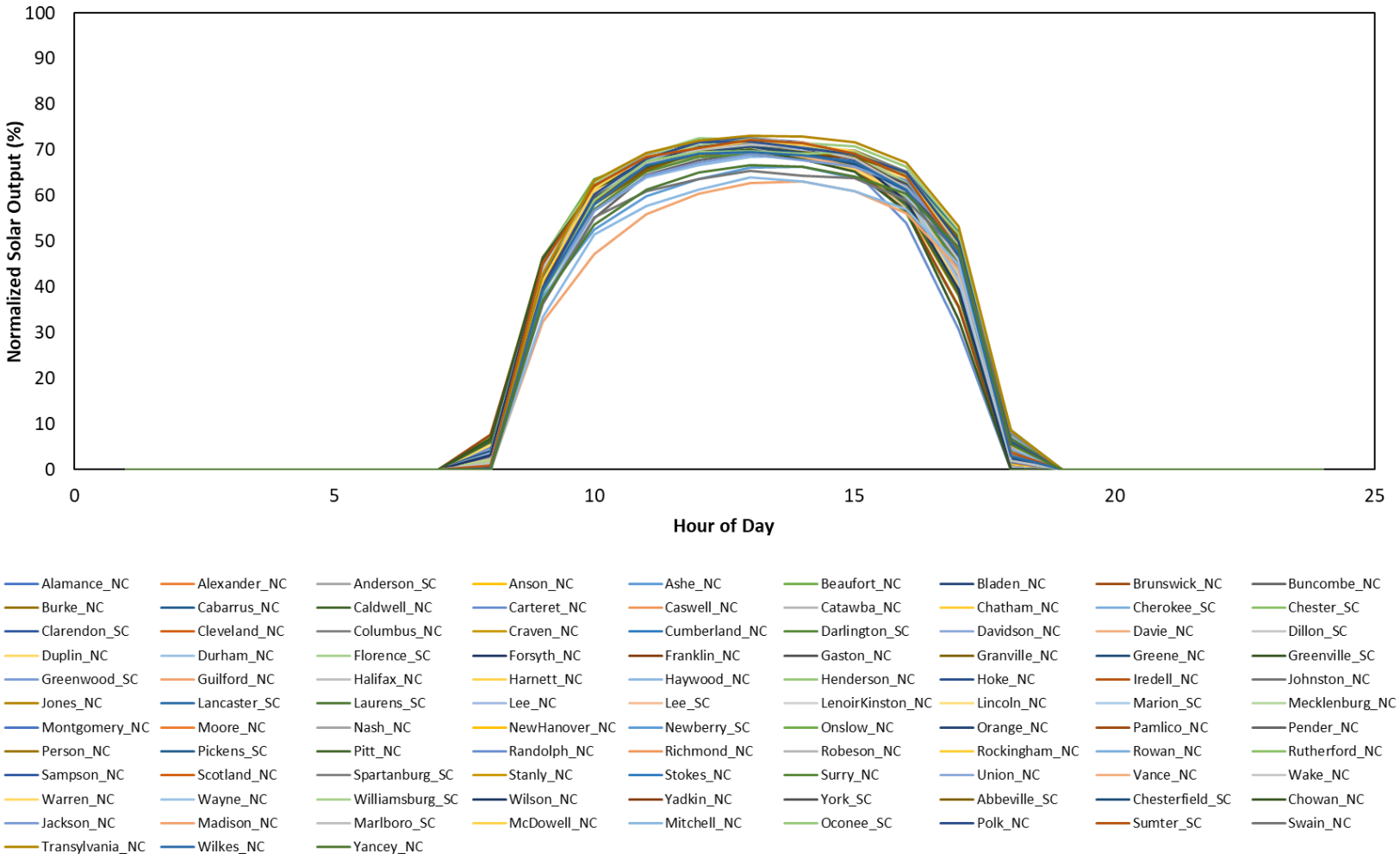
Oct 02 2023




*Shown with a 1.3 ILR

Draft: Preliminary findings.



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# Bifacial Single Axis Tracking – August Average Shape



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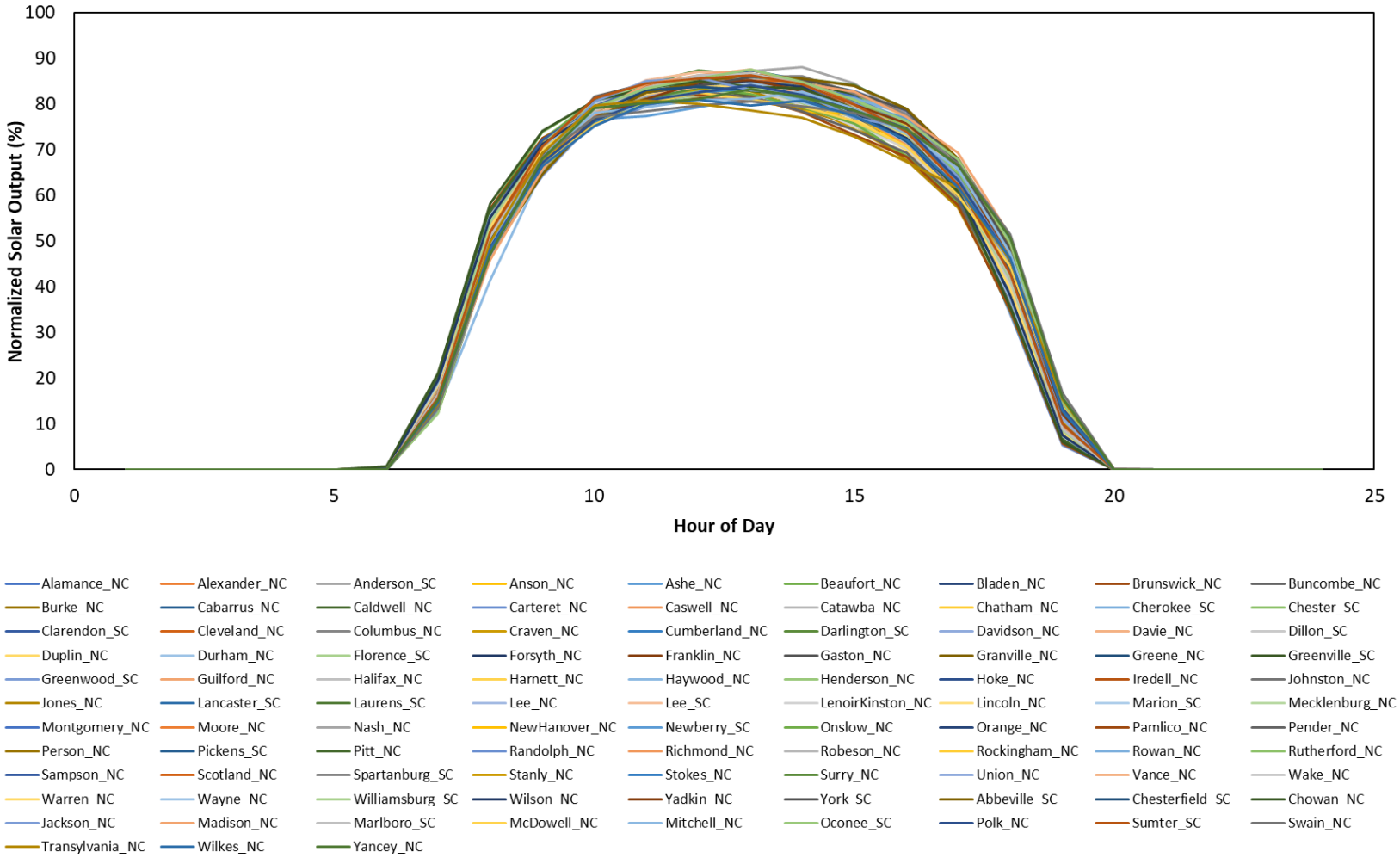


*Shown with a 1.3 ILR

Draft: Preliminary findings.

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# Conventional Hydro and Pumped Storage Modeling

# DEC Modeled Capacity by Month



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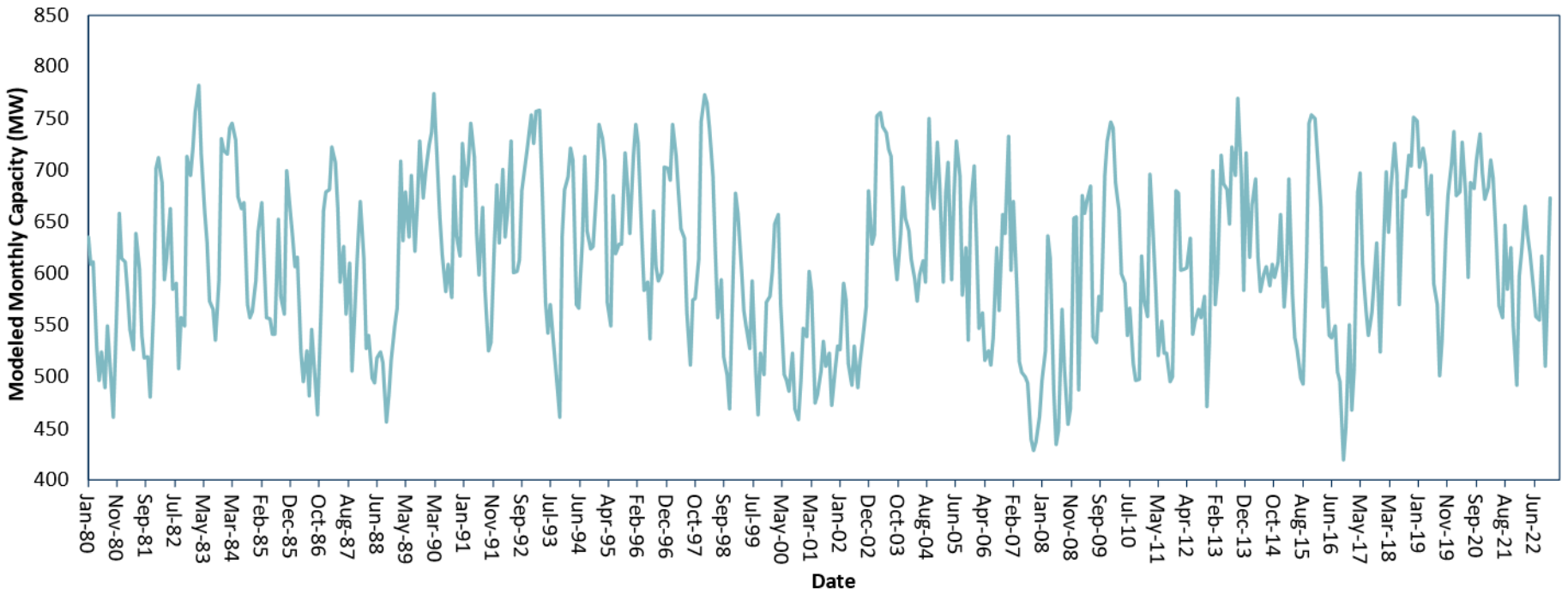


Draft: Preliminary findings.



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# DEC Hydro Energy by Weather Year



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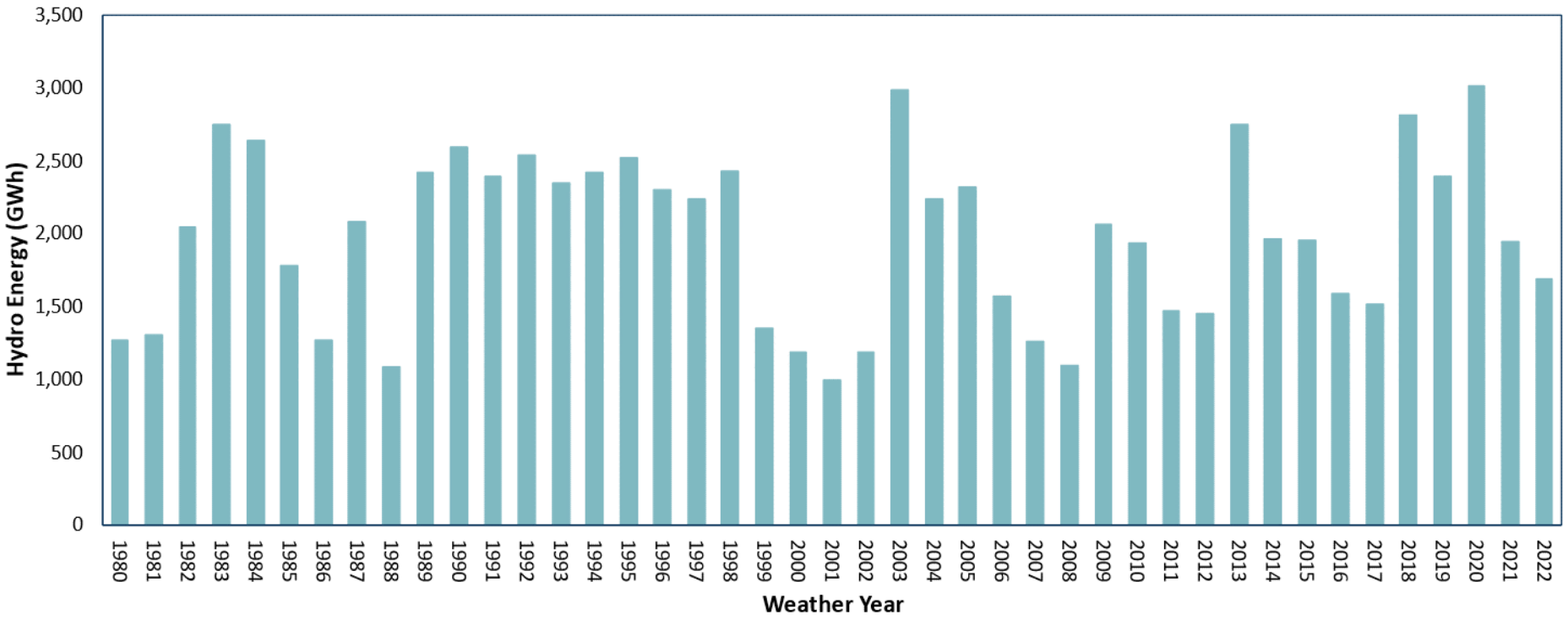


Draft: Preliminary findings.



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# DEP Modeled Capacity by Month



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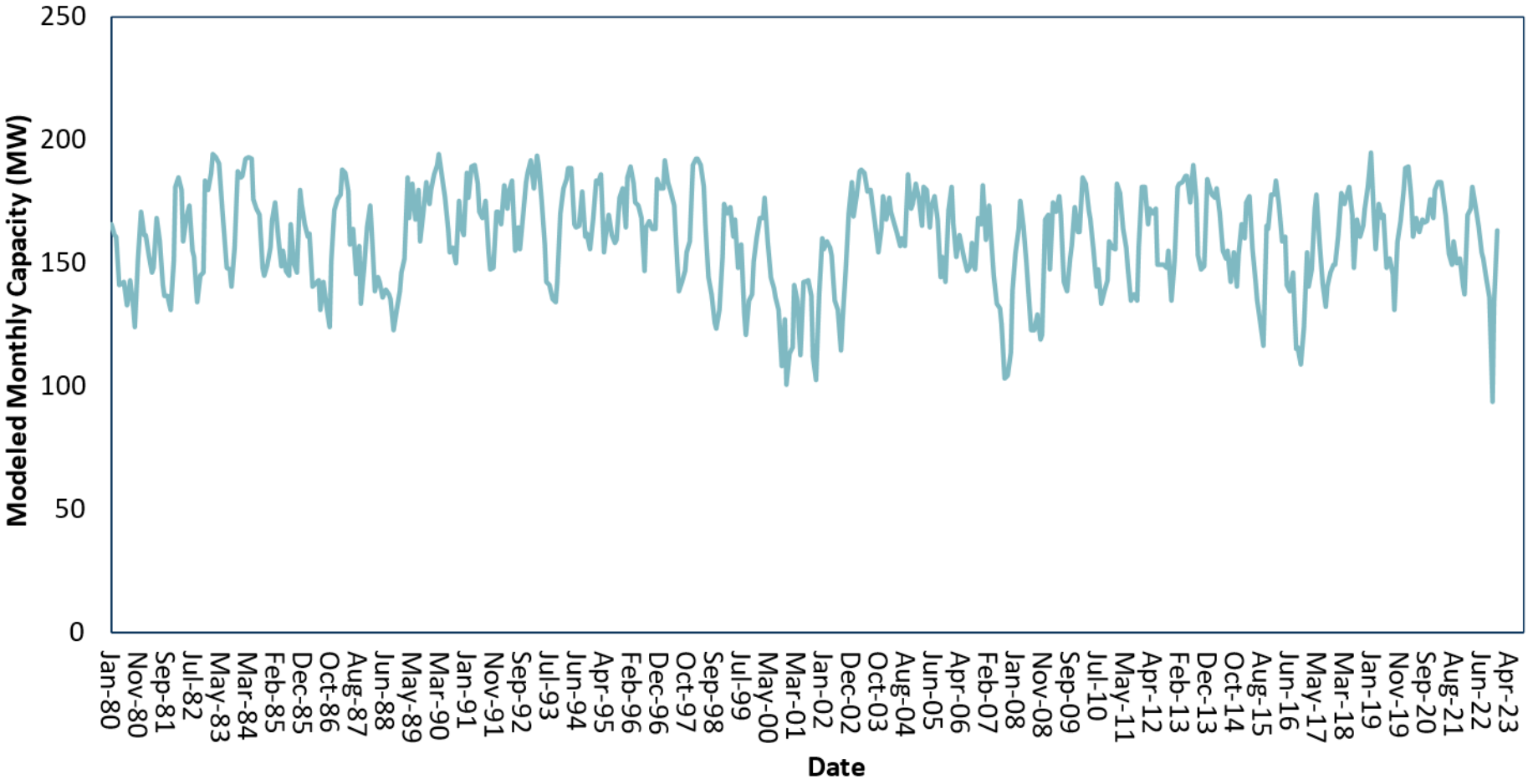


Draft: Preliminary findings.



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# DEP Hydro Energy by Weather Year



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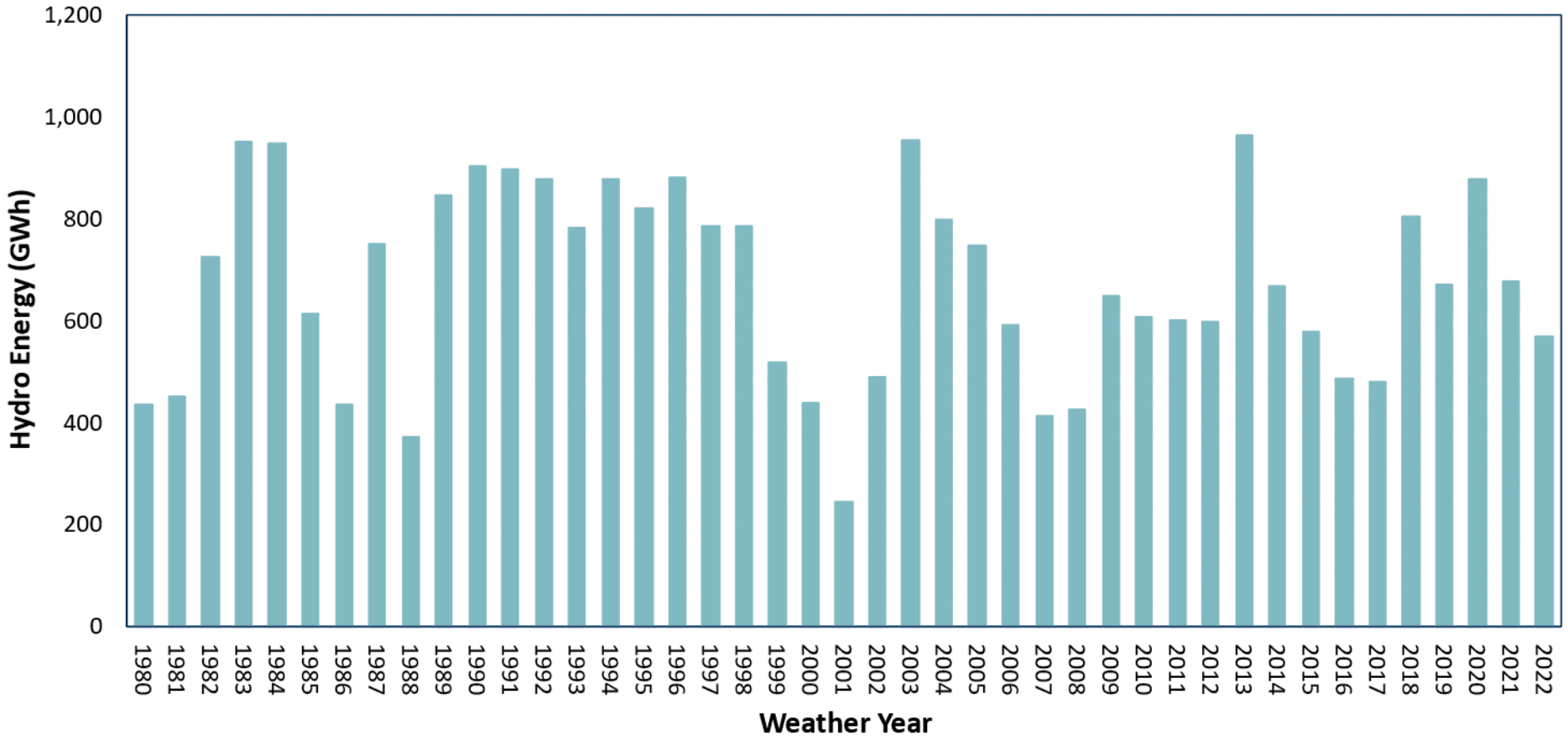


Draft: Preliminary findings.



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# DEC Pumped Storage



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| Unit Name | Capacity (MW) | Pumping Capacity (MW) | Reservoir Capacity (MWh) | Reservoir Generating Hours |
|---|---|---|---|---|
| Bad Creek | 1,640 | 1,500 | 35,192 | 21.5 |
| Jocassee | 780 | 820 | 15,210 | 19.5 |
| | | | | |
| **Total** | 2,420 | | | |

Draft: Preliminary findings.

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**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 |

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| | |
|---|---|
| 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** |

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REDACTED

PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Monday, May 15, 2023

TIME: 9:29 a.m. - 12:01 p.m.

DOCKET NO.: E-2, Sub 1300

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

IN THE MATTER OF:

Application of Duke Energy Progress, LLC,
for Adjustment of Rates and Charges Applicable
to Electric Service in North Carolina and
for Performance-Based Regulation

VOLUME: 20

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CHAIR MITCHELL: All right. CIGFUR.

MS. CRESS: Good morning, Chair Mitchell. As I shared with the Public Staff over the weekend, my co-counsel who has previously entered an appearance in this docket Chris Edwards is here with me and may, with your permission, also potentially ask Mr. Lucas some questions this morning. And as I understand it, the Public Staff has two lawyers defending Mr. Lucas as well, which CIGFUR is fine with. Of course with your permission.

CHAIR MITCHELL: You may proceed.

MS. CRESS: Thank you.

CROSS EXAMINATION BY MS. CRESS:

Q. Good morning, Mr. Lucas. First, I want to speak with you about the genesis of the equal percentage bill increase or decrease method of allocating fuel costs, which I'm going to refer to this morning throughout my questioning as the equal percentage method. Mr. Lucas, I understand that the equal percentage method originated from a stipulation between the Public Staff, DEP's predecessor company, CIGFUR II, and CUCA in Docket Number E-2, Sub 929, back in 2008; is that correct?

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A. Yes.

Q. I'm going to ask you, please, sir, to turn with me to CIGFUR -- what has been premarked as CIGFUR II Potential Cross Exhibit Number 20. You should have a binder up there that has CIGFUR II Potential Cross Exhibit Number 20.

A. I've got it.

Q. Could you turn with me to tab 20?

MS. CRESS: And, Chair Mitchell, I'll go ahead and ask that this document be identified as CIGFUR II Cross Examination Lucas Direct Exhibit Number 1.

CHAIR MITCHELL: All right. The document will be marked as CIGFUR II Cross Examination Lucas Direct Exhibit 1.

(CIGFUR II Cross Examination Lucas Direct Exhibit 1 was marked for identification.)

MS. CRESS: Thank you.

Q. And this is the Sub 929 settlement; is that right, Mr. Lucas?

A. Yes.

Q. And this settlement was approved by this Commission; is that your understanding?

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A. For the most part. The pertinent parts we're talking about the Commission did accept. They didn't accept the whole thing, but I don't think that's really relevant to what we're going to discuss today.

MS. CRESS: Thank you for that.

Chair Mitchell, I request at this time that the Commission take judicial notice of its Order approving fuel charge adjustment issued on November 14, 2008, in Docket Number E-2, Sub 929.

CHAIR MITCHELL: Repeat the date, Ms. Cress, please, ma'am.

MS. CRESS: November 14, 2008.

CHAIR MITCHELL: All right. The Commission will take judicial notice of its Order as requested by counsel.

MS. CRESS: Thank you.

Q. Mr. Lucas, the equal percentage method has been in place as the approved fuel and fuel-related cost allocation methodology for DEP continuously since 2008; is that correct?

A. That's correct. But that had to change because of House Bill 951, and the requirement to eliminate cross subsidies.

Q. And moving from 2008 to 2012, the equal

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percentage method was later proposed by Duke Energy Carolinas or DEC, and approved by the Commission beginning in 2012; is that right?

A. I can't remember the exact year, but somewhere, one of the years back, DEC did start using equal percentage methodology also.

Q. Okay. And the equal percentage method, to the extent you know, has been in place as the approved fuel and fuel-related cost allocation methodology for DEC continuously since 2012?

A. That's correct.

Q. Thank you. Mr. Lucas, I've got a copy of the Sub 929 Order located behind the tab for CIGFUR II Potential Cross Exhibit 26. If you could turn there with me, sir.

A. I'm there.

Q. I'd like to turn your attention to "finding of fact number 8; on page 4 of that Order. Are you there on page 4?

A. Here we go. Yes, I found it.

Q. Okay. And finding of fact number 8 reads that:

"The uniform bill adjustment methodology proposed by DEP's predecessor company, CIGFUR

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II, CUCA, and the Public Staff is just and reasonable and should be approved for the purpose of this proceeding."

Is that correct?

A. Yes. But I need to point out, also in this Order, the Commission accepted the settlement. And part of that settlement agreement was -- one thing the Public Staff wanted was spreading the cost out of this large fuel increase over a 3-year period. This was part of a package that was part of that settlement agreement.

Q. Thank you for that. I want to talk to you a little bit about the mechanics of the fuel rider and this allocation methodology. Specifically, the rate tariffs for DEP include a base fuel component and a separate fuel adjustment clause charge; is that right?

A. The base fuel sets -- are set in a rate case, and then there's an adjustment based upon the perspective period, and there's an adjustment period for an EMF period. That looks into the past.

Q. And what does EMF stand for?

A. Experience Modification Factor.

Q. Great. Thank you. So there's two components through what is recovered through the fuel rider then;

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is that right?

A. Yes.

Q. Great. So I'd like to ask you a few questions about the cost of service study that's been previously entered into the record as CIGFUR II Cross Examination Metz McLawhorn Direct and Settlement Exhibit 1. It was premarked as CIGFUR II Potential Cross Exhibit Number 88. If you could find that binder, sir.

A. I'm there.

Q. Great. Could you please turn with me to page 30 of that document? At the bottom of page 30, do you see the section that reads:

"Allocation of fuel costs."

A. Yes.

Q. Could you please read for the record the first paragraph underneath allocation of fuel cost.

A. I need to point out, I'm not the cost of service witness. I'm only taking about equal percentage fuel adjustments.

Q. Could you please read the first paragraph.

A. I can. I can read that.

"Fuel costs are considered passed-through costs, as they are passed on to customers on

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a dollar for dollar basis and do not include a return component."

Do you want me to read the whole thing?

Q. I do, please. Thank you.

A. Okay. Just tell me when to stop.

Q. I sure will. Thanks.

A. "The rate tariffs for both DEC and DEP include base fuel component and a separate fuel adjustment cost charge. A fuel adjustment clause is a regulatory provision that permits a change in rates to occur because of a change in the cost of fuel, or the variable portion of purchase power. expenses. These changes occur without the utility filing a formal rate case. Rather, in North Carolina and South Carolina, the regulatory Commissions conduct an annual fuel adjustment to adjust proceeding to adjust the fuel adjustment charge up or down as appropriate. These smaller focused proceedings are designed to eliminate the lag between changes of fuel costs and reflection of those charges in rates; thus, a fuel adjustment clause acts as an interim measure

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for adjusting rates to reflect changes in a large and highly volatile expense item so that under recovery or over recovery of the expense does not lead to financial deterioration or excess profits for the utility."

Q. You can stop there. Thank you. And if you could turn with me to the next page. Page 32. Do you see that the last sentence of the first full paragraph on page 32 reads:

"If the variation in hourly fuel cost is substantial, high load factor customers will be allocated a disproportionate share of those fuel costs."

A. Well, that's taken out of context. I'm going to have -- I'd have to see everything that leads up to that sentence. I can't agree with -- I can't agree with that statement just taken out of context. I would have to go through this document. I haven't seen it.

Q. So, Mr. Lucas, just to confirm, you've never seen the cost of study document --

A. No, I haven't.

Q. -- that you're looking at right now. Were you not involved in the cost of service studies

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stakeholder group?

A. No. I wasn't.

Q. Okay. So now let's turn to your testimony that you filed in this rate case. If you could turn with me to page 17.

A. I'm there.

Q. Okay. You state on page 17 lines 5 through 6 of your testimony that:

"DEP is justified charging less per kilowatt hour for certain customer classes that receive service at higher voltages."

Is that right?

A. That's correct. Because taking a service at a higher voltage results in less fuel being burned at the power plant. Higher voltage has less resistance than lower voltage. So it requires less fuel to provide the same kilowatt hour.

Q. Thank you for that. And you testify on the bottom of page 19.

A. Yes.

Q. Continuing through the top of page 20 that:

"Fuel costs are incurred based on the cost of fuel used to produce a kilowatt hour of energy."

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Do you see that?

A. Yes.

Q. And you also state on page 21 of your testimony that:

"Fuel cost allocations should be based on the fuel usage required to provide energy to customers."

Is that correct?

A. I'm sorry. What lines are you on? Page 21.

Q. Lines 7 and 8 -- 6 through 8, rather.

A. That's correct.

Q. It's true, is it not, that some costs recovered through fuel rates are not incurred based on the cost of fuel used to produce a kilowatt hour of energy?

A. That's correct.

MS. CRESS: At this time, Chair Mitchell, I'd and that the Commission take judicial notice of North Carolina General Statute § 62-133.2 and Commission Rule R-855.

CHAIR MITCHELL: Commission will take judicial notice of statute and the rule as requested by counsel.

MS. CRESS: Thank you.

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Q. To get a little bit more into the specifics there, Mr. Lucas, are certain capital costs and capacity costs, and transmission costs associated with purchase power recovered through the fuel rider?

A. I don't know about transmission costs. Payments for kilowatt hours for a renewable energy facility could contain -- they do contain some capital costs.

Q. That are recovered through the fuel rider?

A. Yes. And this is by state law.

Q. Would you agree with me that those capital costs recovered through fuel charges are not being incurred based on the cost of fuel used to produce a kilowatt hour of energy?

A. That's true. But that's a small component of the fuel charges.

Q. And we'll come back to that piece specifically, so thank you. Capacities costs in an approved DEP cost of service study are allocated using a demand factor, correct?

A. I don't do cost of service.

Q. So is that a question I should ask your colleague Mr. Williamson?

A. I'd ask David Williamson, yes.

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Q. Okay. So do you know then, sir, if Duke Energy Progress were to build a new solar energy generating facility, would it be allocated using a production demand factor or is that a question I also need to ask your colleague?

A. If Duke Energy were to build a solar facility, it would be treated like any other generated plant. It would be part of depreciation expense. Those costs would not be in the fuel rider.

Q. Thank you. So turning back to the cost of service study, which I understand your testimony to be that you have not seen before today, nevertheless, I have some questions for you because you are the fuel cost allocation witness; are you not?

MR. JOSEY: I'm going to go ahead and log an objection to any questions dealing with the cost of service study. Again, this witness has said he's not the witness for cost of service. Furthermore, CIGFUR has signed a settlement agreement on cost of service in this case in which it waived cross examination on that issue.

MS. CRESS: Chair Mitchell, to the extent that there are discussions in the cost of service report, which has already been entered into

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evidence in this case, I think it is relevant and material to Mr. Lucas' testimony which deals with the fuel cost allocation which has an issue that was not resolved by the settlement referenced by counsel.

CHAIR MITCHELL: All right. I'm going to overrule the objection. Allow counsel to ask her questions. I recognize Mr. Lucas has said he's not the cost of service expert. He hasn't reviewed the document prior to his time on the stand today, and, so we will give his testimony the weight that it's due. But you may object to questions as she asks them if you have a sound basis for your objection.

MR. JOSEY: Thank you.

Q. Mr. Lucas, do you have that in front of you?

A. Cost of service, yes. I want to warn you, my testimony is not everything there is to know about fuel. I focused on equal percentage fuel adjustments. So some of this may be brand new to me. We'll have to see.

Q. Understood. Thank you for that. And if you could turn to page 7, please.

A. And this is still tab 88?

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Q. Yes, sir.
A. Okay. I'm there.
Q. Do you see the last sentence, and it starts on the previous page at the bottom of page 6. Do you see the last sentence of subsection 2 there states:
"For purposes of these studies, all demand and customer classified costs can be designated as fixed, and all energy classified costs can be designated as variable."
A. I'm sorry. You're at the bottom of page 6?
Q. Right. So number 2 starts at the bottom of page 6, and continues on to page 7.
A. Yes.
Q. I'm asking specifically about the last sentence in Section 2.
A. And the last word begins with the word "the" and then jumps to the next page -- or the previous sentence.
Q. The sentence that reads:
"For purposes of these studies all demand and customer classified costs can be designated as fixed, and all energy classified costs can be designated as variable."

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A. Okay. That's -- that begins -- on my copy different, I guess. On the top of page 7, the first complete sentence it says:

> "For purposes of these studies, all demand and customer classified costs can be designated as fixed, and all energy classified costs can be designated as variable."

Q. Thank you. Did you hear Mr. McLawhorn's testimony provided in this case?

A. Yes.

Q. And Mr. McLawhorn testified that if DEP purchases solar capacity, it's allocated on an energy basis and recovered through the fuel rider; is that right?

A. That's correct. Because one thing about solar facilities, you can't just say, "We're going to pay you a capacity payment because it's a 5 megawatt solar facility." It's output is variable. It's not dependent on capacity. And this is true for all renewable energy facilities. There are all paid for kilowatt hours. They get paid more during peak demand for those kilowatt hours, and that sort of acts like a capacity payment. Like I said, solar facilities and

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other renewables, they are not paid a capacity payment based upon their nameplate capacity. They are all paid in kilowatt hours. They just earn more during peak time kilowatt hours. And that in effect acts as a capacity payment.

Q. Do you consider energy generated by a solar energy facility to be fuel?

A. Yeah. It fuels the su- -- created by the sun.

Q. So that's your testimony, that you consider solar power to be fuel?

A. Solar power's not fuel. The fuel is the sun. Okay. Go back to -- the photons come from the sun. Hit a solar panel. It's a reaction that photons start pushing electrons through a wire. We've got a general statute that says, "Well, it's going to be a fuel-related cost." And that's why we cover those costs in the fuel rider.

Q. Do you acknowledge anywhere in your testimony, or your accompanying exhibits, that there are several fixed costs recovered through the fuel rider?

A. No. They are not really fixed because if a solar panel system is not putting out energy, they are

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not getting paid. It's not a fixed cost. It's not like if a solar panel system breaks for a whole year, they can't come back in and say, "Well, I should get fixed cost anyway, because it cost me to run this solar panel system." If a don't make kilowatt hours, they don't get paid. They are only paid for kilowatt hours. And, like I said earlier, that's variable. That kind of acts like a capacity payment.

Q. And, sir, you previously testified this morning that certain capacity costs and certain capital costs are recovered through the fuel rider.

A. Because a solar does have capacity -- requirements to build its capacity, but he's not paid -- or they are not paid based on any kind of capacity. They are only paid for kilowatt hours.

Q. To your knowledge, has the Public Staff done any analysis to determine whether, or by how much, the proportion of nonfuel costs recovered through the fuel rider will increase this decade as the result of implementing the carbon plan?

A. Not to my knowledge.

Q. Did you hear your colleague Mr. McLawhorn acknowledge that the nonfuel components of cost recovered through the fuel rider are likely going to

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increase as we look toward 2030 with carbon plan implementation?

A. I don't remember that exact statement.

Q. Okay. Do you recall that Mr. McLawhorn also made the point that fuel costs are expected to go down as nonfuel costs are expected to increase?

A. I'd skip over any of his exact statements.

Q. Okay. All right. Shifting gears then. It's your testimony, correct, that the equal percentage method shifts costs from the LGS to other customer classes; is that right?

A. No, that's not correct. The cost shift created by equal percentage fuel adjustments can shift to costs from residential customers to industrial customers, or vice versa. It's not any one customer class will receive all benefits or all harm by the equal percentage fuel adjustment.

Q. Okay. But this distortion, to your use your word, is symmetrical, in that the opposite is true as well. Meaning that in times of more fuel decreases, more of the decrease would flow back to the residential class than it does to, say, the LGS class; is that right?

A. Can you point to where that is in my

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testimony?

Q. The word "distortion?"

A. Well, your whole statement about shifting. Your whole question.

Q. So this is a question for you that is not based on your testimony. This is a question that I'm asking that I would like for you to answer on the stand, please.

A. Okay. Sure.

Q. So this distortion, that you allege occurs, is symmetrical; is it not? And that the opposite is true that in times of fuel decreases, more of the decrease flows back to the residential class than it does to, say, the LGS class?

A. It is definitely not symmetrical. Fuel prices are not in some kind of perfect rhythm, where customer classes are fairly treated, say, at the end of a decade. We want fuel costs to be fair each and every year. And it's true with declining, or inclining, fuel costs that one customer class may take advantage of another, but it's not symmetry. Like I said, fuel prices -- look back they almost seem erratic. It's not like at the end of a period of years that all customer classes are made whole. We don't true-up fuel cost

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that way. Also, there's never any true-up for the time value of money. If one customer class is harmed by the equal percentage fuel adjustment, it's not like they are made whole a few years later if fuel costs go the other way.

Q. At this time, I'd like to turn your attention to Public Staff Potential Redirect Exhibit 137 --

MS. CRESS: And, Chair Mitchell, I request that this document be marked for identification as CIGFUR II Cross Examination Lucas Direct Exhibit 2.

CHAIR MITCHELL: All right. Document will be marked as requested by counsel.

(CIGFUR II Cross Examination Lucas Direct Exhibit 2 was marked for identification.)

MS. CRESS: Thank you.

THE WITNESS: I'm there.

Q. Can you please read the response DEP provided to this data request from the Public Staff, number 187-4.

A. Just read the response itself?

Q. Yes, sir.

A. Okay.

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"Because the equal percent method aims to achieve a uniform total bill impact among all customer classes in an environment of rising costs, the cost increase has shifted to the residential customer class and away from the large and medium general service customer classes.

Respectively, in an environment of declining costs, the cost benefit has also shifted to the residential customer class and away from the large and medium general customer classes."

Q. Thank you. Turning back to your testimony, you testified -- and I'll let you get there. It's page 20.

A. I'm there.

Q. I'm not, so if you give me one moment.

A. No problem.

Q. And you testify, on page 20, that you've had the opportunity to review the 14 DEP fuel proceedings that follow the 929 docket; is that correct?

A. That's correct.

Q. Okay. So you would acknowledge, subject to check, that DEP had fuel decreases in Docket Number

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E-2, Subs 1069, 1107, 1204, 1250, and 1272, correct?

A. I would have to check that, but, subject to check, I would agree.

MS. CRESS: Chair Mitchell, because the witness has testified about his review of these 14 previous proceedings and the way that his review has informed his recommendation in this proceeding to this Commission, we would ask that the Commission take judicial notice of its Orders in each of those subsequent 14 proceedings. And I have them all listed here and happy to go through them either one at a time or all in one fell swoop. However you would prefer.

CHAIR MITCHELL: All right. The Commission will take judicial notice of its Orders but, for -- let's identify each of those Orders with specificity at this time, for purposes of the record.

MS. CRESS: Thank you, Chair Mitchell. Order approving fuel charge adjustment in Docket Number E-2, Sub 924, issued on November 16, 2009. Order approving fuel charge adjustment in Docket Number E-2, Sub 976, issued on November 17, 2010. Order approving fuel charge adjustment in Docket

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Number E-2, Sub 1001, issued on November 14, 2011. Order approving riders in Docket Number E-2, Sub 998, issued on August 12, 2012. Order approving fuel charge adjustment in Docket Number E-2, Sub 1018, issued on November 16, 2012. Order approving fuel charge adjustment in Docket Number E-2, Sub 1031, November 25, 2013. Order approving fuel charge adjustment in Docket Number E-2, Sub 1045, issued on November 19, 2014. Order approving fuel charge adjustment in Docket Number E-2, Sub 1069, issued on November 9, 2015. Order approving fuel charge adjustment in Docket Number E-2, Sub 1107 issued on November 7, 2016. Order approving fuel charge adjustment in Docket Number E-2, Sub 1146, issued on November 17, 2017. Order approving fuel charge adjustment in Docket Number E-2, Sub 1173, issued on November 8, 2018. Order approving interim fuel charge adjustment requiring further testimony and scheduling hearing in Docket Number E-2, Sub 1204, issued on November 25, 2019. Order approving fuel charge adjustment in Docket Number E-2, Sub 1250, issued on November 30, 2020. Order approving fuel charge adjustment in Docket Number E-2, Sub 1272, issued on November 17, 2021. And

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order approving fuel charge adjustment in Docket Number E-2, Sub 1292, issued on November 3, 2022.

CHAIR MITCHELL: All right. Ms. Cress, go back and check for -- for 2011 and 2012, can you go back and identify those orders with specificity because I've got the -- my notes have the sub dockets a bit out of order, and the dates seemed off to me too. So just make sure you've -- and it may be that something strange was happening in those years, but can you go back and make sure you've got those Orders identified correctly?

MS. CRESS: Absolutely. And you said 2011 and '12?

CHAIR MITCHELL: Yes. I have two -- yes. 2011 and 2012.

MS. CRESS: Order approving fuel charge adjustment in Docket Number E-2, Sub 1001, issued on November 14, 2011. Order approving riders in Docket Number E-2, Sub 998, issued on August 20, 2012. And Order approving fuel charge adjustment in Docket Number E-2, Sub 1018, issued on November 16, 2012.

CHAIR MITCHELL: Okay. Reread the -- the Order caption for the Order that was

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issued in Sub 998.

MS. CRESS: Order approving riders.

CHAIR MITCHELL: Okay. All right. Let's proceed.

MS. CRESS: Thank you, Chair Mitchell.

Q. Mr. Lucas, would you agree with me that before supply chain issues arising during COVID and the war in Europe, fuel costs were going down?

A. Let me check. I've got a graph of natural gas prices here from 1998 to the present. Like I said earlier, they're kind of erratic, but it looks like a period from, like, 2019 to 2020 it looks like natural gas prices were generally going down.

Q. And would you agree with me that coal and natural gas prices have increased significantly in recent years?

A. Yeah. From 2020 to 2022, natural gas prices declined significantly. Just the past few months, they've gone way back down. And coal prices did generally go up. I don't have that information in front of me. We don't burn so much coal as we used to.

Q. Thank you. I'd like to turn your attention now to what was premarked as Lucas Exhibit 7.

A. Is it my exhibit from my testimony?

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Q. Yes, sir.
A. Okay. Okay. I'm there.
Q. And now, first, this document is labeled as Public Staff Lucas Exhibit 7; is that right?
A. That's correct.
Q. Is there any other label for it?
A. I don't have another label unless it was put in as a redirect exhibit or something.
Q. Okay. The listed fuel rates that you have in this small table at the top left of this exhibit, those rates do not include the EMF increment; do they?
A. No. They don't include the EMF.
Q. So, in other words, the rates listed in your small tables at the top of this exhibit are not based on the total net fuel and fuel-related cost factors; are they?
A. No. That's from two different fuel years, 2021 and 2022. And those are the -- and that's DEP cases Sub 1272 and Sub 1292. Those are base fuel rates, and the adjustment is if there had not been equal percentage fuel adjustment.
Q. And to be clear for the record, the rates that you have listed in these tables do not include the EMF component of the fuel rider rates, correct?

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A. Well, are you talking about those two small tables? We talked about those. Those are just based fuel rates and the adjustment for the perspective period. The two tables below that, first one is kilowatt hour sales, and the next two are fuel revenues.

Q. Okay. So let me try asking this one more time since you haven't given me the yes or no answer that I'm seeking.

A. Okay.

Q. Do these two tables in the top left-hand corner of this exhibit include the EMF component of the fuel rates?

A. Oh. No, they don't.

Q. Thank you. Do your numbers here assume that fuel costs are the same for every hour?

A. No. This is fuel cost for each month. The total for each month.

Q. Okay. Do your numbers take into account that high load factor LGS customers use more power off-peak periods when fuel costs are lower?

A. No. We don't allocate fuel cost or power plant reduction that way. We don't assign certain fuels to certain customer classes. And we don't assign

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certain power plants to any particular customer class.

Q. Did you remove all nonfuel costs in this analysis, such as capacity cost, chemical cost, transmission cost, profits included in purchase power, losses from sales of coal ash, or transportation costs?

A. No. And this would be -- the last two large tables, this is just fuel revenues total.

Q. Shouldn't you remove all nonfuel costs to make your analysis valid?

A. No. These are fuel revenues and fuel revenues are part of what's used to do the equal percentage fuel adjustment.

Q. Thank you. Do your numbers in the bottom left-hand corner of this exhibit represent what you contend to be the cost shift resulting from the equal percentage method?

A. Yes.

Q. If you have used the total net fuel and fuel-related cost factors, meaning both the base and the EMF component of 2.527 cents per kilowatt hours for LGS customers, your calculations here would have been smaller numbers; isn't that right?

MR. JOSEY: I would object to this question unless she has some evidence of the

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calculation.

MS. CRESS: Chair Mitchell, this exhibit, as I understand it, is a result of calculations that Mr. Lucas has performed, and I am asking a question about what would happen if he tweaked the calculations that he has made here and as reflected in this exhibit that is attached to his testimony.

THE WITNESS: This is a complicated table. I mean, I can't --

CHAIR MITCHELL: Mr. Lucas, let me address the objection first.

And, Mr. Josey, can you respond to Ms. Cress?

MR. JOSEY: I would say it's a complicated table. It's a complicated calculation, and for -- just to be made a tweak is, I think, oversimplifying what is actually happening here.

CHAIR MITCHELL: All right. I'm going -- I'm going to overrule the objection.

Mr. Lucas, just do your best here and help us understand. If you can, respond to her question, and help us understand whatever limitations there may be with respect to your

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response.

Q. Mr. Lucas, do you need me to restate the question?

A. Yes, please.

Q. Okay. If you had used the total net fuel and fuel-related cost factors, meaning both the base plus the EMF of 2.52 cents per kilowatt hours for LGS customers, your calculations of what you contend to be the cost shift would be smaller numbers; is that right?

A. I can't testify to that. I would have to go through the spreadsheet again.

Q. Okay. So just to make sure I understand your position, the Public Staff is proposing an alternative allocation in fuel rates that would eliminate what it contends to be the alleged interclass cross subsidy in fuel rates; is that right?

A. That's correct. And we have to now because of House Bill 951. And that requires us to set rates based on cost causation principles.

Q. So even if we assume for sake of argument that these numbers here in the bottom left-hand corner of your Exhibit 7 are the actual cost shift resulting from the equal percentage method you acknowledge, do you not, that the roughly $5 million that you contend

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is under collected from the LGS class is a little less than one-ninth of the $43 million annual subsidy during rate year zero being provided by LGS customers to other customer classes?

A. I'm sorry. I'm not testifying on particular rate year zero, or the year in this case. It's millions of dollars is a cross subsidy. Now we're required by law to fix it. So that's what we're doing regardless of the dollar amount.

Q. So just to make sure I understood your testimony correctly, are you recommending single-issue ratemaking?

A. No.

Q. How is this not single-issue ratemaking?

A. Well, we found a potential problem and we're trying to fix it. There are lots of expenses in the rate case that we adjust. I mean, this isn't a single issue. This is a rate case. We had a settlement with over 30 issues. It's not picking out one -- one issue. We've found a problem. We're required by law to fix it. It doesn't matter if it's twenty problems or one problem. We're going to fix it.

Q. And just to be clear, the $43 million interclass cross subsidy from LGS customers to other

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customer classes is only being recommended by the Public Staff in this case to be reduced by 10 percent; is that right?

A. I'm sorry. Where'd you get the $43 million dollars from?

Q. Reed -- DEP Witness Reed Exhibit 4 to her testimony; do you have that in front of you?

A. No. Is it available?

Q. If you can turn to CIGFUR II Potential Cross Exhibit Number 70. And we might be able to speed things up a little here if you would just agree, subject to check, that DEP witness Reed testified to this interclass cross subsidy and base rates.

MR. JOSEY: Again, I would object. I think he is not the rates witness.

THE WITNESS: I can't testify. I mean, this --

CHAIR MITCHELL: Mr. Lucas, let me -- let me address the objection first.

I'm going to overrule the objection.

And go ahead and please provide your response.

THE WITNESS: Can you please restate your question?

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Q. Sure. So you said that this alleged cost shift here in your bottom left Exhibit 7 is something that needs to be eliminated because of House Bill 951, and so my question to you is, shouldn't the $43 million annual subsidy that LGS customers are providing to other customer classes in base rates also be eliminated?

A. I'm not the cost of service witness. Like I said earlier, my testimony is only about equal percentage fuel adjustments. I can't make statements about other items in rates, or other cross subsidies.

Q. So your testimony is limited to this single issue of fuel cost allocation?

A. That part of my testimony is. I testified about a lot of things. Coal ash. Plant retirement. If you add up all the other Public Staff testimony, we had lots and lots and lots of issues in this rate case. But I have one particular item we need to correct because of state law now.

Q. But your recommendation pertaining to cross subsidization is based on the single issue of fuel rates, correct?

A. Equal percentage fuel adjustments.

Q. So is that a yes?

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A. Yeah. That applies to fuel rates, yes.

Q. I'd like to turn your attention to what's been premarked as Lucas Direct Exhibit 6. And this is labeled as a draft. Is the Public Staff planning on revising this at a later date?

A. Let me get some things out of the way here. Okay. Exhibit 6 of my testimony?

Q. Yes, sir. And do you see here it says:

"Draft not a component of the 2022 DEP NC fuel filing."

My question is, is this document a draft or is the Public Staff planning on revising this at some point?

A. No. Those are Duke's words. We asked Duke Energy Progress to provide calculations of fuel rates without equal percentage adjustments. Since we are reviewing fuel cases, they just didn't want confusion between the spreadsheet and what was actually in fuel rates.

Q. And Harrington is not a witness in this rate case, correct?

A. No. She was a witness in the previous DEP fuel case.

Q. And so your Exhibit 6, just so I understand

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it, is an altered version of an exhibit that was filed in a different docket?

A. That's correct.

Q. And I see you have this box around one line of numbers, but, to be clear, that's not the only alteration that was made from the original version of this document, correct?

A. Yes. The fuel calculations are a spreadsheet. It's got about 38 tabs that are all linked together. So there's lots of numbers that flow from one spreadsheet to another.

Q. And you haven't included a redline version of the original exhibit to show what was modified from the original version, correct?

A. No. That'd be lots of spreadsheets. But, no, I haven't provided that.

Q. And you also haven't included the original Harrington Exhibit 1 in that other docket as an exhibit to your testimony; have you?

A. No. But it's in the record in E-2, Sub 1292.

Q. That's not this rate case, correct?

A. That's correct.

MS. CRESS: Okay. Chair Mitchell, at this time CIGFUR II would object to the admission

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of Lucas Exhibit 1 and further move to strike it from the record for failure to authenticate it. Mr. Lucas has provided neither the original Harrington Exhibit 1 nor a redline version of the original. Meaning, there is nothing in this record, in this docket, to show what changes have been made nor the directionality or the materiality of those changes. And as we've previously established in this proceeding, it's not proper to take judicial notice of a party's filing in another docket.

Finally, it would constitute rebuttal, or surrebuttal, evidence to allow counsel for Public Staff to now, at this stage in the proceeding, lay the proper foundation to authenticate this exhibit during live redirect examination.

So for all these reasons, Lucas Direct Exhibit 6 is improper, inadmissible, and should be stricken from the record.

CHAIR MITCHELL: All right. Ms. Cress, just so the record is clear, your motion pertains to Lucas Exhibit 6 to his prefiled testimony?

MS. CRESS: That's right.

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CHAIR MITCHELL: Exhibit 6. Okay.

Mr. Josey.

MR. JOSEY: I would say that this is an illustrative exhibit. Ms. Cress has asked Mr. Lucas numerous times to, you know, accept things subject to check, including a spreadsheet change in -- just a minute ago. And to not allow this after allowing that I think would be improper.

MS. CRESS: Chair Mitchell, these are -- with all due respect, these are not analogous things. We're talking about a spreadsheet where numerous changes were made to these numbers. And there's nothing in this record to show what was changed and by how much. And so it -- it's illustrative of what? Without something to compare it to, it's improper.

THE WITNESS: I do show how much.

CHAIR MITCHELL: All right. Mr. Lucas, let me let your attorney respond to counsel.

Mr. Josey, anything else to add here?

MR. JOSEY: Again, I would just say that this is to show what the calculations he did, and if Ms. Cress would like us to -- or the Commission would like us to file late filed exhibit supporting

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that, we can. However, again, we have been through this once with a different spreadsheet on a different line of questioning.

CHAIR MITCHELL: All right. We are going -- I'm going overrule the objection. We'll give the evidence the weight that it's due.

MS. CRESS: Thank you, Chair Mitchell.

Q. Turning back to your testimony, you testify at the --

CHAIR MITCHELL: I'm sorry. Let me -- let me be clear for the record here. I'm going to deny the motion. I'm going to deny the motions made by CIGFUR counsel and we will give the evidence the weight that it's due.

Q. You testify at the bottom of page 24 that:

"DEP should implement the Public Staff's recommended base fuel rates for the perspective period in its next fuel proceeding to be filed in June 2023. With rates taking effect on December 1, 2023."

Is that right?

A. That's correct.

Q. Has the Public Staff quantified what the impact will be on the different customer classes in

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that upcoming DEP fuel rider proceeding in the event this Commission were to adopt the Public Staff's recommendation in this case?

A. We can't because DEP hasn't filed it yet. We don't know exactly what kind of perspective period costs DEP will provide. We don't know what kind of experience modification factor DEP is going to provide. We'll have to review that case and make that decision later.

Q. How can this Commission ensure that the LGS class of customers won't be unreasonably harmed if it were to adopt the Public Staff's recommendation in this rate case regarding a future fuel rider proceeding that hasn't been filed yet?

A. Well, that's the purpose of my testimony. We're trying to make sure no customer class is unreasonably harmed. I think right now, under equal percentage fuel adjustments, that one customer class can take advantage of another one. And my -- we'll have recommendations and the Commission will have to decide of the evidence of the case provided by Public Staff, provided by DEP and other interveners, and make a decision and -- excuse me -- make fair rates.

Q. So if one customer class was taking

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advantage, as to use your words, of another customer class, or other classes of customers in base rates, would you also say that, that should be fixed and addressed by this Commission?

A. I can't testify other than what's in my equal percentage fuel adjustments.

Q. So back to that whole single-issue ratemaking thing?

A. That's not single-issue ratemaking. We found a problem that we are required by law to fix. So in equal percentage fuel adjustments, we are fixing a cross subsidization by law.

Q. Would you also say that you are required by law to fix a cross subsidy in base rates?

MR. JOSEY: I'm going to object. Again, this is asked and answered.

CHAIR MITCHELL: I'm going to overrule the objection.

Mr. Lucas, answer the question, please, sir.

THE WITNESS: I'm not testifying about anything else in base rates other than this fuel percent adjustment. I'm not a lawyer, and can't say exactly how that law has to apply across the

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entire rate case.

Q. Well, you're testifying pretty confidently that this alleged cross subsidy should be eliminated with respect to the fuel rider, but is it your testimony that, that same cross subsidy should not be eliminated in base rates?

A. That's my testimony. I'm not saying it should or should not be. I'm not making a statement about anything else in base rates other than this equal percentage fuel adjustment.

Q. Okay. So your testimony, in this case, is limited solely to fuel costs?

A. The equal percentage adjustment component of fuel costs.

Q. Without considering whether there might be an existing interclass subsidy from the LGS class to other customers in base rates?

MR. JOSEY: Again, objection. Asked and answered.

CHAIR MITCHELL: I'm going to overrule. Ask the question one more time, and Mr. Lucas answer it, please.

Q. Mr. Lucas, does your testimony in this case pertaining to the equal percentage method take into

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account that there is an existing interclass subsidy in base rates from the LGS class to other customer classes?

A. Your question is mixed with a statement. You have a statement that there are other cross subsidies. I did not review any other type of cross subsidies. But I'm not making any other statements about cross subsidies except this equal percentage fuel adjustment.

Q. How can the Commission ensure, if it were to adopt the Public Staff's recommendation in this case, that elimination wouldn't of the equal percentage method wouldn't constitute rate shock for the LGS class of customers in a future fuel rider proceeding that hasn't been filed yet?

A. Oh. Well, all customers can be exposed to rate shock in fuels. We can't guarantee no one will.

Q. How can this Commission ensure, specifically for the LGS class of customers, pursuant to the allocation change you're recommending in this case?

A. Well, there are various ways. Spreading fuel cost over three years. Like Commission did in E-2, Sub 929. There are other ways to mitigate a fuel -- rate shocks.

Q. Has DIP indicated that it's willing to spread

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its fuel costs over three years?

A. No. We're not in a DEP fuel case proceeding right now. We'd have to see what DEP requests this coming June.

Q. DEC has filed its 2023 annual fuel rider application, and its $1 billion under recovery has already been testified to in this case rate by your colleague Mr. McLawhorn; did you hear that testimony?

A. I don't remember specifically about what he said, but DEC in its original filing did request about a billion dollar under recovery collection.

Q. Are you aware that the equal percentage method in DEC's pending fuel rider proceeding will result in an approximately 18 percent total bill increase across customer classes in that docket?

A. I believe the total cost -- I think the average total cost for an increase was about 18 percent for all -- averaged among all customer classes.

Q. Has the Public Staff calculated what the percentage increase would be for DEC's large industrial customers without the equal percentage method?

A. No. We have not. But we're not recommending to eliminate equal percentage fuel adjustments in the current DEC rate case. I recommend, if the Commission

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adopts the elimination of equal percentage fuel adjustments, that it does not do so until DEC's next fuel proceeding in 2024.

Q. Okay. So you just testified previously, that the Public Staff has not calculated what the percentage increase would be for DEC's large industrial customers without the equal percentage method; is that correct?

A. To my knowledge, we have not.

Q. Would you have any reason to disagree with me if I said that without the equal percentage method that 18 percent total bill increase would be closer to a 24 percent total bill increase for DEC's industrial customers?

A. Subject to check. I'd have to go through those calculations.

Q. And it's true, is it not, that this Commission found that rate mitigation for industrial customers was necessary in the Sub 929 Docket?

A. Yes. But that was part of a settlement. We had two things that helped industrial customers. Equal percentage fuel adjustments and a mitigation over a 3-year period as part of a settlement.

Q. And would you agree, subject to check, that the percentage bill increase in the Sub 929 Docket was

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18 percent?

A. I can't remember the total amount, but I'd have to, subject to check, I could -- I could say so.

Q. Are you aware that evidence has been entered into the record in this rate case of multiple recent industrial plant closings and related load in jobs lost in DEP's service territory?

A. I was not aware of that.

Q. Does that change your recommendation in this case?

A. No. I would have to see evidence that equal percentage fuel adjustment elimination would've caused the loss of those industrial customers. I would have to tie it back to equal percentage fuel adjustments.

Q. Are you aware that evidence has been entered into the record in this case rate case regarding anticipated price-induced demand erosion in DEP's service territory?

A. I'm not aware of that.

Q. And did you hear the testimony of CUCA witness Heilig regarding the affordability concerns of LGS customers?

A. I heard his testimony, but he did not testify about equal percentage fuel adjustments to my

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knowledge.

Q. So do you not recall hearing testimony about affordability being a concern of LGS customers?

A. Yes. And we're concerned about affordability for all customers, including industrial customers, and we are about residential customers. In a typical month, thousands of families in DEP territory has have electricity disconnected for nonpayment. So high electricity prices really affect all customer classes, residential, commercial, and industrial.

Q. Are you aware that the Public Staff's own evidence entered into the record in this rate case indicates that U.S -- that the U.S economy is at greater risk of slipping into a recession?

A. I was not aware of that evidence and that --

Q. I'm sorry. Go ahead.

A. -- and, I mean, a recession would hurt all customer classes for sure.

Q. Does that change your recommendation?

A. Not at all.

Q. Are the factors the Commission cited to in its Sub 929 Order approving the Sub 929 settlement present now in the current rate case?

A. No. We were in the midst of the great

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recession back in 2008. We are not in that situation right now.

Q. And you just testified that you weren't aware of the Public Staff's own evidence regarding economic indicators in the United States at present?

A. No.

Q. Okay. And you state on page 17 of your testimony -- let me know when you're there.

A. I'm there.

Q. You state some of the justifications the Public Staff relied on in support of the equal percentage method back in 2008. Including the large increase in fuel costs and the uncertain economic times. Would you not acknowledge that those factors that justified the Public Staff's support of the equal percentage method back in 2008 are present right now in today's circumstances?

A. Can you give me line numbers from that page, please?

Q. 18 through 21.

A. Okay. I see where it is. Can you ask your question, please, again.

Q. So you've testified that the Public Staff relied on several justifications in support of the new

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equal percentage allocation. The large increase of fuel cost, the utilities offered to spread the increase over three years, and the uncertain economic times. Would you not agree that in today's rate case, these are uncertain economic times?

A. No. I would say it's nowhere near the great recession we had at the time. I mean, can we do this rate case in 2008? The great recession was well underway. And I'm not an economist. I can't predict or put a quantifier on amount of uncertainty in economic times. I can't say these conditions are identical to what they were 15 years ago.

Q. Are you aware of the Pactiv Evergreen paper mill announcing its upcoming closure in quarter two, 2023 in DEP's service territory?

A. I've heard that, but I haven't heard that being tied to equal percentage fuel adjustments.

Q. It's true, is it not, that it was tied to market conditions, which could include the equal percentage method?

MR. JOSEY: Objection. She's asking him to speculate.

CHAIR MITCHELL: I'll sustain the objection.

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Q. And turning to page 18 of your testimony, you quote on an affidavit of Tom Lamm -- and just for the record, can you identify who Tom Lamm is, please?

A. He was an engineer in the Public Staff of what was then the electric division which became the energy division.

Q. And so you're providing an excerpt from Mr. Lamm's affidavit that he provided in the Sub 929 docket; is that right?

A. Yes.

Q. And you indicate here on lines 2 through 5:

> "The Public Staff recognizes these significant and disproportionate impact on the industrial class of recovering these increased costs on a uniform cents per kilowatt hour basis, as well as the need to fairly allocate the rate impact on all customer classes in the period of economic uncertainty, plant closings, and rising unemployment."

A. I see that, but the next couple sentences, he talks about supporting this methodology of equal percentage adjustments, but they are being modified by spreading the under collection over the billing

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period -- or the next two billing periods. It was part of the settlement.

Q. If you could turn with me to the Sub 929 Order.

A. In which -- do you know what tab that was in CIGFUR's?

Q. I believe it was Potential Exhibit Number 26.

A. Okay. I'm there.

Q. If you could turn with me to page 16.

A. I'm there.

Q. Do you see at the bottom of page 16 and continuing on to page 17, where it says that:

"The traditional methodology, i.e. a uniform cents per kilowatt hour of usage would result in an approximately 18 percent increase to the Company's large industrial customers?"

A. I see that.

Q. And do you see further that it says:

"Company witness Barkley testified that such a large percentage increase could negatively impact industrial operations, and could result in job losses, shifts in production to states or countries, and plant closings."

A. I see that and. And that's part of why the

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Public Staff entered in the settlement to spread this large increase, right here, over a three-year period.

Q. And did you include an excerpt of Mr. Barkley's testimony that he provided in the Sub 929 Docket in your own testimony?

A. I believe I did. If you could tell me the page and line number. Okay. Yeah. Page 17.

Q. Thank you. Now, since you've included an excerpt from Mr. Barkley's testimony in the Sub 929 Docket, in the testimony that you filed in this case rate case --

MS. CRESS: Chair Mitchell, I ask that the document premarked as Public Staff potential Redirect Exhibit 139 be identified as CIGFUR II Cross Examination Lucas Direct Exhibit Number 3.

CHAIR MITCHELL: 139. All right. The document will be marked for identification as requested by counsel.

(CIGFUR II Cross Examination Lucas Direct Exhibit 3 was marked for identification.)

MS. CRESS: Thank you, Chair Mitchell.

Q. Would you agree with me that the equal percentage method helps to smooth out annual rate

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impacts to nonresidential customers stemming from volatile fuel prices?

A. No. Because, like you said, rate costs are volatile. And we've never true-up the effect of equal percentage fuel adjustments. If one customer is harmed in one year, we never true it up. We never -- would get their money back with interest. I think equal percentage fuel adjustments create problems. It doesn't really solve them.

Q. It's true, is it not, that without the equal percentage method, you would be exposing industrial customers to more volatility in fuel prices?

A. They could be exposed to more volatility, yes. But they burn the fuel. They use fuel and they shouldn't be able to have their costs pushed onto other customer classes just because fuel costs are volatile.

Q. Does that also apply to the residential customers who are being subsidized in base rates?

A. I'm not testifying anything about the subsidizations and base rates, other than what I've said about equal percentage fuel adjustments.

Q. Because it's a single issue here. Got it. So, to your knowledge, has the Public Staff at any time before now challenged account equal percentage method

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in any DEP rate case, or any DEP annual fuel rider proceeding?

A. No. It became accepted practice for a while, but now we have House Bill 951 that says we have to -- we're going to elimination of cross subsidies. So that's what I've done in my testimony.

Q. To your knowledge, has the Public Staff at any time before now challenged the equal percentage method in any DEC rate case or any DEC annual fuel rider proceeding?

A. No.

Q. As we move toward 2030 is it fair to say, since you've already testified, that the nonfuel costs are going to be rising as we get closer to 2030; is that correct?

A. I didn't testify to that.

Q. As you're colleague Mr. McLawhorn testified to, which you agreed, subject to check, this morning that nonfuel costs recovered through the fuel rider are going to increase as we get closer to 2030?

A. Yes. Subject to checking of Mr. McLawhorn's statement.

Q. With that in mind, is it fair to say that the fuel rider is actually going to become somewhat of a

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misnomer, and, instead, we should maybe be calling it the CAPEX rider?

A. No. It's identified in State Law 62-133.2 as a fuel and fuel-related cost. That's put in the state law. So we can't relabel it if it's the state law.

Q. Are you aware that the Public Staff has stated publicly that it is concerned that public support for the energy transition may start right to wane if electric rates increase too much or too quickly?

A. I'm not aware of that.

Q. Is it the Public Staff's position that industrial customers who are already subsidizing other rate classes to the tune of $43 million a year in base rates should also bare the brunt of carbon plant implementation costs by paying for a new renewable energy capacity on a per kilowatt hour basis through the fuel rider?

A. You've put a statement in your question. I can't testify about the $43 million cross subsidy.

Q. Is it the Public Staff's position that industrial customers should bear the brunt of carbon plan implementation costs by paying for new renewable energy capacity on a per kilowatt hour basis through

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the fuel rider?

A. They have to pay their fair share of costs. They're using energy. If they are using kilowatt hours, and all customer classes use kilowatt hours, they should all have to pay their fair share of those costs even if they are increasing.

MS. CRESS: Chair Mitchell, if I could have one moment. I think I am done.

CHAIR MITCHELL: You may.

Q. Mr. Lucas, just for clarity of the record, you did testify, did you not, that natural gas prices have increased in recent years?

A. Hang on a moment. I can give you a very clear answer. From 2020 to 2022, natural gas prices did increase greatly. Past few months they have gone down.

MS. CRESS: Thank you.

No further questions.

CHAIR MITCHELL: All right. We're going to take a morning break now. We will be back on the record at five after 11, and just as a reminder we're going to have lunch at 12:00.

So let's go off the record, please.

(Recess was taken at 10:53 a.m. to 11:07

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REDACTED

PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Monday, May 15, 2023

TIME: 9:29 a.m. - 12:01 p.m.

DOCKET NO.: E-2, Sub 1300

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

IN THE MATTER OF:

Application of Duke Energy Progress, LLC,
for Adjustment of Rates and Charges Applicable
to Electric Service in North Carolina and
for Performance-Based Regulation

VOLUME: 20

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MR. FELLING: Thank you, Chair Mitchell.

Mr. Williamson is now available for cross examination.

CHAIR MITCHELL: All right.

CIGFUR you're up.

MS. CRESS: Thank you, Chair Mitchell.

CROSS EXAMINATION BY MS. CRESS:

Q. Mr. Williamson, would you agree, subject to check, that the North Carolina League of Municipalities, or what I'll refer to in this line of questions as --

CHAIR MITCHELL: Ms. Cress, if you would, get the mic in front of -- there you go.

Q. Would you agree, subject to check, that the North Carolina League of Municipalities, or what I'll refer to in this line of questioning as "the league," intervened in DEP's last general rate case in Docket Number E-2, Sub 1219?

A. Subject to check.

Q. And so is it fair to say that the league had notice of both the comprehensive rate design study and the cost of service stakeholder group that the Commission ordered the parties to undertake after the

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Sub 1219 rate case?

A. I'm not entirely sure how notice to the rate design study roadmap is, as it was titled, was given out. That -- it was -- I don't recall if it was in the Commission's Order or if it was amongst the parties themselves.

Q. Okay. Can you turn with me to what's been previously entered into the record as CIGFUR II Cross Examination Reed Byrd Direct and Rebuttal Exhibit 1, which was premarked as CIGFUR II potential Exhibit 76; if you would turn in the binder in front of you?

A. You said 76?

Q. Yes, sir.

A. I'm there.

Q. Okay. And can you turn to page 53 of that exhibit, please. And that page lists the stakeholders who participated in the comprehensive rate design study; is that correct?

A. That appears to be what it is, correct. And it also shows their participation in respective working groups.

Q. Do you see the league listed on that list of stakeholders who participated in the comprehensive rate design study?

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A. Not specifically the league. I don't know if they --

Q. Do you see the North Carolina League of Municipalities listed?

A. No. I do not.

Q. And if the league had wanted to participate, they would have been able to; is that right?

A. Again, I'm not sure of how notice of this collaboration was involved -- happened. But, I assume that through the number of parties that were involved that if they wanted to, they could've participated, yes.

Q. Okay. And if you could turn with me to what's been previously marked as CIGFUR II Cross Examination Metz and McLawhorn Direct and Settlement Exhibit 1, which was premarked as CIGFUR II potential Exhibit 88.

A. I'm there.

Q. If you could please turn to page 88 of that exhibit. Is this the list of stakeholders who participated in the cost of service stakeholder process that followed the Sub 1219 rate case?

A. It is.

Q. Do you see the NC League of Municipalities

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listed anywhere on that stakeholder participant list?

A. I do not.

Q. Okay. All right. And if you could now turn with me to CIGFUR II Potential Cross Exhibit 78.

A. Okay.

Q. If you could turn to page 20 of this document --

MS. CRESS: Which I will ask, Chair Mitchell, if it could be identified as CIGFUR II Cross Examination D. Williamson Direct Supplemental and Settlement Exhibit Number 1.

CHAIR MITCHELL: All right. Just confirm for me the document that we're looking at.

MS. CRESS: Exhibit 78 of CIGFUR II's.

CHAIR MITCHELL: And what is that document?

MS. CRESS: It's the NRRI.

CHAIR MITCHELL: Okay.

MS. CRESS: By Ken Costello.

CHAIR MITCHELL: All right. The document will be marked for identification as requested by counsel.

(CIGFUR II Cross Examination D. Williamson Direct Supplemental and

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Settlement Exhibit Number 1 was marked for identification.)

Q. Can you turn to page 20 for me.

A. I'm there.

Q. Okay. Do you see on that page where it says: "Some of the elements of social welfare may be conflicting, for example, discounted rates to low income households may diminish economic efficiency and fairness from the perspective of the general ratepayers."

A. Is this under Section D?

Q. It is. It's the first sentence.

A. Okay.

Q. Do you see where it says that phrase that I just read into the record?

A. Just one second (Witness peruses the document.) Okay.

Q. Do you agree with this statement?

A. Not entirely. I guess what -- what I have to say is that this kind of -- or I guess to preface, this document is 80-something pages long and written by Ken Costello, who I know to be an economist of sorts, and so he's kind of talking more broadly in his productions. So I don't know what part of, I guess,

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utility service he may be referring to in this piece. But with regard to how discount rates impact the efficiency of things, I would say that it's really -- it's really unsure how a discounted rate would influence, or impact, a customer. Specifically a low income customer. It's really -- it's really just -- it's -- it's unsure how they would react to the discount as far as diminishing the economic efficiency, as it's been written here.

Q. So just to be clear, do you mean you are unsure how it would impact a low income customer and their usage?

A. Well, I think that it would be -- it would be based off of how every individual low income household is responding to particular discounts. Most of the time in -- or for low income customers, or low income households, I believe they would view a credit as an ability to spend those funds on other items that they need, that they need -- that they need at the time as opposed to spending it on potential utility services.

Q. Okay. Do you see in footnote 57 about halfway down that paragraph where it says:

"Economic efficiency helps to avoid the waste of resources from both consumption and

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production."

A. I do see that. And, I guess, to respond to that as far as low income customers who are struggling to pay their bills on a month basis, I don't -- I don't -- I wouldn't see them as a customer that would increase usage per se just because they receive a credit. I believe they're constantly aware of the bills in all aspects of the types of bills that they have to pay. And so keeping all bills from their perspective minimized is in their best interest.

Q. And what are you basing that belief on?

A. I'm sorry?

Q. You just testified to your belief, and I'm asking what you are basing that belief on?

A. I'm just -- it's just me -- it's my understanding of how all low income customers really have different -- different perspectives of where they are, as far as their energy burden, or how they use their energy, or what -- what other type of life experiences they may be involved with at the moment.

Q. Okay. Could you please turn to page 30 of the same document.

A. I'm here.

Q. Do you see there under Section 2, the very

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first sentence reads:

"Discriminatory pricing occurs when price differences for the same service do not correspond to cost differences."

A. I see that.

Q. Do you agree with that statement?

A. So -- so my understanding is that all classes are going to have different levels of service for -- not different levels of service -- but different customers that cause their own individual cost on the grid. But that's why customer classes are created in order to combine all of these like customers, and within that there's going to be some -- some ebb and flow as far as, I guess, good users of the grid and not so good users of the grid.

Q. So is your answer that, yes, you agree with that statement, or, no, you do not agree with that statement?

A. I don't believe that there are discriminatory prices based off the prices that the Commission approves.

Q. So is it your testimony that the customer assistance program, as proposed, is not discriminatory pricing?

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A. So I believe the Commission has the full authority to approve any type of assistance program. It's done it in the past with regards to economic development riders and job retention riders in a means to provide a level of assistance to a particular class of customers. So I believe the Commission has the ability through recently approved tariffs to apply a similar type of conclusion to this customer assistance program.

Q. And I understand that to be your position. But my question is, does the customer assistance program, as proposed, include discriminatory pricing?

A. I don't believe it includes discriminatory pricing.

Q. Okay. If you could turn with me to page 63.

A. You said page 63?

Q. Yes. Do you see under Section C where it says:

> "Regulators should consider the compromising effects that advancing affordability has on economic efficiency and discriminatory free rates. To what extent do regulators want to diminish economic efficiency or require general ratepayers to subsidize a group of

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low income households? How much discriminatory pricing will they tolerate?" Do you see that?

A. I do see that, yes.

Q. And so understanding your testimony here this morning, I take it you would disagree with this statement?

A. So, I guess, there's two things. One, again, I'm not entirely sure what the perspective of this entire document from this one author is trying to generate. It could be a multiple -- multiple publications from different authors that could come up with different conclusions or statements but, as far -- I guess, but on a second part because -- I mean, I do want to answer your question, could you -- could you repeat the question?

Q. The question was, I take it that you disagree with this statement?

A. This is on page 63 to 64. I guess, what's the starting point again?

Q. "Regulators should consider the compromising effects that advancing affordability has on economic efficiency and discriminatory free rates?"

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A. Yes. And I believe the Commission does recognize that they do have the ability to set what is an allowable amount of cross subsidy that fits the public policy.

Q. Okay. If you could turn with me to page 64, footnote 162. Do you see the first sentence reads:

"If these households face below cost rates, they would tend to consume more energy."

A. I see this statement. And, I guess, I would say that it's -- it's unclear on how individual customers would change their consumption habits from a credit.

Q. And by credit, do you mean a bill credit in the form of a discount customer assistance program?

A. Correct. As far as if -- if they face below cost rates they would tend to consume more energy. I don't know, or I don't believe that customers -- customers as a whole I believe is what this kind of statement is referring to. But it's unclear how individual customers would respond.

Q. So do you agree or disagree with this statement?

A. I disagree.

Q. And what is that disagreement base on?

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A. So -- I guess, again, it's me saying that it's unclear how individual customers would respond to it. It's to make a generalized statement, when individual customers and individual rates on these customers that they're experiencing along with all the other hardships that they have, it's making a statement that they would use more energy when they are already struggling to pay a bill that's currently available they would -- I don't believe they would increase their energy. I believe they would remain consistent, if anything.

Q. So is it your testimony that low income customers do not respond to price signals?

A. I believe that all customers respond to price signals. But I believe that all customers are going to continue to use relatively where they are. I don't think that customers would use more, particularly low income customers, would use more considering all of the other challenges that they have to experience and work with.

Q. Could you please turn with me to CIGFUR II Potential Cross Exhibit Number 79. And in this a regulatory review from the University of Pennsylvania article by Ken Costello that --

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MS. CRESS: Chair Mitchell, I request be marked as CIGFUR II Cross Examination D. Williamson Direct Settlement and Supplemental Exhibit Number 2.

CHAIR MITCHELL: All right. The document will be marked as requested by counsel.

(CIGFUR II Cross Examination D. Williamson Direct Settlement and Supplemental Exhibit Number 2 was marked for identification.)

MS. CRESS: Thank you.

Q. Do you see on page 2, Mr. Williamson, the third full paragraph of this article states:

"Political pressures and legislative mandates has ultimately compelled utilities with approval by their regulators to protect low income households from unaffordable utility bills. Some observers view these actions as taxation by regulation that requires slightly higher rates to the majority of customers to pay for special utility assistance initiatives. Some observers view these actions that require" -- I'm sorry -- "some observers view these actions as taxation by

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regulation that require higher rates to the majority of customers to pay for SUA, or special utility assistance, benefitting a smaller target group of customers."

Do you see that statement?

A. I do.

Q. Do you agree with that statement?

A. So, I mean, in essence, it's causing other customers to pay for particular items of another customer's -- to another customer's benefit. And, I guess, the response I have to that is kind of similar to the response that I gave just a moment ago about how the Commission has already ruled on and ordered on in previous rate cases and deemed it reasonable and appropriate to associate causing other customers to pay for a benefit to particular customers. And so I believe that it is within the Commission's ability to apply that discretion when it is appropriate.

And I believe it depends on the level of appropriate that we're talking about. So to the CAP, I mean, that's essentially why we've agreed to a pilot. And so we, through the settlement discussions, we've agreed to it as a pilot. And that's really to access, and in my view, it's an ability for us to review over

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the 3-year period to access the benefits of this proposal and where -- how that would influence customers, or impact customers, as far as disconnections or reduced arrearages. So there is a potential benefit there. And so it's just trying to better understand that benefit and how we might modify this program in the future going forward that still keeps us within this realm of reasonable and appropriate as far as public policy, because the Commission kind of took this step in the last rate case with regards to initiating this low income and affordability collaborative to make a deeper dive on affordability issues and how we're going to address them, and how we're going to attempt to deal with them.

And I think the LIAC produced a well thought out and surely a very thorough report with an immense amount of data and data points and discussions with a number -- and when I say a number, I mean nearly 2 dozen different intervening bodies -- meeting regularly and trying to figure out this challenge of affordability and what is within the realm of reasonable and appropriate that the Commission can approve and assign this particular program to be a benefit to these particular low income customers.

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Q. Mr. Williamson, did House Bill 951's enactment into law come after the Commission's Order in the Sub 1219 rate case?

A. This is the first rate case where HB951 is applicable, yes.

Q. And you acknowledge, do you not, that the customer assistance program, as proposed, is by definition an interclass subsidy?

A. It is. However, there are a lot of cross subsidies around that the Commission has given its approval on in the past. Like I was saying, with the economic development riders that are to the benefit of increasing load to nonresidential customers. In addition, the job retention or low retention rider that was approved, I believe it was in the 1146, 1142 general rate cases for Progress and Duke Carolinas where it was intended to incentivize the nonresidential -- the particular nonresidential customers to remain in North Carolina.

Q. And, just to be clear, all of those programs that you just listed as examples predate the enactment into law of House Bill 951, correct?

A. That's true. But the Commission still remains it's ability to approve and apply what it deems

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to be within the realm of reasonable and appropriate in every rate case proceeding.

Q. If you could please turn with me to CIGFUR II Number 28.

CHAIR MITCHELL: All right. We will pause there. Take our lunch break.

We'll be back on the record at 1:00. Let's go off the record, please.

(The hearing was adjourned at 12:01 p.m. and set to reconvene at 1:00 p.m. on Monday, May 15th.)

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REDACTED

PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Monday, May 15, 2023

TIME: 1:08 p.m. - 5:00 p.m.

DOCKET NO: E-2, Sub 1300

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

IN THE MATTER OF:

Application of Duke Energy Progress, LLC,
for Adjustment of Rates and Charges Applicable
to Electric Service in North Carolina and
for Performance-Based Regulation

VOLUME 21

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P R O C E E D I N G S

CHAIR MITCHELL: All right. Ms. Cress, you may continue.

MS. CRESS: Thank you, Chair Mitchell.

Whereupon,

DAVID M. WILLIAMSON,

having previously been duly sworn, was examined and testified as follows:

CONTINUED CROSS EXAMINATION BY MS. CRESS:

Q. Mr. Williamson, would you agree, subject to check, that the low-income stipulation filed in this docket on May 4, 2023, includes a sentence that reads: "The stipulating parties acknowledge and agree that the Commission must determine whether the Company's proposed cap is consistent with existing law and the public interest"?

A. Subject to check.

Q. You would agree, subject to check?

A. Yes.

Q. Thank you. Now, if I could have you turn to CIGFUR II Potential Cross Exhibit Number 28.

A. (Witness peruses document.)

I'm at Exhibit -- or Potential Exhibit 28.

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MS. CRESS: And at this time, Chair Mitchell, CIGFUR II would ask that CIGFUR II Potential Cross Exhibit 28 be identified for the record as CIGFUR II Cross Examination D. Williamson Direct Settlement and Supplemental Exhibit Number 3.

CHAIR MITCHELL: Document will be marked for identification as requested by counsel.

MS. CRESS: Thank you.

(CIGFUR II Cross Examination D. Williamson Direct Settlement and Supplemental Exhibit Number 3 was marked for identification.)

Q. Mr. Williamson, do you see, in this email chain, the very first paragraph that says:

"Dear counselors serving on the LIAC subteam C, I asked Lucy Edmondson of the NCUC Public Staff to respectfully share her knowledge about applicable North Carolina constitutional, statutory, case law, or public policy directives on the subject of cross subsidies and our work on LIAC. Lucy replied with a cogent and succinct primer on the subject and was gracious enough to grant

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permission to share it with the LIAC team members. See the string below for Lucy's primer"?

A. That's what it reads.

Q. Okay. Can you turn the page with me, please? And do you see, four arrows down, the sentence that says:

"By using cost causation principles to develop rates, people's bills are based on their usage and they have an incentive to conserve to lower their bills. When rates are not based on cost causation but perhaps on income, the tie between usage and the electric bill can be severed and the incentive to conserve can be reduced or removed"?

A. That's -- that's what it says.

Q. And would you agree with this statement contained in the primer on cross subsidies that was shared with LIAC subteam C by chief counsel for the Public Staff?

A. So it's -- it's a quite lengthy email from Ms. Edmondson. I haven't read the entire email. I wasn't privy to this email, as my name was not added to

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the distribution list of it. So this is new to me.

But I will say that just -- kind of, getting an idea of the email, itself. I don't want to take one sentence out of the email out of context for what might be explained later on.

Q. So you don't disagree with the statement from --

A. I'm trying to get an understanding of the sentence, itself, with regards to the entire email, so.

Q. So is it your testimony that you can't answer unless you were to read the entire email?

A. (Witness peruses document.)

So I guess if you could just, kind of, restate the question.

Q. Sure. The question is: Do you agree with this statement that I just read?

A. (Witness peruses document.)

Again, not necessarily have read the entire document. It kind of -- there -- I'm reading it as the potential for income-based rates. We don't have income-based rates in North Carolina.

Q. Understood. Thank you for that.

Did you hear your colleague, Witness Lucas, testify this morning?

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A. I did.

Q. Do you agree with Witness Lucas that House Bill 951 requires that interclass subsidies be eliminated?

A. I don't believe that's what the statute says. I believe the statute explicitly says minimize to the greatest extent possible. So I don't agree with your characterization of HB 951.

Q. So just to be clear, you're saying you don't agree with Witness Lucas' testimony?

A. I don't remember that exact line from him, but I do know that the statute is explicitly clear when it says minimized to the greatest extent possible when it talks about cross-subsidization.

Q. So if the transcript were to show that Witness Lucas said that interclass subsidies should be eliminated, your testimony here today would be that you disagree with Witness Lucas on that point?

MR. FELLING: Objection. Chair Mitchell, this question's been asked and answered. He's been asked if he agreed with Mr. Lucas' testimony, and he's already given his answer to that question.

MS. CRESS: Chair Mitchell,

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respectfully, he did not answer that exact question. And that is why I'm asking a slightly rephrased version of it.

CHAIR MITCHELL: All right. I'm gonna overrule the objection. Answer this question and then let's move on.

THE WITNESS: Sure. So my understanding of the statute is that it's to minimize, to the greatest extent possible, any cross-subsidization.

MS. CRESS: Chair Mitchell, could you, please, instruct the witness to answer the question that was asked?

CHAIR MITCHELL: Let's do this. Ask the question again and then answer the question she asks.

MS. CRESS: Thank you.

Q. If the transcript were to show that Witness Lucas testified this morning that House Bill 951 requires interclass subsidies to be eliminated, would you disagree with Witness Lucas?

A. If that's what's in the transcript, I would say that I disagree with Mr. Lucas.

Q. Thank you. Would you contend that a one-half-of-1-percentage-point rate increase

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constitutes rate shock?

A. One half of 1 percent?

Q. That's correct?

A. I would say that depends on what that one half of 1 percent is being applied to. If it's a dollar, I don't know what one half of one -- I guess a half of a cent, I don't believe that that would be considered rate shock, per se. It depends on the volume of dollars that are being associated.

Q. If you could please turn with me to your testimony now.

And it's true, is it not, that you filed for the first time in this docket your recommended class rates of return on May 1, 2023?

A. Is this my direct or my supplemental?

Q. I'm asking you.

A. Well, I filed two different times so -- or multiple times, actually.

Q. Would you agree, subject to check, that you filed your recommended class rates of return for the first time in this docket on May 1, 2023?

A. I would say that it was amended, I believe, on May 10th to be perceived as illustrative examples of rate of returns.

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Q. Did you file for the first time in this docket your illustrative rates of return on May 1, 2023?

A. Subject to check. Like I said, I've filed multiple times on, I believe, the 1st, the 4th, and the 10th.

Q. And that would have been after the discovery deadline had already passed in this rate case, correct?

A. I believe so.

Q. And you testified that you amended that testimony twice since May 1st; is that correct?

A. That's correct. I believe once was for -- I believe once was for adding numbers. It was more of an administrative type change, and another was for corrections. I believe that's correct.

Q. And as recently as this past Friday, May 12th, you amended your testimony?

A. May 12th?

(Witness peruses document.)

MR. FELLING: Chair Mitchell, can Counsel please direct the witness to what document she's referring to?

MS. CRESS: The testimony that was filed on behalf of Mr. Williamson on Friday, May 12th.

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MR. FELLING: Chair Mitchell, if I may, for the record, that was a -- we were filing pages that were reflective of the corrections that had previously been made to the testimony. Those corrections were not new corrections as of Friday, May 12th. Those were pages that could be inserted into the record.

I think the -- all the testimony from Mr. Williamson that's relevant to this panel has already been identified at the beginning of offering him as a witness.

CHAIR MITCHELL: All right. Ms. Cress, let's direct the witness to the testimony you want him to review.

MS. CRESS: Sure.

Q. Mr. Williamson, can you please turn to your supplemental Exhibit Number 1?

A. (Witness peruses document.)

Is this the -- I assume this is the corrected exhibit that was filed at some point in time?

Q. So you're the witness. If you could --

A. Yes.

Q. If you could turn to your -- your Supplemental Exhibit Number 1.

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A. Okay. I'm going to go to my Corrected Supplemental Exhibit Number 1, and I'm there.

Q. Are you aware of whether any other party has been able to verify or replicate the results of your class rate of returns that you have here in your supplemental testimony Exhibit Number 1?

A. I have not been -- I have not been approached by any other party, or my legal staff by any other party addressing whether or not they've had concerns with determining the rate of returns.

Q. Okay. And now your supplemental Exhibit Number 2, if you could turn there, please.

A. (Witness peruses document.)

Q. Do you provide three different versions of class rates of return for each rate year in Exhibit Number 2?

A. So Exhibit Number 2 is a variety of illustrations that, kind of, give the Commission an idea about, depending on their -- their recommendation for the final recommendation requirement, how that should be distributed, what that would look like, as far as rate of return and percent increase for the individual customer classes.

And so there's four different examples here.

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There is the class revenue changes equal to the NC retail change. There is the base case with no revenue change. There is an equal rates of return for all classes. And then the fourth one, while it says Public Staff recommended revenue distribution, it should be Public Staff's illustration of revenue distribution. I believe that might have been overlooked in the corrections.

Q. And so just to be clear, does that mean the Public Staff is not actually recommending its illustrative class rates of return?

A. So when I was putting these exhibits together, I believe Mr. Metz touched on it a little bit during when him and Witness McLawhorn were up here, but I guess what I'm getting at is there was a whole process involved with how I get to my exhibits.

And he talked about how there is discovery that took place, where in an ideal world it would take two weeks, sometimes it took longer than two weeks, and then there might be multiple iterations of discovery that would need to be had on particular items.

And so eventually a pencils-down moment has to occur so that we can -- the Public Staff can feed its recommendations and proposals on individual items

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that various Public Staff witnesses took a deep dive into, tried to investigate its reasonableness, and put forth a good recommendation for the Commission's consideration.

And so the -- all of that being said, each individual recommendation on various topics will then get fed and provided to the accounting witnesses, who would then take their numerous spreadsheets of different recommendations and, kind of, roll it all up together in order to figure out what a total revenue requirement would be for not just one revenue requirement but for the base case, rate year one, rate year two, and rate year three, as far as what the -- what revenue requirement would we be working with under the Public Staff, which I think, at this point, we're at partially settled, partially Public Staff position, as far as what accounting -- the Public Staff accounting witnesses have provided.

And that information, when they come up with their final revenue requirements, are what is provided to me in order for me to run those revenue requirements through the various spreadsheets that I have in order to come up with these exhibits.

And so that being said, I know it's a

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long-winded, but it's a long process and it takes a lot of time. Whenever I was provided the revenue requirement -- because like I said, there has to be a pencil-down moment. Whenever I was provided the revenue requirement, there was very little time to move from a final revenue requirement to these spreadsheets.

However, in that little bit of time, I was able to get the core principles that the Public Staff highlighted in its testimony, as far as where we would see these -- or where these -- where these returns and where the revenue requirement distribution would look like under the modified average and excess cost of service methodology and the Public Staff's long-time advocated rate apportionment principles.

And so like I said in my testimony, we had some challenges in distributing these revenues in order to adhere to all of the Public Staff's principles. But we placed a greater focus on the second rate principle, which was to keep rate of returns within a band of reasonableness. So it's the 10 percent of the NC retail's rate of return.

And so what you see here as this Public Staff recommended revenue distribution, how it's titled, it's more -- it's more applicable to be an illustration of

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what it would take under the modified average and excess, and keeping the class rate of returns within a banded window. And this is the result of what that would take in order for that to happen.

And the Company, my observations from Reed Exhibit 10, it's a great -- it's a great exhibit. They -- they give a historical picture of, I believe it's four class rate of returns, and it's a historical look. And so it will -- I think it's over the last 10 or 12 years. It, kind of, illustrates where the rate of returns have fallen, but if you look, there is a dotted line on the graph that's plus or minus 10 percent of the rate of return. And I believe that that is the target that even the Company's aiming for when it's assigning rate of return.

Q. So just to unpack -- that was a very long answer. So just to unpack that answer a little bit, you testified that you gave greater emphasis, I believe were your words, on the Public Staff's second rate apportionment principle.

What is the Public Staff's first rate apportionment principle?

A. So the first rate apportionment principle is that no individual class would experience an increase

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greater than two percentage points higher than the NC retail increase.

Q. And are there any other rate apportionment principles that the Public Staff considered?

A. There are. They're -- if I could switch over to it.

(Witness peruses document.)

So the -- so you've heard the first rate principle, and you heard the second rate principle. The third rate principle is that all class rate of returns move closer to parity with the overall NC retail rate of return. And the fourth rate apportionment principle is that subsidization among the customer classes is minimized.

Q. And so you said that the Public Staff gave greater weight to the second principle than it did to the others; is that correct?

A. With regard to the -- in taking into consideration all of the rate principles, we applied greater focus on the second rate principle as opposed to the first rate principle, because the first rate principle had its challenges that were unattainable.

Q. So if you had to rank the principles in the order in which the Public Staff emphasized them in its

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rate of return recommendations, how would you rank those from greatest emphasis to least?

A. I don't know if I would rank them, per se. I believe that all of the rate principles are valid in their own regard when determining whether or not a revenue apportionment is reasonable and appropriate.

Q. So you said that you gave greater emphasis to the second principle with relation to the first.

What about with relation to the fourth principle?

A. So subsidization among the customer classes is minimized. So under the Public Staff's -- I'm gonna say illustrative, even though it says recommended -- under that, I believe -- so, I guess if we go back to it -- you can pick any of the rate years. I'm just gonna go with the rate year three as an example, just because it's right in front of me.

The -- so the -- if you look at Williamson D Supplemental Testimony Exhibit 2.3, page 4 of 4, and then you look at line 11, that is showing a rate of return that all classes are within that band of reasonableness for that plus or minus 10 percent on the rate of returns. And so the Public Staff views any rate of return for a customer class, whenever it's

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dealing with revenue changes or rate increases or decreases in particular classes, a rate of return that's within that band of reasonableness, we don't see any cross-subsidization.

And I, kind of, have to go back to that Reed Exhibit 10 where every year it's going to be a different rate of return that's realized. It's all dependent on the number of customers, how the usage that's -- the energy that's used, the demand that's accumulated for each class. All of that is gonna be different from year to year. And so the cost of service is just a snapshot in time.

In this case, we're looking at the test year of 2021. And so, under the test year of 2021, the -- this Exhibit 2.3, in order to satisfy that rate of return band of reasonableness, this is the work that would need to get done.

I don't know if I've answered your question or not.

Q. So wouldn't you agree with me that your Exhibit 2.0, page 3, reflects class revenue changes equal to the North Carolina retail change?

A. (Witness peruses document.)

Which one? 2.0 page which of 4?

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Q. Page 3.
A. Class revenue changes equal to the NC retail change.
Q. So your answer is yes?
A. I don't know what your question is, I'm sorry. Is that what this says?
Q. Correct.
A. Yes, that's what it says.
Q. Okay.
A. For rate year zero.
Q. For rate year zero? And you provided --
A. For the base case.
Q. I'm sorry what?
A. For the base case. That's what rate year zero means in this case, is the base case.
Q. And so you provided this document for each of the three rate years, correct?
A. So the -- there are three rate years in which the Commission will need to set rates for, but there are four individual components. The first rate year is a combination of the actual investments in the base case that were completed and put plant in service, and then there are incremental projected amount of projects that are in the multiyear piece. And those two

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combined will total up to the rate year one revenue requirement that will be the rates actually charged to customers.

There is not a revenue requirement for the base case unless the Commission doesn't approve the multiyear case. That's, essentially, why I added in an individual case, was to give the Commission an idea what -- what it would look like if the multiyear was not approved.

Q. Okay. And so you said that your recommended rates of return for all classes changed from being a recommendation to just an illustrative example sometime between when you initially filed them on May 1st and the date upon which you amended your testimony.

Can you explain what changed and why?

A. So, like I was saying before, I was, kind of, crunched on a deadline. I was given a number the day of the filing, and so I had spent the entire day focusing on just this one -- just this one piece of testimony and exhibits.

And so what -- what is here is -- well, like I was saying is, while I did have the ability to provide the rate principles that the Public Staff advocates for to the greatest extent possible that we

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could, placing the focuses where we did, this is the product of what it would take to make that cost of service application and the Public Staff's rate apportionment principles with the focus on the second rate principle happen. And so -- yes.

Q. Just for the record, the Public Staff is recommending in this rate case to reduce the interclass subsidy by 10 percent; is that correct?

A. With regard to exhibit -- Witness Reed's proposed change? Is that what you're referring to?

Q. That's correct.

A. Okay. So the -- my understanding is that that 10 percent change from Witness Reed is just -- it is a method that they are placing in this case -- it's a method they're placing in this case in order to provide some gradualism, some -- from the change in cost of service to try and alleviate some of the increases because of the change in cost of service.

And I believe -- because I wasn't here during when Witness Reed and Byrd were on the stand. I believe that Witness Reed stated that this was as a result of the change in cost of service. And so she believed that it was only going to be applied to this case and this time.

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Q. And is it your understanding that that 10 percent subsidy reduction remains flat over the three-year multiyear rate plan period? In other words, it doesn't increase approximate?

A. For this case, I believe it is set at 10 percent.

Q. For each of the three rate years, correct?

A. Subject to check, but I can't remember -- I'd have to go back in my notes -- of whether or not it was applied to all rate years or just the base case.

Q. Thank you. No further questions.

CHAIR MITCHELL: All right. League?

CROSS EXAMINATION BY MR. SNOWDEN:

Q. Good afternoon, Mr. Williamson. I'm Ben Snowden here for the North Carolina League of Municipalities, and I'd like to ask some questions about the assignment of costs to the lighting class, in general, and especially to rate schedule SLS.

So going back to the cost-of-service methodology. You testified that Duke Energy has relied -- or Duke Energy Progress and Duke Energy Carolinas have relied on a summer coincident peak methodology for their cost-of-service study in recent rate cases; is that right?

Redacted

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PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Monday, July 24, 2023

TIME: 10:23 a.m. - 12:46 p.m.

DOCKET NO.: E-2, Sub 1300

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

IN THE MATTER OF:

Application of Duke Energy Progress, LLC,
for Adjustment of Rates and Charges Applicable
to Electric Service in North Carolina and
for Performance-Based Regulation

VOLUME: 24

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MS. CRESS: I am. Two questions.

CHAIR MITCHELL: Go ahead.

MS. CRESS: Thank you.

CROSS EXAMINATION BY MS. CRESS:

Q. Mr. Williamson, did the Public Staff oppose the rate design stipulation that would affect the medium general service rate classes?

A. Internally, I believe we did, but I think, at the time, we didn't have the ability to put it in testimony.

Q. But you --

A. It would follow along the same -- the same guidelines of the LGS class.

Q. But you did have the ability to put it into testimony for the LGS partial rate design stipulation?

A. Yes.

Q. How is that possible?

A. We just filed it with the supplemental testimony that we requested -- I mean, I'm not an attorney, but the process would -- from what I saw, was that we filed for permission to comment on the settlement testimony.

Q. So the Public Staff opposed internally the medium general service rate design stipulation, but

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only opposed externally the large general service rate design stipulation?

A. So I think the -- our objection was more in general to confining how rate design would get apportioned to individual classes. So I -- as far as whether or not we should have or did file on the MGS, I would say that we probably should have filed to be consistent with our LGS position.

Q. But you didn't, correct?

A. Correct.

Q. If it's moving things in the right direction -- those are your words that I'm repeating back to you -- in terms of cost of service, help me understand why the Public Staff would take issue with that?

A. So the cost of service is what's being used for these -- the rate designs for energy and demand. It's my belief that the rate designers should have that freedom and not individual parties that may not represent the entire class.

Q. Okay.

MS. CRESS: No further questions.

MR. JIRAK: No questions.

CHAIR MITCHELL: Okay. Redirect of your

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witness on this issue?

MR. JOSEY: No.

CHAIR MITCHELL: Okay. Let's see.

EXAMINATION BY CHAIR MITCHELL:

Q. All right, Mr. Williamson. Just help us understand why it's -- why it's the Public Staff's position or opinion that rate designers should be designing the rates as opposed to parties or customers that are gonna take -- customers of a particular class. Can you help us understand that?

A. Sure. So the rate designer is gonna have the most understanding of how the load shapes are working for individual classes that encompass all the customers within that class. They have the best position to be able to adequately price -- adequately price energy, demand, the customer -- the basic facilities charges, any other fees that go along with it.

When the Company files for a rate case, they are filing to update any charge that may be applied to a customer, and this is just a piece of it. And so as far as the revenue requirement that gets divvied out between the basic facilities charges, the energy charges, and demand charges, we think that it's more appropriate for the rate designers to get to that

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Q. Okay.

CHAIR MITCHELL: Any questions from Commissioners?

(No response.)

CHAIR MITCHELL: Okay. Questions on Commissioner's questions? We will start with Mr. Jirak.

MR. JIRAK: No questions.

CHAIR MITCHELL: Okay. Over here. Go ahead, Ms. Cress.

EXAMINATION BY MS. CRESS:

Q. So just to clarify, the rate designer is the Company, and the Company is the one who not only entered into this Stipulation with CIGFUR but also sent a witness here this morning who said that this Stipulation will help to better align rates with costs of service, correct?

A. That's correct. But if that is the situation, then a stipulation isn't needed, because the rate designer would have came to that conclusion on its own.

Q. And so the rate designer -- your words -- really it's just the Company. The Company did come to that conclusion, because it entered into the

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Stipulation, correct?

A. I can't really state what happened between CIGFUR and the Company when they were making the Stipulation, as far as what was given, what was taken.

Q. And just to be clear, there is nothing in this stipulation that says that it would apply to any other rate case or any other docket or future proceeding, correct?

A. I don't believe so. But it's more for clarity in the future that the rate designers be given the flexibility.

Q. Is it fair to say the Public Staff simply disagrees on principle but doesn't actually disagree with the underlying rationale for this stipulation?

A. Well, the rationale, from my understanding, is that it's fixing what the rate designer would be able to use in formulating the energy and demand rates.

Q. And that, as you already testified to several times, is directionally in alignment -- closer to alignment with cost of service, correct?

A. It can be in this situation, and I think that, based off of what I've seen, it is in alignment. However, the process of fixing the -- how energy and capacity -- energy and demand rates in a rate case,

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based off an agreement between two parties that may or may not encapsulate the entirety of the customers within a class, I think the Public Staff is generally in disagreement -- in disagreement with that.

Q. Does the Public Staff still generally support rates based on cost of service?

A. So it's a combination of cost of service and the policy that's currently invoked with the North Carolina law.

Q. And by policy, what do you mean exactly?

A. So there is the current -- for a rate case, there is several statutes that cover general rate cases in general. And so you can go back to my second supplemental testimony -- I don't know if we're in that situation yet, but in my second supplemental testimony, I go into all of the different policy factors that come into how to apportion rates, but we're going a step farther into how to divvy up the individual rate components of the rate classes tariff.

Q. And which policy, specifically, are you talking about this morning with respect to your opinion on the stipulation?

A. The policy of North Carolina with regards to how general rate cases are upheld, previous Commission

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orders, HB-951. There is a lot that goes into consideration. Like I've highlighted in my second supplemental, in my first supplemental, and in my direct on what needs to be taken into consideration in order to get down to a class level revenue requirement.

Q. Okay. Thanks.

MR. JOSEY: Just a few.

EXAMINATION BY MR. JOSEY:

Q. What would happen if multiple parties entered into stipulations in future cases to lock in individual rate elements in various rate schedules?

A. If a number of different customer classes did that, or -- I guess different parties that contain different customer classes -- customer class groups, I mean, you would start to see agreements -- again, like I was saying earlier, you would start to see agreements between certain members -- or certain customers within a class that would, essentially, be provided a scenario that benefits them the most without having the ability to consult the other customers that are also in that class that would also be paying those rates. Similar to how Jonathan Byrd -- witness Byrd was describing how the higher the load factor customers, when you switch to more demand rate charges, you are going to cause the

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CROSS EXAMINATION BY MS. CRESS:

Q. Mr. Williamson, if you could turn to your corrected Exhibit Number 3?

A. (Witness complies.)

I'm there.

Q. Okay. Can you please explain the 10 percent band of reasonableness in the context of this Exhibit 3, specifically which customer classes would fall outside of the 10 percent band of reasonableness?

A. So depending on the rate year, the proposed distribution, only the residential class would be within that 10 percent band.

Q. Only the residential class and no other class?

A. So when you're looking at just that one principle, that is the situation that you asked, and so that's the answer that I have to give. But you have to take into consideration all of the principles of -- that were put in in 951, and then the Public Staff has always advocated for its four design principles.

And so it's not a situation where one is going to prevail over the other. And like I've said in my previous testimonies, there were challenges in this case that prohibited certain -- certain rate principles

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from being able to be accomplished. And so the Public Staff, in this -- in this second supplemental -- in my second supplemental testimony and exhibits, it's applying the rate principles and the highlighted items in HB-951 that are also in my -- earlier in my testimony, in the words part, in addition to gradualism, trying to accomplish a fair distribution of rates and revenues to the customer classes.

And so in this situation, we weren't able to get to that 10 percent band. However, gradualism was, kind of, the other aspect that I had mentioned a second ago. And with gradualism, as far as all the customer classes making positive, if not sometimes significant, movement, getting closer to that band, the Public Staff was satisfied that, in this case, that was acceptable, as far as our four rate principles. Because the -- with this new law, unlike in previous cases where -- previous rate cases where when a Company would come in for a general rate case, it was unknown when the next rate case would be. However, in this case, it's almost presumed for it to be cyclical. And so we are going to start seeing rate cases filed very regularly, and that would give us more opportunities to make that movement, getting closer towards -- for some of the -- for some

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of the classes that are far outside of that 10 percent band, to make that positive movement, but also not -- but also incorporate a level of gradualism to where they don't experience levels of rate shock because of the drastic jump that would be required of them.

Q. That was a very long answer to what was supposed to be a very simple question.

Could you please confirm that the Public Staff's position is that strict adherence to the 10 percent band of reasonableness would achieve the minimization of interclass subsidization as required by 951.

A. So 951 -- not an attorney, but 951, to me, doesn't say that you must minimize, it says that you should minimize to the greatest extent possible. And so whether or not we hit that 10 percent band, I don't believe is required in this case. Because like I said, you still have to incorporate a level of gradualism in order to ensure that the rate increases that are being applied to customers are going to be fair and reasonable and make the movement that it needs to in order to set you up for the next cases.

Like I said, the expectation is -- I hope I'm wrong, but the expectation is that they will be filing

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very regularly to take advantage of this new law of having multiyear rate cases, and so we will be able to make that movement for customer classes getting closer and closer to being within that band.

But a customer being in the band of reasonableness isn't required, it just -- they want to minimize as much as possible. And this situation, given the changing costs of service and given the first attempt at a multiyear rate case for an electric utility in the state of North Carolina, this was the most reasonable approach that we could come up with, as far as ensuring that the revenue requirement was apportioned in totality to all the customer classes and that rates for customer classes didn't jump extraordinarily high.

Q. So you answered a different question than I asked, and so I'm gonna ask that question again, and hopefully you can answer the question that I'm actually asking.

I understand that this is not the recommendation the Public Staff is making, but it is the Public Staff's position that strict adherence -- again, understanding that's not the recommendation of the Public Staff -- strict adherence to the 10 percent

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band of reasonableness would achieve the minimization of interclass subsidization pursuant to 951, yes or no?

A. So moving towards that band I believe is just as good in a rate case --

MS. CRESS: Chair Mitchell, if I could ask that you please instruct the witness to answer the question. It is a "yes" or "no." We are gonna be here all day if this is, you know, the kind of answers that I'm gonna get that are nonresponsive to the questions that are being asked.

CHAIR MITCHELL: I would -- let's -- Mr. Williamson was about to answer your question. I want to hear what he has to say. I don't think he's being nonresponsive at this point, so I'm gonna allow him to continue his testimony.

Go ahead, Mr. Williamson.

THE WITNESS: So again, the 10 percent band is one of the components that are needed in order to come up with rates. We can talk about one particular rate principle or -- but in this case, we can't. We're gonna isolate it to one principle. We have to talk about all of the factors that go into -- all the policy, all of the gradualism that must be taken into effect. We -- we just have to

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understand that the -- everything that's in front of us is needed in order to come up with what the Commission can rule on in a case in order to determine what rates are just and reasonable.

Q. Are you aware that the word "gradualism" does not appear in 951 anywhere?

A. (Witness peruses document.)

So I'm not aware -- I guess I'd have to answer that as a subject to check. I'm not aware that gradualism is specifically labeled in HB-951, but HB-951 is not the only law or precedent that's being applied in this case, to my knowledge. 951 is just a structure for how a multiyear rate case should be handled.

Q. Thank you.

MS. CRESS: At this time, Chair Mitchell, I'd ask to please have an exhibit identified and marked for the record and be passed to the witness after counsel has an opportunity to take a look.

CHAIR MITCHELL: All right. Let's go ahead and get it marked, Ms. Cress.

MS. CRESS: Chair Mitchell, thank you. We ask that this be marked CIGFUR II Williamson

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Second Supplemental Cross Exhibit 1.

CHAIR MITCHELL: All right. The document will be marked as CIGFUR II Williamson Second Supplemental Cross Examination Exhibit 1.

(CIGFUR II Williamson Second Supplemental Cross Examination Exhibit 1 was marked for identification.)

MS. CRESS: Thank you.

Q. Mr. Williamson, to help you answer the question that I tried to ask a couple of times, if you could turn with me to the Public Staff's response to Data Request 1-12 on the very last page?

A. (Witness complies.)

Q. Can you please read that response into the record?

A. Sure. So:

D. Williamson's first supplemental exhibits were provided for illustrative purposes only. While strict adherence to the 10 percent band of reasonableness would, from the Public Staff's perspective, achieve the minimization of interclass subsidization as expressed in 951, it would also result in significant rate shock for certain classes of customers.

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Public Staff proposes its four guiding principles to provide a level of structure for rate apportionment. All four principles work in tandem, and in many cases it is impossible to satisfy all four of every -- all four for every rate case. In cases where it is impossible to adhere to some of the principles to avoid significant rate shock, gradualism is appropriate -- is the appropriate approach to take.

Q. Thank you. And if you could now turn with me to the Public Staff's response to CIGFUR II Data Request 1-11 on the previous page, and you'll see that that data request says:

"Provide the subsidy level paid/received by each class that corresponds to Williamson Exhibit 3."

Could you please read the Public Staff's response to that data request?

A. Sure. It says:

"This request seeks the production of documents that are not in the Public Staff's possession. The Public Staff objects to this request because it would require the creation

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of new work product that does not currently exist."

Q. Can you help me understand how the Public Staff can opine that your recommendations contained in your second supplemental testimony and exhibits minimize, to the greatest extent practicable, interclass cross-subsidization in this rate case, when the Public Staff didn't even calculate the interclass subsidies at issue?

A. So on a dollar value, we didn't calculate the interclass subsidies, but as far as a rate of return value, those values were provided as part of -- I believe it was Williamson exhibit -- Corrected Exhibit 3, like what we were looking at a little bit ago.

And so that is what we used as the guide to understanding how each rate class is moving progressionally with minimizing its -- its interclass -- or, yeah, its subsidization that's being provided.

So we used that as our guide to understanding how cross-subsidization was being taken into account and ensuring that positive movement was being made.

Q. Okay. Let's talk about how the Public

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Staff's position on this issue, that being revenue apportionment, changed from your first supplemental testimony to your second supplemental testimony.

So why don't you tell us, in your words, what changed and why?

A. So I don't believe anything changed, as far as the considerations that I took when creating the revenue apportionment for each rate class. Like my first supplemental testimony stated, it was for illustrative purposes.

The -- this rate case -- one of the goals of the Public Staff is to inform the Commission on our findings of what we see as notable and things that you -- we believe you should take into consideration. And so with this, for illustrative purposes, we provided, in the first supplemental, I think it was four different scenarios that the Commission could take into consideration of, if we took this approach, what would the rate impacts be; if we took this approach, what would the rate impacts be for all four of the rate years -- or the base case and the three incremental rate periods.

And so, for illustrative purposes, in that -- in that instance, we tried to inform the Commission, as

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much as possible, about the -- the challenges that not only the Public Staff were experiencing, but the challenges of trying to make rates for four different -- or three rate periods, but four different years. It's confusing. It's four periods, three rate years -- come together in a manner that would produce fair and reasonable rates, as far as an increase to each of the customer classes.

But in this final -- in the second supplemental, this is our approach to satisfy -- excuse me -- satisfying the revenue requirement while also accomplishing all of the rate principles and 951 to the greatest extent that's possible. And that's our -- our position on the matter.

Q. So is it your testimony today that the Public Staff's methodology for calculating revenue apportionment between customer classes did not change from your first supplemental testimony to your second supplemental testimony?

A. Well, it was two different situations. This -- the second one, which was our final proposal -- our only proposal, actually -- provided the best approach to incorporating gradualism. In the first supplemental there were customer classes that were

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going to experience an increase that was just, Public Staff's opinion, not attainable. Specifically looking at the lighting classes, they were going to experience drastic rate changes. And so that doesn't really apply a level of gradualism that we believe is required when the Commission sets its final Order on the rates that should get distributed to the customers.

And so, in this instance, we believe that the second supplemental methodology for apportioning the revenue requirement is reasonable, and we believe that the Commission should apply this methodology in this case.

Q. And now the Public Staff produced in discovery its work papers associated with both your first supplemental and your second supplemental testimony, correct?

A. I believe so.

MS. CRESS: Chair Mitchell, if we may pass out another exhibit, and -- counsel first. And if we could request that this be marked CIGFUR II Williamson Second Supplemental Cross Exhibit 2.

CHAIR MITCHELL: All right. The document will be marked CIGFUR II Williamson Second Supplemental Cross Examination Exhibit Number 2.

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(CIGFUR II Williamson Second Supplemental Cross Examination Exhibit 2 was marked for identification.)

MR. JOSEY: Can Ms. Cress specifically identify -- okay -- worksheet -- which worksheet this is?

MS. CRESS: Sure. So, in what has already been identified as CIGFUR II Williamson Second Supplemental Cross Exhibit 1, the Public Staff provided some work papers, and Mr. Williamson just testified to the fact that the Public Staff provided work papers both for his --

CHAIR MITCHELL: Actually, Ms. Cress, I'm gonna stop you. Put this in front of the witness. Ask the witness if he recognizes this document. If he doesn't, then that will provide the Commission with some guidance on the weight to give the evidence that the witness provides on this document.

Q. Mr. Williamson, do you recognize the methodology that is contained on the bottom half of the front sheet of paper that has red, blue, green, and orange boxes?

A. I do. It's kind of a description of what --

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these other individual tabs that are cut off, but it's a description of, kind of, what's going on in this situation.

Q. Is it also the instructions for the Public Staff's methodology for revenue apportionment that was contained in the very first tab of the Public Staff's work papers underlining your first supplemental testimony?

A. It was. And so I guess the -- what I have to say about this right here is that the Public Staff has to be able to model its own revenue requirement apportionment. It's the only way we could really go and double-check what has been provided by the Company, as far as our own independent analysis, to determine whether or not they have come close or how they might have modeled things. Because the -- this is the preferred model -- or underlying model that the Public Staff has used for years.

Had to modify it slightly, because typically it's a one-year rate case, so we had to add a lot more tabs in order to incorporate different rate years, but the same principles are still there. And so it's just a means for the Public Staff to be able to double-check was -- was this the best approach that could have

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happened, as far as revenue apportionment, compared to what the Company has provided. Or if -- it would give us the ability to play around with the policy of trying to move -- make the positive movement for the different rate principles and the various components of 951.

Q. Would you have any reason to disagree with me, Mr. Williamson, that the metadata for those initial work papers, underlying your first supplemental testimony, as snipped on the top half of this piece of paper, reflect that these work papers were an Excel spreadsheet initially created by James McLawhorn in 2004?

A. I don't have any reason to deny that. That's why I said that we've used this spreadsheet for many years, and we had to modify the -- modify it to incorporate a multiyear component.

Q. And if you could flip -- flip the piece of paper over.

Would you have any reason to disagree with me that the work papers underlying your second supplemental testimony indicate that the author is Sumita Deshmukh, an employee of Duke's rate design and regulatory strategy team?

A. So, like my second supplemental testimony

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said, we had conversations with the Company to try and work through apportioning out these revenues.

And so the Company initiated conversation with the Public Staff to try and work through what -- what could be done, because they understood that there were challenges, as well, and trying to apportion these revenues and create the rates.

And so there was conversations with the Company, and at some point in time -- I don't remember the day, but at some point in time there was a file that was provided that the Public Staff agreed with, as far as a reasonable approach to apportioning these revenues. And the impacts of that document are what -- what's reflecting in my three exhibits and my second supplemental.

We agreed with that apportionment as a reasonable apportionment strategy for this case, and so there wasn't a need to go back and recreate the methodology when we were already in agreement with the Company on the methodology that we had had conversations on.

Q. So just to be clear, that's a different methodology than the Public Staff's initial methodology underlying your first supplemental testimony that is

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reflected in the colored tabs on the front of this document?

A. So the methodology is different. They accomplish the goals to the Public Staff's satisfaction, as far as the second supplemental. We agree with the methodology that -- the conversations that the Company and the Public Staff had, and as far as the difference between the first supplemental and the second supplemental, the first supplemental was, again, the Public Staff's created document versus the Company's created document. So we're gonna have our own approaches to figuring out how revenue requirement should be divvied up amongst the customer classes, but it doesn't discredit the work that's being done to apportion those customer -- those revenue requirements.

There is many ways to design the model to apportion the rates, but it's just a matter of do the rev- -- are the revenue requirements adhering to the Public Staff's principles and 951 and any other state policy goals that are in effect at the time.

Q. Let's take a look and see how Duke's work papers compare to the Public Staff's work papers for your second supplemental testimony.

If you could, just confirm with me -- let's

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lay some foundation. If you could confirm with me that, in response to CIGFUR's Data Request 1-6 to the Public Staff, which you should still have that document in front of you, the Public Staff produced a series of emails; is that correct?

A. That's correct.

Q. And is it your understanding that those emails showed some of what you just testified to about how the Public Staff and the Company talked through and reached, sort of, a meeting of the minds as to the best approach for, in your opinion, revenue apportionment in this rate case?

A. Yes.

Q. And is it your understanding that the Company provided a series of their own work papers that they shared with the Public Staff during those discussions?

A. Yes. That's why this -- the support comes from Duke Energy, like you pointed out.

Q. Okay.

MS. CRESS: So if I could, Chair Mitchell, instead of having four different exhibits passed around, it's just -- there is one for the test year and then one for each multiyear rate plan year, and so I'm wondering if we could pass them

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out in one fell swoop.

CHAIR MITCHELL: Yeah, please do.

MS. CRESS: Okay.

CHAIR MITCHELL: Can somebody help? Let's just get him some assistance so we could do this more quickly. Mr. Snowden, Mr. Trathen, one of you guys just help him.

Hopefully, Ms. Cress can stay at her seat so she could be ready to conduct her examination.

(Pause.)

CHAIR MITCHELL: All right. Ms. Cress, let's keep moving here.

MS. CRESS: Okay. Chair Mitchell -- I'm sorry, go ahead.

MR. JOSEY: No, I just don't think the witness has got --

CHAIR MITCHELL: Mr. Williamson, do you have the documents? Okay.

MS. CRESS: Chair Mitchell, we would request that the test year page, the one that says "partial settlement test year" in bold at the top left-hand corner of the document, be marked as CIGFUR II Williamson Second Supplemental Cross

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Exhibit 3; followed by multiyear rate plan year one be marked as CIGFUR II Williamson Second Supplemental Cross Exhibit 4; rate year two be Exhibit 5; and rate year three be Exhibit 6.

CHAIR MITCHELL: All right. The documents will be so marked. I want to make sure the court reporter gets her copy as well.

(CIGFUR II Williamson Second Supplemental Cross Examination Exhibits 3 through 6 were marked for identification.)

MS. CRESS: Mr. Williamson, do you have four pages of exhibits?

THE WITNESS: I have five pages of exhibits.

MS. CRESS: Okay. Is it possible you have a duplicate?

CHAIR MITCHELL: No. We have five pages.

MS. CRESS: You have five?

CHAIR MITCHELL: Yeah.

MS. CRESS: Understood. Thank you.

In which case, Chair Mitchell, I think I also need an Exhibit 7.

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CHAIR MITCHELL: All right. The document that shows ROR's percent of average?

MS. CRESS: Yes, that's correct.

CHAIR MITCHELL: Okay. We will mark that document as CIGFUR II Williamson Second Supplemental Cross Examination Exhibit 7.

MS. CRESS: Thank you.

(CIGFUR II Williamson Second Supplemental Cross Examination Exhibit 7 was marked for identification.)

Q. Mr. Williamson, would you agree, subject to check, that the documents that were just put in front of you and identified as CIGFUR II Second Supplemental Williamson Cross Exhibits 3, 4, 5, 6, and 7 were the work papers that Duke shared with the Public Staff leading up to the filing of your second supplemental testimony in this rate case?

A. That's correct.

Q. Thank you.

MS. CRESS: And now, for comparison's sake, we have the same documents from the Public Staff's work papers, and so if I may take a moment to try to make this process more streamlined.

CHAIR MITCHELL: Go ahead.

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(Pause.)

CHAIR MITCHELL: So we'll mark these 8, 9, 10, and 11?

MS. CRESS: Yes. Thank you.

CHAIR MITCHELL: All right. The document identified as partial settlement test year should be marked as Exhibit -- as CIGFUR II Williamson Second Supplemental Cross Examination Exhibit 8, document identified as test year MYRP year one will be CIGFUR II Williamson Second Supplemental Cross Examination Exhibit Number 9, document identified as test year and multiyear rate plan year two will be marked as CIGFUR II Williamson Second Supplemental Cross Examination Exhibit 10, and then document identified as test year and multiyear rate plan year three will be marked as CIGFUR II -- marked for identification as CIGFUR II Williamson Second Supplemental Cross Examination Exhibit Number 11.

MS. CRESS: Thank you, Chair Mitchell.

(CIGFUR II Williamson Second Supplemental Cross Examination Exhibits 8 through 11 were marked for identification.)

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Q. Mr. Williamson, would you agree with me, subject to check, that the documents just placed before you and identified as CIGFUR II Williamson Second Supplemental Exhibit -- Cross Exhibits 8, 9, 10, and 11 are the Public Staff's work papers supporting your second supplemental testimony filed in this docket?

A. Yes, that's correct.

Q. Okay. Can you -- are you able to point to us -- point out to us what changes were made from the Company's work papers to the Public Staff's work papers and why?

A. So the only change is the additional column, and that has the blue highlighted cells. The only change is that the Public Staff put in what the percent increases would be excluding riders, and that's reflected in the Public Staff's, I believe it was Exhibit 2 -- the Corrected Supplemental Exhibit 2. I can -- and so -- yes. It's the Williamson D Second Supplemental Testimony Corrected Exhibit Number 2, and on that exhibit there are two sets of percent increases, one that includes riders and then one that excludes riders.

And the Public Staff has generally advocated that a general rate case is designed to adjust rates

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and only rates where it related to the base -- base rates. The inclusion of riders provides a skewed picture, because riders change more frequently. Or at different points in time. Let me phrase it that way.

Q. Thank you for that.

And, Mr. Williamson, are you aware that, on July 3rd, Duke caused to be filed in this Docket a letter indicating that they support the revenue apportionment recommendations contained in your second supplemental testimony?

A. I believe that's correct.

Q. And are you aware that that letter also indicates that the Public Staff's recommendations are consistent with what DEP initially recommended in their prefiled direct testimony back in October?

A. I believe that's correct. I'm not -- I don't have the letter right in front of me, but subject to check, sure.

Q. And so is there any reason why the Public Staff couldn't have indicated that it supported that same methodology in your first supplemental testimony?

A. So my direct testimony, we had them put -- we hadn't gathered a revenue requirement. So my direct. Hadn't gathered a revenue requirement, but we had done

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a review of each individual principle. And there is a couple of pages in my direct testimony that highlight where the rates, quote, unquote, failed those tests.

So in the first supplemental, we provided some illustrations of, kind of, what's -- what's going on with apportioning out the rates to try and adhere to the rate principles to the best that we could at that time, but it was illustrative. It was just -- again, it was just trying to educate the Commission about what's going on.

And so in the final -- in the second supplemental, we -- after working through our -- going back to our own, you know, revenue apportionment model, and given the challenges that I've echoed in every testimony in this case, that we're experiencing with trying to adhere to all the principles as best as possible, at that point in time, we were able to tell that the Company had made the best effort to try and apportion rates in a reasonable manner. And so now we're in a situation where we are -- I couldn't, at the time, declare that, but now I can say that.

Q. And so looking at these comparisons side by side of the Public Staff's work papers versus the Company's, and taken together with the metadata showing

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that this spreadsheet constituting the Public Staff's work papers originated with Duke Energy, is it fair to say that the Public Staff, essentially, adopted the Company's approach and the Company's methodology to revenue apportionment?

A. So we believe that the -- it's a fair approach to use the model that was filed in our second supplemental, and the Company agreed with it in their supplemental letter.

Q. And so with very few exceptions, would you agree with me that Exhibits 8, 9, 10, and 11, are almost mirrored copies of 3, 4, 5, and 6?

A. Yes. With the exception of the additional column to exclude the riders and figure out what that percentage would be.

Q. Thank you. Can you explain why total lighting is separated out as its own line item, separate and apart from the rest of the rate classes?

A. (Witness peruses document.)

I can't answer that question, but my hope is that it's the Company trying to come together in realizing that some of the lighting classes are in need of having some changes applied to them. And so maybe it's the Company -- and I'm just, you know, speculating

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here. Maybe the Company is trying to work through what it would look like to combine the lighting classes.

Q. And so you can't answer that question, but these are your work papers, correct?

A. So my recommendation is applying everything that's in the gray. Everything -- the total lighting down at the bottom is just -- it appears to be a combination of a couple of different line items related to the lighting classes.

Q. Okay. And so just to be clear, Exhibits 8, 9, 10, and 11 are your work papers underlying your second supplemental testimony, and you can't tell us why total lighting is listed below the rest of --

A. So my recommendation applies to the shaded area. That's where my focus was.

Q. So what -- what is the total lighting row in your work papers? What does that mean and what is that denoting?

A. The combination of lines 19 and 22, which is the ALS, SLS, and SFL classes.

Q. Why is that in your work papers?

MR. JOSEY: Objection. This wasn't in his supplemental testimony.

MS. CRESS: Chair Mitchell, it's in the

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work papers which formed the basis and support for his second supplemental testimony that were produced in discovery.

CHAIR MITCHELL: I'll overrule the objection. Just provide the answer, Mr. Williamson.

THE WITNESS: Sure. Appears that it was just carryover from the files that the Company had provided to the Public Staff. So that's a question for the Company, as to why that was down there.

Q. Thank you.

MS. CRESS: I now have some questions on behalf of Haywood EMC, and I'm not sure if you would like me to go ahead and do those now.

CHAIR MITCHELL: Go ahead.

(Pause.)

Q. Mr. Williamson, are you familiar with these Public Staff --

MS. CRESS: Oh, I'm sorry.

Chair Mitchell, may I please request that this be marked Haywood EMC Williamson Second Supplemental Cross Exhibit Number 1.

CHAIR MITCHELL: All right. The document will be marked Haywood EMC Williamson

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Second Supplemental Cross Examination Exhibit Number 1.

MS. CRESS: Thank you.

(Haywood EMC Williamson Second Supplemental Cross Examination Exhibit 1 was marked for identification.)

Q. Mr. Williamson, are you familiar with this document?

A. I am.

Q. Did you help provide the Public Staff's responses to these data requests?

A. I did.

Q. Thank you. If you could turn with me to Data Request 1-8, please?

A. (Witness complies.)

Q. And this data request states, does it not: "Provide the information contained in D. Williamson's First Supplemental Testimony Exhibits 1, 2.0, 2.1, 2.2, and 2.3, updated to reflect the final revenue requirement number recommended by the Public Staff"? Is that what that data request says?

A. It does.

Q. And could you state for the record the Public

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Staff's response to this data request?

A. Sure.

This request seeks the production of documents that are not in the Public Staff's possession. The Public Staff objects to this request, because it would require their creation of new work product that does not currently exist. Without waiving said objection, and relying specifically thereon: Williamson -- D. Williamson's First Supplemental Testimony Exhibits 1, 2.0, 2.1, 2.2, and 2.3 were for illustrative purposes based on an, at the time, unknown final revenue requirement. D. Williamson did not update the illustrative exhibits with the known final recommended revenue requirement; therefore, this request would require the creation of new work.

Q. And could you please turn with me to Data Request 1-9?

A. Can I say something first? As far as -- the reason that we did not produce those documents is because we had already had the conversations with the Company and basically agreed to the distribution, so it

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was not needed to go back and go through that process.

Q. Could you please turn with me to the Public Staff's response to Data Request 1-9, which asks:

"Provide a revenue distribution that adheres to the 10 percent ROR index band to all classes"?

A. Sure.

This request seeks production of documents that are not in the Public Staff's possession. The Public Staff objects to this request because it would require the creation of new -- of new work product that does not currently exist. Without waiving said objection and relying specifically thereon: D. Williamson's amended supplemental testimony filed on May 4, 2023, contains illustrative exhibits that showed the illustrative revenue distribution based on 10 percent revenue requirement of -- rate of return index band for all classes, Exhibits 2.0, pages 4 of 4; 2.1, page 4 of 4; 2.2, page 4 of 4; and 2.3 page 4 of 4. D. Williamson did produce an updated distribution that utilizes the methodology

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that was applied to the first supplemental testimony for the Public Staff's first known final recommended revenue requirement; therefore, this request would require the creation of new work product.

Q. Thank you. And finally, Data Request 1-10, which requests:

"Provide a class revenue distribution that eliminates all interclass subsidies by the conclusion of the proposed multiyear rate plan."

And the Public Staff's response was?

A. "This request seeks the production of documents that are not in the Public Staff's possession. The Public Staff objects to this request because it would require the creation of a new work product that does not currently exist. Without waiving said objection, and relying specifically thereon:

The Public Staff understands this question to mean that all rate classes should have a rate of return index of 1.0. Please see the illustrative exhibits found in his first supplemental testimony. This request for the

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final revenue requirement proposed the Public Staff's second supplemental testimony would require the creation of new work product."

Q. Thank you.

MS. CRESS: No further questions.

MR. JIRAK: No questions.

CHAIR MITCHELL: All right. Anything additional from intervenors?

(No response.)

CHAIR MITCHELL: All right.

Mr. Josey --

MR. JOSEY: Thank you.

CHAIR MITCHELL: -- redirect?

REDIRECT EXAMINATION BY MR. JOSEY:

Q. Mr. Williamson, there was a large discussion on gradualism and if gradualism was included in 951; do you remember that?

A. I do.

Q. Okay. And what is the purpose of gradualism, as we talk about setting rates?

A. So gradualism, with regards to increasing rates, is to -- it really -- it really just -- I don't -- and I think I talked about this in the original hearing, is that I don't know if there is a

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CHAIR MITCHELL: I will take questions on Commissioner's questions. We'll start -- nothing from --

MR. JIRAK: No questions.

CHAIR MITCHELL: Over here. Ms. Cress, you may proceed.

MS. CRESS: Thank you, Chair Mitchell.

EXAMINATION BY MS. CRESS:

Q. When you talked about the discussions that the Public Staff and the Company had in June leading up to the filing of your second supplemental testimony in this Docket, were any other parties to this rate case invited to those discussions?

A. To my knowledge, it was just the Public Staff and the Company, but the Company initiated those conversations, so you would have to ask them why they didn't invite anyone else.

Q. Understood. And so none of the illustrative examples that you provided in your first supplemental testimony, in terms of the methodology, none of those methodologies form the basis of your recommendations contained in the second supplemental testimony you filed, correct?

A. The principles are still there. As far as

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how we were modeling the revenue apportionment, that's -- that's really the only difference. We had to -- we built our -- the Public Staff built its own model or used its own model that it's used since, as we were -- stated before in this document, dating all the way back to 2004, updated to reflect a multiyear-type component. And in that situation, we were trying to come up with an approach, because at the time, we were unaware if what the Company -- because when you do the first analysis, in my direct testimony, you can clearly see that I highlight the failures to some of the rate principles. But again, I also state that there are a ton of challenges that are existing in all of the -- this whole process, as far as trying to apportion the rates across all four of the years -- or three of the rate years. And in that situation compared to now, the revenue requirement methodology that we're proposing now that, you know, we worked with the Company on, we believe this to be the best, most reasonable approach that can be done in this case.

Q. But your relative ranking of the Public Staff's principles changed from your first supplemental to your second supplemental, correct?

A. So they've always worked in tandem, all of

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the principles. It's just an acknowledgement of whether or not any of the rate principles are achievable. And so it -- but they all work in tandem, in concert with one another.

Q. So is it your testimony that the relative weighting that the Public Staff gives to each respective principle did not change from your first supplemental to your second supplemental?

A. Correct.

Q. So is it your testimony that the Public Staff applied an emphasis on the second principle?

A. So all four of the rate principles were taken into consideration when coming up with the rate apportionment that was provided in the second supplemental of my testimony, to the greatest extent that they could.

Q. And then can you just help us understand why the Public Staff didn't just run its final revenue requirement number through its work papers, spreadsheet that it's been using since 2004, for your second supplemental testimony?

A. Because we -- the reason we didn't run it through that model was because we had already agreed with the Company on the model that -- the revenue

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apportionment that should be applied, out of fear of taking away more days before us to file and prolonging this process even farther. We think -- we believed it to be not necessary to take that extra step when we were already in agreement with the methodology.

Q. Did the Public Staff and the Company file a stipulation on revenue apportionment?

A. I believe the only stipulation with regards to rates that we filed was on cost of service.

Q. So the answer then is no, the Public Staff and the Company did not enter into a stipulation on revenue apportionment?

A. As far as the class level revenue requirements, no.

Q. Would you -- since you were asked one question about Haywood, would you have any reason to disagree that Haywood EMC takes retail electric service from DEP under a small general service rate schedule?

A. I don't know what type of service Haywood EMC takes its power from for DEC -- or DEP, excuse me.

Q. Would you agree, subject to check?

A. Subject to check, sure. Subject to check.

Q. Great.

MS. CRESS: That's all. Thank you.

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# Cost of Service Study per Stipulation in Docket Nos. E-2, Sub 1219 and E-7, Sub 1214

January 25, 2022

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# List of Exhibits

## Duke Energy Carolinas, LLC Specific Exhibits

DEC Exhibit 1 – Test year monthly loads by rate class

DEC Exhibit 2 – FERC 12 CP Tests – 2009 through 2018

DEC Exhibit 3 – Development of peak responsibility methods – SCP, WCP, 4CP, 12CP

DEC Exhibit 4 – Development of Summer / Winter Peak & Average Method

DEC Exhibit 5 – Development of Average & Excess (A&E) Method

DEC Exhibit 6 – Development of Average & Excess 4CP (A&E 4CP) Method

DEC Exhibit 7 – Development of Average & Excess Dominion (A&E DOM) Method

DEC Exhibit 8 – Development of Base, Intermediate & Peaking (BIP) Method

DEC Exhibit 9 – Development of DEC Composite BIP Allocator

DEC Exhibit 10 – Comparison of DEC Allocation Factors

DEC Exhibit 11 – Comparison of DEC Rate of Return on Rate Base by Allocation Method

DEC Exhibit 12 - DEC Rate of Return on Rate Base Indexes

DEC Exhibit 13 – Development of Alternative Fuel Allocation

DEC Exhibit 14 - Comparison of Rate of Return on Rate Base by Allocation Method with Alt Fuel

DEC Exhibit 15 – Unit Cost Report – Single Summer CP

DEC Exhibit 16 – Unit Cost Report – Single Winter CP

DEC Exhibit 17 – Unit Cost Report – 4CP

DEC Exhibit 18 – Unit Cost Report – 12CP

DEC Exhibit 19 – Unit Cost Report – SWPA

DEC Exhibit 20 – Unit Cost Report – Average & Excess

DEC Exhibit 21 – Unit Cost Report – Average & Excess 4CP

DEC Exhibit 22 – Unit Cost Report – Average & Excess - Dominion

DEC Exhibit 23 – Production Demands – Six Key Months

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**Duke Energy Progress, LLC Specific Exhibits**

DEP Exhibit 1 – Test year monthly DEP loads by rate class

DEP Exhibit 2 – FERC 12 CP Tests – 2009 through 2018

DEP Exhibit 3 – Development of peak responsibility methods – SCP, WCP, 4CP, 12CP

DEP Exhibit 4 – Development of Summer / Winter Peak & Average Method

DEP Exhibit 5 – Development of Average & Excess (A&E) Method

DEP Exhibit 6 – Development of Average & Excess 4CP (A&E 4CP) Method

DEP Exhibit 7 – Development of Average & Excess Dominion (A&E DOM) Method

DEP Exhibit 8 – Development of Base, Intermediate & Peaking (BIP) Method

DEP Exhibit 9 – Development of DEP Composite BIP Allocator

DEP Exhibit 10 – Comparison of DEP Allocation Factors

DEP Exhibit 11 – Comparison of DEP Rate of Return on Rate Base by Allocation Method

DEP Exhibit 12 - DEP Rate of Return on Rate Base Indexes

DEP Exhibit 13 – Development of Alternative Fuel Allocation

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DEP Exhibit 18 – Unit Cost Report – 12CP

DEP Exhibit 19 – Unit Cost Report – SWPA

DEP Exhibit 20 – Unit Cost Report – Average & Excess

DEP Exhibit 21 – Unit Cost Report – Average & Excess 4CP

DEP Exhibit 22 – Unit Cost Report – Average & Excess - Dominion

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**Duke Energy Exhibits**

DE Exhibit 1 – Strengths by Method Matrix

DE Exhibit 2 – Weaknesses by Method Matrix

DE Exhibit 3 – Cost of Service Study Participants

**CIGFUR Exhibit**

CIGFUR Exhibit 1 - CIGFUR Comments on Base, Intermediate and Peaking Allocation Method

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## Regulatory Basis for this Analysis

Pursuant to the North Carolina Utilities Commission's (the "Commission") March 31, 2021 *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice* in Docket No. E-7, Sub 1214 and its April 16, 2021 *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice* in Docket No. E-2, Sub 1219 (collectively, the "Orders"), Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and collectively with DEC, the "Companies") have performed analyses of various cost of service study methodologies consistent with the terms of the Second Agreement and Stipulation of Partial Settlement entered into between the Public Staff and DEC and DEP, respectively (collectively, the "Second Partial Stipulations").

The Companies undertook analyses of additional cost of service studies subject to the following conditions set forth in the Second Partial Stipulations:

1. The Company agrees to analyze and develop cost of service studies based on each of the following methodologies:
   a. Single Summer Coincident Peak;
   b. Single Winter Coincident Peak;
   c. One that utilizes the four highest monthly system peaks (two monthly peaks in summer and two monthly peaks in winter);
   d. Summer/Winter Peak and Average ("SWPA");
   e. Base Intermediate and Peak (as Described in the RAP "Electric Cost Allocation for a New Era" manual published January 2020); since the Company's accounting systems do not have the data developed to produce such a study, this method may be analyzed by looking at how it has been used at another utility or with a higher level hypothetical analysis;
   f. One that utilizes the 12 highest monthly system peaks in the test year; and
   g. Any other identified relevant methodologies.
2. Each methodology studied will include an evaluation of the allocation of the functions of utility service (production plant, transmission plant, distribution plant, and customer costs), including an identification of which cost components associated with these functions of utility service are fixed, and which are variable costs of service. The

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above methodologies only impact production and transmission allocations; however, the cost of service studies will show the allocation of all functions. For purposes of these studies, all demand and customer classified costs can be designated as fixed, and all energy classified costs can be designated as variable.

3. Each methodology studied will include an evaluation of its strengths and weaknesses on both a jurisdictional and class allocation basis.
4. Included in the studies shall be a discussion of how the allocation of fuel and other variable O&M expenses align with system planning.
5. The Company shall consult with the Public Staff and any other interested parties throughout the study process.

The Companies have undertaken this cost of service analysis with specific emphasis on production cost allocation methodologies.

The major events defining this study were as follows:

- June 2, 2021 – Duke Energy provided notice to parties of record in its DEC and DEP rate proceedings that it was undertaking the stipulated study and asked interested individuals to indicate their interest in participating.
- June 3, 2021 – Duke Energy informed the South Carolina Public Service Commission of this study and the Companies' intention to reach out to and include South Carolina stakeholders who have historically shown an interest in this topic.
- June 29, 2021 – Initial project stakeholder meeting was held to clarify the scope of the study and present the study timeline. After reviewing the list of methods to be evaluated, one of the stakeholders suggested the group also evaluate the Average & Excess method. Several agreed, and that method was added to the list to be studied.
- July 13, 2021 – A stakeholder meeting was held and the Companies presented the development of the four peak responsibility methods (1 Summer Coincident Peak ("CP"), 1 Winter CP, 4CP and 12CP), the Summer-Winter Peak and Average method, the Average & Excess method, the Average & Excess 4CP method and the Base,

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Intermediate & Peaking method. The presentation also provided the resulting allocation factors for the North Carolina, South Carolina, and wholesale jurisdictions as well as the rate classes within the retail jurisdictions for both utilities. A stakeholder suggested the group investigate the Average & Excess method as implemented by Dominion Energy in its Virginia jurisdiction, which is different than the other Average & Excess methods reviewed. In response to comments from another stakeholder, it was pointed out that the issue of curtailable load was not within the scope of the study but would be addressed in a future rate case. Other stakeholders offered comments based on their observations of the allocation factor results.

- August 12, 2021 – A stakeholder meeting was held with a focus on the Average & Excess method as used by Dominion Energy and as requested by one of the study's stakeholders. In addition, a revised Base, Intermediate & Peaking method was introduced. Lastly, the rates of return by rate class resulting from the application of each allocation methodology were presented.
- September 14, 2021 – A stakeholder meeting was held with a focus on a method to allocate fuel expenses to rate classes instead of on a uniform cents per kWh basis. Tables were provided showing rates of return by rate class before and after the fuel adjustments. Lastly, an outline of the draft final report was presented. Following the meeting, the draft final report was sent to the study participants for comments.
- October 14, 2021 – A stakeholder meeting was held for the purpose of reviewing an initial draft of the stakeholder group's final report.
- November 16, 2021 – A second stakeholder meeting was held for the purpose of reviewing an updated draft of the stakeholder group's final report.

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## Introduction

The overall purpose of cost of service studies is to determine whether each class of customers is providing the utility with a reasonable level of revenue to recover the costs necessary to provide service to each customer class. Duke Energy utilizes an embedded cost of service approach where the majority of its plant investment and costs are incurred to serve all customers in a joint manner. To the extent that certain costs can be explicitly attributed to a specific group of customers, those costs will be directly assigned to those customers. Since most costs are jointly incurred to serve all customers, they must be allocated across all customer classes. To the maximum extent possible, joint costs are allocated to the customer classes based on the principle of cost causation[1]. The application of cost causation is greatly influenced by the methodology chosen for the cost of service study.

As a result, cost of service studies prepared for the same utility and for the same test period using different allocation methodologies will yield different results. In addition, a cost of service study prepared for the same utility and using the same allocation methodology, but a different test period, will yield different results as well.

The process of conducting a cost of service study involves three steps:

- functionalization
- classification
- allocation

[1] The "Cost Causation Principle" as defined by G.S. 62-133.16 (ratified October 13, 2021), means establishment of a causal link between a specific customer class, how that class uses the electric system, and costs incurred by the electric public utility for the provision of electric service.

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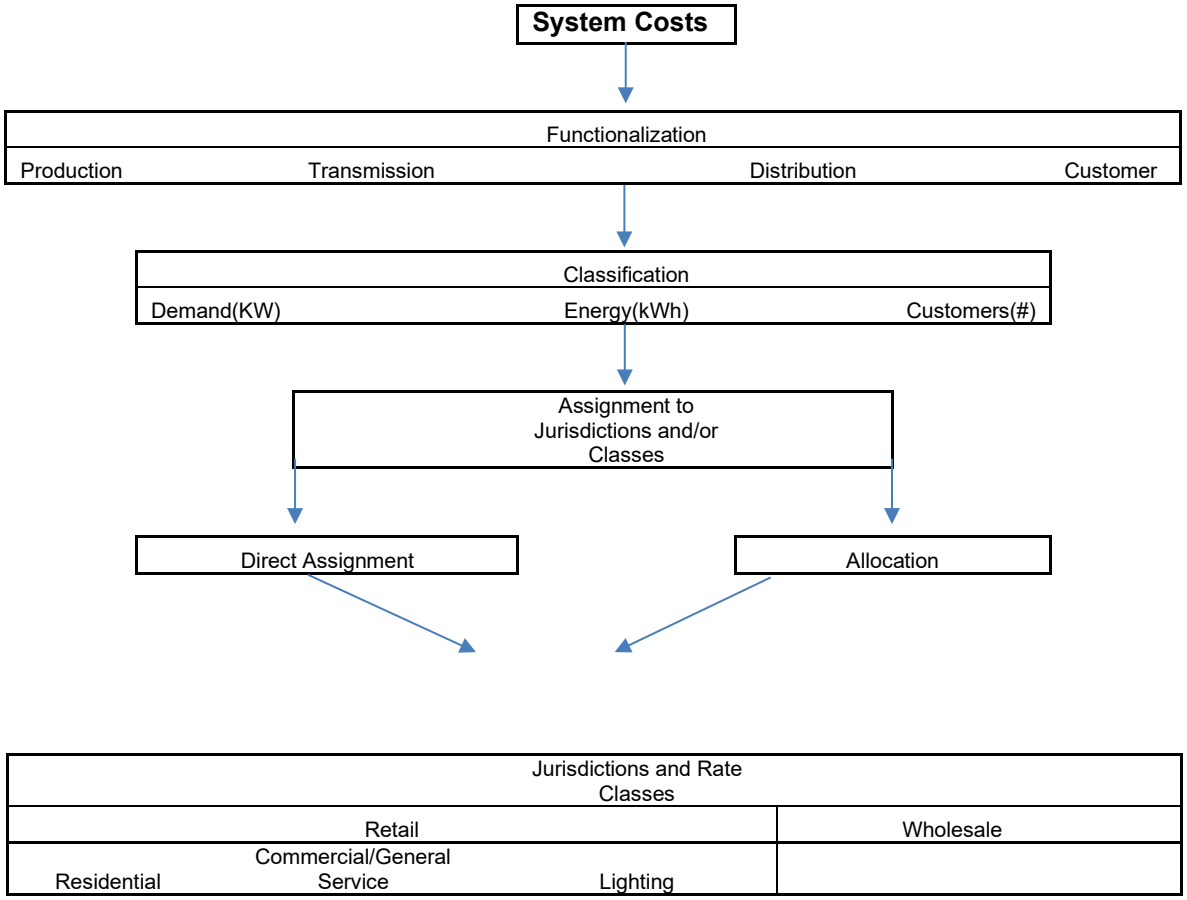
The chart below provides a pictorial representation of this process in their order of occurrence.




The result is a revenue requirement by rate class that serves as a starting point for rate design, and a cost of service for the North Carolina or South Carolina retail jurisdiction that is a foundation for determining the overall jurisdictional revenue requirement.

Functionalization entails the sorting of plant investment and expenses by system component, such as production, transmission, distribution or customer operations. For the most part, the functionalization of costs follows the utility's accounting system, which is based on the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts. For example, FERC Account 312 is Boiler Plant Equipment. Boiler Plant Equipment is equipment used in the production of steam, to be used primarily for generating electricity. Therefore, FERC account 312 is functionalized as production.

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Classification takes the functionalization step beyond the accounting records by identifying the primary driver of each cost. The three basic types of costs are:

1. Capacity-related costs incurred to ensure reliable service during periods of highest load.
2. Energy-related costs incurred to generate the energy that customers require over time.
3. Customer-related costs incurred to connect customers to the system, bill them and administer their service on an ongoing basis.

The allocation step involves the assignment or allocation of classified costs to the various jurisdictions and customer classes. One of the primary goals of a cost of service study is to develop rate class cost allocation factors that accurately reflect cost causation. Therefore, the allocation of costs is usually based on some measure of class loads or class service characteristics. For example, fixed production capacity costs are typically allocated using a production demand allocator while billing costs are often allocated based on the number of customers in each rate class.

As demonstrated by the diagram above, the allocation of system costs occurs at both the jurisdictional level and the rate class level. If regulators among the different jurisdictions select different allocation methodologies to allocate the utility's costs, the sum of the allocators may not equal 100%, and the utility may not be able to fully recover its costs, or it may recover more than 100% of its costs.

Some state regulatory commissions have addressed this by selecting one allocation method for the jurisdictional allocator to separate the retail jurisdiction from the wholesale jurisdiction – usually one of the preferred FERC methods – and a different allocation method to allocate costs among the retail classes. A few examples of this are:

1. Arizona Public Service Company uses the 4CP method for jurisdictional separation purposes and the Average & Excess method for allocating to rate classes.

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2. Duke Energy Florida uses a 12CP demand method for jurisdictional purposes and 12CP demand plus 1/13th average demand for allocating to rate classes.
3. Minnesota Power uses the 12CP demand method for jurisdictional separation purposes and the Peak and Average method for allocating to rate classes.

However, North Carolina has maintained consistency between the methodology applicable to the jurisdiction and customer-class levels.

## The Production Capacity/Energy Tradeoff

For a vertically integrated electric utility, production-related costs are typically the largest single component of costs it incurs. Since the allocation method chosen can have significant impacts on the costs assigned to the utility's rate classes, it can be a topic of considerable debate among the various participants in a utility rate case.

Electric utilities design and build their generation resources to meet both the demand and energy requirements of their customers on an aggregate basis. Since production facilities are joint costs, they must be allocated to the various customer classes.

Electric utilities experience periods of higher demand during various hours of the day and during certain times of the year. At the same time, the various customer classes do not contribute in the same proportions to these varying demands over time. To demonstrate this phenomenon, the graph below provides Duke Energy Carolinas' twelve monthly peaks for 2018 with each of the major classes' contribution to those peaks.

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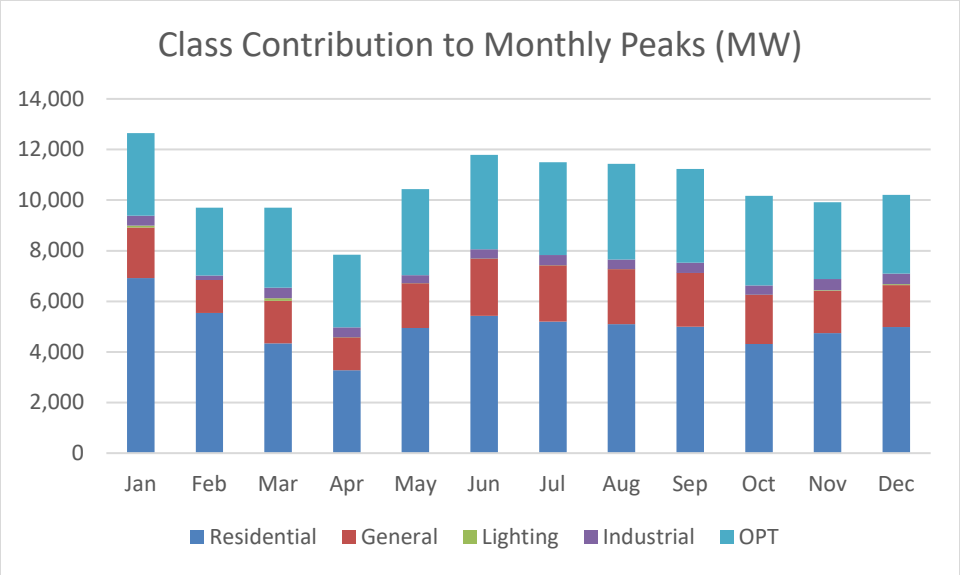


DEC Exhibit 1 provides the load data which is the basis for the above chart[2]. DEP Exhibit 1 provides the same data for DEP. DEC Exhibit 23 provides the same data as DEC Exhibit 1 for two winter peak months, two summer peak months and two off-peak months. It more clearly shows the weather impacts on the residential class and the more consistent loads of the OPT class.

Utilities are required to have adequate generating resources to meet the system's peak demand plus a reserve margin (i.e., additional generation resources above and beyond the peak demand). At the same time, electric utilities have historically designed their mix of generation facilities and purchased power resources to minimize the total cost of electric service. Base load units, like nuclear, coal and natural gas combined-cycle, have historically required high capital expenditures per kW of capacity but have relatively lower variable production costs per kWh for fuel and operations and maintenance ("O&M") expenses. On the other hand, peaking units have

[2] OPT rates are optional power service time-of-use rates defined by the voltage level needs of the DEC customer.

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historically required lower capital costs per kW but relatively higher production costs per kWh. Based on the varying levels of demand incurred by an electric utility system over time, the utility seeks through the integrated resource planning process to determine the optimal mix of production facilities that minimizes the total cost of production.

In addition, many utilities are transforming their generation systems to meet clean energy plans for the generation and resources that serve their customers, through the retirement of coal-fired facilities and the addition of clean renewable resources, including intermittent solar and wind capacity and energy limited resources such as battery storage. Intermittent resources affect system operations since dispatchable resources must be available to ramp up and down to accommodate unexpected movements in solar and wind output.

In this report, this concept of how energy usage influences resource planning and fixed cost resource additions is referred to as the production capacity/energy trade-off. Some production demand allocation methods attempt to capture the impacts of the production capacity/energy trade-off by including energy – or average demand – in the calculation of the production demand allocator. Other methods assume this trade-off is accounted for by allocating variable production costs based on energy allocators and fixed production costs based on peak demand allocators. This concept will be referenced in the review of the strengths and weaknesses of each method.

## Production and Transmission Cost Allocation Methods

The National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual ("CAM"), first published in 1992, serves as a primer on cost allocation methodologies. This manual discusses more than a dozen embedded cost allocation methods. The NARUC manual classifies these methods as:

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- Peak responsibility demand methods that reflect the view that capacity is built to meet peak demand requirements and not energy needs.
- Energy weighting methods that reflect the view that generation facilities are built to meet both demand and energy requirements.
- Time differentiated methods – These methods are designed to allocate costs to base and peaking periods and sometimes to an intermediate period. Some of these methods are complex and require significant data to perform the necessary calculations.

This study focuses on the methods agreed to in the Second Partial Stipulations as well as some other commonly used methods requested by the stakeholder group. This section includes a discussion of strengths and weaknesses of the various methods. Charts summarizing the strengths and weaknesses are found in Duke Energy ("DE") Exhibits 1 and 2, respectively.

**Single Coincident Peak:** One of the most fundamental operating concepts for an electric utility is that it must have sufficient generating capacity to meet the electric system's maximum coincident peak demand for the year. To that end, capacity planners must ensure there is enough generation capacity available to meet that demand plus a prescribed reserve margin. The reserve margin is designed to ensure adequate generation in the event that the weather is more extreme or load is more robust than forecasted or in the event of planned or forced outages of generating units. A major strength of the single coincident peak method is that it generally aligns with the resource planning objective of meeting peak demand and energy requirements throughout the year by delivering affordable, reliable and increasingly cleaner energy to customers.

For DEC and DEP, capital costs were incurred over several decades when the utilities were primarily summer peaking. From a maximum capacity (MW) standpoint, resource planning

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was based on the summer peak. A Winter CP reflects how resource planning will reflect drivers of costs going forward. Also, single CP methods justify or support rate design structures that encourage reduction of load at the times of system peak and the shifting of usage to off-peak, both of which can eliminate or delay the addition of future generation resources. A final advantage of this method is that it is relatively simple to understand.

Advocates for this method argue that each customer class is responsible for their contribution to this single peak demand and should be allocated its proportional share of the utility's fixed capacity cost. Critics of this method argue that it does not address the capacity/energy tradeoff discussed above. Under this method, all the system's fixed capacity costs are allocated based on each classes' relative contribution to the single peak hour. Or, said another way, it does not consider the fact that customers use the production system during the other 8,759 hours of the year. They further argue that as the utility decides the size and type of generating capacity to build, it must consider not only the maximum coincident peak load but also the utility's customer demands throughout the year. They contend that if the utility only needed to consider the single peak hour, the utility would only install peaking units since they have the lowest installed cost per kW. But peaking units have the highest operating costs per kWh. As a result, as noted above, a utility installs a mix of generation to meet demand and energy needs to optimize total capital and operating costs.

Another argument against this method is that a typical utility's maximum coincident peak is usually driven by weather extremes (heat or cold). Residential customer loads, more than other customer class loads, are impacted significantly by weather due to the significance of heating and cooling loads to the total loads of residential customers. In addition, the actual peak load can vary significantly from forecasted load. This volatility can result in significant changes

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in rate class cost responsibility from year to year. The result may be large swings in cost allocation to customers, impacting the ability of the utility to maintain stable rates for its customers. The stakeholder group discussed that one potential way to mitigate this issue of volatility is to use forecasted/weather normalized peak demand data when developing the allocation factors. This approach would remove the volatility created by test years with extreme weather at the peak.

Another issue with the single coincident peak method is that some rate classes may not be allocated any production and transmission related fixed costs because they have no load at the time of the peak. For example, the lighting class for DEC/DEP, other than traffic signals, are allocated little, if any, fixed cost under the summer coincident peak method because there is no lighting load at the time of DEC's/DEP's summer peaks.

**Four Coincident Peak Method ("4CP"):** A 4CP method has some of the same advantages and disadvantages as the single coincident peak method discussed above but takes some of the variation of utility monthly peaks into account. This method has several variations; it may average the four maximum monthly peaks regardless of season, or average the two maximum summer peaks and the two maximum winter peaks to deliberately reflect seasonal differences.

Advocates for this method point out that it can capture the seasonal variation in the utility's loads while at the same time reducing the volatility inherent in the single CP method. Also, FERC commonly accepts multiple CP methods.

Similar to the single coincident peak method, critics of this method believe that looking at four hours of load is not enough to represent the non-peak usage of the generating fleet.

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**Twelve Coincident Peak Method ("12CP"):** This method averages all twelve of the utility's monthly coincident peaks in an attempt to capture the seasonal variation in the loads while also reducing the possibility of a rate class avoiding any peak responsibility. Generally, the more peaks used, the less impact any individual peak has on the allocation of fixed production and transmission costs. The averaging effect of multiple peaks also temper the impact of seasonal differences in peaks and the character of those peaks.

FERC has issued guidance on when the 12CP method may be an appropriate allocation method in proceedings before it. On page 31 of Opinion No. 501 in Docket Nos. EL05-19-002 and ER05-168-001 FERC said:

> A company that has a relatively flat demand curve throughout the year would typically allocate demand on a 12 CP basis, which assumes that a utility's demand is relatively constant throughout all twelve months of the year.

In this same order, FERC proceeded to describe three tests that could be used by FERC to determine whether a utility's load shape qualified it for the 12CP allocation method. Upon a review of these three tests, it is apparent that FERC has constructed these tests to measure the relative "flatness" of the twelve-monthly peaks to each other. DEC Exhibit 2 and DEP Exhibit 2 provide the results of these three tests for their respective utility for the ten years ending with 2018. DEC qualifies for 12CP treatment with tests 1 and 3 in all ten years but only six of ten years for test 2. DEP qualifies for 12CP treatment with test 1 in all ten years but only seven out of ten years for tests 2 and 3.

Advocates for this method point out that it mitigates some of the weaknesses of the single CP method in that it ensures that those rate classes that use the system pay for the system and

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moderates the impact of weather extremes in any month by equally weighting all twelve monthly peaks.

Critics of the 12CP method contend that utilities do not design their generating systems to meet twelve peaks. Nevertheless, utilities typically have high system peaks in the summer and winter months and lower system peaks during the spring and fall months. If the utility assigns peak responsibility to its rate classes based on their contributions to each monthly peak, then their allocated costs will reflect that the utility called on almost all its generating resources during the highest peak months but only its more efficient generating units during the lower peak periods. In addition, the 12CP method does not encourage load shifting to the same extent as a single CP method.

DEC Exhibit 3 and DEP Exhibit 3 show peak demands for each of the four peak-responsibility methods discussed above.

**Summer Winter Peak and Average Method ("SWPA"):** The concept behind the SWPA method is that a utility builds generating facilities to not only meet peak demand but also to serve customer energy needs throughout the year. Thus, these methods allocate fixed capacity costs partially based on each classes' contribution to peak demand and partially on the basis of energy consumption throughout the year. While there is no universal approach as to what peak demands should be used or the weighting between the peak and average portions, typical methods use coincident peak demand for the peak component and the system load factor for the weight of the energy portion and one minus the system load factor to weight the peak segment.

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Advocates for this method state that this method recognizes the capacity/energy tradeoff in the allocation of fixed capacity costs, which is not present in the various peak responsibility methods described above.

Critics of this method point out that a significant amount of production fixed costs is allocated to the rate classes based on energy consumption but with no offset for the lower fuel costs incurred by the utility during off-peak periods. They contend that this method is detrimental to high load factor customers, who more efficiently utilize the utility's facilities than low load factor customers whose load is more volatile, requiring more capacity to serve their load. High load factor customers consume a more constant amount of energy across the hours of the year including the less expensive off-peak hours. Under this method, a high load factor class will be assigned significant fixed capacity costs while, at the same time, allocated fuel costs based on a system average. If the variation in hourly fuel costs is substantial, high load factor customers will be allocated a disproportionate share of the fuel costs.

Another issue with this method, argued by some customer groups, is the use of average load in the calculation of the peak demand component. If peak demand is defined as average demand plus excess demand (the difference between a class's demand and its corresponding average demand), these groups believe that using a weighted average of peak demand and average demand results in allocation factors that double count average demand. This result occurs because the peak demand segment contains an average load component.

DEC Exhibit 4 and DEP Exhibit 4 provide an example calculation of the SWPA method for each utility.

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**Average & Excess Method ("A&E"):** Another energy weighting method described in the NARUC CAM is the average and excess method. While the A&E method was not a method included in the Second Partial Stipulations, it was included in this study at the request of a stakeholder. The A&E method considers that generation facilities are needed to serve a utility's "average load," as well as its "excess or peak load," in assigning responsibility for the recovery of production fixed costs. The A&E allocation demand factor is composed of two parts. The average demand for the test year is calculated by dividing the test year number of kilowatt-hours at the generator by the number of hours in the test year (for 2018 there were 8,760 hours). The excess portion of the demand factor is the difference between the system average demand and the system peak demand. It is important to note that the NARUC CAM defines the excess demand for this method as the difference between non-coincident demand (the sum of the individual maximum demands regardless of time of occurrence within the specified period) and average demand[3]. The average demand component of the A&E allocation factor is each class's average demand times the system load factor. This measures the amount of demand incurred if the utility served this amount of load at a constant 100% load factor. The excess demand component of the A&E factor measures the variability of each class's load. The greater a class's load variability, the greater the amount of load-following resources needed to provide the total load requirement. This excess portion is multiplied by one minus the load factor. Lastly, the sum of these two demands by class or jurisdiction are divided by the system total to produce each class or jurisdiction's Average & Excess allocator.

[3] The NARUC CAM also points out that the use of non-coincident peaks with the Average & Excess method avoids the potential of a negative allocator caused by a rate class with a zero CP. For example, using Summer CPs, the lighting class could produce negative excess demand.

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Like the SWPA method, this method recognizes the capacity/energy tradeoff in the allocation of fixed capacity costs and ensures that all classes are allocated some portion of fixed production costs. Unlike the SWPA method, the A&E method avoids the double counting of demand as excess demand is defined as peak demand less average demand.

Critics of this method note that coincident demands, and not non-coincident demands, are a parameter of interest to system planners. The use of non-coincident demands will, in general, shift production fixed costs to lower load factor customer classes. Like all energy methods, it does not provide for a fuel offset to reflect lower variable fuel costs during off-peak periods to assist high load factor classes that are allocated a larger proportion of fixed costs under average methods.

DEC Exhibit 5 and DEP Exhibit 5 provide an example calculation of the A&E method for each utility.

**Average & Excess 4CP Method ("A&E 4CP"):** The Average & Excess 4CP method is constructed in the same manner as the Average & Excess Method described above except that 4CP demands are substituted for the non-coincident demands used in the standard A&E method.

Advocates for this method believe that it has some of the same advantages as the peak responsibility methods, like encouraging off-peak usage, while including an energy component to capture off-peak usage.

DEC Exhibit 6 provides an example calculation of the Average & Excess 4CP method for DEC, and DEP Exhibit 6 provides the same example calculation for DEP.

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**Average & Excess Dominion Method ("A&E DOM"):** The Average & Excess Dominion method is not a method mentioned in the NARUC CAM but rather a negotiated, customized variant used by Dominion for its Virginia retail customers that the stakeholder group requested be included in the study. As implemented by Dominion, it uses diversified non-coincident demands instead of non-diversified, non-coincident demands as utilized in the A&E method described above. Use of diversified demands recognize that each customer's maximum load does not occur at the same time. Thus, diversified non-coincident demands represent the class's maximum demand during the period and are invariably less than the non-diversified, non-coincident demands for the same rate class. (For example, the maximum demand for one class may be at 5 PM while the maximum demand for another class may be at 2 PM.) Average demand and excess demand are calculated in the same manner as the two previously described A&E methods. This method adds an additional step of scaling down the excess demands for each rate class such that the average plus excess demands equal the summer coincident demands at a system level for each utility. The result of all these calculations is that the interrelationships between the classes matches their non-coincident demands but the total excess demand equals the system excess based on the summer coincident demand. These resulting class excess demands are then added to their respective average demands to determine the total average & excess demands under this method.

In general, this method has the same strengths and weaknesses as the A&E method described above. Additionally, the extra steps outlined above make its calculations a little more difficult to understand than the standard A&E method.

DEC Exhibit 7 provides an example calculation of the A&E DOM method for DEC, and DEP Exhibit 7 provides the same example calculation for DEP.

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**Base, Intermediate and Peak Method ("BIP"):** The NARUC CAM classifies this method as a time-differentiated method. This method classifies each generating resource as base, intermediate or peaking based on its role within a utility's portfolio of generation facilities and, likewise, assigns each unit's plant investment to each category of generating plant. In this manner, a weighting of high fixed cost base load units relative to lower fixed cost peaking units is achieved.

Advocates of this method contend that it recognizes that generating facilities are added to meet the varying needs of the system. High fixed cost, low variable cost base load units with high capacity factors run continuously throughout the year to meet the energy needs of all customers. Thus, base load units, under this method, are allocated based on energy. In contrast, low fixed cost, high variable cost peaking units are built to run only a few hours per year during high peak demand periods and, therefore, have relatively low capacity factors. These peaking units are typically allocated based on a peak demand method like 1CP or 4CP. Both DEC and DEP allocated these peaking unit costs at the summer single coincident peak demand allocation method in this study as presented in DEC Exhibit 8 and DEP Exhibit 8.

In between the base load units and the peaking units are the intermediate generating resources. While these units may not be dispatched during periods of low system load, these relatively efficient units do operate for many hours of the year. Under this method, the plant investment in these units is typically allocated to the energy classification based on their annual capacity factors with the remainder allocated to capacity.

Hydro units are addressed on a case-by-case basis. Pumped storage units by design are intended to provide peaking power although in actual practice they may be used at other times as

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well. A case can be made to assign these units 100% to demand. Since reservoir or storage hydro units can be subject to daily or seasonal restrictions on water releases, assignments could be based 50% energy and 50% demand. Run-of-river hydro units are typically assigned to the energy component based on their annual capacity factors. In this study, solar units were assigned to the energy component based on the overall annual solar capacity factor.

Example calculations of this method can be found in DEC Exhibit 8 and DEP Exhibit 8.

Assigning the plant investment costs of each generator to their respective energy or demand classification does not result in values that immediately translate into allocation factors that are useable in the DEC and DEP cost of service allocation models. Thus, it was necessary to allocate each generation type's energy and demand investment costs to the rate classes using the appropriate allocator and then sum the resulting values by rate class to calculate a composite BIP allocator. The development of these allocators can be found in DEC Exhibit 9 and DEP Exhibit 9. Please note that the Exhibit 9s represent an attempt by each utility to create traditional class allocation factors based on the calculation of the BIP method.

Advocates for this method state that it recognizes the mix of a utility's resources used to serve its varying demands throughout the year and that it permits the weighting of expensive base load plants versus less expensive peak load units. Lastly, it recognizes the capacity/energy tradeoff.

Critics argue that a major weakness in the BIP method is that it allocates 100% of base production fixed costs using an energy allocator. Said another way, it fails to consider that baseload units are not simply operated for purposes of providing energy, but also contribute towards meeting peak demand. Critics further state that given that base units, by definition, have high capacity factors, it seems illogical not to assign some proportion of their fixed costs with a

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demand factor. Critics also say another major weakness of the BIP method, like all the methods using energy to allocate capacity fixed costs, is that no offset is made to reflect lower variable fuel costs during off-peak periods. Another drawback to this method is the lack of consensus among industry experts on which demands (1CP, 4CP, 12CP, etc.) to apply to the intermediate and peak categories. Finally, this approach may distort the relative values of the base, intermediate and peaking components due to the timing of each component member's plant installation dates.

CIGFUR Exhibit 1 provides specific comments on the BIP method by the Carolina Industrial Group for Fair Utility Rates.

## Summary of Production Demand Allocation Methods

The table below summarizes the 2018 DEC production demand allocators by rate class for each of the nine allocation methods described herein:

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# Duke Energy Carolinas, Inc.

**DEC Exhibit 10**

## Cost of Service Analysis Results
## Production Demand Allocation Factors
## For the twelve months ending December 2018

| | | Peak Responsibility Methods | | | | Energy Weighting Methods | | | | Time Differentiated Method |
|---|---|---|---|---|---|---|---|---|---|---|
| | Load Factor | Summer 1 CP | Winter 1 CP | 4CP | 12CP | SWPA | A&E | A&E 4CP | A&E Dom | BIP |
| | | Exhibit3 | Exhibit3 | Exhibit3 | Exhibit3 | Exhibit4 | Exhibit5 | Exhibit6 | Exhibit7 | Exhibit8 |
| **North Carolina:** | | | | | | | | | | |
| Residential | 50.11% | 30.9900% | 36.6484% | 32.5594% | 31.4863% | 29.6899% | 38.8639% | 30.5591% | 31.1211% | 27.0273% |
| SGS | 46.63% | 6.7074% | 5.2708% | 5.8334% | 5.5219% | 5.5322% | 5.8993% | 5.6279% | 5.6949% | 5.3972% |
| LGS | 56.23% | 6.2578% | 5.3386% | 5.9541% | 6.1287% | 5.7486% | 4.9931% | 5.8888% | 5.6962% | 5.8592% |
| Lighting | | 0.0073% | 0.4168% | 0.1764% | 0.1332% | 0.4874% | 0.6955% | 0.3381% | 1.0029% | 0.5587% |
| Industrial | 66.93% | 2.0918% | 2.0516% | 2.2797% | 2.3447% | 2.1698% | 2.3050% | 2.2781% | 2.7276% | 2.2557% |
| OPT-Small | 67.49% | 8.2635% | 7.0243% | 7.6300% | 7.7505% | 8.3204% | 6.0084% | 8.0195% | 7.2305% | 8.7455% |
| OPT-Medium | 78.04% | 2.7678% | 2.3229% | 2.6391% | 2.7923% | 3.0099% | 2.1277% | 2.8762% | 2.6956% | 3.2896% |
| OPT-Large | 83.72% | 9.5019% | 7.2610% | 8.8122% | 9.5791% | 10.5692% | 7.2286% | 9.9324% | 9.2848% | 11.9047% |
| OPT-Trans | 97.01% | 0.8471% | 0.6880% | 0.8322% | 0.9322% | 1.0421% | 0.6813% | 0.9692% | 0.8887% | 1.2005% |
| NC Retail | | 67.4345% | 67.0222% | 66.7165% | 66.6688% | 66.5694% | 68.8029% | 66.4893% | 66.3423% | 66.2385% |
| NC Wholesale | 78.09% | 4.1506% | 5.8272% | 4.9532% | 4.8449% | 5.1394% | 4.0024% | 5.0381% | 5.7230% | 5.0301% |
| Total NC | 61.19% | 71.5851% | 72.8494% | 71.6698% | 71.5137% | 71.7088% | 72.8052% | 71.5274% | 72.0652% | 71.2687% |
| **South Carolina:** | | | | | | | | | | |
| Residential | 49.01% | 9.6153% | 10.8916% | 10.1920% | 10.0098% | 9.0002% | 12.3610% | 9.4998% | 9.4302% | 8.2998% |
| SGS | 48.60% | 1.9186% | 1.4200% | 1.6870% | 1.6619% | 1.5890% | 1.7157% | 1.6399% | 1.6762% | 1.5988% |
| LGS | 54.22% | 1.4567% | 1.2166% | 1.3819% | 1.3633% | 1.3081% | 1.2142% | 1.3549% | 1.4368% | 1.3215% |
| Lighting | | 0.0016% | 0.1312% | 0.0562% | 0.0420% | 0.1566% | 0.2208% | 0.1088% | 0.3242% | 0.1806% |
| Industrial | 60.75% | 0.8638% | 0.7101% | 0.8518% | 0.8673% | 0.8173% | 0.7531% | 0.8520% | 0.9073% | 0.8563% |
| OPT-G | 69.26% | 3.0100% | 2.5992% | 2.7900% | 2.8590% | 3.0837% | 2.2284% | 2.9526% | 2.6195% | 3.2513% |
| OPT-I | 88.21% | 6.4648% | 5.0703% | 6.3133% | 6.7756% | 7.4552% | 5.2306% | 7.1174% | 6.5993% | 8.4667% |
| SC Retail | | 23.3309% | 22.0390% | 23.2723% | 23.5790% | 23.4101% | 23.7237% | 23.5254% | 22.9934% | 23.9750% |
| Greenwood | 52.13% | 0.0660% | 0.0687% | 0.0685% | 0.0688% | 0.0618% | 0.0966% | 0.0650% | 4.8046% | 0.0593% |
| SC Wholesale | 56.40% | 5.0180% | 5.0428% | 4.9895% | 4.8385% | 4.8193% | 3.3744% | 4.8823% | 0.1368% | 4.6970% |
| Total SC | 62.52% | 28.4149% | 27.1506% | 28.3302% | 28.4863% | 28.2912% | 27.1948% | 28.4726% | 27.9348% | 28.7313% |
| System | | 100.0000% | 100.0000% | 100.0000% | 100.0000% | 100.0000% | 100.0000% | 100.0000% | 100.0000% | 100.0000% |

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The table below summarizes the 2018 DEP production demand allocators by rate class for each of the nine allocation methods described above:

**Duke Energy Progress, LLC** **DEP Exhibit 10**
**Cost of Service Analysis Results**
**Production Demand Allocation Factors**
**For the twelve months ending December 2018**

| | | Peak Responsibility Methods | | | | Energy Weighting Methods | | | | Time Differentiated Method |
|---|---|---|---|---|---|---|---|---|---|---|
| | Load Factor | Summer 1 CP Exhibit3 | Winter 1 CP Exhibit3 | 4CP Exhibit3 | 12CP Exhibit3 | SWPA Exhibit4 | A&E Exhibit5 | A&E 4CP Exhibit6 | A&E Dom Exhibit7 | BIP Exhibit8 |
| **North Carolina:** | | | | | | | | | | |
| Residential | 51.63% | 30.5172% | 38.3159% | 33.2051% | 32.2792% | 30.0550% | 41.7009% | 31.7100% | 27.8609% | 27.7355% |
| SGS | 49.49% | 3.7875% | 3.5686% | 3.6127% | 3.6016% | 3.3859% | 3.9997% | 3.5090% | 3.1883% | 3.2581% |
| MGS | 60.85% | 17.3390% | 12.0421% | 15.6483% | 16.3051% | 16.3220% | 13.7520% | 16.0965% | 16.3072% | 17.3977% |
| Industrial | 92.93% | 0.0436% | 0.0241% | 0.0554% | 0.0662% | 0.0524% | 0.3771% | 0.0581% | 0.2613% | 0.0666% |
| LGS | 80.28% | 9.8361% | 5.6365% | 8.4253% | 9.3489% | 10.7321% | 6.5313% | 9.4837% | 9.4051% | 12.3316% |
| Lighting | | 0.0045% | 0.0045% | 0.0046% | 0.0049% | 0.3117% | 0.4407% | 0.1287% | 0.6374% | 0.4347% |
| NC Retail | 59.25% | 61.5278% | 59.5918% | 60.9514% | 61.6058% | 60.8591% | 66.8018% | 60.9861% | 57.6602% | 61.2242% |
| NC Wholesale | 58.96% | 28.6661% | 31.5845% | 29.4869% | 28.5332% | 29.1464% | 22.6109% | 29.2320% | 32.4976% | 28.3821% |
| Total NC | 59.16% | 90.1939% | 91.1763% | 90.4383% | 90.1390% | 90.0056% | 89.4127% | 90.2181% | 90.1578% | 89.6063% |
| **South Carolina:** | | | | | | | | | | |
| Residential | 52.20% | 3.9667% | 5.1778% | 4.3745% | 4.2060% | 3.9720% | 5.6226% | 4.1756% | 3.6040% | 3.6358% |
| SGS | 48.07% | 0.5573% | 0.5127% | 0.5559% | 0.5432% | 0.4882% | 0.6619% | 0.5324% | 0.5699% | 0.4719% |
| MGS | 61.60% | 2.5321% | 1.8243% | 2.2811% | 2.3852% | 2.4158% | 2.0602% | 2.3544% | 2.4248% | 2.5656% |
| Industrial | 72.36% | 0.0240% | 0.0277% | 0.0264% | 0.0247% | 0.0276% | 0.0875% | 0.0270% | 0.0544% | 0.0281% |
| LGS | 89.84% | 2.3649% | 0.9578% | 1.9834% | 2.3735% | 2.6962% | 1.8390% | 2.3305% | 2.7211% | 3.2787% |
| Lighting | | 0.0008% | 0.0008% | 0.0008% | 0.0009% | 0.0701% | 0.0961% | 0.0288% | 0.1405% | 0.0978% |
| SC Retail | 64.75% | 9.4459% | 8.5010% | 9.2222% | 9.5335% | 9.6699% | 10.3673% | 9.4487% | 9.5147% | 10.0780% |
| SC Wholesale | 51.41% | 0.3602% | 0.3227% | 0.3395% | 0.3275% | 0.3245% | 0.2200% | 0.3331% | 0.3275% | 0.3157% |
| Total SC | 64.26% | 9.8061% | 8.8237% | 9.5617% | 9.8610% | 9.9944% | 10.5873% | 9.7819% | 9.8422% | 10.3937% |
| System | | 100.0000% | 100.0000% | 100.0000% | 100.0000% | 100.0000% | 100.0000% | 100.0000% | 100.0000% | 100.0000% |

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## The Duke Energy Cost of Service System

The financial inputs into the cost of service study are based on the official accounting books and records of Duke Energy Carolinas ("DEC") and Duke Energy Progress (DEP) using the FERC Uniform System of Accounts.

The Duke Energy cost of service study is an internally developed Microsoft Excel-based model that established the cost to serve each class, and functionalizes those costs across production, transmission, distribution and customer functions. These functionalized costs are grouped into demand, energy and customer classifications based on cost causation. Supporting files for the cost of service study include the financial inputs mentioned earlier as well as the input allocation factors for each customer class based on each class's contribution to peak demands (KW), annual consumption of energy (kWh), number of customers, etc. The final workbook in this system develops derived allocation factors[4], which it uses along with the input allocation factors to allocate or directly assign the costs described above to the appropriate jurisdiction and customer class based on cost causation. The result of the cost of service study is the assignment or spread of revenues, expenses, and rate base components to the jurisdictions and customer classes served by the electric utility. The cost of service study can be prepared in different versions in a rate case, ranging from a per books cost of service to a proforma adjusted cost of service at present or proposed rates. It can also be prepared using different allocation methods such as the Single Summer Coincident Peak or the SWP&A.

[4] Derived allocation factors are calculated by summing by class specifically defined values that have been allocated using input allocation factors and dividing by the sum of all the classes.

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Once the allocation process is complete, the operating income for return is derived for each jurisdiction and rate class by subtracting the allocated operating expenses and interest on customer deposits from the revenues. Next, the rate of return on rate base is determined by dividing the income for return by the allocated rate base for each rate class. Once the rate of return by rate schedule is known, the unit cost calculation provides for a functionalized view of each rate class's revenue requirement such that each function earns the same rate of return within that class. These unit costs are a guide or starting point in the rate design process. DEC Exhibits 15 through 23 provide the unit costs for each of the nine DEC allocation methods described in this report. DEP unit cost reports can be found in DEP Exhibits 15 through 22.

As mentioned earlier, one of the most important parameters calculated in a cost of service study is return on rate base as it provides an indication of how much of a rate increase/decrease each rate class must experience so that each rate class earns the same overall return. DEC Exhibit 11 and DEP Exhibit 11 provide the rate of return under present rates for each rate class of the respective utilities. DEC Exhibit 12 and DEP Exhibit 12 provide each rate classes' rate of return index with respect to its jurisdiction's overall rate of return. An index value of less than one indicates that the rate class's return is less than the jurisdictional return and likely needs a revenue increase to match that jurisdictional return.

## Allocation of Fuel Costs

Fuel costs are considered "pass-through" costs as they are passed on to customers on a dollar-for-dollar basis, and do not include a return component. The rate tariffs for both DEC and DEP include a base fuel component and a separate fuel adjustment clause charge. A fuel adjustment clause is a regulatory provision that permits a change in rates to occur because of a change in the

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cost of fuel or the variable portion of purchased power expenses. These changes occur without the utility filing a formal rate case. Rather, in North Carolina and South Carolina, the regulatory commissions conduct annual fuel adjustment proceedings to adjust the fuel adjustment charge up or down as appropriate. These smaller focused proceedings are designed to eliminate the lag between changes in fuel costs and the reflection of these changes in rates. Thus, a fuel adjustment clause acts as an interim measure for adjusting rates to reflect changes in a large and highly volatile expense item so that under-recovery or over-recovery of the expense does not lead to financial deterioration or excess profits for the utility.

The base fuel component (approved in a general rate proceeding) plus the prospective adjustment to the base fuel component (approved in each annual fuel proceeding) (in total, the prospective fuel rate) is set to collect from customers the estimated prospective cost of fuel and purchased power energy costs. The deferred fuel rate (experience modification factor, or EMF) is designed to eliminate the difference between the prospective fuel rate revenues and the utility's actual costs of fuel and purchased power, so that in the end customers only reimburse the utility for its actual costs. If the prospective fuel rate is higher than actual costs, customers receive a credit in the deferred fuel account. If the prospective rate is lower than actual costs, the utility collects the difference. Both rates (prospective rate and EMF) are updated each year in the utility's fuel proceeding.

Since both electric utilities have fuel adjustment clauses which are separately reviewed and approved by the regulatory commissions, the fuel expense captured in a cost of service study is only that portion related to the base fuel component in rates plus the deferred fuel expense for the test year. Said another way, the base fuel expense plus deferred fuel expense for any rate class is

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exactly offset by that same rate class's fuel revenues. Since these revenues and expenses cancel each other, fuel has no bearing on the final results of the cost of service study.

One criticism of fixed cost allocation methods using average energy is that high load factor customers will be assigned more fixed capacity costs while, at the same time, allocated fuel costs based on an average. (In North Carolina, the average rate is modified to produce an equal percent increase across all rate classes). High-load factor customers consume a more constant amount of energy across the hours of the year including the less expensive off-peak hours. If the variation in hourly fuel costs is substantial, high load factor customers will be allocated a disproportionate share of those fuel costs.

DEC Exhibit 13 and DEP Exhibit 13 provide one of many possible approaches that could be used to ensure that those rate classes that cause the system to incur more fuel costs are then allocated proportionately more of the higher-priced fuel. Each generator that uses fuel was classified as base, intermediate or peaking and their fuel costs were included in their respective BIP total. Each rate classes' average demand, 12CP demand and SCP demand (columns 3, 6 & 9) were used to develop allocators as a percent of the total system (columns 5, 8 & 11). In turn, these allocators were applied to the total annual base, intermediate and peaking fuel costs to determine each classes' allocated share of these three fuel classifications. These three fuel costs are then added to produce the rate classes' allocated share of fuel expense for the test year.

As shown in column 19 on page 2 of DEC Exhibit 13, under this conceptual approach, the NC Residential class and the SC Residential class are allocated almost $65 million more in fuel costs than under a system average method. In contrast, the high-load factor NC OPT Large rate class is allocated $26 million less in fuel costs.

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For only those methods that employ average energy to allocate production fixed costs, DEC Exhibit 14 and DEP Exhibit 14 provide each rate classes' rate of return on rate base after the application of these incremental fuel costs to each rate classes' expenses[5].

## Conclusions

Based on the Second Partial Stipulations between Duke Energy and the Public Staff, Duke Energy formed a stakeholder group to engage in an investigation of nine different production demand allocation methods. Industry accepted approaches for each method used in the study were determined and the strengths and weaknesses of each method were documented. Next, the resulting allocation factors for each method were used in each utility's cost of service tool to calculate each jurisdiction/rate class's rate of return on rate base. Lastly, a calculation method was developed to examine whether certain rate classes might be assigned more or less fuel costs than under a simple average fuel rate method.

Unfortunately, this effort to evaluate nine different methods did not result in a single method that all involved stakeholders would support. It will be up to each interested party to propose and support its preferred methodology and for the regulatory commissions to make a finding based on the facts and evidence presented in each rate case. Nonetheless, many members of the study group agreed that their knowledge and understanding of these allocation methods was increased by their participation in this process.

[5] In a typical year, fuel revenues and fuel expenses should offset with no impact on ROR. For illustrative purposes, however, Exhibit 14 demonstrates the impact of modifying fuel expense allocations (and revenues) in the 2018 test year to address some of the issues around the energy weighting allocation methods and indicate how each rate class might be affected.

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Lastly, the participants in this study hope the North Carolina Utilities Commission, the South Carolina Public Service Commission, the North Carolina Public Staff, the South Carolina Office of Regulatory Staff and other interested parties find this final report both helpful and informative.

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## Definition of Terms

**Coincident Peak or CP** – a customer's or customer classes' demand at the moment in time that the total system experiences its maximum peak load.

**Non-Coincident Peak or NCP** – a customer's or customer classes' maximum demand irrespective of when it occurs.

**Demand** - the amount of energy consumed at a single point in time. Expressed in either KW, MW or GW.

**Average Demand –**the total kWh of energy consumed in the period divided by the total number of hours in the period. If a customer consumes 876,000 kWh during a year, the customer's average demand is then 100KW. This calculation is analogous to the average speed of an automobile on a trip.

**KW** – Kilowatt or 1000 watts which is a measure of power. A KW represents how much power is needed at an instant in time.

**MW** – Megawatt or 1,000,000 watts.

**KWH** –a measure of energy. A 100-watt light bulb burning 10 hours will consume 1,000 watt-hours or 1 kWh. It measures how much energy is used in one hour.

**KV** - Kilovolt – A volt is the difference of potential that would drive one ampere of current against one ohm of resistance between two points on a conducting wire. A kilovolt is 1,000 volts.

**KVA** – Kilovolt-ampere - A volt-ampere (VA) is the voltage times the current feeding an electrical load. A kilovolt-ampere (**kVA**) is 1000 volt-amperes.

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**Load Factor (kWh consumed in period)/ (KW peak x hours in period)** – a measure that captures the degree of variation in the pattern of demand. The closer the load factor is to 1, the less variation in the pattern of demand. The closer the load factor is to zero, the more the variation in the pattern of demand. A high system load factor translates into a higher utilization of the generating system and into a lower average cost per kWh. A higher load factor customer requires less capacity for the same amount of energy as demonstrated by this simple example:

30% Annual Load Factor = 100,000kWh / (38.05KW x 8760 hours)

60% Annual Load Factor = 100,000kWh / (19.025KW x 8760 hours)

Thus, a low load factor customer requires more capacity to be built to serve their load than a high load factor customer; however, a high load factor customer requires more baseload (higher capital cost) capacity to be built than a low load factor customer.

**Load Curve –** the pattern of instantaneous demand through a defined period. A monthly load curve looks at 730 hours while an annual load curve examines 8760 hours.

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# Duke Energy Carolinas

**DEC Exhibit 1**

**Production Demands**

Year: 2018

| | Coincident Peaks | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **January** | **February** | **March** | **April** | **May** | **June** | **July** | **August** | **September** | **October** | **November** | **December** |
| **North Carolina:** | | | | | | | | | | | | |
| Residential | 6,917,677 | 5,539,660 | 4,344,394 | 3,276,672 | 4,944,475 | 5,420,002 | 5,204,310 | 5,096,485 | 4,996,228 | 4,315,875 | 4,744,968 | 4,979,116 |
| SGS | 994,904 | 598,217 | 727,931 | 507,600 | 865,296 | 1,173,097 | 1,124,484 | 1,056,617 | 1,047,055 | 947,796 | 698,474 | 742,457 |
| LGS | 1,007,695 | 704,430 | 948,385 | 790,920 | 909,849 | 1,094,460 | 1,097,280 | 1,120,252 | 1,072,929 | 998,580 | 972,143 | 918,945 |
| Lighting | 78,669 | 1,609 | 95,192 | 1,161 | 1,117 | 1,270 | 1,190 | 1,151 | 1,330 | 1,085 | 28,258 | 40,885 |
| Industrial | 387,247 | 172,857 | 425,886 | 393,083 | 310,135 | 365,855 | 404,088 | 375,869 | 402,920 | 361,622 | 432,369 | 419,636 |
| OPT-Small | 1,325,901 | 950,939 | 1,177,102 | 990,661 | 1,239,465 | 1,445,244 | 1,391,153 | 1,368,461 | 1,347,734 | 1,283,613 | 1,079,412 | 1,115,340 |
| OPT-Medium | 438,459 | 331,189 | 442,154 | 382,657 | 445,958 | 484,083 | 482,442 | 509,055 | 484,294 | 450,848 | 429,733 | 420,496 |
| OPT-Large | 1,370,565 | 1,273,450 | 1,403,547 | 1,365,432 | 1,568,791 | 1,661,833 | 1,644,906 | 1,744,159 | 1,716,897 | 1,644,612 | 1,374,660 | 1,418,051 |
| OPT-Trans | 129,864 | 133,755 | 135,412 | 136,065 | 148,822 | 148,149 | 144,905 | 164,262 | 163,789 | 161,124 | 151,072 | 152,697 |
| NC Retail | 12,650,981 | 9,706,106 | 9,700,003 | 7,844,251 | 10,433,908 | 11,793,993 | 11,494,758 | 11,436,311 | 11,233,176 | 10,165,155 | 9,911,089 | 10,207,623 |
| NC Wholesale | 1,099,929 | 858,892 | 745,336 | 671,533 | 651,301 | 725,919 | 732,710 | 704,329 | 689,597 | 588,581 | 862,931 | 867,561 |
| Total NC | 13,750,910 | 10,564,998 | 10,445,339 | 8,515,784 | 11,085,209 | 12,519,912 | 12,227,468 | 12,140,640 | 11,922,773 | 10,753,736 | 10,774,020 | 11,075,184 |
| **South Carolina:** | | | | | | | | | | | | |
| Residential | 2,055,870 | 1,608,802 | 1,344,568 | 1,292,230 | 1,543,104 | 1,681,673 | 1,667,212 | 1,665,234 | 1,399,069 | 1,469,744 | 1,632,180 | 1,644,981 |
| SGS | 268,044 | 188,632 | 182,798 | 161,281 | 253,879 | 335,555 | 353,517 | 353,049 | 322,217 | 313,492 | 213,093 | 209,767 |
| LGS | 229,652 | 129,532 | 193,725 | 176,566 | 192,881 | 254,778 | 247,683 | 251,243 | 241,317 | 224,448 | 222,695 | 223,767 |
| Lighting | 24,774 | 286 | 30,245 | 277 | 266 | 280 | 284 | 268 | 308 | 257 | 8,985 | 13,522 |
| Industrial | 134,030 | 61,609 | 158,247 | 145,254 | 123,802 | 151,075 | 156,262 | 151,666 | 146,097 | 137,901 | 132,895 | 147,848 |
| OPT-G | 490,613 | 344,840 | 415,846 | 358,715 | 456,654 | 526,432 | 512,616 | 523,287 | 488,935 | 503,093 | 406,999 | 400,162 |
| OPT-I | 957,062 | 871,188 | 1,039,461 | 934,757 | 1,132,868 | 1,130,670 | 1,179,448 | 1,178,427 | 1,205,087 | 1,129,341 | 1,006,177 | 1,099,713 |
| SC Retail | 4,160,045 | 3,204,889 | 3,364,890 | 3,069,080 | 3,703,454 | 4,080,463 | 4,117,022 | 4,123,174 | 3,803,030 | 3,778,276 | 3,623,024 | 3,739,760 |
| SC Wholesale | 951,870 | 678,846 | 649,363 | 553,015 | 765,538 | 877,626 | 866,904 | 837,027 | 781,045 | 736,314 | 734,088 | 754,780 |
| Greenwood | 12,974 | 11,005 | 9,107 | 7,669 | 10,638 | 11,544 | 12,220 | 12,515 | 10,794 | 11,569 | 9,887 | 10,617 |
| Total SC | 5,124,889 | 3,894,740 | 4,023,360 | 3,629,764 | 4,479,630 | 4,969,633 | 4,996,146 | 4,972,716 | 4,594,869 | 4,526,159 | 4,366,999 | 4,505,157 |
| System | 18,875,799 | 14,459,738 | 14,468,698 | 12,145,548 | 15,564,838 | 17,489,545 | 17,223,614 | 17,113,356 | 16,517,641 | 15,279,895 | 15,141,019 | 15,580,340 |

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# Duke Energy Carolinas, LLC

**DEC Exhibit 2**

## Cost of Service Analysis Results
## FERC 12CP Test
## For the twelve months ending December 2018

| | | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | Test Results |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Annual Maximum: | | 16,246 | 16,715 | 16,985 | 16,973 | 15,866 | 18,253 | 18,490 | 18,022 | 17,422 | 18,935 | |
| | Month | Aug | Aug | Jul | Jul | Jul | Jan | Feb | Jul | Aug | Jan | |
| | Month # | 8 | 8 | 7 | 7 | 7 | 1 | 2 | 7 | 8 | 1 | |
| Annual Minimum: | | 10,626 | 11,224 | 11,243 | 11,426 | 11,799 | 11,597 | 11,591 | 12,921 | 12,661 | 12,230 | |
| | Month | Nov | Oct | Oct | Oct | Apr | Apr | Oct | Nov | Apr | Apr | |
| | Month # | 11 | 10 | 10 | 10 | 4 | 4 | 10 | 11 | 4 | 4 | |
| Summer Max: | | 16,246 | 16,715 | 16,985 | 16,973 | 15,866 | 16,480 | 17,353 | 18,022 | 17,422 | 17,632 | |
| | Month | Aug | Aug | Jul | Jul | Jul | Jul | Jun | Jul | Aug | Jun | |
| | Month # | 8 | 8 | 7 | 7 | 7 | 7 | 6 | 7 | 8 | 6 | |
| Winter Max: | | 15,869 | 16,454 | 15,822 | 15,391 | 14,681 | 18,253 | 18,490 | 17,053 | 16,743 | 18,935 | |
| | Month | Feb | Dec | Jan | Jan | Feb | Jan | Feb | Jan | Jan | Jan | |
| | Month # | 2 | 12 | 1 | 1 | 2 | 1 | 2 | 1 | 1 | 1 | |
| **Test 1: ON and Off Peak Test** | | | | | | | | | | | | |
| **Summer CP Method:** | | | | | | | | | | | | |
| | Summer Max | 16,246 | 16,715 | 16,985 | 16,973 | 15,866 | 16,480 | 17,353 | 18,022 | 17,422 | 17,632 | |
| | Annual Max | 16,246 | 16,715 | 16,985 | 16,973 | 15,866 | 18,253 | 18,490 | 18,022 | 17,422 | 18,935 | |
| | | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 90.3% | 93.9% | 100.0% | 100.0% | 93.1% | |
| | Avg Off-Peak | 13,581 | 14,356 | 14,259 | 13,986 | 14,173 | 15,014 | 15,107 | 15,059 | 15,096 | 15,771 | |
| | Annual Max | 16,246 | 16,715 | 16,985 | 16,973 | 15,866 | 18,253 | 18,490 | 18,022 | 17,422 | 18,935 | |
| | | 83.6% | 85.9% | 83.9% | 82.4% | 89.3% | 82.3% | 81.7% | 83.6% | 86.6% | 83.3% | |
| | Difference | 16.4% | 14.1% | 16.1% | 17.6% | 10.7% | 8.0% | 12.1% | 16.4% | 13.4% | 9.8% | |
| | <= 19% | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | |
| | **Supports 12CP?** | **Yes** | **Yes** | **Yes** | **Yes** | **Yes** | **Yes** | **Yes** | **Yes** | **Yes** | **Yes** | **10 of 10** |
| **Test 2: Low to Annual Peak Test** | | | | | | | | | | | | |
| | Annual Min | 10,626 | 11,224 | 11,243 | 11,426 | 11,799 | 11,597 | 11,591 | 12,921 | 12,661 | 12,230 | |
| | Annual Max | 16,246 | 16,715 | 16,985 | 16,973 | 15,866 | 18,253 | 18,490 | 18,022 | 17,422 | 18,935 | |
| | | 65.4% | 67.1% | 66.2% | 67.3% | 74.4% | 63.5% | 62.7% | 71.7% | 72.7% | 64.6% | |
| | >= 66% | No | Yes | Yes | Yes | Yes | No | No | Yes | Yes | No | |
| | **Supports 12CP?** | **No** | **Yes** | **Yes** | **Yes** | **Yes** | **No** | **No** | **Yes** | **Yes** | **No** | **6 of 10** |
| **Test 3: Average to Annual Peak Test** | | | | | | | | | | | | |
| | 12CP Average | 13,803 | 14,552 | 14,486 | 14,235 | 14,314 | 15,136 | 15,294 | 15,306 | 15,290 | 15,926 | |
| | Annual Max | 16,246 | 16,715 | 16,985 | 16,973 | 15,866 | 18,253 | 18,490 | 18,022 | 17,422 | 18,935 | |
| | | 85.0% | 87.1% | 85.3% | 83.9% | 90.2% | 82.9% | 82.7% | 84.9% | 87.8% | 84.1% | |
| | >= 81% | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | |
| | **Supports 12CP?** | **Yes** | **Yes** | **Yes** | **Yes** | **Yes** | **Yes** | **Yes** | **Yes** | **Yes** | **Yes** | **10 of 10** |

From FERC Opinion 501 - Docket Nos. EL05-19-002 and ER05-168-001 - Golden Spread EMC - April 2008

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# Duke Energy Carolinas

**DEC Exhibit 3**

**Peak Responsibility Methods**

Year: 2018

| | June Summer 1CP-Sum | January Winter 1CP-Win | January December June July 4CP | 12CP |
|---|---|---|---|---|
| **North Carolina:** | | | | |
| Residential | 5,420,002 | 6,917,677 | 5,630,276 | 4,981,655 |
| SGS | 1,173,097 | 994,904 | 1,008,736 | 873,661 |
| LGS | 1,094,460 | 1,007,695 | 1,029,595 | 969,656 |
| Lighting | 1,270 | 78,669 | 30,504 | 21,076 |
| Industrial | 365,855 | 387,247 | 394,207 | 370,964 |
| OPT-Small | 1,445,244 | 1,325,901 | 1,319,410 | 1,226,252 |
| OPT-Medium | 484,083 | 438,459 | 456,370 | 441,781 |
| OPT-Large | 1,661,833 | 1,370,565 | 1,523,839 | 1,515,575 |
| OPT-Trans | 148,149 | 129,864 | 143,904 | 147,493 |
| NC Retail | 11,793,993 | 12,650,981 | 11,536,839 | 10,548,113 |
| NC Wholesale | 725,919 | 1,099,929 | 856,530 | 766,552 |
| Total NC | 12,519,912 | 13,750,910 | 12,393,368 | 11,314,664 |
| **South Carolina:** | | | | |
| Residential | 1,681,673 | 2,055,870 | 1,762,434 | 1,583,722 |
| SGS | 335,555 | 268,044 | 291,721 | 262,944 |
| LGS | 254,778 | 229,652 | 238,970 | 215,691 |
| Lighting | 280 | 24,774 | 9,715 | 6,646 |
| Industrial | 151,075 | 134,030 | 147,304 | 137,224 |
| OPT-G | 526,432 | 490,613 | 482,456 | 452,349 |
| OPT-I | 1,130,670 | 957,062 | 1,091,723 | 1,072,017 |
| SC Retail | 4,080,463 | 4,160,045 | 4,024,323 | 3,730,592 |
| SC Wholesale | 877,626 | 951,870 | 862,795 | 765,535 |
| Greenwood | 11,544 | 12,974 | 11,839 | 10,878 |
| Total SC | 4,969,633 | 5,124,889 | 4,898,956 | 4,507,005 |
| System | 17,489,545 | 18,875,799 | 17,292,325 | 15,821,669 |

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## Duke Energy Carolinas

**DEC Exhibit 4**

**Summer/Winter Peak & Average Allocation Method**

**Year:** 2018

| | Inputs | | | Calculation | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Summer Coin. Peak June | Winter Coin. Peak January | MWH @ Gen | Energy Portion of Demand | Energy Allocator | Average Sum/Win Peak | Demand Portion of Demand | Demand Allocator | Peak & Average Demand | Class Allocator |
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) |
| **North Carolina:** | | | | | | | | | | |
| Residential | 5,420,002 | 6,917,677 | 23,793,860 | 1,672,350 | 25.22% | 6,168,840 | 2,370,708 | 33.93% | 4,043,059 | 29.69% |
| SGS | 1,173,097 | 994,904 | 4,791,551 | 336,774 | 5.08% | 1,084,001 | 416,585 | 5.96% | 753,359 | 5.53% |
| LGS | 1,094,460 | 1,007,695 | 5,390,752 | 378,889 | 5.71% | 1,051,078 | 403,933 | 5.78% | 782,822 | 5.75% |
| Lighting | 1,270 | 78,669 | 725,804 | 51,013 | 0.77% | 39,970 | 15,360 | 0.22% | 66,374 | 0.49% |
| Industrial | 365,855 | 387,247 | 2,144,966 | 150,759 | 2.27% | 376,551 | 144,710 | 2.07% | 295,469 | 2.17% |
| OPT-Small | 1,445,244 | 1,325,901 | 8,544,626 | 600,559 | 9.06% | 1,385,573 | 532,481 | 7.62% | 1,133,039 | 8.32% |
| OPT-Medium | 484,083 | 438,459 | 3,309,507 | 232,609 | 3.51% | 461,271 | 177,268 | 2.54% | 409,877 | 3.01% |
| OPT-Large | 1,661,833 | 1,370,565 | 12,187,525 | 856,600 | 12.92% | 1,516,199 | 582,681 | 8.34% | 1,439,281 | 10.57% |
| OPT-Trans | 148,149 | 129,864 | 1,258,942 | 88,485 | 1.33% | 139,007 | 53,421 | 0.76% | 141,905 | 1.04% |
| NC Retail | 11,793,993 | 12,650,981 | 62,147,533 | 4,368,037 | 65.88% | 12,222,487 | 4,697,148 | 67.22% | 9,065,185 | 66.57% |
| NC Wholesale | 725,919 | 1,099,929 | 4,965,845 | 349,024 | 5.26% | 912,924 | 350,840 | 5.02% | 699,864 | 5.14% |
| Total NC | 12,519,912 | 13,750,910 | 67,113,378 | 4,717,061 | 71.15% | 13,135,411 | 5,047,988 | 72.24% | 9,765,049 | 71.71% |
| **South Carolina:** | | | | | | | | | | |
| Residential | 1,681,673 | 2,055,870 | 7,219,706 | 507,437 | 7.65% | 1,868,772 | 718,176 | 10.28% | 1,225,613 | 9.00% |
| SGS | 335,555 | 268,044 | 1,428,590 | 100,408 | 1.51% | 301,800 | 115,983 | 1.66% | 216,391 | 1.59% |
| LGS | 254,778 | 229,652 | 1,210,028 | 85,047 | 1.28% | 242,215 | 93,084 | 1.33% | 178,131 | 1.31% |
| Lighting | 280 | 24,774 | 234,925 | 16,512 | 0.25% | 12,527 | 4,814 | 0.07% | 21,326 | 0.16% |
| Industrial | 151,075 | 134,030 | 804,037 | 56,512 | 0.85% | 142,553 | 54,783 | 0.78% | 111,295 | 0.82% |
| OPT-G | 526,432 | 490,613 | 3,194,096 | 224,497 | 3.39% | 508,523 | 195,427 | 2.80% | 419,924 | 3.08% |
| OPT-I | 1,130,670 | 957,062 | 8,736,687 | 614,058 | 9.26% | 1,043,866 | 401,162 | 5.74% | 1,015,219 | 7.46% |
| SC Retail | 4,080,463 | 4,160,045 | 22,828,069 | 1,604,470 | 24.20% | 4,120,254 | 1,583,429 | 22.66% | 3,187,899 | 23.41% |
| SC Wholesale | 877,626 | 951,870 | 4,335,679 | 304,733 | 4.60% | 914,748 | 351,541 | 5.03% | 656,274 | 4.82% |
| Greenwood | 11,544 | 12,974 | 52,719 | 3,705 | 0.06% | 12,259 | 4,711 | 0.07% | 8,417 | 0.06% |
| Total SC | 4,969,633 | 5,124,889 | 27,216,467 | 1,912,908 | 28.85% | 5,047,261 | 1,939,681 | 27.76% | 3,852,590 | 28.29% |
| SYSTEM | 17,489,545 | 18,875,799 | 94,329,844 | 6,629,969 | 100.00% | 18,182,672 | 6,987,669 | 100.00% | 13,617,638 | 100.00% |

Hours in Year: 8,760

System Load Factor: 61.5696% = (94,329,844,000 / 17,489,545) / 8,760

column(4)=LF x column(3) / 8760

column(5)=column(4) / (column(4)Total

column(6)=(column(1)+column(2))/2

column(7)=(1-LF) x column(6)

column(8)=column(7) / column(7)Total

column(9)=column(5) x LF + column(8) x (1-LF)

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# Duke Energy Carolinas

**DEC Exhibit 5**

## Average & Excess Demand Allocation Method

**Year:** 2018

| | Inputs | | | Calculation | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Summer Coin. Peak June | MWH @ Gen | NCD (kW) | Average Demand (KW) | Class Load Factor | Excess Demand (Hourly kW) | Average Demand Component (KW) | Excess Demand Component (KW) | Average & Excess Demand | Average & Excess Hourly Demand Ratio |
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) |
| **North Carolina:** | | | | | | | | | | |
| Residential | 5,420,002 | 23,793,860 | 12,761,819 | 2,716,194 | 50.11% | 10,045,625 | 1,672,350 | 3,860,572 | 5,532,922 | 38.86% |
| SGS | 1,173,097 | 4,791,551 | 1,856,082 | 546,981 | 46.63% | 1,309,101 | 336,774 | 503,092 | 839,866 | 5.90% |
| LGS | 1,094,460 | 5,390,752 | 1,479,187 | 615,383 | 56.23% | 863,805 | 378,889 | 331,963 | 710,852 | 4.99% |
| Lighting | 1,270 | 725,804 | 207,752 | 82,854 | 6523.96% | 124,897 | 51,013 | 47,999 | 99,012 | 0.70% |
| Industrial | 365,855 | 2,144,966 | 706,475 | 244,859 | 66.93% | 461,616 | 150,759 | 177,401 | 328,160 | 2.31% |
| OPT-Small | 1,445,244 | 8,544,626 | 1,638,526 | 975,414 | 67.49% | 663,112 | 600,559 | 254,837 | 855,395 | 6.01% |
| OPT-Medium | 484,083 | 3,309,507 | 560,748 | 377,798 | 78.04% | 182,951 | 232,609 | 70,309 | 302,917 | 2.13% |
| OPT-Large | 1,661,833 | 12,187,525 | 1,840,166 | 1,391,270 | 83.72% | 448,896 | 856,600 | 172,512 | 1,029,112 | 7.23% |
| OPT-Trans | 148,149 | 1,258,942 | 165,874 | 143,715 | 97.01% | 22,159 | 88,485 | 8,516 | 97,001 | 0.68% |
| NC Retail | 11,793,993 | 62,147,533 | 21,216,630 | 7,094,467 | 60.15% | 14,122,163 | 4,368,037 | 5,427,200 | 9,795,237 | 68.80% |
| NC Wholesale | 725,919 | 4,965,845 | 1,141,365 | 566,877 | 78.09% | 574,488 | 349,024 | 220,778 | 569,802 | 4.00% |
| Total NC | 12,519,912 | 67,113,378 | 22,357,995 | 7,661,344 | 61.19% | 14,696,650 | 4,717,061 | 5,647,978 | 10,365,039 | 72.81% |
| **South Carolina:** | | | | | | | | | | |
| Residential | 1,681,673 | 7,219,706 | 4,082,919 | 824,167 | 49.01% | 3,258,752 | 507,437 | 1,252,351 | 1,759,787 | 12.36% |
| SGS | 335,555 | 1,428,590 | 537,378 | 163,081 | 48.60% | 374,297 | 100,408 | 143,844 | 244,252 | 1.72% |
| LGS | 254,778 | 1,210,028 | 366,644 | 138,131 | 54.22% | 228,513 | 85,047 | 87,819 | 172,865 | 1.21% |
| Lighting | 280 | 234,925 | 65,659 | 26,818 | 9577.83% | 38,841 | 16,512 | 14,927 | 31,439 | 0.22% |
| Industrial | 151,075 | 804,037 | 223,708 | 91,785 | 60.75% | 131,923 | 56,512 | 50,698 | 107,210 | 0.75% |
| OPT-G | 526,432 | 3,194,096 | 605,976 | 364,623 | 69.26% | 241,353 | 224,497 | 92,753 | 317,250 | 2.23% |
| OPT-I | 1,130,670 | 8,736,687 | 1,337,197 | 997,339 | 88.21% | 339,858 | 614,058 | 130,609 | 744,666 | 5.23% |
| SC Retail | 4,080,463 | 22,828,069 | 7,219,481 | 2,605,944 | 63.86% | 4,613,537 | 1,604,470 | 1,772,999 | 3,377,469 | 23.72% |
| SC Wholesale | 877,626 | 4,335,679 | 952,046 | 494,940 | 56.40% | 457,106 | 304,733 | 175,667 | 480,400 | 3.37% |
| Greenwood | 11,544 | 52,719 | 32,171 | 6,018 | 52.13% | 26,153 | 3,705 | 10,051 | 13,756 | 0.10% |
| Total SC | 4,969,633 | 27,216,467 | 8,203,698 | 3,106,903 | 62.52% | 5,096,795 | 1,912,908 | 1,958,718 | 3,871,626 | 27.19% |
| SYSTEM | 17,489,545 | 94,329,844 | 30,561,692 | 10,768,247 | 61.57% | 19,793,445 | 6,629,969 | 7,606,696 | 14,236,665 | 100.00% |

Hours in Year: 8,760

System Load Factor: 61.5696% = (94,329,844,000 / 17,489,545) / 8,760

column(4)=column(2)/8760

column(5)=column(4)/column(1)

column(6)=column(3)-column(4)

column(7)=(column(4)/(column(4) Total))xLoad Factor

column(8)=(column(6)/(column(6) Total))x(1-Load Factor)

column(9)=column(7)+column(8)

column(10)=column(9)*column(10) Total

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# Duke Energy Carolinas

**DEC Exhibit 6**

## Average & Excess Demand - 4CP Allocation Method

**Year:** 2018

| | Inputs | | | Calculation | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Summer Coin. Peak June | MWH @ Gen | 4CP (kW) | Average Demand (KW) | Class Load Factor | Excess Demand (Hourly kW) | Average Demand Component (KW) | Excess Demand Component (KW) | Average & Excess Demand | Average & Excess Hourly Demand Ratio |
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) |
| **North Carolina:** | | | | | | | | | | |
| Residential | 5,420,002 | 23,793,860 | 5,630,276 | 2,716,194 | 50.11% | 2,914,082 | 1,672,350 | 1,119,893 | 2,792,243 | 30.56% |
| SGS | 1,173,097 | 4,791,551 | 1,008,736 | 546,981 | 46.63% | 461,755 | 336,774 | 177,454 | 514,228 | 5.63% |
| LGS | 1,094,460 | 5,390,752 | 1,029,595 | 615,383 | 56.23% | 414,212 | 378,889 | 159,183 | 538,072 | 5.89% |
| Lighting | 1,270 | 725,804 | 30,504 | 82,854 | 6523.96% | -52,351 | 51,013 | -20,119 | 30,894 | 0.34% |
| Industrial | 365,855 | 2,144,966 | 394,207 | 244,859 | 66.93% | 149,347 | 150,759 | 57,395 | 208,154 | 2.28% |
| OPT-Small | 1,445,244 | 8,544,626 | 1,319,410 | 975,414 | 67.49% | 343,996 | 600,559 | 132,199 | 732,757 | 8.02% |
| OPT-Medium | 484,083 | 3,309,507 | 456,370 | 377,798 | 78.04% | 78,572 | 232,609 | 30,196 | 262,804 | 2.88% |
| OPT-Large | 1,661,833 | 12,187,525 | 1,523,839 | 1,391,270 | 83.72% | 132,569 | 856,600 | 50,947 | 907,546 | 9.93% |
| OPT-Trans | 148,149 | 1,258,942 | 143,904 | 143,715 | 97.01% | 189 | 88,485 | 73 | 88,557 | 0.97% |
| NC Retail | 11,793,993 | 62,147,533 | 11,536,839 | 7,094,467 | 60.15% | 4,442,372 | 4,368,037 | 1,707,220 | 6,075,257 | 66.49% |
| NC Wholesale | 725,919 | 4,965,845 | 856,530 | 566,877 | 78.09% | 289,652 | 349,024 | 111,315 | 460,339 | 5.04% |
| Total NC | 12,519,912 | 67,113,378 | 12,393,368 | 7,661,344 | 61.19% | 4,732,024 | 4,717,061 | 1,818,535 | 6,535,596 | 71.53% |
| **South Carolina:** | | | | | | | | | | |
| Residential | 1,681,673 | 7,219,706 | 1,762,434 | 824,167 | 49.01% | 938,267 | 507,437 | 360,579 | 868,016 | 9.50% |
| SGS | 335,555 | 1,428,590 | 291,721 | 163,081 | 48.60% | 128,640 | 100,408 | 49,437 | 149,845 | 1.64% |
| LGS | 254,778 | 1,210,028 | 238,970 | 138,131 | 54.22% | 100,839 | 85,047 | 38,753 | 123,800 | 1.35% |
| Lighting | 280 | 234,925 | 9,715 | 26,818 | 9577.83% | -17,103 | 16,512 | -6,573 | 9,939 | 0.11% |
| Industrial | 151,075 | 804,037 | 147,304 | 91,785 | 60.75% | 55,519 | 56,512 | 21,336 | 77,848 | 0.85% |
| OPT-G | 526,432 | 3,194,096 | 482,456 | 364,623 | 69.26% | 117,833 | 224,497 | 45,284 | 269,781 | 2.95% |
| OPT-I | 1,130,670 | 8,736,687 | 1,091,723 | 997,339 | 88.21% | 94,385 | 614,058 | 36,272 | 650,330 | 7.12% |
| SC Retail | 4,080,463 | 22,828,069 | 4,024,323 | 2,605,944 | 63.86% | 1,418,379 | 1,604,470 | 545,088 | 2,149,558 | 23.53% |
| SC Wholesale | 877,626 | 4,335,679 | 862,795 | 494,940 | 56.40% | 367,854 | 304,733 | 141,368 | 446,101 | 4.88% |
| Greenwood | 11,544 | 52,719 | 11,839 | 6,018 | 52.13% | 5,821 | 3,705 | 2,237 | 5,942 | 0.07% |
| Total SC | 4,969,633 | 27,216,467 | 4,898,956 | 3,106,903 | 62.52% | 1,792,054 | 1,912,908 | 688,693 | 2,601,601 | 28.47% |
| SYSTEM | 17,489,545 | 94,329,844 | 17,292,325 | 10,768,247 | 61.57% | 6,524,078 | 6,629,969 | 2,507,228 | 9,137,197 | 100.00% |

Hours in Year: 8,760

System Load Factor: 61.5696% = (94,329,844,000 / 17,489,545) / 8,760

column(4)=column(2)/8760

column(5)=column(4)/column(1)

column(6)=column(3)-column(4)

column(7)=(column(4)/(column(4) Total))xLoad Factor

column(8)=(column(6)/(column(6) Total))x(1-Load Factor)

column(9)=column(7)+column(8)

column(10)=column(9)*column(10) Total

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# Duke Energy Carolinas

**DEC Exhibit 7**

## Average & Excess Demand Allocation - Dominion Method

**Year:** 2018

| | Inputs | | | Calculation | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Summer Coin. Peak June | MWH @ Gen | Diversified NCD (kW) | Average Demand (KW) | System Peak Less Avg Dmnd | Excess = NCD Less Avg Dmnd (kW) | Ratio (%) | Allocation of NCD Excess (KW) | Average & Excess Demand (KW) | Average & Excess Demand Ratio |
| | (1) | (2) | (3) | (4)=(2)/ 8,760 | (5)=(1)-(4) | (6)=(3)-(4) | (7)=(5)/(6) | (8)=(6)x 75.55% | (9)=(4)+(8) | (10) |
| **North Carolina:** | | | | | | | | | | |
| Residential | 5,420,002 | 23,793,860 | 6,325,239 | 2,716,194 | | 3,609,045 | | 2,726,742 | 5,442,936 | 31.12% |
| SGS | 1,173,097 | 4,791,551 | 1,141,313 | 546,981 | | 594,332 | | 449,036 | 996,016 | 5.69% |
| LGS | 1,094,460 | 5,390,752 | 1,119,464 | 615,383 | | 504,082 | | 380,849 | 996,232 | 5.70% |
| Lighting | 1,270 | 725,804 | 205,342 | 82,854 | | 122,488 | | 92,543 | 175,397 | 1.00% |
| Industrial | 365,855 | 2,144,966 | 552,183 | 244,859 | | 307,324 | | 232,192 | 477,051 | 2.73% |
| OPT-Small | 1,445,244 | 8,544,626 | 1,358,144 | 975,414 | | 382,730 | | 289,164 | 1,264,578 | 7.23% |
| OPT-Medium | 484,083 | 3,309,507 | 501,752 | 377,798 | | 123,955 | | 93,652 | 471,449 | 2.70% |
| OPT-Large | 1,661,833 | 12,187,525 | 1,699,133 | 1,391,270 | | 307,863 | | 232,600 | 1,623,870 | 9.28% |
| OPT-Trans | 148,149 | 1,258,942 | 159,222 | 143,715 | | 15,507 | | 11,716 | 155,431 | 0.89% |
| NC Retail | 11,793,993 | 62,147,533 | 13,061,793 | 7,094,467 | | 5,967,325 | | 4,508,493 | 11,602,960 | 66.34% |
| NC Wholesale | 725,919 | 4,965,845 | 1,141,365 | 566,877 | | 574,488 | | 434,043 | 1,000,920 | 5.72% |
| Total NC | 12,519,912 | 67,113,378 | 14,203,158 | 7,661,344 | | 6,541,813 | | 4,942,536 | 12,603,880 | 72.07% |
| **South Carolina:** | | | | | | | | | | |
| Residential | 1,681,673 | 7,219,706 | 1,916,284 | 824,167 | | 1,092,117 | | 825,127 | 1,649,294 | 9.43% |
| SGS | 335,555 | 1,428,590 | 335,245 | 163,081 | | 172,164 | | 130,075 | 293,156 | 1.68% |
| LGS | 254,778 | 1,210,028 | 287,912 | 138,131 | | 149,781 | | 113,164 | 251,295 | 1.44% |
| Lighting | 280 | 234,925 | 66,372 | 26,818 | | 39,554 | | 29,884 | 56,702 | 0.32% |
| Industrial | 151,075 | 804,037 | 180,328 | 91,785 | | 88,543 | | 66,897 | 158,682 | 0.91% |
| OPT-G | 526,432 | 3,194,096 | 488,392 | 364,623 | | 123,769 | | 93,511 | 458,134 | 2.62% |
| OPT-I | 1,130,670 | 8,736,687 | 1,204,932 | 997,339 | | 207,594 | | 156,843 | 1,154,182 | 6.60% |
| SC Retail | 4,080,463 | 22,828,069 | 4,479,465 | 2,605,944 | | 1,873,521 | | 1,415,502 | 4,021,445 | 22.99% |
| SC Wholesale | 877,626 | 4,335,679 | 952,046 | 494,940 | | 457,106 | | 345,357 | 840,297 | 4.80% |
| Greenwood | 11,544 | 52,719 | 29,715 | 6,018 | | 23,697 | | 17,904 | 23,922 | 0.14% |
| Total SC | 4,969,633 | 27,216,467 | 5,461,226 | 3,106,903 | | 2,354,324 | | 1,778,762 | 4,885,665 | 27.93% |
| SYSTEM | 17,489,545 | 94,329,844 | 19,664,384 | 10,768,247 | 6,721,298 | 8,896,137 | 75.55% | 6,721,298 | 17,489,545 | 100.00% |
| Hours in Year: | 8,760 | | | | | | | | | |

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# Duke Energy Carolinas, LLC

**DEC Exhibit 8**

## Base, Intermediate & Peak - Hydro Summarized

**Year:** 2018

| Generating Plant | Fuel Type | Capacity MW | Average Fuel Cost $/kWh | Net mWh | Annual Capacity Factor | Gross Plant $ | Pct Energy | Gross Investment Energy | Gross Investment Demand |
|---|---|---|---|---|---|---|---|---|---|
| **Base Load Units:** | | | | | | | | | |
| Catawba | Nuclear | 445 | 6.30 | 3,614,344 | 92.8% | 848,785,604 | 100% | 848,785,604 | - |
| McGuire | Nuclear | 2,316 | 6.17 | 19,862,068 | 97.9% | 3,325,889,462 | 100% | 3,325,889,462 | - |
| Oconee | Nuclear | 2,554 | 6.10 | 21,294,245 | 95.2% | 4,346,860,741 | 100% | 4,346,860,741 | - |
| Cliffside - Unit 6 | Gas | 844 | 47.96 | 4,311,825 | 58.3% | 1,801,928,192 | 100% | 1,801,928,192 | - |
| Buck Steam CC | Gas | 668 | 28.94 | 5,173,061 | 88.4% | 625,046,454 | 100% | 625,046,454 | - |
| Dan River CC | Gas | 662 | 30.08 | 4,967,660 | 88.4% | 647,353,043 | 100% | 647,353,043 | - |
| Lee CC | Gas | 753 | 24.84 | 3,523,669 | 85.7% | 553,446,598 | 100% | 553,446,598 | - |
| **Total Base Load Units** | | 8,241 | | 62,746,872 | | 12,149,310,094 | | 12,149,310,094 | - |
| **Intermediate Units:** | | | | | | | | | |
| Belews Creek | Coal | 2,220 | 30.41 | 8,021,417 | 41.2% | 2,208,964,382 | 41.2% | 911,134,993 | 1,297,829,388 |
| Cliffside - Unit 5 | Coal | 544 | 30.66 | 1,242,648 | 26.1% | 1,161,432,389 | 26.1% | 302,858,037 | 858,574,352 |
| Marshall | Coal | 2,058 | 29.53 | 8,486,270 | 47.1% | 1,750,490,966 | 47.1% | 824,000,058 | 926,490,908 |
| **Total Intermediate Units** | | 4,822 | | 17,750,335 | | 5,120,887,737 | | 2,037,993,089 | 3,082,894,648 |
| **Peaking Units:** | | | | | | | | | |
| Allen | Coal | 1,098 | 37.86 | 819,761 | 8.5% | 1,237,322,437 | 0.0% | - | 1,237,322,437 |
| Lee | Gas | 180 | 24.84 | 54,152 | 3.4% | 113,252,956 | 0.0% | - | 113,252,956 |
| Lincoln CT | Gas | 1,193 | 318.15 | 82,484 | 0.8% | 408,308,728 | 0.0% | - | 408,308,728 |
| Mill Creek CT | Gas | 563 | 69.26 | 201,194 | 4.1% | 255,955,475 | 0.0% | - | 255,955,475 |
| Rockingham CT | Gas | 825 | 40.28 | 2,325,235 | 32.2% | 304,373,541 | 0.0% | - | 304,373,541 |
| Lee CT | Gas | 84 | 53.47 | 79,514 | 10.8% | 61,654,879 | 0.0% | - | 61,654,879 |
| DEC On-Site Generators | | | | | | 17,731,892 | 0.0% | - | 17,731,892 |
| **Total Peaking Units** | | 3,943 | | 3,562,340 | | 2,398,599,908 | | - | 2,398,599,908 |
| **Hydro Units:** | | | | | | | | | |
| Bad Creek | Pumped Storage | 1,360 | | 1,447,036 | 12.1% | 1,021,400,662 | 50.0% | 510,700,331 | 510,700,331 |
| Jocassee | Pumped Storage | 780 | | 1,204,730 | 17.6% | 175,327,093 | 50.0% | 87,663,546 | 87,663,546 |
| Storage | Storage | 964 | | 2,230,656 | 26.4% | 880,512,113 | 50.0% | 440,256,057 | 440,256,057 |
| Run-of-River | Run-of-River | 141 | | 646,398 | 52.3% | 109,296,164 | 100.0% | 109,296,164 | - |
| **Total Hydro Units** | | 3,245 | | 5,528,820 | | 2,186,536,032 | | 1,147,916,098 | 1,038,619,934 |
| **Solar Units:** | | | | | | | | | |
| DEC Solar | | 2.4 | | | | 42,438,732 | 47.3% | 20,060,055 | 22,378,677 |
| Mocksville - Solar | | 6.2 | | | | 31,773,280 | 47.3% | 15,018,680 | 16,754,599 |
| Monroe - Solar | | 21.8 | | | | 116,568,189 | 47.3% | 55,099,769 | 61,468,420 |
| **Total Renewable Units** | | 31.4 | | 130,018 | 47.3% | 190,780,201 | | 90,178,505 | 100,601,696 |
| **Total System** | | 20,283 | | 89,718,385 | | 22,046,113,971 | | 15,425,397,785 | 6,620,716,186 |
| **Percent of Total** | | | | | | | | 70.0% | 30.0% |

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# Duke Energy Carolinas, LLC

**DEC Exhibit 9**

## Base, Intermediate & Peak Allocation Method

## Development of DEC BIP Plant Composite Allocator

| | | Factor | Total Company | NC Retail | NCRS | NCRT | NCRE | RES | NCSGS | NCLGS |
|---|---|---|---|---|---|---|---|---|---|---|
| **Plant-in-Service** | | | | | | | | | | |
| Base | Energy | Energy | 12,149,310,094 | 8,004,355,885 | 1,735,495,027 | 6,723,411 | 1,322,336,406 | 3,064,554,844 | 617,132,774 | 694,307,488 |
| | Demand | SCP | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Total | | 12,149,310,094 | 8,004,355,885 | 1,735,495,027 | 6,723,411 | 1,322,336,406 | 3,064,554,844 | 617,132,774 | 694,307,488 |
| Intermediate | Energy | Energy | 2,037,993,089 | 1,342,695,334 | 291,121,623 | 1,127,822 | 221,816,090 | 514,065,535 | 103,521,296 | 116,467,013 |
| | Demand | 12CP | 3,082,894,648 | 2,055,328,017 | 528,804,435 | 2,123,504 | 439,760,855 | 970,688,795 | 170,235,181 | 188,940,064 |
| | Total | | 5,120,887,737 | 3,398,023,351 | 819,926,058 | 3,251,327 | 661,576,945 | 1,484,754,330 | 273,756,478 | 305,407,077 |
| Peaking | Energy | Energy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Demand | SCP | 2,398,599,908 | 1,617,484,647 | 477,945,602 | 1,516,136 | 263,863,277 | 743,325,015 | 160,884,137 | 150,099,483 |
| | Total | | 2,398,599,908 | 1,617,484,647 | 477,945,602 | 1,516,136 | 263,863,277 | 743,325,015 | 160,884,137 | 150,099,483 |
| Pumped Storage | Energy | Energy | 598,363,878 | 394,221,350 | 85,474,609 | 331,134 | 65,126,195 | 150,931,938 | 30,394,315 | 34,195,236 |
| | Demand | SCP | 598,363,878 | 403,503,887 | 119,230,132 | 378,221 | 65,824,339 | 185,432,692 | 40,134,770 | 37,444,389 |
| | Total | | 1,196,727,755 | 797,725,236 | 204,704,741 | 709,355 | 130,950,534 | 336,364,630 | 70,529,085 | 71,639,625 |
| Run-of-River | Energy | Energy | 109,296,164 | 72,007,825 | 15,612,652 | 60,484 | 11,895,844 | 27,568,980 | 5,551,776 | 6,246,046 |
| | Demand | SCP | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Total | | 109,296,164 | 72,007,825 | 15,612,652 | 60,484 | 11,895,844 | 27,568,980 | 5,551,776 | 6,246,046 |
| Storage | Energy | Energy | 440,256,057 | 290,054,837 | 62,889,349 | 243,637 | 47,917,668 | 111,050,654 | 22,363,117 | 25,159,707 |
| | Demand | SCP | 440,256,057 | 296,884,616 | 87,725,529 | 278,282 | 48,431,339 | 136,435,151 | 29,529,817 | 27,550,325 |
| | Total | | 880,512,113 | 586,939,453 | 150,614,878 | 521,919 | 96,349,008 | 247,485,805 | 51,892,934 | 52,710,031 |
| Solar | Energy | Energy | 90,178,505 | 59,412,496 | 12,881,748 | 49,905 | 9,815,069 | 22,746,721 | 4,580,681 | 5,153,512 |
| | Demand | 12CP | 100,601,696 | 67,069,916 | 17,256,063 | 69,295 | 14,350,373 | 31,675,730 | 5,555,152 | 6,165,534 |
| | Total | | 190,780,201 | 126,482,413 | 30,137,810 | 119,199 | 24,165,442 | 54,422,452 | 10,135,833 | 11,319,045 |
| Total | | | 22,046,113,971 | 14,603,018,810 | 3,434,436,769 | 12,901,831 | 2,511,137,456 | 5,958,476,056 | 1,189,883,016 | 1,291,728,794 |
| Check: | | | | | | | | | | |
| Plant_BIP_Composite_Factor ==> | | | 100.0000% | 66.2385% | 15.5784% | 0.0585% | 11.3904% | 27.0273% | 5.3972% | 5.8592% |

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# Duke Energy Carolinas, Inc.

**DEC Exhibit 10**

## Cost of Service Analysis Results
## Production Demand Allocation Factors
## For the twelve months ending December 2018

| | | Peak Responsibility Methods | | | | Energy Weighting Methods | | | | Time Differentiated Method |
|---|---|---|---|---|---|---|---|---|---|---|
| | Load Factor | Summer 1 CP | Winter 1 CP | 4CP | 12CP | SWPA | A&E | A&E 4CP | A&E Dom | BIP |
| | | Exhibit3 | Exhibit3 | Exhibit3 | Exhibit3 | Exhibit4 | Exhibit5 | Exhibit6 | Exhibit7 | Exhibit8 |
| **North Carolina:** | | | | | | | | | | |
| Residential | 50.11% | 30.9900% | 36.6484% | 32.5594% | 31.4863% | 29.6899% | 38.8639% | 30.5591% | 31.1211% | 27.0273% |
| SGS | 46.63% | 6.7074% | 5.2708% | 5.8334% | 5.5219% | 5.5322% | 5.8993% | 5.6279% | 5.6949% | 5.3972% |
| LGS | 56.23% | 6.2578% | 5.3386% | 5.9541% | 6.1287% | 5.7486% | 4.9931% | 5.8888% | 5.6962% | 5.8592% |
| Lighting | | 0.0073% | 0.4168% | 0.1764% | 0.1332% | 0.4874% | 0.6955% | 0.3381% | 1.0029% | 0.5587% |
| Industrial | 66.93% | 2.0918% | 2.0516% | 2.2797% | 2.3447% | 2.1698% | 2.3050% | 2.2781% | 2.7276% | 2.2557% |
| OPT-Small | 67.49% | 8.2635% | 7.0243% | 7.6300% | 7.7505% | 8.3204% | 6.0084% | 8.0195% | 7.2305% | 8.7455% |
| OPT-Medium | 78.04% | 2.7678% | 2.3229% | 2.6391% | 2.7923% | 3.0099% | 2.1277% | 2.8762% | 2.6956% | 3.2896% |
| OPT-Large | 83.72% | 9.5019% | 7.2610% | 8.8122% | 9.5791% | 10.5692% | 7.2286% | 9.9324% | 9.2848% | 11.9047% |
| OPT-Trans | 97.01% | 0.8471% | 0.6880% | 0.8322% | 0.9322% | 1.0421% | 0.6813% | 0.9692% | 0.8887% | 1.2005% |
| NC Retail | | 67.4345% | 67.0222% | 66.7165% | 66.6688% | 66.5694% | 68.8029% | 66.4893% | 66.3423% | 66.2385% |
| NC Wholesale | 78.09% | 4.1506% | 5.8272% | 4.9532% | 4.8449% | 5.1394% | 4.0024% | 5.0381% | 5.7230% | 5.0301% |
| Total NC | 61.19% | 71.5851% | 72.8494% | 71.6698% | 71.5137% | 71.7088% | 72.8052% | 71.5274% | 72.0652% | 71.2687% |
| **South Carolina:** | | | | | | | | | | |
| Residential | 49.01% | 9.6153% | 10.8916% | 10.1920% | 10.0098% | 9.0002% | 12.3610% | 9.4998% | 9.4302% | 8.2998% |
| SGS | 48.60% | 1.9186% | 1.4200% | 1.6870% | 1.6619% | 1.5890% | 1.7157% | 1.6399% | 1.6762% | 1.5988% |
| LGS | 54.22% | 1.4567% | 1.2166% | 1.3819% | 1.3633% | 1.3081% | 1.2142% | 1.3549% | 1.4368% | 1.3215% |
| Lighting | | 0.0016% | 0.1312% | 0.0562% | 0.0420% | 0.1566% | 0.2208% | 0.1088% | 0.3242% | 0.1806% |
| Industrial | 60.75% | 0.8638% | 0.7101% | 0.8518% | 0.8673% | 0.8173% | 0.7531% | 0.8520% | 0.9073% | 0.8563% |
| OPT-G | 69.26% | 3.0100% | 2.5992% | 2.7900% | 2.8590% | 3.0837% | 2.2284% | 2.9526% | 2.6195% | 3.2513% |
| OPT-I | 88.21% | 6.4648% | 5.0703% | 6.3133% | 6.7756% | 7.4552% | 5.2306% | 7.1174% | 6.5993% | 8.4667% |
| SC Retail | | 23.3309% | 22.0390% | 23.2723% | 23.5790% | 23.4101% | 23.7237% | 23.5254% | 22.9934% | 23.9750% |
| Greenwood | 52.13% | 0.0660% | 0.0687% | 0.0685% | 0.0688% | 0.0618% | 0.0966% | 0.0650% | 4.8046% | 0.0593% |
| SC Wholesale | 56.40% | 5.0180% | 5.0428% | 4.9895% | 4.8385% | 4.8193% | 3.3744% | 4.8823% | 0.1368% | 4.6970% |
| Total SC | 62.52% | 28.4149% | 27.1506% | 28.3302% | 28.4863% | 28.2912% | 27.1948% | 28.4726% | 27.9348% | 28.7313% |
| System | | 100.0000% | 100.0000% | 100.0000% | 100.0000% | 100.0000% | 100.0000% | 100.0000% | 100.0000% | 100.0000% |

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# Duke Energy Carolinas, Inc.

**DEC Exhibit 11**

## Cost of Service Analysis Results
## Present Rate of Return on Rate Base
## For the twelve months ending December 2018

| | | Peak Responsibility Methods | | | | Energy Weighting Methods | | | | Time Differentiated Method | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Load Factor | Summer 1 CP | Winter 1 CP | 4CP | 12CP | SWPA | A&E | A&E 4CP | A&E Dom | BIP | Average of Returns |
| **North Carolina:** | | | | | | | | | | | |
| Residential | 50.11% | 5.56% | 4.20% | 5.16% | 5.43% | 5.79% | 3.90% | 5.66% | 5.53% | 6.63% | 5.32% |
| SGS | 46.63% | 7.00% | 9.58% | 8.48% | 9.09% | 8.97% | 8.21% | 8.67% | 8.56% | 9.10% | 8.63% |
| LGS | 56.23% | 6.13% | 8.10% | 6.73% | 6.38% | 7.15% | 8.66% | 6.80% | 7.17% | 6.89% | 7.11% |
| Lighting | | 4.11% | 2.97% | 3.61% | 3.74% | 2.85% | 2.43% | 3.25% | 1.80% | 2.67% | 3.05% |
| Industrial | 66.93% | 8.08% | 8.30% | 7.04% | 6.72% | 7.68% | 7.02% | 7.15% | 5.25% | 7.28% | 7.17% |
| OPT-Small | 67.49% | 5.07% | 6.97% | 5.99% | 5.81% | 5.08% | 8.49% | 5.38% | 6.47% | 4.43% | 5.96% |
| OPT-Medium | 78.04% | 5.58% | 7.67% | 6.13% | 5.48% | 4.79% | 8.42% | 5.18% | 5.86% | 3.74% | 5.87% |
| OPT-Large | 83.72% | 4.44% | 7.52% | 5.26% | 4.36% | 3.52% | 7.21% | 4.01% | 4.67% | 2.22% | 4.80% |
| OPT-Trans | 97.01% | 5.60% | 8.15% | 5.81% | 4.51% | 3.56% | 7.98% | 4.21% | 5.10% | 2.02% | 5.22% |
| NC Retail | | 5.58% | 5.62% | 5.67% | 5.68% | 5.68% | 5.41% | 5.69% | 5.71% | 5.73% | 5.64% |
| **South Carolina:** | | | | | | | | | | | |
| Residential | 49.01% | 7.88% | 6.56% | 7.26% | 7.46% | 8.42% | 5.50% | 7.99% | 8.06% | 9.39% | 7.61% |
| SGS | 48.60% | 11.19% | 15.36% | 12.93% | 13.14% | 13.69% | 12.54% | 13.09% | 12.84% | 13.44% | 13.13% |
| LGS | 54.22% | 13.10% | 16.79% | 14.12% | 14.40% | 15.19% | 16.37% | 14.37% | 13.34% | 14.86% | 14.73% |
| Lighting | | 3.16% | 1.91% | 2.62% | 2.76% | 1.80% | 1.38% | 2.23% | 0.66% | 1.61% | 2.01% |
| Industrial | 60.75% | 22.13% | 27.32% | 22.47% | 22.02% | 23.62% | 25.24% | 22.43% | 21.06% | 22.31% | 23.18% |
| OPT-G | 69.26% | 9.65% | 12.26% | 10.96% | 10.54% | 9.38% | 14.55% | 9.94% | 11.85% | 8.37% | 10.83% |
| OPT-I | 88.21% | 4.83% | 8.25% | 5.14% | 4.23% | 3.29% | 7.47% | 3.71% | 4.58% | 1.69% | 4.80% |
| SC Retail Excl GW | | 8.22% | 8.92% | 8.24% | 8.09% | 8.20% | 8.03% | 8.12% | 8.38% | 7.90% | 8.23% |

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# Duke Energy Carolinas, Inc.

**DEC Exhibit 12**

## Cost of Service Analysis Results
## Rate of Return on Rate Base Index
## For the twelve months ending December 2018

| | | Peak Responsibility Methods | | | | Energy Weighting Methods | | | | Time Differentiated Method |
|---|---|---|---|---|---|---|---|---|---|---|
| | Load Factor | Summer 1 CP | Winter 1 CP | 4CP | 12CP | SWPA | A&E | A&E 4CP | A&E Dom | BIP |
| **North Carolina:** | | | | | | | | | | |
| Residential | 50.11% | 99.66% | 74.78% | 90.91% | 95.56% | 101.90% | 72.03% | 99.41% | 96.76% | 115.73% |
| SGS | 46.63% | 125.51% | 170.55% | 149.62% | 159.96% | 157.97% | 151.83% | 152.24% | 149.78% | 158.90% |
| LGS | 56.23% | 109.88% | 144.18% | 118.67% | 112.32% | 126.01% | 160.10% | 119.35% | 125.46% | 120.22% |
| Lighting | | 73.67% | 52.80% | 63.71% | 65.74% | 50.15% | 44.89% | 57.08% | 31.57% | 46.54% |
| Industrial | 66.93% | 144.95% | 147.79% | 124.17% | 118.22% | 135.32% | 129.80% | 125.63% | 91.96% | 126.99% |
| OPT-Small | 67.49% | 90.93% | 124.06% | 105.59% | 102.26% | 89.38% | 156.90% | 94.49% | 113.26% | 77.29% |
| OPT-Medium | 78.04% | 100.03% | 136.52% | 108.09% | 96.44% | 84.38% | 155.59% | 91.02% | 102.53% | 65.23% |
| OPT-Large | 83.72% | 79.65% | 133.78% | 92.80% | 76.69% | 62.01% | 133.26% | 70.51% | 81.73% | 38.79% |
| OPT-Trans | 97.01% | 100.44% | 145.16% | 102.38% | 79.42% | 62.75% | 147.54% | 73.97% | 89.27% | 35.17% |
| NC Retail | | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% |
| **South Carolina:** | | | | | | | | | | |
| Residential | 49.01% | 95.87% | 73.57% | 88.13% | 92.22% | 102.69% | 68.50% | 98.39% | 96.21% | 118.91% |
| SGS | 48.60% | 136.10% | 172.20% | 156.87% | 162.45% | 166.89% | 156.14% | 161.17% | 153.16% | 170.22% |
| LGS | 54.22% | 159.34% | 188.25% | 171.33% | 178.04% | 185.16% | 203.91% | 176.92% | 159.18% | 188.16% |
| Lighting | | 38.44% | 21.45% | 31.81% | 34.17% | 21.92% | 17.17% | 27.45% | 7.86% | 20.38% |
| Industrial | 60.75% | 269.31% | 306.37% | 272.61% | 272.26% | 287.92% | 314.38% | 276.11% | 251.23% | 282.48% |
| OPT-G | 69.26% | 117.41% | 137.44% | 132.97% | 130.27% | 114.32% | 181.19% | 122.40% | 141.41% | 105.99% |
| OPT-I | 88.21% | 58.80% | 92.53% | 62.33% | 52.30% | 40.07% | 93.08% | 45.70% | 54.68% | 21.45% |
| SC Retail Excl GW | | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% |

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## Duke Energy Carolinas, LLC

**DEC Exhibit 13**

**Alternative Fuel Allocation Method**

Pg 1 of 2

**Year:** 2018

Intermediate Method: 12CP  Peak Method: 1CP-Sum

| | Base | | | | Intermediate | | | Peak | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Rate Class | Sales at Generator kWh | Average Annual Hourly Demand KW | Base Period Ratio 58.77% | Base as % of Total | 12 CP Demand KW | Demand Peak Ratio 27.90% | Intermediate as % of Total | 1CP-Sum Peak Demand KW | Demand Ratio 13.33% | Peak as % of Total |
| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) |
| **North Carolina:** | | | | | | | | | | |
| Residential | 23,793,860,000 | 2,716,194 | 1,596,236 | 25.2241% | 4,981,655 | 1,389,793 | 31.4863% | 5,420,002 | 722,725 | 30.9900% |
| SGS | 4,791,551,000 | 546,981 | 321,446 | 5.0796% | 873,661 | 243,736 | 5.5219% | 1,173,097 | 156,425 | 6.7074% |
| LGS | 5,390,752,000 | 615,383 | 361,644 | 5.7148% | 969,656 | 270,517 | 6.1287% | 1,094,460 | 145,940 | 6.2578% |
| Lighting | 725,804,000 | 82,854 | 48,691 | 0.7694% | 21,076 | 5,880 | 0.1332% | 1,270 | 169 | 0.0073% |
| Industrial | 2,144,966,000 | 244,859 | 143,897 | 2.2739% | 370,964 | 103,492 | 2.3447% | 365,855 | 48,785 | 2.0918% |
| OPT-Small | 8,544,626,000 | 975,414 | 573,225 | 9.0582% | 1,226,252 | 342,103 | 7.7505% | 1,445,244 | 192,715 | 8.2635% |
| OPT-Medium | 3,309,507,000 | 377,798 | 222,022 | 3.5084% | 441,781 | 123,249 | 2.7923% | 484,083 | 64,550 | 2.7678% |
| OPT-Large | 12,187,525,000 | 1,391,270 | 817,613 | 12.9201% | 1,515,575 | 422,819 | 9.5791% | 1,661,833 | 221,596 | 9.5019% |
| OPT-Trans | 1,258,942,000 | 143,715 | 84,457 | 1.3346% | 147,493 | 41,148 | 0.9322% | 148,149 | 19,755 | 0.8471% |
| NC Retail | 62,147,533,000 | 7,094,467 | 4,169,232 | 65.8832% | 10,548,113 | 2,942,736 | 66.6688% | 11,793,993 | 1,572,659 | 67.4345% |
| NC Wholesale | 4,965,844,574 | 566,877 | 333,139 | 5.2643% | 766,552 | 213,854 | 4.8449% | 725,919 | 96,797 | 4.1506% |
| Total NC | 67,113,377,574 | 7,661,344 | 4,502,371 | 71.1476% | 11,314,664 | 3,156,590 | 71.5137% | 12,519,912 | 1,669,456 | 71.5851% |
| **South Carolina:** | | | | | | | | | | |
| Residential | 7,219,706,000 | 824,167 | 484,342 | 7.6537% | 1,583,722 | 441,830 | 10.0098% | 1,681,673 | 224,241 | 9.6153% |
| SGS | 1,428,590,000 | 163,081 | 95,838 | 1.5145% | 262,944 | 73,357 | 1.6619% | 335,555 | 44,744 | 1.9186% |
| LGS | 1,210,028,000 | 138,131 | 81,176 | 1.2828% | 215,691 | 60,174 | 1.3633% | 254,778 | 33,973 | 1.4567% |
| Lighting | 234,925,000 | 26,818 | 15,760 | 0.2490% | 6,646 | 1,854 | 0.0420% | 280 | 37 | 0.0016% |
| Industrial | 804,037,000 | 91,785 | 53,940 | 0.8524% | 137,224 | 38,283 | 0.8673% | 151,075 | 20,145 | 0.8638% |
| OPT-G | 3,194,096,000 | 364,623 | 214,279 | 3.3861% | 452,349 | 126,197 | 2.8590% | 526,432 | 70,197 | 3.0100% |
| OPT-I | 8,736,687,000 | 997,339 | 586,110 | 9.2618% | 1,072,017 | 299,074 | 6.7756% | 1,130,670 | 150,768 | 6.4648% |
| SC Retail | 22,828,069,000 | 2,605,944 | 1,531,445 | 24.2003% | 3,730,592 | 1,040,769 | 23.5790% | 4,080,463 | 544,105 | 23.3309% |
| SC Wholesale | 4,335,678,506 | 494,940 | 290,864 | 4.5963% | 765,535 | 213,571 | 4.8385% | 877,626 | 117,026 | 5.0180% |
| Greenwood | 52,719,000 | 6,018 | 3,537 | 0.0559% | 10,878 | 3,035 | 0.0688% | 11,544 | 1,539 | 0.0660% |
| Total SC | 27,216,466,506 | 3,106,903 | 1,825,845 | 28.8524% | 4,507,005 | 1,257,374 | 28.4863% | 4,969,633 | 662,671 | 28.4149% |
| SYSTEM | 94,329,844,080 | | 6,328,216 | 100.0000% | 15,821,669 | 4,413,964 | 100.0000% | 17,489,545 | 2,332,127 | 100.0000% |

Hours in Year: 8,760
System Load Factor: 61.5696% = (94,329,844,080 / 17,489,545) / 8,760

column(2) - values are from Data worksheet

column(3)=column(2) / 8,760

column(4)=column(3) x 58.77%

column(5)=column(4) / 6,328,216

Column(6) - values are from DEC Exhibit 2

column(7)=column(6) x 27.90%

column(8)=column(7) / 4,413,964

column(9) - values are from DEC Exhibit 2

column(10)=column(9) x 13.33%

column(11)=column(10) / 2,332,127

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## Duke Energy Carolinas, LLC

**DEC Exhibit 13**

**Alternative Fuel Allocation Method**

Pg 2 of 2

**Year:** 2018

| | |
|---|---|
| Fuel - Generation | 1,583,377,319 |
| Fuel - Purchased Power | 277,523,485 |
| | 1,860,900,804 |

| Rate | Base Fuel | Intermediate Fuel | Peak Fuel | Total | Average Fuel ($/kWh) | Increase (Decrease) Over Average |
|---|---|---|---|---|---|---|
| Class | 1,084,290,467 | 592,069,805 | 184,540,532 | 1,860,900,804 | 0.01973 | |
| (1) | (14)=BasexCol(5) | (15)=Int x Col(8) | (16)=Pk x Col(11) | (17)=(14)+(15)+(16) | (18) | (19)=(17)-(18) |
| **North Carolina:** | | | | | | |
| Residential | 273,502,578 | 186,420,758 | 57,189,027 | 517,112,363 | 469,395,594 | 47,716,769 |
| SGS | 55,077,299 | 32,693,649 | 12,377,906 | 100,148,854 | 94,525,770 | 5,623,085 |
| LGS | 61,964,917 | 36,285,921 | 11,548,170 | 109,799,008 | 106,346,563 | 3,452,445 |
| Lighting | 8,342,878 | 788,710 | 13,400 | 9,144,988 | 14,318,366 | -5,173,378 |
| Industrial | 24,655,677 | 13,882,008 | 3,860,311 | 42,397,995 | 42,315,017 | 82,978 |
| OPT-Small | 98,217,660 | 45,888,131 | 15,249,459 | 159,355,249 | 168,564,907 | -9,209,658 |
| OPT-Medium | 38,041,692 | 16,532,073 | 5,107,791 | 59,681,556 | 65,288,608 | -5,607,052 |
| OPT-Large | 140,091,583 | 56,715,023 | 17,534,793 | 214,341,399 | 240,430,537 | -26,089,138 |
| OPT-Trans | 14,471,123 | 5,519,402 | 1,563,191 | 21,553,716 | 24,835,896 | -3,282,180 |
| NC Retail | 714,365,409 | 394,725,674 | 124,444,046 | 1,233,535,129 | 1,226,021,258 | 7,513,870 |
| NC Wholesale | 57,080,747 | 28,685,468 | 7,659,513 | 93,425,728 | 97,964,162 | -4,538,434 |
| Total NC | 771,446,155 | 423,411,142 | 132,103,560 | 1,326,960,857 | 1,323,985,421 | 2,975,436 |
| **South Carolina:** | | | | | | |
| Residential | 82,988,141 | 59,265,182 | 17,744,134 | 159,997,457 | 142,427,424 | 17,570,033 |
| SGS | 16,421,171 | 9,839,733 | 3,540,601 | 29,801,505 | 28,182,643 | 1,618,863 |
| LGS | 13,908,873 | 8,071,454 | 2,688,284 | 24,668,612 | 23,870,940 | 797,671 |
| Lighting | 2,700,385 | 248,703 | 2,954 | 2,952,043 | 4,634,505 | -1,682,462 |
| Industrial | 9,242,140 | 5,135,115 | 1,594,064 | 15,971,319 | 15,861,715 | 109,605 |
| OPT-G | 36,715,081 | 16,927,568 | 5,554,635 | 59,197,284 | 63,011,827 | -3,814,543 |
| OPT-I | 100,425,338 | 40,116,415 | 11,930,239 | 152,471,991 | 172,353,808 | -19,881,818 |
| SC Retail | 262,401,129 | 139,604,170 | 43,054,912 | 445,060,211 | 450,342,862 | -5,282,651 |
| SC Wholesale | 49,837,195 | 28,647,412 | 9,260,255 | 87,744,863 | 85,532,502 | 2,212,360 |
| Greenwood | 605,988 | 407,080 | 121,806 | 1,134,874 | 1,040,019 | 94,855 |
| Total SC | 312,844,312 | 168,658,662 | 52,436,973 | 533,939,947 | 536,915,384 | -2,975,436 |
| SYSTEM | 1,084,290,467 | 592,069,805 | 184,540,532 | 1,860,900,804 | 1,860,900,804 | 0 |

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# Duke Energy Carolinas, LLC

## Cost of Service Analysis Results

## ROR At Present Rates - After Fuel Adjustment

## For the twelve months ending December 2018

**DEC Exhibit 14**



| | After Fuel Adjustment | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Peak Responsibility Methods | | | | Energy Weighting Methods | | | | Time Differentiated Method |
| | Summer 1 CP | Winter 1 CP | 4CP | 12CP | SWPA | A&E | A&E 4CP | A&E Dom | BIP |
| **North Carolina:** | | | | | | | | | |
| Residential | 5.56% | 4.20% | 5.16% | 5.43% | 5.23% | 3.41% | 5.11% | 4.98% | 6.05% |
| SGS | 7.00% | 9.58% | 8.48% | 9.09% | 8.58% | 7.84% | 8.28% | 8.17% | 8.71% |
| LGS | 6.13% | 8.10% | 6.73% | 6.38% | 6.86% | 8.34% | 6.50% | 6.87% | 6.59% |
| Lighting | 4.11% | 2.97% | 3.61% | 3.74% | 3.54% | 3.10% | 3.97% | 2.44% | 3.35% |
| Industrial | 8.08% | 8.30% | 7.04% | 6.72% | 7.67% | 7.01% | 7.14% | 5.24% | 7.26% |
| OPT-Small | 5.07% | 6.97% | 5.99% | 5.81% | 5.65% | 9.19% | 5.96% | 7.09% | 4.97% |
| OPT-Medium | 5.58% | 7.67% | 6.13% | 5.48% | 5.76% | 9.62% | 6.17% | 6.89% | 4.64% |
| OPT-Large | 4.44% | 7.52% | 5.26% | 4.36% | 4.83% | 8.87% | 5.36% | 6.08% | 3.40% |
| OPT-Trans | 5.60% | 8.15% | 5.81% | 4.51% | 5.29% | 10.26% | 6.01% | 7.01% | 3.54% |
| NC Retail | 5.58% | 5.62% | 5.67% | 5.68% | 5.63% | 5.37% | 5.65% | 5.67% | 5.68% |
| **South Carolina:** | | | | | | | | | |
| Residential | 7.88% | 6.56% | 7.26% | 7.46% | 7.65% | 4.84% | 7.23% | 7.30% | 8.57% |
| SGS | 11.19% | 15.36% | 12.93% | 13.14% | 13.27% | 12.13% | 12.68% | 12.43% | 13.02% |
| LGS | 13.10% | 16.79% | 14.12% | 14.40% | 14.83% | 16.00% | 14.03% | 13.01% | 14.51% |
| Lighting | 3.16% | 1.91% | 2.62% | 2.76% | 2.62% | 2.17% | 3.07% | 1.41% | 2.41% |
| Industrial | 22.13% | 27.32% | 22.47% | 22.02% | 23.54% | 25.17% | 22.36% | 20.99% | 22.23% |
| OPT-G | 9.65% | 12.26% | 10.96% | 10.54% | 10.15% | 15.51% | 10.73% | 12.71% | 9.10% |
| OPT-I | 4.83% | 8.25% | 5.14% | 4.23% | 5.01% | 9.67% | 5.48% | 6.45% | 3.22% |
| SC Retail Excl GW | 8.22% | 8.92% | 8.24% | 8.09% | 8.31% | 8.14% | 8.23% | 8.49% | 8.00% |

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# Duke Energy Carolinas, LLC

**DEC Exhibit 14**

Pg 2 of 2

## Cost of Service Analysis Results

## ROR At Present Rates - After Fuel Adj less Before Fuel Adj

## For the twelve months ending December 2018

| | After Fuel Adjustment less Before Fuel Adjustment | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Peak Responsibility Methods | | | | Energy Weighting Methods | | | | Time Differentiated Method |
| | Summer 1 CP | Winter 1 CP | 4CP | 12CP | SWPA | A&E | A&E 4CP | A&E Dom | BIP |
| **North Carolina:** | | | | | | | | | |
| Residential | 0.00% | 0.00% | 0.00% | 0.00% | -0.55% | -0.49% | -0.55% | -0.54% | -0.58% |
| SGS | 0.00% | 0.00% | 0.00% | 0.00% | -0.39% | -0.38% | -0.38% | -0.38% | -0.39% |
| LGS | 0.00% | 0.00% | 0.00% | 0.00% | -0.30% | -0.32% | -0.29% | -0.30% | -0.29% |
| Lighting | 0.00% | 0.00% | 0.00% | 0.00% | 0.69% | 0.67% | 0.72% | 0.64% | 0.69% |
| Industrial | 0.00% | 0.00% | 0.00% | 0.00% | -0.02% | -0.02% | -0.02% | -0.02% | -0.02% |
| OPT-Small | 0.00% | 0.00% | 0.00% | 0.00% | 0.57% | 0.70% | 0.58% | 0.62% | 0.55% |
| OPT-Medium | 0.00% | 0.00% | 0.00% | 0.00% | 0.97% | 1.20% | 0.99% | 1.04% | 0.90% |
| OPT-Large | 0.00% | 0.00% | 0.00% | 0.00% | 1.31% | 1.66% | 1.35% | 1.41% | 1.18% |
| OPT-Trans | 0.00% | 0.00% | 0.00% | 0.00% | 1.73% | 2.28% | 1.80% | 1.91% | 1.53% |
| NC Retail | 0.00% | 0.00% | 0.00% | 0.00% | -0.04% | -0.04% | -0.04% | -0.04% | -0.04% |
| **South Carolina:** | | | | | | | | | |
| Residential | 0.00% | 0.00% | 0.00% | 0.00% | -0.78% | -0.66% | -0.76% | -0.77% | -0.81% |
| SGS | 0.00% | 0.00% | 0.00% | 0.00% | -0.42% | -0.40% | -0.41% | -0.41% | -0.42% |
| LGS | 0.00% | 0.00% | 0.00% | 0.00% | -0.36% | -0.37% | -0.35% | -0.33% | -0.35% |
| Lighting | 0.00% | 0.00% | 0.00% | 0.00% | 0.82% | 0.79% | 0.84% | 0.75% | 0.80% |
| Industrial | 0.00% | 0.00% | 0.00% | 0.00% | -0.07% | -0.08% | -0.07% | -0.07% | -0.07% |
| OPT-G | 0.00% | 0.00% | 0.00% | 0.00% | 0.77% | 0.96% | 0.79% | 0.86% | 0.73% |
| OPT-I | 0.00% | 0.00% | 0.00% | 0.00% | 1.72% | 2.20% | 1.76% | 1.87% | 1.53% |
| SC Retail Excl GW | 0.00% | 0.00% | 0.00% | 0.00% | 0.11% | 0.11% | 0.11% | 0.11% | 0.11% |

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# Duke Energy Carolinas, LLC

**DEC Exhibit 15**

## Single Summer CP Method

## Unit Cost Report

**Year:** 2018

| | Demand | UNIT | COSTS | Energy | UNIT | COSTS | CUSTOMER | UNIT | COSTS |
|---|---|---|---|---|---|---|---|---|---|
| | Revenue | KW [1] | $/KW/Mo | Revenue | Annual MWH [2] | Cents/KWH | Revenue | Avg Bills [3] | $/Cust/Mo |
| **North Carolina:** | | | | | | | | | |
| Residential | 1,346,689,611 | 5,420,002 | 20.71 | 526,109,965 | 22,763,030 | 2.31 | 470,177,117 | 1,756,541 | 22.31 |
| SGS | 294,299,359 | 1,173,097 | 20.91 | 114,420,455 | 4,567,331 | 2.51 | 68,973,083 | 242,917 | 23.66 |
| LGS | 256,197,441 | 1,094,460 | 19.51 | 129,636,327 | 5,142,000 | 2.52 | 2,519,931 | 9,171 | 22.90 |
| Lighting | 98,775,718 | 1,270 | - | 16,796,317 | 691,829 | 2.43 | 19,449,674 | 291,039 | 5.57 |
| Industrial | 96,343,394 | 365,855 | 21.94 | 49,906,598 | 2,048,172 | 2.44 | 1,077,248 | 3,707 | 24.22 |
| OPT-Small | 315,111,691 | 1,445,244 | 31.49 | 203,645,383 | 8,149,226 | 4.92 | 4,436,244 | 16,808 | 36.22 |
| OPT-Medium | 107,128,640 | 484,083 | 36.46 | 77,952,613 | 3,162,303 | 4.94 | 92,154 | 355 | 40.80 |
| OPT-Large | 332,887,579 | 1,661,833 | 33.48 | 285,399,407 | 11,720,190 | 4.86 | 48,040 | 215 | 38.02 |
| OPT-Transmission | 28,141,179 | 148,149 | 15.83 | 31,157,210 | 1,236,620 | 2.52 | 272 | 4 | 5.67 |
| TOTAL RETAIL | $ 2,875,574,611 | 11,793,993 | 20.32 | $ 1,435,024,274 | 59,480,701 | 2.41 | $ 566,773,763 | 2,320,757 | 20.35 |

[1] Allocation Factor: All - Production Demand

[2] Allocation Factor: All - MWHs at Meter

[3] Allocation Factor: All - Cust Num

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# Duke Energy Carolinas, LLC

**DEC Exhibit 16**

**Single Winter CP Method**

**Unit Cost Report**

**Year:** 2018

| | Demand | UNIT | COSTS | Energy | UNIT | COSTS | CUSTOMER | UNIT | COSTS |
|---|---|---|---|---|---|---|---|---|---|
| | Revenue | KW [1] | $/KW/Mo | Revenue | Annual MWH [2] | Cents/KWH | Revenue | Avg Bills [3] | $/Cust/Mo |
| **North Carolina:** | | | | | | | | | |
| Residential | 1,425,840,620 | 6,917,677 | 17.18 | 522,414,966 | 22,763,030 | 2.30 | 450,714,979 | 1,756,541 | 21.38 |
| SGS | 269,167,555 | 994,904 | 22.55 | 116,298,037 | 4,567,331 | 2.55 | 76,282,010 | 242,917 | 26.17 |
| LGS | 244,068,671 | 1,007,695 | 20.18 | 131,299,667 | 5,142,000 | 2.55 | 2,732,759 | 9,171 | 24.83 |
| Lighting | 103,179,427 | 78,669 | | 16,660,860 | 691,829 | 2.41 | 19,156,718 | 291,039 | 5.49 |
| Industrial | 95,709,715 | 387,247 | 20.60 | 49,960,290 | 2,048,172 | 2.44 | 1,084,924 | 3,707 | 24.39 |
| OPT-Small | 298,316,809 | 1,325,901 | 18.75 | 206,171,435 | 8,149,226 | 2.53 | 4,804,189 | 16,808 | 23.82 |
| OPT-Medium | 101,123,346 | 438,459 | 19.22 | 79,013,625 | 3,162,303 | 2.50 | 100,330 | 355 | 23.55 |
| OPT-Large | 302,521,333 | 1,370,565 | 18.39 | 291,224,977 | 11,720,191 | 2.48 | 54,463 | 215 | 21.11 |
| OPT-Transmission | 25,827,135 | 129,864 | 16.57 | 31,669,185 | 1,236,620 | 2.56 | 280 | 4 | 5.83 |
| TOTAL RETAIL | $ 2,865,754,613 | 12,650,981 | 18.88 | $ 1,444,713,039 | 59,480,702 | 2.43 | $ 554,930,651 | 2,320,757 | 19.93 |

[1] Allocation Factor: All - Production Demand

[2] Allocation Factor: All - MWHs at Meter

[3] Allocation Factor: All - Cust Num

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# Duke Energy Carolinas, LLC

**DEC Exhibit 17**

## 4CP - 2 Summer, 2 Winter Method

## Unit Cost Report

**Year:** 2018

| | Demand | UNIT | COSTS | Energy | UNIT | COSTS | CUSTOMER | UNIT | COSTS |
|---|---|---|---|---|---|---|---|---|---|
| | Revenue | KW [1] | $/KW/Mo | Revenue | Annual MWH [2] | Cents/KWH | Revenue | Avg Bills [3] | $/Cust/Mo |
| **North Carolina:** | | | | | | | | | |
| Residential | 1,365,230,478 | 5,630,276 | 20.21 | 524,326,137 | 22,763,030 | 2.30 | 461,488,117 | 1,756,541 | 21.89 |
| SGS | 278,475,821 | 1,008,736 | 23.01 | 115,430,523 | 4,567,331 | 2.53 | 72,974,167 | 242,917 | 25.03 |
| LGS | 251,322,774 | 1,029,595 | 20.34 | 130,056,010 | 5,142,000 | 2.53 | 2,575,852 | 9,171 | 23.41 |
| Lighting | 100,100,155 | 30,504 | | 16,723,148 | 691,829 | 2.42 | 19,297,459 | 291,039 | 5.53 |
| Industrial | 98,308,192 | 394,207 | 20.78 | 49,518,270 | 2,048,172 | 2.42 | 1,027,929 | 3,707 | 23.11 |
| OPT-Small | 305,541,852 | 1,319,410 | 19.30 | 204,707,349 | 8,149,226 | 2.51 | 4,623,381 | 16,808 | 22.92 |
| OPT-Medium | 105,028,169 | 456,370 | 19.18 | 78,165,608 | 3,162,303 | 2.47 | 93,929 | 355 | 22.05 |
| OPT-Large | 322,500,413 | 1,523,839 | 17.64 | 286,715,628 | 11,720,191 | 2.45 | 49,630 | 215 | 19.24 |
| OPT-Transmission | 27,800,410 | 143,904 | 16.10 | 31,174,283 | 1,236,620 | 2.52 | 272 | 4 | 5.68 |
| TOTAL RETAIL | $ 2,854,308,264 | 11,536,839 | 20.62 | $ 1,436,816,956 | 59,480,702 | 2.42 | $ 562,130,735 | 2,320,757 | 20.18 |

[1] Allocation Factor: All - Production Demand

[2] Allocation Factor: All - MWHs at Meter

[3] Allocation Factor: All - Cust Num

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# Duke Energy Carolinas, LLC

**DEC Exhibit 18**

**12 CP Method**

**Unit Cost Report**

**Year:** 2018

| | Demand | UNIT | COSTS | Energy | UNIT | COSTS | CUSTOMER | UNIT | COSTS |
|---|---|---|---|---|---|---|---|---|---|
| | Revenue | KW [1] | $/KW/Mo | Revenue | Annual MWH [2] | Cents/KWH | Revenue | Avg Bills [3] | $/Cust/Mo |
| **North Carolina:** | | | | | | | | | |
| Residential | 1,346,671,139 | 4,981,655 | 22.53 | 525,209,863 | 22,763,030 | 2.31 | 466,641,682 | 1,756,541 | 22.14 |
| SGS | 272,778,315 | 873,661 | 26.02 | 115,871,140 | 4,567,331 | 2.54 | 74,682,434 | 242,917 | 25.62 |
| LGS | 253,310,761 | 969,656 | 21.77 | 129,743,583 | 5,142,000 | 2.52 | 2,536,309 | 9,171 | 23.05 |
| Lighting | 99,527,436 | 21,076 | | 16,735,720 | 691,829 | 2.42 | 19,319,365 | 291,039 | 5.53 |
| Industrial | 99,025,306 | 370,964 | 22.25 | 49,405,900 | 2,048,172 | 2.41 | 1,013,379 | 3,707 | 22.78 |
| OPT-Small | 306,832,507 | 1,226,252 | 20.85 | 204,458,086 | 8,149,226 | 2.51 | 4,592,115 | 16,808 | 22.77 |
| OPT-Medium | 106,900,755 | 441,781 | 20.16 | 77,817,626 | 3,162,303 | 2.46 | 91,239 | 355 | 21.42 |
| OPT-Large | 332,042,513 | 1,515,575 | 18.26 | 284,952,683 | 11,720,190 | 2.43 | 47,693 | 215 | 18.49 |
| OPT-Transmission | 29,123,429 | 147,493 | 16.45 | 30,906,533 | 1,236,620 | 2.50 | 268 | 4 | 5.59 |
| TOTAL RETAIL | $ 2,846,212,162 | 10,548,113 | 22.49 | $ 1,435,101,133 | 59,480,701 | 2.41 | $ 568,924,485 | 2,320,757 | 20.43 |

[1] Allocation Factor: All - Production Demand

[2] Allocation Factor: All - MWHs at Meter

[3] Allocation Factor: All - Cust Num

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# Duke Energy Carolinas, LLC

**DEC Exhibit 19**

**SWPA Method**

**Unit Cost Report**

**Year:** 2018

| | Demand | UNIT | COSTS | Energy | UNIT | COSTS | CUSTOMER | UNIT | COSTS |
|---|---|---|---|---|---|---|---|---|---|
| | Revenue | KW [1] | $/KW/Mo | Revenue | Annual MWH [2] | Cents/KWH | Revenue | Avg Bills [3] | $/Cust/Mo |
| **North Carolina:** | | | | | | | | | |
| Residential | 1,324,781,796 | 4,043,058 | 27.31 | 526,507,667 | 22,763,030 | 2.31 | 474,331,558 | 1,756,541 | 22.50 |
| SGS | 273,964,308 | 753,359 | 30.30 | 115,781,359 | 4,567,331 | 2.53 | 74,347,718 | 242,917 | 25.51 |
| LGS | 248,714,930 | 782,822 | 26.48 | 130,413,806 | 5,142,000 | 2.54 | 2,621,919 | 9,171 | 23.82 |
| Lighting | 103,241,854 | 66,375 | | 16,637,065 | 691,829 | 2.40 | 19,093,967 | 291,039 | 5.47 |
| Industrial | 96,793,644 | 295,469 | 27.30 | 49,727,938 | 2,048,172 | 2.43 | 1,055,465 | 3,707 | 23.73 |
| OPT-Small | 313,507,359 | 1,133,041 | 23.06 | 203,427,034 | 8,149,226 | 2.50 | 4,428,215 | 16,808 | 21.95 |
| OPT-Medium | 109,099,919 | 409,877 | 22.18 | 77,455,715 | 3,162,303 | 2.45 | 88,467 | 355 | 20.77 |
| OPT-Large | 341,814,505 | 1,439,281 | 19.79 | 283,350,039 | 11,720,191 | 2.42 | 45,893 | 215 | 17.79 |
| OPT-Transmission | 30,210,860 | 141,906 | 17.74 | 30,711,981 | 1,236,620 | 2.48 | 266 | 4 | 5.53 |
| TOTAL RETAIL | $ 2,842,129,174 | 9,065,188 | 26.13 | $ 1,434,012,603 | 59,480,702 | 2.41 | $ 576,013,467 | 2,320,757 | 20.68 |

[1] Allocation Factor: All - Production Demand

[2] Allocation Factor: All - MWHs at Meter

[3] Allocation Factor: All - Cust Num

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# Duke Energy Carolinas, LLC

**DEC Exhibit 20**

## Average & Excess Method

## Unit Cost Report

**Year:** 2018

| | Demand | UNIT | COSTS | Energy | UNIT | COSTS | CUSTOMER | UNIT | COSTS |
|---|---|---|---|---|---|---|---|---|---|
| | Revenue | KW [1] | $/KW/Mo | Revenue | Annual MWH [2] | Cents/KWH | Revenue | Avg Bills [3] | $/Cust/Mo |
| **North Carolina:** | | | | | | | | | |
| Residential | 1,470,762,314 | 5,532,922 | 22.15 | 521,139,314 | 22,763,030 | 2.29 | 440,987,860 | 1,756,541 | 20.92 |
| SGS | 284,040,575 | 839,866 | 28.18 | 115,497,633 | 4,567,331 | 2.53 | 72,964,352 | 242,917 | 25.03 |
| LGS | 243,199,186 | 710,852 | 28.51 | 132,024,891 | 5,142,000 | 2.57 | 2,817,953 | 9,171 | 25.61 |
| Lighting | 106,975,988 | 99,012 | | 16,629,331 | 691,829 | 2.40 | 19,104,315 | 291,039 | 5.47 |
| Industrial | 99,478,867 | 328,160 | 25.26 | 49,626,341 | 2,048,172 | 2.42 | 1,038,505 | 3,707 | 23.35 |
| OPT-Small | 289,838,818 | 855,395 | 28.24 | 208,628,723 | 8,149,226 | 2.56 | 5,210,155 | 16,808 | 25.83 |
| OPT-Medium | 100,192,581 | 302,917 | 27.56 | 79,546,046 | 3,162,303 | 2.52 | 104,400 | 355 | 24.51 |
| OPT-Large | 308,121,006 | 1,029,112 | 24.95 | 291,109,861 | 11,720,190 | 2.48 | 54,534 | 215 | 21.14 |
| OPT-Transmission | 26,230,695 | 97,001 | 22.53 | 31,690,568 | 1,236,620 | 2.56 | 280 | 4 | 5.83 |
| TOTAL RETAIL | $ 2,928,840,031 | 9,795,237 | 24.92 | $ 1,445,892,707 | 59,480,701 | 2.43 | $ 542,282,353 | 2,320,757 | 19.47 |

[1] Allocation Factor: All - Production Demand

[2] Allocation Factor: All - MWHs at Meter

[3] Allocation Factor: All - Cust Num

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# Duke Energy Carolinas, LLC

**DEC Exhibit 21**

## Average & Excess 4CP Method

## Unit Cost Report

**Year:** 2018

| | Demand | UNIT | COSTS | Energy | UNIT | COSTS | CUSTOMER | UNIT | COSTS |
|---|---|---|---|---|---|---|---|---|---|
| | Revenue | KW [1] | $/KW/Mo | Revenue | Annual MWH [2] | Cents/KWH | Revenue | Avg Bills [3] | $/Cust/Mo |
| **North Carolina:** | | | | | | | | | |
| Residential | 1,332,009,482 | 2,792,243 | 39.75 | 525,907,081 | 22,763,030 | 2.31 | 470,812,126 | 1,756,541 | 22.34 |
| SGS | 276,577,605 | 514,228 | 44.82 | 115,542,170 | 4,567,331 | 2.53 | 73,434,580 | 242,917 | 25.19 |
| LGS | 250,707,885 | 538,072 | 38.83 | 130,086,106 | 5,142,000 | 2.53 | 2,580,570 | 9,171 | 23.45 |
| Lighting | 101,389,973 | 30,895 | | 16,673,339 | 691,829 | 2.41 | 19,193,311 | 291,039 | 5.50 |
| Industrial | 97,933,835 | 208,154 | 39.21 | 49,544,634 | 2,048,172 | 2.42 | 1,031,742 | 3,707 | 23.19 |
| OPT-Small | 310,564,462 | 732,758 | 35.32 | 203,841,391 | 8,149,226 | 2.50 | 4,495,679 | 16,808 | 22.29 |
| OPT-Medium | 107,787,898 | 262,804 | 34.18 | 77,651,324 | 3,162,303 | 2.46 | 90,003 | 355 | 21.13 |
| OPT-Large | 335,826,455 | 907,546 | 30.84 | 284,258,369 | 11,720,190 | 2.43 | 46,932 | 215 | 18.19 |
| OPT-Transmission | 29,433,529 | 88,557 | 27.70 | 30,841,138 | 1,236,620 | 2.49 | 268 | 4 | 5.57 |
| TOTAL RETAIL | $ 2,842,231,124 | 6,075,257 | 38.99 | $ 1,434,345,552 | 59,480,701 | 2.41 | $ 571,685,211 | 2,320,757 | 20.53 |

[1] Allocation Factor: All - Production Demand

[2] Allocation Factor: All - MWHs at Meter

[3] Allocation Factor: All - Cust Num

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# Duke Energy Carolinas, LLC

**DEC Exhibit 22**

## Average & Excess Dominion Method

## Unit Cost Report

**Year:** 2018

| | Demand | UNIT | COSTS | Energy | UNIT | COSTS | CUSTOMER | UNIT | COSTS |
|---|---|---|---|---|---|---|---|---|---|
| | Revenue | KW [1] | $/KW/Mo | Revenue | Annual MWH [2] | Cents/KWH | Revenue | Avg Bills [3] | $/Cust/Mo |
| **North Carolina:** | | | | | | | | | |
| Residential | 1,331,049,077 | 5,442,936 | 20.38 | 526,418,061 | 22,763,030 | 2.31 | 474,792,853 | 1,756,541 | 22.53 |
| SGS | 277,410,278 | 996,016 | 23.21 | 115,439,284 | 4,567,331 | 2.53 | 73,055,583 | 242,917 | 25.06 |
| LGS | 248,324,743 | 996,232 | 20.77 | 130,387,368 | 5,142,000 | 2.54 | 2,619,390 | 9,171 | 23.80 |
| Lighting | 107,826,621 | 175,397 | | 16,519,821 | 691,829 | 2.39 | 18,849,174 | 291,039 | 5.40 |
| Industrial | 102,714,740 | 477,051 | 17.94 | 48,903,321 | 2,048,172 | 2.39 | 948,486 | 3,707 | 21.32 |
| OPT-Small | 301,070,552 | 1,264,578 | 19.84 | 205,332,682 | 8,149,226 | 2.52 | 4,707,659 | 16,808 | 23.34 |
| OPT-Medium | 105,631,949 | 471,449 | 18.67 | 77,998,181 | 3,162,303 | 2.47 | 92,567 | 355 | 21.73 |
| OPT-Large | 328,167,797 | 1,623,870 | 16.84 | 285,467,856 | 11,720,190 | 2.44 | 48,408 | 215 | 18.76 |
| OPT-Transmission | 28,443,730 | 155,431 | 15.25 | 31,018,104 | 1,236,620 | 2.51 | 270 | 4 | 5.63 |
| TOTAL RETAIL | $ 2,830,639,487 | 11,602,960 | 20.33 | $ 1,437,484,677 | 59,480,701 | 2.42 | $ 575,114,391 | 2,320,757 | 20.65 |

[1] Allocation Factor: All - Production Demand

[2] Allocation Factor: All - MWHs at Meter

[3] Allocation Factor: All - Cust Num

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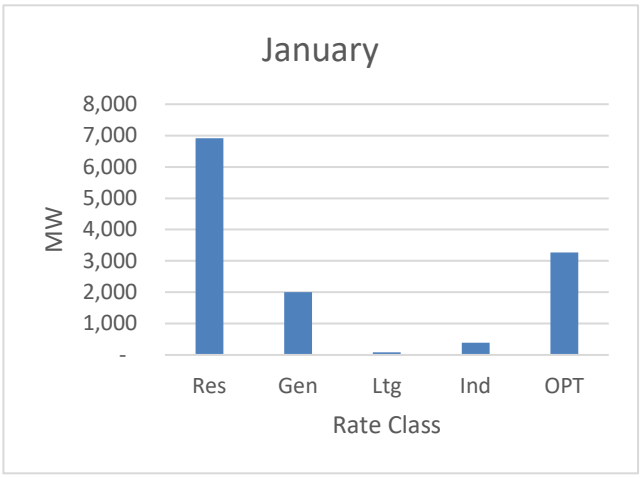
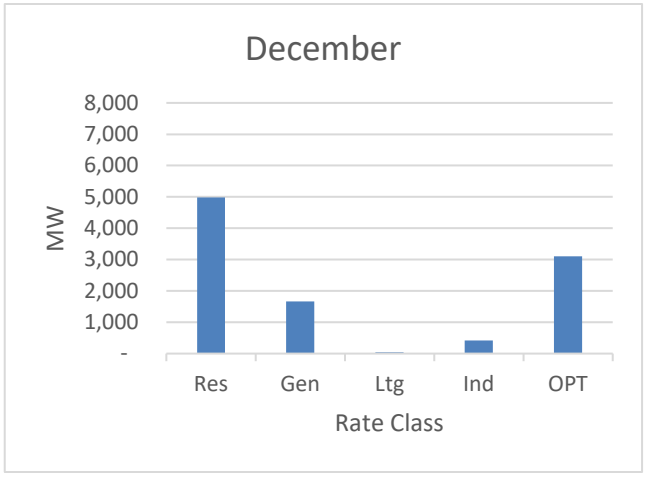
**Duke Energy Carolinas, LLC**
**Production Demands**
**North Carolina Retail**

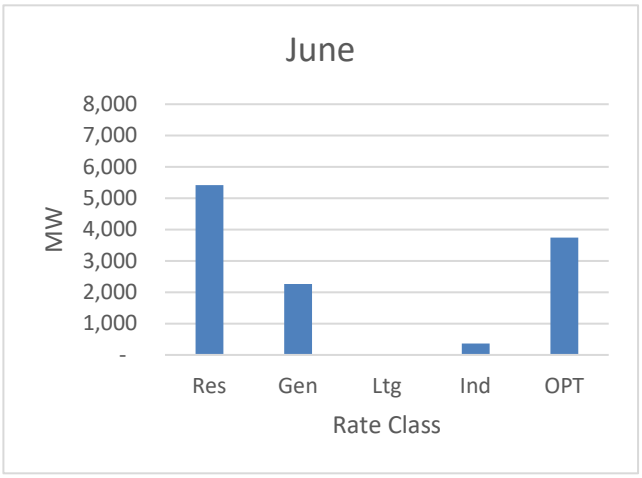
**DEC Exhibit 23**

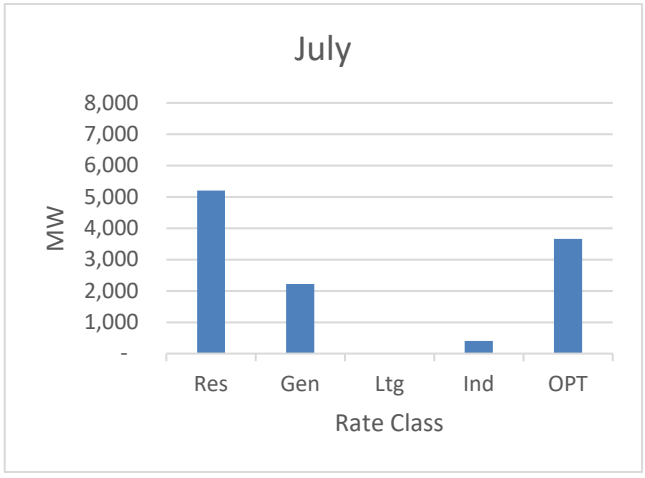
## Winter Peak Months



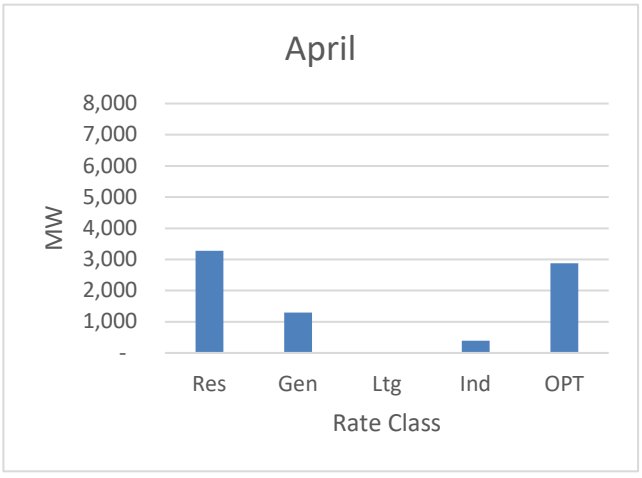



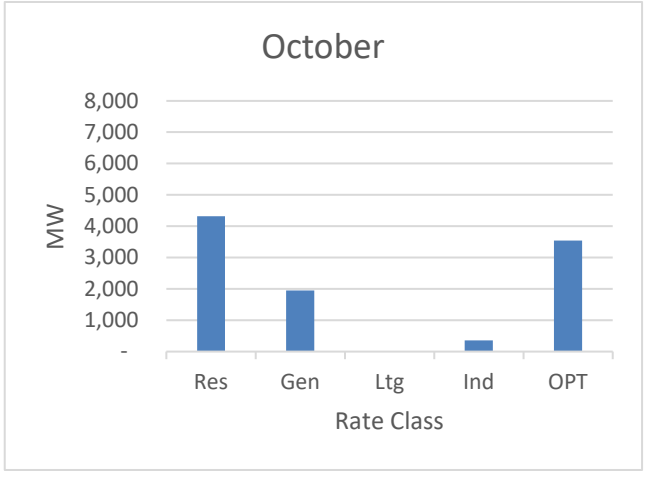

## Summer Peak Months




## Off Peak Months



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# Duke Energy Progress, LLC

**DEP Exhibit 1**

**Production Demands (KW)**

Year: 2018

| | Coincident Peaks | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **January** | **February** | **March** | **April** | **May** | **June** | **July** | **August** | **September** | **October** | **November** | **December** |
| **North Carolina:** | | | | | | | | | | | | |
| Residential | 5,755,959 | 4,338,513 | 3,636,141 | 2,439,634 | 3,218,023 | 3,850,873 | 3,741,128 | 3,700,888 | 3,183,980 | 3,117,060 | 3,631,160 | 3,793,185 |
| SGS | 536,092 | 339,033 | 395,170 | 236,250 | 389,810 | 477,928 | 480,154 | 430,733 | 483,043 | 491,295 | 353,125 | 342,072 |
| MGS | 1,809,014 | 1,244,757 | 1,780,871 | 1,322,069 | 1,941,993 | 2,187,952 | 2,083,819 | 2,111,483 | 2,301,785 | 1,928,597 | 1,920,826 | 1,797,867 |
| SI | 3,614 | 2,404 | 2,145 | 1,706 | 3,446 | 5,504 | 7,969 | 8,635 | 19,265 | 20,404 | 11,224 | 4,693 |
| LGS | 846,735 | 905,725 | 1,009,730 | 987,854 | 1,081,800 | 1,241,189 | 1,213,649 | 1,205,273 | 1,218,096 | 1,142,512 | 1,006,648 | 1,002,048 |
| Lighting | 678 | 464 | 623 | 504 | 560 | 566 | 590 | 601 | 554 | 536 | 541 | 563 |
| NC Retail | 8,952,091 | 6,830,896 | 6,824,679 | 4,988,017 | 6,635,632 | 7,764,011 | 7,527,308 | 7,457,613 | 7,206,721 | 6,700,404 | 6,923,524 | 6,940,428 |
| NC Wholesale | 4,744,742 | 3,181,890 | 3,064,984 | 1,999,387 | 2,904,497 | 3,617,292 | 3,506,689 | 3,518,194 | 3,308,381 | 3,047,405 | 3,209,152 | 3,150,546 |
| Total NC | 13,696,834 | 10,012,786 | 9,889,664 | 6,987,404 | 9,540,129 | 11,381,303 | 11,033,997 | 10,975,807 | 10,515,102 | 9,747,809 | 10,132,675 | 10,090,974 |
| **South Carolina:** | | | | | | | | | | | | |
| Residential | 777,822 | 559,023 | 450,153 | 304,774 | 410,176 | 500,552 | 487,337 | 496,675 | 429,226 | 398,889 | 471,169 | 500,406 |
| SGS | 77,013 | 47,000 | 53,219 | 32,314 | 56,023 | 70,327 | 70,872 | 64,844 | 71,670 | 92,380 | 66,024 | 45,594 |
| MGS | 274,056 | 183,954 | 260,698 | 195,978 | 285,582 | 319,517 | 304,283 | 311,361 | 342,825 | 267,138 | 268,570 | 267,419 |
| SI | 4,159 | 1,538 | 1,073 | 856 | 1,966 | 3,033 | 2,552 | 1,625 | 3,544 | 3,989 | 3,779 | 5,814 |
| LGS | 143,886 | 212,943 | 267,500 | 267,608 | 309,470 | 298,421 | 303,362 | 325,016 | 297,416 | 293,580 | 268,511 | 277,504 |
| Lighting | 118 | 82 | 111 | 89 | 99 | 101 | 108 | 108 | 102 | 98 | 100 | 104 |
| SC Retail | 1,277,055 | 1,004,541 | 1,032,754 | 801,620 | 1,063,316 | 1,191,950 | 1,168,513 | 1,199,629 | 1,144,783 | 1,056,074 | 1,078,153 | 1,096,840 |
| SC Wholesale | 48,476 | 32,363 | 35,654 | 19,161 | 35,819 | 45,452 | 43,627 | 41,812 | 39,353 | 36,615 | 36,062 | 36,173 |
| Total SC | 1,325,530 | 1,036,904 | 1,068,408 | 820,781 | 1,099,135 | 1,237,402 | 1,212,140 | 1,241,441 | 1,184,136 | 1,092,688 | 1,114,216 | 1,133,013 |
| System | 15,022,364 | 11,049,690 | 10,958,072 | 7,808,185 | 10,639,264 | 12,618,705 | 12,246,137 | 12,217,248 | 11,699,238 | 10,840,497 | 11,246,891 | 11,223,987 |

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# Duke Energy Progress, LLC

**DEP Exhibit 2**

## Cost of Service Analysis Results
## FERC 12CP Test
## For the twelve months ending December 2018

| | | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | Test Results |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Annual Maximum: | | 11,831 | 12,531 | 12,094 | 12,770 | 12,376 | 14,159 | 15,515 | 13,248 | 14,407 | 15,322 | |
| | Month | Feb | Jan | Jul | Jul | Feb | Jan | Feb | Jan | Jan | Jan | |
| | Month # | 2 | 1 | 7 | 7 | 2 | 1 | 2 | 1 | 1 | 1 | |
| Annual Minimum: | | 8,308 | 8,811 | 8,233 | 8,616 | 8,505 | 8,362 | 7,887 | 9,031 | 9,711 | 8,012 | |
| | Month | Nov | Apr | Oct | Apr | Apr | Apr | Apr | Apr | Apr | Apr | |
| | Month # | 11 | 4 | 10 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | |
| Summer Max: | | 11,796 | 12,074 | 12,094 | 12,770 | 12,166 | 12,219 | 12,706 | 13,061 | 12,590 | 12,841 | |
| | Month | Aug | Aug | Jul | Jul | Aug | Sep | Jun | Jul | Jul | Jun | |
| | Month # | 8 | 8 | 7 | 7 | 8 | 9 | 6 | 7 | 7 | 6 | |
| Winter Max: | | 11,831 | 12,531 | 12,013 | 11,338 | 12,376 | 14,159 | 15,515 | 13,248 | 14,407 | 15,322 | |
| | Month | Feb | Jan | Jan | Jan | Feb | Jan | Feb | Jan | Jan | Jan | |
| | Month # | 2 | 1 | 1 | 1 | 2 | 1 | 2 | 1 | 1 | 1 | |
| **Test 1: ON and Off Peak Test** | | | | | | | | | | | | |
| **Summer CP Method:** | | | | | | | | | | | | |
| | Summer Max | 11,796 | 12,074 | 12,094 | 12,770 | 12,166 | 12,219 | 12,706 | 13,061 | 12,590 | 12,841 | |
| | Annual Max | 11,831 | 12,531 | 12,094 | 12,770 | 12,376 | 14,159 | 15,515 | 13,248 | 14,407 | 15,322 | |
| | | 99.7% | 96.4% | 100.0% | 100.0% | 98.3% | 86.3% | 81.9% | 98.6% | 87.4% | 83.8% | |
| | Avg Off-Peak | 10,238 | 10,616 | 10,303 | 10,616 | 11,088 | 11,425 | 11,269 | 11,067 | 11,315 | 11,600 | |
| | Annual Max | 11,831 | 12,531 | 12,094 | 12,770 | 12,376 | 14,159 | 15,515 | 13,248 | 14,407 | 15,322 | |
| | | 86.5% | 84.7% | 85.2% | 83.1% | 89.6% | 80.7% | 72.6% | 83.5% | 78.5% | 75.7% | |
| | Difference | 13.2% | 11.6% | 14.8% | 16.9% | 8.7% | 5.6% | 9.3% | 15.1% | 8.9% | 8.1% | |
| | <= 19% | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | |
| | **Supports 12CP?** | **Yes** | **Yes** | **Yes** | **Yes** | **Yes** | **Yes** | **Yes** | **Yes** | **Yes** | **Yes** | **10 of 10** |
| **Test 2: Low to Annual Peak Test** | | | | | | | | | | | | |
| | Annual Min | 8,308 | 8,811 | 8,233 | 8,616 | 8,505 | 8,362 | 7,887 | 9,031 | 9,711 | 8,012 | |
| | Annual Max | 11,831 | 12,531 | 12,094 | 12,770 | 12,376 | 14,159 | 15,515 | 13,248 | 14,407 | 15,322 | |
| | | 70.2% | 70.3% | 68.1% | 67.5% | 68.7% | 59.1% | 50.8% | 68.2% | 67.4% | 52.3% | |
| | >= 66% | Yes | Yes | Yes | Yes | Yes | No | No | Yes | Yes | No | |
| | **Supports 12CP?** | **Yes** | **Yes** | **Yes** | **Yes** | **Yes** | **No** | **No** | **Yes** | **Yes** | **No** | **7 of 10** |
| **Test 3: Average to Annual Peak Test** | | | | | | | | | | | | |
| | 12CP Average | 10,368 | 10,738 | 10,453 | 10,795 | 11,178 | 11,491 | 11,389 | 11,233 | 11,421 | 11,704 | |
| | Annual Max | 11,831 | 12,531 | 12,094 | 12,770 | 12,376 | 14,159 | 15,515 | 13,248 | 14,407 | 15,322 | |
| | | 87.6% | 85.7% | 86.4% | 84.5% | 90.3% | 81.2% | 73.4% | 84.8% | 79.3% | 76.4% | |
| | >= 81% | Yes | Yes | Yes | Yes | Yes | Yes | No | Yes | No | No | |
| | **Supports 12CP?** | **Yes** | **Yes** | **Yes** | **Yes** | **Yes** | **Yes** | **No** | **Yes** | **No** | **No** | **7 of 10** |

From FERC Opinion 501 - Docket Nos. EL05-19-002 and ER05-168-001 - Golden Spread EMC - April 2008

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# Duke Energy Progress, LLC

**DEP Exhibit 3**

**Peak Responsibility Methods (KW) - Non-Firm**

Year: 2018

| | June Summer 1CP-Sum | January Winter 1CP-Win | January November June July 4CP | 12CP |
|---|---|---|---|---|
| **North Carolina:** | | | | |
| Residential | 3,850,873 | 5,755,959 | 4,244,780 | 3,700,545 |
| SGS | 477,928 | 536,092 | 461,825 | 412,892 |
| MGS | 2,187,952 | 1,809,014 | 2,000,403 | 1,869,253 |
| SI | 5,504 | 3,614 | 7,078 | 7,584 |
| LGS | 1,241,189 | 846,735 | 1,077,055 | 1,071,772 |
| Lighting | 566 | 678 | 594 | 565 |
| NC Retail | 7,764,011 | 8,952,091 | 7,791,734 | 7,062,610 |
| NC Wholesale | 3,617,292 | 4,744,742 | 3,769,469 | 3,271,097 |
| Total NC | 11,381,303 | 13,696,834 | 11,561,202 | 10,333,707 |
| Per Docket E-2 Sub 1219 | 11,381,303 | 13,696,834 | 11,561,202 | 10,333,707 |
| **South Carolina:** | | | | |
| Residential | 500,552 | 777,822 | 559,220 | 482,184 |
| SGS | 70,327 | 77,013 | 71,059 | 62,273 |
| MGS | 319,517 | 274,056 | 291,606 | 273,448 |
| SI | 3,033 | 4,159 | 3,381 | 2,827 |
| LGS | 298,421 | 143,886 | 253,545 | 272,101 |
| Lighting | 101 | 118 | 107 | 102 |
| SC Retail | 1,191,950 | 1,277,055 | 1,178,918 | 1,092,936 |
| SC Wholesale | 45,452 | 48,476 | 43,404 | 37,547 |
| Total SC | 1,237,402 | 1,325,530 | 1,222,322 | 1,130,483 |
| Per Docket E-2 Sub 1219 | 1,237,402 | 1,325,530 | 1,222,322 | 1,130,483 |
| System | 12,618,705 | 15,022,364 | 12,783,524 | 11,464,190 |

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# Duke Energy Progress, LLC

**DEP Exhibit 4**

**Summer/Winter Peak & Average Allocation Method**

**Year:** 2018

| Rate Schedule | E1 Prod Out. Level kWh | Ratio of Each Rate Schedule To Total | Col.(3) x Energy Weighting Factor | June Summer CP Demand (KW) | Ratio of Each Rate Schedule To Total | Col.(6) x Demand Weighting Factor | January Winter CP Demand (KW) | Ratio of Each Rate Schedule To Total | Col.(9) x Demand Weighting Factor | S/W P&A Allocation Factors |
|---|---|---|---|---|---|---|---|---|---|---|
| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) |
| **North Carolina:** | | | | | | | | | | |
| Residential | 17,416,906,173 | 0.264097 | 0.143861 | 3,850,873 | 0.305172 | 0.069468 | 5,755,959 | 0.383159 | 0.087221 | 30.0550% |
| SGS | 2,071,898,933 | 0.031417 | 0.017114 | 477,928 | 0.037875 | 0.008622 | 536,092 | 0.035686 | 0.008124 | 3.3859% |
| MGS | 11,663,352,961 | 0.176855 | 0.096337 | 2,187,952 | 0.173390 | 0.039470 | 1,809,014 | 0.120421 | 0.027412 | 16.3220% |
| SI | 44,807,202 | 0.000679 | 0.000370 | 5,504 | 0.000436 | 0.000099 | 3,614 | 0.000241 | 0.000055 | 0.0524% |
| LGS | 8,728,935,826 | 0.132359 | 0.072100 | 1,241,189 | 0.098361 | 0.022391 | 846,735 | 0.056365 | 0.012831 | 10.7321% |
| Lighting | 374,947,587 | 0.005685 | 0.003097 | 566 | 0.000045 | 0.000010 | 678 | 0.000045 | 0.000010 | 0.3117% |
| NC Retail | 40,300,848,683 | 0.611093 | 0.332878 | 7,764,011 | 0.615278 | 0.140060 | 8,952,091 | 0.595918 | 0.135653 | 60.8591% |
| NC Wholesale | 18,682,169,387 | 0.283283 | 0.154312 | 3,617,292 | 0.286661 | 0.065255 | 4,744,742 | 0.315845 | 0.071898 | 29.1464% |
| Total NC | 58,983,018,069 | 0.894376 | 0.487190 | 11,381,303 | 0.901939 | 0.205315 | 13,696,834 | 0.911763 | 0.207551 | 90.0056% |
| **South Carolina:** | | | | | | | | | | |
| Residential | 2,288,678,709 | 0.034704 | 0.018904 | 500,552 | 0.039667 | 0.009030 | 777,822 | 0.051778 | 0.011787 | 3.9720% |
| SGS | 296,123,138 | 0.004490 | 0.002446 | 70,327 | 0.005573 | 0.001269 | 77,013 | 0.005127 | 0.001167 | 0.4882% |
| MGS | 1,724,140,413 | 0.026144 | 0.014241 | 319,517 | 0.025321 | 0.005764 | 274,056 | 0.018243 | 0.004153 | 2.4158% |
| SI | 19,221,900 | 0.000291 | 0.000159 | 3,033 | 0.000240 | 0.000055 | 4,159 | 0.000277 | 0.000063 | 0.0276% |
| LGS | 2,348,530,475 | 0.035611 | 0.019398 | 298,421 | 0.023649 | 0.005383 | 143,886 | 0.009578 | 0.002180 | 2.6962% |
| Lighting | 84,386,208 | 0.001280 | 0.000697 | 101 | 0.000008 | 0.000002 | 118 | 0.000008 | 0.000002 | 0.0701% |
| SC Retail | 6,761,080,842 | 0.102520 | 0.055845 | 1,191,950 | 0.094459 | 0.021502 | 1,277,055 | 0.085010 | 0.019351 | 9.6699% |
| SC Wholesale | 204,676,844 | 0.003104 | 0.001691 | 45,452 | 0.003602 | 0.000820 | 48,476 | 0.003227 | 0.000735 | 0.3245% |
| Total SC | 6,965,757,686 | 0.105624 | 0.057536 | 1,237,402 | 0.098061 | 0.022322 | 1,325,530 | 0.088237 | 0.020086 | 9.9944% |
| SYSTEM | 65,948,775,755 | 1.000000 | 0.544726 | 12,618,705 | 1.000000 | 0.227637 | 15,022,364 | 1.000000 | 0.227637 | 100.0000% |

Note 1: Excludes NCEMC Peaking Capacity

**Calculation of Load Factor for SWP&A Weights:**

| | |
|---|---|
| Summer Peak - Col (5) | 12,618,705 |
| Winter Peak - Col (8) | 15,022,364 |
| Average for LF Calc | 13,820,535 |
| Total E1 mWh - Col (2) | 65,948,776 |
| Test Year Hours | 8,760 |
| Load Factor (Energy Wgt) | 54.4726% |
| Peaks @ (1-LF)/2 each | 22.7637% |

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# Duke Energy Progress, LLC

**DEP Exhibit 5**

## Average & Excess Demand Allocation Method

**Year:** 2018

| | Inputs | | | Calculation | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Summer Coin. Peak June | MWH @ Gen | NCD (kW) | Average Demand (KW) | Class Load Factor | Excess Demand (Hourly kW) | Average Demand Component (KW) | Excess Demand Component (KW) | Average & Excess Demand | Average & Excess Hourly Demand Ratio |
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) |
| **North Carolina:** | | | | | | | | | | |
| Residential | 3,850,873 | 17,416,906 | 10,833,545 | 1,988,231 | 51.63% | 8,845,314 | 1,186,191 | 3,568,144 | 4,754,335 | 41.70% |
| SGS | 477,928 | 2,071,899 | 1,017,156 | 236,518 | 49.49% | 780,638 | 141,108 | 314,905 | 456,013 | 4.00% |
| MGS | 2,187,952 | 11,663,353 | 3,248,999 | 1,331,433 | 60.85% | 1,917,566 | 794,341 | 773,534 | 1,567,875 | 13.75% |
| SI | 5,504 | 44,807 | 104,121 | 5,115 | 92.93% | 99,006 | 3,052 | 39,938 | 42,990 | 0.38% |
| LGS | 1,241,189 | 8,728,936 | 1,368,665 | 996,454 | 80.28% | 372,211 | 594,491 | 150,147 | 744,638 | 6.53% |
| Lighting | 566 | 374,948 | 104,059 | 42,802 | 7568.75% | 61,256 | 25,536 | 24,710 | 50,247 | 0.44% |
| NC Retail | 7,764,011 | 40,300,849 | 16,676,545 | 4,600,554 | 59.25% | 12,075,991 | 2,744,719 | 4,871,379 | 7,616,098 | 66.80% |
| NC Wholesale | 3,617,292 | 18,682,169 | 5,369,000 | 2,132,668 | 58.96% | 3,236,332 | 1,272,363 | 1,305,516 | 2,577,879 | 22.61% |
| Total NC | 11,381,303 | 58,983,018 | 22,045,545 | 6,733,221 | 59.16% | 15,312,324 | 4,017,082 | 6,176,895 | 10,193,977 | 89.41% |
| **South Carolina:** | | | | | | | | | | |
| Residential | 500,552 | 2,288,679 | 1,463,974 | 261,265 | 52.20% | 1,202,710 | 155,872 | 485,165 | 641,038 | 5.62% |
| SGS | 70,327 | 296,123 | 170,870 | 33,804 | 48.07% | 137,066 | 20,168 | 55,291 | 75,459 | 0.66% |
| MGS | 319,517 | 1,724,140 | 487,989 | 196,820 | 61.60% | 291,170 | 117,424 | 117,456 | 234,880 | 2.06% |
| SI | 3,033 | 19,222 | 23,680 | 2,194 | 72.36% | 21,486 | 1,309 | 8,667 | 9,976 | 0.09% |
| LGS | 298,421 | 2,348,530 | 391,354 | 268,097 | 89.84% | 123,257 | 159,948 | 49,721 | 209,670 | 1.84% |
| Lighting | 101 | 84,386 | 22,536 | 9,633 | 9544.88% | 12,903 | 5,747 | 5,205 | 10,952 | 0.10% |
| SC Retail | 1,191,950 | 6,761,081 | 2,560,403 | 771,813 | 64.75% | 1,788,590 | 460,468 | 721,506 | 1,181,974 | 10.37% |
| SC Wholesale | 45,452 | 204,677 | 51,000 | 23,365 | 51.41% | 27,635 | 13,940 | 11,148 | 25,087 | 0.22% |
| Total SC | 1,237,402 | 6,965,758 | 2,611,403 | 795,178 | 64.26% | 1,816,225 | 474,408 | 732,654 | 1,207,062 | 10.59% |
| SYSTEM | 12,618,705 | 65,948,776 | 24,656,948 | 7,528,399 | 59.66% | 17,128,549 | 4,491,490 | 6,909,548 | 11,401,039 | 100.00% |

Hours in Year: 8,760

System Load Factor: 59.6606% = (65,948,776,000 / 12,618,705) / 8,760

column(4)=column(2)/8760

column(5)=column(4)/column(1)

column(6)=column(3)-column(4)

column(7)=(column(4)/(column(4) Total))xLoad Factor

column(8)=(column(6)/(column(6) Total))x(1-Load Factor)

column(9)=column(7)+column(8)

column(10)=column(9)*column(10) Total

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# Duke Energy Progress, LLC

**DEP Exhibit 6**

## Average & Excess 4CP Demand Allocation Method

**Year:** 2018

| | Inputs | | | Calculation | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Summer Coin. Peak June | MWH @ Gen | 4CP (kW) | Average Demand (KW) | Class Load Factor | Excess Demand (Hourly kW) | Average Demand Component (KW) | Excess Demand Component (KW) | Average & Excess Demand | Average & Excess Hourly Demand Ratio |
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) |
| **North Carolina:** | | | | | | | | | | |
| Residential | 3,850,873 | 17,416,906 | 4,244,780 | 1,988,231 | 51.63% | 2,256,548 | 1,186,191 | 910,277 | 2,096,469 | 31.71% |
| SGS | 477,928 | 2,071,899 | 461,825 | 236,518 | 49.49% | 225,306 | 141,108 | 90,887 | 231,995 | 3.51% |
| MGS | 2,187,952 | 11,663,353 | 2,000,403 | 1,331,433 | 60.85% | 668,970 | 794,341 | 269,858 | 1,064,200 | 16.10% |
| SI | 5,504 | 44,807 | 7,078 | 5,115 | 92.93% | 1,963 | 3,052 | 792 | 3,843 | 0.06% |
| LGS | 1,241,189 | 8,728,936 | 1,077,055 | 996,454 | 80.28% | 80,601 | 594,491 | 32,514 | 627,005 | 9.48% |
| Lighting | 566 | 374,948 | 594 | 42,802 | 7568.75% | -42,208 | 25,536 | -17,027 | 8,509 | 0.13% |
| NC Retail | 7,764,011 | 40,300,849 | 7,791,734 | 4,600,554 | 59.25% | 3,191,180 | 2,744,719 | 1,287,302 | 4,032,021 | 60.99% |
| NC Wholesale | 3,617,292 | 18,682,169 | 3,769,469 | 2,132,668 | 58.96% | 1,636,801 | 1,272,363 | 660,275 | 1,932,638 | 29.23% |
| Total NC | 11,381,303 | 58,983,018 | 11,561,202 | 6,733,221 | 59.16% | 4,827,981 | 4,017,082 | 1,947,577 | 5,964,659 | 90.22% |
| **South Carolina:** | | | | | | | | | | |
| Residential | 500,552 | 2,288,679 | 559,220 | 261,265 | 52.20% | 297,955 | 155,872 | 120,193 | 276,066 | 4.18% |
| SGS | 70,327 | 296,123 | 71,059 | 33,804 | 48.07% | 37,255 | 20,168 | 15,028 | 35,196 | 0.53% |
| MGS | 319,517 | 1,724,140 | 291,606 | 196,820 | 61.60% | 94,787 | 117,424 | 38,236 | 155,660 | 2.35% |
| SI | 3,033 | 19,222 | 3,381 | 2,194 | 72.36% | 1,186 | 1,309 | 479 | 1,788 | 0.03% |
| LGS | 298,421 | 2,348,530 | 253,545 | 268,097 | 89.84% | -14,552 | 159,948 | -5,870 | 154,078 | 2.33% |
| Lighting | 101 | 84,386 | 107 | 9,633 | 9544.88% | -9,527 | 5,747 | -3,843 | 1,904 | 0.03% |
| SC Retail | 1,191,950 | 6,761,081 | 1,178,918 | 771,813 | 64.75% | 407,105 | 460,468 | 164,224 | 624,692 | 9.45% |
| SC Wholesale | 45,452 | 204,677 | 43,404 | 23,365 | 51.41% | 20,039 | 13,940 | 8,084 | 22,023 | 0.33% |
| Total SC | 1,237,402 | 6,965,758 | 1,222,322 | 795,178 | 64.26% | 427,144 | 474,408 | 172,307 | 646,715 | 9.78% |
| SYSTEM | 12,618,705 | 65,948,776 | 12,783,524 | 7,528,399 | 59.66% | 5,255,125 | 4,491,490 | 2,119,884 | 6,611,375 | 100.00% |

Hours in Year: 8,760

System Load Factor: 59.6606% = (65,948,776,000 / 12,618,705) / 8,760

column(4)=column(2)/8760

column(5)=column(4)/column(1)

column(6)=column(3)-column(4)

column(7)=(column(4)/(column(4) Total))xLoad Factor

column(8)=(column(6)/(column(6) Total))x(1-Load Factor)

column(9)=column(7)+column(8)

column(10)=column(9)*column(10) Total

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# Duke Energy Progress, LLC

**DEP Exhibit 7**

## Average & Excess Demand Allocation - Dominion Method

**Year:** 2018

| | Inputs | | | Calculation | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Summer Coin. Peak June | MWH @ Gen | Diversified NCD (kW) | Average Demand (KW) | System Peak Less Avg Dmnd | Excess = NCD Less Avg Dmnd (kW) | Ratio (%) | Allocation of Excess (KW) | Average & Excess Demand (KW) | Average & Excess Demand Ratio |
| | (1) | (2) | (3) | (4)=(2)/ 8,760 | (5)=(1)-(4) | (6)=(3)-(4) | (7)=(5)/(6) | (8)=(6)x 64.99% | (9)=(4)+(8) | (10) |
| **North Carolina:** | | | | | | | | | | |
| Residential | 3,850,873 | 17,416,906 | 4,338,514 | 1,988,231 | | 2,350,282 | | 1,527,449 | 3,515,681 | 27.86% |
| SGS | 477,928 | 2,071,899 | 491,645 | 236,518 | | 255,127 | | 165,807 | 402,325 | 3.19% |
| MGS | 2,187,952 | 11,663,353 | 2,449,019 | 1,331,433 | | 1,117,586 | | 726,320 | 2,057,753 | 16.31% |
| SI | 5,504 | 44,807 | 47,975 | 5,115 | | 42,860 | | 27,855 | 32,970 | 0.26% |
| LGS | 1,241,189 | 8,728,936 | 1,289,349 | 996,454 | | 292,895 | | 190,353 | 1,186,807 | 9.41% |
| Lighting | 566 | 374,948 | 100,703 | 42,802 | | 57,901 | | 37,630 | 80,432 | 0.64% |
| NC Retail | 7,764,011 | 40,300,849 | 8,717,206 | 4,600,554 | | 4,116,652 | | 2,675,414 | 7,275,967 | 57.66% |
| NC Wholesale | 3,617,292 | 18,682,169 | 5,161,000 | 2,132,668 | | 3,028,332 | | 1,968,114 | 4,100,782 | 32.50% |
| Total NC | 11,381,303 | 58,983,018 | 13,878,206 | 6,733,221 | | 7,144,985 | | 4,643,528 | 11,376,749 | 90.16% |
| **South Carolina:** | | | | | | | | | | |
| Residential | 500,552 | 2,288,679 | 559,023 | 261,265 | | 297,758 | | 193,513 | 454,778 | 3.60% |
| SGS | 70,327 | 296,123 | 92,438 | 33,804 | | 58,634 | | 38,106 | 71,910 | 0.57% |
| MGS | 319,517 | 1,724,140 | 364,790 | 196,820 | | 167,970 | | 109,164 | 305,983 | 2.42% |
| SI | 3,033 | 19,222 | 9,379 | 2,194 | | 7,185 | | 4,669 | 6,864 | 0.05% |
| LGS | 298,421 | 2,348,530 | 383,911 | 268,097 | | 115,813 | | 75,267 | 343,364 | 2.72% |
| Lighting | 101 | 84,386 | 22,093 | 9,633 | | 12,460 | | 8,098 | 17,731 | 0.14% |
| SC Retail | 1,191,950 | 6,761,081 | 1,431,633 | 771,813 | | 659,821 | | 428,818 | 1,200,631 | 9.51% |
| SC Wholesale | 45,452 | 204,677 | 51,000 | 23,365 | | 27,635 | | 17,960 | 41,325 | 0.33% |
| Total SC | 1,237,402 | 6,965,758 | 1,482,633 | 795,178 | | 687,456 | | 446,778 | 1,241,956 | 9.84% |
| SYSTEM | 12,618,705 | 65,948,776 | 15,360,839 | 7,528,399 | 5,090,306 | 7,832,440 | 64.99% | 5,090,306 | 12,618,705 | 100.00% |
| | | | | | | | | | 12,618,705 | |

Hours in Year: 8,760

System Load Factor: 59.6606% = (65,948,776,000 / 12,618,705) / 8,760

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# Duke Energy Progress, LLC

**DEP Exhibit 8**

## Base, Intermediate & Peak Allocation Method

**Year:** 2018

| Generating Plant | Fuel Type | Capacity MW | Average Fuel Cost $/kWh | Net mWh | Annual Capacity Factor | Gross Plant $ | Pct Energy | Gross Investment Energy | Gross Investment Demand |
|---|---|---|---|---|---|---|---|---|---|
| **Base Load Units:** | | | | | | | | | |
| Robinson | Nuclear | 741 | 7.11 | 5,276,118 | 81.3% | 1,641,168,860 | 100% | 1,641,168,860 | - |
| Brunswick | Nuclear | 1,870 | 6.51 | 14,626,967 | 89.3% | 3,083,781,826 | 100% | 3,083,781,826 | - |
| Harris | Nuclear | 932 | 6.77 | 7,587,914 | 92.9% | 4,187,436,155 | 100% | 4,187,436,155 | - |
| HF Lee | Gas Turbine/CC | 888 | 34.16 | 7,210,666 | 92.7% | 695,299,706 | 100% | 695,299,706 | - |
| Smith Energy | Gas Turbine/CC | 1,073 | 29.19 | 8,821,723 | 93.9% | 761,984,596 | 100% | 761,984,596 | - |
| Sutton | Gas Turbine/CC | 607 | 42.63 | 3,424,568 | 64.4% | 541,123,187 | 100% | 541,123,187 | - |
| **Total Base Load Units** | | 6,111 | | 46,947,956 | | 10,910,794,329 | | 10,910,794,329 | - |
| **Intermediate Units:** | | | | | | | | | |
| Asheville | Coal | 378 | 39.93 | 1,237,903 | 37.4% | 467,059,817 | 37.4% | 174,607,629 | 292,452,188 |
| Mayo | Coal | 727 | 41.62 | 1,491,333 | 23.4% | 1,215,045,064 | 23.4% | 284,530,283 | 930,514,781 |
| Roxboro | Coal | 2,439 | 34.90 | 5,927,599 | 27.7% | 2,333,238,869 | 27.7% | 647,324,601 | 1,685,914,268 |
| Smith Energy | Gas Turbine | 772 | 47.81 | 3,073,958 | 45.5% | 289,995,526 | 45.5% | 131,815,906 | 158,179,619 |
| Sutton | Gas Turbine | 78 | 45.73 | 218,887 | 32.0% | 100,187,704 | 32.0% | 32,094,875 | 68,092,829 |
| **Total Intermediate Units** | | 4,394 | | 11,949,680 | | 4,405,526,980 | | 1,270,373,294 | 3,135,153,686 |
| **Peaking Units:** | | | | | | | | | |
| Asheville | Gas Turbine | 320 | 57.65 | 506,865 | 18.1% | 114,191,604 | 0.0% | - | 114,191,604 |
| Blewett | Gas Turbine | 52 | | 199 | 0.0% | 13,460,860 | 0.0% | - | 13,460,860 |
| Darlington | Gas Turbine | 664 | 112.94 | 230,819 | 4.0% | 129,888,403 | 0.0% | - | 129,888,403 |
| Wayne | Gas Turbine | 857 | 79.17 | 458,014 | 6.1% | 275,074,172 | 0.0% | - | 275,074,172 |
| Weatherspoon | Gas Turbine | 124 | 440.49 | 1,712 | 0.2% | 23,763,288 | 0.0% | - | 23,763,288 |
| **Total Peaking Units** | | 2,017 | | 1,197,609 | | 556,378,327 | | - | 556,378,327 |
| **Hydro Units:** | | | | | | | | | |
| Blewett | Storage | 27 | | 88,367 | 37.4% | 38,202,535 | 50.0% | 19,101,267 | 19,101,267 |
| Marshall | Storage | 4 | | 812 | 2.3% | 13,497,283 | 50.0% | 6,748,642 | 6,748,642 |
| Tillery | Storage | 84 | | 238,608 | 32.4% | 33,822,515 | 50.0% | 16,911,257 | 16,911,257 |
| Walters | Storage | 112 | | 477,853 | 48.7% | 58,194,566 | 50.0% | 29,097,283 | 29,097,283 |
| **Total Hydro Units** | | 227 | | 805,640 | | 143,716,899 | | 71,858,449 | 71,858,449 |
| **Solar Units:** | | | | | | | | | |
| Warsaw | | 22.75 | | 112,927 | 56.7% | 84,436,980 | 56.7% | 47,845,927 | 36,591,053 |
| Fayetteville | | 8.09 | | 23,122 | 32.6% | 31,564,234 | 32.6% | 10,304,728 | 21,259,506 |
| Camp Lejeune | | 4.48 | | 19,769 | 50.4% | 17,891,334 | 50.4% | 9,012,501 | 8,878,833 |
| Elm City | | 14.00 | | 79,375 | 64.7% | 49,603,093 | 64.7% | 32,104,089 | 17,499,004 |
| **Total Renewable Units** | | 49.3 | | 235,193 | | 183,495,640 | | 99,267,245 | 84,228,396 |
| **Total System** | | 12,798 | | 61,136,078 | | 16,199,912,175 | | 12,352,293,317 | 3,847,618,858 |
| **Percent of Total** | | | | | | | | 76.2% | 23.8% |

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# Duke Energy Progress, LLC
## Base, Intermediate & Peak
Year: 2018

**DEP Exhibit 9**

| Plant-in-Service | | Factor | Total Company | NCRES | NCRET | NCSGS | NCSGSTCLR | NCSGTM | NCMGS | NCSI | NCLGS |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Base | Energy | Energy | 10,910,794,329 | 2,793,822,085 | 87,691,316 | 337,316,108 | 5,466,042 | 1,444,760,786 | 484,864,804 | 7,413,059 | 195,630,465 |
| | Demand | SCP | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Total | | 10,910,794,329 | 2,793,822,085 | 87,691,316 | 337,316,108 | 5,466,042 | 1,444,760,786 | 484,864,804 | 7,413,059 | 195,630,465 |
| Intermediate | Energy | Energy | 1,270,373,294 | 325,292,262 | 10,210,137 | 39,274,627 | 636,426 | 168,217,406 | 56,454,121 | 863,123 | 22,777,784 |
| | Demand | 12CP | 3,135,153,686 | 984,376,370 | 27,625,185 | 111,887,131 | 1,027,962 | 355,030,238 | 156,161,104 | 2,074,013 | 42,431,719 |
| | Total | | 4,405,526,980 | 1,309,668,632 | 37,835,322 | 151,161,758 | 1,664,388 | 523,247,644 | 212,615,225 | 2,937,135 | 65,209,503 |
| Peaking | Energy | Energy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Demand | SCP | 556,378,327 | 165,349,728 | 4,441,239 | 20,900,577 | 172,020 | 67,647,137 | 28,823,081 | 242,675 | 8,112,443 |
| | Total | | 556,378,327 | 165,349,728 | 4,441,239 | 20,900,577 | 172,020 | 67,647,137 | 28,823,081 | 242,675 | 8,112,443 |
| Storage | Energy | Energy | 71,858,449 | 18,400,101 | 577,535 | 2,221,563 | 35,999 | 9,515,189 | 3,193,318 | 48,822 | 1,288,421 |
| | Demand | SCP | 71,858,449 | 21,355,568 | 573,603 | 2,699,392 | 22,217 | 8,736,894 | 3,722,614 | 31,342 | 1,047,754 |
| | Total | | 143,716,899 | 39,755,669 | 1,151,138 | 4,920,954 | 58,216 | 18,252,083 | 6,915,932 | 80,165 | 2,336,175 |
| Solar | Energy | Energy | 99,267,245 | 25,418,408 | 797,822 | 3,068,928 | 49,730 | 13,144,545 | 4,411,337 | 67,445 | 1,779,861 |
| | Demand | 12CP | 84,228,396 | 26,446,054 | 742,173 | 3,005,937 | 27,617 | 9,538,170 | 4,195,392 | 55,720 | 1,139,962 |
| | Total | | 183,495,640 | 51,864,461 | 1,539,995 | 6,074,865 | 77,347 | 22,682,714 | 8,606,729 | 123,165 | 2,919,823 |
| Total | | | 16,199,912,175 | 4,360,460,575 | 132,659,009 | 520,374,261 | 7,438,014 | 2,076,590,364 | 741,825,772 | 10,796,198 | 274,208,410 |
| Check: | | | | | | | | | | | |
| Plant_BIP_Composite_Factor ==> | | | 100.0000% | 26.9166% | 0.8189% | 3.2122% | 0.0459% | 12.8185% | 4.5792% | 0.0666% | 1.6927% |

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# Duke Energy Progress, LLC

**DEP Exhibit 10**

## Cost of Service Analysis Results
## Production Demand Allocation Factors
## For the twelve months ending December 2018

| | | Peak Responsibility Methods | | | | Energy Weighting Methods | | | | Time Differentiated Method |
|---|---|---|---|---|---|---|---|---|---|---|
| | Load Factor | Summer 1 CP Exhibit3 | Winter 1 CP Exhibit3 | 4CP Exhibit3 | 12CP Exhibit3 | SWPA Exhibit4 | A&E Exhibit5 | A&E 4CP Exhibit6 | A&E Dom Exhibit7 | BIP Exhibit8 |
| **North Carolina:** | | | | | | | | | | |
| Residential | 51.63% | 30.5172% | 38.3159% | 33.2051% | 32.2792% | 30.0550% | 41.7009% | 31.7100% | 27.8609% | 27.7355% |
| SGS | 49.49% | 3.7875% | 3.5686% | 3.6127% | 3.6016% | 3.3859% | 3.9997% | 3.5090% | 3.1883% | 3.2581% |
| MGS | 60.85% | 17.3390% | 12.0421% | 15.6483% | 16.3051% | 16.3220% | 13.7520% | 16.0965% | 16.3072% | 17.3977% |
| SI | 92.93% | 0.0436% | 0.0241% | 0.0554% | 0.0662% | 0.0524% | 0.3771% | 0.0581% | 0.2613% | 0.0666% |
| LGS | 80.28% | 9.8361% | 5.6365% | 8.4253% | 9.3489% | 10.7321% | 6.5313% | 9.4837% | 9.4051% | 12.3316% |
| Lighting | | 0.0045% | 0.0045% | 0.0046% | 0.0049% | 0.3117% | 0.4407% | 0.1287% | 0.6374% | 0.4347% |
| NC Retail | 59.25% | 61.5278% | 59.5918% | 60.9514% | 61.6058% | 60.8591% | 66.8018% | 60.9861% | 57.6602% | 61.2242% |
| NC Wholesale | 58.96% | 28.6661% | 31.5845% | 29.4869% | 28.5332% | 29.1464% | 22.6109% | 29.2320% | 32.4976% | 28.3821% |
| Total NC | 59.16% | 90.1939% | 91.1763% | 90.4383% | 90.1390% | 90.0056% | 89.4127% | 90.2181% | 90.1578% | 89.6063% |
| **South Carolina:** | | | | | | | | | | |
| Residential | 52.20% | 3.9667% | 5.1778% | 4.3745% | 4.2060% | 3.9720% | 5.6226% | 4.1756% | 3.6040% | 3.6358% |
| SGS | 48.07% | 0.5573% | 0.5127% | 0.5559% | 0.5432% | 0.4882% | 0.6619% | 0.5324% | 0.5699% | 0.4719% |
| MGS | 61.60% | 2.5321% | 1.8243% | 2.2811% | 2.3852% | 2.4158% | 2.0602% | 2.3544% | 2.4248% | 2.5656% |
| SI | 72.36% | 0.0240% | 0.0277% | 0.0264% | 0.0247% | 0.0276% | 0.0875% | 0.0270% | 0.0544% | 0.0281% |
| LGS | 89.84% | 2.3649% | 0.9578% | 1.9834% | 2.3735% | 2.6962% | 1.8390% | 2.3305% | 2.7211% | 3.2787% |
| Lighting | | 0.0008% | 0.0008% | 0.0008% | 0.0009% | 0.0701% | 0.0961% | 0.0288% | 0.1405% | 0.0978% |
| SC Retail | 64.75% | 9.4459% | 8.5010% | 9.2222% | 9.5335% | 9.6699% | 10.3673% | 9.4487% | 9.5147% | 10.0780% |
| SC Wholesale | 51.41% | 0.3602% | 0.3227% | 0.3395% | 0.3275% | 0.3245% | 0.2200% | 0.3331% | 0.3275% | 0.3157% |
| Total SC | 64.26% | 9.8061% | 8.8237% | 9.5617% | 9.8610% | 9.9944% | 10.5873% | 9.7819% | 9.8422% | 10.3937% |
| System | | 100.0000% | 100.0000% | 100.0000% | 100.0000% | 100.0000% | 100.0000% | 100.0000% | 100.0000% | 100.0000% |

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# Duke Energy Progress, Inc.

**DEP Exhibit 11**

## Cost of Service Analysis Results
## ROR At Present Rates
## For the twelve months ending December 2018

| | | Peak Responsibility Methods | | | | Energy Weighting Methods | | | | Time Differentiated Method | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Load Factor | Summer 1 CP | Winter 1 CP | 4CP | 12CP | SWPA | A&E | A&E 4CP | A&E Dom | BIP | Average of Returns |
| **North Carolina:** | | | | | | | | | | | |
| Residential | 51.63% | 4.48% | 2.77% | 3.84% | 4.06% | 4.47% | 2.33% | 4.23% | 5.12% | 5.12% | 4.05% |
| SGS | 49.49% | 4.90% | 5.39% | 5.29% | 5.31% | 5.73% | 4.48% | 5.44% | 6.14% | 5.96% | 5.41% |
| MGS | 60.85% | 4.41% | 8.71% | 5.55% | 5.09% | 5.21% | 6.62% | 5.13% | 5.03% | 4.38% | 5.57% |
| SI | 92.93% | 4.93% | 7.16% | 3.86% | 2.99% | 4.31% | -5.42% | 3.76% | -3.78% | 3.15% | 2.33% |
| LGS | 80.28% | 5.16% | 12.92% | 7.10% | 5.78% | 4.53% | 9.60% | 5.55% | 5.67% | 2.87% | 6.58% |
| Lighting | | 8.84% | 8.85% | 8.84% | 8.84% | 7.65% | 7.17% | 8.34% | 6.54% | 7.21% | 8.03% |
| NC Retail | | 4.74% | 5.03% | 4.83% | 4.73% | 4.84% | 4.08% | 4.81% | 5.26% | 4.78% | 4.79% |
| **South Carolina:** | | | | | | | | | | | |
| Residential | 52.20% | 6.14% | 3.61% | 5.20% | 5.59% | 5.98% | 3.18% | 5.70% | 6.96% | 6.93% | 5.48% |
| SGS | 48.07% | 6.03% | 6.73% | 6.04% | 6.27% | 7.14% | 4.69% | 6.40% | 5.85% | 7.39% | 6.28% |
| MGS | 61.60% | 11.38% | 17.67% | 13.27% | 12.48% | 12.45% | 14.89% | 12.54% | 12.06% | 11.23% | 13.11% |
| SI | 72.36% | 18.25% | 15.92% | 16.71% | 17.85% | 16.18% | 1.77% | 16.60% | 7.17% | 16.17% | 14.07% |
| LGS | 89.84% | 5.76% | 22.46% | 8.37% | 5.72% | 4.51% | 9.18% | 5.94% | 4.04% | 1.95% | 7.55% |
| Lighting | | 10.31% | 10.23% | 10.29% | 10.31% | 8.28% | 7.67% | 9.43% | 6.55% | 7.60% | 8.96% |
| SC Retail | | 7.40% | 8.60% | 7.67% | 7.30% | 7.22% | 6.48% | 7.39% | 7.31% | 6.75% | 7.35% |

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# Duke Energy Progress, Inc.

**DEP Exhibit 12**

## Cost of Service Analysis Results
## ROR At Present Rates Index
## For the twelve months ending December 2018

| | | Peak Responsibility Methods | | | | Energy Weighting Methods | | | | Time Differentiated Method |
|---|---|---|---|---|---|---|---|---|---|---|
| | Load Factor | Summer 1 CP | Winter 1 CP | 4CP | 12CP | SWPA | A&E | A&E 4CP | A&E Dom | BIP |
| **North Carolina:** | | | | | | | | | | |
| Residential | 51.63% | 94.58% | 55.15% | 79.66% | 85.76% | 92.33% | 57.08% | 87.88% | 97.22% | 107.17% |
| SGS | 49.49% | 103.36% | 107.26% | 109.56% | 112.24% | 118.25% | 109.76% | 113.16% | 116.65% | 124.74% |
| MGS | 60.85% | 93.04% | 173.27% | 115.03% | 107.52% | 107.66% | 162.15% | 106.57% | 95.59% | 91.65% |
| SI | 92.93% | 103.98% | 142.41% | 79.89% | 63.29% | 88.92% | -132.81% | 78.20% | -71.75% | 65.92% |
| LGS | 80.28% | 108.82% | 256.99% | 147.17% | 122.14% | 93.63% | 235.24% | 115.32% | 107.72% | 60.03% |
| Lighting | | 186.55% | 176.02% | 183.27% | 186.82% | 157.93% | 175.63% | 173.40% | 124.27% | 150.78% |
| NC Retail | | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% |
| **South Carolina:** | | | | | | | | | | |
| Residential | 52.20% | 83.06% | 42.04% | 67.83% | 76.61% | 82.92% | 49.09% | 77.12% | 95.20% | 102.64% |
| SGS | 48.07% | 81.54% | 78.28% | 78.83% | 85.91% | 98.88% | 72.34% | 86.54% | 79.96% | 109.51% |
| MGS | 61.60% | 153.89% | 205.51% | 173.14% | 171.00% | 172.52% | 229.57% | 169.65% | 164.91% | 166.37% |
| SI | 72.36% | 246.66% | 185.18% | 217.93% | 244.67% | 224.21% | 27.37% | 224.52% | 97.99% | 239.56% |
| LGS | 89.84% | 77.86% | 261.24% | 109.16% | 78.32% | 62.46% | 141.57% | 80.38% | 55.21% | 28.95% |
| Lighting | | 139.35% | 119.01% | 134.16% | 141.33% | 114.77% | 118.33% | 127.62% | 89.55% | 112.61% |
| SC Retail | | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% |

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# Duke Energy Progress, LLC

**DEP Exhibit 13**

Pg 1 of 2

**Allocation of Fuel**

**Year:** 2018

Intermediate Method: 12CP  Peak Method: 1CP-Sum

| | Base | | | | Intermediate | | | Peak | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Rate Class | Sales at Gen kWh | Average Annual Hourly Demand KW | Base Period Ratio 70.48% | Base as % of Total | 12 CP Demand KW | Demand Peak Ratio 24.24% | Intermediate as % of Total | 1CP-Sum Peak Demand KW | Demand Ratio 5.28% | Peak as % of Total |
| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) |
| **North Carolina:** | | | | | | | | | | |
| Residential | 17,416,906,173 | 1,988,231 | 1,401,357 | 26.4097% | 3,700,545 | 896,846 | 32.2792% | 3,850,873 | 203,399 | 30.5172% |
| SGS | 2,071,898,933 | 236,518 | 166,704 | 3.1417% | 412,892 | 100,067 | 3.6016% | 477,928 | 25,244 | 3.7875% |
| MGS | 11,663,352,961 | 1,331,433 | 938,428 | 17.6855% | 1,869,253 | 453,023 | 16.3051% | 2,187,952 | 115,565 | 17.3390% |
| SI | 44,807,202 | 5,115 | 3,605 | 0.0679% | 7,584 | 1,838 | 0.0662% | 5,504 | 291 | 0.0436% |
| LGS | 8,728,935,826 | 996,454 | 702,326 | 13.2359% | 1,071,772 | 259,749 | 9.3489% | 1,241,189 | 65,558 | 9.8361% |
| Lighting | 374,947,587 | 42,802 | 30,168 | 0.5685% | 565 | 137 | 0.0049% | 566 | 30 | 0.0045% |
| NC Retail | 40,300,848,683 | 4,600,554 | 3,242,589 | 61.1093% | 7,062,610 | 1,711,660 | 61.6058% | 7,764,011 | 410,087 | 61.5278% |
| NC Wholesale | 18,682,169,387 | 2,132,668 | 1,503,159 | 28.3283% | 3,271,097 | 792,767 | 28.5332% | 3,617,292 | 191,061 | 28.6661% |
| Total NC | 58,983,018,069 | 6,733,221 | 4,745,749 | 89.4376% | 10,333,707 | 2,504,428 | 90.1390% | 11,381,303 | 601,148 | 90.1939% |
| **South Carolina:** | | | | | | | | | | |
| Residential | 2,288,678,709 | 261,265 | 184,146 | 3.4704% | 482,184 | 116,860 | 4.2060% | 500,552 | 26,439 | 3.9667% |
| SGS | 296,123,138 | 33,804 | 23,826 | 0.4490% | 62,273 | 15,092 | 0.5432% | 70,327 | 3,715 | 0.5573% |
| MGS | 1,724,140,413 | 196,820 | 138,724 | 2.6144% | 273,448 | 66,272 | 2.3852% | 319,517 | 16,877 | 2.5321% |
| SI | 19,221,900 | 2,194 | 1,547 | 0.0291% | 2,827 | 685 | 0.0247% | 3,033 | 160 | 0.0240% |
| LGS | 2,348,530,475 | 268,097 | 188,962 | 3.5611% | 272,101 | 65,945 | 2.3735% | 298,421 | 15,762 | 2.3649% |
| Lighting | 84,386,208 | 9,633 | 6,790 | 0.1280% | 102 | 25 | 0.0009% | 101 | 5 | 0.0008% |
| SC Retail | 6,761,080,842 | 771,813 | 543,994 | 10.2520% | 1,092,936 | 264,879 | 9.5335% | 1,191,950 | 62,958 | 9.4459% |
| SC Wholesale | 204,676,844 | 23,365 | 16,468 | 0.3104% | 37,547 | 9,100 | 0.3275% | 45,452 | 2,401 | 0.3602% |
| Total SC | 6,965,757,686 | 795,178 | 560,462 | 10.5624% | 1,130,483 | 273,978 | 9.8610% | 1,237,402 | 65,358 | 9.8061% |
| SYSTEM | 65,948,775,755 | 7,528,399 | 5,306,210 | 100.0000% | 11,464,190 | 2,778,406 | 100.0000% | 12,618,705 | 666,506 | 100.0000% |

Hours in Year: 8,760

column(2) - values are from DataNonFirm worksheet

column(3)=column(2) / 8,760

column(4)=column(3) x 70.48%

column(5)=column(4) / 5,306,210

Column(6) - values are from DEP Exhibit 3

column(7)=column(6) x 24.24%

column(8)=column(7) / 2,778,406

column(9) - values are from DEP Exhibit 3

column(10)=column(9) x 5.28%

column(11)=column(10) / 666,506

| $000 | Plnt-in-Svc | Accum Depr | Net Plant | Ratio |
|---|---|---|---|---|
| Base | 10,910,794 | (4,224,151) | 6,686,644 | 70.48% |
| Intermediate | 4,497,544 | (2,198,334) | 2,299,210 | 24.24% |
| Peak | 791,574 | (290,484) | 501,090 | 5.28% |
| | 16,199,912 | (6,712,968) | 9,486,944 | 100.00% |

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**Duke Energy Progress, LLC** **DEP Exhibit 13**
**Allocation of Fuel** Pg 2 of 2
**Year:** 2018

| | |
|---|---|
| Generation Fuel | 1,401,869,034 |
| Purchased Power Fuel | 203,772,134 |
| | 1,605,641,168 |

| Rate | Base Fuel | Intermediate Fuel | Peak Fuel | Total | Average Fuel ($/kWh) | Increase (Decrease) Over Average |
|---|---|---|---|---|---|---|
| Class | 669,623,378 | 828,366,874 | 107,650,916 | 1,605,641,168 | 0.02435 | |
| (1) | 669,623,378 x (5) | 828,366,874 x (8) | 107,650,916 x (11) | (15) | (16) | (17)=(15)-(16) |
| **North Carolina:** | | | | | | |
| Residential | 176,845,854 | 267,389,943 | 32,852,022 | 477,087,819 | 424,045,803 | 53,042,015 |
| SGS | 21,037,418 | 29,834,302 | 4,077,233 | 54,948,954 | 50,444,094 | 4,504,860 |
| MGS | 118,426,062 | 135,066,417 | 18,665,550 | 272,158,029 | 283,965,236 | -11,807,208 |
| SI | 454,958 | 547,993 | 46,954 | 1,049,906 | 1,090,912 | -41,006 |
| LGS | 88,630,902 | 77,442,895 | 10,588,655 | 176,662,452 | 212,521,591 | -35,859,139 |
| Lighting | 3,807,101 | 40,816 | 4,824 | 3,852,742 | 9,128,771 | -5,276,029 |
| NC Retail | 409,202,296 | 510,322,366 | 66,235,239 | 985,759,900 | 981,196,406 | 4,563,494 |
| NC Wholesale | 189,692,943 | 236,359,318 | 30,859,329 | 456,911,590 | 454,850,904 | 2,060,686 |
| Total NC | 598,895,239 | 746,681,684 | 97,094,568 | 1,442,671,490 | 1,436,047,310 | 6,624,180 |
| **South Carolina:** | | | | | | |
| Residential | 23,238,532 | 34,841,089 | 4,270,240 | 62,349,861 | 55,721,986 | 6,627,875 |
| SGS | 3,006,742 | 4,499,682 | 599,967 | 8,106,391 | 7,209,649 | 896,742 |
| MGS | 17,506,386 | 19,758,537 | 2,725,814 | 39,990,737 | 41,977,289 | -1,986,552 |
| SI | 195,173 | 204,299 | 25,871 | 425,344 | 467,992 | -42,648 |
| LGS | 23,846,249 | 19,661,206 | 2,545,845 | 46,053,300 | 57,179,184 | -11,125,884 |
| Lighting | 856,831 | 7,344 | 861 | 865,036 | 2,054,534 | -1,189,497 |
| SC Retail | 68,649,914 | 78,972,156 | 10,168,598 | 157,790,668 | 164,610,633 | -6,819,965 |
| SC Wholesale | 2,078,225 | 2,713,035 | 387,750 | 5,179,010 | 4,983,225 | 195,785 |
| Total SC | 70,728,139 | 81,685,191 | 10,556,348 | 162,969,678 | 169,593,858 | -6,624,180 |
| SYSTEM | 669,623,378 | 828,366,874 | 107,650,916 | 1,605,641,168 | 1,605,641,168 | 0 |

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# Duke Energy Progress, Inc.

**DEP Exhibit 14**

Pg 1 of 2

## Cost of Service Analysis Results
## ROR At Present Rates - After Fuel Adjustment
## For the twelve months ending December 2018

| | After Fuel Adjustment | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Peak Responsibility Methods | | | | Energy Weighting Methods | | | | Time Differentiated Method |
| | Summer 1 CP | Winter 1 CP | 4CP | 12CP | SWPA | A&E | A&E 4CP | A&E Dom | BIP |
| **North Carolina:** | | | | | | | | | |
| Residential | 4.48% | 2.77% | 3.84% | 4.06% | 3.58% | 1.55% | 3.34% | 4.18% | 4.19% |
| SGS | 4.90% | 5.39% | 5.29% | 5.31% | 5.06% | 3.86% | 4.79% | 5.46% | 5.29% |
| MGS | 4.41% | 8.71% | 5.55% | 5.09% | 5.75% | 7.19% | 5.65% | 5.55% | 4.88% |
| SI | 4.93% | 7.16% | 3.86% | 2.99% | 4.56% | -5.32% | 4.01% | -3.65% | 3.39% |
| LGS | 5.16% | 12.92% | 7.10% | 5.78% | 7.29% | 13.19% | 8.44% | 8.59% | 5.30% |
| Lighting | 8.84% | 8.85% | 8.84% | 8.84% | 8.89% | 8.37% | 9.63% | 7.71% | 8.42% |
| NC Retail | 4.74% | 5.03% | 4.83% | 4.73% | 4.80% | 4.04% | 4.77% | 5.22% | 4.74% |
| **South Carolina:** | | | | | | | | | |
| Residential | 6.14% | 3.61% | 5.20% | 5.59% | 5.08% | 2.43% | 4.81% | 6.01% | 5.98% |
| SGS | 6.03% | 6.73% | 6.04% | 6.27% | 6.26% | 3.93% | 5.56% | 5.03% | 6.51% |
| MGS | 11.38% | 17.67% | 13.27% | 12.48% | 13.08% | 15.58% | 13.18% | 12.69% | 11.83% |
| SI | 18.25% | 15.92% | 16.71% | 17.85% | 17.05% | 2.19% | 17.48% | 7.75% | 17.03% |
| LGS | 5.76% | 22.46% | 8.37% | 5.72% | 8.11% | 13.74% | 9.83% | 7.50% | 4.95% |
| Lighting | 10.31% | 10.23% | 10.29% | 10.31% | 10.08% | 9.40% | 11.34% | 8.20% | 9.33% |
| SC Retail | 7.40% | 8.60% | 7.67% | 7.30% | 7.66% | 6.91% | 7.84% | 7.76% | 7.18% |

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# Duke Energy Progress, Inc.

**DEP Exhibit 14**

## Cost of Service Analysis Results

Pg 2 of 2

## ROR At Present Rates - After Fuel Adj less Before Fuel Adj

## For the twelve months ending December 2018

| | After Fuel Adjustment less Before Fuel Adjustment | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Peak Responsibility Methods | | | | Energy Weighting Methods | | | | Time Differentiated Method |
| | Summer 1 CP | Winter 1 CP | 4CP | 12CP | SWPA | A&E | A&E 4CP | A&E Dom | BIP |
| **North Carolina:** | | | | | | | | | |
| Residential | 0.00% | 0.00% | 0.00% | 0.00% | -0.89% | -0.77% | -0.89% | -0.94% | -0.94% |
| SGS | 0.00% | 0.00% | 0.00% | 0.00% | -0.67% | -0.62% | -0.66% | -0.69% | -0.68% |
| MGS | 0.00% | 0.00% | 0.00% | 0.00% | 0.53% | 0.57% | 0.52% | 0.52% | 0.50% |
| SI | 0.00% | 0.00% | 0.00% | 0.00% | 0.26% | 0.09% | 0.25% | 0.12% | 0.24% |
| LGS | 0.00% | 0.00% | 0.00% | 0.00% | 2.76% | 3.59% | 2.90% | 2.92% | 2.43% |
| Lighting | 0.00% | 0.00% | 0.00% | 0.00% | 1.24% | 1.21% | 1.28% | 1.17% | 1.21% |
| NC Retail | 0.00% | 0.00% | 0.00% | 0.00% | -0.04% | -0.04% | -0.04% | -0.04% | -0.04% |
| **South Carolina:** | | | | | | | | | |
| Residential | 0.00% | 0.00% | 0.00% | 0.00% | -0.90% | -0.76% | -0.89% | -0.96% | -0.95% |
| SGS | 0.00% | 0.00% | 0.00% | 0.00% | -0.88% | -0.76% | -0.84% | -0.82% | -0.88% |
| MGS | 0.00% | 0.00% | 0.00% | 0.00% | 0.64% | 0.69% | 0.64% | 0.62% | 0.60% |
| SI | 0.00% | 0.00% | 0.00% | 0.00% | 0.87% | 0.42% | 0.88% | 0.59% | 0.86% |
| LGS | 0.00% | 0.00% | 0.00% | 0.00% | 3.61% | 4.56% | 3.89% | 3.46% | 2.99% |
| Lighting | 0.00% | 0.00% | 0.00% | 0.00% | 1.80% | 1.73% | 1.91% | 1.65% | 1.73% |
| SC Retail | 0.00% | 0.00% | 0.00% | 0.00% | 0.45% | 0.42% | 0.45% | 0.45% | 0.43% |

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# Duke Energy Progress, LLC

**DEP Exhibit 15**

**Single Summer CP Method**

**Unit Cost Report**

**Year:** 2018

| | Demand | UNIT | COSTS | Energy | UNIT | COSTS | CUSTOMER | UNIT | COSTS |
|---|---|---|---|---|---|---|---|---|---|
| | Revenue | KW [1] | $/KW/Mo | Revenue | Annual KWH [2] | Cents/KWH | Revenue | Customers [3] | $/Cust/Mo |
| **North Carolina:** | | | | | | | | | |
| Residential | 875,269,766 | 3,690,872 | 19.76 | 576,845,306 | 16,666,046,589 | 3.46 | 398,044,753 | 1,199,988 | 27.64 |
| SGS | 107,683,501 | 458,072 | 19.59 | 70,868,603 | 1,982,596,401 | 3.57 | 57,038,037 | 166,073 | 28.62 |
| MGS | 459,217,424 | 2,099,254 | 18.23 | 406,986,841 | 11,178,964,878 | 3.64 | 16,227,247 | 38,728 | 34.92 |
| SI | 3,192,168 | 5,292 | 50.27 | 1,635,108 | 43,075,313 | 3.80 | 418,939 | 851 | 41.02 |
| LGS | 239,150,351 | 1,204,485 | 16.55 | 264,167,036 | 8,457,791,022 | 3.12 | 1,051,493 | 279 | 314.07 |
| Lighting | 86,223,218 | - | N/A | 8,422,839 | 358,793,310 | N/A | 743,463 | 858 | N/A |
| TOTAL RETAIL | $ 1,770,736,430 | 7,457,976 | 19.79 | $ 1,328,925,733 | 38,687,267,513 | 3.44 | $ 473,523,933 | 1,406,777 | 28.05 |

[1] Allocation Factor: All - Production Demand at Meter

[2] Allocation Factor: All - Kwhr at Meter

[3] Allocation Factor: All - Number of Customers

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# Duke Energy Progress, LLC

**DEP Exhibit 16**

## Single Winter CP Method

**Year:** 2018

| | Demand | UNIT | COSTS | Energy | UNIT | COSTS | CUSTOMER | UNIT | COSTS |
|---|---|---|---|---|---|---|---|---|---|
| | Revenue | KW [1] | $/KW/Mo | Revenue | Annual KWH [2] | Cents/KWH | Revenue | Customers [3] | $/Cust/Mo |
| **North Carolina:** | | | | | | | | | |
| Residential | 953,520,423 | 5,516,803 | 14.40 | 571,085,119 | 16,666,046,589 | 3.43 | 368,187,369 | 1,199,988 | 25.57 |
| SGS | 103,380,005 | 513,820 | 16.77 | 70,905,407 | 1,982,596,401 | 3.58 | 57,403,580 | 166,073 | 28.80 |
| MGS | 398,560,764 | 1,735,671 | 19.14 | 415,471,326 | 11,178,964,878 | 3.72 | 18,828,811 | 38,728 | 40.52 |
| SI | 2,909,962 | 3,477 | 69.75 | 1,652,317 | 43,075,313 | 3.84 | 449,222 | 851 | 43.99 |
| LGS | 192,419,558 | 822,814 | 19.49 | 275,544,967 | 8,457,791,022 | 3.26 | 1,187,540 | 279 | 354.70 |
| Lighting | 85,097,655 | - | N/A | 8,406,302 | 358,793,310 | N/A | 734,045 | 858 | N/A |
| TOTAL RETAIL | $ 1,735,888,367 | 8,592,584 | 16.84 | $ 1,343,065,439 | 38,687,267,513 | 3.47 | $ 446,790,566 | 1,406,777 | 26.47 |

[1] Allocation Factor: All - Production Demand at Meter

[2] Allocation Factor: All - Kwhr at Meter

[3] Allocation Factor: All - Cust Num

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# Duke Energy Progress, LLC

**DEP Exhibit 17**

## 4 CP - 2 Summer, 2 Winter Method

**Year:** 2018

| | Demand | UNIT | COSTS | Energy | UNIT | COSTS | CUSTOMER | UNIT | COSTS |
|---|---|---|---|---|---|---|---|---|---|
| | Revenue | KW [1] | $/KW/Mo | Revenue | Annual KWH [2] | Cents/KWH | Revenue | Customers [3] | $/Cust/Mo |
| **North Carolina:** | | | | | | | | | |
| Residential | 904,164,120 | 4,068,413 | 18.52 | 574,760,982 | 16,666,046,589 | 3.45 | 387,276,815 | 1,199,988 | 26.89 |
| SGS | 104,942,612 | 442,638 | 19.76 | 70,935,079 | 1,982,596,401 | 3.58 | 57,637,898 | 166,073 | 28.92 |
| MGS | 440,247,063 | 1,919,270 | 19.12 | 409,193,213 | 11,178,964,878 | 3.66 | 16,919,899 | 38,728 | 36.41 |
| SI | 3,316,114 | 6,807 | 40.60 | 1,624,540 | 43,075,313 | 3.77 | 400,441 | 851 | 39.21 |
| LGS | 224,311,616 | 1,045,436 | 17.88 | 266,983,866 | 8,457,791,022 | 3.16 | 1,073,731 | 279 | 320.71 |
| Lighting | 85,890,173 | - | N/A | 8,417,865 | 358,793,310 | N/A | 739,070 | 858 | N/A |
| TOTAL RETAIL | $ 1,762,871,697 | 7,482,564 | 19.63 | $ 1,331,915,545 | 38,687,267,513 | 3.44 | $ 464,047,854 | 1,406,777 | 27.49 |

[1] Allocation Factor: All - Production Demand at Meter

[2] Allocation Factor: All - Kwhr at Meter

[3] Allocation Factor: All - Cust Num

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# Duke Energy Progress, LLC

**DEP Exhibit 18**

## 12 CP Method

**Year:** 2018

| | Demand | UNIT | COSTS | Energy | UNIT | COSTS | CUSTOMER | UNIT | COSTS |
|---|---|---|---|---|---|---|---|---|---|
| | Revenue | KW [1] | $/KW/Mo | Revenue | Annual KWH [2] | Cents/KWH | Revenue | Customers [3] | $/Cust/Mo |
| **North Carolina:** | | | | | | | | | |
| Residential | 897,134,090 | 3,546,791 | 21.08 | 575,668,610 | 16,666,046,589 | 3.45 | 391,906,233 | 1,199,988 | 27.22 |
| SGS | 105,248,567 | 395,739 | 22.16 | 70,966,056 | 1,982,596,401 | 3.58 | 57,892,680 | 166,073 | 29.05 |
| MGS | 448,887,340 | 1,793,487 | 20.86 | 408,445,948 | 11,178,964,878 | 3.65 | 16,657,058 | 38,728 | 35.84 |
| SI | 3,457,304 | 7,291 | 39.51 | 1,617,715 | 43,075,313 | 3.76 | 388,570 | 851 | 38.05 |
| LGS | 234,465,486 | 1,040,008 | 18.79 | 265,110,522 | 8,457,791,022 | 3.13 | 1,059,128 | 279 | 316.35 |
| Lighting | 86,262,000 | - | N/A | 8,423,207 | 358,793,310 | N/A | 740,233 | 858 | N/A |
| TOTAL RETAIL | $ 1,775,454,786 | 6,783,316 | 21.81 | $ 1,330,232,057 | 38,687,267,513 | 3.44 | $ 468,643,903 | 1,406,777 | 27.76 |

[1] Allocation Factor: All - Production Demand at Meter

[2] Allocation Factor: All - Kwhr at Meter

[3] Allocation Factor: All - Cust Num

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# Duke Energy Progress, LLC

**DEP Exhibit 19**

**SWPA Method**

**Year:** 2018

| | Demand | UNIT | COSTS | Energy | UNIT | COSTS | CUSTOMER | UNIT | COSTS |
|---|---|---|---|---|---|---|---|---|---|
| | Revenue | KW [1] | $/KW/Mo | Revenue | Annual KWH [2] | Cents/KWH | Revenue | Customers [3] | $/Cust/Mo |
| **North Carolina:** | | | | | | | | | |
| Residential | 872,484,135 | 3,690,872 | 19.70 | 576,472,719 | 16,666,046,589 | 3.46 | 396,324,162 | 1,199,988 | 27.52 |
| SGS | 102,395,700 | 458,072 | 18.63 | 71,035,619 | 1,982,596,401 | 3.58 | 58,469,652 | 166,073 | 29.34 |
| MGS | 444,235,594 | 2,099,254 | 17.63 | 408,437,669 | 11,178,964,878 | 3.65 | 16,833,962 | 38,728 | 36.22 |
| SI | 3,248,125 | 5,292 | 51.15 | 1,628,456 | 43,075,313 | 3.78 | 407,206 | 851 | 39.88 |
| LGS | 242,360,241 | 1,204,485 | 16.77 | 263,126,857 | 8,457,791,022 | 3.11 | 1,040,709 | 279 | 310.84 |
| Lighting | 87,936,312 | - | N/A | 8,326,583 | 358,793,310 | N/A | 728,636 | 858 | N/A |
| TOTAL RETAIL | $ 1,752,660,106 | 7,457,976 | 19.58 | $ 1,329,027,903 | 38,687,267,513 | 3.44 | $ 473,804,328 | 1,406,777 | 28.07 |

[1] Allocation Factor: All - Production Demand at Meter

[2] Allocation Factor: All - Kwhr at Meter

[3] Allocation Factor: All - Cust Num

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# Duke Energy Progress, LLC

**DEP Exhibit 20**

## Average & Excess Method

## Unit Cost Report

**Year:** 2018

| | Demand | UNIT | COSTS | Energy | UNIT | COSTS | CUSTOMER | UNIT | COSTS |
|---|---|---|---|---|---|---|---|---|---|
| | Revenue | KW [1] | $/KW/Mo | Revenue | Annual KWH [2] | Cents/KWH | Revenue | Customers [3] | $/Cust/Mo |
| **North Carolina:** | | | | | | | | | |
| Residential | 1,024,694,579 | 4,754,335 | 17.96 | 572,893,970 | 16,666,046,589 | 3.44 | 376,639,206 | 1,199,988 | 26.16 |
| SGS | 113,585,322 | 456,013 | 20.76 | 70,946,657 | 1,982,596,401 | 3.58 | 57,724,378 | 166,073 | 28.97 |
| MGS | 440,409,065 | 1,567,875 | 23.41 | 413,458,342 | 11,178,964,878 | 3.70 | 18,095,087 | 38,728 | 38.94 |
| SI | 6,502,745 | 42,990 | 12.61 | 1,552,048 | 43,075,313 | 3.60 | 274,391 | 851 | 26.87 |
| LGS | 216,184,142 | 744,638 | 24.19 | 271,825,214 | 8,457,791,022 | 3.21 | 1,155,060 | 279 | 345.00 |
| Lighting | 92,086,845 | - | N/A | 8,343,489 | 358,793,310 | N/A | 765,389 | 858 | N/A |
| TOTAL RETAIL | $ 1,893,462,698 | 7,565,851 | 20.86 | $ 1,339,019,721 | 38,687,267,513 | 3.46 | $ 454,653,511 | 1,406,777 | 26.93 |

[1] Allocation Factor: All - Production Demand at Meter

[2] Allocation Factor: All - Kwhr at Meter

[3] Allocation Factor: All - Cust Num

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# Duke Energy Progress, LLC

**DEP Exhibit 21**

## Average & Excess 4CP Method

## Unit Cost Report

**Year:** 2018

| | Demand | UNIT | COSTS | Energy | UNIT | COSTS | CUSTOMER | UNIT | COSTS |
|---|---|---|---|---|---|---|---|---|---|
| | Revenue | KW [1] | $/KW/Mo | Revenue | Annual KWH [2] | Cents/KWH | Revenue | Customers [3] | $/Cust/Mo |
| **North Carolina:** | | | | | | | | | |
| Residential | 884,760,019 | 2,096,469 | 35.17 | 575,885,968 | 16,666,046,589 | 3.46 | 393,185,537 | 1,199,988 | 27.30 |
| SGS | 104,156,336 | 231,995 | 37.41 | 70,976,221 | 1,982,596,401 | 3.58 | 57,978,782 | 166,073 | 29.09 |
| MGS | 446,848,626 | 1,064,200 | 34.99 | 408,323,831 | 11,178,964,878 | 3.65 | 16,712,635 | 38,728 | 35.96 |
| SI | 3,326,941 | 3,843 | 72.14 | 1,623,847 | 43,075,313 | 3.77 | 399,193 | 851 | 39.09 |
| LGS | 235,384,079 | 627,005 | 31.28 | 264,674,754 | 8,457,791,022 | 3.13 | 1,053,995 | 279 | 314.81 |
| Lighting | 86,807,112 | - | N/A | 8,380,336 | 358,793,310 | N/A | 735,080 | 858 | N/A |
| TOTAL RETAIL | $ 1,761,283,113 | 4,023,512 | 36.48 | $ 1,329,864,956 | 38,687,267,513 | 3.44 | $ 470,065,222 | 1,406,777 | 27.85 |

[1] Allocation Factor: All - Production Demand at Meter

[2] Allocation Factor: All - Kwhr at Meter

[3] Allocation Factor: All - Cust Num

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# Duke Energy Progress, LLC

**DEP Exhibit 22**

## Average & Excess - Dominion Method

## Unit Cost Report

**Year:** 2018

| | Demand | UNIT | COSTS | Energy | UNIT | COSTS | CUSTOMER | UNIT | COSTS |
|---|---|---|---|---|---|---|---|---|---|
| | Revenue | KW [1] | $/KW/Mo | Revenue | Annual KWH [2] | Cents/KWH | Revenue | Customers [3] | $/Cust/Mo |
| **North Carolina:** | | | | | | | | | |
| Residential | 824,803,227 | 3,515,681 | 19.55 | 576,942,951 | 16,666,046,589 | 3.46 | 399,105,416 | 1,199,988 | 27.72 |
| SGS | 98,257,364 | 402,325 | 20.35 | 71,011,916 | 1,982,596,401 | 3.58 | 58,412,828 | 166,073 | 29.31 |
| MGS | 438,945,973 | 2,057,753 | 17.78 | 407,087,924 | 11,178,964,878 | 3.64 | 16,104,711 | 38,728 | 34.65 |
| SI | 4,982,535 | 32,970 | 12.59 | 1,545,900 | 43,075,313 | 3.59 | 273,649 | 851 | 26.80 |
| LGS | 229,796,645 | 1,186,807 | 16.14 | 264,040,975 | 8,457,791,022 | 3.12 | 1,015,972 | 279 | 303.46 |
| Lighting | 88,287,976 | - | N/A | 8,226,969 | 358,793,310 | N/A | 710,109 | 858 | N/A |
| TOTAL RETAIL | $ 1,685,073,722 | 7,195,535 | 19.52 | $ 1,328,856,635 | 38,687,267,513 | 3.43 | $ 475,622,685 | 1,406,777 | 28.17 |

[1] Allocation Factor: All - Production Demand at Meter

[2] Allocation Factor: All - Kwhr at Meter

[3] Allocation Factor: All - Cust Num

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**Duke Energy Carolinas and Duke Energy Progress** **DE Exhibit 1**

Comprehensive Cost of Service Study

Strengths and Weaknesses Matrix

| Line No. | Description | SCP | WCP | 4CP | 12CP | SWPA | A&E | A&E (4CP) | A&E (Dom) | BIP |
|---|---|---|---|---|---|---|---|---|---|---|
| | STRENGTHS | | | | | | | | | |
| 1 | Multiple CP methods are commonly used and accepted by FERC | | | | X | | | | | |
| 2 | Encourages shifting of usage to off-peak times | X | X | | | | | | | |
| 3 | Easy for customer to understand | X | X | | | | | | | |
| 4 | Data requirements are not burdensome | X | X | X | X | X | | | | |
| 5 | Calculations are relatively simple | X | X | X | X | X | | | | |
| 6 | Captures seasonal variation in a utility's loads | | | X | X | | | | | |
| 7 | Creates a more normalizing or smoothing effect from year to year | | | X | X | | | | | |
| 8 | Reflects the concept that the utility called on almost all of its generating resources during the highest peak months but only its more efficient generating units during the lower peak periods (The resulting allocated costs recognize/consider the capacity/energy tradeoff for the twelve monthly peaks under evaluation) | | | | X | | | | | |
| 9 | Since each monthly peak is weighted equally in calculating the annual average peak, peaks caused by extreme weather in any month are moderated. | | | | X | | | | | |
| 10 | Recognizes that generation is built to meet both peak demands and energy usage (to meet load both 'instantaneously' and 'over time') | | | | | X | X | X | X | X |
| 11 | Takes into consideration the generation facilitates needed to serve the company's "average load," as well as its "peak load", in assigning cost responsibility | | | | | X | X | X | X | |
| 12 | Since excess demand is peak demand less average demand, it avoids the double counting issue prevalent in the peak and average methods | | | | | | X | X | X | |
| 13 | Provides incentive for customers with low load factors to lower demand which aligns with the company's pricing that encourages off-peak usage | | | | | | | X | | |
| 14 | Does not penalize classes of customers for incurring peak demands during off peak months | | | | | | | X | | |
| 15 | Recognizes capacity/energy tradeoff | | | | | X | X | X | X | X |
| 16 | Specifically recognizes the mix of a utility's resources used to serve the varying demands throughout the year | | | | | | | | | X |
| 17 | Permits the weighting of expensive base load plants versus less expensive peak load units | | | | | | | | | X |
| 18 | Method can be modified to accommodate the diversity of generation resources | | | | | | | | | X |

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**Duke Energy Carolinas and Duke Energy Progress** **DE Exhibit 2**

Comprehensive Cost of Service Study

Strengths and Weaknesses Matrix

| Line No. | Description | SCP | WCP | 4CP | 12CP | SWPA | A&E | A&E (4CP) | A&E (Dom) | BIP |
|---|---|---|---|---|---|---|---|---|---|---|
| | WEAKNESSES | | | | | | | | | |
| 19 | Ignores capacity/energy trade-off | X | X | X | X | | | | | |
| 20 | Assigns same weight to expensive base load unit that provides energy throughout the year as it does a relatively inexpensive peaking unit that provides energy for only a few hours a year | X | X | X | X | | | | | |
| 21 | Ignores use of generation system other than the peak hour of the year | X | X | X | X | | | | | |
| 22 | Results can be unstable from year-to year due to the peak being driven by severe weather events | X | X | X | X | | | | | |
| 23 | Suffers from the "free-ride" phenomenon where, for ex., lighting class maybe not be assigned any cost | X | X | X | X | | | | | |
| 24 | Utilities do not design their generating systems to meet twelve peaks | | | | X | | | | | |
| 25 | Significant amount of fixed capacity cost is allocated based on energy consumption which harms high-load factor customers | | | | | X | X | X | X | X |
| 26 | No consideration is given to the lower fuel costs incurred during off-peak hours | | | | | X | X | X | X | X |
| 27 | Calculation double counts average load (this occurs because the peak demand segment contains an average load component) | | | | | X | | | | |
| 28 | Moves peak demand cost responsibility towards lower load factor customer classes | | | | | | X | X | X | |
| 29 | Can produce results that are an outlier as compared to other methods | | | | | | | | | X |
| 30 | Fails to consider that baseload units are not simply operated for purposes of providing energy, but also contribute towards meeting peak demand | | | | | | | | | X |
| 31 | Penalizes high load factor customers that use the system in a more efficient manner | | | | | X | | | | X |
| 32 | Inherently assumes that the test year use of each generator (B, I, or P) reflects the way in which plant will be used over its remaining operating life | | | | | | | | | X |
| 33 | Method has not been adopted by any state commission | | | | | | | | | X |
| 34 | Method requires a set of decisions about the definition of the generation classes and the classification percentage for each class | | | | | | | | | X |

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**DE Exhibit 3**

# Duke Energy Carolinas, LLC - Docket No. E-7, Sub 1214
# Duke Energy Progress, LLC - Docket No. E-2, Sub 1219

## Cost of Service Study - Participants

| | Participant | Organization |
|---|---|---|
| 1 | Laura Bateman | Duke Energy |
| 2 | Ginny Boucher | Duke Energy |
| 3 | Kim H Smith | Duke Energy |
| 4 | Kaari Beard | Duke Energy Carolinas |
| 5 | Karen Keller | Duke Energy Carolinas |
| 6 | Sumita Deshmukh | Duke Energy Progress |
| 7 | LaWanda Jiggetts | Duke Energy Progress |
| 8 | Skip Seekamp | Duke Energy |
| 9 | Paul Halstead | Duke Energy |
| 10 | Brad Harris | Duke Energy |
| 11 | Jack Floyd | Public Staff - North Carolina Utilities Commission |
| 12 | James McLawhorn | Public Staff - North Carolina Utilities Commission |
| 13 | Lucy Edmondson | Public Staff - North Carolina Utilities Commission |
| 14 | Bob Hinton | Public Staff - North Carolina Utilities Commission |
| 15 | Benjamin Lozier | Public Staff - North Carolina Utilities Commission |
| 16 | Mike Maness | Public Staff - North Carolina Utilities Commission |
| 17 | Jeff Thomas | Public Staff - North Carolina Utilities Commission |
| 18 | Tommy C. Williamson | Public Staff - North Carolina Utilities Commission |
| 19 | David Williamson | Public Staff - North Carolina Utilities Commission |
| 20 | Michelle Boswell | Public Staff - North Carolina Utilities Commission |
| 21 | Christina D. Cress | CIGFUR |
| 22 | Nick Phillips | Brubaker & Associates, Inc. |
| 23 | Steve Castracane | Messer |
| 24 | David L. Neal | SELC |
| 25 | Dennis Derricks | Facebook |
| 26 | Peter H. Ledford | NC Sustainable Energy Association |
| 27 | Ben Smith | NC Sustainable Energy Association |
| 28 | Michael Seaman-Huynh | South Carolina Office of Regulatory Staff |
| 29 | Anthony Sandonato | South Carolina Office of Regulatory Staff |
| 30 | Tyler Fitch | Vote Solar |
| 31 | Hasala Dharmawardena | |
| 32 | Kevin O'Donnell | CUCA |
| 33 | Margaret A. Force | NC DOJ - Attorney General |
| 34 | Teresa L. Townsend | NC DOJ - Attorney General |

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**CIGFUR Exhibit 1**

CIGFUR's primary concerns with the Base, Intermediate and Peaking ("BIP") method as proposed and discussed during the Cost of Service Study Group meeting on July 13, 2021:

- The BIP methodology is not an accepted method of allocating production plant and should not be endorsed by this Study Group. Moreover, the inherent flexibility built into this method can lead to a number of arguably arbitrary decisions surrounding implementation of this methodology, which will be ripe fodder for opponents in a rate case and/or a legal challenge on appeal.

    - "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." RAP, Electric Cost Allocation for a New Era, p. 113.

- The BIP methodology as interpreted would be inconsistent with system planning in that it minimizes the need for, and value of, capacity by over-allocating on an energy basis. Over-classifying costs as energy-related in turn leads to an over-recovery via energy charges, which in turn results in a disproportionate assignment of costs to the industrial class, and specifically to high load factor customers within that class.

- The methodology as interpreted, and as applied, would deviate from cost causation principles (and Jack Floyd conceded as much during the call on July 13, 2021 when he stated that higher load customers do not support having to pay a large share for peak resources that are not driven by those same customers' use of such resources).

- Normally, a utility doesn't plan to construct intermediate generation, most often it is plant that has aged and no longer efficient. Allocating such plant as if it were planned is problematic at best.

- A significant issue with this method and other methods that allocate relatively more base load plant to high load factor classes is the fuel symmetry problem. The allocation of fuel costs would require a great deal of additional study so that lower fuel cost is allocated to the classes that received the higher allocation of base load plant. This would require a great deal of modeling and study and based on prior experience would burden this process with an allocation method that is unproven and not seriously considered for adoption by this commission or most others, if any.

- See also Rebuttal Testimony of William R. Hopkins, Duke Energy Carolinas, LLC, Docket No. E-7, Sub 909, pp. 14-16; https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=9d581cc4-3018-4ef4-973f-69822db9e57f.

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March 31, 2022

**VIA ELECTRONIC FILING**

Ms. A. Shonta Dunston
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

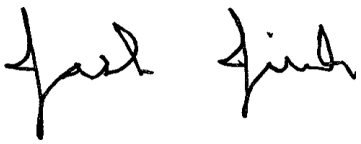
**RE: Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Rate Design Study Roadmap**
**Docket Nos. E-7, Sub 1214 and E-2, Sub 1219**

Dear Ms. Dunston:

Pursuant to the North Carolina Utilities Commission's March 31, 2021 *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice* in Docket No. E-7, Sub 1214 and its April 16, 2021 *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice* in Docket No. E-2, Sub 1219, Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (collectively "Duke Energy") enclose for filing in the above-referenced dockets Duke Energy's Comprehensive Rate Design Study roadmap and timeline for proposing new rate designs and identifying areas for additional study.

If you have any questions, please do not hesitate to contact me. Thank you for your attention to this matter.

Sincerely,



Jack E. Jirak

Enclosure

cc: Parties of Record

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# Comprehensive Rate Design Study Roadmap

## Duke Energy

**March 31, 2022**

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# 1 Executive Summary

Rate design modernization options present valuable opportunities for North Carolina, including customers of all classes. Pricing and rate design seek to achieve multiple goals that must be carefully balanced. Rate design must collect the revenue requirements of the Companies in a manner that is not unduly discriminatory while also encouraging beneficial consumption patterns to improve system efficiency and keep costs low for all customers. Accordingly, rate design often involves complicated tradeoffs that must consider both system dynamics and wide-ranging differences across customer classes and individual customers, particularly when considering varying levels of energy technology adoption. Several factors led to the intensive rate design review, including:

- Technology Support – The Companies' investments in smart meters, data analytics capabilities, and a new billing system enable more potential options for creative and tailored rate designs to match increasingly diverse customer expectations. Not only is data more available than ever before, but we can now extract actionable insights and have the sophisticated tools necessary to implement improvements based on the findings.
- Desire for Options – Customers desire and expect more pricing options and more control over energy costs.
- Grid Dynamics – The electric grid is becoming more complex and dynamic with the current energy transition, and solutions must include both supply-side and demand-side considerations, including novel pricing approaches.

Importantly, rate design must be customer-centric. An elegantly designed rate with novel pricing features but with zero participation or interest from customers is worthless – thus, customer ideas and constructive dialogue are necessary to developing and improving rate designs that will achieve the intended purposes. The findings and ideas from the Comprehensive Rate Design Study and included in the following Roadmap are the product of concentrated and collaborative efforts from numerous stakeholders over the past 12 months. While not all ideas can be expected to garner full consensus or support, future filings and applications for rate design changes will flow from the discussions and tradeoff analysis in the Comprehensive Rate Design Study, which included:

- Participation from more than 50 organizations including commercial and industrial (C&I) customers, EV companies and advocates, environmental advocates, government agencies, public advocates, renewable/distributed energy resource (DER) companies, and legal/consulting companies.
- Communication facilitated by a third party (ICF) including two-way dialogue, broad information sharing with focused discussions on particular topics, technology-enabled interactive brainstorming sessions, with directions and priorities informed by stakeholder surveys.
- Investigation into rate design questions and pricing elements using big data techniques on questions pertinent to diverse rate design ideas suggested by the collaborative.

Finally, the effort focused on actionable outcomes with the potential for meaningful impacts. The investigations and analytics demonstrated that Duke Energy's historic rates were well-founded and provided fair apportionment of costs with satisfactory price signals, but which should be updated to address increasing levels of distributed energy technology adoption and use of intermittent resources. Major findings from the study include:

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- Duke Energy's current rate designs demonstrate good alignment to cost-causation for the major customer classes across factors such as size and load factor. Historic rates were well designed, fairly apportioned costs, and reflected historic system dynamics.
- Enabling beneficial growth and economic development, including electric vehicles, and equitable outcomes given increasing levels of energy technology adoption (e.g. solar, storage) requires more sophisticated rate designs that recognize both current and expected system changes.
- Some improvements are possible immediately (some program or rate design tariff filings have occurred during the course of the study), but others will require holistic design considerations and are best addressed in the context of rate case filings.
- The following Roadmap demonstrates the success of the collaborative approach at recognizing, organizing, and prioritizing improvement opportunities for a complex topic, to an extent not possible were such efforts confined to a rate case proceeding. The concerted efforts and substantial commitment of resources from many groups will prove beneficial to all electric consumers in the state of North Carolina as the following concepts are fully prioritized and implemented.

# 2 Purpose and Rationale for Pricing Modernization

Duke Energy Carolinas' (DEC) and Duke Energy Progress' (DEP) (Collectively referred to as Duke Energy, the Company or Companies) existing pricing strategies and rate designs were thoughtfully developed and approved by the Commission and have been effective for many years. Many rate design features have been able to deliver effective price signals even with historical limitations on granular customer usage data and billing system constraints. Indeed, the analyses conducted as part of the Comprehensive Rate Design Study (CRDS) have validated the quality of historic rate designs. Much has changed in the electric industry over the last 20 to 30 years, however, and current conditions both require and enable modernization of pricing and rate design for the benefit of customers. The Companies' deployment of smart meters and the innovative Customer Connect billing system create opportunities to enhance and improve customer pricing and rate designs in ways that simply were not possible just a few years ago. As ordered by the North Carolina Utilities Commission (NCUC) in Docket Nos. E-7, Sub 1214 and E-2, Sub 1219 for DEC and DEP, respectively, the Companies engaged with stakeholders in the CRDS through a process organized by a third-party facilitator, ICF, to develop an informed vision and direction for the Companies' future pricing and rate design options.

As noted by the originating NCUC order, "as the Company and customers adopt new technologies and uses of the electric system change, rate design must evolve in order to maximize the efficiency and effectiveness of these new technologies and ensure usage of the electric system that is consistent with the public interest." Although the list of topics discussed in the CRDS was comprehensive, the major objectives of the CRDS process were essentially two-fold: First, tariffs, both existing and potential, were evaluated for alignment to system costs and their ability to provide fair and equitable pricing to customers. Second, opportunities to reduce complexity and harmonize the rates offered by DEC and DEP were explored. These two overarching goals can be further expanded as follows:

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**Fair, Equitable, and Modernized Pricing:**

- Provide more customer options as customers increasingly desire more control over energy consumption and costs.
- Account for both the costs and benefits of customer-sited resources and new/expanding technologies such as solar, storage, and electric vehicles (EVs).
- Encourage system-beneficial behavior and discourage the wasteful and/or uneconomic use of energy.
- Modernize pricing to better link to specific system costs and address decreasing homogeneity among customer classes.
- Incorporate affordability elements as developed by a parallel collaborative.

**Simplify and Harmonize Tariffs:**

- Evaluate suite of tariffs offered across DEC and DEP for opportunities to increase commonality of tariffs and/or structures within tariffs.
- Seek ways to simplify tariffs while avoiding undue discrimination.

Several factors both call for and enable meaningful changes to rates and pricing structures in North Carolina today. The electricity value chain has changed dramatically since the existing rate structures were developed. Although those designs have proven robust, they have increasingly come under strain to address both changes to the electric system and customer energy usage behaviors. Thankfully, at the same time, grid technology changes have enabled the necessary modernization of rate design structures. The following factors are driving meaningful changes to rate design structures in the Carolinas.

1. **Electric System Dynamics and Distributed Energy:** North Carolina has one of the highest levels of utility-scale solar penetration as compared to any state in the US. In 2021, DEC and DEP had roughly 4,600 MW of utility scale solar capacity that was expected to grow to more than 7,300 MW by 2026 – a 57% increase[1]. Additional solar resulting from the Carolinas' Carbon Plan could be a further catalyst for expanding solar in the Carolinas. In contrast to the electric system from 30 years ago, Duke Energy has new grid reliability challenges to manage, including the advancing "duck-curve,"[2] and new price signals are needed to encourage customer behaviors to align with new electric system realities. The adoption of EVs over the next decade will have a major effect on the electricity system as one of the largest sources of energy demand converts from gasoline to electric.
2. **Distributed Energy Technologies:** Customers are increasingly adopting distributed energy technologies, such as rooftop solar, advanced energy management systems, and energy storage devices – including an expected increase in dual usage of storage for transportation and backup power. Such adoption is reducing the homogeneity across customer groups, calling for more sophisticated pricing to address issues of fairness and clarity. For example, the number of registered EVs in the United States more than

[1] Numbers from the A2 portfolio from the 2020 modified IRP.
[2] The "duck curve" is an industry term describing the broad system impacts from high solar penetration characterized by relatively low net loads during mid-day hours when solar production is high, followed by a sharp increase in net load in the late afternoon as demand increases and solar production declines.

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tripled from 2016-2020.[3] EV sales have only increased since then, with some models having up to a 12-month backlog in orders.[4] Any increase in gas prices would be expected to only increase interest in EVs from both residential and C&I customers, and the number and variety of available models is expanding to meet the growing demand.

3. **Customer Expectations:** Customers and diverse advocacy and interest groups are requesting new rates and pricing structures to reflect usage differences and help mitigate price pressures. Following virtually every other industry and product, customers and interest groups alike are demanding more choice and control in their energy purchases.
4. **Grid Technology Advancement:** The Company has invested in Advanced Metering Infrastructure (AMI) and a new billing system (Customer Connect), providing the capability for greater customer choice, flexibility and transparency in rates. Full deployment of AMI and Customer Connect provides a platform for more data intensive, yet administratively manageable, rate offerings.

Rate design must collect the revenue requirements of the Companies in a manner that is not unduly discriminatory while also encouraging beneficial consumption patterns to improve system efficiency and keep costs low for all customers. Accordingly, rate design often involves complicated tradeoffs that must consider both system dynamics and wide-ranging differences across customer classes and individual customers, particularly when considering varying levels of energy technology adoption. In other words, customers who operate large facilities around-the-clock and those who use energy sparingly or intermittently should receive pricing designed to reflect those differences. Similarly, solar adopters, EV purchasers, or customers with highly flexible loads should receive price signals that reflect the system economics of the decisions, including consideration of impacts on all other customers.

The following Rate Design Roadmap ("Roadmap") outlines the rate design findings, vision, and direction that resulted from the collaborative stakeholder process that transpired over the past year. Additionally, the Roadmap offers a summary of the CRDS process as designed by the third-party facilitator, ICF, including efforts made to ensure opportunities for feedback from all parties involved.

Foremost, the Companies wish to express, again, their gratitude for the active participation from numerous and diverse organizations and individuals throughout the process. Stakeholders shared their original ideas, feedback, and opinions through the various working group sessions, large forums, and topically focused subgroup discussions. The following represents the Companies' views on future pricing structures and designs, as informed by the collaborative process, but does not necessarily represent full consensus from all parties involved in the Comprehensive Rate Design Study process.

# 3 Roadmap Structure

[3] Electric vehicle market growing more slowly in U.S. than China, Europe | Pew Research Center.
[4] Waiting times for electric cars 2022 | Electrifying.

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The following Roadmap envisions changes across the portfolio of tariffs that will impact virtually all DEC and DEP customers and create opportunities for customers to economically use emerging energy technologies. The ideas and options presented throughout this Roadmap have been discussed at varying levels of detail throughout the large forums, working groups, and stakeholder subgroup meetings over the past 12 months. The collaborative stakeholder process has been detailed extensively with the NCUC in prior quarterly filings.[5] The Companies appreciate all the insights and feedback, questions and discussions, and commitments of time and resources from the diverse stakeholders who reviewed current and potential tariff options and elements. Accordingly, the Companies' plans and priorities listed below are the result of two-way dialogue with stakeholders within the facilitated process. The Companies are hopeful that many of the options identified in the Roadmap will be widely supported and implemented as part of future filings focused on rate design improvements in consideration of the goals listed above.

The Companies recognize the potential for improvements in the following areas, as described in more detail in the remaining sections of this Roadmap:

System-wide Foundational Changes

1. Time-of-Use Period Changes
2. Demand Charge Structure Alignment to TOU Periods
3. Electric Vehicle Options

Rate Design Changes for Residential Customers

4. Expanded Options for Residential Customers
5. Residential Net Energy Metering Reform
6. Subscription Pricing Rates

Rate Design Changes for Non-Residential Customers

7. Improved Price Alignment for Non-Residential Rates
8. Simplification of Non-Residential Rates
9. Expanded Hourly Pricing Options for Non-Residential Customers
10. Non-Residential Net Energy Metering Reform
11. Economic Development
12. Renewable and Clean Tariffs and Programs
13. Historic/Closed Tariffs

Importantly, many of the ideas in the list above cannot be considered in isolation. Rather, the ideas and options are often deeply interconnected and to be effective and cohesive should be implemented in conjunction with

[5] See Comprehensive Rate Design Study Quarterly Status Reports filed on July 21, 2021, October 21, 2021 and January 21, 2022 in Docket Nos. E-7, Sub 1214 and E-2, Sub 1219.

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other options. For example, the options should consider customers with different usage profiles, consumption levels, and degrees of advanced energy technology adoption.

While rate design ultimately must recover the revenue requirement, the ideas stemming from the collaborative process can create benefits, ultimately reducing rates for everyone. When rate designs incorporate the proper balance between reflecting system costs and considering operational capabilities of new or existing loads, the result will be lower overall system costs than would have otherwise occurred (and accordingly, lower rates) as well as an important additional cost-effective tool that will support achievement of the planned energy transition in North Carolina.

# 4 System-wide Foundational Changes

Concepts discussed in this section are both wide-ranging and foundational. The following changes will impact customers of all classes, Residential and Non-Residential alike, across both DEC and DEP. Importantly, the pricing improvement opportunities discussed in subsequent sections assume implementation of foundational alignments for both time-of-use periods and demand charge structures. Rate design simplification and modernization ideas discussed elsewhere for specific tariffs or customer classes is predicated upon alignment of all tariffs to the new system realities, including both demand and energy charges.

## 4.1 Time-of-Use Period Changes

Time-of-Use energy rates include a wide variety of pricing and design options, but generally all seek to align price signals to the cost differences that exist across time (days, seasons, hours) for the electricity grid. Grid operations require that supply must match demand at any given point in time, thus supply resources are called upon based on the level of system demand, which can vary greatly across days and seasons. Increasingly, intermittent and non-dispatchable supply resources (e.g. solar) are complicating the supply/demand relationship, calling for changes in operational capabilities for other supply resources but also demand. Proper rate design seeks not only to recover the costs of providing service to customers based on their use of the system, but also to provide price signals so customers who can respond to price signals, can do so in an informed manner. Time-of-use pricing with properly defined periods is increasingly necessary for such proper signaling.

Time-of-Use (TOU) periods currently in place for DEC and DEP were established as early as the 1980s. Although the TOU periods have been reviewed more recently, the latest reviews noted that new TOU periods should be considered after the deployment of smart meters, which would allow a more seamless transition to new rate designs. Given the deployment of Advanced Metering Infrastructure ("AMI") in the Carolinas, metering capabilities are no longer a barrier to changing TOU periods. Furthermore, the desire for this review of TOU periods comes from the evolving needs of the electric system and its ability to provide superior price signals, which can enable cost-effective customer adoption of new technologies, such as energy storage and EVs.

The Companies took a forward-looking approach in designing the new TOU periods discussed below, considering both current conditions and expected system evolution over the next decade. Multiple perspectives and goals were considered in crafting periods that: 1) better reflect cost causation and the growing impact of solar generation; 2) accurately reflect the benefits of distributed energy technologies such as electric vehicle charging, energy storage, rooftop solar, and other distributed energy technologies; and 3) make it easier for customers to modify energy consumption patterns and create bill savings.

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The Companies analyzed projected load patterns and costs to develop refreshed TOU periods. Historic and forecasted costs were analyzed through six different lenses: gross load, net load after utility-scale solar, retail load, marginal energy cost, marginal capacity cost, and loss of load expectation (LOLE). Gross load, net load, retail load, and marginal energy cost were examined using the Companies' Cost Duration Model (CDM). The CDM is a model for evaluating TOU prices and TOU periods. The CDM displays weighted data in a single chart for ease of analysis. A detailed explanation of this process was shared in Working Group #1 ("Fast Track") and was also included in the Technical Report filed September 30, 2021 in Docket No. E-2, Sub 1280 in a filing that introduced two new rate designs utilizing the new TOU periods. Figures showing historic marginal cost (Figure 1) and LOLE (Figure 5) are also included as a point of comparison and validation of the CDM. The following Figures 2 through 4 display how the CDM showed expected high and low-cost time periods in 2021, 2026, and 2030.

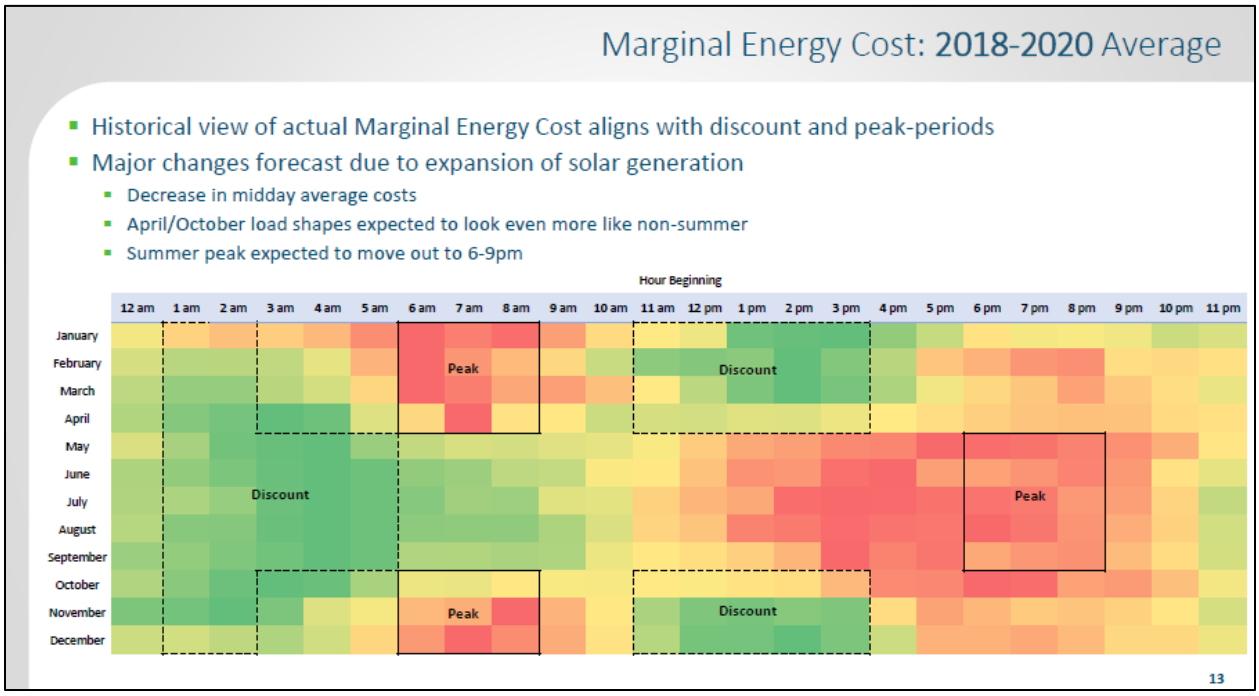


Figure 1: TOU Period Alignment with Recent Marginal Energy Costs

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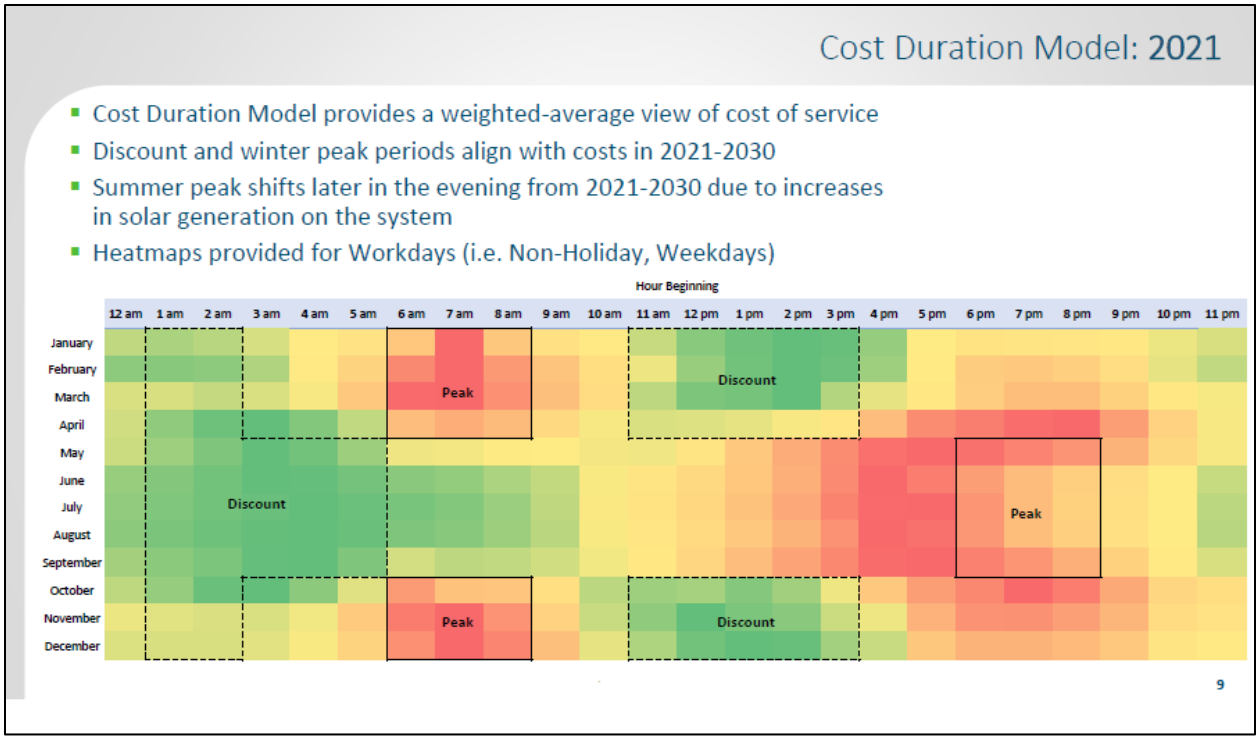


Figure 2: TOU Period Alignment with the Cost Duration Model Output for 2021

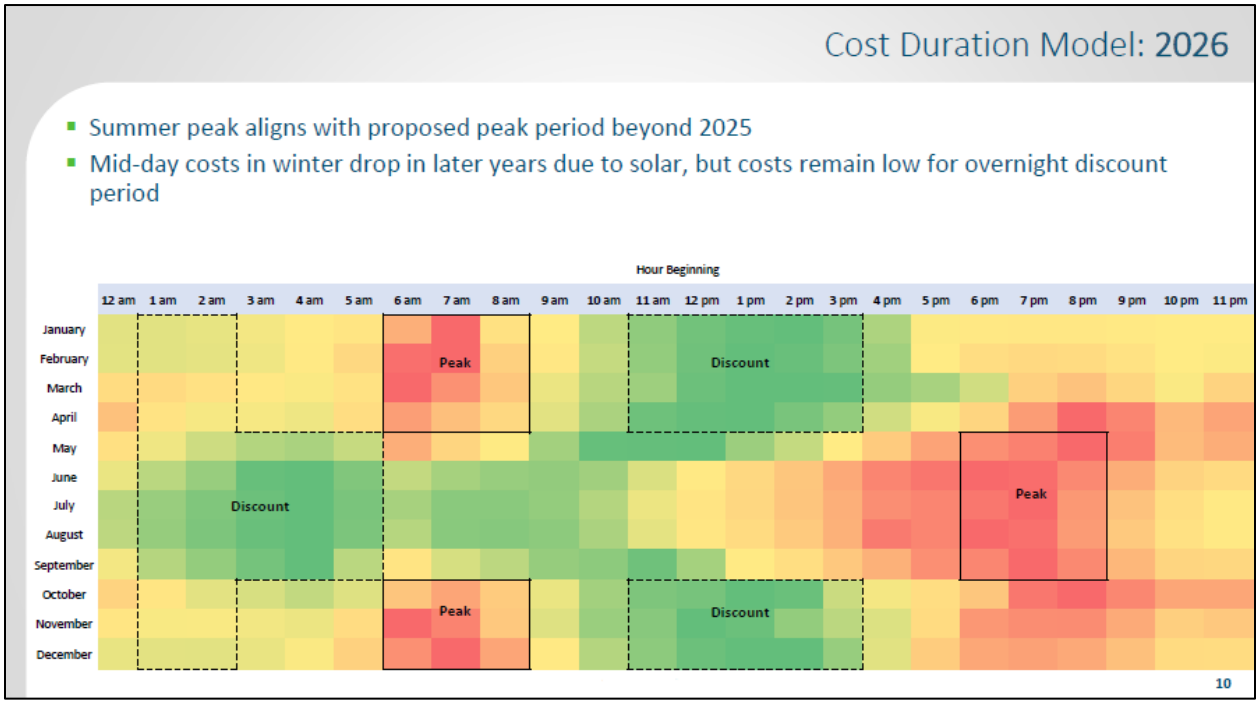


Figure 3: TOU Period Alignment with the Cost Duration Model Output for 2026

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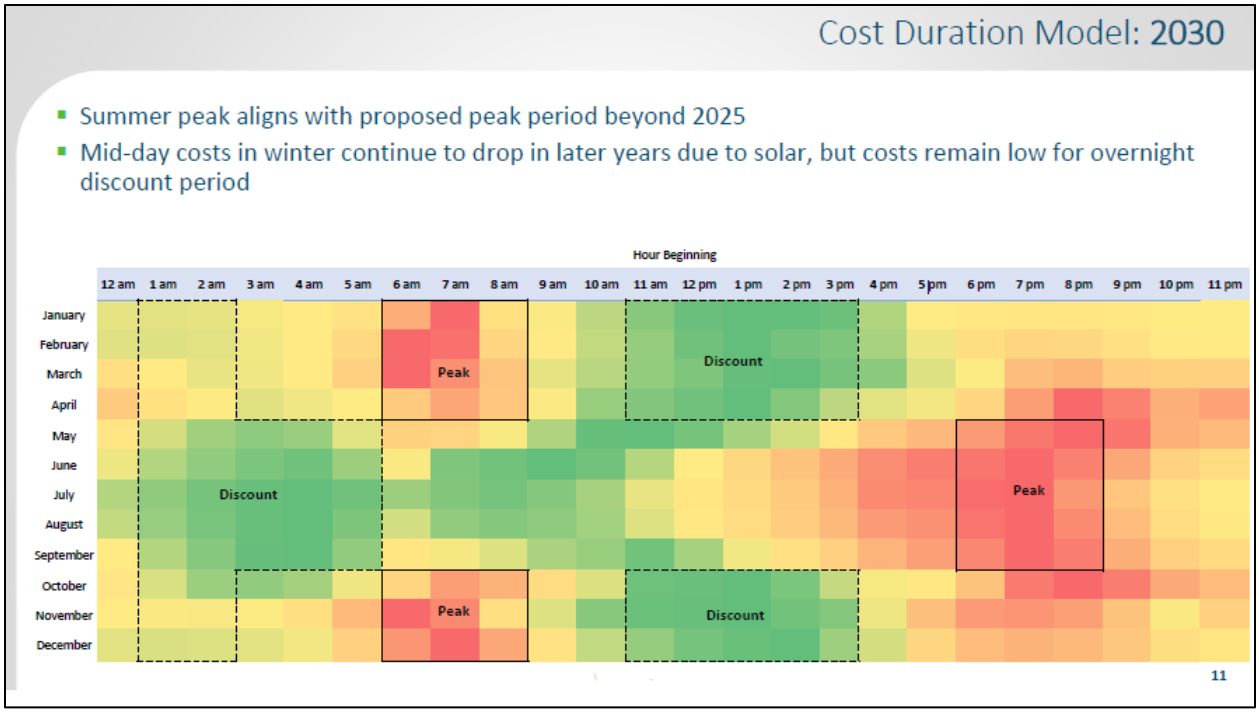


Figure 4: TOU Period Alignment with the Cost Duration Model Output for 2030

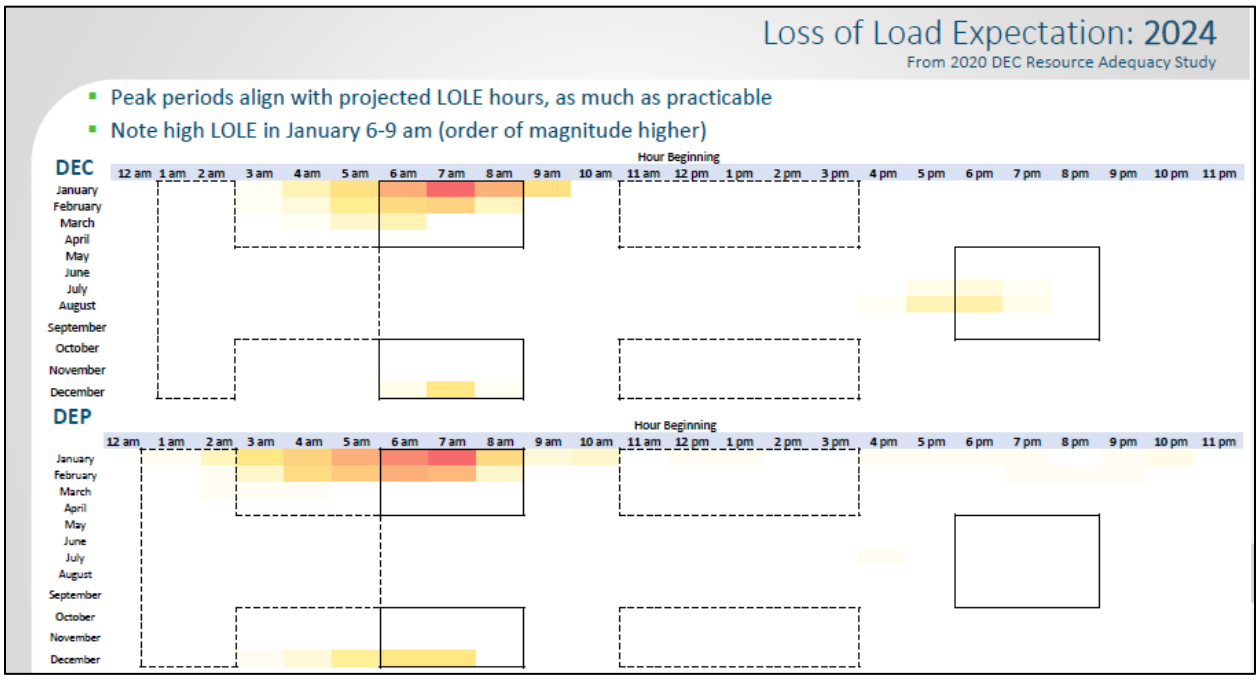


Figure 5: TOU Period Alignment with 2024 Loss of Load Expectation Times

The heat maps above show that the CDM is in alignment with historical marginal energy costs. Since capacity-constrained hours will also have high marginal energy costs (when the utility is at the high end of its economic dispatch curve), this shows good alignment on capacity costs as well. The impacts of additional solar energy

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added between 2021 and 2030 are clearly reflected in the summer afternoon peak being pushed further back into hours with less sunlight. For the same reason, the non-summer mid-day discount periods become even lower cost, as these times of high solar generation and relatively low load lead to "duck-curve" situations where solar curtailment could become necessary. Finally, the LOLE chart shows that the highest capacity cost hours are in winter mornings and relatively little of the LOLE is not covered by peak time periods.

These proposed TOU rate designs will not only offer customers new options to reduce their bills and create system benefits, but also reflect Duke Energy's commitment to providing customers with innovative rate design choices and program offerings to accommodate differences in how customers consume energy. The Companies expect these designs to be a constructive step forward and to comprise one part of a suite of new rate designs, programs, and customer options resulting, in part, from the collaborative CRDS stakeholder process.

The Companies believe the new TOU periods described below will support accomplishment of the rate design goals listed above. Additional supporting materials and descriptions of how the TOU periods were derived in light of system costs and reliability can be found in the DEP Application for Approval of Two Dynamic Rate Pilots.[6]

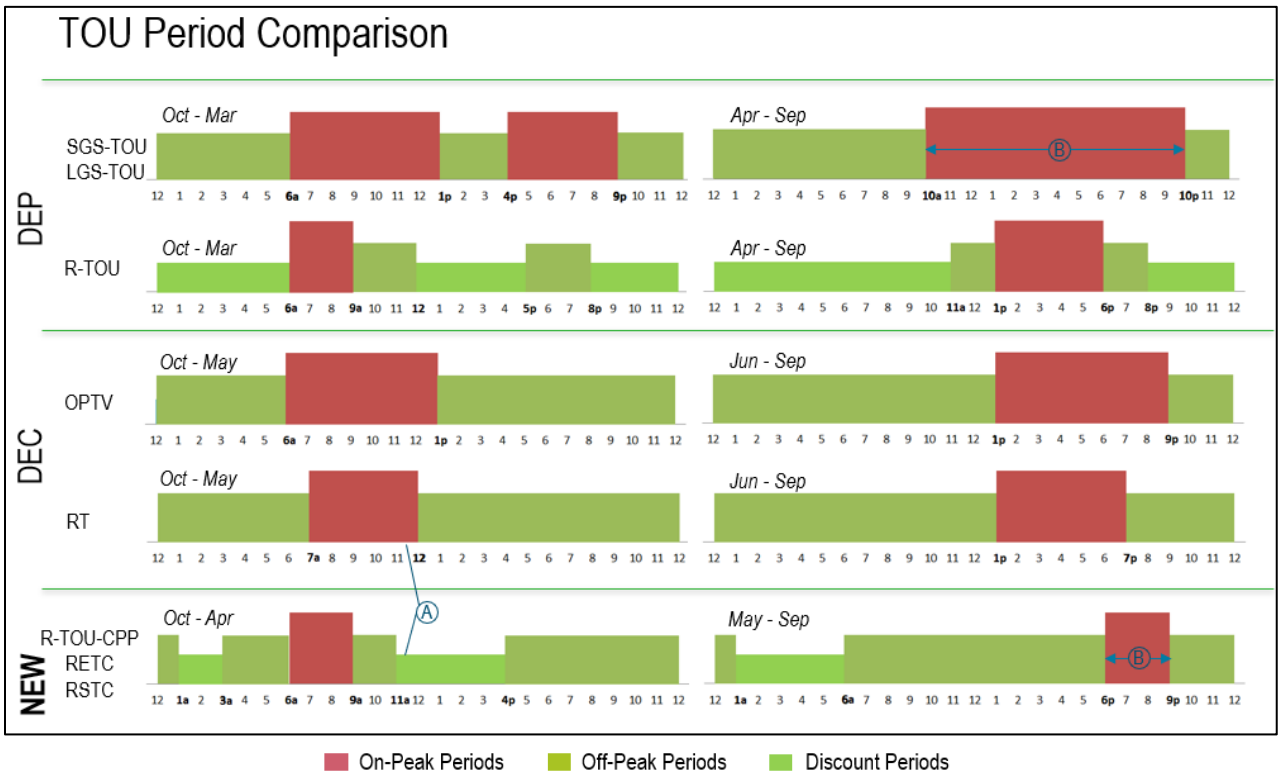


Figure 6: Historic and Modernized TOU Periods

As seen in the "DEP" and "DEC" sections at the top of Figure 6, the Companies' historic TOU periods vary significantly and do not reflect current system costs and operational realities. Notably, periods present in some of the Companies' more popular rates (e.g. DEC's OPT-V) have on-peak periods that are currently low-cost hours for the system, as denoted by letter A in the Figure. Practically, continuation of the existing periods means the

[6] See Application filed in Docket No. E-2, Sub 1280 on September 30, 2021.

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customers would be receiving high price signals that discourage consumption when the system in fact has an abundance of solar energy. Failure to change TOU periods could thus increase the likelihood of solar curtailment. Conversely, the historic periods have off-peak hours that are increasingly times of system peaks, notably late afternoon hours during the summer. Thus, customer responsiveness to the current periods and price signals may exacerbate the evening summer peak and increase costs to all customers.

Additionally, the historic on-peak periods present challenges for customers seeking to respond to prices, whether through advanced energy management controls or with distributed energy technologies such as storage. Letter B shows that some present on-peak periods are as long as 12 hours, compared to the 3-hour window for the modernized TOU periods that reflect the system dynamics in the Carolinas today. This new, shorter window creates more opportunities for customers to change their usage patterns or utilize distributed energy storage to reduce their electricity bill.

The modernized periods, shown in the bottom "NEW" section of Figure 1, provide a consistent discount period for owners with flexible loads, for example EVs (whether Residential or Fleet), during overnight hours from 1 a.m. to 3 a.m.[7] While other EV solutions are described below, the discount charging periods provide an important foundation available to all customers with such flexible loads.

During the CRDS, the Company described both the rationale and implications of the new TOU periods to stakeholders for both residential and non-residential classes. Consistent TOU periods across all rates with time-differentiated pricing is desirable and system beneficial. Accordingly, the Companies will prioritize aligning all TOU periods to those present in the CPP tariffs recently approved in both DEC and DEP. With that in mind, DEC recently proposed and was authorized by the NCUC to freeze residential Rate RT[8]. In the future, DEC plans to redesign and reopen the tariff to increase rate optionality for customers.

The Companies recognize new TOU periods may impact customers with different load profiles either favorably or unfavorably. Accordingly, careful consideration will be given to ultimate pricing levels and tariff attributes to mitigate adverse outcomes and rate shock for impacted customers. However, such pricing differences will not be arbitrary, but rather commensurate with how different usage profiles drive system costs, both now and going forward. In addition to TOU rates, the Companies recognize the need for a suite of rate options to provide customers with a choice in available rates. Importantly, TOU rates today are optional, and newly designed periods may result in some customers finding non-TOU rate options more favorable.

## 4.2 Demand Charge Structure Alignment to TOU Periods

The modernized TOU periods described above will also require changes to the demand charge structures for all TOU-D rates, both residential and non-residential, including DEC's recently frozen residential Rate RT and DEP's residential R-TOUD rate.[9] Redesigning these rates will require a thoughtful review of the demand charges, such as

[7] The CRDS discussed the likely need to employ more sophisticated programs in the future to avoid many EVs all starting to charge at the same time to take advantage of TOU periods. A sudden, massive increase in load could lead to ramping issues and distribution circuit or even system peaks that occur suddenly. Some solutions to this issue were discussed in the CRDS, including providing slightly different TOU periods for each EV customers (e.g. some would start at 1 am, others at 1:01 am, still others at 1:02 am, etc. All customers would still get 3 hours of discount electricity prices). While this is an important topic, since this issue is not expected to emerge in the next five years, priority was given to more immediate challenges.

[8] See *Order Approving Closing of Rate Schedule RT*, issued March 4, 2022, Docket No. E-7, Sub 1214.

[9] DEP's R-TOUD rate is currently closed to new customers except Net Energy Metering (NEM) customers.

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the design concept below which was discussed with the Non-Residential Working Group and described in Section 6.2.

As part of the CRDS, the Company discussed demand charge modifications that could support the modernized TOU periods discussed above, including the relatively short on-peak window. As the TOU periods transition to a three time-period structure, the demand structure must also change to maintain and improve upon the price structure alignment with system costs. This will also provide actionable price signals to customers with flexible loads or enabled technology. Both objectives (alignment to cost-causation and actionable price signals) are important and must be held in balance when designing the ultimate rate structure.

One suitable solution is a three-part demand structure that reflects cost causation and promotes customer behavior beneficial to the overall system. The three parts are shown in Figure 7 and described below, including the costs each is conceptually designed to recover.

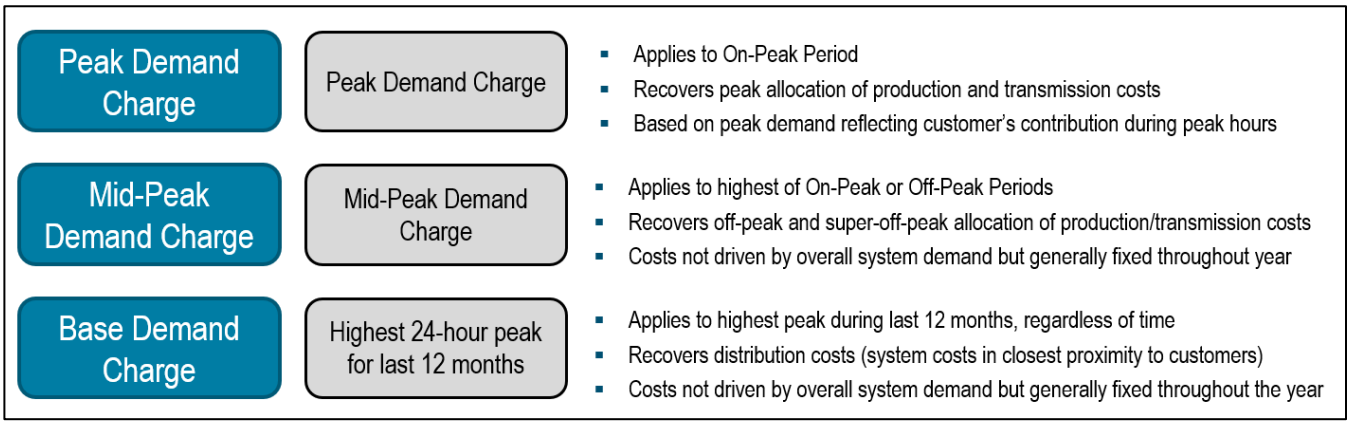


Figure 7: Three-part Demand Structure Overview

**Base Demand Charge:** Recovers distribution costs, which are the system costs in closest proximity to the distribution-served customers. Such costs are not driven by overall system demand and are generally fixed throughout the year. Accordingly, the Base Demand Charge would apply to the customer's highest on-peak, off-peak or super-off-peak demand over the last 12 months.

**Mid-Peak Demand Charge:** Recovers off-peak and super-off-peak allocation of production and transmission costs. This charge recovers capacity costs incurred to provide service during non-peak times. Accordingly, the Mid-Peak Demand Charge would apply to the customer's maximum demand during off-peak or peak periods (excludes super-off-peak).

**Peak Demand Charge:** Recovers peak allocation of production and transmission costs resulting from the customer's contribution to system demand during peak hours. Accordingly, the Peak Demand Charge would apply to the customer's measured on-peak demand.

The three-part demand structure would improve price transparency and better align with cost causation based on both the size and timing of customer demands. Relative recovery of costs between the three parts of this proposed demand charge structure would be determined through the CDM to maintain cost causation linkage, as well as alignment with the methodologies used to set TOU energy charges. Mid-Peak and Peak Demand Charges reflect the reality that demands at certain times impose more or less costs on the production and transmission components of the electric system. Similarly, the Base Demand Charge recovers system costs most directly caused by specific customers that do not vary based on the time of use (either by hour, by day, or by month). The

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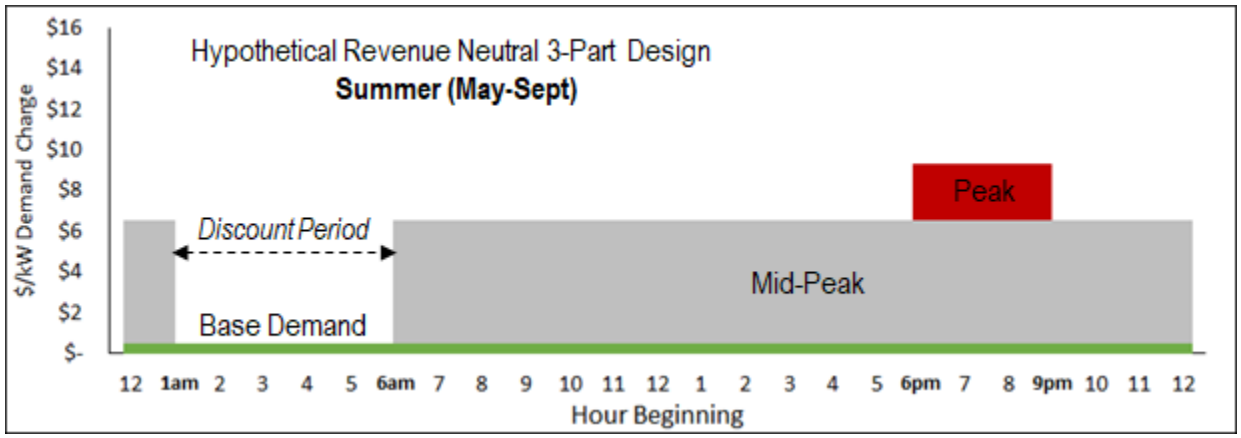
base demand charge reduces bill volatility for customers, while the Mid-Peak and Peak charges offer opportunities for customers to reduce their peaks and lower their bills.

For example, consider a customer that has some level of demand constantly, but also has some high-demand, infrequent processes. If this customer can avoid having a spike in demand during the 3-hour peak period, they can avoid an increase in associated peak demand charges. This is appropriate because these high-demand processes are not adding to demand or capacity costs during peak periods. However, these high-demand processes are still adding demand during times with moderately high capacity costs and should contribute to intermediate peaking resources. If this customer could run these high-demand processes exclusively during discount time periods, then they are only increasing demand when there is plenty of excess system capacity in the generation or transmission system. Thus, these processes will not increase production or transmission capacity costs making it appropriate for the customer to not pay any incremental peak or mid-peak demand charges for running these processes. However, these high-demand processes could still lead to a local peak at the distribution circuit level rather than in the whole electric system. Therefore, it is appropriate that the increase in demand from these high-demand processes will increase the customer's base demand charge that recovers distribution costs.

The Company shared this hypothetical framework with customers and stakeholders during CRDS discussions in the Non-Residential Working Group, including a simplified revenue-neutral example with prices, as shown in Figure 8 below. Actual structures proposed in future regulatory proceedings could differ and may include attributes to address potential customer impacts from introducing a new rate design. Figure 8 is a helpful representation of the concept and was presented for discussion purposes only.



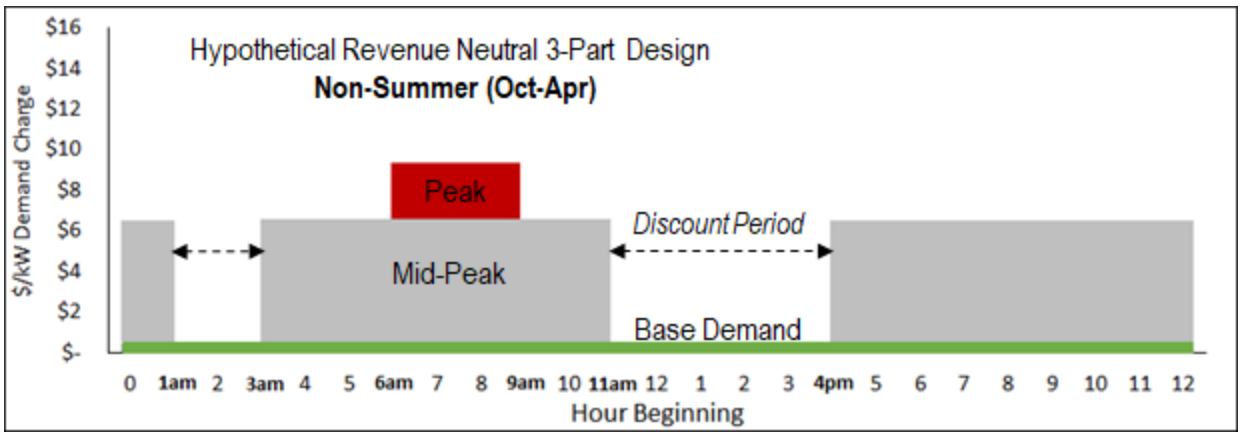



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Figure 8: Three-part Demand Structure Overview

Thoughtfully designed demand charges, along with the new TOU periods, will be foundational to many of the following ideas and potential solutions in this Roadmap. Indeed, sending proper baseline price signals is necessary for constructive and fair expansion of rules governing NEM and other distributed energy technologies (such as storage, microgrids, or other forms of cogeneration) as well as balancing price with cost-causation for customers with beneficial usage patterns (e.g. high load factor customers who make efficient use of system resources). The priorities and opportunities with rate design described elsewhere in this document assume and require redesigned demand charge structures in some fashion to achieve the objectives described.

Customers and customer advocates provided helpful feedback on the new periods during working group sessions, noting the following:

- Impacts to specific customers will depend on the final prices as rate designs are proposed.
- Justified cost shifts could occur between customers who can shift load and those who cannot. *(Note Company comments below.)*
- Allocation of fixed cost recovery to demand charges vs. energy charges should be considered.
- Tiered pricing or other size considerations should be a part of the demand structure design to better align with cost causation.

The Companies will carefully consider and continue exploring these more detailed components of rate design as part of the implementation of new TOU periods and demand structures. Such features would be important to provide rate gradualism and avoid unintentional cost shifts between customers with varying usage patterns, while still supporting the overall goals of improving rate alignment with cost-causation and encouraging system beneficial consumption patterns. The Companies also note that improved alignment between pricing and cost-causation should alleviate some customer concerns, in particular regarding cost shifts. For example, when pricing is aligned appropriately to costs following the CDM approach above, customers who can shift loads away from peak periods would lower overall system costs, thus benefitting themselves and all other customers. In contrast, TOU periods or demand structures that fail to keep up with the changing system cost structure would be more susceptible to adverse cost impacts from load-shifting that provided price signals divorced from system cost realities.

## 4.3 Consistent Price Signal Alignment to System Costs

The Companies analyzed projected load patterns and costs to develop refreshed TOU periods. The Companies used the Cost Duration Model to evaluate TOU periods by examining gross load, net load, retail load, and marginal energy costs. Both historical and forecasted data were used to create robust TOU periods to reflect costs over the next decade and advance the goal of maintaining rate stability over time. It is important to note that the purpose of this analysis is only to set TOU periods. Price ratios and exact prices for any rate schedule will be determined through analyses specific for each utility and jurisdiction. The data sources and lenses were summarized in a presentation shared with the Fast Track Working Group. The full details can be found in the Technical Report filed September 30, 2021 in Docket No. E-2, Sub 1280.

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## 4.4 Electric Vehicle Options

The NCUC explicitly referenced EV rate considerations in its order establishing the CRDS,[10] and several stakeholder participants were focused almost exclusively on improving offerings for this growing customer segment. Furthermore, the NC Governor's recent Executive Order No. 246 set an ambitious goal to increase the total number of registered zero-emissions vehicles in North Carolina to at least 1,250,000 by 2030. The Companies acknowledge the importance of the anticipated growth in EVs and accordingly devoted considerable time to explore options that address EV charging costs and system impacts.

With material and constructive feedback from CRDS participants, the following categories represent ideas that could support the burgeoning EV market in North Carolina. The suite of potential rate designs is intended to provide both favorable pricing and encouragement for system-beneficial charging behaviors, as described. Importantly, beneficial growth of EV load is premised on implementing new TOU periods as discussed elsewhere in this document. Ideas encompass both residential and non-residential EV applications, and some may be considered as pilots prior to broader implementation as this market grows.

**TOU Charging:** The easiest approach to regulating timing for EV charging may be providing simple, low-risk incentives to EV owners to charge during off-peak times. One simple approach is EV-only TOU charging, which allows a residential customer to participate in a TOU structure for their EV load alone, leaving the rest of the residence on a non-TOU tariff. Considering the utilization rate of cars is generally low (i.e. they spend much more time parked than driving), it is expected that customers should be able to shift charging across time periods with limited to no effect on convenience. As a result, shifting to a TOU rate design, especially one with shorter 3-hour peak periods, should yield cost-justified savings and a positive customer experience. However, many customers could be reluctant to adopt TOU rate schedules for their entire home due to concerns that regular behaviors for other sources of load may increase bills. This concern is mitigated by allowing customers to be on a TOU design for their EVs while retaining a non-TOU design for the rest of their energy use. EV-only TOU charging received considerable support from stakeholders during the CRDS, with virtually no opposition voiced throughout the process.

Stakeholders generally showed support for EV-only TOU options to encourage Off-peak charging

**Off-Peak Charging Credits:** Off-peak charging credits provide an upside-only approach where customers can receive a bill credit for months in which there are no instances of on-peak charging, with some allowances. The program could provide a monthly bill savings for average EV drivers, present few challenges in terms of risk or effort, and benefit the system by creating a positive economic incentive for charging during off-peak periods. (Note: Both EV-only TOU and Off-peak charging programs require some technical capabilities to estimate or measure EV usage without a dedicated second meter. Such capabilities are being investigated by the Companies.)

**Subscription Pricing:** EV owners who are concerned about the impact of charging on their monthly bill can benefit from a flat rate subscription program. Many potential EV adopters may not have confidence in how charging their EV will increase electric bills, and a subscription pricing program can provide certainty and eliminate a potential barrier to adoption. Most stakeholders in the CRDS were supportive of managed charging, in which

[10] See *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice* issued March 31, 2021 in Docket No. E-7, Sub 1214 and *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice* issued April 16, 2021 in Docket No. E-2, Sub 1219.

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charging would be actively managed by the utility to ensure EV load is brought online in a way that has the lowest costs and environmental impact. Some stakeholders voiced concerns that any fixed price would encourage wasteful usage, and the proposed pilot will study and attempt to address this concern through the following program design considerations. First, the utility would have the ability to call managed charging events that would slow the speed of charging or completely stop charging for a limited period in accordance with program design. Additionally, total allowable energy usage under the subscription program would need to be limited to reasonable levels based on available data concerning EV usage patterns. Based on stakeholder feedback, the Companies filed for pilot Subscription Pricing programs in both DEC and DEP in February 2022.[11] Findings from the pilot could lead to expanded program offerings and a refining of program designs to improve customer experience and enhance grid benefits.

**Economic Development:** Fleet EV owners are typically concerned about demand charges for new/growing fleets that may have low energy consumption and therefore low load factors. One approach is to consider fleet EV adopters in a redesigned Economic Development tariff, to alleviate concerns with demand charges for new or growing EV fleet adopters. In particular, the Company's Economic Development tariffs could be modified to lower availability thresholds and exemptions for the employment requirements for EV fleets. Along with other possible changes to the Economic Development tariffs (see below), such changes would encourage fleet owners to confidently grow into larger fleet sizes with favorable pricing over several years, providing environmental and system utilization benefits. (Notably, such benefits would be compounded when coupled with the new TOU periods and appropriate charging behaviors.)

**Hourly Pricing:** Also, as described in Section 6.3, one stakeholder working group devoted considerable time to evaluating improvements to the Companies' Hourly Pricing tariffs, specifically considering options to introduce a new program with greater availability, including for larger and sophisticated EV fleet owners. The potential design is described in more detail in Section 6.3, but thoughtful consideration was given to the appropriateness of the design for EV fleet customers, particularly fleets expected to growth over 7-10 years or more. In addition, as the Company gains more experience with EV fleets, it may become apparent that the unique characteristics of these customers warrant special application of Hourly Pricing policies to ensure such rate designs work as intended. This may create additional cost-based benefits for these customers.

**Fleet EV Options:** Throughout the CRDS, stakeholders emphasized that EV fleets may have unique needs and capabilities to utilize various rate structures. A few of the ideas presented for consideration include establishing EV fleets as a separate rate class, allowing EV-only TOU for non-residential customers and a non-residential CPP offering. When considered in addition to the potential modifications to Economic Development, Hourly Pricing and TOU pricing, these additional ideas may have limited incremental value for customers.

The suite of possible EV options is presented in summary form below, in Figure 9.

[11] See Application for Approval of Electric Vehicle Managed Charging Pilot, filed February 11, 2022 in Docket Nos. E-7, Sub 1266 and E-2, Sub 1291.

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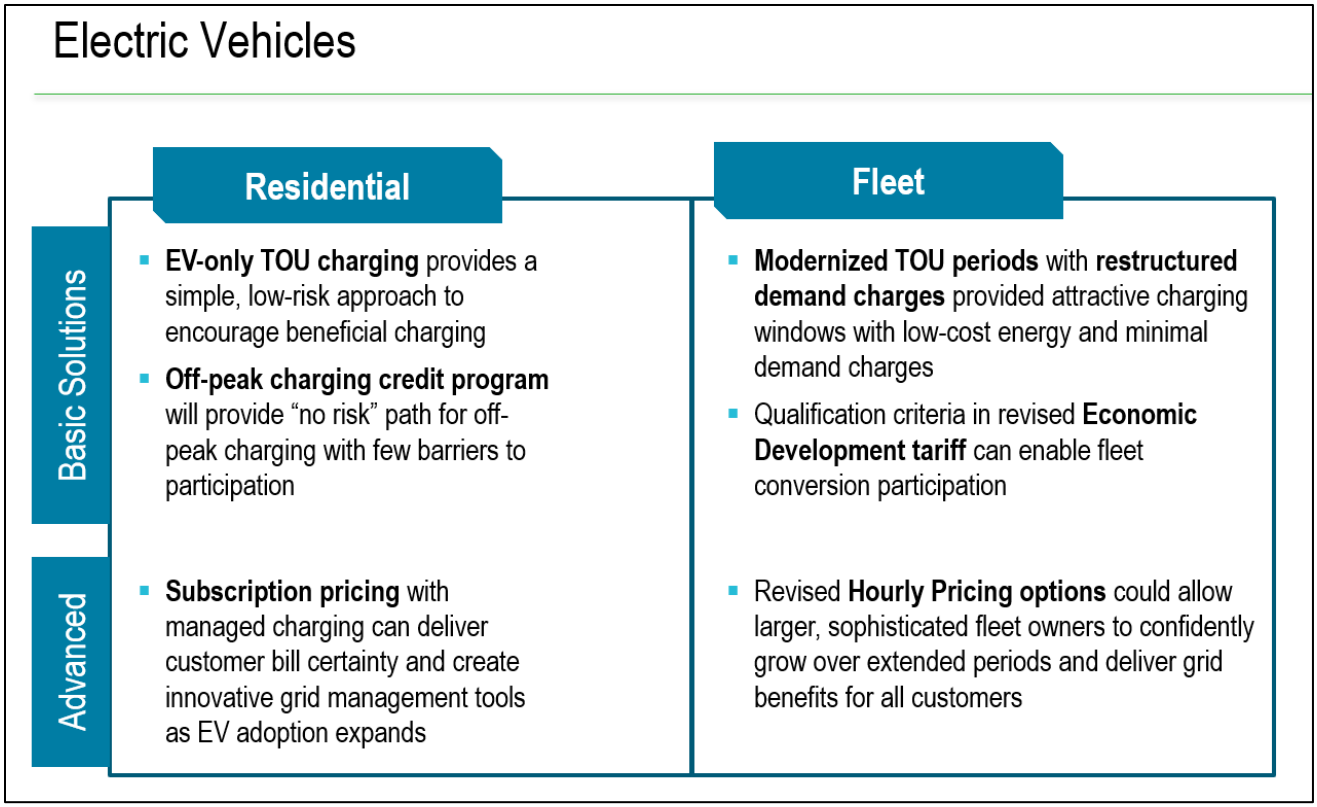


Figure 9: EV Program Options for Residential and Fleet Customers

# 5 Rate Design Vision for Residential Customers

## 5.1 Customer Class Consideration for Residential Customers

Currently, DEC has three residential rate classes – RS (standard service), RE (all-electric service) and RT (Time-of-Use). DEP has one residential rate class. Consideration was given to possible introduction of an all-electric rate schedule or rate class in DEP to provide different rates for this segment of customers. A cross-subsidy analysis of DEP residential customers was conducted across several different categories, some of which are shown below. Please note that both analyses only measure intra-rate class subsidization and have no bearing on potential subsidizations across rate classes (i.e. no conclusions can be drawn from this analysis about subsidizations between residential and non-residential rate classes).

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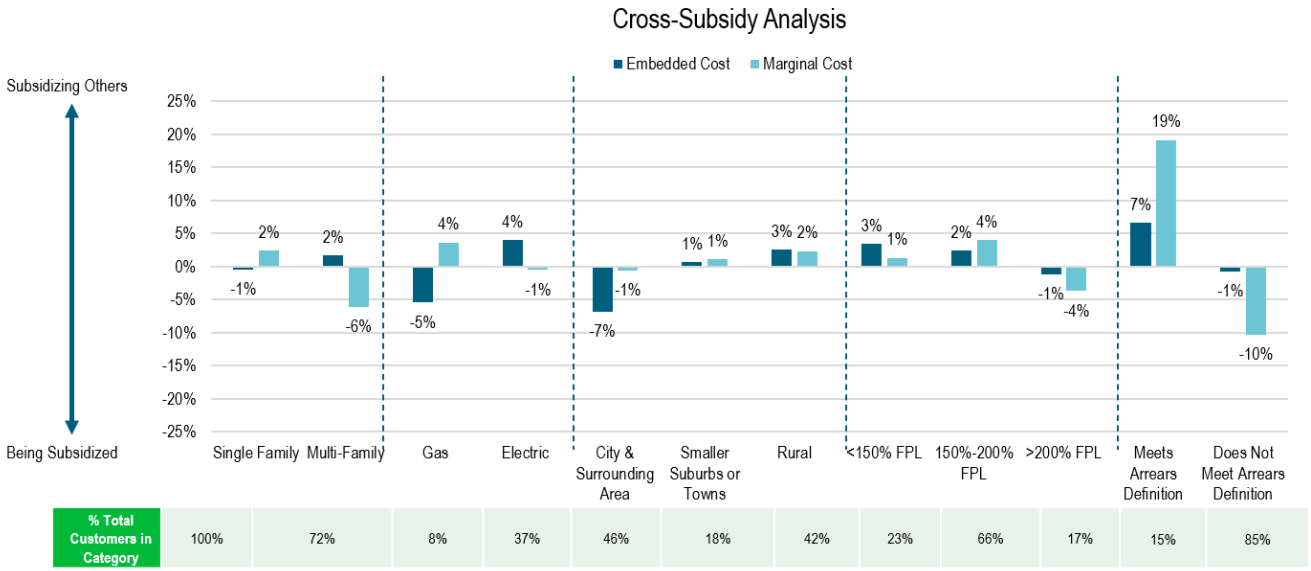


Figure 10: Cross-Subsidy Analysis for DEP Residential Rate RES (as Presented to Residential WG)

This analysis did not show conclusive evidence of benefits in the creation of an all-electric rate schedule or rate class in DEP. While it appears that electric-heat customers are subsidizing customers with gas heating from an embedded perspective, the reverse is true under a marginal lens. Since both embedded and marginal analyses are important in ratemaking, the overall result is ambiguous. Furthermore, the embedded cost analysis necessarily only utilized the allocation methodologies approved in the most recent rate cases. Any change in the cost of service allocation methodology would impact such intra-class subsidization analyses. Therefore, even though the analysis showed 4% higher bills for electric than the cost to serve those customers under the embedded perspective, on balance a separate all-electric rate schedule does not appear warranted.

The DEP cross-subsidization analysis included other interesting findings such as that customers who are behind in paying their bill (the "meets arrears definition") appear to be cross-subsidizing those that do not meet that definition.[12] Rural customers also appear to be mildly subsidizing urban customers. This is due to an overall subsidization of low-usage customers by high-usage customers and cost recovery primarily through kWh charges. Additionally, the costs included in the cross-subsidy analysis used the Commission-approved processes and methodologies. Those methodologies do not consider potential differences in serving different residential customers. For example, rural residential customers could have a higher distribution cost than customers living in a downtown apartment building. However, the Commission-approved methodologies treat all residential customers as the same in the cost of service study and such distribution cost differences were not included.

The working group discussed how the low fixed charge compared to the customer unit cost and higher load factors relative to the summer peak for high-usage customers were contributing factors to the high-usage/low-usage subsidization. However, the working group showed little interest in adapting rate schedules or rate classes to address this, especially given public policy goals of encouraging energy efficiency and energy conservation.

[12] The definition is either being late 1x one's average bill for 6 out of the 12 months analyzed (50% of the time) or 2x one's average bill for 2 out of the 12 months analyzed (16.7% of the time).

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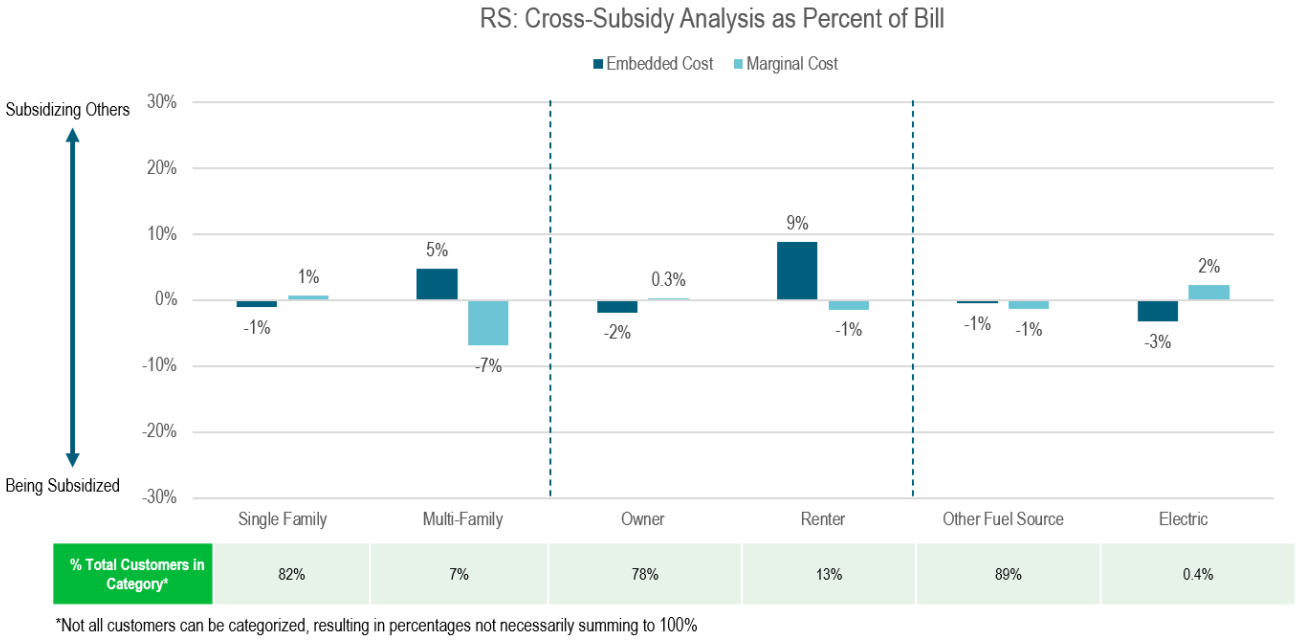
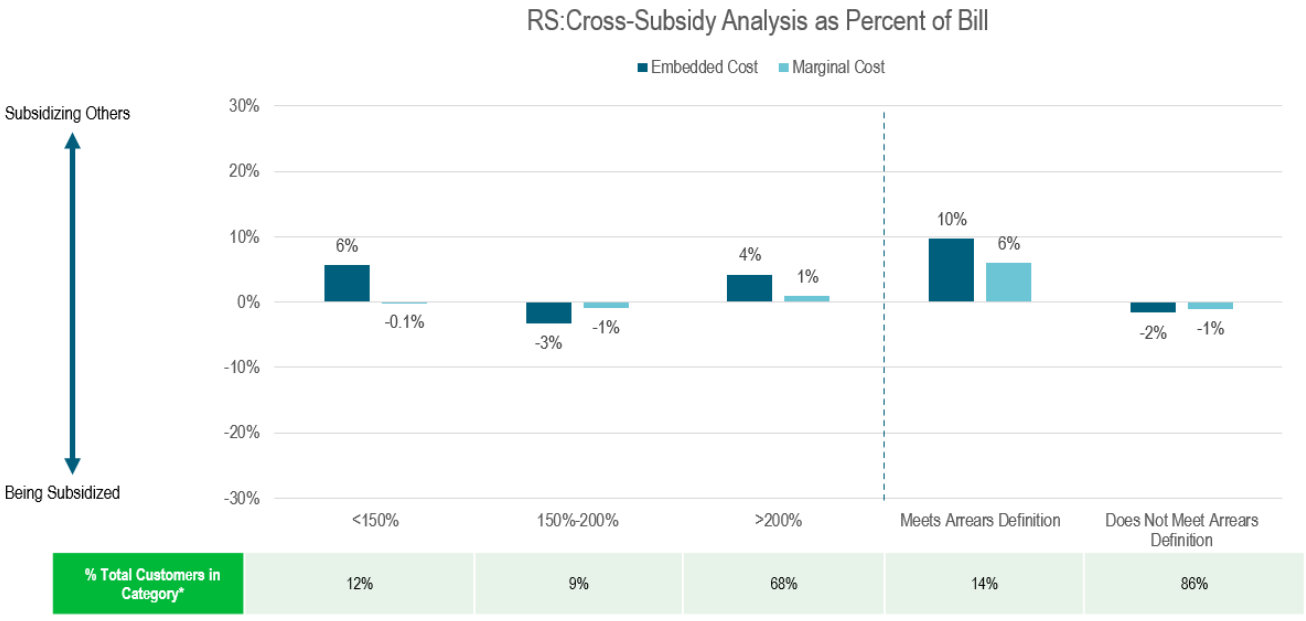
Although this analysis is informative and will be used to inform future rate designs, there was little interest in dividing the DEP residential rate class into multiple groups.

A cross-subsidization analysis was also conducted for DEC, as shown in Figures 11 through 14 below.




*Not all customers can be categorized, resulting in percentages not necessarily summing to 100%

Figure 11: Cross-Subsidy Analysis for DEC Residential Rate RS (as Presented to Residential WG)




*Not all customers can be categorized, resulting in percentages not necessarily summing to 100%

Figure 12: Cross-Subsidy Analysis for DEC Residential Rate RS (as Presented to Residential WG)

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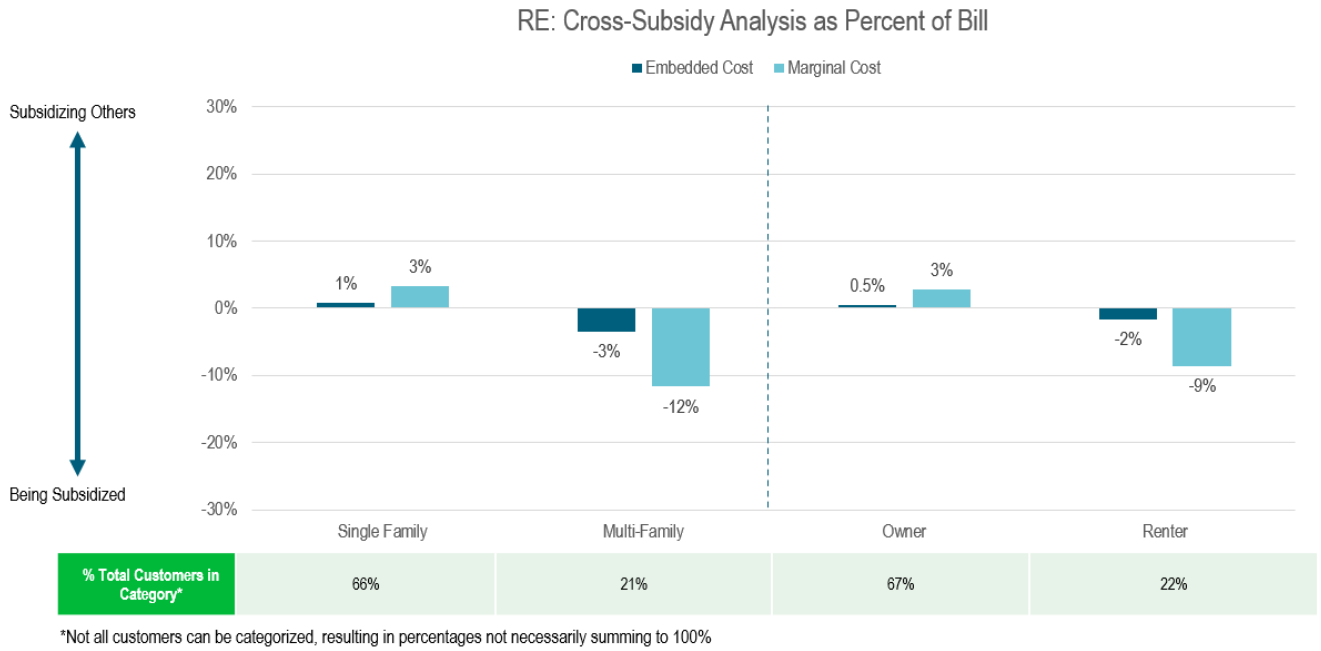
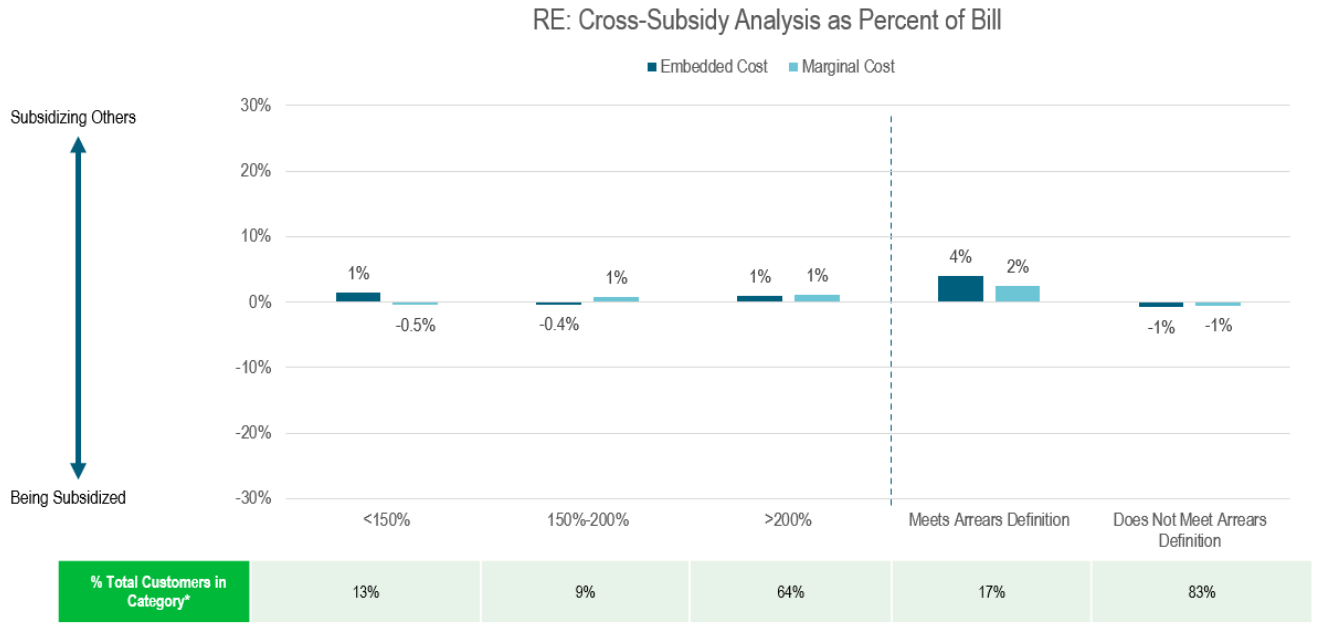



*Not all customers can be categorized, resulting in percentages not necessarily summing to 100%

Figure 13: Cross-Subsidy Analysis for DEC Residential Rate RE (as Presented to Residential WG)




*Not all customers can be categorized, resulting in percentages not necessarily summing to 100%

Figure 14: Cross-Subsidy Analysis for DEC Residential Rate RE (as Presented to Residential WG)

As this analysis is focused on intra-class cross-subsidizations and DEC has different rate classes for RS and RE, this analysis does not directly address if the split rate classes are appropriate. DEC has also moved to be winter planning and therefore electric heat customers invariably contribute more to winter peaks than if they had gas heat. If the allocation methodology for production and transmission costs changes, it is possible that customers

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that are part of the RE rate class would face rates that are equal or even greater than the rates under RS. If this occurs, DEC may want to consider creating one residential rate class, creating alignment with DEP.

## 5.2 Expanded Options for Residential Customers

At present, the Companies essentially have four types of core residential tariffs between DEC and DEP. While adoption rates for the various TOU options remain low at present, customer appeal may increase with more customer-friendly TOU periods alongside customer adoption of distributed energy technologies. These four rate structure types were considered as part of the CRDS and are outlined below, including a summary in Figure 5. At a high level, the Company favors as much consistency and commonality between DEC and DEP across the suite of Residential rate offerings as practicable.

1. **Rate RES/RS/RE (Non-TOU Rates)** – DEP's standard volumetric rate and the tariff chosen presently by ~98% of residential customers. The rate consists of a fixed customer charge and volumetric energy charges, with some pricing features to address seasonality and expected higher load factors from customers with electric heating. For example, DEP-RES currently prices winter energy consumption lower, while DEC-RE is reserved for all-electric customers and provides a lower price for higher consumption levels during winter months. The appropriateness of such features was discussed in the CRDS given DEC and DEP's winter planning status. The Company will continue to review cost of service differences for these customers and design tariff attributes to fairly represent usage behaviors. Also, the Company's new data capabilities and billing system will help interested customers understand their potential to save by switching to TOU rates, which can provide actionable alternatives to customers, who today have limited tools to evaluate the merits of TOU options.
2. **Rate R-TOU (Time-of-Use Rate)** – DEP's TOU rate serves only a fraction of customers at present. As described above, the TOU periods for this rate need to be modernized to provide actionable price signals and more opportunities for customers to save. Some customers interested in TOU options may be wary of Critical Peak Pricing (CPP) or demand charges and may find a static TOU rate attractive, but in most cases the TOU-CPP rate and TOU-Demand options provide customer choice with a manageable number of options.
3. **Rates R-TOUD/RT (Time-of-Use Demand Rates)** – The Companies each have residential tariffs that include TOU and demand features. DEP's TOU-D rate is currently closed to new customers except those taking service on the net metering Rider, and DEC's RT rate will be closed to new customers as of April 1st, 2022. The Companies plan to modernize and reopen these tariffs to residential customers in the next rate case for each utility. While demand rates are more complex and likely only desired by a fraction of customers, expanding customer choice to include a relevant and appropriately priced demand rate is desirable. Importantly, the demand structure for this rate option will need to be modified using similar considerations described for the non-residential demand charge structure changes outlined elsewhere, although with less complexity. Customers with peak shaving capabilities (e.g. battery storage) would be the most likely candidates to benefit from a rate schedule with a demand charge. Conversely, customers with an EV or

Stakeholders noted concern for residential demand rate complexity but also a desire for options

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rooftop solar may not benefit from a demand charge. A modernized demand charge structure is necessary to ensure appropriate recovery of fixed distribution costs given the potential capability of a 4-hour battery to avoid peak demand charges, which as described in the non-residential discussion would only avoid the on-peak related transmission and generation embedded costs.

Stakeholders in the CRDS process expressed concern about such demand rates, and the Companies agree that such rates are more complex and generally not the most appropriate structure for residential customers. However, maintaining a well-designed rate with a demand feature could meet the needs of a possibly growing subset of residential customers.

4. **Rate R-TOU-CPP/RSTC/RETC (Critical Peak Pricing Rates)** – The Companies have both filed and received approval for new TOU-CPP rates over the past 2 years. DEC's new rates stemmed from information gleaned from a suite of CPP options tested in pilot form. DEP's new rate similarly benefitted from the pilots as well as the CRDS process. These rates were described in detail in their respective dockets and include the modernized TOU periods the Company believes are appropriate to reflect in all other TOU rates. Namely, the new periods provide customers the ability to save through both load-shifting to off-peak and discount periods. The CPP aspect of the rates provides an opportunity for the customer to respond to up to 20 critical-peak events per calendar year, called on a day-ahead basis. Importantly, these rates are foundational to the Companies recent residential NEM reform applications, if approved, because all future residential NEM customers would be required to take service under these base tariffs.

The Companies will also investigate the need for any continuing cost differential in the Fixed Customer Charge between TOU and non-TOU rates, given the potential for such differences to create a barrier, however small, to adoption. At present, DEP's TOU and TOU-D tariffs have fixed customer charges that are higher than the purely volumetric tariff. The Companies are investigating the cost differences with the efficiencies and capabilities from AMI metering to determine if such price differentials are still necessary. Future study may also include the extent to which Fixed Customer Charges for non-TOU rates should be higher than TOU or TOU-D rates given the improved alignment to fixed costs for such pricing structures.

Figure 15 below outlines the current suite of Residential rate offering for both DEC and DEP, including existing features and potential attributes for interested customers.

| | RES / RS / RE | R-TOU | R-TOUD / RT | R-TOU-CPP / RSTC / RETC |
|---|---|---|---|---|
| Direction | Largely Remain the Same (may change seasonal pricing and tiering) | Modify *(TOU Periods)* | Modify *(TOU Periods)* | Remain Same |
| Basic Customer Charge | Existing feature | Existing feature; consider continuing need for differences vs. volumetric rate | | Existing feature |
| Energy Charges | Volumetric with some seasonal and tiering features | Energy pricing will align to new TOU periods and include on-peak, off-peak, and discount pricing for each TOU option | | |

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| | | | | |
|---|---|---|---|---|
| Demand Charges | N/A | N/A | Conform to new TOU periods, accommodate storage | N/A |
| Dynamic Price | N/A | N/A | N/A | Up to 20 Critical Peak events per year |
| Interested Customers | At present, majority of customers | Customers adopting smart t-stats or EVs | Customers adopting storage technology | NEM Customers or those with smart t-stats or EVs |

Figure 15: Suite of Current Residential Tariff Options Across DEC and DEP

For Comparison, Figure 16 below shows a stylized view of the differences in energy rates by time period for the non-demand options described above. (Riders have been excluded for simplicity.) Energy charges for RES-TOU-D would be lower as some costs would be recovered through demand charges. Customers willing to accept higher prices during peak periods and during Critical Peak Periods can enjoy the lowest prices during off-peak and discount periods, which can benefit flexible loads such as EV charging. While the addition of on-peak pricing in the TOU rate allows for considerable differences between on-peak and off-peak/discount pricing, the addition of CPP events only modestly adjusts the off-peak pricing benefits (due to the limited number of CPP events annually).

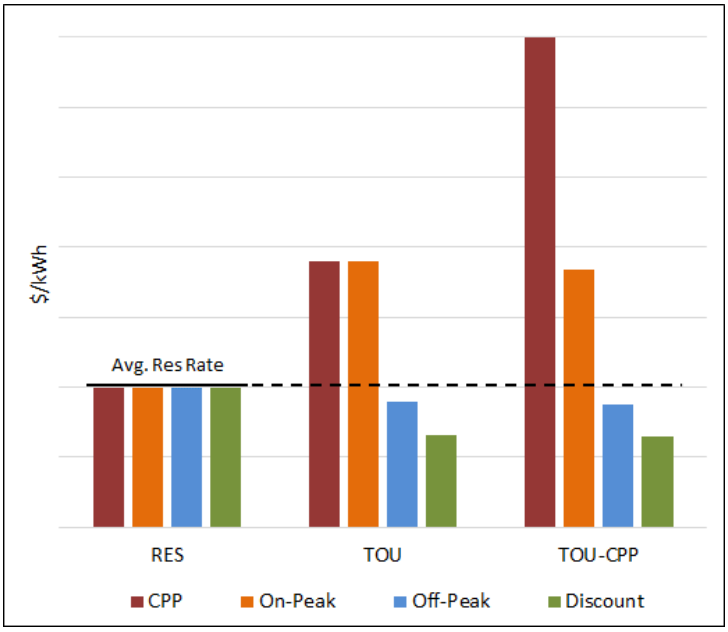


Figure 16: Stylized Pricing Comparison for Potential Suite of Residential Tariffs

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Finally, the Companies' note that Residential participation on TOU rates remains low, certainly in comparison to non-residential customers. There is an interest to get more participation as TOU rates better reflect cost causation even though variable pricing may be intimidating to many customers who have concerns about bill uncertainty. Accordingly, the Companies recognize the potential need to bundle behavioral demand response programs, such as Peak Time Rebates, or other load management tools with rate design options to encourage adoption and enable additional responsiveness. As availability and customer interest in distributed energy technologies increase, the Companies will seek ways to harness the usefulness of these various devices through product offerings that work with well-designed rate structures to provide value to both the customer and the overall system. These devices would potentially include in-home storage, EVs, load control technology, smart thermostats and behind the meter solar systems. The potential for EVs to provide Vehicle to Home (V2H) or Vehicle to Grid (V2G) could also create opportunities. The overlay of subscription concepts to these devices in a bundled offering can lead to managed use in product offerings that provide cost certainty for the customer while seamlessly providing system benefits that flow to all customers.

## 5.3 Residential Net Energy Metering Reform

The Companies recently filed a Residential Net Energy Metering reform application with the NCUC in Docket No. E-100, Sub 180. The filing resulted from discussions within the CRDS and subsequent agreements on reform with a broad group of stakeholders. The Companies' joint application represents an important and early outcome from the CRDS that provides benefits to all customers, as described in the application documents. Additionally, the Companies noted details of the discussions leading to the application in the CRDS quarterly reports.

## 5.4 Subscription Pricing Rates

The Companies recently filed a Residential EV Managed Charging pilot application with the NCUC in Docket No. E-7, Sub 1266 for DEC and Docket No. E-2, Sub 1291 for DEP. The pilot will consist of up to 200 participants (up to 100 participants in DEC and DEP each) and last for 12 months. The price is a flat, subscription rate of $19.99 (DEC) or $24.99 (DEP) for participants to charge their EV at their home, with few limits on the amount that vehicle can charge.[13] In return, the Companies will actively manage charging of the vehicle and schedule up to three managed charging events per month. The Companies discussed with the CRDS how managed charging can be beneficial for EV owners and non-EV owners.

The Residential EV Managed Charging Pilot eliminates a barrier for customers with respect to EV adoption and cost uncertainty, but also affords the Companies a powerful grid management tool that would not exist or exist only partially with self-managed charging. This is because subscription rates offer possibilities for improved grid management from customers who may lack either the capabilities or sufficient financial incentive to manage consumption independently. Absent the subscription program, EV owners may default to initiating charging whenever they arrive home, quite possibly yielding poor or detrimental charging patterns for

Managed charging assuaged some stakeholder concerns regarding subscription rate energy usage

[13] As filed, a participant will receive a warning for using more than 800 kWh in one month for charging. Any participant that uses more than 800 kWhs for three months, or more than 1,200 kWhs in any month, may be removed from the pilot at the Company's discretion.

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the grid (e.g. 6 pm on a summer afternoon). Even a customer using a timer to charge during only off-peak periods when on a TOU rate falls short of the value creation from utility management – specifically, the ability to space out charging across the window to avoid coincident charging peaks and respond to critical grid events as necessary – including events affecting specific grid locations, which cannot be addressed fully through a TOU price signal alone. Indeed, broader price responsiveness, including on a locational basis, from the residential customer class is likely to factor heavily in the Companies' Carbon Plan for the Carolinas.

Subscription Rates may also be worthy of consideration beyond EVs. Customers have historically shown a strong preference for the bill certainty associated with Fixed Bill products, as demonstrated by high annual renewal rates, and managed components can help ensure grid benefits for consumption beyond just EVs. Utility-managed solutions paired with Subscription Rates also has the potential to reach an entirely new set of customers that otherwise may not choose to go on TOU rates. Customers who might not naturally save money by switching to a TOU rate may not migrate to TOU rates and would thus not have the ability to take advantage of savings through improved consumption management. Subscription Rates, however, enable the utility to design a price specific to an individual customer's profile and leverage management tools to benefit the customer and the grid. Given the significant opportunity to address system needs as shown in the Companies' Winter Peak Study filed in Docket No. E-100, Sub 165, the Companies may consider future subscription options beyond EVs.

Results from a recent survey of customers regarding subscription pricing were shared with the Residential Working Group. The survey found that there was customer interest in such a program, especially among low-income customers who appreciate bill certainty. Stakeholders mentioned concerns regarding how fixed prices could result in higher energy use, which the company promised to carefully consider in any potential future programs or filings.

# 6 Rate Design Vision for Non-Residential Customers

## 6.1 Evaluation of Present Rates' Alignment to Costs

Based on questions and feedback from stakeholders during the CRDS, as well as the initial directives provided by the NCUC, the Companies explored the extent to which present rate designs reflected cost causation, primarily evaluating embedded costs[14] based on the unit costs developed as part of the cost of service in the Companies' most recent rate cases.[15] Importantly, such investigations were enabled by advances made in the Companies'

[14] The Companies also verified that current rates are above marginal cost. Embedded costs are historical and relate to the cost of existing production, transmission, and distribution assets, etc. Marginal costs are forward-looking and include the incremental cost of additional energy or capacity. Both are important measures used to determine proper rate designs.
[15] NCUC Docket No. E-7, Sub 1214 – In the Matter of Application by Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina; and NCUC Docket No. E-2, Sub 1219 - In the Matter of Application by Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina.

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capabilities and approaches to data analytics. The following elements constituted the Companies' advanced analytic approach.

- Population level analysis – Rather than relying upon a sampling approach to understand bill impacts for various customer classes, near-population level data sets were used to eliminate concerns with sampling errors. As customers classes become less homogenous, greater levels of granularity are helpful in understand the full impacts of rate design changes.
- Interval data – The Company used hourly, 15-minute, or 30-minute consumption data to evaluate tariff pricing effectiveness and new TOU period considerations. Billing determinants based on prior TOU periods are inadequate for designing and pricing new TOU periods, including determining the impacts across the range of customer usage profiles.
- Embedded and marginal costs – The Companies leveraged both the unit cost analysis from the prior rate case and marginal cost histories to evaluate the effectiveness of pricing approaches through both important lenses.
- Customer Segmentation Data – The Companies used customer segmentation data where appropriate to evaluation price and cost causation alignment within customer classes, particularly within the residential classes. The Companies also discussed Non-Residential classes within the Non-Residential Working Group and implications to rate design. Ultimately, focus on improving cost-causation alignment with pricing across existing tariffs and rate classes through TOU period changes and demand charge restructuring was prioritized over restructured classes. Making substantial changes to both the tariffs and rate classes at the same time would be more complex, therefore revisiting the classes subsequent to TOU modernization is appropriate.

The most relevant question pertaining to existing rate design is whether pricing reflects the differences in embedded costs across customers with varying load factors within a particular tariff. The Company considered several tariffs in the CRDS, and presents example results here for context.

**DEP – Small General Service Time-of-Use (SGS-TOU) and Medium General Service (MGS)**

SGS-TOU is available for customers with demands between 30kW and 1,000kW. The following analysis considers the present tariff design, which is comprised of a two-tier TOU structure (on and off peak) with on-peak and economy demand charges. Demand charges currently contain a seasonality feature, with lower pricing during non-summer months. Also, as seen in Figure 17 below, SGS-TOU becomes the preferred rate for customers in this demand range once load factors exceed 35-40%. Customers with load factors below 40% are more likely to be on Rate MGS, the non-TOU option for customers with demands ranging from 30kW to 1,000kW. (Load Factor is the ratio of average demand to peak demand, with higher load factor indicating that a customer operates at/near their peak demand more often, consuming more units of energy per unit of demand.)

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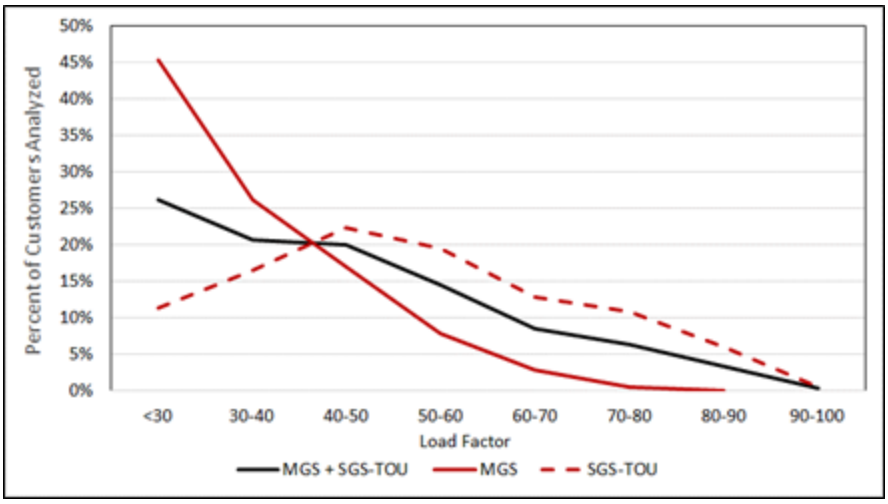


Figure 17: Customer Load Factors on DEP's NC Medium General Service Tariffs

The Company then evaluated the embedded cost contribution for each customer in the load factor ranges shown in Figure 17 using the unit costs developed for DEP's last rate case. In parallel, the Company calculated the bills for a majority of customers on the current tariffs using the same interval data for comparison. As the relationship between embedded cost and pricing is a function of inter-class recovery resulting from the rate cases, the Company normalized the data using the 40-50% load factor range as a baseline (effectively controlling for inter-class differences and allowing isolated focus on differences across the tariff based solely on load factor). The results for the price and embedded cost analysis are in Figures 18 and 19 below.

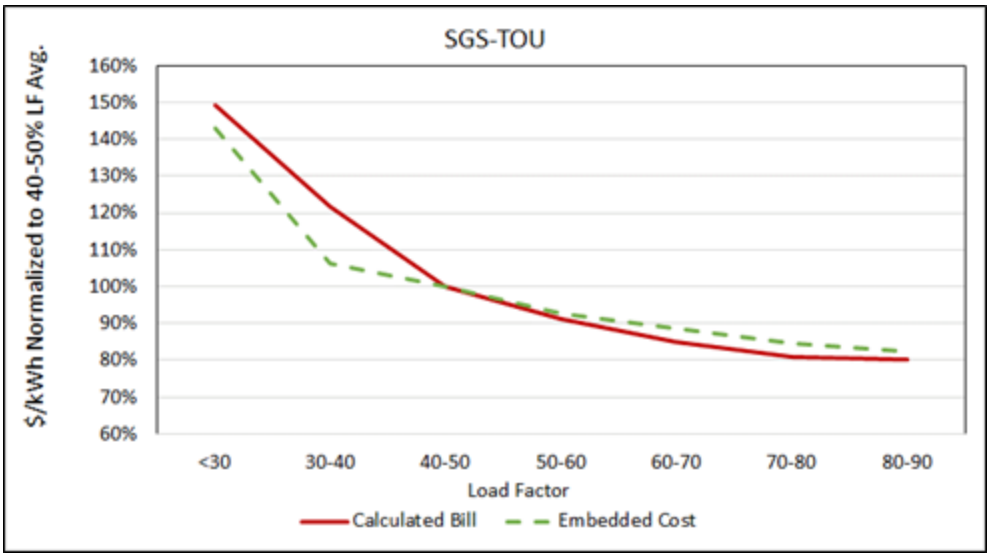


Figure 18: Relationship of Price to Embedded Cost for DEP's Current NC Medium General Service TOU Rate

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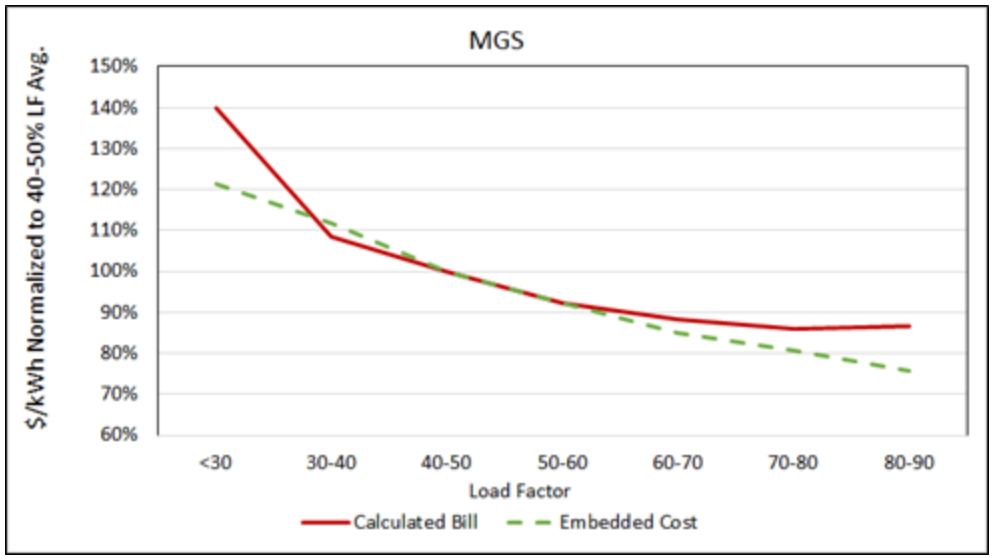


Figure 19: Relationship of Price to Embedded Cost for DEP's Current NC Medium General Service Rate

As seen in the graphs above, SGS-TOU yields a declining cost per unit of energy ($/kWh) with increasing load factor, which is expected and desired given the more efficient use of resources by high load factor customers (the cost of providing capacity for service is covered by more kWh, thus lowering the unit cost per kWh). Notably, for the range of load factors typically taking service under SGS-TOU (i.e. >40% load factor), the price curves matched with the embedded cost curves quite well. Note that embedded cost per unit of energy for customers with 80-90% load factor is around 80% of the per unit of energy cost for customers with 40-50% load factors. Similarly, prices paid by these high load factor customers is about 80% of the per unit price paid for customers with 40-50% load factors. In short, SGS-TOU is working quite well in providing a pricing signal across load factors that reflects embedded costs.

MGS shows some opportunity to improve price/cost alignment, particularly for customers with very low load factors. Such outcomes can be investigated in subsequent rate cases to determine if pricing adjustments in demand vs. energy charges or other rate design features can improve alignment.

**DEP – Large General Service Time-of-Use (LGS-TOU)**

Similar to the analysis above for SGS and MGS customers, the Company evaluated the alignment of price with embedded costs within LGS-TOU, normalized to the 50-60% load factor range. Customers tend to favor LGS-TOU when their load factors exceed 70%, which is higher than was typical for MGS and reflective of the class overall. Figure 20 below demonstrates that LGS-TOU pricing declines generally commensurate with embedded costs as load factors increase within the class.

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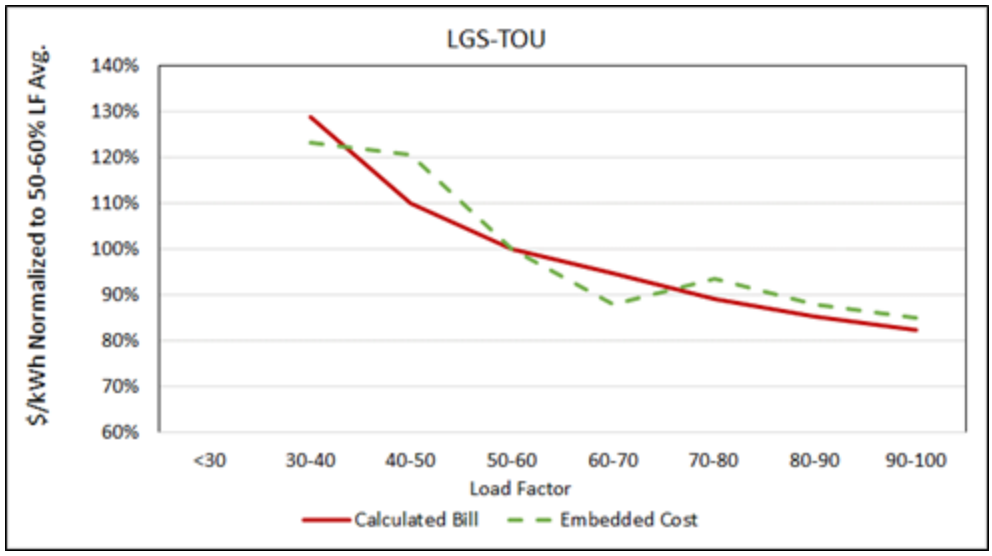


Figure 20: Relationship of Price to Embedded Cost for DEP's Current NC Large General Service TOU Rate

The Company followed the same process in the evaluation of DEC's OPT-V tariffs, with Primary and Secondary delivery for Large and Medium customers shown in Figures 21 and 22 below. In contrast to the DEP analysis above, the Company notes opportunities to improve in a few areas.

1. OPT-V Primary Large embedded costs drop considerably with rising load factors, consistent with SGS-TOU as described in the prior section. However, per unit of energy prices do not decline commensurately, leaving some opportunity for rate design improvements. Increasing the extent to which fixed costs are recovered through demand charges is one option to improving price/cost alignment. (OPT-V Primary Medium, in contrast, shows pricing aligned quite well with embedded costs across the range of load factors.)
2. OPT-V Secondary presents similar opportunities to improve as OPT-V Primary. Customers with higher load factors pay less per unit of energy than customers with lower load factors, but not as much as might be justified based on embedded cost differences. Rate designs in future rate cases could work to address these pricing differences through the mix of cost recovery via demand vs. energy or other rate design features.

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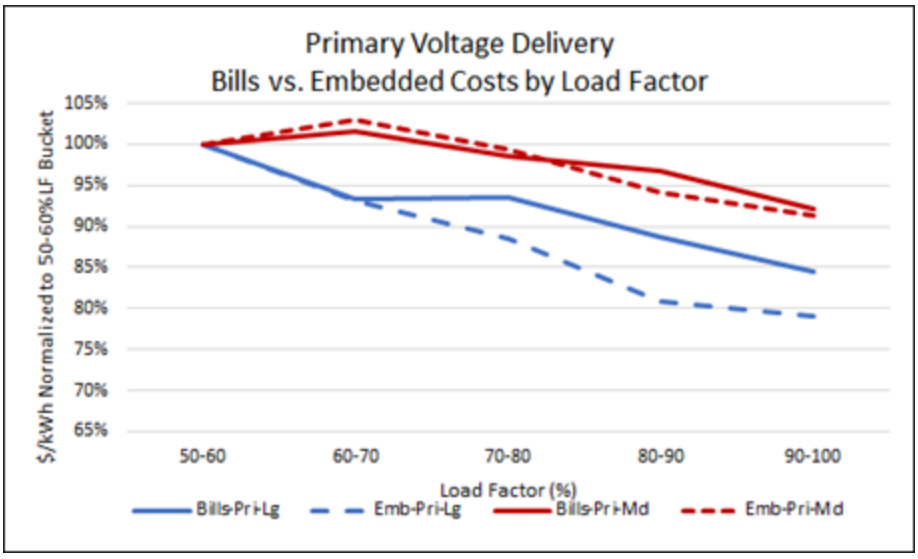


Figure 21: Relationship of Price to Embedded Cost for DEC's Current NC OPT-V Primary Medium and Large General Service Rates

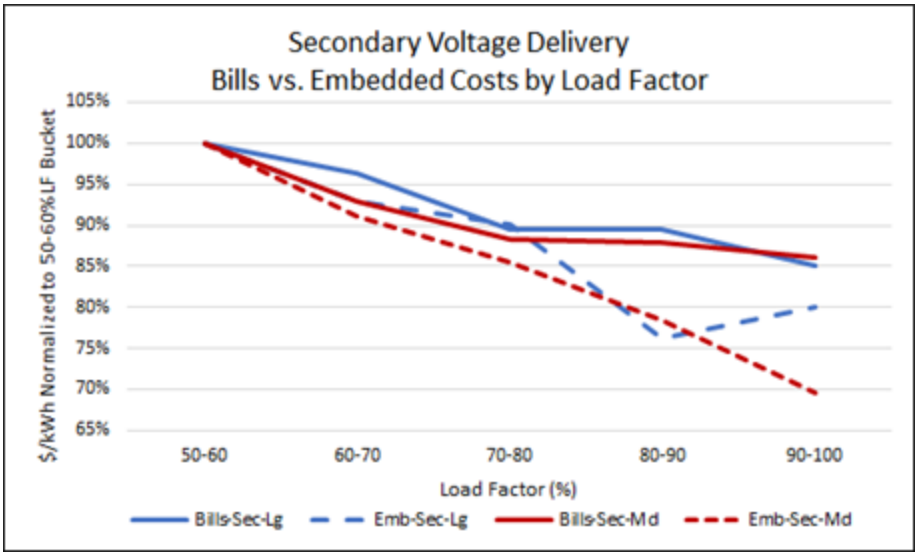


Figure 22: Relationship of Price to Embedded Cost for DEC's Current NC OPT-V Primary and Secondary Medium and Large General Service Rates

Importantly, as described elsewhere, the TOU periods and demand charge structure for these non-residential rates should be modernized to reflect today's electric system realities. Such improvements should better align embedded costs and pricing for individual customers based on differences in usage profiles. While the graphs above show some opportunity to improve for groups of customers, new TOU periods would begin to better distinguish between usage profiles and price. The Company will continue evaluating and consider improving such alignment over successive rate cases.

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## 6.2 Opportunities to Improve Alignment of Cost-Causation with Price

Rate designs should adjust to recognize changes coming from two fundamental factors – the upending of historic system operational norms and the increasing desire from customers to align price signals with usage behavior, particularly with respect to adoption of distributed energy technologies. Accordingly, non-residential rates should also be modernized to properly align pricing with cost-causation, thus ensuring energy investment and consumption decisions receive the appropriate economic signals with respect to system costs and potential impacts to other customers. The following areas require critical advancements and modifications to update the Companies' historic suite of rate offerings for these new realities.

**TOU Period Modernization:** As mentioned above, TOU modernization forms the foundation for many rate design opportunities discussed in this Roadmap, in particular advancing the goals of better alignment between price signals (and bills paid) with cost-causation. The Companies reviewed the potential changes to non-residential rates with CRDS participants in the non-residential working group, including the implications that modernizing TOU periods will have for most of the other rate design ideas presented in this Roadmap. CRDS participants expressed concerns regarding the impacts across the spectrum of customer usage profiles. Accordingly, in creating prices for the new periods, the Companies will need to consider the disparate potential impacts between customers with flexible loads vs. those with operational challenges that do not permit load shifting, as well differences across varying load factors. The Companies discussed options for mitigating those concerns with customers and stakeholders and recognize that ultimate rate designs proposed in future regulatory proceedings must carefully weigh rate gradualism and concerns about unintended consequences, as well as maintaining non-TOU rate options for customers that would not benefit from being on a TOU rate. The Companies will use migration studies and near-population level analyses based on interval data to better understand how new revenue neutral rate design changes might result in a range of impacts across specific customers in some rate classes.

Stakeholders expressed concern that TOU changes might increase bills for customers with inflexible loads

Notwithstanding important transition considerations, TOU period reform requires significant design changes across several of the Companies' tariffs that include time-differentiated pricing. Figure 23 lists the non-residential tariffs that would need to accommodate the new TOU periods.

| **DEC-NC** | **DEP-NC** |
|---|---|
| OPT-V | SGS-TOU, SGS-TOUE |
| PG | SGS-TOU-CPP *(modernized periods already)* |
| SGSTC *(modernized periods already)* | LGS-TOU, LGS-RTP-TOU |
| | CH-TOUE, SGS-TES, APH-TES |

Figure 23: Tariffs that would be updated through Time-of-Use Period Modernization

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**Demand Charges Restructuring:** As described in Section 4.2, demand charges must be reimagined to create cost-based price signals that match the new TOU periods. The three-part demand charge structure described in this Roadmap is an example of improved alignment to cost causation and equitable pricing for customers, for both those who adopt distributed energy technologies and those who do not. Stakeholders in the CRDS have shown significant interest in aligning capacity costs with demand charges as well as improving the alignment of cost-causation with pricing, particularly for high load factor customers. Implementing a new demand charge structure for TOU rates, such as the three-part demand charge structure, will be foundational to align costs with new TOU periods and better align time-period price signals with specific electric system asset utilization and, accordingly, costs. Increasingly, intermittent resources are reshaping grid cost profiles such that load factor is only one lens through which to view the efficient use of system resources. As an example, consider flexible loads, such as a fleet EV charging customer who constrains charging activities to only the Companies' proposed discount charging periods. Such a customer would have a very low load factor, but costs for production and transmission would be much lower than for a customer with a comparable load factor but with on-peak demands. As a result, even a low-load factor customer with certain usage profiles should receive appropriate system-reflective price signals. The three-part demand structure creates the framework by which price and system cost alignment can be maintained or improved gradually over time.

**Adjustment of Demand Tiers:** LGS-TOU and OPT-V Primary Large both currently have demand tiering features with lower $/kW charges for demand above certain kW thresholds. Such features account for cost differences associated with system use efficiency, but as described in the previous section, such pricing features may overlap with the restructured demand charges. The Companies explored one approach to retaining and adapting demand tiers to the new TOU periods during the CRDS, and further consideration will be needed, including considerations of rate gradualism, as the demand structures are evaluated in future regulatory proceedings.

**Capacity Related Costs in Demand Charges:** Several stakeholders suggested recovering more capacity-related costs in demand charges rather than energy charges, to better reflect cost drivers within the electric system. Importantly, the Companies believe such recovery should reflect the extent to which those capacity costs are driven by peak or non-peak costs, with recovery flowing through peak or mid-peak demand charges as appropriate. As noted above, expanding cost recovery through demand charges would help with price and cost alignment for DEC's OPT-V rates, and should be considered in future regulatory proceedings. Such changes would improve structural harmonization between DEC and DEP tariffs but must consider the potential for unintended consequences on customers across a variety of usage profiles. Thus, the Company would consider gradualism and perform detailed analysis across the rate class to support such modifications.

**Voltage Differentiated Rates:** While DEC's OPT-V tariff is divided up based on customer delivery voltage and load size, DEP uses load size to delineate between Small, Medium, and Large General Service classes. LGS-TOU provides a price differential for customer-supplied transformation as well as demand tiers, reflecting a typical correlation between size and delivery voltage. Size, delivery voltage, and load factor are all important considerations in creating customer classes, but the overarching objective is to align price with cost causation

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using a simple approach. Voltage-differentiated rates may be considered long-term for DEP, but at present the Company sees decent alignment between price and embedded cost across varying load factors (see Section 6.1). The benefits and complexities of additional pricing differentiation, including based on voltage delivery, will be evaluated and considered over successive regulatory proceedings.

**High Load Factor Rates:** Finally, some stakeholders in the CRDS advocated for rates designed for customers with higher load factors. The Company explored this idea in Working Group sessions and in several conversations with interested stakeholders and is continuing to evaluate the opportunity for possible inclusion in future regulatory proceedings, in addition to the adjustments referenced above with respect to load factors. While one approach may be to adjust demand charges and the mix of recovery between demand and energy to better align with cost-causation, another approach may be an entirely different tariff designed with demand charge structures suitable for high load factor customers.

The preceding ideas are interrelated and overlapping and cannot be considered in isolation. Indeed, good rate design requires consideration of the full set of changes together, considering the impacts to revenue requirements for the full class as well as individual customers within a particular tariff. The analytics capabilities the Company has developed will help ensure balanced and intentional outcomes for customers considering the balance of benefits from more precise pricing, rate design simplicity, and rate gradualism.

**Emergency Interruptible Rates:** The Company discussed an option for an additional interruptible rate to be used during system emergency conditions, possibly when response times are more rapid than current demand response programs. Additional program attribute design and valuation would need to be developed looking specifically at the unique characteristics of the Companies' system. In addition, potential overlap between other dynamic pricing options (Critical Peak Pricing and Hourly Pricing) would need to be considered.

**Peak Demand Rates:** A minority of stakeholders also put forward alternative approaches to demand structures in new rates, such as a non-residential Critical Peak Pricing rate or a Coincident Peak Pricing rate. Broad support for such structures was not expressed, with generally stronger preference for other alternatives (e.g. new Hourly Pricing Rate concepts discussed below). The Company will consider the alternatives with stakeholder preferences in mind, as well as considering how the characteristics of the Companies' system have evolved over the last several decades.

**Load Aggregation:** One stakeholder presented and advocated for Load Aggregation as a potential option to recognize the volume purchases made by customers with facilities located across the Companies' system. The Company discussed options to address such a design considering the modernized demand charge approach outlined above. The concept suggested by the stakeholder would allocate generation and transmission costs based on the aggregated load shape, which would reflect any load diversity, and would allocate distribution costs using the non-aggregated load.

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The preceding rate design concepts are interrelated and cannot be considered in isolation. Indeed, good rate design requires a holistic view, considering the impacts to revenue requirements for the full class as well as individual customers within a particular tariff. The analytics capabilities the Company has developed will help ensure balanced and intentional outcomes for customers considering precise pricing, rate design simplicity, and rate gradualism.

## 6.3 Expanded Hourly Pricing Options for Non-Residential Customers

The Companies' current hourly pricing programs provide hourly prices for incremental loads based on the Companies' marginal cost of generation. Both DEC's Hourly Pricing tariff and DEP's Real Time Pricing tariff are capped based on the number of participants. Customers and Stakeholders in the CRDS process have requested an increase in availability for these tariffs, as well as certain other options for flexibility with respect to the setting of Customer Baseline Loads (CBL). CBL's determine the amount of a customer's load that is priced at the marginal rate, with the core tariff being applied to the CBL for each customer's bill, and marginal energy prices either being charged or credited to the customer based on usage above or below the CBL, respectively. Importantly, an expanded hourly price tariff with significant levels of price-responsive load could be an important enabler for the Companies' Carolinas Carbon Plan, in addition to its other merits.

Stakeholder suggestions to modify the hourly pricing offerings discussed in the CRDS included the following:

- Expanded availability to more customers
- Allow existing load to take advantage of hourly (marginal) pricing
- Reduced complexity for setting and adjusting the CBL (simple, less restrictive, more frequent)
- Transparency in pricing and cost drivers
- Hourly pricing rates that considered EV charging and smaller customer participation

The Company provided an overview and responded to questions on hourly price derivation during the CRDS working sessions with stakeholders, providing increased transparency as to the derivation and basis for hourly prices. The remaining stakeholder suggestions were discussed in the context of a possible new hourly price offering. Importantly, the Company made clear that participants in a marginal price rate should not be able to avoid paying embedded cost-based rates if participating load was not truly incremental; in other words, if the load contributes to construction of new peak production and transmission resources. Accordingly, the discussion stressed the tradeoff between CBL flexibility and price responsiveness during times of grid constraints. As a result of those customer discussions, the Company suggested a possible new tariff that balanced customer desires for broader access to marginal pricing with consideration for possible impacts to the system and non-participating customers. This is particularly acute as it relates to recovery of embedded capacity costs and the needed alignment to the cost to provide service. The attributes of a potential new offer were generally described as follows:

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- **Availability:** Consider lower demand thresholds as compared to the current 1MW. Such broad expansion was proposed by a minority of stakeholders and should be balanced against the complexity and administrative burden of hourly pricing tariffs, as well as the availability of similarly beneficial options for many customers, such as Economic Development tariffs or core tariffs with revised TOU periods. Additionally, possible interest for smaller commercial and industrial customers would need to be evaluated given the complexity and price-responsive design elements described below.
- **Participation Limits:** Evaluate participation limits, currently set at 85 customers for LGS-RTP (DEP-NC) and 150 customers for HP (DEC-NC).
- **CBL Establishment:** Include a process for reestablishing the CBL every 4 years and adjustments based on the customer's 12-month usage history. Under the current tariffs and practices, CBL adjustments are not required on any set frequency. Importantly, the approach discussed would have the following implications for CBL establishment:
    - Growing loads with an inability to be price-responsive would receive marginal pricing for the incremental loads for only a limited time. Without the benefits of responsiveness to times of grid constraints, new capacity resources would ultimately need to be constructed for such loads, thus the CBL would be adjusted accordingly.
    - For loads that responded during periods of grid constraints, the CBL could be maintained lower based on the extent to which a customer reduced such loads during times of constraint.
    - The specific methodology for adjusting the CBL for price-responsiveness would need to be established in detailed program design.
    - The structure enables existing/historic loads to take advantage of marginal pricing provided such loads cease contributing to peak system demands during times of transmission and generation constraints, demonstrated by actual price-responsiveness over a period of time. Price-responsive behavior is system beneficial and reduces the extent to which such loads contribute to long-run marginal costs. In contrast, CBLs would increase to cover loads that are not price-responsive.
- **CBL Management:** DEC's process for CBL management is simpler and less administratively burdensome than DEP. Any new hourly pricing program would need to reflect a simpler approach in order to increase availability.
- **Energy Marginal Pricing:** The Company presented several variants of Hourly Pricing rates that would continue to enable embedded cost recovery but expand participation, including putting some margin as an adder to the energy prices. Stakeholders generally preferred to maintain the current approach of keeping the energy margin adder very small and recovering embedded costs through demand charges.
- **Existing and Incremental Loads:** As described above, stakeholders wanted the Company to consider allowing participation from both existing loads and incremental loads, which would require the CBL adjustment considerations outlined above.

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## 6.4 Simplification of Non-Residential Rates

For historical reasons, DEC and DEP have different approaches to Non-Residential rate designs and rate classes, with DEP generally using broad customer classes separated by size, and DEC using more narrowly defined customer classes separated by size, delivery voltage, and other factors. Both approaches are valid and indeed both often result in similar outcomes and impacts to customers; nevertheless, improvements and changes are appropriate to both simplify and modernize the tariffs as well as harmonize differences between the Companies. Figures 24 and 25 below provide considerations for specific improvements across the Companies' suite of non-residential rates.

Figure 24: Duke Energy Progress NC Non-Residential Tariff and Future Design Considerations

| Existing Tariff | Preferred Direction | Review Considerations |
|---|---|---|
| **Small General Service Class:** | | |
| SGS | Remain same | No change |
| SGS-TOU-CPP | Remain same | No change (newly available tariff with modernized TOU periods) |
| SGS-TOUE | Modify | Redesign TOU periods (no demand charges in tariff) |
| SGS-TOU-CLR | Remain same | No Change; consider need to remain separate from SGS |
| **Medium General Service Class:** | | |
| MGS | Remain same | No Change |
| SGS-TOU | Modify | Modernize TOU periods and demand charge structure |
| CSE | Modify | Modify price to encourage migration, per prior settlements |
| CSG | Modify | Modify price to encourage migration, per prior settlements |
| CH-TOUE | Modify | Modernize TOU periods |
| GS-TES | Modify or Replace | Replace with modernized TOU periods and demand charge structure, *or* Replace with modernized SGS-TOU and LGS-TOU |
| APH-TES | Modify or Replace | Replace with modernized TOU periods and demand charge structure, *or* Replace with modernized SGS-TOU and LGS-TOU |
| **Large General Service Class:** | | |
| LGS | Remain same | No Change |
| LGS-TOU | Modify | Modernize TOU periods and demand charge structure |
| LGS-RTP | Replace | Replace with new Hourly Pricing Option with greater availability |
| LGS-RTP-TOU | Replace | Replace with new Hourly Pricing Option with greater availability |

Figure 25: Duke Energy Carolinas NC Non-Residential Tariff and Future Design Considerations

| Current Rate Schedule | Direction | Review Considerations |
|---|---|---|
| **General Service Tariffs:** | | |
| SGS | Modify | Simplify Energy Block structure |
| SGSTC | Remain same | No change (newly available tariff with modernized TOU periods) |

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| | | |
|---|---|---|
| BC | Remain same | No change |
| I | Modify | Evaluate Block structures for simplification |
| LGS | Modify | Evaluate Block structures for simplification |
| OPT-V | Modify | Modernize TOU periods and demand charge structure |
| PG | Modify | Modernize TOU periods and demand charge structure |
| HP | Replace | Replace with new Hourly Pricing Option with greater availability |

## 6.5 Non-Residential Net Energy Metering Reform

As described above, the Companies recently filed a proposed NEM reform for residential customers in NC based on collaborative outcomes in the CRDS.[16] The Company also discussed possible changes and improvements for non-residential NEM policies with stakeholders during the CRDS. The following NEM elements were discussed with stakeholders and could be considered in the context of future regulatory proceedings.

- **Expand Capacity Limits:** Currently, for DEP customers, NEM systems are limited to "the lesser of Customer's estimated maximum annual kilowatt demand or 1,000 kilowatts." DEC presently limits non-residential system sizes to the lesser of the Customer's Contract Demand or 1,000 kW.[17] Consideration should be given to harmonizing the approach between the utilities. Stakeholders have requested the 1MW limit be raised. As mentioned above, the Companies note that restructuring demand charges to a 3-tier approach as described above could provide cost alignment sufficient to consider raising the limits as requested by stakeholders. Additionally, the new TOU periods could similarly address cost recovery concerns stemming from differing energy values across time periods.
- **Review Standby Charges for Solar Facilities:** Stakeholders have expressed interest in having the standby charge practices of the Companies reviewed, and such changes would impact both solar and non-solar resources. Indeed, HB951 requires the review of such charges. The Company is undertaking such a review at present, in light of the changes related to fixed-cost recovery associated with the demand charge structure modernization described above.
- **TOU Rate Participation:** The Company's proposed residential NEM reform included a requirement that residential NEM customers take service under a TOU-CPP tariff. Similarly, the Company could consider a requirement for non-residential NEM customers to take service under a TOU demand rate with the view toward achieving appropriate economic consideration for the value of the solar resource.
- **Revise Netting Periods:** Consideration should be given to following the netting approach proposed in the Companies' residential NEM reform application, which nets energy within each TOU period.
- **Renewable Energy Certificate (REC) Retention:** NEM Customers taking service under one of the Company's TOU tariffs will retain ownership of all RECs generated by their system. *[The Companies will*

[16]See Joint Petition for Approval of Revised Net Energy Metering Tariffs, filed on November 29, 2021 in Docket Nos. E-7, Sub 1214; E-2, Sub 1219 and E-2, Sub 1076 but subsequently transferred by the Commission to Docket No. E-100, Sub 180.
[17] The 1,000kW limit applies to NEM customers. Customers wishing to install more than 1,000kW must do so under an alternate tariff, for example DEC-HP or DEC-PG.

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*work to align REC ownership rules across NC and SC, including consistency with outcomes from the NEM reform activities.]*

- **Accommodate Energy Storage:**
  - Some stakeholders would like to see a program that incorporates energy storage for demand response or grid service credits.
  - NEM needs to clarify whether batteries count as part of the generation system or load, and the answer may depend on where in the system the battery is electrically located.
  - Clarity here is needed for customers wish to be "net-zero." The Companies' Large Account Managers (LAM) and Rates teams increasingly encounter such requests and more clarity is needed on what is allowed.
- **Minimum Bill:** The Companies will evaluate the extent to which a minimum bill is needed for customers on a non-demand rate, such as DEP-SGS and DEP-SGS-TOUE.

## 6.6 Economic Development

The Companies received meaningful and helpful proposals and feedback from stakeholders in reviewing current Economic Development tariffs and potential improvements. Figure 26 below shows the differences in the current DEC and DEP Economic Development tariff options. Considerations for improvement are provided below, including many recommendations from stakeholders on specific elements to include and/or adjust. Overall, the suggestions provide more flexibility to offer credits based on the merits of specific growth opportunities. Ultimately, expanded load through economic development can reduce the prices paid by all customers, through contribution to fixed cost recovery, and promotes the prosperity of the citizens and businesses in the Companies' territories. Some combination of the improvements discussed would assist the State of North Carolina and local communities in competing for projects.

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| Rider Attribute | Econ Dev. (DEC – EC) | Econ Re-Dev. (DEC – ER) | Econ Dev. (DEP – ED) | Econ. Re-Dev. (DEP – ERD) |
|---|---|---|---|---|
| Availability | • 1,000 kW min.<br>• LGS, I, OPT-V<br>• Excl. Retail, Pub. Admin. | • 500 kW min.<br>• LGS, I, OPT-V<br>• Excl. Retail, Pub. Admin. | • 1,000 kW min.<br>• LGS & LGS TOU<br>• Excl. Retail, Pub. Admin. | • 500 kW min.<br>• MGS, SGS-TOU, LGS, LGS-TOU<br>• Excl. Retail, Pub. Admin. |
| Qualification | 75 FTEs or $400k capital invested per 1,000kW | 35 FTEs or $200k capital invested per 500kW | 75 FTEs or 1FTE + $400k capital invested | 35 FTEs or 1FTE + $200k capital invested |
| Location | New or existing building | Existing building | New or existing building | Existing building |
| Discount | 4-yr. declining discount from 20%→5% | 50% for 12 months | • 5-yr. declining $/kW<br>• Scales w/ LF (>40%) | • 1-yr.; 25% if <1MW, 50% if >1MW<br>• LF >40% only |
| Ramp Period | 18 months | 12 months | 18 months | 12 months |
| Contract Term | 10 years | 5 years | 5 years | 5 years |
| Termination Penalty | Lower of NPV of remaining Min Bills or LDER + difference between Credits and Marginal costs | Lower of NPV of remaining Min Bills or LDER + difference between Credits and Marginal costs | Return all discounts | Return all discounts |

Figure 26: Key Attributes of DEC and DEP Current Economic Development Tariffs

- **Availability:** Availability criteria regarding size, load factor, and other considerations were discussed. As mentioned above the Company's Economic Development tariffs could be modified to lower availability thresholds and exemptions for the employment requirements for EV fleets. Stakeholders also proposed possible expansion of participation availability to include customers where retention of load and employment is at risk, such as efforts to modernize or reinvest in plant or equipment where such investment could be competitively relocated outside the Companies' service territories. The Company may explore ways to address such situations where NC may otherwise be placed at a competitive disadvantage, recognizing that additional qualification criteria may be required for such circumstances (e.g. capital investment levels, etc.).
- **Qualifications:** Qualifications are important to ensure the incremental loads are system-beneficial for an extended period and will ultimately provide benefits to all customers. Stakeholders offered a variety of suggestions regarding employment, investment levels and participation in renewable or green programs. The Company will consider these criteria, as well as possible changes to the discount structure outlined below. To the extent credit levels become flexible with respect to project-specific attributes, the importance of qualifications as threshold barriers decline. In addition, the North Carolina Department of Commerce offers Job Development Investment Grants (JDIGs) for High Yield Project (HYP) status for creation of 1,750 jobs and $500M investment in NC and Transformational Project (TP) status for creation

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of 3,000 jobs and $1B investment in NC. The Company will consider the merits of additional support for Economic Development projects meeting these Department of Commerce criteria.

- **Discount Credit Level:** DEC's present credit approach is essentially one-size-fits-all, while DEP's approach scales with load factor under the assumption that system benefits of new projects increase given the more efficient asset utilization. Similarly, other project attributes also warrant consideration for determining the scale of credit levels. During the CRDS, the Company presented the example of Duke Energy Indiana's economic development tariff which scales the credit based on several factors, similar to those in the list below. Additionally, the credits can be tailored across the duration of the incentive period to reflect specific needs or attributes of each project. As such, the Companies may consider proposing credit levels that could vary by year and reflect the following value factors for each project:
  - Peak monthly demand
  - Average monthly load factor
  - The Company's incremental costs to serve
  - Number of new FTEs
  - Economic multiplier (e.g. supply chain impacts upstream for OEM)
  - Total new capital investment of the customer
  - Others as appropriate
- **Ramp Period:** The Ramp Period allows a customer who elects to participate in the Economic Development program to defer initiation of the credits for a time during the startup operational phase. Some industries have significant startup periods that extend beyond the currently allowed 18-month window. CRDS participants discussed the possibility of a 36-month ramp period, which would provide a more meaningful credit to customers with extended start-up timeframes, which usually correlates to significant customer investment (and thus worthy of extra consideration). Without such expansion, some customers may effectively lose the entire first year or more of the benefit from the ED rider.
- **Contract and Termination:** DEC's current contract term of 10 years is longer than DEP's 5-year term. Given the increase in flexibility and potentially flattening of credits across the term, the Company will consider lengthening the contract term to 10 years, further yielding consistency between DEC and DEP. Similarly, the early termination penalty could be simplified and made consistent across DEC and DEP. Finally, the Company will consider provisions for longer duration credits and contract terms for projects that may merit such consideration.
- **EVs:** During the CRDS, stakeholders expressed an interest in Duke Energy working directly with non-residential EV customers – both EV fleets and owners of charging stations – to address their needs. As mentioned above, one concept considered removing possible barriers for such loads to participate on economic development tariffs. The Company may consider changes to qualification criteria specific for such incremental loads, for example, reducing the employment thresholds. Additionally, any economic development benefit to these customers will need to consider possibly overlapping benefits from Make-Ready or marginal-cost-based pricing options to ensure that these policies do not enable "double-dipping" (i.e. giving multiple benefits for the same system benefit).

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## 6.7 Renewable and Clean Tariffs and Programs

Throughout the course of the CRDS, the Company engaged with several interested customers and advocacy groups to explore possible new or expanded renewable or clean energy programs and offers. In accordance with HB951, the Company would pursue such programs to the extent non-participants are held harmless and supporting resources are developed in accordance with state policy. While the Company recognizes some elements of bill credits and recovery may need to be addressed for the program designs being considered, the Company sees the following desirable program attributes:

- Participating customers are able to own/purchase RECs for desired renewable energy levels
- Customers could have optional access to storage resources as part of the program to time-align consumption of renewable or clean energy
- Flexibility to adjust for the diverse sustainability goals within Duke Energy's current customer base as well as prospective Economic Development opportunities

The Company will continue conversations with interested customers in order to ensure future programs are sufficiently flexible and durable, meeting the needs of a broad mix of interested customers as well as complying with HB 951 requirements.

## 6.8 Historic/Closed Tariffs

The Company reviewed a few historic rates that have low participation or are currently frozen to new participants. Additionally, new program offerings such as modernized TOU offerings and an expanded and revised hourly pricing option create opportunities to close and/or freeze existing tariffs, such as the following:

- **Real Time Pricing (DEC-HP, DEP-LGS-RTP and DEP-LGS-RTP-TOU)** – To the extent the Company moves forward with the new hourly pricing option as described above in future regulatory proceedings, the existing DEC-HP and DEP-RT hourly pricing options should be evaluated for freezing to new customers. As such, noted administrative challenges and program limitations would be addressed.
- **Small General Service Constant Load (DEP-SGS-TOU-CLR)** – The Company may consider the need to retain tariffs, such as the Constant Load tariff, in light of the capabilities now present with AMI metering and also the planned modernization of TOU periods and demand charge structures.
- **Church and School Service Tariffs (CSE and CSG)** – These two tariffs have been closed to new customers since 1977 and have a dwindling number of participants. To the extent the modernized tariffs with new TOU periods present savings opportunities to CSE and CSG customers, the Company may move customers to the new rates (per the terms of the tariffs), providing the opportunity to close these historic tariffs.
- **Church Service TOU (CH-TOUE)** – The Company will need to consider either redesigning this tariff with the new TOU periods or closing the tariff to new customers. Consideration would likely include an analysis of the extent to which the redesigned SGS-TOU rate might be a favorable alternative for customers presently taking service on CH-TOUE.

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- **Thermal Energy Storage Tariffs (SGS-TES and APH-TES)** – These tariffs were designed for customers using thermal energy storage systems. As the modernized demand structures and TOU periods described should address economic use of other forms of storage, the Company should evaluate the ongoing need for these tariffs given the redesigned core tariffs in upcoming regulatory proceedings.

For the rates listed above, customers could migrate to another alternative core rate, as appropriate (for example, SGS-TOU or OPT-V). Overall, the Companies prefer a simplification for the overall suite of rate offerings, but with meaningful options remaining based on the customers interest in TOU, demand, or dynamic pricing schedules – all of which would have improved price signals with the changes envisioned in this document.

# 7 Timeline for Implementation of Rate Design Changes

## 7.1 Timeline for Changes and Improvements

Throughout the CRDS, the Company stressed a bias for action, specifically preferring to advance the changes that improved options and addressed issues for the most customer as soon as possible. Many of the items discussed will need to be addressed in the context of a rate case, but others are able to be advanced more quickly or in other proceedings. The following areas presented opportunities to pursue improvement more quickly.

**DEP TOU-Critical Peak Pricing (R-TOU-CPP) Rate:** Filing in September 2021 consistent with the new TOU periods and in an effort to increase customer options for dynamic rate structures.

**Net Energy Metering:** As a result of the CRDS process, on November 29, 2021, DEC and DEP jointly filed a Petition for Approval of Revised Net Energy Metering Tariffs (Docket Nos. E-7, Sub 1214; E-2, Sub 1219 and E-2, Sub 1076). The proposed reforms will align solar adopter compensation to utility system benefits and create long-term stability for the residential solar industry in North Carolina. The agreement was crafted by Duke Energy and NCSEA; the SELC on behalf of Vote Solar and SACE; Sunrun Inc. and the Solar Energy Industries Association and must be approved by the NCUC.

**Residential Tariff Availability:** As a result of the CRDS process and customer feedback, on December 16, 2021, DEC filed Proposed Revisions to Service Regulations and Rate Schedules (Docket No. E-7, 1214). The proposed changes to the Availability provisions of certain residential tariffs removes the requirement that facilities be permanent, thus reflecting a more liberal application of residential rate provisions as part of the resolution of the "tiny homes" issue. The Company proposed revisions to its Service Regulations to allow eligible tiny homes to be billed on a residential schedule, which DEP Service Regulations currently allow. The proposed changes must be approved by the NCUC.

**Freezing DEC Rate RT:** The Company proposed and has received approval to freeze DEC Rate RT to new participants as of April 1, 2022 in an effort to improve TOU period alignment across the suite of tariff offerings and reduce customer impacts for customers on TOU based rates when such transitions occur.

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**EV Managed Charging Pilot:** As described in Section 4.4 above, The Companies recently filed a Residential EV Managed Charging pilot application with the NCUC in Docket No. E-7, Sub 1266 for DEC and Docket No. E-2, Sub 1291 for DEP.

In the medium to long term, the Companies will pursue opportunities through rate case proceedings in North Carolina to propose rate design changes in alignment with the vision laid out in this Roadmap and allow for further stakeholder consideration and vetting of the proposed impacts prior to implementation.

# 8 Comprehensive Rate Design Study (CRDS)

## 8.1 Background and Initiating Orders

On March 31, 2021, the North Carolina Utilities Commission (NCUC) issued an Order directing DEC to conduct a comprehensive Rate Design Study and Roadmap to maximize the efficiency and effectiveness of new utility and customer technologies and their impact on the electric system.[18] The Order established specific topics, considerations, and timing for the rate design study (12 months), such as:

> *"The Commission finds that the Rate Design Study should: (1) include an analysis of each rate schedule to determine whether the schedule remains pertinent to current utility service, including whether the schedule should remain the same, be modified, or be replaced; (2) address the potential for new schedules to address the changes affecting utility service; (3) provide more rate design choices for customers; and (4) explore the feasibility of consolidating the rates offered by DEC and DEP." (p. 181)*

On April 14, 2021, the NCUC issued another Order addressing DEP rate case stipulations and including more details regarding Rate Design Study scope, for example, noting that cost of service allocation methods discussions with stakeholders were out of scope.[19] Finally, the Order directed Duke Energy to engage an independent third-party facilitator for the stakeholder portion of the CRDS. As such, Duke Energy contracted with ICF to facilitate the CRDS stakeholder engagement process and prepare quarterly status reports. Together, Duke Energy and ICF developed an overall project plan, timeline, and stakeholder engagement approach. The project plan and timeline can be seen in Figure 27 below, which shows key milestones such as filed quarterly reports, interviews, and forums for all participating stakeholders. The stakeholder collaboration and vetting of rate design concepts primarily occurred in topically focused working groups (WGs), as described below.

[18] NCUC Docket No. E-7, Sub 1214 – In the Matter of Application by Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, *Order Accepting Stipulations, Granting Partial Rate Increase, And Requiring Customer Notice* (DEC Order) (March 31, 2021).
[19] NCUC Docket No. E-2, Sub 1219 - In the Matter of Application by Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, *Order Accepting Stipulations, Granting Partial Rate Increase, And Requiring Customer Notice* (DEP Order) (April 16, 2021), p. 182.

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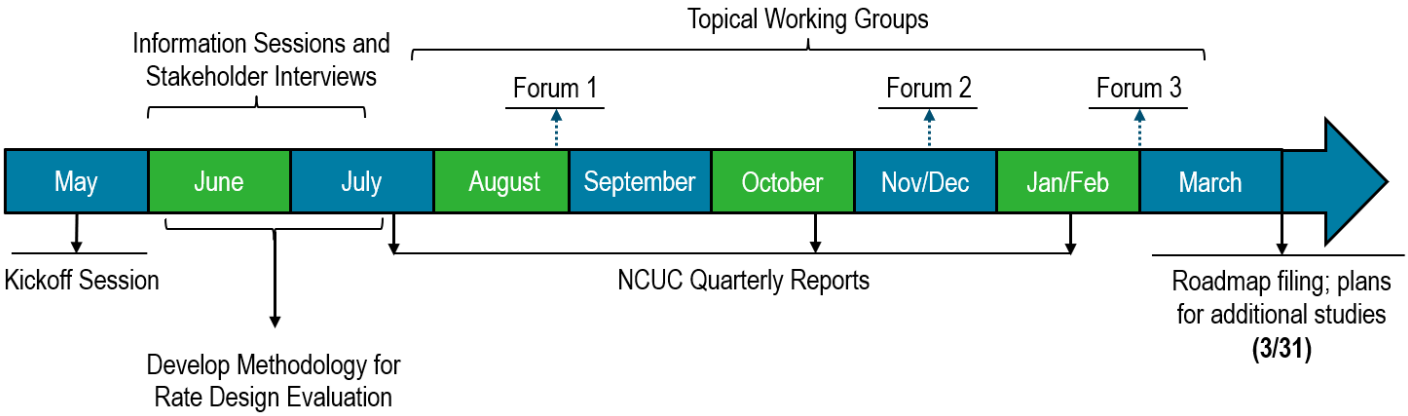


Figure 27: Comprehensive Rate Design Study High Level Timeline

Over the 12-month CRDS process, Duke Energy and stakeholders explored a list of rate design topics proposed in the NCUC Order and by stakeholders through interviews, surveys, and specific working group (WG) participation. This Roadmap Section describes the stakeholder engagement framework, CRDS participants, and activities.

## 8.2 Stakeholder Participation

ICF conducted extensive outreach at the beginning of the CRDS process to ensure that a broad range of stakeholder perspectives would be included. The stakeholders who participated in the CRDS spanned several sectors, such as commercial and industrial (C&I) customers, EV companies and advocates, environmental advocates, government agencies, public advocates, renewable/distributed energy resource (DER) companies, and legal/consulting companies. The list of stakeholders included the intervenors in the proceeding, per the NCUC Order; Duke Energy also extended participation to other interested parties not formally part of the proceeding. A full list of participating organizations by WG can be found in Appendix B.

The stakeholders had opportunities to participate in the process through WG discussions, forums, interviews, surveys, and individual outreach at their convenience. Some stakeholders offered to present on specific topics or case studies during their WG meetings (see Figure 28).

| Working Group | Stakeholder Speaker | Topic |
|---|---|---|
| **WG 1 - Fast Track Topics** | Environmental Defense Fund | Rate design for medium and heavy-duty electric vehicles |
| | Sunrun and Southern Environmental Law Center (SELC) | Historical context surrounding NEM reform |
| | NC WARN, Appalachian Voices, Advance Carolina, and The Center for Biological Diversity | NEM reform and perceived issues, including accessibility to clean energy economy for disadvantaged communities |

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| | | |
|---|---|---|
| **WG 2 - Hourly Pricing & Economic Development** | Carolina Industrial Group for Fair Utility Rates (CIGFUR) | Proposals for new economic development and jobs retention riders |
| | Utility Management Services | Case study on Virginia Electric and Power Company's Schedule 10 Large General Service rate |
| **W4 - Non-Residential Rates** | Kroger | Concept of load aggregation (also referred to as conjunctive billing) and potential benefits to customers with load at multiple locations through reduced generation and transmission charges. |
| | CIGFUR and NCSEA | Recent non-residential NEM changes in South Carolina |

Figure 28: Stakeholder presentations in CRDS Working Groups

In addition, during the three CRDS Study Forums, assigned stakeholders delivered activity updates for each WG. Figure 29 lists the stakeholders who reported out on behalf of their WG during the three stakeholder Forums.

| | **Stakeholder Speakers** | | |
|---|---|---|---|
| **Working Group** | **Forum 1 - Speakers** | **Forum 2 - Speakers** | **Forum 3 – Speakers** |
| **WG 1 - Fast Track Topics** | Thad Culley (Sunrun) | David Neal (SELC) | Elizabeth Stein (EDF) |
| **WG 2 - Hourly Pricing & Economic Development** | Justin Bieber (Energy Strategies, LLC, on behalf of Harris Teeter and Kroger) | Christina Cress (Bailey & Dixon, on behalf of CIGFUR) | N/A |
| **WG 3 - Residential Rates** | N/A | Benjamin Smith (NCSEA) | N/A |
| **W4 - Non-Residential Rates** | Christina Cress (Bailey & Dixon, on behalf of CIGFUR) | Justin Bieber (Energy Strategies, LLC, on behalf of Kroger) | N/A |

Figure 29: Stakeholder Speakers at CRDS Forums

## 8.3 Stakeholder Engagement Framework

The CRDS process systematically addressed rate design topics over the year-long effort to allow stakeholder engagement on each topic, dedicating additional time to topics as needed based on stakeholder's requests. Stakeholders were able to share their opinion through WG discussions, large group forums and were kept informed by receiving periodic email updates and quarterly status reports. Stakeholder engagement was central to developing the CRDS Roadmap. On April 30, 2021, Duke Energy initiated a process to engage parties across North Carolina and South Carolina in a comprehensive rate review process.[20] ICF and Duke Energy coordinated outreach and communication approaches to engage stakeholders participating in the CRDS. Initial surveys and

[20] NCUC Docket Nos. E-7, Sub 1214 and E-2, Sub 1219, Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Notice of Rate Design Study Initiation (April 30, 2021).

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interviews informed the structure of each WG, its participants, and topics to cover. Figure 30 shows the four CRDS WGs and topics covered.

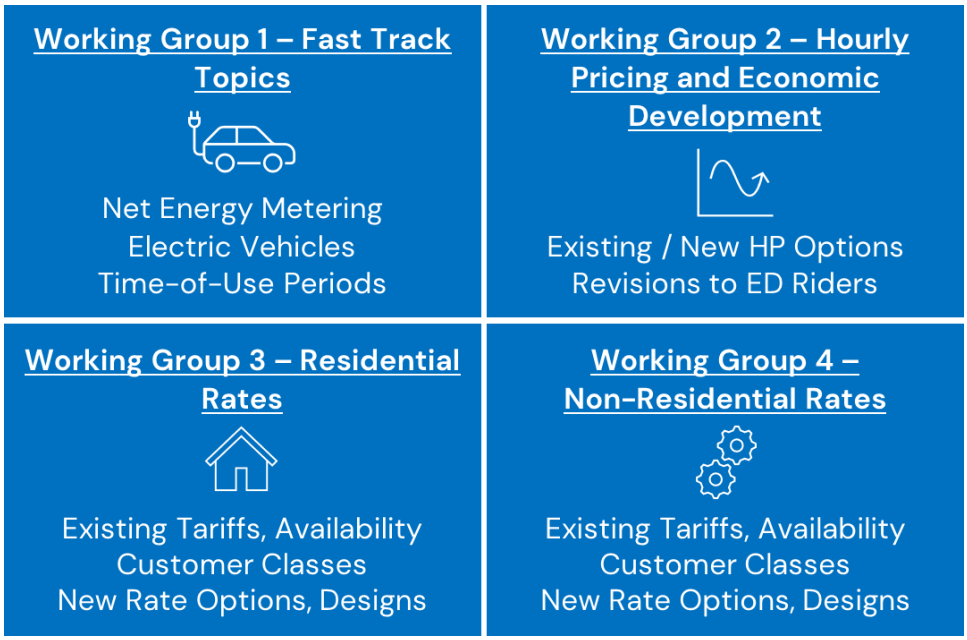


Figure 30: Four Working Groups Organized for Comprehensive Rate Review

The stakeholder process prioritized collaboration and opportunities to discuss the merits of rates and rate design options, including potential effects on all Duke Energy customers, seeking consensus where possible on rate design ideas to consider.

ICF served as the independent third-party facilitator for the stakeholder portion of the CRDS to coordinate stakeholder meetings and communications, and to ensure the process provided opportunities for all voices to be heard. Over the past 12 months, stakeholders were invited to participate through interviews, surveys, Working Group meetings, and forums.

Figure 31 provides an overview of how stakeholders were able to engage throughout the process.

| Method | Benefit |
|---|---|
| **Initial Interviews** | ICF Interviews with individual stakeholders to set expectations and prioritize ideas for consideration. |
| **Rate Design 101 Training Sessions** | Virtual informational sessions covering the ratemaking process, including fundamental principles of revenue requirements, cost allocation, and rate design. Sessions provided an overview of how cost of service relates to rate design as well as guiding principles for rate design. |

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| | |
|---|---|
| **Stakeholder Forums** | Three collaborative-wide meetings covering Working Group progress, items discussed, and considerations around ideas. Forums occurred on August 25, 2021, November 16, 2021, and February 10, 2022. |
| **Working Group Sessions** | Topically focused meetings with smaller numbers of participants that were often interactive and with agendas that varied based on stakeholder feedback. Many sessions included presentations by stakeholders on topics of interest. |
| **MURAL Boards** | Interactive collaboration tool used to gather stakeholder positions and feedback on rate design ideas. Boards were used during meetings for interactive Q&A and also as documentation of topics discussed. |
| **Subgroup Discussions** | Smaller sessions to discuss details or narrow design elements, typically between Duke Energy and 1-2 stakeholders, as requested by stakeholders or for topics not covered in larger Working Group Sessions. |
| **Duke Energy / Stakeholder 1:1 Discussions** | As requested by stakeholders, time to discuss particular ideas or understand potential implications to customers from rate design topics. |
| **ICF / Stakeholder 1:1 Discussions** | As initiated by stakeholders, opportunity to voice concerns over the process, ask questions about priorities, or seek additional means of communications. |
| **Rate Review Email Address** | Duke Energy-monitored email address used for material distribution and broad stakeholder communications. Stakeholders could request to be on the distribution list. |
| **Rate Review Information Portal** | Duke Energy website providing an overview of the process and access to materials distributed to the entire stakeholder group. |
| **Materials Distributions** | Forum presentations, Working Group slides, case studies, etc., were distributed for each session to allow for consideration and further questions by stakeholders. |
| **Periodic Stakeholder Digests** | At the suggestion of a CRDS participant, ICF and Duke Energy began issuing email digests during months when NCUC quarterly reports were not filed, providing short summarized updates on activities and progress made. |
| **Quarterly Reports** | Status reports of progress made and upcoming activities for the CRDS were filed with the NCUC on July 21, 2021, October 21, 2021, and January 21, 2022. |

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| | |
|---|---|
| **Working Group Surveys** | ICF leveraged surveys at initiation of Working Groups to determine priority of topics for discussion as well as at the conclusion to ascertain the extent to which topics were covered and identify potential gaps. |

Figure 31: Description of CRDS Engagement Channels

## 8.4 Summary of Engagement Activities

Stakeholder participation in the overall process was broad and included very engaged organizations. The Companies recognize and appreciate the level of effort, resource commitment, and constructive engagement from the many organizations and individuals interested in advancing rate design for the benefit of North Carolina's electric customers. Stakeholders participated consistently throughout the 12-month process, offering feedback, ideas, and questions throughout. Stakeholders were also flexible as calendars were stretched with other energy related activities and events, working with Duke Energy and ICF to ensure meeting times and communication channels that facilitated ongoing broad participation. Figure 32 summarizes the levels of engagement across the communication channels referenced previously.

| Engagement Channel | Engagement Statistics |
|---|---|
| **Rate Review Email Address** | Approximately 300 individuals registered to receive email notifications and updates on progress |
| **Initial Interviews** | 9 key stakeholders interviewed to understand priorities for topic focus and shape the engagement process |
| **Working Group Sessions** | 18 Sessions held across four Working Groups |
| **Subgroup Discussions** | 22 Subgroup Discussions held across four Working Groups |
| **Stakeholder Presentations at Working Group Sessions** | 7 Stakeholder presenters (non-Duke Energy and non-ICF) across the Working Group Sessions |
| **Stakeholder Presentations at Stakeholder Forums** | 8 Stakeholder presenters (non-Duke Energy and non-ICF) during the 3 Stakeholder Forums |
| **Surveys** | 8 Surveys issued across the Working Groups |
| **Periodic Stakeholder Digests** | 3 summaries of CRR activities distributed to stakeholders via email |
| **Mural Boards** | 20 Mural boards created to gather stakeholder feedback during WG sessions |

Figure 32: Summary of Completed CRDS Engagement Activities

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## 8.5 Working Group Sessions

ICF facilitated four working groups which included kick off sessions and between two and five rate design discussion sessions for each working group. In addition to the regular WG sessions, a total of 22 subgroup meetings were added during the process, based on requests for additional information, to dive deeper into specific topics, design attributes, or analytics. Figures 33-36 show the sessions and subgroup meetings for the four WGs. Also, 1:1 stakeholder discussions were held as needed or requested throughout the process.

| Date | Fast Track Sessions |
|---|---|
| 7/9/2021 | Kick-Off |
| 7/22/2021 | Subgroup A: Duke Energy TOU Period Proposal and Supporting Analytics |
| 7/29/2021 | Subgroup B: Stakeholder NEM Presentations |
| 8/5/2021 | Subgroup C: Duke Energy NEM Mechanics Proposal |
| 8/12/2021 | Session 1: TOU Rates and NEM Discussion |
| 8/19/2021 | Subgroup D: NEM Design Embedded and Marginal Costs Studies |
| 9/2/2021 | Subgroup E (NDA Only): Duke Energy Forecast Data Review |
| 9/14/2021 | Subgroup F: Final Discussion on TOU and NEM Proposals |
| 9/29/2021 | Session 2: EV Rates Discussion |
| 10/27/2021 | Subgroup A: Residential EV Rates |
| 11/4/2021 | Subgroup B: Non-Residential EV Rates |
| 11/10/2021 | Subgroup C: Residential EV Rates |
| 11/17/2021 | Subgroup D: Non-Residential EV Rates |
| 1/28/2022 | Subgroup E: Non-Residential EV Rates |

Figure 33: Fast Track Working Group Meetings

| Date | Hourly Pricing / Economic Development Sessions |
|---|---|
| 7/21/2021 | Kickoff |
| 9/15/2021 | Session 1: Existing Duke Energy RTP/HP rates and national case studies |
| 9/21/2021 | Subgroup A: Duke Energy presentation on marginal cost pricing analysis |
| 9/28/2021 | Subgroup B: Stakeholder Presentations<br>• Carolina Industrial Group for Fair Utility Rates (CIGFUR) presented their proposals for new Economic Development and Jobs Retention Riders.<br>• Utility Management Services (UMS) presented a case study on Virginia Electric and Power Company's Schedule 10 Large General Service rate, highlighting beneficial rate design elements and customer benefits. |
| 10/12/2021 | Subgroup C: Modified Economic Development Rider, Dynamic Pricing for Large Businesses, Expansion of HP rates |
| 10/19/2021 | Subgroup D: Duke Energy conducted a working session to solicit stakeholder feedback for HP rate solutions and CBL setting process. |

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| | |
|---|---|
| 11/2/2021 | Subgroup E: Duke Energy summarized the stakeholder objectives heard to date through the CRR and presented three rate design concepts: an expanded HP option, a new dynamic pricing rate option, and new Economic Development Rider. |
| 12/7/2021 | Session 2: ICF summarized the topics covered over the course of the 8 WG meetings. Duke Energy provided a requested overview of the current price derivation process for HP and RTP rates, and how the CBL impacts fixed cost recovery. |

Figure 34: Hourly Pricing and Economic Development Working Group

| Date | Residential Rates Sessions |
|---|---|
| 8/4/2021 | Kick-Off |
| 9/20/2021 | Residential Rate Overview |
| 9/27/2021 | Session 1: Existing Rates and TOU Proposal Review |
| 10/20/2021 | Session 2: HB 951, Permanent Foundation, Schedule RT, Fixed Charges and Analytics |
| 11/3/2021 | Session 3: DEP Analytics |
| 12/12/2021 | Session 4: Marginal cost details, minimum bill analysis, declining block rate, seasonal price difference, all electric option, demand charge TOU options |
| 3/11/2022 | Session 5: DEC Analytics and Whole Home Subscription concept |

Figure 35: Residential Rates Working Group

| Date | Non-Residential Sessions |
|---|---|
| 7/14/2021 | Kick-Off Session |
| 8/11/2021 | Session 1: Load factor-based rates and demand charges |
| 9/8/2021 | Session 2: Demand charges and demand response |
| 9/14/2021 | Subgroup A: Non-residential NEM policies |
| 9/15/2021 | Subgroup B: Aggregation of loads / conjunctive billing |
| 10/13/2021 | Session 3: Continuation of demand charge design issues and interruptible/curtailable rates |
| 12/1/2021 | Subgroup C: Case studies on load aggregation |
| 1/11/2022 | Subgroup D: Load factor rates |
| 1/27/2022 | Subgroup E: Review merit of current rates and customer class appropriateness; DEP marginal cost analysis |
| 2/15/2022 | Subgroup F: Demand charges; TOU rating periods impacts |
| 3/2/2022 | Session 4: TOU rates and Wrap up |

Figure 36: Non-Residential Rates Working Group

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## 8.6 Alignment with Other Duke Energy Stakeholder Collaboratives

While the CRDS was focused on rate design items in particular, thoughtful alignment and information sharing occurred between the CRDS and other collaborative stakeholder efforts focused on affordability and electric transportation. Rate design considerations from both parallel efforts were included in CRDS Working Groups as appropriate, and in some cases joint meetings occurred to ensure alignment and clarity for participating stakeholders. Notably, significant overlap existed between CRDS participants and those in other collaboratives.

**Low-Income Collaborative ("LIAC"):** The Commission recognized that the CRDS and the LIAC are separate but parallel efforts and encouraged parties to share low-income rate design recommendations with the CRDS participants for consideration.[21]

Duke Energy kicked off the LIAC on July 29, 2021. The LIAC has several tasks including 1) assessing affordability challenges, 2) defining affordability, 3) investigating the current state of programs that can help low-income or vulnerable customers, and 4) developing recommendations for both existing and new programs. While developing rate schedules is not a core function for the LIAC, efforts were made to keep this group informed of rate design considerations from the CRDS Residential Working Group that could impact low-income and vulnerable customers. On the other hand, any low-income discounts or programs would be considered in the LIAC rather than the CRDS, as these typically are layered on top of, rather than replace, the base rate schedule. Duke Energy held a joint meeting in January 2022 with the CRDS Residential Working Group, the LIAC and Demand Side management (DSM)/Energy Efficiency (EE) Collaborative to increase awareness across the initiatives and share LMI rate design ideas.

**Electric Transportation Collaborative:** Through the Electric Transportation (ET) Collaborative, Duke Energy engages in a collaborative stakeholder process to provide input and feedback on future EV programs and pilots. The ET Collaborative process was ordered by the NCUC in November 2020,[22] along with the partial approval of Phase I pilot programs designed to help North Carolina increase the number of registered, zero-emission vehicles to 80,000 by 2025 as directed by Governor Roy Cooper's Executive Order 80: North Carolina's Commitment to Address Climate Change and Transition to a Clean Energy Economy. With the support of the ET Collaborative, Phase II pilot programs were filed in May 2021. The Phase II pilot programs will, among other objectives, increase EV charging options along state highways, expand EV options in low- to moderate-income communities, and provide support to school systems to purchase up to 60 electric school buses. The ET collaborative meets quarterly to allow stakeholders to receive updates on Phase I pilots and the status of the Phase II pilot application.

[21] NCUC March 31, 2021 Order, p. 182.
[22] See *Order Approving Electric Transportation Pilot, in Part,* issued November 24, 2020, Docket Nos. E-7, Sub 1195 and E-2, Sub 1197.

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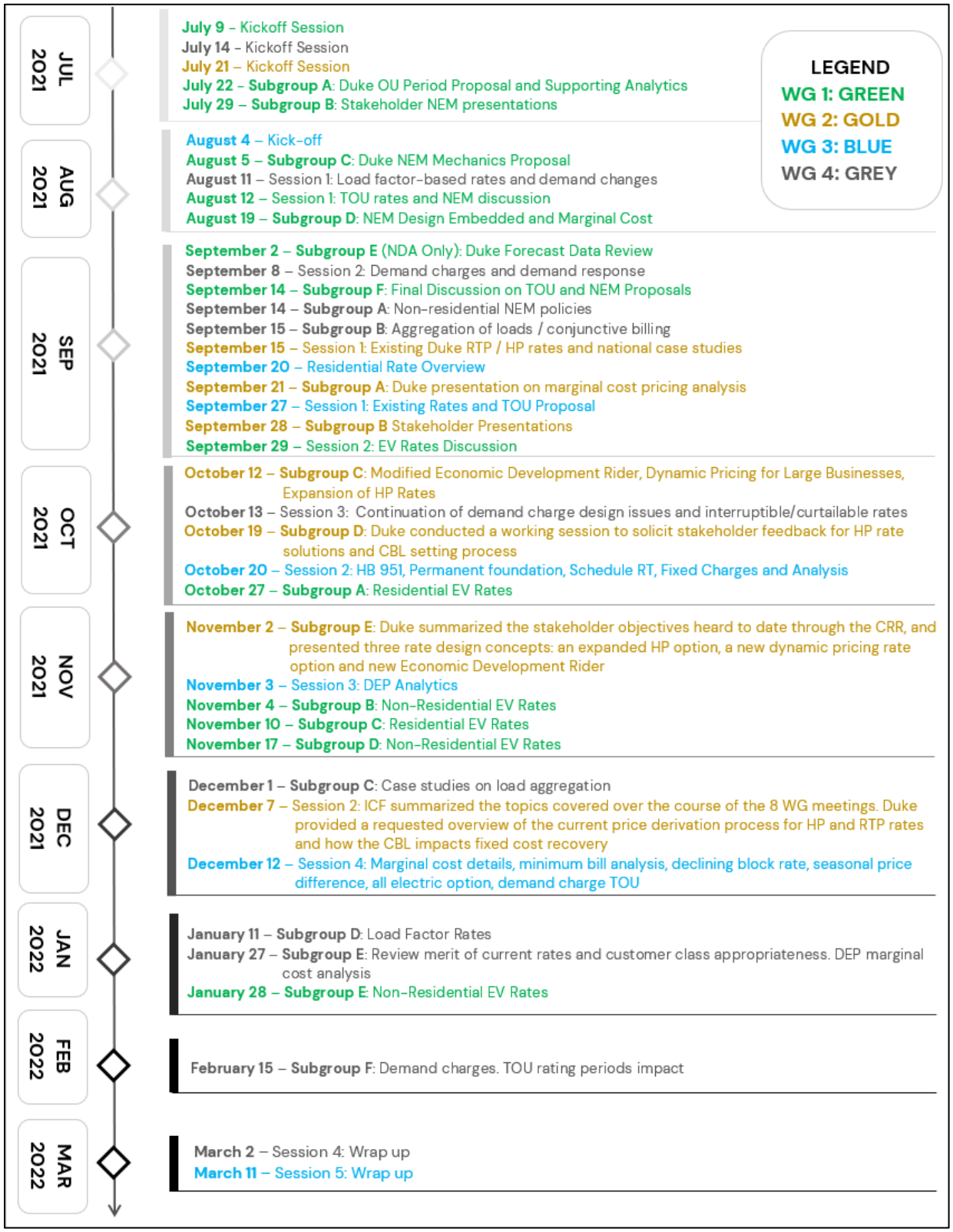
# 9 Appendices

## A. CRDS Working Group Timeline



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## B. CRDS Stakeholders by Working Group

| Organization | WG 1 | WG 2 | WG 3 | WG 4 |
|---|---|---|---|---|
| AARP South Carolina | | | ✓ | |
| Alliance for Transportation Electrification | ✓ | | | |
| Appalachian Voices | ✓ | | ✓ | |
| Archer Daniels Midland (ADM) | | ✓ | | ✓ |
| Bailey & Dixon, LLP (Counsel for CIGFUR) | ✓ | ✓ | ✓ | ✓ |
| Brooks Pierce | | ✓ | | ✓ |
| Calstart | ✓ | | | ✓ |
| Center for Biological Diversity | ✓ | | | |
| ChargePoint | ✓ | | ✓ | ✓ |
| CIGFUR (Representative) | | ✓ | | ✓ |
| City of Winston-Salem | | | | ✓ |
| Clean Air Carolina | ✓ | ✓ | ✓ | ✓ |
| Coastal Conservation League | ✓ | ✓ | ✓ | ✓ |
| Corning | | ✓ | | ✓ |
| Department of the Army, Army Legal Services | | ✓ | ✓ | ✓ |
| Environmental Defense Fund | ✓ | | | ✓ |
| Duke University | | | | ✓ |
| EVgo | ✓ | | | ✓ |
| Facebook | | ✓ | | ✓ |
| FreeWire Tech | ✓ | | | |
| Google | | ✓ | | ✓ |
| Greenlots | ✓ | | | |
| ICF | ✓ | ✓ | ✓ | ✓ |
| Kroger Co. and Harris Teeter | ✓ | ✓ | | ✓ |
| Linde | | ✓ | | |
| Lion Electric | ✓ | | | ✓ |
| Lockhart Power Company | ✓ | ✓ | ✓ | ✓ |
| Messer North America | | ✓ | | ✓ |
| NC Commerce Public Staff Energy Division | ✓ | ✓ | ✓ | ✓ |
| NC Conservation Network | | | ✓ | |
| NC Department of Justice | ✓ | ✓ | ✓ | ✓ |
| NC Electric Cooperatives | ✓ | ✓ | | |
| NC Justice Center | ✓ | | | |
| NC Sustainable Energy Association | ✓ | ✓ | ✓ | ✓ |
| NC Utilities Commission Public Staff | ✓ | ✓ | ✓ | ✓ |
| NC WARN | ✓ | | | |

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| Organization | WG 1 | WG 2 | WG 3 | WG 4 |
|---|---|---|---|---|
| North Carolina Electric Membership Commission (NCEMC) | ✓ | ✓ | ✓ | ✓ |
| North Carolina Department of Transportation | ✓ | | | |
| Nova Energy Consultants (representing CUCA) | | ✓ | | ✓ |
| Parkdale Mills | | ✓ | | ✓ |
| Southern Alliance for Clean Energy (SACE) | ✓ | ✓ | ✓ | ✓ |
| South Carolina Office of Regulatory Staff | ✓ | ✓ | ✓ | ✓ |
| Solar Energy Industries Association (SEIA) | ✓ | | | |
| Sierra Club | ✓ | ✓ | ✓ | |
| Solar United Neighbors | ✓ | | | |
| Southern Environmental Law Center | ✓ | | ✓ | |
| St. Paul's Christian Church | ✓ | | ✓ | ✓ |
| Sunrun | ✓ | | ✓ | |
| United States Department of Defense | | ✓ | | ✓ |
| Utility Management Services Inc. | ✓ | ✓ | | ✓ |
| Vote Solar | ✓ | | ✓ | |

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A. Shonta Dunston
Chief Clerk
North Carolina Utilities Commission
430 North Salisbury St.
Dobbs Building
5th Floor
Raleigh, NC 27603

31 March 2022

Dear Chief Clerk Dunston:

In accordance with Orders in Docket Nos. E-7, Sub 1214 and E-2, Sub 1219, Duke Energy (Duke) retained ICF Resources, LLC (ICF) in May 2021 to serve as a third-party independent facilitator for the stakeholder portion of its Comprehensive Rate Design Study (CRDS).

In the above referenced Orders, the Commission stated that it was "persuaded that in depth evaluation, debate, and discussion by and among stakeholders regarding cost to serve, rate design, and making the most efficient use of the electric system is necessary to achieve results that are in the public interest[.]" The Commission further required that "[a]ll parties to the rate case proceeding be afforded the opportunity to participate as stakeholders in the Rate Design Study."

This letter confirms that ICF and Duke coordinated engagement with stakeholders in accordance with the above requirements of the Commission Orders. All parties to the relevant NCUC rate proceedings were given the opportunity to participate in the stakeholder working groups, as were additional groups based on targeted outreach, and those who requested to participate at any point in the process.

Further detail regarding the stakeholder engagement process has been submitted to the Commission in Duke's quarterly status reports.

We firmly believe these stakeholder discussions have thus informed Duke's approach to rate modernization as described in its Rate Design Roadmap. This letter is not an official endorsement by ICF of the Rate Design Roadmap, but rather is meant to certify and underscore the inclusiveness and effectiveness of the CRDS stakeholder process only.

Sincerely,

Maureen Quinlan
Manager, Distributed Grid Strategy
ICF

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## CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Rate Design Study Roadmap, in Docket Nos. E-7, Sub 1214 and E-2, Sub 1219, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid to parties of record.

This the 31st day of March, 2022.

Jack E. Jirak
Deputy General Counsel
Duke Energy Corporation
P.O. Box 1551/NCRH 20
Raleigh, North Carolina 27602
(919) 546-3257
jack.jirak@duke-energy.com

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**REVENUE IMPACT OF PUBLIC STAFF ADJUSTMENTS**
**For the Test Year Ended December 31, 2021**
**(Dollar Amounts Expressed in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 1**

| Line No. | | Public Staff Excluding CCR Amount | Public Staff CCR Amount | Public Staff Amount |
|---|---|---|---|---|
| 1 | Revenue requirement increase per Company application, base rates | $304,806 1/ | $66,696 1/ | $371,502 1/ |
| 2 | Revenue impact of Company updates | 66,226 | (3,242) | 62,984 |
| 3 | **Revenue requirement increase per Company** | **$371,032** | **$ 63,454** | **$434,486** |
| 4 | Revenue impact of Public Staff adjustments: 2/ | | | |
| 5 | Change in equity ratio from 53.00% to 52.00% equity | ($17,338) | $0 | ($17,338) |
| 6 | Change in return on equity from 10.40% to 9.35% | (136,209) | (1,358) | (137,567) |
| 7 | Change in debt cost rate from 4.50% to 4.53% | 2,754 | 27 | 2,781 |
| 8 | Update plant and accumulated depreciation to April 30, 2023 | (45,826) | | (45,826) |
| 9 | Adjust depreciation rates | (73,481) | | (73,481) |
| 10 | Adjust cash working capital under present rates | 1,642 | | 1,642 |
| 11 | Adjust cash working capital under proposed rates | 2,335 | | 2,335 |
| 12 | Adjust materials and supplies | (680) | | (680) |
| 13 | Adjust coal inventory | (1,377) | | (1,377) |
| 14 | Update revenues, customer growth, and weather to April 30, 2023 | | | 0 |
| 15 | Adjust GIP deferral | (31,782) | | (31,782) |
| 16 | Adjust Allen Unit 4 deferral | ($121) | | (121) |
| 17 | Adjust lighting audit deferral | (207) | | (207) |
| 18 | Adjust nonresidential credit card fees | (1,518) | | (1,518) |
| 19 | Adjust for COVID expense & deferral | (65,918) | | (65,918) |
| 20 | Adjust aviation expenses | (113) | | (113) |
| 21 | Adjust executive compensation | (335) | | (335) |
| 22 | Adjust salaries & wage expense | 0 | | 0 |
| 23 | Adjust rent expense | 6,373 | | 6,373 |
| 24 | Adjust Test Year EFC Revenue, Nuclear Outage Amortization, Reliability Assurance, Bad Creek, & Marshall O&M | (16,703) | | (16,703) |
| 25 | Adjust rate case expense | (4,814) | | (4,814) |
| 26 | Adjust EOL nuclear materials & supplies reserve amortization expense | (349) | | (349) |
| 27 | Adjust to normalize storm costs | 0 | | 0 |
| 28 | Adjust test year expenses | | | 0 |
| 29 | Adjust for vegetation management | (1,497) | | (1,497) |
| 30 | Adjust incentives | (33,194) | | (33,194) |
| 31 | Adjust uncollectibles | 0 | | 0 |
| 32 | Adjust steam deferral | 33,881 | | 33,881 |
| 33 | Adjust charitable contributions, corporate sponsorships, and corporate donations | (23) | | (23) |
| 34 | Adjust lobbying expense | (548) | | (548) |
| 35 | Adjust Board of Directors expense | (1,884) | | (1,884) |
| 36 | Adjust inflation | (36,478) | | (36,478) |
| 37 | Adjust over amortization - Sub 1146 rate case expense | (529) | | (529) |
| 38 | Adjust over amortization - CCR deferral | 0 | 2,053 | 2,053 |
| 39 | Rounding | 4 | | 4 |
| 40 | Total revenue impact of Public Staff adjustments | ($423,935) | $722 | ($423,213) |
| 41 | **Public Staff recommended increase (decrease) in base rate revenue requirement** | **($52,903)** | **$64,176** | $11,273 |
| 42 | Public Staff recommended increase (decrease) in base rate revenue requirement (L41) | ($52,903) | $64,176 | $11,273 |
| 43 | Public Staff recommended overamortizations one year rider | ($57,405) | | ($57,405) |
| 44 | Annual Federal unprotected EDIT Rider recommended (3 year annual) | ($8,468) 3/ | | ($8,468) 3/ |
| 45 | Public Staff recommended change in revenue requirement including rider (Sum of L42 through L 44) | ($118,776) | $64,176 | ($54,600) |

1/ Bowman Exhibit 2, Page 1.
2/ Calculated based on Accounting Exhibit 1, Schedules 2, 3, 4, 5, and backup schedules.
3/ Accounting Exhibit 2, Schedule 1.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**SUPPORT FOR RECONCILIATION SCHEDULE**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 1-1**

| Line No. | Item | Rate Base Impact 1/ (a) | Income Statement Impact 2/ (b) | Total Revenue Impact 3/ (c) |
|---|---|---|---|---|
| 1 | Update plant and accumulated depreciation to April 30, 2023 | ($36,693) | ($9,133) | ($45,826) |
| 2 | Adjust rate case expense | (684) | (4,130) | (4,814) |
| 3 | Adjust depreciation rates | 6,842 | (80,323) | (73,481) |
| 4 | Adjust GIP deferral | 633 | (32,415) | (31,782) |
| 5 | Adjust COVID deferral | (8,522) | (57,396) | (65,918) |
| 6 | Remove Lighting audit deferral | 14 | (221) | (207) |
| 7 | Adjust steam deferral | (3,977) | 37,858 | 33,881 |
| 8 | Adjust Allen Unit 4 deferral | (394) | 273 | (121) |
| | **CCR:** | | | |
| 9 | Adjust over amortization - CCR | $384 | $1,669 | $2,053 |

1/ Accounting Exhibit 1, Schedule 2-1, Line 16.
2/ Accounting Exhibit 1, Schedule 3-1, Line 18.
3/ Column (a) plus Column (b).

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**CALCULATION OF GROSS REVENUE EFFECT FACTORS**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 1-2**

| Line No. | Item | Capital Structure | Cost Rates | Retention Factor | Gross Revenue Effect |
|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) |
| 1 | Rate Base Factor | | | | |
| 2 | Long-term debt | 48.000% 1/ | 4.530% 1/ | 0.9927689 2/ | 0.0219024 4/ |
| 3 | Common equity | 52.000% 1/ | 9.35% 1/ | 0.7609549 3/ | 0.0638934 4/ |
| 4 | Total (Sum of Lines 2 and 3) | 100.000% | | | 0.0857958 |

| | | | Amount |
|---|---|---|---|
| 5 | Net Income Factor | | |
| 6 | Total revenue | | 1.0000000 |
| 7 | Uncollectibles | | 0.0058474 5/ |
| 8 | Balance (L6 - L7) | | 0.9941526 |
| 9 | Regulatory fee (L8 x .013918%) | 6/ | 0.0013837 |
| 10 | Balance (L8 - L9) | | 0.9927689 |
| 11 | State income tax (L10 x 2.9750%) | 7/ | 0.0295349 |
| 12 | Balance (L10 - L11) | | 0.9632340 |
| 13 | Federal income tax (L12 x 21%) | 8/ | 0.2022791 |
| 14 | Retention factor (L12 - L13) | | 0.7609549 |

1/ Per Public Staff witness Walters.
2/ Line 10.
3/ Line 14.
4/ Column (a) times Column (b) divided by Column (c).
5/ NC1010-5.
6/ Current regulatory fee rate.
7/ Accounting Exhibit 1, Schedule 1-3, Line 4, Column (a).
8/ Statutory rate.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**CALCULATION OF GROSS REVENUE EFFECT FACTORS**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 1-2 CCR**

| Line No. | Item | Capital Structure | Cost Rates | Retention Factor | Gross Revenue Effect |
|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) |
| 1 | Rate Base Factor | | | | |
| 2 | Long-term debt | 48.000% 1/ | 4.530% 1/ | 0.9927689 2/ | 0.0219024 4/ |
| 3 | Common equity | 52.000% 1/ | 7.85% 1/ | 0.7609549 3/ | 0.0536431 4/ |
| 4 | Total (Sum of Lines 2 and 3) | 100.000% | | | 0.0755455 |

| | | | Amount |
|---|---|---|---|
| 5 | Net Income Factor | | |
| 6 | Total revenue | | 1.0000000 |
| 7 | Uncollectibles | | 0.0058474 5/ |
| 8 | Balance (L6 - L7) | | 0.9941526 |
| 9 | Regulatory fee (L8 x .013918%) | 6/ | 0.0013837 |
| 10 | Balance (L8 - L9) | | 0.9927689 |
| 11 | State income tax (L10 x 2.9750%) | 7/ | 0.0295349 |
| 12 | Balance (L10 - L11) | | 0.9632340 |
| 13 | Federal income tax (L12 x 21%) | 8/ | 0.2022791 |
| 14 | Retention factor (L12 - L13) | | 0.7609549 |

1/ Per Public Staff witness Walters.
2/ Line 10.
3/ Line 14.
4/ Column (a) times Column (b) divided by Column (c).
5/ NC1010-5.
6/ Current regulatory fee rate.
7/ Accounting Exhibit 1, Schedule 1-3, Line 4, Column (a).
8/ Statutory rate.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**CALCULATION OF COMPOSITE INCOME TAX RATE**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 1-3**

| Line No. | Item | Total System | North Carolina | South Carolina |
|---|---|---|---|---|
| | | (a) | (b) | (c) |
| 1 | Weighted state income tax rate | | | |
| 2 | Apportionment factor | | 67.0000% 2/ | 26.0000% 2/ |
| 3 | State income tax rate | | 2.50% 3/ | 5.00% 3/ |
| 4 | Weighted state income tax rate | 2.9750% 1/ | 1.67500% 4/ | 1.30000% 4/ |
| 5 | Composite income tax rate | | | |
| 6 | Weighted state income tax rate (L4) | 2.9750% | | |
| 7 | Federal income tax rate | 21% 5/ | | |
| 8 | Composite income tax rate | 23.3503% 6/ | | |

1/ Sum of Columns (b) and (c).
2/ Per NC1010-4 Tax Rate, Column (b).
3/ Per NC1010-4 Tax Rate, Column (a).
4/ Line 2 times Line 3.
5/ Statutory rate.
6/ 1 minus ((1 minus Line 6) times (1 minus Line 7)).

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ORIGINAL COST RATE BASE**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 2**

| Line No. | Item | Under Present Rates: NC Retail Adjusted Per Company 1/ (a) | Under Present Rates: Public Staff Adjustments 2/ (b) | Under Present Rates: After Public Staff Adjustments 3/ (c) | After Public Staff Recommended Decrease: Rate Decrease (d) | After Public Staff Recommended Decrease: After Rate Decrease 5/ (e) |
|---|---|---|---|---|---|---|
| 1 | Electric plant in service | $33,830,200 | ($611,385) | $33,218,815 | $0 | $33,218,815 |
| 2 | Accumulated depreciation and amortization | (12,882,840) | 263,450 | (12,619,390) | - | (12,619,390) |
| 3 | Net electric plant in service (L1 + L2) | 20,947,360 | (347,934) | 20,599,426 | - | 20,599,426 |
| 4 | Materials and supplies | 685,872 | (23,972) | 661,900 | - | 661,900 |
| | Other Working Capital | | | | | |
| 5 | Operating funds per lead-lag study | 153,321 | 8,951 | 162,272 | (80,231) 4/ | 82,041 |
| 6 | Unamortized debt | 73,360 | - | 73,360 | - | 73,360 |
| 7 | Regulatory assets and liabilities, excluding ARO-related CCR | 85,590 | (163,537) | (77,947) | - | (77,947) |
| 8 | Total other working capital | 312,271 | (154,586) | 157,685 | (80,231) | 77,454 |
| 9 | ARO-related CCR regulatory assets and liabilities | $0 | - | - | - | - |
| 10 | Customer deposits | (47,201) | - | (47,201) | - | (47,201) |
| 11 | Accumulated deferred income taxes | (2,764,809) | 23,011 | (2,741,798) | - | (2,741,798) |
| 12 | Operating reserves | (150,195) | - | (150,195) | - | (150,195) |
| 13 | Adjustments to federal excess deferred income taxes | | - | - | | - |
| 14 | Construction work in progress | - | - | - | - | - |
| 15 | Total original cost rate base (L3 + L4 + L8 + sum of L9 thru L14) | 18,983,298 | ($503,481) | 18,479,817 | ($80,231) | $18,399,585 |

1/ Per Bowman Supplemental Exhbit 2
2/ Accounting Exhibit 1, Schedule 2-1, Column (l).
3/ Column (a) plus Column (b).
4/ Accounting Exhibit 1, Schedule 2-1(g), Line 82, Column (k).
5/ Column (c) plus Column (d).

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**CCR DEFERRAL RATE BASE**
**For the Test Year Ended December 31, 2021**
**(Dollar Amounts Expressed in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 2 CCR**

| Line No. | Item | Under Present Rates: NC Retail as Adjusted Per Company | Under Present Rates: Public Staff Adjustments | Under Present Rates: After Public Staff Adjustments | After Public Staff Recommended Increase: Rate Increase | After Public Staff Recommended Increase: After Rate Increase |
|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) |
| 1 | ARO-related CCR regulatory assets and liabilities | $247,088 1/ | $6,628 3/ | $253,716 | - | $253,716 |
| 2 | Accumulated deferred income taxes | (57,696) 1/ | ($1,548) 3/ | (59,243) | - | (59,243) |
| 3 | Total original cost rate base (L1 + L2) | $189,392 | 5,080 | $194,473 | - | $194,473 |
| 4 | Retention factor | 0.075546 2/ | | 0.075546 | | 0.075546 |
| 5 | Rate base revenue requirement (L3 x L4) | $14,308 | | $14,692 | | $14,692 |

1/ Bowman Exhibit 2, Page 4.
2/ Accounting Exhibit 1, Schedule 1-2 CCR, Line 4, Column (d).
3/ Accounting Exhibit 1, Schedule 2-1, Column (m).

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 2-1**


**SUMMARY OF PUBLIC STAFF RATE BASE ADJUSTMENTS**

**For the Test Year Ended December 31, 2021**
**(in Thousands)**

| Line No. | Item | | Update Plant and Accumulated Depreciation to 4/30/23 1/ (a) | Adjust Allen Unit 4 Deferral 2/ (b) | Adjust Steam Deferral 3/ (c) | Adjust GIP Deferral 4/ (d) | Adjust Coal Inventory 5/ (e) |
|---|---|---|---|---|---|---|---|
| 1 | Electric plant in service | | ($611,385) | | | | |
| 2 | Accumulated depreciation and amortization | | $183,708 | | | | |
| 3 | Net electric plant in service (L1 + L2) | | ($427,676) | - | - | - | - |
| 4 | Materials and supplies | | - | | | | (16,044) |
| | Other Working Capital | | | | | | |
| 5 | Operating funds per lead-lag study | | - | | | | |
| 6 | Unamortized debt | | - | | | | |
| 7 | Regulatory assets and liabilities, excluding ARO-related CCR | | - | ($5,997) | ($37,584) | $9,634 | |
| 8 | Total Working Capital | | - | (5,997) | (37,584) | 9,634 | - |
| 9 | CCR regulatory assets and liabilities | | | | | | |
| 10 | Customer deposits | | | | | | |
| 11 | Accumulated deferred income taxes | | | $1,400 | ($8,776) | ($2,250) | |
| 12 | Operating reserves | | | | | | |
| 13 | Adjustments to federal excess deferred income taxes | | | | | | |
| 14 | Construction work in progress | | | | | | |
| 15 | Total original cost rate base (L3 + L4 + L8 + sum of L9 thru L14) | | ($427,676) | (4,597) | (46,360) | 7,384 | (16,044) |
| 16 | Revenue requirement impact | 14/ | ($36,693) | ($394) | ($3,977) | $633 | ($1,377) |

1/ Accounting Exhibit 1, Schedule 2-1(a), Line 3.
2/ Accounting Exhibit 1, Schedule 2-1(b), Lines 13 and 15.
3/ Accounting Exhibit 1, Schedule 2-1(c), Lines 6 and 9.
4/ Accounting Exhibit 1, Schedule 2-1(d), Lines 12 and 16.
5/ Accounting Exhibit 1, Schedule 2-1(e), Line 10.
14/ Line 15 x rate base retention factor from Accounting Exhibit 1, Schedule 1-2.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 2-1**


**SUMMARY OF PUBLIC STAFF RATE BASE ADJUSTMENTS**

**For the Test Year Ended December 31, 2021**
**(in Thousands)**

| Line No. | Item | | Adjust Depreciation Rates 6/ (f) | Adjust Materials and Supplies 7/ (g) | Adjust COVID Deferral 8/ (h) | Adjust Lighting Audit Deferral 9/ (i) |
|---|---|---|---|---|---|---|
| 1 | Electric plant in service | | | | | |
| 2 | Accumulated depreciation and amortization | | $79,742 | | | |
| 3 | Net electric plant in service (L1 + L2) | | 79,742 | - | - | - |
| 4 | Materials and supplies | | - | (7,928) | | |
| | Other Working Capital | | | | | |
| 5 | Operating funds per lead-lag study | | - | | | $219 |
| 6 | Unamortized debt | | - | | | |
| 7 | Regulatory assets and liabilities, excluding ARO-related CCR | | - | | (129,590) | |
| 8 | Total Working Capital | | - | - | (129,590) | 219 |
| 9 | CCR regulatory assets and liabilities | | | | | |
| 10 | Customer deposits | | | | | |
| 11 | Accumulated deferred income taxes | | | | $30,260 | ($51) |
| 12 | Operating reserves | | | | | |
| 13 | Adjustments to federal excess deferred income taxes | | | | | |
| 14 | Construction work in progress | | | | | |
| 15 | Total original cost rate base (L3 + L4 + L8 + sum of L9 thru L14) | | 79,742 | (7,928) | (99,330) | 168 |
| 16 | Revenue requirement impact | 14/ | $6,842 | ($680) | ($8,522) | $14 |

6/ Accounting Exhibit 1, Schedule 3-1(b), Line 10.
7/ Accounting Exhibit 1, Schedule 3-1(f), Line 8.
8/ Accounting Exhibit 1, Schedule 3-1(g), Lines 20 and 21.
9/ Accounting Exhibit 1, Schedule 3-1(s), Lines 7 and 10.
14/ Line 15 x rate base retention factor from Accounting Exhibit 1, Sch 1-2.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 2-1**


**SUMMARY OF PUBLIC STAFF RATE BASE ADJUSTMENTS**

**For the Test Year Ended December 31, 2021**
**(in Thousands)**

| Line No. | Item | | Remove Rate Case Expense from rate base | | Adjust Cash Working Capital | | Total Rate Base Adjustments | | CCR Adjust Over Amortization CCR | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | (j) | | (k) | | (l) | | (m) | |
| 1 | Electric plant in service | | | | | | ($611,385) | | | |
| 2 | Accumulated depreciation and amortization | | | | | | $263,450 | | | |
| 3 | Net electric plant in service (L1 + L2) | | - | | - | | ($347,934) | | | |
| 4 | Materials and supplies | | | | | | (23,972) | | | |
| | Other Working Capital | | | | | | | | | |
| 5 | Operating funds per lead-lag study | | ($10,401) | | $19,133 | | 8,951 | | | |
| 6 | Unamortized debt | | | | | | - | | | |
| 7 | Regulatory assets and liabilities, excluding ARO-related CCR | | | | | | (163,537) | | | |
| 8 | Total Working Capital | | (10,401) | | 19,133 | | (154,586) | | - | |
| 9 | CCR regulatory assets and liabilities | | | | | | - | | $6,628 | |
| 10 | Customer deposits | | | | | | - | | | |
| 11 | Accumulated deferred income taxes | | $2,429 | | | | 23,011 | | ($1,548) | |
| 12 | Operating reserves | | | | | | - | | | |
| 13 | Adjustments to federal excess deferred income taxes | | | | | | - | | | |
| 14 | Construction work in progress | | | | | | - | | | |
| 15 | Total original cost rate base (L3 + L4 + L8 + sum of L9 thru L14) | | (7,972) | | 19,133 | | ($503,481) | | 5,080 | |
| 16 | Revenue requirement impact | 14/ | ($684) | | $1,642 | | ($43,197) | | $384 | |

10/ Accounting Exhibit 1, Schedule 3-1(t), Lines 19 and 22.
11/ Accounting Exhibit 1, Schedule 2-1(f), Line 87.
12/ Sum of Column (a) through Column (k).
13/ Accounting Exhibit 1, Schedule 3-1(v)(1), Lines 7 and 9.
14/ Line 15 x rate base retention factor from Accounting Exhibit 1, Schedule 1-2.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO UPDATE PLANT AND ACCUMULATED DEPRECIATION**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 2-1(a)**

| Line No. | Item | Plant in Service (a) | Accumulated Depreciation (b) |
|---|---|---|---|
| 1 | Adjustment to update balances to April 30, 2023 | ($611,385) 1/ | $183,708 2/ |
| 2 | Adjustment for annualization of depreciation expense | 0 | (0) 3/ |
| 3 | Total adjustment to update plant and accumulated depreciation (L1 + L2 | ($611,385) | $183,708 |

1/ Accounting Exhibit 1, Schedule 2-1(a)(1), Line 16, Column (e).
2/ Accounting Exhibit 1, Schedule 2-1(a)(2), Line 12, Column (e).
3/ Accounting Exhibit 1, Schedule 2-1(a)(3), Line 17.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO UPDATE PLANT IN SERVICE TO APRIL 30, 2023**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 2-1(a)(1)**

| Line No. | Item | Total System Amount As Of 4/30/2023 1/ (a) | Total System Amount As Of 12/31/2021 2/ (b) | Total System Change in Plant in Service 3/ (c) | NC Retail Percentage 4/ (d) | NC Retail Amount (e) |
|---|---|---|---|---|---|---|
| 1 | Steam plant | $8,813,770 | $8,876,973 | ($63,203) | | |
| 2 | Hydro plant | 2,756,939 | 2,561,084 | 195,855 | | |
| 3 | Other production plant | 3,561,481 | 3,446,850 | 114,631 | | |
| 4 | Nuclear plant | 9,349,424 | 9,133,654 | 215,770 | | |
| 5 | Total production plant (Sum of L1 to L4) | 24,481,614 | 24,018,561 | 463,053 | 66.9690% | $310,102 5/ |
| 6 | Transmission plant | 5,379,585 | 4,963,954 | 415,631 | 48.1470% | 200,114 5/ |
| 7 | Distribution plant | 15,996,038 | 14,480,906 | 1,515,132 | 74.0820% | 1,122,439 5/ |
| 8 | General plant | 2,023,483 | 1,424,450 | 599,033 | 68.1625% | 408,316 5/ |
| 9 | Intangible plant | 1,278,516 | 1,206,177 | 72,339 | 69.5124% | 50,285 5/ |
| 10 | Total plant in service (Sum of L5 to L9) | $49,159,236 | $46,094,048 | $3,065,188 | | $2,091,256 |
| 11 | Update to plant (L10) | | | | | $2,091,256 |
| 12 | Less: additional plant related to REPS & CPRE | | | | | 2,678 6/ |
| 13 | Update to plant through 4/30/2023 per Public Staff (L11 - L12) | | | | | 2,088,578 |
| 14 | Company adjustment for plant additions since last rate case | | | | | 2,492,839 7/ |
| 15 | Public Staff engineer adjustments to plant | | | | | (207,123) 8/ |
| 16 | Public Staff adjustment to update plant (L13 - L14 + L15) | | | | | ($611,385) |

1/ Per NC3030(B)-6.
2/ Per NC3030-6.
3/ Column (a) minus Column (b).
4/ Per E-1, Item 45a, 12 CP.
5/ Column (c) times Column (d).
6/ Per NC3030(B) with actuals through April 30, 2023.
7/ Per NC3030(B)-1, Line 21.
8/ Per Accounting Exhibit 1, Schedule 2-1(a)1(a).

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO PLANT IN SERVICE**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 2-1(a)(1)(a)**

| Line No. | Item | Total System Plant Type | Public Staff Adjustment Amount 1/ | NC Retail Percentage 2/ | NC Retail Amount 3/ |
|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) |
| | **Adjustment to Test Year Plant In Service:** | | | | |
| 1 | Mount Holly Project | Intang ble Plant | $ (2,208) | 69.5124% | $ (1,535) |
| 2 | Mount Holly Project | General Plant | (5,813) | 68.1625% | (3,962) |
| 3 | 526 S. Church Reno - Switchgear and Generator Replacement | General Plant | (7,197) | 68.1625% | (4,906) |
| 4 | Remove EV charging infrastructure costs - 2021 | General Plant | (403) | 68.1625% | (275) |
| 5 | Lincoln Ct Unit 17 - Combustion Turbine Pipeline | Other Production Plant | (353) | 66.9690% | (236) |
| 6 | Total Public Staff adjustmnet to TY plant in service (Sum of L1 to L5) | | (15,975) | | (10,914) |
| | **Adjustment to Post Test Year Plant In Service Update:** | | | | |
| 7 | Mount Holly Project | Intang ble Plant | (648) | 69.5124% | (451) |
| 8 | Pleasant Garden 550kV Breaker Replacements | Distribution Plant | (16,273) | 74.0820% | (12,055) |
| 9 | Pleasant Garden 550kV Breaker Replacements | Transmission Plant | 16,273 | 48.1470% | 7,835 |
| 10 | Bad Creek 3 Hydroelectric | Hydro Plant | (5,000) | 66.9690% | (3,348) |
| 11 | Dearborn Dam Hydroelectric | Hydro Plant | (5,000) | 66.9690% | (3,348) |
| 12 | Remove EV charging infrastructure costs - 2022 | General Plant | (485) | 68.1625% | (331) |
| 11 | Workstation Project | General Plant | (2,657) | 68.1625% | (1,811) |
| 12 | Duke Plaza | General Plant | (236,801) | 68.1625% | (161,409) |
| 13 | Duke Plaza - Land | General Plant | (28,474) | 68.1625% | (19,409) |
| 14 | Lincoln Ct Unit 17 removal | Other Production Plant | (2,809) | 66.9690% | (1,881) |
| 15 | Total Public Staff adjustmnet to Post TY plant additions (Sum of L7 to L14) | | (281,875) | | (196,209) |
| 16 | Total Public Staff adjustmnet to plant in service (L6 + L15) | | $ (297,849) | | $ (207,123) |

1/ Accounting Exhibit 1, Schedule 2-1(a)(1)(a)(1).
2/ E-1, Item No. 45a, 12CP.
3/ Column (b) times Column (c).

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT DETAILS FOR PLANT IN SERVICE, ACCUM. DEPRECIATION AND DEPRECIATION EXPENSE**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 2-1(a)(1)(a)(1)**

| Line No. | Item | Plant Type | Total System Public Staff Adjustment Amount 1/ | Closed to Plant 2/ | Depreciation Rates 3/ | Depreciation Amount 4/ | Total System Accumulated Depr. Amount as of 5/1/2023 5/ |
|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) |
| | **Adjustment to Test Year & Post TY Plant In Service:** | | | | | | |
| 1 | Pleasant Garden 550kV Breaker Replacements | Distribution Plant | (16,273) | 12/15/2022 | 2.44% | ($397) | 165 |
| 2 | Pleasant Garden 550kV Breaker Replacements | Transmission Plant | 16,273 | 12/15/2022 | 2.39% | 389 | (162) |
| 3 | Bad Creek 3 Hydroelectric | Hydro Plant | (5,000) | 2/1/2023 | 2.27% | (114) | 28 |
| 4 | Dearborn Dam Hydroelectric | Hydro Plant | (5,000) | 12/1/2022 | 2.27% | (114) | 47 |
| 5 | Remove EV charging infrastructure costs - 2021 | General Plant | (403) | 1/1/2021 | 5.31% | (21) | 50 |
| 6 | Remove EV charging infrastructure costs - 2022 | General Plant | (485) | 1/1/2022 | 5.31% | (26) | 34 |
| 7 | Mt Holly Traning Facility Renovatio - 2020 | General Plant | (3,509) | 6/1/2020 | 5.31% | (186) | 544 |
| 8 | Mt Holly Traning Facility Renovatio - 2021 | General Plant | (7) | 1/1/2021 | 5.31% | (0) | 1 |
| 9 | Mt Holly ETO Renovation - 2020 | General Plant | (1,493) | 6/1/2020 | 5.31% | (79) | 231 |
| 10 | Mt Holly ETO Renovation - 2021 | General Plant | (21) | 1/1/2021 | 5.31% | (1) | 3 |
| 11 | Mount Holly microgrid control sys | General Plant | (782) | 6/1/2020 | 5.31% | (42) | 121 |
| 12 | Open Field Message Bus (OpenFMB) | Intangible Plant | (666) | 6/1/2020 | 5.00% | (33) | 97 |
| 13 | Feeder Operational Controls | Intangible Plant | (515) | 1/1/2021 | 5.00% | (26) | 60 |
| 14 | (OpenFMB) Microservices Development | Intangible Plant | (449) | 6/1/2020 | 5.00% | (22) | 66 |
| 15 | MT Holly Simulation an Testing - 2021 | Intangible Plant | (330) | 1/1/2021 | 5.00% | (17) | 39 |
| 16 | Mount Holly Simulation and Testing - 2020 | Intangible Plant | (248) | 6/1/2020 | 5.00% | (12) | 36 |
| 17 | Mt. Holly Simulation & Testing -2022 | Intangible Plant | (648) | 1/1/2022 | 5.00% | (32) | 43 |
| 18 | Workstation Refresh 2023-2024 | General Plant | (2,657) | 3/1/2023 | 5.31% | (141) | 24 |
| 19 | 526 S. Church Reno - Switchgear and Generator Replacement - 2020 | General Plant | (7,191) | 6/1/2020 | 5.31% | (382) | 1,114 |
| 20 | 526 S. Church Reno - Switchgear and Generator Replacement - 2021 | General Plant | (6) | 1/1/2021 | 5.31% | (0) | 1 |
| 21 | Duke Plaza | General Plant | (236,801) | 4/30/2023 | 5.31% | (12,574) | - |
| 22 | Duke Plaza - Land | General Plant | (28,474) | n/a | n/a | n/a | n/a |
| 23 | Lincoln Ct Unit 17 - Combustion Turbine Pipeline | Other Production Plant | (353) | 6/1/2020 | 3.40% | (12) | 35 |
| 24 | Lincoln Ct Unit 17 removal | Other Production Plant | (2,809) 6/ | n/a | 3.40% | (96) | 587 6/ |
| 25 | Total Public Staff adjustment (Sum of L1 to L24) | | (297,849) | | | ($13,939) | 3,163 |

1/ Per Public Staff engineers Lawrence, Lucas, Metz, Thomas, and Williamson.
2/ Per PSDR 10-2 response.
3/ Per McCullar.
4/ Column (b) times Column (d).
5/ Column (b) times Column (d), then prorated through April 30, 2023.
6/ Per NC3030(B)-9, 100% exclusion.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO UPDATE**
**ACCUMULATED DEPRECIATION TO**
**APRIL 30, 2023**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 2-1(a)(2)**

| Line No. | Item | Total Carolinas Amount As Of 4/30/2023 1/ (a) | Total Carolinas Amount As Of 12/31/2021 1/ (b) | Change in Accumulated Depreciation 2/ (c) | NC Retail Percentage 3/ (d) | NC Retail Amount (e) |
|---|---|---|---|---|---|---|
| 1 | Production plant | ($10,542,084) | ($9,872,951) | ($669,133) | 66.9690% | ($448,111) 4/ |
| 2 | Transmission plant | (1,521,876) | (1,440,993) | (80,883) | 48.1470% | (38,943) 4/ |
| 3 | Distribution plant | (5,177,885) | (5,110,132) | (67,753) | 74.0820% | (50,193) 4/ |
| 4 | General plant | (411,691) | (459,397) | 47,707 | 68.1625% | 32,518 4/ |
| 5 | Intangible plant | (806,137) | (737,984) | (68,153) | 69.5124% | (47,375) 4/ |
| 6 | Total accumulated depreciation | ($18,459,673) | ($17,621,457) | ($838,215) | | ($552,104) |
| 7 | Change in accumulated depreciation (L6) | | | | | ($552,104) |
| 8 | Less: Non-fuel rider activity | | | | | (5,926) 5/ |
| 9 | Public Staff adjustment to update to 4/30/2023 (L7 - L8) | | | | | (546,178) |
| 10 | Company adjustment to update | | | | | (727,692) 6/ |
| 11 | Public Staff engineer adjustments | | | | | 2,194 7/ |
| 12 | Public Staff adjustment (L9 - L10 + L11) | | | | | $183,708 |

1/ Per NC3030(B)-6.
2/ Column (a) minus Column (b).
3/ Per E-1, Item 45a, 12 CP.
4/ Column (c) times Column (d).
5/ Per NC3030(B) with actuals through April 30, 2023.
6/ Per NC3030(B)-1, Line 29.
7/ Accounting Exhibit 1, Schedule 2-1(a)(2)(a).

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**DUKE ENERGY PROGRESS, LLC**
**Docket No. E-2, Sub 1300**
**North Carolina Retail Operations**
**ADJUSTMENT TO ACCUMULATED DEPRECIATION FOR PUBLIC STAFF PLANT ADJUSTMENTS**
**For the Test Year Ended December 31, 2021**
**(Dollar Amounts Expressed in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 2-1(a)(2)(a)**

| Line No. | Item | Plant Type | Total System Public Staff Accum. Depr. Adj. Amount 1/ | NC Retail NC Retail Percentage 2/ | NC Retail Accum. Depr. Adjustment 3/ |
|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) |
| | **Adjustment to Test Year Accumulated Depreciation:** | | | | |
| 1 | Mount Holly Project | Intang ble Plant | $ 297 | 69.5124% | $ 207 |
| 2 | Mount Holly Project | General Plant | 899 | 68.1625% | 613 |
| 3 | 526 S. Church Reno - Switchgear and Generator Replacement | General Plant | 1,115 | 68.1625% | 760 |
| 4 | Remove EV charging infrastructure costs - 2021 | General Plant | 50 | 68.1625% | 34 |
| 5 | Lincoln Ct Unit 17 - Combustion Turbine Pipeline | Other Production Plant | 35 | 66.9690% | 23 |
| 6 | Total Test Year adjustments (sum of L1 to L5) | | $ 2,396 | | $ 1,637 |
| | **Adjustment to Post Test Year Accumulated Depreciation:** | | | | |
| 7 | Mount Holly Project | Intang ble Plant | 43 | 69.5124% | 30 |
| 8 | Pleasant Garden 550kV Breaker Replacements | Distr bution Plant | $165 | 74.0820% | 123 |
| 9 | Pleasant Garden 550kV Breaker Replacements | Transmission Plant | ($162) | 48.1470% | (78) |
| 10 | Bad Creek 3 Hydroelectric | Hydro Plant | 28 | 66.9690% | 19 |
| 11 | Dearborn Dam Hydroelectric | Hydro Plant | 47 | 66.9690% | 32 |
| 12 | Remove EV charging infrastructure costs - 2022 | General Plant | 34 | 68.1625% | 23 |
| 13 | Workstation Project | General Plant | 24 | 68.1625% | 16 |
| 14 | Duke Plaza | General Plant | - | 68.1625% | - |
| 15 | Lincoln Ct Unit 17 removal | Other Production Plant | 587 | 66.9690% | 393 |
| 16 | Total Post Test Year adjustments (sum of L7 to L15) | | $ 767 | | $ 558 |
| 17 | Total adjustment impact (L6 + L16) | | $ 3,163 | | $ 2,194 |

1/ Accounting Exhbit 1, Schedule 2-1(a)(1)(a)(1).
2/ E-1, Item No. 45a, 12CP.
3/ Column (b) times Column (c).

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO ACCUMULATED DEPRECIATION FOR ANNUALIZATION OF DEPRECIATION EXPENSE**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 2-1(a)(3)**

| Line No. | Item | Annualized Depreciation Expense at 4/30/2023 1/ (a) | Per Books Depreciation Expense for Twelve Months 4/30/2023 1/ (b) | Difference 2/ (c) | NC Retail Percentage 3/ (d) | NC Retail Amount 4/ (e) |
|---|---|---|---|---|---|---|
| 1 | Production plant | $696,788 | $689,627 | $7,161 | 66.9690% | $4,796 |
| 2 | Production Direct assigned to NC | | | $0 | 100.0000% | - |
| 3 | Production Direct assigned to SC | | | $0 | 0.0000% | - |
| 4 | Transmission plant | $118,796 | $114,344 | $4,452 | 48.1470% | 2,144 |
| 5 | Transmission Direct assigned to NC | | | $0 | 100.0000% | - |
| 6 | Transmission Direct assigned to SC | | | $0 | 0.0000% | - |
| 7 | NC Distribution plant | 272,617 | 252,965 | 19,652 | 99.6277% | 19,579 |
| 8 | Distribution Direct assigned to NC | | | - | 100.0000% | - |
| 9 | SC Distr bution plant | 81,925 | 86,894 | (4,969) | 0.0000% | - |
| 10 | General plant | 101,039 | 91,323 | 9,716 | 68.1625% | 6,623 |
| 11 | General Direct assigned to SC | | | - | 0.0000% | - |
| 12 | Intangible plant | 74,585 | 74,585 | - | 69.5124% | - |
| 13 | Adjustment to depreciation Sum of L1 to L12) | $1,345,750 | $1,309,738 | $36,012 | | $33,142 |
| 14 | Adjustment to depreciation recovered through in riders | | | | | ($68) |
| 15 | Total adjustment to accumulated depreciation | | | | | ($33,073) |
| 16 | Company adjustment | | | | | (33,073) 1/ |
| 17 | Public Staff adjustment to accumulated depreciation | | | | | ($0) |

1/ NC3030-5(B).
2/ Column (a) minus Column (b).
3/ E-1, Item 45a, 12CP.
4/ Column (c) times Column (d).

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO ALLEN NET BOOK VALUE AND AMORTIZATION**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 2-1(b)**

| Line No. | Item | Amount (a) | |
|---|---|---|---|
| | **Income Statement Impact** | | |
| 1 | Allen Unit 4 deferred costs per Company at December 31, 2023 | $29,050 | 1/ |
| 2 | Costs removed by Public Staff | 1,067 | 2/ |
| 3 | Add back Buck over amortization per Company | 2,691 | 3/ |
| 4 | Public Staff Allen Unit 4 deferred costs (L1 - L2 + L3) | $30,673 | |
| 5 | Amortization period | 6 | 1/ |
| 6 | Public Staff annual amortization (L4/L5) | $5,112 | |
| 7 | Company annual amortization | 4,842 | 4/ |
| 8 | Public Staff adjustment to annual amortization (L6 - L7) | $271 | |
| | **Rate Base Impact** | | |
| 9 | Adjusted regulatory assets and liabilities (-L4) | $30,673 | |
| 10 | Less first year amortization (L6) | 5,112 | |
| 11 | Impact to working capital investment (L9 - L10) | 25,561 | |
| 12 | Working capital impact per Company | 31,558 | 5/ |
| 13 | Adjustment to rate base (L11 - L12) | ($5,997) | |
| 14 | Composite income tax rate | 23.3503% | 6/ |
| 15 | Public Staff Adjustment to ADIT (L13 x L14) | $1,400 | |

1/ Per NC5060(B)-2, Line 34.
2/ Per Public Staff witness Lucas.
3/ Per NC5060(B)-2, Line 28.
4/ Per NC5060(B)-1, Line 2.
5/ Per NC5060(B)-1, Line 12.
6/ Composite tax rate.
7/ Per NC5060(B)-1, Line 16.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 2-1(c)**

**ADJUSTMENT TO STEAM DEFERRAL**

**For the Test Year Ended December 31, 2021**
**(in Thousands)**

| Line No. | Item | Amount | |
|---|---|---|---|
| | **Income Statement Impact** | | |
| 1 | Adjustment to depreciation & amortization for steam deferral per Company | ($37,584) | 1/ |
| 2 | Adjustment to depreciation & amortization for steam deferral per Public Staff | - | 2/ |
| 3 | Public Staff adjustment to steam deferral | 37,584 | |
| | **Rate Base Impact** | | |
| 4 | Adjustment to working capital investment per Company | $37,584 | 1/ |
| 5 | Adjustment to working capital investment per Public Staff | - | 2/ |
| 6 | Adjustment to working capital (L5 - L4) | ($37,584) | |
| 7 | Adjustment to ADIT per Company | $8,776 | 1/ |
| 8 | Adjustment to ADIT per Public Staff | - | 2/ |
| 9 | Adjustment to ADIT (L8 - L7) | ($8,776) | |

1/ NC3040-1
2/ Per Public Staff.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 2-1(d)**

**ADJUSTMENT TO GIP DEFERRAL**
**For the Test Year Ended December 31, 2021**
**(Dollar Amounts Expressed in Thousands)**

| Line No. | Item | Amount (a) | |
|---|---|---|---|
| | **Income Statement Impact** | | |
| 1 | GIP deferred costs per Company | $104,762 | 1/ |
| 2 | Costs removed by Public Staff | 22,547 | 2/ |
| 3 | Public Staff GIP deferred costs (L1 + L2) | $82,215 | |
| 4 | Public Staff amortization period | 30 | 1/ |
| 5 | Public Staff annual amortization (L3/L4) | $2,741 | |
| 6 | Company annual amortization | 34,921 | 2/ |
| 7 | Public Staff adjustment to annual amortization (L5 - L6) | ($32,180) | |
| | **Rate Base Impact** | | |
| 8 | Adjusted regulatory assets and liabilities (-L3) | $82,215 | |
| 9 | Less first year amortization (L5) | 2,741 | |
| 10 | Impact to working capital investment (L8 - L9) | $79,475 | |
| 11 | Working capital impact per Company | $69,841 | 2/ |
| 12 | Adjustment to rate base (L10 - L11) | $9,634 | |
| 13 | Composite income tax rate | 23.3503% | 1/ |
| 14 | Impact to accumulated deferred income taxes (-L10 x L13) | (18,558) | |
| 15 | ADIT per Company | (16,308) | 2/ |
| 16 | Adjustment to ADIT (L14 - L15) | ($2,250) | |

1/ Per Public Staff witness Thomas.
2/ NC5040(B)-1

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO COAL INVENTORY**
**For the Test Year Ended December 31, 2021**
**(Dollar Amounts Expressed in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 2-1(e)**

| Line No. | Item | Total System (a) | | NC Retail Allocation (b) | Total NC Retail (c) | |
|---|---|---|---|---|---|---|
| | **Rate Base impact** | | | | | |
| 1 | Estimated full load burn - excluding retirements, in tons | 51,746 | 1/ | | | |
| 2 | Target number of days inventory per Public Staff | 35 | 2/ | | | |
| 3 | Target coal inventory balance at December 31, 2023 in tons (L1 x L2) | 1,811,110 | *Tons* | | | |
| 4 | Projected average delivered coal cost per ton | 91.89 | 3/ | | | |
| 5 | Projected coal inventory balance at target (L3 x L4/1,000) | 166,423 | | 67.4869% | 4/ $112,314 | |
| 6 | Total coal inventory balance at target | 166,422.90 | | | 112,314 | |
| 7 | Actual coal inventory balance per Company | 195,023.00 | 5/ | 67.4869% | 4/ 131,615 | |
| 8 | Impact to materials and supplies (L7 - L8) | (28,601) | | | (19,301) | |
| 9 | Company adjustment | | | | (3,257) | 6/ |
| 10 | Public Staff adjustment to coal inventory (L8 - L9) | | | | ($16,044) | |

1/ Per NC6010-1
2/ Per Public Staff witness Michna, the number of days in coal inventory.
3/ NC6010-2 - Docket No. E-2, Sub 1263, Direct Testimony of John Verderame page 8, line 24.
4/ NC Retail Allocation Factor - All MWHs at Generation - Jur.
5/ E-1 Item 2, Working Trial Balance - Accounts 0151130, 0151131 and 0151132.
6/ Per NC6010(B)-1, Line 12.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**CALCULATION OF WORKING CAPITAL FROM LEAD / LAG STUDY UNDER PRESENT RATES**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 2-1(f)**

| Line No. | Item | Per Books Amounts 1/ | Company Ratemaking Adjustments 2/ | After Company Adjustments 3/ | Public Staff Adjustments 4/ | After Public Staff Adjustments 5/ | (Lead) / Lag Days 6/ | Working Capital From Lead/ Lag Study 7/ |
|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) |
| 1 | Electric operating revenues: | | | | | | | |
| 2 | Rate revenues | $4,745,958 | $364,667 | $5,110,625 | $260,727 | $5,371,352 | 39 58 | $582,461 |
| 3 | Sales for resale revenues | 46,066 | | 46,066 | - | 46,066 | 35.44 | 4,473 |
| 4 | Forfeited discounts | 3,355 | | 3,355 | - | 3,355 | 70 00 | 643 |
| 5 | Miscellaneous service revenues | 3,422 | | 3,422 | - | 3,422 | 76 00 | 713 |
| 6 | Total miscellaneous rider revenue | (65,229) | | (65,229) | - | (65,229) | | - |
| 7 | Rent revenues - extra facilities - other | 23,937 | | 23,937 | - | 23,937 | 30.13 | 1,976 |
| 8 | Rent revenues - pole & line attachments | 27,824 | | 27,824 | - | 27,824 | 143 39 | 10,931 |
| 9 | Tower lease revenues | 13,295 | | 13,295 | - | 13,295 | (93 97) | (3,423) |
| 10 | Other electric rents | 4,199 | | 4,199 | - | 4,199 | 45 21 | 520 |
| 11 | 454 Rent - labor- REL | 10,091 | | 10,091 | - | 10,091 | (15 21) | (421) |
| 12 | Other misc revenues - CIAC & comp for svc | 1,061 | | 1,061 | - | 1,061 | (15 21) | (44) |
| 13 | Other misc revenues - profit/loss on sale of M&S | 15 | | 15 | - | 15 | - | - |
| 14 | Lincoln Siemens billing | 167 | | 167 | - | 167 | (15 21) | (7) |
| 15 | Deferred DSM costs - NC | (657) | | (657) | - | (657) | - | - |
| 16 | Steam sales revenues (Clemson CHP) | 1,109 | | 1,109 | - | 1,109 | 25 50 | 77 |
| 17 | Revenues from transm of electricity to others | 6,343 | | 6,343 | | 6,343 | 40.41 | 702 |
| 18 | Other electric revenues | 1,468 | | 1,468 | (12,344) | (10,876) | 36 03 | (1,074) |
| 19 | Other transmission revenues | 1,535 | | 1,535 | | 1,535 | | - |
| 20 | Electric operating revenues | 4 823 959 | 364 667 | 5 188 626 | $248 383 | $5 437 009 | 40.11 | 597 527 |
| 21 | Fuel used in electric generation | 1,023,187 | 124,178 | 1,147,365 | 256,361 | 1,403,726 | (25 50) | (98,069) |
| 22 | Account 555 - Purchased Power | 279,049 | (44,929) | 234,120 | - | 234,120 | (39 00) | (25,016) |
| 23 | Retail Deferred Fuel Exp - NCR | (220,117) | | (220,117) | | (220,117) | (25 50) | 15,378 |
| 24 | Transmission reallocation | | 19,749 | 19,749 | - | 19,749 | | - |
| 25 | NRC inspection fees in Acct 524 | | | - | - | - | | - |
| 26 | Labor expense | 465,451 | 6,743 | 472,194 | (33,498) | 438,696 | (36 37) | (43,713) |
| 27 | Benefits expense | 54,175 | (641) | 53,534 | - | 53,534 | (12 21) | (1,791) |
| 28 | Uncollectibles expense | 18,913 | | 18,913 | - | 18,913 | | - |
| 29 | Regulatory commission expense | 8,889 | | 8,889 | - | 8,889 | (89 82) | (2,187) |
| 30 | Property insurance | (3,412) | | (3,412) | - | (3,412) | 474 55 | (4,436) |
| 31 | Injuries and damages for corp | 6,091 | | 6,091 | - | 6,091 | 145 50 | 2,428 |
| 32 | Other O&M expense | 642,759 | | 642,759 | ($15,789) | 626,970 | (36.49) | (62,680) |
| 33 | Remove non-fuel rider costs and update fuel | | (98,298) | (98,298) | - | (98,298) | (35 69) | 9,612 |
| 34 | Adjust for executive comp | | (4,130) | (4,130) | (333) | (4,463) | (36 37) | 445 |
| 35 | Adjust for inflation | | 55,836 | 55,836 | (36,214) | 19,622 | (32 50) | (1,747) |
| 36 | Adjust for approved reg assets and liabilities | | | - | - | - | | - |
| 37 | Adjust for O&M reliability assurance | | 5,943 | 5,943 | - | 5,943 | (36.49) | (594) |
| 38 | Adjust vegetation management, storm, & DE plaza | | 11,668 | 11,668 | (5,747) | 5,921 | (36.49) | (592) |
| 39 | Adjust for credit card fees | | 1,507 | 1,507 | ($1,507) | - | (36.49) | - |
| 40 | Adjust for nuclear refueling outage costs | | | - | | - | (36.49) | - |

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**CALCULATION OF WORKING CAPITAL FROM LEAD / LAG STUDY UNDER PRESENT RATES**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 2-1(f)**

| Line No. | tem | Per Books Amounts 1/ | Company Ratemaking Adjustments 2/ | After Company Adjustments 3/ | Public Staff Adjustments 4/ | After Public Staff Adjustments 5/ | (Lead) / Lag Days 6/ | Working Capital From Lead/ Lag Study 7/ |
|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) |
| 41 | Adjust for COV D & storm normalization | | 27,558 | 27,558 | ($1,680) | 25,878 | (35 69) | (2,530) |
| 42 | Annualize retail revenues for current rates | | | - | | - | (33 90) | - |
| 43 | Normalize for weather | | 110 | 110 | | 110 | (35 69) | (11) |
| 44 | Annualize revenues for customer growth | | 3,056 | 3,056 | | 3,056 | (35 69) | (299) |
| 45 | Amortize rate case costs & expiring amortizations | | (16,942) | (16,942) | (4,101) | (21,043) | - | - |
| 46 | Adjust aviation expense and test year | | (2,774) | (2,774) | (111) | (2,885) | (35 69) | 282 |
| 47 | Adjust NC regulatory fee | | 490 | 490 | - | 490 | (89 82) | (121) |
| 48 | Adjust other revenues | | 1,567 | 1,567 | - | 1,567 | (35 69) | (153) |
| 49 | Other adjustments to reg fees and uncoll. | | | | | | | |
| 50 | Total O&M expenses | 2 274 985 | 90 691 | 2 365 676 | 157 383 | 2 523 059 | | (215 794) |
| 51 | Depreciation expense | 1,033,226 | 261,529 | 1,294,755 | (139,183) | 1,155,572 | - | - |
| 52 | REPS rider NC amortization expense | | | - | - | - | | - |
| 53 | Annual NOx proceeds | | | - | - | - | | - |
| 54 | Other amortization expense | | - | - | - | - | | - |
| 55 | Remove non-fuel rider costs | | | - | - | - | | - |
| 56 | Rounding | | | | | - | | - |
| 57 | Depreciation and amortization expense | 1,033,226 | 261,529 | 1,294,755 | (139,183) | 1,155,572 | | - |
| 58 | Other taxes - NC property tax | 97,922 | | 97,922 | (2,100) | 95,822 | (186 50) | (48,961) |
| 59 | Other taxes - NC franchise & deferred prop. tax | | | - | - | - | | - |
| 60 | Other taxes - NC state unemployment tax | | | - | - | - | | - |
| 61 | Other taxes - NC industrial comm - electric | | | - | - | - | | - |
| 62 | Other taxes - SC property tax | 96,571 | | 96,571 | - | 96,571 | (196 50) | (51,990) |
| 63 | Other taxes - SC property tax - license fee | | | - | - | - | | - |
| 64 | Other taxes - NC franchise tax | | | - | - | - | | - |
| 65 | Other taxes - SC state unemployment tax | | | - | - | - | | - |
| 66 | Other taxes - federal payroll taxes | 26,503 | | 26,503 | - | 26,503 | (51.17) | (3,716) |
| 67 | Other taxes - federal unemployment tax | | | - | - | - | | - |
| 68 | Adjust propoerty taxes | | (2,484) | (2,484) | - | (2,484) | (186 50) | 1,269 |
| 69 | Other taxes | (8,506) | | (8,506) | (1) | (8,507) | (21 04) | 490 |
| 70 | Adjust payroll taxes | | 564 | 564 | - | 564 | (180.79) | (279) |
| 71 | Total taxes other than income | 212,490 | (1,920) | 210,570 | (2,101) | 208,469 | | (103,187) |
| 72 | Interest on customer deposits | 5 652 | - | 5 652 | - | 5 652 | (218.40) | (3 382) |
| 73 | Current state and federal income tax | 184,634 | - | 184,634 | - | 184,634 | (44.75) | (22,637) |
| 74 | Deferred income taxes | 35,671 | | 35,671 | - | 35,671 | - | - |
| | Adjust Incme tax and Interest Synch | | (5,346) | (5,346) | | (5,346) | (521.75) | 7,642 |
| | EDIT amortization | (204,469) | 180,377 | (24,092) | | (24,092) | - | - |
| 75 | Adjust income taxes | | | - | | - | | - |
| 76 | Total income taxes | 15,836 | 175,031 | 190,867 | - | 190,867 | | (14,995) |
| 77 | Amortization of ITC | (2,830) | 1,026 | (1,804) | - | (1,804) | - | - |
| 78 | Total electric operating expenses | 3,539,359 | 526,357 | 4,065,716 | 16,098 | 4,081,814 | | (337,358) |

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**CALCULATION OF WORKING CAPITAL FROM LEAD / LAG STUDY UNDER PRESENT RATES**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 2-1(f)**

| Line No. | tem | Per Books Amounts 1/ | Company Ratemaking Adjustments 2/ | After Company Adjustments 3/ | Public Staff Adjustments 4/ | After Public Staff Adjustments 5/ | (Lead) / Lag Days 6/ | Working Capital From Lead/ Lag Study 7/ |
|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) |
| 79 | Interest expense | 358,096 | 46,711 | 404,807 | 695 | 405,502 | (85 20) | (94,654) |
| 80 | Income available for common equity | 926,504 | (208,401) | 718,103 | (533) | 717,570 | | - |
| 81 | Net operating income for return | 1,284,600 | (161,690) | 1,122,910 | 162 | 1,123,072 | | (94,654) |
| 82 | Total requirement | $4,823,959 | $364,667 | $5,188,626 | $16,260 | $5,204,886 | | (432,012) |
| 83 | Cash working capital before sales tax requirement | | | | | | | $165,515 |
| 84 | Working capital related to sales tax | | | | | | | 6 939 |
| 85 | Cash working capital per Public Staff | | | | | | | 172,454 |
| 86 | Amount per Company application | | | | | | | 153,321 2/ |
| 87 | Adjustment to cash working capital | | | | | | | $19,133 |

1/ E-1, tem No. 14, Appendix A, Lead Lag Details, NC Retail Jurisdictional Amount.
2/ Bowman Exhibit 1.
3/ Column (a) plus Column (b).
4/ Accounting Exhibit 1, Schedule 2-1(f)(1), Column (z).
5/ Column (c) plus Column (d).
6/ E-1, tem No. 14, Appendix A, Lead Lag Details, Lead Lag Days, corrected per responses to Company data request responses.
7/ Column (e) divided by 365 days times Column (f).

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**PUBLIC STAFF ADJUSTMENTS TO BE REFLECTED IN LEAD / LAG CALCULATION**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**



| Line No. | Item | Adjust Weather Normalization 1/ (a) | Update Plant to 4/30/2023 1/ (b) | Adjust GIP Deferral 1/ (c) | Adjust Distr bution Vegetation Management 1/ (d) | Adjust Salaries and Wages 1/ (e) |
|---|---|---|---|---|---|---|
| 1 | Electric operating revenues: | | | | | |
| 2 | Rate revenues | $0 | $0 | $0 | $0 | $0 |
| 3 | Sales for resale revenues | | - | - | - | - |
| 4 | Forfeited discounts | | - | - | - | - |
| 5 | Miscellaneous service revenues | | - | - | - | - |
| 6 | Total miscellaneous rider revenue | | - | - | - | - |
| 7 | Rent revenues - extra fac lities - other | | - | - | - | - |
| 8 | Rent revenues - pole & line attachments | | - | - | - | - |
| 9 | Tower lease revenues | | - | - | - | - |
| 10 | Other electric rents | | - | - | - | - |
| 11 | 454 Rent - labor- REL | | - | - | - | - |
| 12 | Other misc revenues - CIAC & comp for svc | | - | - | - | - |
| 13 | Other misc revenues - profit/loss on sale of M&S | | - | - | - | - |
| 14 | Lincoln Siemens billing | | - | - | - | - |
| 15 | Deferred DSM costs - NC | | - | - | - | - |
| 16 | Steam sales revenues (Clemson CHP) | | - | - | - | - |
| 17 | Revenues from transm of electricity to others | | - | - | - | - |
| 18 | Other electric revenues | | - | - | - | - |
| 19 | Electric operating revenues | - | - | - | - | - |
| 20 | Fuel used in electric generation | $0 | - | $0 | - | - |
| 21 | Account 555 - Purchased Power | | - | - | - | - |
| 22 | Transmission reallocation | | - | - | - | - |
| 23 | NRC inspection fees in Acct 524 | | - | - | - | - |
| 24 | Labor expense | | - | - | - | - |
| 25 | Benefits expense | | - | - | - | - |
| 26 | Uncollectibles expense | | - | | - | - |
| 27 | Regulatory commission expense | | - | | - | - |
| 28 | Property insurance | | - | - | - | - |
| 29 | Injuries and damages for corp | | - | - | - | - |
| 30 | Other O&M expense | | - | - | - | - |
| 31 | Remove non-fuel rider costs and update fuel | | - | - | - | - |
| 32 | Adjust for executive comp | | - | - | - | - |
| 33 | Adjust for inflation | | - | - | - | - |
| 34 | Adjust for approved reg assets and liabi ities | | - | - | - | - |
| 35 | Adjust for O&M reliability assurance | | - | - | - | - |
| 36 | Adjust vegetation management, storm, & DE plaza | | - | - | (1,487) | - |
| 37 | Adjust NC regulatory fee<br>Adjust rate case expense & expiring amortizations | | - | - | - | - |
| 38 | Adjust other revenues | | - | - | - | - |
| 39 | Total O&M expenses | - | - | - | (1,487) | - |
| 40 | Depreciation expense | | (6,967) | ($32,180) | - | - |
| 41 | REPS rider NC amortization expense | | - | - | - | - |
| 42 | Annual NOx proceeds | | - | - | - | - |
| 43 | Other amortization expense | | - | - | - | - |
| 44 | Remove non-fuel rider costs | | - | - | - | - |
| 45 | Depreciation and amortization expense | - | (6,967) | (32,180) | - | - |
| 46 | Other taxes - NC property tax | | (2,100) | - | - | - |
| 47 | Other taxes - NC franchise & deferred prop. tax | | - | - | - | - |
| 48 | Other taxes - NC state unemployment tax | | - | - | - | - |
| 49 | Other taxes - NC industrial comm - electric | | - | - | - | - |
| 50 | Other taxes - SC property tax | | - | - | - | - |
| 51 | Other taxes - SC property tax - license fee | | - | - | - | - |
| 52 | Other taxes - NC franchise tax | | - | - | - | - |
| 53 | Other taxes - SC state unemployment tax | | - | - | - | - |
| 54 | Other taxes - federal payroll taxes | | - | - | - | - |
| 55 | Other taxes - federal unemployment tax | | - | - | - | - |
| 56 | Adjust propoerty taxes | | - | - | - | - |
| 57 | Other taxes | | - | - | - | - |
| 58 | Adjust payroll taxes | | - | - | - | - |
| 59 | Total taxes other than income | - | (2,100) | - | - | - |
| 60 | Interest on customer deposits | - | - | - | - | - |
| 61 | Current state and federal income tax | - | - | - | - | - |
| 62 | Deferred income taxes | - | - | - | - | - |
| 63 | Adjust income taxes | - | 2,117 | 7,514 | | - |
| 64 | Total income taxes | - | 2,117 | 7,514 | - | - |
| 65 | Amortization of ITC | - | - | - | - | - |
| 66 | Total electric operating expenses | - | (6,950) | (24,666) | (1,487) | - |
| 67 | Interest expense | - | - | - | - | - |
| 68 | Income available for common equity (L39 -L66 - L67) | - | 6,950 | 24,666 | 1,487 | - |
| 69 | Net operating income for return | - | 6,950 | 24,666 | 1,487 | - |
| 70 | Total requirement | $0 | $0 | $0 | $0 | $0 |

1/ Accounting Exhibit 1, Schedule 3-1.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**PUBLIC STAFF ADJUSTMENTS TO BE REFLECTED IN LEAD / LAG CALCULATION**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**



| Line No. | Item | Adjust COVID Deferral 1/ | Adjust Adjust Fuel Rates 1/ | Adjust Depreciation Rates 1/ | Adjust Incentives 1/ | Adjust Executive Compensation 1/ |
|---|---|---|---|---|---|---|
| | | (f) | (g) | (h) | (i) | (j) |
| 1 | Electric operating revenues: | | | | | |
| 2 | Rate revenues | $0 | $256,361 | $0 | $0 | $0 |
| 3 | Sales for resale revenues | - | - | - | - | - |
| 4 | Forfeited discounts | - | - | - | - | - |
| 5 | Miscellaneous service revenues | - | - | - | - | - |
| 6 | Total miscellaneous rider revenue | - | - | - | - | - |
| 7 | Rent revenues - extra fac lities - other | - | - | - | - | - |
| 8 | Rent revenues - pole & line attachments | - | - | - | - | - |
| 9 | Tower lease revenues | - | - | - | - | - |
| 10 | Other electric rents | - | - | - | - | - |
| 11 | 454 Rent - labor- REL | - | - | - | - | - |
| 12 | Other misc revenues - CIAC & comp for svc | - | - | - | - | - |
| 13 | Other misc revenues - profit/loss on sale of M&S | - | - | - | - | - |
| 14 | Lincoln Siemens billing | - | - | - | - | - |
| 15 | Deferred DSM costs - NC | - | - | - | - | - |
| 16 | Steam sales revenues (Clemson CHP) | - | - | - | - | - |
| 17 | Revenues from transm of electricity to others | - | - | - | - | - |
| 18 | Other electric revenues | (1,757) | - | - | - | - |
| 19 | Electric operating revenues | (1,757) | 256,361 | - | - | - |
| 20 | Fuel used in electric generation | - | 256,361 | - | - | - |
| 21 | Account 555 - Purchased Power | - | - | - | - | - |
| 22 | Transmission reallocation | - | - | - | - | - |
| 23 | NRC inspection fees in Acct 524 | - | - | - | - | - |
| 24 | Labor expense | - | - | - | (32,954) | (333) |
| 25 | Benefits expense | - | - | - | - | - |
| 26 | Uncollectibles expense | - | - | - | - | - |
| 27 | Regulatory commission expense | - | - | - | - | - |
| 28 | Property insurance | - | - | - | - | - |
| 29 | Injuries and damages for corp | - | - | - | - | - |
| 30 | Other O&M expense | ($1,680) | - | - | - | - |
| 31 | Remove non-fuel rider costs and update fuel | - | - | - | - | - |
| 32 | Adjust for executive comp | - | - | - | - | - |
| 33 | Adjust for inflation | - | - | - | - | - |
| 34 | Adjust for approved reg assets and liabi ities | - | - | - | - | - |
| 35 | Adjust for O&M reliability assurance | - | | - | - | - |
| 36 | Adjust vegetation management, storm, & DE plaza | - | - | - | - | - |
| 37 | Adjust NC regulatory fee | - | - | - | - | - |
| | Adjust rate case expense & expiring amortizations | | | | | |
| 38 | Adjust other revenues | - | - | - | - | - |
| 39 | Total O&M expenses | (1,680) | 256,361 | - | (32,954) | (333) |
| 40 | Depreciation expense | (57,058) | - | (79,742) | - | - |
| 41 | REPS rider NC amortization expense | - | - | - | - | - |
| 42 | Annual NOx proceeds | - | - | - | - | - |
| 43 | Other amortization expense | - | - | - | - | - |
| 44 | Remove non-fuel rider costs | - | - | - | - | - |
| 45 | Depreciation and amortization expense | (57,058) | - | (79,742) | - | - |
| 46 | Other taxes - NC property tax | - | - | - | - | - |
| 47 | Other taxes - NC franchise & deferred prop. tax | - | - | - | - | - |
| 48 | Other taxes - NC state unemployment tax | - | - | - | - | - |
| 49 | Other taxes - NC industrial comm - electric | - | - | - | - | - |
| 50 | Other taxes - SC property tax | - | - | - | - | - |
| 51 | Other taxes - SC property tax - license fee | - | - | - | - | - |
| 52 | Other taxes - NC franchise tax | - | - | - | - | - |
| 53 | Other taxes - SC state unemployment tax | - | - | - | - | - |
| 54 | Other taxes - federal payroll taxes | - | - | - | - | - |
| 55 | Other taxes - federal unemployment tax | - | - | - | - | - |
| 56 | Adjust propoerty taxes | - | - | - | - | - |
| 57 | Other taxes | - | - | - | - | - |
| 58 | Adjust payroll taxes | - | - | - | - | - |
| 59 | Total taxes other than income | - | - | - | - | - |
| 60 | Interest on customer deposits | - | - | - | - | - |
| 61 | Current state and federal income tax | - | - | - | - | - |
| 62 | Deferred income taxes | - | - | - | - | - |
| 63 | Adjust income taxes | 13,305 | - | 18,620 | 7,695 | 78 |
| 64 | Total income taxes | 13,305 | - | 18,620 | 7,695 | 78 |
| 65 | Amortization of ITC | - | - | - | - | - |
| 66 | Total electric operating expenses | (45,433) | 256,361 | (61,122) | (25,259) | (255) |
| 67 | Interest expense | - | - | - | - | - |
| 68 | Income available for common equity (L39 -L66 - L67) | 43,676 | - | 61,122 | 25,259 | 255 |
| 69 | Net operating income for return | 43,676 | - | 61,122 | 25,259 | 255 |
| 70 | Total requirement | ($1,757) | $256,361 | $0 | $0 | $0 |

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**PUBLIC STAFF ADJUSTMENTS TO BE REFLECTED IN LEAD / LAG CALCULATION**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**



| Line No. | Item | Adjust Aviation Expenses 1/ (k) | Adjust Credit Card Fees 1/ (l) | Adjust Advertising Expense 1/ (m) | Adjust Lighting Audit Deferral 1/ (n) |
|---|---|---|---|---|---|
| 1 | Electric operating revenues: | | | | |
| 2 | Rate revenues | $0 | $0 | $0 | $0 |
| 3 | Sales for resale revenues | - | - | - | - |
| 4 | Forfeited discounts | - | - | - | - |
| 5 | Miscellaneous service revenues | - | - | - | - |
| 6 | Total miscellaneous rider revenue | - | - | - | - |
| 7 | Rent revenues - extra fac lities - other | - | - | - | - |
| 8 | Rent revenues - pole & line attachments | - | - | - | - |
| 9 | Tower lease revenues | - | - | - | - |
| 10 | Other electric rents | - | - | - | - |
| 11 | 454 Rent - labor- REL | - | - | - | - |
| 12 | Other misc revenues - CIAC & comp for svc | - | - | - | - |
| 13 | Other misc revenues - profit/loss on sale of M&S | - | - | - | - |
| 14 | Lincoln Siemens billing | - | - | - | - |
| 15 | Deferred DSM costs - NC | - | - | - | - |
| 16 | Steam sales revenues (Clemson CHP) | - | - | - | - |
| 17 | Revenues from transm of electricity to others | - | - | - | - |
| 18 | Other electric revenues | - | - | - | - |
| 19 | Electric operating revenues | - | - | - | - |
| 20 | Fuel used in electric generation | - | - | - | - |
| 21 | Account 555 - Purchased Power | - | - | - | - |
| 22 | Transmission reallocation | - | - | - | - |
| 23 | NRC inspection fees in Acct 524 | - | - | - | - |
| 24 | Labor expense | - | - | - | - |
| 25 | Benefits expense | - | - | - | - |
| 26 | Uncollectibles expense | - | - | - | - |
| 27 | Regulatory commission expense | - | - | - | - |
| 28 | Property insurance | - | - | - | - |
| 29 | Injuries and damages for corp | - | - | - | - |
| 30 | Other O&M expense | (111) | ($1,507) | $0 | - |
| 31 | Remove non-fuel rider costs and update fuel | - | - | - | - |
| 32 | Adjust for executive comp | - | | - | - |
| 33 | Adjust for inflation | - | - | - | - |
| 34 | Adjust for approved reg assets and liabi ities | - | - | - | - |
| 35 | Adjust for O&M reliability assurance | - | - | - | - |
| 36 | Adjust vegetation management, storm, & DE plaza | | - | - | - |
| 37 | Adjust NC regulatory fee | - | - | - | - |
| | Adjust rate case expense & expiring amortizations | | | | |
| 38 | Adjust other revenues | - | - | - | - |
| 39 | Total O&M expenses | (111) | (1,507) | - | - |
| 40 | Depreciation expense | - | - | | ($219) |
| 41 | REPS rider NC amortization expense | - | - | - | - |
| 42 | Annual NOx proceeds | - | - | - | - |
| 43 | Other amortization expense | - | - | - | - |
| 44 | Remove non-fuel rider costs | - | - | - | - |
| 45 | Depreciation and amortization expense | - | - | - | (219) |
| 46 | Other taxes - NC property tax | - | - | - | - |
| 47 | Other taxes - NC franchise & deferred prop. tax | - | - | - | - |
| 48 | Other taxes - NC state unemployment tax | - | - | - | - |
| 49 | Other taxes - NC industrial comm - electric | - | - | - | - |
| 50 | Other taxes - SC property tax | - | - | - | - |
| 51 | Other taxes - SC property tax - license fee | - | - | - | - |
| 52 | Other taxes - NC franchise tax | - | - | - | - |
| 53 | Other taxes - SC state unemployment tax | - | - | - | - |
| 54 | Other taxes - federal payroll taxes | - | - | - | - |
| 55 | Other taxes - federal unemployment tax | - | - | - | - |
| 56 | Adjust propoerty taxes | - | - | - | - |
| 57 | Other taxes | (1) | - | - | - |
| 58 | Adjust payroll taxes | | - | - | - |
| 59 | Total taxes other than income | (1) | - | - | - |
| 60 | Interest on customer deposits | - | - | - | - |
| 61 | Current state and federal income tax | - | - | - | - |
| 62 | Deferred income taxes | - | - | - | - |
| 63 | Adjust income taxes | 26 | 352 | - | 51 |
| 64 | Total income taxes | 26 | 352 | - | 51 |
| 65 | Amortization of ITC | - | - | - | - |
| 66 | Total electric operating expenses | (86) | (1,155) | - | (168) |
| 67 | Interest expense | - | - | - | - |
| 68 | Income available for common equity (L39 -L66 - L67) | 86 | 1,155 | - | 168 |
| 69 | Net operating income for return | 86 | 1,155 | - | 168 |
| 70 | Total requirement | $0 | $0 | $0 | $0 |

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**PUBLIC STAFF ADJUSTMENTS TO BE REFLECTED IN LEAD / LAG CALCULATION**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**



| Line No. | Item | Adjust Lobbying Expense 1/ | Adjust Board of Directors Expense 1/ | Adjust Allen Unit 4 1/ | Adjust Rent Expense 1/ | Adjust Sponsorships and Donations 1/ |
|---|---|---|---|---|---|---|
| | | (o) | (p) | (q) | (r) | (s) |
| 1 | Electric operating revenues: | | | | | |
| 2 | Rate revenues | $0 | $0 | $0 | $0 | $0 |
| 3 | Sales for resale revenues | - | - | - | - | - |
| 4 | Forfeited discounts | - | - | - | - | - |
| 5 | Miscellaneous service revenues | - | - | - | - | - |
| 6 | Total miscellaneous rider revenue | - | - | - | - | - |
| 7 | Rent revenues - extra fac lities - other | - | - | - | - | - |
| 8 | Rent revenues - pole & line attachments | - | - | - | - | - |
| 9 | Tower lease revenues | - | - | - | - | - |
| 10 | Other electric rents | - | - | - | - | - |
| 11 | 454 Rent - labor- REL | - | - | - | - | - |
| 12 | Other misc revenues - CIAC & comp for svc | - | - | - | - | - |
| 13 | Other misc revenues - profit/loss on sale of M&S | - | - | - | - | - |
| 14 | Lincoln Siemens billing | - | - | - | - | - |
| 15 | Deferred DSM costs - NC | - | - | - | - | - |
| 16 | Steam sales revenues (Clemson CHP) | - | - | - | - | - |
| 17 | Revenues from transm of electricity to others | - | - | - | - | - |
| 18 | Other electric revenues | - | - | - | (10,587) | - |
| 19 | Electric operating revenues | - | - | - | (10,587) | - |
| 20 | Fuel used in electric generation | - | - | - | - | - |
| 21 | Account 555 - Purchased Power | - | - | - | - | - |
| 22 | Transmission reallocation | - | - | - | - | - |
| 23 | NRC inspection fees in Acct 524 | - | - | - | - | - |
| 24 | Labor expense | (544) | - | - | - | - |
| 25 | Benefits expense | - | - | - | - | - |
| 26 | Uncollectibles expense | - | - | - | - | - |
| 27 | Regulatory commission expense | - | - | - | - | - |
| 28 | Property insurance | - | - | - | - | - |
| 29 | Injuries and damages for corp | - | - | - | - | - |
| 30 | Other O&M expense | - | (1,870) | - | | (23) |
| 31 | Remove non-fuel rider costs and update fuel | - | - | - | - | - |
| 32 | Adjust for executive comp | - | - | - | - | - |
| 33 | Adjust for inflation | - | - | - | - | - |
| 34 | Adjust for approved reg assets and liabi ities | - | - | - | - | - |
| 35 | Adjust for O&M reliability assurance | - | - | - | - | - |
| 36 | Adjust vegetation management, storm, & DE plaza | - | - | - | (4,260) | - |
| 37 | Adjust NC regulatory fee<br>Adjust rate case expense & expiring amortizations | - | - | - | - | - |
| 38 | Adjust other revenues | - | - | - | - | - |
| 39 | Total O&M expenses | (544) | (1,870) | - | (4,260) | (23) |
| 40 | Depreciation expense | - | - | 271 | - | - |
| 41 | REPS rider NC amortization expense | - | - | - | - | - |
| 42 | Annual NOx proceeds | - | - | - | - | - |
| 43 | Other amortization expense | - | - | - | - | - |
| 44 | Remove non-fuel rider costs | - | - | - | - | - |
| 45 | Depreciation and amortization expense | - | - | 271 | - | - |
| 46 | Other taxes - NC property tax | - | - | - | - | - |
| 47 | Other taxes - NC franchise & deferred prop. tax | - | - | - | - | - |
| 48 | Other taxes - NC state unemployment tax | - | - | - | - | - |
| 49 | Other taxes - NC industrial comm - electric | - | - | - | - | - |
| 50 | Other taxes - SC property tax | - | - | - | - | - |
| 51 | Other taxes - SC property tax - license fee | - | - | - | - | - |
| 52 | Other taxes - NC franchise tax | - | - | - | - | - |
| 53 | Other taxes - SC state unemployment tax | - | - | - | - | - |
| 54 | Other taxes - federal payroll taxes | - | - | - | - | - |
| 55 | Other taxes - federal unemployment tax | - | - | - | - | - |
| 56 | Adjust propoerty taxes | - | - | - | - | - |
| 57 | Other taxes | - | - | - | - | - |
| 58 | Adjust payroll taxes | - | - | - | - | - |
| 59 | Total taxes other than income | - | - | - | - | - |
| 60 | Interest on customer deposits | - | - | - | - | - |
| 61 | Current state and federal income tax | - | - | - | - | - |
| 62 | Deferred income taxes | - | - | - | - | - |
| 63 | Adjust income taxes | 127 | 437 | (63) | (1,477) | 5 |
| 64 | Total income taxes | 127 | 437 | (63) | (1,477) | 5 |
| 65 | Amortization of ITC | - | - | - | - | - |
| 66 | Total electric operating expenses | (417) | (1,433) | 207 | (5,737) | (18) |
| 67 | Interest expense | - | - | - | - | - |
| 68 | Income available for common equity (L39 -L66 - L67) | 417 | 1,433 | (207) | (4,850) | 18 |
| 69 | Net operating income for return | 417 | 1,433 | (207) | (4,850) | 18 |
| 70 | Total requirement | $0 | $0 | $0 | ($10,587) | $0 |

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**PUBLIC STAFF ADJUSTMENTS TO BE REFLECTED IN LEAD / LAG CALCULATION**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 2-1(f)(1)**


| Line No. | Item | Adjust Storm Normalization 1/ (t) | Adjust Test Year Revenue & Expenses 1/ (u) | Adjust Rate Case Expense 1/ (v) | Adjust Steam Deferral 1/ (w) | (x) |
|---|---|---|---|---|---|---|
| 1 | Electric operating revenues: | | | | | |
| 2 | Rate revenues | $0 | $ 4,366 | $0 | $0 | |
| 3 | Sales for resale revenues | - | | | | |
| 4 | Forfeited discounts | - | | | | |
| 5 | Miscellaneous service revenues | - | | | | |
| 6 | Total miscellaneous rider revenue | - | | | | |
| 7 | Rent revenues - extra fac lities - other | - | | | | |
| 8 | Rent revenues - pole & line attachments | - | | | | |
| 9 | Tower lease revenues | - | | | | |
| 10 | Other electric rents | - | | | | |
| 11 | 454 Rent - labor- REL | - | | | | |
| 12 | Other misc revenues - CIAC & comp for svc | - | | | | |
| 13 | Other misc revenues - profit/loss on sale of M&S | - | | | | |
| 14 | Lincoln Siemens billing | - | | | | |
| 15 | Deferred DSM costs - NC | - | | | | |
| 16 | Steam sales revenues (Clemson CHP) | - | | | | |
| 17 | Revenues from transm of electricity to others | - | | | | |
| 18 | Other electric revenues | - | | | - | |
| 19 | Electric operating revenues | - | 4,366 | - | - | |
| 20 | Fuel used in electric generation | - | | | | |
| 21 | Account 555 - Purchased Power | - | | | | |
| 22 | Transmission reallocation | - | | | | |
| 23 | NRC inspection fees in Acct 524 | - | | | | |
| 24 | Labor expense | - | | | | |
| 25 | Benefits expense | - | | | | |
| 26 | Uncollectibles expense | - | | | | |
| 27 | Regulatory commission expense | - | | | | |
| 28 | Property insurance | - | | | | |
| 29 | Injuries and damages for corp | - | | | | |
| 30 | Other O&M expense | - | (12,216) | | 0 | |
| 31 | Remove non-fuel rider costs and update fuel | - | | | | |
| 32 | Adjust for executive comp | - | | | | |
| 33 | Adjust for inflation | - | | | | |
| 34 | Adjust for approved reg assets and liabi ities | - | | | | |
| 35 | Adjust for O&M reliability assurance | - | | | | |
| 36 | Adjust vegetation management, storm, & DE plaza | - | | | | |
| 37 | Adjust NC regulatory fee | - | | | | |
| | Adjust rate case expense & expiring amortizations | | | (4,101) | | |
| 38 | Adjust other revenues | - | | | | |
| 39 | Total O&M expenses | - | (12,216) | (4,101) | - | |
| 40 | Depreciation expense | - | | | 37,584 | |
| 41 | REPS rider NC amortization expense | - | | | | |
| 42 | Annual NOx proceeds | - | | | | |
| 43 | Other amortization expense | - | | | | |
| 44 | Remove non-fuel rider costs | - | | | | |
| 45 | Depreciation and amortization expense | - | - | - | 37,584 | |
| 46 | Other taxes - NC property tax | - | | | | |
| 47 | Other taxes - NC franchise & deferred prop. tax | - | | | | |
| 48 | Other taxes - NC state unemployment tax | - | | | | |
| 49 | Other taxes - NC industrial comm - electric | - | | | | |
| 50 | Other taxes - SC property tax | - | | | | |
| 51 | Other taxes - SC property tax - license fee | - | | | | |
| 52 | Other taxes - NC franchise tax | - | | | | |
| 53 | Other taxes - SC state unemployment tax | - | | | | |
| 54 | Other taxes - federal payroll taxes | - | | | | |
| 55 | Other taxes - federal unemployment tax | - | | | | |
| 56 | Adjust propoerty taxes | - | | | | |
| 57 | Other taxes | - | | | | |
| 58 | Adjust payroll taxes | - | | | | |
| 59 | Total taxes other than income | - | - | - | - | |
| 60 | Interest on customer deposits | - | - | - | - | |
| 61 | Current state and federal income tax | - | | | | |
| 62 | Deferred income taxes | - | | | | |
| 63 | Adjust income taxes | - | 3,872 | 957 | 81 | |
| 64 | Total income taxes | - | 3,872 | 957 | 81 | |
| 65 | Amortization of ITC | - | - | - | - | |
| 66 | Total electric operating expenses | - | (8,344) | (3,143) | 37,665 | |
| 67 | Interest expense | - | - | - | - | |
| 68 | Income available for common equity (L39 -L66 - L67) | - | 12,710 | 3,143 | (37,665) | |
| 69 | Net operating income for return | - | 12,710 | 3,143 | (37,665) | |
| 70 | Total requirement | $0 | $4,366 | $0 | $0 | |

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**PUBLIC STAFF ADJUSTMENTS TO BE REFLECTED IN LEAD / LAG CALCULATION**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**



| Line No. | Item | Adjustment to Inflation Adjustment 1/ (x) | Adjust EOL Nuclear M&S Reserve Amortization 1/ (y) | Adjust Aover Amortization Rate Case Expense 1/ (z) | Interest Synchronization 1/ (aa) | Total Public Staff Adjustments 1/ (bb) |
|---|---|---|---|---|---|---|
| 1 | Electric operating revenues: | | | | | |
| 2 | Rate revenues | $0 | $0 | $0 | $0 | $260,727 |
| 3 | Sales for resale revenues | - | | | - | 0 |
| 4 | Forfeited discounts | - | | | - | 0 |
| 5 | Miscellaneous service revenues | - | | | - | 0 |
| 6 | Total miscellaneous rider revenue | - | | | - | 0 |
| 7 | Rent revenues - extra fac lities - other | - | | | - | 0 |
| 8 | Rent revenues - pole & line attachments | - | | | - | 0 |
| 9 | Tower lease revenues | - | | | - | 0 |
| 10 | Other electric rents | - | | | - | 0 |
| 11 | 454 Rent - labor- REL | - | | | - | 0 |
| 12 | Other misc revenues - CIAC & comp for svc | - | | | - | 0 |
| 13 | Other misc revenues - profit/loss on sale of M&S | - | | | - | 0 |
| 14 | Lincoln Siemens billing | - | | | - | 0 |
| 15 | Deferred DSM costs - NC | - | | | - | 0 |
| 16 | Steam sales revenues (Clemson CHP) | - | | | - | 0 |
| 17 | Revenues from transm of electricity to others | - | | | - | 0 |
| 18 | Other electric revenues | - | | | - | (12,344) |
| 19 | Electric operating revenues | - | - | - | - | 248,383 |
| 20 | Fuel used in electric generation | - | | | - | $256,361 |
| 21 | Account 555 - Purchased Power | - | | | - | - |
| 22 | Transmission reallocation | - | | | - | - |
| 23 | NRC inspection fees in Acct 524 | - | | | - | - |
| 24 | Labor expense | - | | | - | (33,831) |
| 25 | Benefits expense | - | - | | - | - |
| 26 | Uncollectibles expense | - | | | - | - |
| 27 | Regulatory commission expense | - | | | - | - |
| 28 | Property insurance | - | | | - | - |
| 29 | Injuries and damages for corp | - | | | - | - |
| 30 | Other O&M expense | - | | | - | (17,406) |
| 31 | Remove non-fuel rider costs and update fuel | - | | | - | - |
| 32 | Adjust for executive comp | - | | | - | - |
| 33 | Adjust for inflation | (36,214) | | | - | (36,214) |
| 34 | Adjust for approved reg assets and liabi ities | - | | | - | - |
| 35 | Adjust for O&M reliability assurance | - | | | - | - |
| 36 | Adjust vegetation management, storm, & DE plaza | - | | | - | (5,747) |
| 37 | Adjust NC regulatory fee | - | | | - | - |
| | Adjust rate case expense & expiring amortizations | | | | | (4,101) |
| 38 | Adjust other revenues | - | | | - | - |
| 39 | Total O&M expenses | (36,214) | - | - | - | 159,063 |
| 40 | Depreciation expense | - | (346) | ($525) | - | (139,183) |
| 41 | REPS rider NC amortization expense | - | | | - | - |
| 42 | Annual NOx proceeds | - | | | - | - |
| 43 | Other amortization expense | - | | | - | - |
| 44 | Remove non-fuel rider costs | - | | | - | - |
| 45 | Depreciation and amortization expense | - | (346) | (525) | - | (139,183) |
| 46 | Other taxes - NC property tax | - | | | - | (2,100) |
| 47 | Other taxes - NC franchise & deferred prop. tax | - | | | - | - |
| 48 | Other taxes - NC state unemployment tax | - | | | - | - |
| 49 | Other taxes - NC industrial comm - electric | - | | | - | - |
| 50 | Other taxes - SC property tax | - | | | - | - |
| 51 | Other taxes - SC property tax - license fee | - | | | - | - |
| 52 | Other taxes - NC franchise tax | - | | | - | - |
| 53 | Other taxes - SC state unemployment tax | - | | | - | - |
| 54 | Other taxes - federal payroll taxes | - | | | - | - |
| 55 | Other taxes - federal unemployment tax | - | | | - | - |
| 56 | Adjust propoerty taxes | - | | | - | - |
| 57 | Other taxes | - | | | - | (1) |
| 58 | Adjust payroll taxes | - | | | - | - |
| 59 | Total taxes other than income | - | - | - | - | (2,101) |
| | | | - | - | | |
| 60 | Interest on customer deposits | - | - | - | - | - |
| 61 | Current state and federal income tax | - | - | | - | - |
| 62 | Deferred income taxes | - | - | | - | - |
| 63 | Adjust income taxes | 8,456 | - | 123 | 793 | 63,069 |
| 64 | Total income taxes | 8,456 | - | 123 | 793 | 63,069 |
| 65 | Amortization of ITC | - | - | - | - | - |
| 66 | Total electric operating expenses | (27,758) | (346) | (403) | 793 | 80,848 |
| 67 | Interest expense | - | - | - | (3,398) | (3,398) |
| 68 | Income available for common equity (L39 -L66 - L67) | 27,758 | 346 | 403 | 2,604 | 170,934 |
| 69 | Net operating income for return | 27,758 | 346 | 403 | (793) | 167,536 |
| 70 | Total requirement | $0 | $0 | $0 | $0 | $248,383 |

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E 7, Sub 1276**
**North Carolina Retail Operations**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 2 1(g)**
**Page 1 of 2**

**CALCULATION OF WORKING CAPITAL FROM LEAD / LAG STUDY AFTER RATE DECREASE**

**For the Test Year Ended December 31, 2021**
**(in Thousands)**

| Line No. | Item | Under Present Rates After Adjustments 1/ (a) | (Lead) Lag Days / (b) | Iteration 1 Increase (c) | Iteration 1 With Increase 11/ (d) | CWC Change 13/ (e) |
|---|---|---|---|---|---|---|
| 1 | Electric operating revenues | | | | | |
| 2 | Rate revenues | $5,371,352 | 39.58 | $249,853 5/ | $5,621,205 | $27,094 |
| 3 | Sales for resale revenues | 46,066 | 35.44 | - | 46,066 | - |
| 4 | Forfeited discounts | 3,355 | 70.00 | - | 3,355 | - |
| 5 | Miscellaneous service revenues | 3,422 | 76.00 | - 6/ | 3,422 | - |
| 6 | Total miscellaneous rider revenue | (65,229) | - | - | (65,229) | - |
| 7 | Rent revenues - extra facilities - other | 23,937 | 30.13 | - | 23,937 | - |
| 8 | Rent revenues - pole & line attachments | 27,824 | 143.39 | - | 27,824 | - |
| 9 | Tower lease revenues | 13,295 | (93.97) | - | 13,295 | - |
| 10 | Other electric rents | 4,199 | 45.21 | - | 4,199 | - |
| 11 | 454 Rent - labor- REL | 10,091 | (15.21) | - | 10,091 | - |
| 12 | Other misc revenues - CIAC & comp for svc | 1,061 | (15.21) | - | 1,061 | - |
| 13 | Other misc revenues - profit/loss on sale of M&S | 15 | - | - | 15 | - |
| 14 | Lincoln Siemens billing | 167 | (15.21) | - | 167 | - |
| 15 | Deferred DSM costs - NC | (657) | - | - | (657) | - |
| 16 | Steam sales revenues (Clemson CHP) | 1,109 | 25.50 | - | 1,109 | - |
| 17 | Revenues from transm of electricity to others | 6,343 | 40.41 | - | 6,343 | - |
| 18 | Other electric revenues | (10,876) | 36.03 | - | (10,876) | - |
| | Other transmission revenues | 1 535 | - | | 1 535 | - |
| 19 | Electric operating revenues | 5 437 009 | | 249 853 7/ | 5 686 862 | $27 094 |
| 20 | Fuel used in electric generation | 1,403,726 | (25.50) | - | 1,403,726 | - |
| 21 | Account 555 - Purchased Power | 234,120 | (39.00) | - | 234,120 | - |
| 22 | Retail Deferred Fuel Exp - NCR | (220,117) | (25.50) | - | (220,117) | - |
| 23 | Transmission reallocation | 19,749 | - | - | 19,749 | - |
| 24 | NRC inspection fees in Acct 524 | - | - | - | - | - |
| 25 | Labor expense | 438,696 | (36.37) | - | 438,696 | - |
| 26 | Benefits expense | 53,534 | (12.21) | - | 53,534 | - |
| 27 | Uncollectibles expense | 18,913 | - | - | 18,913 | - |
| 28 | Regulatory commission expense | 8,889 | (89.82) | - | 8,889 | - |
| 29 | Property insurance | (3,412) | 474.55 | - | (3,412) | - |
| 30 | Injuries and damages for corp | 6,091 | 145.50 | - | 6,091 | - |
| 31 | Other O&M expense | 626,970 | (36.49) | - | 626,970 | - |
| 32 | Remove non-fuel rider costs and update fuel | (98,298) | (35.69) | - | (98,298) | - |
| 33 | Adjust for executive comp | (4,463) | (36.37) | - | (4,463) | - |
| 34 | Adjust for inflation | 19,622 | (32.50) | - | 19,622 | - |
| 35 | Adjust for approved reg assets and liabilities | - | - | - | - | - |
| 36 | Adjust for O&M reliability assurance | 5,943 | (36.49) | - | 5,943 | - |
| 37 | Adjust vegetation management, storm, & DE plaza | 5,921 | (36.49) | - | 5,921 | - |
| 38 | Adjust for credit card fees | - | (36.49) | - | - | - |
| 39 | Adjust for nuclear refueling outage costs | - | (36.49) | - | - | - |
| 40 | Adjust for merger related costs | 25,878 | (35.69) | - | 25,878 | - |
| 41 | Annualize retail revenues for current rates | - | (33.90) | - | - | - |
| 42 | Normalize for weather | 110 | (35.69) | - | 110 | - |
| 43 | Annualize revenues for customer growth | 3,056 | (35.69) | - | 3,056 | - |
| 44 | Amortize rate case costs | (21,043) | - | - | (21,043) | - |
| 45 | Adjust aviation expense | (2,885) | (35.69) | - | (2,885) | - |
| 46 | Adjust NC regulatory fee | 490 | (89.82) | - | 490 | - |
| 47 | Adjust other revenues | 1,567 | (35.69) | - | 1,567 | - |
| 48 | Other adjustments to reg fees and uncoll. | - | (36.49) | 1,807 8/ | 1,807 | (181) |
| 49 | Total O&M expenses | 2 523 059 | | 1 807 | 2 524 866 | - |
| 50 | | | | | | |
| 51 | Depreciation expense | 1,155,572 | - | - | 1,155,572 | - |
| 52 | REPS rider NC amortization expense | - | - | - | - | - |
| 53 | Annual NOx proceeds | - | - | - | - | - |
| 54 | Other amortization expense | - | - | - | - | - |
| 55 | Remove non-fuel rider costs | - | - | - | - | - |
| 56 | Depreciation and amortization expense | 1 155 572 | | - | 1 155 572 | - |
| 57 | Other taxes - NC property tax | 95,822 | (186.50) | - | 95,822 | - |
| 58 | Other taxes - NC franchise & deferred prop. tax | - | - | - | - | - |
| 59 | Other taxes - NC state unemployment tax | - | - | - | - | - |
| 60 | Other taxes - NC industrial comm - electric | - | - | - | - | - |
| 61 | Other taxes - SC property tax | 96,571 | (196.50) | - | 96,571 | - |
| 62 | Other taxes - SC property tax - icense fee | - | - | - | - | - |
| 63 | Other taxes - NC franchise tax | - | - | - | - | - |
| 64 | Other taxes - SC state unemployment tax | - | - | - | - | - |
| 65 | Other taxes - federal payroll taxes | 26,503 | (51.17) | - | 26,503 | - |
| 66 | Other taxes - federal unemployment tax | - | - | - | - | - |
| 67 | Adjust propoerty taxes | (2,484) | (186.50) | - | (2,484) | - |
| 68 | Other taxes | (8,507) | (21.04) | - | (8,507) | - |
| 69 | Adjust payroll taxes | 564 | (180.79) | - | 564 | - |
| 70 | Current state and federal income tax | 208 469 | | - | 208 469 | - |
| 71 | Interest on customer deposits | 5,652 | (218.40) | - | 5,652 | - |
| 72 | Current state and federal income tax | 184,634 | (44.75) | - | 184,634 | - |
| 73 | Deferred income taxes | 35,671 | - | - | 35,671 | - |
| | Adjust Incme tax and Interest Synch | (5,346) | (521.75) | - | (5,346) | |
| | EDIT amortization | (24,092) | - | - | (24,092) | - |
| 74 | Adjust income taxes | | (521.75) | 57 920 9/ | 57 920 | (82 793) |
| 75 | Total income taxes | 190,867 | | 57,920 | 248,787 | (82,793) |
| 76 | Amortization of ITC | (1 804) | - | - | (1 804) | - |
| 77 | Total electric operating expenses | 4,081,814 | | 59,727 | 4,141,541 | (82,793) |
| 78 | Interest expense | 405,502 | (85.20) | - | 405,502 | - |
| 79 | Income available for common equity | 717,570 | - | 190,127 10 | 907,697 12/ | - |
| 80 | Net operating income for return | 1 123 072 | | 190 127 | 1 313 199 | - |
| 81 | Total requirement | $5 204 886 | | $249 854 | $5 454 740 | ($82 793) |
| 82 | Cumulative change in working capital | | | | | ($55,699) |
| 83 | Rate base under present rates | | | | | 18,669,209 |
| 84 | Rate base after rate increase | $18 669 209 2/ | | | | $18 613 509 |
| 85 | Overall rate of return | 6.02% | | | | 7.06% |
| 86 | Target rate of return | 7.04% 3/ | | | | 7.04% 3/ |

1/ Accounting Exhibit 1, Schedule 2-1(f), Column (e).
2/ Accounting Exhibit 1, Schedule 2, Line 13, Column (c).
3/ Accounting Exhibit 1, Schedule 4, Line 3, Column (h).
4/ Accounting Exhibit 1, Schedule 2-1(f), Column (f).
5/ Line 19 minus (Sum of Line 3 thru Line 18).
6/ Accounting Exhibit 1, Schedule 3, Line 3, Column (d).
7/ Line 79 divided by retention factor of 0.7609549.
8/ Line 19 times (uncolectibles rate of 0.58474% plus regulatory fee rate, net of uncollectibles, of 0.13837%).
9/ (Line 79 divided by (1 minus 23.3503%)) minus Line 79.
10/ Column (d) minus Column (a).
11/ Column (a) plus Column (c), unless footnoted otherwise.
12/ Line 84, Column (a) times 52.000% times 9.350%.
13/ Column (c) divided by 365 days times Column (b).

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E 7, Sub 1276**
**North Carolina Retail Operations**
**CALCULATION OF WORKING CAPITAL**
**FROM LEAD / LAG STUDY AFTER RATE INCREASE**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 2 1(g)**
**Page 2 of 2**

| Line No. | Item | Iteration 2 Increase | Iteration 2 With Increase | Iteration 2 CWC Change | Iteration 3 Increase | Iteration 3 With Increase | Iteration 3 CWC Change | After Increase Cumulative Increase | After Increase After Increase |
|---|---|---|---|---|---|---|---|---|---|
| | | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) |
| 1 | Electric operating revenues | | | | | | | | |
| 2 | Rate revenues | ($238,232) 5/ | $5,382,973 | ($25,834) | ($2,085) 5/ | $5,380,889 | ($226) | $9,536 | $5,380,889 |
| 3 | Sales for resale revenues | - | 46,066 | - | - | 46,066 | - | - | 46,066 |
| 4 | Forfeited discounts | - | 3,355 | - | - | 3,355 | - | - | 3,355 |
| 5 | Miscellaneous service revenues | - | 3,422 | - | - | 3,422 | - | - | 3,422 |
| 6 | Total miscellaneous rider revenue | - | (65,229) | - | - | (65,229) | - | - | (65,229) |
| 7 | Rent revenues - extra facilities - other | - | 23,937 | - | - | 23,937 | - | - | 23,937 |
| 8 | Rent revenues - pole & line attachments | - | 27,824 | - | - | 27,824 | - | - | 27,824 |
| 9 | Tower lease revenues | - | 13,295 | - | - | 13,295 | - | - | 13,295 |
| 10 | Other electric rents | - | 4,199 | - | - | 4,199 | - | - | 4,199 |
| 11 | 454 Rent - labor- REL | - | 10,091 | - | - | 10,091 | - | - | 10,091 |
| 12 | Other misc revenues - CIAC & comp for svc | - | 1,061 | - | - | 1,061 | - | - | 1,061 |
| 13 | Other misc revenues - profit/loss on sale of M&S | - | 15 | - | - | 15 | - | - | 15 |
| 14 | Lincoln Siemens billing | - | 167 | - | - | 167 | - | - | 167 |
| 15 | Deferred DSM costs - NC | - | (657) | - | - | (657) | - | - | (657) |
| 16 | Steam sales revenues (Clemson CHP) | - | 1,109 | - | - | 1,109 | - | - | 1,109 |
| 17 | Revenues from transm of electricity to others | - | 6,343 | - | - | 6,343 | - | - | 6,343 |
| 18 | Other electric revenues | - | (10,876) | - | - | (10,876) | - | - | (10,876) |
| 19 | Electric operating revenues | (238 232) 1 / | 5 448 630 16/ | (25 834) | (2 085) 20/ | 5 446 546 16/ | (226) | 9 536 | 5 446 546 |
| 20 | Fuel used in electric generation | - | 1,403,726 | - | - | 1,403,726 | - | - | 1,403,726 |
| 21 | Account 555 - Purchased Power | - | 234,120 | - | - | 234,120 | - | - | 234,120 |
| 22 | Retail Deferred Fuel Exp - NCR | - | (220,117) | - | - | (220,117) | - | - | (220,117) |
| 23 | Transmission reallocation | - | 19,749 | - | - | 19,749 | - | - | 19,749 |
| 24 | NRC inspection fees in Acct 524 | - | - | - | - | - | - | - | - |
| 25 | Labor expense | - | 438,696 | - | - | 438,696 | - | - | 438,696 |
| 26 | Benefits expense | - | 53,534 | - | - | 53,534 | - | - | 53,534 |
| 27 | Uncollectibles expense | - | 18,913 | - | - | 18,913 | - | - | 18,913 |
| 28 | Regulatory commission expense | - | 8,889 | - | - | 8,889 | - | - | 8,889 |
| 29 | Property insurance | - | (3,412) | - | - | (3,412) | - | - | (3,412) |
| 30 | Injuries and damages for corp | - | 6,091 | - | - | 6,091 | - | - | 6,091 |
| 31 | Other O&M expense | - | 626,970 | - | - | 626,970 | - | - | 626,970 |
| 32 | Remove non-fuel rider costs and update fuel | - | (98,298) | - | - | (98,298) | - | - | (98,298) |
| 33 | Adjust for executive comp | - | (4,463) | - | - | (4,463) | - | - | (4,463) |
| 34 | Adjust for inflation | - | 19,622 | - | - | 19,622 | - | - | 19,622 |
| 35 | Adjust for approved reg assets and liabilities | - | - | - | - | - | - | - | - |
| 36 | Adjust for O&M reliability assurance | - | 5,943 | - | - | 5,943 | - | - | 5,943 |
| 37 | Adjust vegetation management, storm, & DE plaza | - | 5,921 | - | - | 5,921 | - | - | 5,921 |
| 38 | Adjust for credit card fees | - | - | - | - | - | - | - | - |
| 39 | Adjust for nuclear refueling outage costs | - | - | - | - | - | - | - | - |
| 40 | Adjust for merger related costs | - | 25,878 | - | - | 25,878 | - | - | 25,878 |
| 41 | Annualize retail revenues for current rates | - | - | - | - | - | - | - | - |
| 42 | Normalize for weather | - | 110 | - | - | 110 | - | - | 110 |
| 43 | Annualize revenues for customer growth | - | 3,056 | - | - | 3,056 | - | - | 3,056 |
| 44 | Amortize rate case costs | - | (21,043) | - | - | (21,043) | - | - | (21,043) |
| 45 | Adjust aviation expense | - | (2,885) | - | - | (2,885) | - | - | (2,885) |
| 46 | Adjust NC regulatory fee | - | 490 | - | - | 490 | - | - | 490 |
| 47 | Adjust other revenues | - | 1,567 | - | - | 1,567 | 1 | - | 1,567 |
| 48 | Other adjustments to reg fees and uncoll. | (31) 8/ | 1,776 | 3 | (15) 8/ | 1,761 | | 1,761 | 1,761 |
| 49 | Total O&M expenses | (31) | 2 523 059 | - | (15) | 2 523 059 | 1 | - | 2 523 059 |
| 50 | | | | | | | | | |
| 51 | Depreciation expense | - | 1,155,572 | - | - | 1,155,572 | - | - | 1,155,572 |
| 52 | REPS rider NC amortization expense | - | - | - | - | - | - | - | - |
| 53 | Annual NOx proceeds | - | - | - | - | - | - | - | - |
| 54 | Other amortization expense | - | - | - | - | - | - | - | - |
| 55 | Remove non-fuel rider costs | - | - | - | - | - | - | - | - |
| 56 | Depreciation and amortization expense | - | 1 155 572 | - | - | 1 155 572 | - | - | 1 155 572 |
| 57 | Other taxes - NC property tax | - | 95,822 | - | - | 95,822 | - | - | 95,822 |
| 58 | Other taxes - NC franchise & deferred prop. tax | - | - | - | - | - | - | - | - |
| 59 | Other taxes - NC state unemployment tax | - | - | - | - | - | - | - | - |
| 60 | Other taxes - NC industrial comm - electric | - | - | - | - | - | - | - | - |
| 61 | Other taxes - SC property tax | - | 96,571 | - | - | 96,571 | - | - | 96,571 |
| 62 | Other taxes - SC property tax - icense fee | - | - | - | - | - | - | - | - |
| 63 | Other taxes - NC franchise tax | - | - | - | - | - | - | - | - |
| 64 | Other taxes - SC state unemployment tax | - | - | - | - | - | - | - | - |
| 65 | Other taxes - federal payroll taxes | - | 26,503 | - | - | 26,503 | - | - | 26,503 |
| 66 | Other taxes - federal unemployment tax | - | - | - | - | - | - | - | - |
| 67 | Adjust propoerty taxes | - | (2,484) | - | - | (2,484) | - | - | (2,484) |
| 68 | Other taxes | - | (8,507) | - | - | (8,507) | - | - | (8,507) |
| 69 | Adjust payroll taxes | - | 564 | - | - | 564 | - | - | 564 |
| 70 | Current state and federal income tax | - | 208 469 | - | - | 208 469 | - | - | 208 469 |
| 71 | Interest on customer deposits | - | 5,652 | - | - | 5,652 | - | - | 5,652 |
| 72 | Current state and federal income tax | - | 184,634 | - | - | 184,634 | - | - | 184,634 |
| 73 | Deferred income taxes | - | 35,671 | - | - | 35,671 | - | - | 35,671 |
| | | - | (5,346) | | | (5,346) | | | (5,346) |
| | | - | (24,092) | | | (24,092) | | | (24,092) |
| 74 | Adjust income taxes | (825) 9/ | 57 095 | 1 179 | (363) 9/ | 56 732 | 44 | 56 732 | 56 732 |
| 75 | Total income taxes | (825) | 247,962 | 1,179 | (363) | 247,599 | 44 | 56,732 | 247,599 |
| 76 | Amortization of ITC | - | (1 804) | - | - | (1 804) | - | - | (1 804) |
| 77 | Total electric operating expenses | (856) | 4,138,909 | 1,179 | (378) | 4,138,547 | 45 | 56,732 | 4,138,547 |
| 78 | Interest expense | (770) 1 / | 404,732 17/ | 180 | (532) 20/ | 404,200 22/ | 124 | (1,302) | 404,200 |
| 79 | Income available for common equity | (2,708) 1 / | 904,989 18/ | - | (1,190) 20/ | 903,799 23/ | - | 186,229 | 903,799 |
| 80 | Net operating income for return | (3 478) | 1 309 721 | 180 | (1 722) | 1 307 999 | 124 | 184 927 | 1 307 999 |
| 81 | Total requirement | ($4 334) | $5 448 630 | $1 359 | ($2 100) | $5 446 546 | $169 | $241 659 | $5 446 546 |
| 82 | Cumulative change in working capital | | | ($80,174) | | | (80,231) | | ($80,231) |
| 83 | Rate base under present rates | | | 18,669,209 | | | 18,669,209 | | 18,669,209 |
| 84 | Rate base after rate increase | | | $18 589 034 | | | $18 588 977 | | $18 588 977 |
| 85 | Overall rate of return | | | 7.05% | | | 7.04% | | 7.04% |
| 86 | Target rate of return | | | 7.04% 3/ | | | 7.04% 3/ | | 7.04% |

14/ Column (g) minus Column (d).
15/ Column (d) plus Column (f), unless footnoted otherwise.
16/ Sum of Line 77 and Line 80.
17/ Line 84, Column (e) times 48.000% times 4.530%.
18/ Line 84, Column (e) times 52.000% times 9.350%.
19/ Column (f) divided by 365 days times Column (b).
20/ Column (j) minus Column (g).
21/ Column (g) plus Column (i), unless footnoted otherwise.
22/ Line 84, Column (h) times 48.000% times 4.530%.
23/ Line 84, Column (h) times 52.000% times 9.350%.
24/ Column (i) divided by 365 days times Column (b).

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**NET OPERATING INCOME FOR RETURN**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3**

| Line No. | Item | Under Present Rates: NC Retail Adjusted Per Company 1/ (a) | Public Staff Adjustments 2/ (b) | After Public Staff Adjustments 3/ (c) | After Public Staff Recommended Decrease: Rate Decrease (d) | After Rate Decrease 8/ (e) |
|---|---|---|---|---|---|---|
| 1 | Electric operating revenues: | | | | | |
| 2 | Sales of electricity | $5,163,800 | $260,727 | $5,424,527 | ($52,911) 4/ | $5,371,616 |
| 3 | Other revenues | 0 | (12,344) | (12,344) | | (12,344) |
| 4 | Electric operating revenues (L2 + L3) | $5,163,800 | 248,383 | 5,412,183 | (52,911) 5/ | 5,359,272 |
| 5 | Electric operating expenses: | | | | | |
| 6 | Operations and maintenance: | | | | | |
| 7 | Fuel used in electric generation | 1,147,365 | 256,361 | 1,403,726 | - | 1,403,726 |
| 8 | Purchased power | 33,754 | - | 33,754 | - | 33,754 |
| 9 | Other operations and maintenance expenses | 1,184,462 | (97,298) | 1,087,164 | (383) 6/ | 1,086,781 |
| 10 | Depreciation and amortization | 1,223,801 | (139,183) | 1,084,618 | - | 1,084,618 |
| 11 | General taxes | 210,570 | (2,101) | 208,469 | - | 208,469 |
| 12 | Interest on customer deposits | 5,652 | - | 5,652 | - | 5,652 |
| 13 | Net income taxes | 225,589 | 53,770 | 279,359 | (11,855) 7/ | 267,504 |
| 14 | Amortization of protected EDIT, net of tax | (24,092) | $0 | (24,092) | | (24,092) |
| 15 | Amortization of investment tax credit | (1,804) | - | (1,804) | - | (1,804) |
| 16 | Total electric operating expenses (Sum of L7 thru L15) | 4,005,296 | 71,548 | 4,076,845 | (12,238) | 4,064,607 |
| 17 | Net operating income for return (L4 minus L16) | $1,158,504 | 176,835 | $1,335,339 | ($40,673) | $1,294,666 |

1/ Per Bowman Supplemental Exhbit 2
2/ Accounting Exhibit 1, Schedule 3-1, Column (z).
3/ Column (a) plus Column (b).
4/ Line 4 minus Line 3.
5/ Accounting Exhibit 1, Schedule 5, Line 5, Column (c).
6/ Line 4 times (1 minus retention factor after uncollect bles and regulatory fee of 0.9927689 from Accounting Exhibit 1, Schedule 1-2, Line 10.)
7/ Line 4 minus Line 9 minus change in interest expense from Accounting Exhibit 1, Schedule 5, Line 3, Column (a), times composite income tax rate of 23.3503%.
8/ Column (c) plus Column (d).

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**NET OPERATING INCOME FOR RETURN - CCR DEFERRAL**
**For the Test Year Ended December 31, 2021**
**(Dollar Amounts Expressed in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3 CCR**

| Line No. | | Under Present Rates: NC Retail Adjusted Per Company 1/ (a) | Public Staff Adjustments 2/ (b) | After Public Staff Adjustments 3/ (c) | After Public Staff Recommended Increase: Rate Increase (d) | After Rate Increase 7/ (e) |
|---|---|---|---|---|---|---|
| 1 | Electric operating revenues: | | | | | |
| 2 | Sales of electricity | $24,826 | | $ 24,826 | $64,184 4/ | $ 89,010 |
| 3 | Other revenues | - | | - | - | - |
| 4 | Electric operating revenues (Sum of L2 through L3) | $24,826 | $0 | $24,826 | $64,184 | $89,010 |
| 5 | Electric operating expenses: | | | | | |
| 6 | Operations and maintenance: | | | | | |
| 7 | Fuel used in electric generation | | | - | - | - |
| 8 | Purchased power | | | - | | - |
| 9 | Other operations and maintenance expenses | 94 | | 94 | $464 5/ | 558 |
| 10 | Depreciation and amortization | 70,955 | $1,657 | 72,612 | | 72,612 |
| 11 | General taxes | | | - | | - |
| 12 | Interest on customer deposits | | | - | | - |
| 13 | Net income taxes | (10,793) | (387) | (11,180) | $14,853 6/ | 3,673 |
| 14 | Amortization of protected EDIT, net of tax | | | - | | - |
| 15 | Amortization of investment tax credit | | | - | | - |
| 16 | Total electric operating expenses (Sum of L6 through L15) | 60,256 | 1,270 | 61,526 | 15,317 | 76,843 |
| 17 | Net operating income for return (L4 minus L16) | ($35,430) | ($1,270) | ($36,700) | $48,867 | $12,167 |

1/ Per Bowman Exhibit 2.
2/ Column (a) plus Column (b).
3/ Accounting Exhibit 1, Schedule 5 CCR, Line 5, Column (c).
4/ Line 4 times (1 minus retention factor after uncollectibles and regulatory fee of 0.9963091 from Exhibit 1, Schedule 1-2, Line 10).
5/ (Line 4 minus Line 9) minus (increase in debt expense from Accounting Exhibit 1, Schedule 5, Line 5, Column (a) multiplied by composite income tax rate of 23.133%).
6/ Column (c) plus Column (d).

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**SUMMARY OF PUBLIC STAFF NET OPERATING INCOME ADJUSTMENTS**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**



| Line No. | Item | | Update Plant to 4/30/2023 1/ | Adjust Depreciation Rates 2/ | Adjust EOL Nuclear M&S Reserve Amortization 3/ | Adjust Distribution Vegetation Management 4/ | Adjust Fuel rates 5/ |
|---|---|---|---|---|---|---|---|
| | | | (a) | (b) | (c) | (d) | (e) |
| 1 | Electric operating revenues: | | | | | | |
| 2 | Sales of electricity | | | $0 | | $0 | $256,361 |
| 3 | Other revenues | | - | - | | - | |
| 4 | Electric operating revenues (L2 + L3) | | - | - | $0 | - | 256,361 |
| 5 | Electric operating expenses: | | | | | | |
| 6 | Operations and maintenance: | | | | | | |
| 7 | Fuel used in electric generation | | | | | | 256,361 |
| 8 | Purchased power | | | | | | |
| 9 | Other operations and maintenance expenses | | | | | ($1,487) | |
| 10 | Depreciation and amortization | | ($6,967) | ($79,742) | (346) | | |
| 11 | General taxes | | ($2,100) | | | | |
| 12 | Interest on customer deposits | | | | | | |
| 13 | Net income taxes | 28/ | 2,117 | 18,620 | 81 | 347 | - |
| 14 | Amortization of protected EDIT, net of tax | | | | | | |
| 15 | Amortization of investment tax credit | | - | - | | - | |
| 16 | Total electric operating expenses (Sum of L7 thru L15) | | (6,950) | (61,122) | (265) | (1,140) | 256,361 |
| 17 | Net operating income for return (L4 minus L16) | | 6,950 | 61,122 | 265 | 1,140 | - |
| 18 | Calculated revenue requirement impact | 29/ | ($9,133) | ($80,323) | ($349) | ($1,497) | $0 |

1/ Accounting Exhibit 1, Schedule 3-1(a), Lines 4 and 12.
2/ Accounting Exhibit 1, Schedule 3-1(b), Line 9.
3/ Accounting Exhibit 1, Schedule 3-1(c), Line 14.
4/ Accounting Exhibit 1, Schedule 3-1(d), Line 16.
5/ Accounting Exhibit 1, Schedule 3-1(e), Lines 6 and 7.
28/ Line 4 minus Sum of Line 7 through 12 times composite income tax rate of 23.3503%.
29/ Negative Line 17 divided by Accounting Exhibit 1, Schedule 1-2, Line 14.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**SUMMARY OF PUBLIC STAFF NET OPERATING INCOME ADJUSTMENTS**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**



| Line No. | Item | | Adjust Test Year Revenue and Expenses 6/ | Adjust COVID Deferral 7/ | Adjust Aviation Expenses 8/ | Adjust Incentives 9/ |
|---|---|---|---|---|---|---|
| | | | (f) | (g) | (h) | (i) |
| 1 | Electric operating revenues: | | | | | |
| 2 | Sales of electricity | | $ 4,366 | $0 | $0 | $0 |
| 3 | Other revenues | | | (1,757) | - | - |
| 4 | Electric operating revenues (L2 + L3) | | 4,366 | (1,757) | - | - |
| 5 | Electric operating expenses: | | | | | |
| 6 | Operations and maintenance: | | | | | |
| 7 | Fuel used in electric generation | | | | | |
| 8 | Purchased power | | | | | |
| 9 | Other operations and maintenance expenses | | $ (12,216) | ($1,680) | ($111) | ($32,954) |
| 10 | Depreciation and amortization | | | ($57,058) | | |
| 11 | General taxes | | | | ($1) | |
| 12 | Interest on customer deposits | | | | | |
| 13 | Net income taxes | 28/ | 3,872 | 13,305 | 26 | 7,695 |
| 14 | Amortization of protected EDIT, net of tax | | | | | |
| 15 | Amortization of investment tax credit | | | - | - | - |
| 16 | Total electric operating expenses (Sum of L7 thru L15) | | (8,344) | (45,433) | (86) | (25,259) |
| 17 | Net operating income for return (L4 minus L16) | | 12,710 | 43,676 | 86 | 25,259 |
| 18 | Calculated revenue requirement impact | 29/ | ($16,703) | ($57,396) | ($113) | ($33,194) |

6/ Accounting Exhibit 1, Schedule 3-1(f), Lines 2 and 6.
7/ Accounting Exhibit 1, Schedule 3-1(g), Lines 3, 6, and 19.
8/ Accounting Exhibit 1, Schedule 3-1(h), Lines 9, 16, and 21.
9/ Accounting Exhibit 1, Schedule 3-1(i), Line 17.
28/ Line 4 minus Sum of Line 7 through 12 times composite income tax rate of 23.3503%.
29/ Negative Line 17 divided by Accounting Exhibit 1, Schedule 1-2, Line 14.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**SUMMARY OF PUBLIC STAFF NET OPERATING INCOME ADJUSTMENTS**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**



| Line No. | Item | | Adjust Executive Compensation | | Adjust Rent Expense | | Adjust Credit Card Fees | | Adjust Lobbying Expense | | Adjust Sponsorships & Donations | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | (j) | | (k) | | (l) | | (m) | | (n) | |
| 1 | Electric operating revenues: | | | | | | | | | | | |
| 2 | Sales of electricity | | $0 | | $0 | | $0 | | $0 | | $0 | |
| 3 | Other revenues | | - | | (10,587) | | - | | - | | - | |
| 4 | Electric operating revenues (L2 + L3) | | - | | (10,587) | | - | | - | | - | |
| 5 | Electric operating expenses: | | | | | | | | | | | |
| 6 | Operations and maintenance: | | | | | | | | | | | |
| 7 | Fuel used in electric generation | | | | | | | | | | | |
| 8 | Purchased power | | | | | | | | | | | |
| 9 | Other operations and maintenance expenses | | ($333) | | ($4,260) | | ($1,507) | | ($544) | | ($23) | |
| 10 | Depreciation and amortization | | | | | | | | | | | |
| 11 | General taxes | | | | | | | | | | | |
| 12 | Interest on customer deposits | | | | | | | | | | | |
| 13 | Net income taxes | 28/ | 78 | | (1,477) | | 352 | | 127 | | 5 | |
| 14 | Amortization of protected EDIT, net of tax | | | | | | | | | | | |
| 15 | Amortization of investment tax credit | | - | | - | | - | | - | | - | |
| 16 | Total electric operating expenses (Sum of L7 thru L15) | | (255) | | (5,737) | | (1,155) | | (417) | | (18) | |
| 17 | Net operating income for return (L4 minus L16) | | 255 | | (4,850) | | 1,155 | | 417 | | 18 | |
| 18 | Calculated revenue requirement impact | 29/ | ($335) | | $6,373 | | ($1,518) | | ($548) | | ($23) | |

10/ Accounting Exhibit 1, Schedule 3-1(j), Line 13.
11/ Accounting Exhibit 1, Schedule 3-1(k), Lines 3 and 20.
12/ Accounting Exhibit 1, Schedule 3-1(l) Line 3.
13/ Accounting Exhibit 1, Schedule 3-1(m), Line 7.
14/ Accounting Exhibit 1, Schedule 3-1(n), Line 5.
28/ Line 4 minus Sum of Line 7 through 12 times composite income tax rate of 23.3503%.
29/ Negative Line 17 divided by Accounting Exhibit 1, Schedule 1-2, Line 14.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**SUMMARY OF PUBLIC STAFF NET OPERATING INCOME ADJUSTMENTS**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**



| Line No. | Item | | Adjust Board of Directors Expense | 15/ | Adjust Salaries & Wages | 16/ | Adjust Storm Normaliztion | 17/ | Adjust Lighting Audit Deferral | 18/ | Adjust Rate Case Expense | 19/ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | (o) | | (p) | | (q) | | (r) | | (s) | |
| 1 | Electric operating revenues: | | | | | | | | | | | |
| 2 | Sales of electricity | | $0 | | | | | | $0 | | | |
| 3 | Other revenues | | - | | - | | - | | - | | | |
| 4 | Electric operating revenues (L2 + L3) | | - | | - | | - | | - | | - | |
| 5 | Electric operating expenses: | | | | | | | | | | | |
| 6 | Operations and maintenance: | | | | | | | | | | | |
| 7 | Fuel used in electric generation | | | | | | | | | | | |
| 8 | Purchased power | | | | | | | | | | | |
| 9 | Other operations and maintenance expenses | | ($1,870) | | $0 | | $0 | | | | (4,101) | |
| 10 | Depreciation and amortization | | | | | | | | ($219) | | | |
| 11 | General taxes | | | | | | | | | | | |
| 12 | Interest on customer deposits | | | | | | | | | | | |
| 13 | Net income taxes | 28/ | 437 | | - | | - | | 51 | | 957 | |
| 14 | Amortization of protected EDIT, net of tax | | | | | | | | | | | |
| 15 | Amortization of investment tax credit | | - | | - | | - | | - | | | |
| 16 | Total electric operating expenses (Sum of L7 thru L15) | | (1,433) | | - | | - | | (168) | | (3,143) | |
| 17 | Net operating income for return (L4 minus L16) | | 1,433 | | - | | - | | 168 | | 3,143 | |
| 18 | Calculated revenue requirement impact | 29/ | ($1,884) | | $0 | | $0 | | ($221) | | ($4,130) | |

15/ Accounting Exhibit 1, Schedule 3-1(o), Line 15.
16/ Accounting Exhibit 1, Schedule 3-1(p), Lines 16, and 21.
17/ Accounting Exhibit 1, Schedule 3-1(q), Line 13.
18/ Accounting Exhibit 1, Schedule 3-1(r), Line 4.
19/ Accounting Exhibit 1, Schedule 3-1(s), Line 16.
28/ Line 4 minus Sum of Line 7 through 12 times composite income tax rate of 23.3503%.
29/ Negative Line 17 divided by Accounting Exhibit 1, Schedule 1-2, Line 14.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**SUMMARY OF PUBLIC STAFF NET OPERATING INCOME ADJUSTMENTS**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**



| Line No. | Item | | Adjustment to Inflation Adjustment | | Adjust Steam Deferral | | Adjust GIP Deferral | | Adjust Allen Unit 4 Deferral | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | (t) | 20/ | (u) | 21/ | (v) | 22/ | (w) | 23/ |
| 1 | Electric operating revenues: | | | | | | | | | |
| 2 | Sales of electricity | | | | | | | 4/ | $0 | |
| 3 | Other revenues | | - | | | | - | | - | |
| 4 | Electric operating revenues (L2 + L3) | | - | | - | | - | | - | |
| 5 | Electric operating expenses: | | | | | | | | | |
| 6 | Operations and maintenance: | | | | | | | | | |
| 7 | Fuel used in electric generation | | | | | | | | | |
| 8 | Purchased power | | | | | | | | | |
| 9 | Other operations and maintenance expenses | | ($36,214) | | | | | | | |
| 10 | Depreciation and amortization | | | | 37,584 | | ($32,180) | | $271 | |
| 11 | General taxes | | | | | | | | | |
| 12 | Interest on customer deposits | | | | | | | | | |
| 13 | Net income taxes | 28/ | 8,456 | | (8,776) | | 7,514 | | (63) | |
| 14 | Amortization of protected EDIT, net of tax | | | | | | | | | |
| 15 | Amortization of investment tax credit | | - | | | | - | | - | |
| 16 | Total electric operating expenses (Sum of L7 thru L15) | | (27,758) | | 28,808 | | (24,666) | | 207 | |
| 17 | Net operating income for return (L4 minus L16) | | 27,758 | | (28,808) | | 24,666 | | (207) | |
| 18 | Calculated revenue requirement impact | 29/ | ($36,478) | | $37,858 | | ($32,415) | | $273 | |

20/ Accounting Exhibit 1, Schedule 3-1(t), Line 15.
21/ Accounting Exhibit 1, Schedule 2-1(c), Line 3.
22/ Accounting Exhibit 1, Schedule 2-1(d), Line 7.
23/ Accounting Exhibit 1, Schedule 2-1(b), Line 8.
28/ Line 4 minus Sum of Line 7 through 12 times composite income tax rate of 23.3503%.
29/ Negative Line 17 divided by Accounting Exhibit 1, Schedule 1-2 CCR, Line 14.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**SUMMARY OF PUBLIC STAFF NET OPERATING INCOME ADJUSTMENTS**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**



| Line No. | Item | | Adjust Over Amortization Rate Case Expense | | Interest Synchronization Adjustment | | Total NOI Adjustments | | Adjust Over Amortization CCR | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | (x) | | (y) | | (z) | | (aa) | |
| 1 | Electric operating revenues: | | | | | | | | | |
| 2 | Sales of electricity | | | | | | $260,727 | | | |
| 3 | Other revenues | | | | - | | (12,344) | | | |
| 4 | Electric operating revenues (L2 + L3) | | - | | - | | 248,383 | | - | |
| 5 | Electric operating expenses: | | | | | | | | | |
| 6 | Operations and maintenance: | | | | | | | | | |
| 7 | Fuel used in electric generation | | | | - | | $256,361 | | | |
| 8 | Purchased power | | | | - | | - | | | |
| 9 | Other operations and maintenance expenses | | | | - | | (97,298) | | | |
| 10 | Depreciation and amortization | | ($525) | | - | | (139,183) | | $1,657 | |
| 11 | General taxes | | | | - | | (2,101) | | | |
| 12 | Interest on customer deposits | | | | - | | - | | | |
| 13 | Net income taxes | 28/ | 123 | | (77) | | 53,770 | | (387) | |
| 14 | Amortization of protected EDIT, net of tax | | | | | | - | | | |
| 15 | Amortization of investment tax credit | | | | - | | - | | | |
| 16 | Total electric operating expenses (Sum of L7 thru L15) | | (403) | | (77) | | 71,548 | | 1,270 | |
| 17 | Net operating income for return (L4 minus L16) | | 403 | | 77 | | 176,835 | | (1,270) | |
| 18 | Calculated revenue requirement impact | 29/ | ($529) | | ($101) | | ($232,386) | | $1,669 | 31/ |

24/ Accounting Exhibit 1, Schedule 3-1(u)(2), Line 2.
25/ Accounting Exhibit 1, Schedule 3-1(v), Line 8.
26/ Sum of Columns (a) to (y).
27/ Accounting Exhibit 1, Schedule 3-1(u)(1), Line 4.
28/ Line 4 minus Sum of Line 7 through 12 times composite income tax rate of 23.3503%.
29/ Negative Line 17 divided by Accounting Exhibit 1, Schedule 1-2 CCR, Line 14.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO DEPRECIATION EXPENSE AND PROPERTY TAXES FOR PLANT UPDATE**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3-1(a)**

| Line No. | Item | Amount | |
|---|---|---|---|
| 1 | Depreciation expense | | |
| 2 | Depreciation expense on increase in plant per Public Staff | $60,888 | 1/ |
| 3 | Company adjustment | 67,855 | 2/ |
| 4 | Public Staff adjustment to depreciation expense for update of plant (L2 - L3) | ($6,967) | |
| 5 | General taxes | | |
| 6 | Update to plant per Public Staff | 2,088,578 | 3/ |
| 7 | Less: adjustment to intangible plant | 50,285 | 4/ |
| 8 | Adjustment to plant excluding intangible plant (L6 - L7) | 2,038,293 | |
| 9 | Property tax rate per $1000 | 0.52227% | 5/ |
| 10 | Impact to property taxes of Public Staff plant update (L8 x L9) | 10,645 | |
| 11 | Company adjustment | 12,745 | 6/ |
| 12 | Public Staff adjustment to property taxes (L10 - L11) | ($2,100) | |

1/ Accounting Exhibit 1, Schedule 3-1(a)(1), Line 13, Column (e).
2/ Per NC3030-1(B)
3/ Accounting Exhibit 1, Schedule 2-1(a)(1), Line 13, Column (e).
4/ Accounting Exhibit 1, Schedule 2-1(a)(1), Line 9, Column (e).
5/ Per NC3030-1(B).
6/ Per NC3030(B)-1, Line 67.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**CALCULATION OF DEPRECIATION EXPENSE ON PLANT UPDATE**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3-1(a)(1)**

| Line No. | Item | Increase in Plant in Service 1/ (a) | Depreciation Rate 2/ (b) | Increase in Depreciation 3/ (c) | NC Retail Percentage 5/ (d) | NC Retail Amount 6/ (e) |
|---|---|---|---|---|---|---|
| 1 | Steam plant | $ (63,203) | 4.97% | $ (3,141) | | |
| 2 | Hydro plant | 195,855 | 2.27% | 4,446 | | |
| 3 | Other production plant | 114,631 | 3.39% | 3,886 | | |
| 4 | Nuclear plant | 215,770 | 2.21% | 4,769 | | |
| 5 | Total production plant | 463,053 | | 9,960 | 66.9690% | 6,670 |
| 6 | Transmission plant | 415,631 | 2.39% | 9,934 | 48.1470% | 4,783 |
| 7 | Distribution plant | 1,515,132 | 2.44% | 36,969 | 74.0820% | 27,387 |
| 8 | General plant | 599,033 | 5.31% | 31,809 | 68.1625% | 21,682 |
| 9 | Intangible plant | 72,339 | 20.00% 4/ | 14,468 | 69.5124% | 10,057 |
| 10 | Total | $ 3,065,188 | | $ 103,140 | | 70,579 |
| 11 | Less: depreciation on REPS additions | | | | | 91 7/ |
| 12 | Depreciation expense on Public Staff plant adjustment | | | | | (9,600) 8/ |
| 13 | Depreciation expense per Public Staff (L10-L11+L12) | | | | | $ 60,888 |

1/ Accounting Exhibit 1, Schedule 2-1(a)(1), Column (c).
2/ Based on recommendation of Public Staff witness McCullar, unless footnoted otherwise.
3/ Column (a) times Column (b).
4/ Based on NC3030(B)-1, Line 11.
5/ E-1, Item 45a, 12CP.
6/ Column (c) times Column (d).
7/ Accounting Exhibit 1, Schedule 2-1(a)(1), Line 12 times other production depreciation rate from Line 3, Column (b).
8/ Accounting Exhibit 1, Schedule 3-1(a)(1)(a), Column (d), Line 17.

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**DUKE ENERGY PROGRESS, LLC**
**Docket No. E-2, Sub 1300**
**North Carolina Retail Operations**
**ADJUSTMENT TO DEPRECIATION FOR PUBLIC STAFF PLANT ADJUSTMENTS**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3-1(a)(1)(a)**

| Line No. | Item | Plant Type | Total System Public Staff Depreciation Adj. Amount 1/ | NC Retail NC Retail Percentage 2/ | NC Retail Depreciation Adjustment 3/ |
|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) |
| | **Adjustment to Test Year Depreciation Expense:** | | | | |
| 1 | Mount Holly Project | Intangible Plant | $ (110) | 69.5124% | $ (77) |
| 2 | Mount Holly Project | General Plant | (309) | 68.1625% | (210) |
| 3 | 526 S. Church Reno - Switchgear and Generator Replacement | General Plant | (382) | 68.1625% | (261) |
| 4 | Remove EV charging infrastructure costs - 2021 | General Plant | (21) | 68.1625% | (15) |
| 5 | Lincoln Ct Unit 17 - Combustion Turbine Pipeline | Other Production Plant | (12) | 66.9690% | (8) |
| 6 | Total Test Year adjustments Sum of L1 to L4) | | $ (835) | | $ (570) |
| | **Adjustment to Post Test Year Depreciation Expense:** | | | | |
| 7 | Mount Holly Project | Intangible Plant | (32) | 69.5124% | (23) |
| 8 | Pleasant Garden 550kV Breaker Replacements | Distr bution Plant | ($397) | 74.0820% | (294) |
| 9 | Pleasant Garden 550kV Breaker Replacements | Transmission Plant | $389 | 48.1470% | 187 |
| 10 | Bad Creek 3 Hydroelectric | Hydro Plant | (114) | 66.9690% | (76) |
| 11 | Dearborn Dam Hydroelectric | Hydro Plant | (114) | 66.9690% | (76) |
| 12 | Remove EV charging infrastructure costs - 2022 | General Plant | (26) | 68.1625% | (18) |
| 13 | Workstation Project | General Plant | (141) | 68.1625% | (96) |
| 14 | Duke Plaza | General Plant | (12,574) | 68.1625% | (8,571) |
| 15 | Lincoln Ct Unit 17 removal | Other Production Plant | (96) | 66.9690% | (64) |
| 16 | Total Post Test Year adjustments Sum of L6 to L13) | | $ (13,104) | | $ (9,030) |
| 17 | Total adjustment impact (L5 + L14) | | $ (13,939) | | $ (9,600) |

1/ Accounting Exhbit 1, Schedule 2-1(a)(1)(a)(1).
2/ E-1, Item No. 45a, 12CP.
3/ Column (b) times Column (c).

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT FOR CHANGE IN DEPRECIATION RATES**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3-1(b)**

| Line No. | Item | Total System 1/ (a) | NC Retail Percentage 2/ (b) | NC Retail Amount (c) | |
|---|---|---|---|---|---|
| | Change in depreciation and amortization per Public Staff | | | | |
| 1 | Production | $114,161 | 66.9690% | $76,453 | 3/ |
| 2 | Transmission | 7,539 | 48.1470% | 3,630 | 3/ |
| 3 | Distribution | 37,023 | 74.0820% | 27,427 | 3/ |
| 4 | General | 571 | 68.1625% | 389 | 3/ |
| 5 | General amortization | - | 68.1625% | - | 3/ |
| 6 | Adjust to depr and amort for costs recovered through riders | | 66.9690% | - | 3/ |
| 7 | Public Staff adjustment to depreciation and amortization expense (Sum of L1 to L6) | $159,294 | | 107,899 | |
| 8 | Adjustment per Company | | | 187,641 | 4/ |
| 9 | Adjustment to depreciation and amortization expense (L7 - L8) | | | ($79,742) | |
| 10 | Adjustment to accumulated depreciation (-L9) | | | $79,742 | |

1/ Per recommendation of Public Staff witness McCullar.
2/ Per E-1, Item 45a, 12 CP.
3/ Column (a) times Column (b).
4/ Per NC3040.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO END OF LIFE RESERVE FOR NUCLEAR MATERIALS AND SUPPLIES AMORTIZATION EXPENSE**
**For the Test Year Ended December 31, 2021**
**(Dollar Amounts Expressed in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3-1(c)**

| Line No. | Item | McGuire (a) | Oconee (b) | Catawba (c) | Total (d) 8/ |
|---|---|---|---|---|---|
| 1 | Inventory as of December 31, 2021 | $ 141,072 1/ | $ 182,903 1/ | $ 30,173 1/ | $ 354,148 |
| 2 | Percentage of M&S with salvage value or transferrable per Public Staff | 5% 2/ | 5% 2/ | 5% 2/ | |
| 3 | Public Staff adjustment for salvage value (L1 x L2) | (7,054) | (9,145) | (1,509) | (17,708) |
| 4 | Nuclear M&S inventory base for amortization per Public Staff(L1 + L3) | 134,018 | 173,758 | 28,664 | $ 336,440 |
| 5 | NC Retail Allocation Factor | 66.969% 3/ | 66.969% 3/ | 66.969% 3/ | |
| 6 | NC retail nuclear M&S base for amortization (L4 x L5) | 89,751 | 116,364 | 19,196 | 225,311 |
| 7 | Less: Projected inventory reserve at 12/31/2023 | 31,302 4/ | 57,866 4/ | 5,771 4/ | 94,939 |
| 8 | NC nuclear reserve required at rates effective date (L6 - L7) | 58,449 | 58,498 | 13,425 | 130,372 |
| 9 | Years of remaining plant life | 39 5/ | 31 5/ | 40 5/ | |
| 10 | NC retail annual expense for reserve per Public Staff (L8 / L9) | 1,492 | 1,915 | 336 | 3,743 |
| 11 | Current NC Retail annual expense for reserve per Company | 3,474 6/ | 6,228 6/ | 612 6/ | 10,314 |
| 12 | Public Staff adjustment to annual expense for end of life reserve for nuclear M&S (L10 - L11) | (1,982) | (4,313) | (276) | (6,571) |
| 13 | Adjustment per Company | (1,861) 7/ | (4,113) 7/ | (251) 7/ | (6,225) |
| 14 | Public Staff adjustment to nuclear M&S reserve amortization expense (L12 - L13) | $ (121) | $ (200) | $ (25) | $ (346) |

1/ NC2120-3, Lines 2 and 3.
2/ Per Public Staff witness Metz.
3/ NC Retail Allocation Factor - All - Production Demand
4/ NC2120-3, Line 13.
5/ NC2120-3, Line 19.
6/ NC2120-3, Line 23.
7/ NC2120-3, Line 24.
8/ Sum of Columns (a) through (c).

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO DISTRIBUTION AND TRANSMISSION**
**VEGETATION MANAGEMENT**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3-1(d)**

| Line No. | Item | Total Miles (a) 1/ | Target Cycle (In Years) (b) 1/ | Test Year Amount (c) 1/ | Adjusted Amount (d) | |
|---|---|---|---|---|---|---|
| | **Vegetation Management Adjustment - Distribution** | | | | | |
| 1 | Number of trim miles per year: | | | | | |
| 2 | Urban Miles | 2,097 | 5 | | 419 | 2/ |
| 3 | Mountain Miles | 4,295 | 7 | | 614 | 2/ |
| 4 | Other Miles (includes Nantahala Mountain Miles) | 45,200 | 9 | | 5,022 | 2/ |
| 5 | Total number of trim miles (L2 + L3 + L4) | 51,592 | | 6,168 | 6,055 | |
| 6 | Cost per Mile in dollars | | | 9,884 | 10,256 | 3/ |
| 7 | Production $ (Sum L5 x L6) | | | $ 60,961,236 | $62,102,037 | |
| 8 | Demand $ | | | 3,073,167 | 3,144,679 | 1/ |
| 9 | Herbicide $ | | | 3,245,598 | 3,310,510 | 1/ |
| 10 | Contract Inspectors $ | | | 762,418 | 785,290 | 1/ |
| 11 | Program Target $ (Sum L7 through L10) | | | $ 68,042,419 | $69,342,516 | |
| 12 | Adjusted VM program costs (Line 11, Col (d) less Col (c)) | | | | $1,300,097 | |
| 13 | NC Retail allocation | | | | 74.1732% | 4/ |
| 14 | Total distribution vegetation management per Public Staff (L12 x L13) | | | | 964 | |
| | **Vegetation Management Adjustment - Transmission** | | | | | |
| 15 | Transmission Routine Maintenance $ | | | $ 3,177,323 | $ 3,973,197 | 3/ |
| 16 | Transmission Reactive Maintenance $ | | | 2,405,781 | 2,477,954 | |
| 17 | Transmission Herbicide $ | | | 4,980,145 | 5,129,549 | |
| 18 | Transmission Inspections $ | | | 48,182 3/ | 49,627 | 3/ |
| 19 | Transmission Substation Maintenance $ | | | 1,481,083 | 1,629,191 | |
| 20 | Targeted Program Costs $ (Sum L15 through L19) | | | $ 12,092,514 | $ 13,259,520 | |
| 21 | Adjusted VM program costs (Line 20, Col (d) less Col (c)) | | | | $ 1,167,006 | |
| 22 | NC Retail allocation | | | | 48.1470% | 5/ |
| 23 | Total transmission vegetation management adjusment per Public Staff (L21 x L22) | | | | 562 | |
| 24 | Total Adjusted VM per Public Staff (L14 + L23) | | | | 1,526 | |
| 25 | Adjusted VM per Company | | | | 3,013 | 6/ |
| 26 | Public Staff adjustment to VM (L24 - L25) | | | | ($1,487) | |

1/ Per NC2070-2, unless otherwise noted.
2/ Column (a) divided by Column (b).
3/ Per Public Staff Witness Tommy Williamson.
4/ Per E-1, Item 45a, 12CP, All - Dist Plt OH allocation factor.
5/ Per E-1, Item 45a, 12CP, All - Transmission Demand - Jur allocation factor.
6/ Per NC2070, Line 9.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO FUEL RATES**
**For the Test Year Ended December 31, 2021**
**(Dollar Amounts Expressed in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3-1(e)**

| Line No. | Item | Test Year kWh by Class 1/ (a) | Fuel Costs in Cents per KWH 2/ (b) | Amount 3/ (c) |
|---|---|---|---|---|
| | **Fuel Cost Update:** | | | |
| 1 | Residential | 22,379,004,323 | 2.3345 | $ 522,438 |
| 2 | Gerneral Service and Lighting | 23,421,233,214 | 2.3387 | 547,752 |
| 3 | Industrial | 12,268,184,505 | 2.3326 | 286,168 |
| 4 | Public Staff calculated fuel costs update (Sum of L1 through L6) | 58,068,422,042 | | $ 1,356,358 |
| 5 | Company's fuel cost update | | | $ 1,099,997 1/ |
| 6 | Public Staff adjustment to fuel cost update (L7 - L8) | | | $ 256,361 |
| 7 | Fuel Revenue Impact | | | $ 256,361 |

1/ NC2010(B)-1, Lines 11-12.
2/ Per Public Staff Engineer Lucas.
3/ Column (a) x Column (c) divided by (100 x 1000).

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO REVENUE AND TEST YEAR EXPENSES**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3-1(f)**

| Line No. | Item | Amount per Company (a) | Amount per Public Staff (b) | NC Retail Allocation Factors (c) 1/ | Adjustment Amount (d) 2/ |
|---|---|---|---|---|---|
| | **Revenue Impact:** | | | | |
| 1 | NC Retail Extra Facility Charge | $ - | $ 4,366 4/ | 100.0000% | $ 4,366 |
| 2 | Total Revenue adjustment (L1) | $ - | $ 4,366 | | $ 4,366 |
| | **Income Statement Impact:** | | | | |
| 3 | NC Retail annual amortization on Outage Costs | 57,535 3/ | 55,185 4/ | 100.0000% | (2,350) |
| 4 | System O&M for Reliability Assurance | 8,874 5/ | 760 4/ | 66.9690% | (5,434) |
| 5 | O&M cost reduction related to Bad Creek - Sec. 40331 Hydro Production Incentives | - 6/ | (1,000) 7/ | 66.9690% | (670) |
| 5 | Non-fuel O&M cost reduction for Marshall | - 6/ | (7,814) 8/ | 48.1470% | (3,762) |
| 6 | Total Public Staff O&M adjustment | $ 66,409 | $ 47,131 | | $ (12,216) |
| | **Rate Base Impact:** | | | | |
| 7 | Material and supplies for coal plant retirements | - 6/ | (11,838) 9/ | 66.9690% | (7,928) |
| 8 | Total rate base adjustment | $ - | $ (11,838) | | $ (7,928) |

1/ E1, Item 45a, 12CP.
2/ [Column (b) - Column (a)] x Column (c).
3/ Per NC2100-1(B), Line 20.
4/ Per Public Staff witness Metz.
5/ Per NC2160-1(B).
6/ Company does not make adjustments.
7/ Per Public Staff witness Thomas.
8/ Per Public Staff witness Michna.
9/ Per Public Staff witness Lucas.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO COVID DEFERRAL**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Accounting Exhibit 1**
**Schedule 3-1(g)**

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| Line No. | Item | Amount |
|---|---|---|
| | Income Statement Impact | |
| 1 | Waived fees in 2021 - adjust test period | $14,591 1/ |
| 2 | Waived fees in 2021 - adjust test period (avg 2018 & 2019) | 12,834 2/ |
| 3 | Public Staff adjustment to waived fees in 2021 (L2 - L1) | ($1,757) |
| 4 | Annual level of ongoing COV D expenses per Company | $1,680 1/ |
| 5 | Annual level of ongoing COV D expenses per Public Staff | - 3/ |
| 6 | Adjustment to annual level of ongoing COVID expenses (L5 - L6) | ($1,680) |
| 7 | COVID deferral balance per Company | $194,385 1/ |
| 8 | Amortization period per Company | 3 |
| 9 | Annual amortization of COV D deferral balance per Company | 64,795 |
| | [redacted] | |
| 16 | COVID deferral balance per Public Staff (L7 + L13) | $92,846 |
| 17 | Amortization period per Public Staff | 12 3/ |
| 18 | Annual amortization of COV D deferral per Public Staff | 7,737 |
| 19 | Adjustment to annual amortization of COVID deferral (L18 - L9) | ($57,058) |
| | Rate Base Impact | |
| 20 | Remove unamortized balance of COV D costs from rate base (L7 + L9) | ($129,590) |
| 21 | Remove impact of ADIT | 30,260 7/ |

1/ NC5090(B).
2/ PSDR 31-9a.
3/ Per Public Staff.
4/ PSDR 31-30.
5/ PSDR 31-33 and PSDR 31-40.
6/ PSDR 31-32, PSDR 180-3 and PSDR 210-2.
7/ Negative Line 20 times composite tax rate.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO AVIATION EXPENSES**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3-1(h)**

| Line No. | Item | Amount | |
|---|---|---|---|
| | **Wages, benefits, materials, etc.** | | |
| 1 | Corporate aviation O&M and depreciation expense | $5,467 | 1/ |
| 2 | Percentage to be excluded per Public Staff | 52.00% | 2/ |
| 3 | Corporate aviation expenses to be excluded per Public Staff (L1 x L2) | 2,843 | |
| 4 | Specific charter flights to be excluded | 43 | 2/ |
| 5 | Total corporate aviation expenses to be excluded per Public Staff (L3 + L4) | 2,886 | |
| 6 | Corporate aviation expenses to be excluded per Company | 2,734 | 3/ |
| 7 | Additional aviation O&M expenses to be excluded (L5 - L6) | 152 | |
| 8 | NC retail percentage | 68.2076% | 4/ |
| 9 | Public Staff adjustment to aviation O&M expenses (-L7 x L8) | ($104) | |
| | **General taxes** | | |
| 10 | Corporate aviation general taxes | $100 | 5/ |
| 11 | Percentage to be excluded per Public Staff | 52.00% | 2/ |
| 12 | Corporate aviation general taxes to be excluded per Public Staff (L10 x L11) | 52 | |
| 13 | Corporate aviation general taxes to be excluded per Company | 50 | 6/ |
| 14 | Additional aviation general taxes to be excluded (L12 - L13) | 2 | |
| 15 | NC retail percentage | 68.2076% | 4/ |
| 16 | Public Staff adjustment to aviation general taxes (-L14 x L15) | ($1) | |
| | **Commercial flights** | | |
| 17 | International flight expense | $30 | 2/ |
| 18 | Allocation percentage from DEBS to DEC | 33.90% | 7/ |
| 19 | International flight expense allocated to DEC (L17 x L18) | 10 | |
| 20 | NC retail percentage | 68.2076% | 4/ |
| 21 | Public Staff adjustment to O&M for commercial flights (-L19 x L20) | ($7) | |

1/ NC2090-2, Line 29.
2/ Per Public Staff.
3/ NC2090-2, Line 31.
4/ NC2090-1, Line 5.
5/ NC2090-2, Line 1.
6/ NC2090-2, Line 3.
7/ NC2090-5.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO INCENTIVES**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3-1(i)**

| Line No. | Item | Amount | |
|---|---|---|---|
| | **Short Term Incentive Plan (STIP)** | | |
| 1 | Total Company STIP pay accrued expense associated with earnings per share (EPS) | $155,325 | 1/ |
| 2 | Total Company STIP accrual | 353,012 | 1/ |
| 3 | Percentage of STIP related to EPS (L1 / L2) | 44.00% | |
| 4 | STIP at target level associated with O&M expense per Company, net of Joint Owners | 91,603 | 2/ |
| 5 | Adjustment to remove STIP related to EPS outcomes - total system (-L3 x L4) | (40,305) | |
| 6 | NC retail percentage | 68.2076% | 2/ |
| 7 | Adjustment to remove STIP related to EPS outcomes - NC retail (L5 x L6) | (27,491) | |
| 8 | Executive STIP already removed in executive compensation adjustment | 40 | 3/ |
| 9 | Adjustment to STIP (L7 + L8) | ($27,451) | |
| | **Long Term Incentive Plan (LTIP)** | | |
| 10 | LTIP Performance Shares at target, net Joint Owners | $10,986 | 4/ |
| 11 | Percentage associated with EPS and TSR | 75.00% | |
| 12 | Adjustment to remove LTIP associated with EPS and TSR - total system (-L10 x L11) | (8,240) | |
| 13 | NC retail percentage | 68.2076% | 2/ |
| 14 | Adjustment to remove LTIP associated with EPS and TSR - NC retail (L12 x L13) | (5,620) | |
| 15 | Executive LTIP already removed in executive compensation adjustment | 117 | 3/ |
| 16 | Adjustment to LTIP (L13 + L14) | ($5,503) | |
| 17 | Total adjustment to incentive pay (L9 + L15) | ($32,954) | |

1/ Company response to PSDR 94-24.
2/ NC2050-1(B).
3/ Based on executive compensation adjustment.
4/ NC2050(B)-10(c) net of Catawba Joint Owners.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO EXECUTIVE COMPENSATION**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3-1(j)**

| Line No. | Item | Amount | |
|---|---|---|---|
| 1 | Executive compensation for top 5 executives per Company | $13,405 | 1/ |
| 2 | Inclusion of executive benefits in adjustment | 1,080 | 2/ |
| 3 | Executive compensation subject to exclusion adjustment per Public Staff (L1 + L2) | 14,485 | |
| 4 | Catawba reimbursement allocation rate | 11.956% | 1/ |
| 5 | Non-ownership percentage in Catawba plant | 80.754% | 1/ |
| 6 | Costs reimbursed by Catawba Joint Owners (L3 x L4 x L5) | 1,399 | |
| 7 | Compensation subject to exclusion after Joint Owners' Share (L3 - L6) | 13,086 | |
| 8 | NC retail Allocation Factor | 68.2076% | 1/ |
| 9 | NC retail portion of executive compensation subject to exclusion adjustment (L7 x L8) | 8,926 | |
| 10 | Exclusion percentage | 50.00% | 1/ |
| 11 | Public Staff adjustment to exclude executive compensation (L9 x L10) | (4,463) | |
| 12 | Adjustment per Company | (4,130) | 1/ |
| 13 | Adjustment to remove additional executive compensation (L11 - L12) | ($333) | |

1/ NC2040(B).
2/ From Company response to PSDR 44-2.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO RENT EXPENSE**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3-1(k)**

| Line No. | Item | Amount | |
|---|---|---|---|
| 1 | Inter-Company rent revenue per Company | $26,339 | 1/ |
| 2 | Inter-Company rent revenue per Public Staff | 15,752 | 2/ |
| 3 | Adjustment to the rent revenue Public Staff (L2-L1) | ($10,587) | |
| 4 | Adjustment to removed impact of retirement on depr expense per Company | $3,195 | 1/ |
| 5 | Adjustment to removed impact of retirement on depreciation expense per Public Staff | 3,195 | 2/ |
| 6 | Public Staff adjustment to removed impact of retirement on depr expense (L5 - L4) | $0 | |
| 7 | Adjustment to removed impact of retirement on property tax | ($31) | 1/ |
| 8 | Adjustment to removed impact of retirement on property tax per Public Staff | (31) | 2/ |
| 9 | Public Staff adjustment to removed impact of retirement on property tax (L8 - L7) | $0 | |
| 10 | Inter-Company rent expense increase per Company | $5,491 | 1/ |
| 11 | DEBS allocated depreciation expense per Company | (2,975) | 1/ |
| 12 | Increased property insurance | 7 | 1/ |
| 13 | Remove test year DEBS allocated expenses related to artwork | (14) | 1/ |
| 14 | Total Public Staff adjustment to rent expense (sum of Lines 10 through 13) | 2,509 | |
| 15 | Inter-Company rent expense per Public Staff | $1,231 | 2/ |
| 16 | DEBS allocated depreciation expense per Company | (2,975) | 2/ |
| 17 | Increased property insurance | 7 | 2/ |
| 18 | Remove test year DEBS allocated expenses related to artwork | (14) | 2/ |
| 19 | Impact to operations and maintenance expense per Public Staff (sum of Lines 15 through 18) | (1,751) | |
| 20 | Adjustment to the rent expense per Public Staff (L19 - L14) | ($4,260) | |

1/ Supplemental NC2150-1(B)
2/ Per Public Staff

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO CREDIT CARD FEES**
**For the Test Year Ended November 30, 2019**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3-1(l)**

| Line No. | Item | Amount |
|---|---|---|
| 1 | Non-residential credit card transaction fees per Company | 1,529 1/ |
| 2 | O&M transaction costs included in cost of service adjusted per Company | (22) 2/ |
| 3 | Public Staff adjustment to remove non-residential credit card fee (-(L1 + L2)) | (1,507) |

1/ NC2140-2.
2/ NC2140-3.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO LOBBYING**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3-1(m)**

| Line No. | | Amount | |
|---|---|---|---|
| 1 | Remove Federal Governmental Affair charges related to lobbying | ($158) | 1/ |
| 2 | Remove Government Affairs & External Relation charges related to lobbying | (100) | 1/ |
| 3 | Remove Natural Engagement charges related to lobbying | (13) | 1/ |
| 4 | Remove Edison Electric Institute (EEI) O&M charges related to lobbying | (526) | 1/ |
| 5 | Total lobbying costs to be removed from O&M expense (sum L1 through L4) | (797) | |
| 6 | NC Retail Allocation Factor | 68.2076% | 2/ |
| 7 | Public Staff adjustment to remove lobbying costs (L5 x L6) | ($544) | |

1/ Per Company responses to PSDR-63-2.
2/ Per Company.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO SPONSORSHIPS AND DONATIONS**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3-1(n)**

| Line No. | Item | Amount | |
|---|---|---|---|
| 1 | Remove contributions included by the Company in error | ($32) | 1/ |
| 2 | Remove corporate donations & membership dues related to unregulated products | (2) | 2/ |
| 3 | Total sponsorships and donations to be removed per Public Staff (L1 + L2) | (34) | |
| 4 | NC Retail percentage | 68.2076% | 3/ |
| 5 | Public Staff adjustment to remove sponsorships and donations - NC retail (L4 x L5) | ($23) | |

1/ From Company response to Public Staff Data Request No. 62-3
2/ From Company response to Public Staff Data Request No. 62-4.
3/ Per Company.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO BOARD OF DIRECTORS EXPENSE**
**For the Test Year Ended December 31, 2016**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3-1(o)**

| Line No. | Item | Amount |
|---|---|---|
| 1 | Total Board of Directors (BOD) cash compensation | $587 1/ |
| 2 | Percentage of exclusion per Public Staff | 50% 2/ |
| 3 | Public Staff adjustment to BOD compensation (-L1 x L2) | (293) |
| 4 | BOD expenses | 133 3/ |
| 5 | Percentage of exclusion per Public Staff | 50% 2/ |
| 6 | Public Staff adjustment to BOD expenses (-L4 x L5) | (66) |
| 7 | BOD insurance charged to DEC | 4,727 4/ |
| 8 | Percentage of exclusion per Public Staff | 50% 2/ |
| 9 | Public Staff adjustment to BOD insurance (-L4 x L5) | (2,364) |
| 10 | BOD and executive members expenses allocated to DEC | 36 3/ |
| 11 | Percentage of exclusion per Public Staff | 50% 2/ |
| 12 | Public Staff adjustment to BOD and executive members expenses (-L7 x L8) | (18) |
| 13 | Total Public Staff adjustment to BOD compensation and expenses (L3 + L6 + L9 + L12) | (2,741) |
| 14 | NC retail percentage | 68.2076% 5/ |
| 15 | Public Staff adjustment to BOD expenses - NC retail (L13 x L14) | ($1,870) |

1/ Amount from 2021 Proxy Statement, allocated to DEC.
2/ Recommended by Public Staff.
3/ Company Response to PSDR 161-2 and 161-4.
4/ Company Response to PSDR 161-1.
5/ NC retail allocation factor.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO SALARIES AND WAGES**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3-1(p)**

| Line No. | Item | Duke Energy Carolinas (a) | Duke Energy Progress (b) | Service Company (c) | Total (d) |
|---|---|---|---|---|---|
| 1 | Labor per payroll company at April 30, 2023 | $874,773 1/ | $449,858 1/ | $807,997 1/ | |
| 2 | April 2023 allocation percentages | 81.37% 1/ | 7.68% 1/ | 24.59% 1/ | |
| 3 | Annual salaries as of April 30, 2023 per Public Staff (L1 x L2) | 711,836 | 34,531 | 198,665 | |
| 4 | Per books salaries | 664 741 2/ | 32 987 2/ | 193 129 2/ | |
| 5 | Adjustment to salaries and wages for employees per Public Staff | 47,095 | 1,544 | 5,536 | $54,175 3/ |
| 6 | Company adjustment to salaries and wages for employees | 47,096 2/ | 1,543 2/ | 5,536 2/ | 54,175 3/ |
| 7 | Adjustment to salaries and wages | ($1) | $1 | $0 | 0 |
| 8 | Public Staff adjustment to total salaries and wages (L7) | | | | 0 |
| 9 | Percent charged to electric expense | | | | 58 29% 1/ |
| 10 | Adjustment to net electric O&M salaries and wages (L7 x L8) | | | | 0 |
| 11 | Adjustment to net electric O&M salaries and wages (L10) | | | | 0 |
| 12 | Fringe benefits contribution rate | | | | 10 01% 1/ |
| 13 | Adjustment to fringe benefits (L10 x L12) | | | | 0 |
| 14 | Total adjustment to O&M expense - total system (L10 + L13) | | | | 0 |
| 15 | NC retail percentage | | | | 68 2076% 7/ |
| 16 | Total adjustment to O&M expense - NC retail (L14 x L15) | | | | $0 |
| 17 | Impact on payroll taxes before Medicare | | | | $0 8/ |
| 18 | Impact on Medicare payroll taxes | | | | 0 9/ |
| 19 | Adjustment to payroll taxes - total system (L17 + L18) | | | | 0 |
| 20 | NC retail percentage | | | | 68 2076% 7/ |
| 21 | Adjustment to payroll taxes - NC retail (L19 x L20) | | | | $0 |

1/ NC2050-4(B).
2/ NC2050-1(B).

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO NORMALIZE STORM COSTS**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3-1(q)**

| Line No. | Item | Amount | |
|---|---|---|---|
| | Normalized storm expense | | |
| 1 | NC retail amount of storm costs considered normal for 2022 | $48,652 | 1/ |
| 2 | NC retail percentage | 100.0000% | 1/ |
| 3 | 2022 storm costs to be included in calculation of normalized level (L1 x L2) | 48,652 | |
| 4 | 2013 through 2022 costs adjusted for inflation, excluding 2022 | 385,810 | 1/ |
| 5 | Total storm costs for ten years adjusted for inflation (L3 + L4) | 434,462 | |
| 6 | Number of years | 10 | 1/ |
| 7 | Normalized level of storm costs - total system (L5 x L6) | 43,446 | |
| 8 | NC retail percentage | 74.1732% | 1/ |
| 9 | Normalized level of storm costs per Public Staff (L7 x L8) | 32,225 | |
| 10 | 2021 storm costs to be included in calculation of normalized level | 6,347 | 1/ |
| 11 | Public Staff adjustment to normalized level of storm costs (L9 - L10) | 25,878 | |
| 12 | Company adjustment to normalizaed level of storm costs | 25,878 | 1/ |
| 13 | Adjustment to normalize level of storm costs (L11 - L12) | $0 | |

1/ NC7010-1(B), assuming deferrals sought for Hurricane Zeta, Izzy, and Ian are approved by the Commission.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO LIGHTING AUDIT DEFERRAL**
**For the Test Year Ended December 31, 202**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3-1(r)**

| Line No. | Item | Amount | |
|---|---|---|---|
| | **Income Statement:** | | |
| 1 | Annual amortization of lighting audit per Company | $219 | 1/ |
| 2 | Annual amortization of lighting audit per Public Staff | 0 | 2/ |
| 4 | Adjustment to deprecation and amortization for storm deferral (L2 - L1) | ($219) | |
| | **Rate Base Impact:** | | |
| 5 | Adjusted lighting audit in rate base per Company | ($219) | 1/ |
| 6 | Adjusted lighting audit in rate base per Public Staff | - | 2/ |
| 7 | Adjustment to workinng capital for storm deferral (L6 - L5) | $219 | |
| 8 | Impact to ADIT for storm deferral per Company | $51 | 3/ |
| 9 | Impact to ADIT for storm deferral per Public Staff | - | 2/ |
| 10 | Adjustment to ADIT for storm deferral (L9 - L8) | ($51) | |

1/ NC5130-1.
2/ Per Public Staff.
3/ Line 5 times composite income tax rate.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO RATE CASE EXPENSE AND AMORTIZATION**
**For the Test Year Ended December 31, 2023**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3-1(s)**

| Line No. | Item | Amount | |
|---|---|---|---|
| | **Income Statement Impact** | | |
| 1 | Actual rate case expense incurred through April 2023 | $4,399 | 1/ |
| 2 | Amortization period in years | 4 | 2/ |
| 3 | Annual normalized level of rate case expense per Public Staff (L1 / L2) | $1,100 | |
| 4 | Additional rate case expense incurred Sub 1214 per Company | 6,990 | 3/ |
| 5 | NC Retail actual expenses incurred Sub 1276 per Company | 4,399 | 3/ |
| 6 | NC projection remaining through rates effective date per Company | 4,678 | 3/ |
| 7 | Total NC Retail rate case expenses per Company (L4 + L5 + L6) | $16,067 | |
| 8 | Amortization period in years | 3 | 3/ |
| 9 | Adjustment to annual normalized rate case expense (L7/L8) | $5,356 | |
| 10 | Adjustment to annual normalized rate case expense (L3 - L9) | ($4,256) | |
| 11 | Over amortization amounts per Company | ($466) | 3/ |
| 12 | Amortization period in years | 3 | 3/ |
| 13 | Annual amortization of over amortized amounts per Company(L10/L11) | ($155) | |
| 14 | Annual amortization per the Public Staff | 0 | 2/ |
| 15 | Removal of amortization (L14 - L13) | $155 | |
| 16 | Total Adjustment to O&M (L10 + L15) | ($4,101) | |
| | **Rate Base Impact** | | |
| 17 | Projected working capital after first year of amortization per Company | $10,401 | 3/ |
| 18 | Public Staff recommended regulatory asset amount for rate case expense | 0 | 2/ |
| 19 | Adjustment to rate base for rate case expense (L18 - L17) | ($10,401) | |
| 20 | Impact to ADIT for rate case expense per Company | ($2,429) | 3/ |
| 21 | Impact to ADIT for rate case expense per Public Staff | 0 | 2/ |
| 22 | Adjustment to ADIT for rate case expense (L21 - L20) | $2,429 | |

1/ NC5020(E).
2/ Per Public Staff.
3/ NC5020(E).

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO COMPANY'S INFLATION ADJUSTMENT**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3-1(t)**

| Line No. | Item | Amount | |
|---|---|---|---|
| 1 | Total non-labor O&M expense to be adjusted per Company | $448,737 | 1/ |
| 2 | | | |
| 3 | Public Staff adjustment to variable O&M expenses for changes in customer growth | 0 | |
| 4 | Public Staff adjustment to aviation expense | (111) | 2/ |
| 5 | Public Staff adjustment to rent expense | (4,260) | 3/ |
| 6 | Public Staff adjustment to sponsorships and donations | (23) | 4/ |
| 7 | Public Staff adjustment to advertising | 0 | |
| 8 | Public Staff adjustment to uncollectibles | 0 | |
| 9 | Public Staff adjustmnet to lobbying | (544) | 5/ |
| 10 | Public Staff adjustment to Board of Directors expenses | (1,870) | 6/ |
| 11 | Total adjusted O&M subject to inflation (Sum of L1 thru L10) | 441,929 | |
| 12 | Inflation percentage per Public Staff | 4.44% | 7/ |
| 13 | Public Staff inflation adjustment (L11 x L12) | 19,622 | |
| 14 | Inflation adjustment per Company | 55,836 | 1/ |
| 15 | Public Staff adjustment to inflation adjustment (L13- L14) | ($36,214) | |

1/ NC2110-1(B).
2/ Accounting Exhibit 1, Schedule 3-1(h), Line 9 plus Line 21.
3/ Accounting Exhibit 1, Schedule 3-1(k), Line 6.
4/ Accounting Exhibit 1, Schedule 3-1(n), Line 5.
5/ Accounting Exhibit 1, Schedule 3-1(m).
6/ Accounting Exhibit 1, Schedule 3-1(0).
7/ Accounting Exhibit 1, Schedule 3-1(t)(1).

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**CALCULATION OF INFLATION RATE**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3-1(t)(1)**

| Line No. | Item | CPI (a) | PPI Finished Goods Less Food & Energy (b) | PPI Processed Materials Less Food & Energy (c) | PPI Average (d) | Inflation Rate (e) |
|---|---|---|---|---|---|---|
| 1 | April 2023 | 303.4 1/ | 246.0 1/ | 259.1 1/ | | |
| 2 | Thirteen month average for test year | 270.2 2/ | 217.9 2/ | 230.8 2/ | | |
| 3 | Increase from average to April 2023 (L1 - L2) | 33.2 | 28.1 | 28.3 | | |
| 4 | Percentage increase | 12.29% 3/ | 12.92% 3/ | 12.28% 3/ | 12.60% 4/ | 12.45% 5/ |
| 5 | Five year average inflation per Public Staff | 3.80% 1/ | 3.80% 1/ | 6.20% 1/ | 5.04% 4/ | 4.44% 5/ |

1/ Based on information from Bureau of Labor & Statistics, provided in response to Public Staff Data Request No. 62, Items 7, 8, and 9.
2/ NC2110-2, Line 15.
3/ Line 3 divided by Line 2.
4/ Average of percentage increases in Columns (b) and (c).
5/ Average of CPI percentage increase and PPI average percentage increase in Columns (a) and (d).

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ONE YEAR RIDER - OVER AMORTIZATIONS**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3-1(u)**

| Line No. | Item | Amount (a) | |
|---|---|---|---|
| 1 | Rate case expense - Sub 1146 | (782) | 1/ |
| 2 | Severance | (7,695) | |
| 3 | Buck retired plant | (4,844) | 2/ |
| 4 | CCR | (40,310) | |
| 5 | Total over amortization (sum of L1 to L5) | (53,630) | |
| 6 | Interest on over amortization (L5 times PS WACC) | (3,776) | |
| 7 | Total over amortization (L5 + L6) | $ (57,405) | |

1/ Calculated based on NC5010(B) workpapers through December 31, 2023, unless otherwise noted.
2/ NC5060(B)-2, Line 3 times 9 months.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**OVER AMORTIZATION - CCR DEFERRAL**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3-1(u)(1)**

| Line No. | Item | Amount | |
|---|---|---|---|
| | **Income Statement Impact** | | |
| 1 | Correct the balance by removing Company's over amortization and return | $ 8,285 | 1/ |
| 2 | Total increase to deferred balance (L1) | 8,285 | |
| 3 | Year to amortize | 5 | 2/ |
| 4 | Public Staff annual amortization increase (L2/L3) | $ 1,657 | |
| | **Rate Base Impact** | | |
| 5 | Public Staff adjustment to CCR deferral - to interim rates | 8,285 | 1/ |
| 6 | Less first year amortization decrease (L4) | 1,657 | |
| 7 | Adjustment to rate base (L5 - L6) | 6,628 | |
| 8 | Composite income tax rate | 23.3503% | 3/ |
| 9 | Adjustment to accumulated deferred income taxes (-L7 x L8) | $ (1,548) | |

1/ Per NC4010(B)-2, Column (e), Line 44.
2/ Per NC4010(B)-1, Line 6.
3/ Accounting Exhibit 1, Schedule 1-3.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**EXPIRING AMORTIZATION**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3-1(u)(2)**

| Line No. | Item | Amount |
|---|---|---|
| | **Income Statement Impact** | |
| 1 | Remove the Sub 1146 rate case expense expiring amortization | $ (525) 1/ |
| 2 | Public Staff annual amortization increase (L2/L3) | $ (525) |

1/ Per E-7, Sub 1146, NC2500(D).

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**INTERIM SYNCHRONIZATION ADJUSTMENT**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3-1(v)**

| Line No. | Item | Amount | |
|---|---|---|---|
| 1 | Public Staff original cost rate base | $18,479,817 | 1/ |
| 2 | Public Staff long term debt ratio | 48.000% | 2/ |
| 3 | Public Staff embedded cost of debt | 4.530% | 3/ |
| 4 | Public Staff interest expense income tax deduction (L1 x L2 x L3) | 401,825 | |
| 5 | Company interest expense income tax deduction | 401,497 | 4/ |
| 6 | Adjustment to interest expense (L4 - L5) | 328 | |
| 7 | Composite tax rate | 23.3503% | 5/ |
| 8 | Adjustment to income taxes (-L6 x L7) | ($77) | |

1/ Accounting Exhibit 1, Schedule 2, Line 12, Column (c).
2/ Accounting Exhibit 1, Schedule 4, Line 1, Column (a).
3/ Accounting Exhibit 1, Schedule 4, Line 1, Column (c).
4/ Accounting Exhibit 1, Schedule 3-1(v)(1), Line 4.
5/ Accounting Exhibit 1, Schedule 1-3, Line 8.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**CALCULATION OF COMPANY'S INTEREST SYNCHRONIZATION ADJUSTMENT**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 3-1(v)(1)**

| Line No. | Item | Amount | |
|---|---|---|---|
| 1 | NC retail rate base per Company | $18,983,298 | 1/ |
| 2 | Long tern debt ratio per Company | 47.000% | 2/ |
| 3 | Long term debt cost rate per Company | 4.500% | 2/ |
| 4 | Interest tax deduction per Company (L1 x L2 x L3) | $401,497 | |

1/ Accounting Exhibit 1, Schedule 2, Line 12, Column (a).
2/ Per NC6030(B).

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**RETURN ON EQUITY AND ORIGINAL COST RATE BASE BEFORE AND AFTER PUBLIC STAFF PROPOSED DECREASE**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 4**

| | | | Before Public Staff Proposed Decrease | | | | After Public Staff Proposed Decrease | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Item | Capitalization Ratio | NC Retail Rate Base | Embedded Cost or Return | Weighted Cost or Return | Net Operating Income | NC Retail Rate Base | Embedded Cost or Return | Weighted Cost or Return | Net Operating Income |
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| 1 | Long-term debt | 48.000% 1/ | $8,870,312 2/ | 4.530% 1/ | 2.17% 5/ | $401,825 6/ | $8,831,801 9/ | 4.530% 1/ | 2.17% 11/ | $400,081 12/ |
| 2 | Common equity | 52.000% 1/ | 9,609,505 2/ | 9.71% 4/ | 5.05% 5/ | 933,514 7/ | 9,567,784 9/ | 9.35% 1/ | 4.86% 11/ | 894,588 12/ |
| 3 | Total (L1 + L2) | 100.000% | $18,479,817 3/ | | 7.22% | $1,335,339 8/ | $18,399,585 10/ | | 7.03% | $1,294,669 |

1/ Per Public Staff witness Walters.
2/ Column (b), Line 3 times Column (a)
3/ Accounting Exhibit 1, Schedule 2, Line 12, Column (c).
4/ Column (e) divided by Column (b).
5/ Column (a) times Column (c).
6/ Column (b) times Column (c).
7/ Line 3, Column (e) minus Line 1, Column (e).
8/ Accounting Exhibit 1, Schedule 3, Line 16, Column (c).
9/ Column (f), Line 3 times Column (a)
10/ Accounting Exhibit 1, Schedule 2, Line 12, Column (e).
11/ Column (a) times Column (g).
12/ Column (f) times Column (g).

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**RETURN ON EQUITY AND ORIGINAL COST RATE BASE BEFORE AND AFTER PUBLIC STAFF PROPOSED INCREASE**
**For the Test Year Ended December 31, 2021**
**(Dollar Amounts Expressed in Thousands)**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 4**

| | | | Before Public Staff Proposed Increase | | | | After Public Staff Proposed Increase | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Item | Capitalization Ratio | NC Retail Rate Base | Embedded Cost or Return | Weighted Cost or Return | Net Operating Income | NC Retail Rate Base | Embedded Cost or Return | Weighted Cost or Return | Net Operating Income |
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| | **CCR:** | | | | | | | | | |
| 1 | Long-term debt | 48.000% 1/ | $90,908 2/ | 4.53% 1/ | 2.17% 5/ | $4,118 6/ | $93,347 9/ | 4 53% 1/ | 2.17% 11/ | $4,229 12/ |
| 2 | Common equity | 52.000% 1/ | 98,484 2/ | -41.45% 4/ | -21.55% 5/ | ($40,818) 7/ | 101,126 9/ | 7 85% 1/ | 4.08% 11/ | 7,938 12/ |
| 3 | Total (L1 + L2) | 100.000% | $189,392 3/ | | -19.38% | ($36,700) 8/ | $194,473 10/ | | 6.2564% | $12,167 |

1/ Per Public Staff witness Walters, reduced by 1 5% per Commission Order.
2/ Column (b), Line 3 times Column (a)
3/ Accounting Exhibit 1, Schedule 2 CCR, Line 3, Column (a).
4/ Column (e) divided by Column (b).
5/ Column (a) times Column (c).
6/ Column (b) times Column (c).
7/ Line 3, Column (e) minus Line 1, Column (e).
8/ Accounting Exhibit 1, Schedule 3, Line 16, Column (c).
9/ Column (f), Line 3 times Column (a)
10/ Accounting Exhibit 1, Schedule 2, Line 12, Column (e).
11/ Column (a) times Column (g).
12/ Column (f) times Column (g).

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**CALCULATION OF PUBLIC STAFF'S ADDITIONAL GROSS REVENUE REQUIREMENT**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibi**
**Schedule 5**

| Line No. | Item | Debt (a) | Equity (b) | Total 7/ (c) |
|---|---|---|---|---|
| | Calculation of additional gross revenue requirement | | | |
| 1 | Required net operating income | $400,081 1/ | $894,588 4/ | $1,294,669 |
| 2 | Net operating income before proposed increase | $401,825 2/ | 933,514 5/ | 1,335,339 |
| 3 | Additional net operating income requirement (L1 - L2) | (1,744) | (38,926) | (40,670) |
| 4 | Retention factor | 0.9927689 3/ | 0.7609549 6/ | |
| 5 | Additional revenue requirement (L3 / L4) | ($1,757) | ($51,154) | ($52,911) |

1/ Accounting Exhibit 1, Schedule 4, Line 1, Column (i).
2/ Accounting Exhibit 1, Schedule 4, Line 1, Column (e).
3/ Accounting Exhibit 1, Schedule 1-2, Line 10.
4/ Accounting Exhibit 1, Schedule 4, Line 2, Column (i).
5/ Accounting Exhibit 1, Schedule 4, Line 2, Column (e).
6/ Accounting Exhibit 1, Schedule 1-2, Line 14.
7/ Column (a) plus Column (b).

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**

**Public Staff**
**Accounting Exhibit 1**
**Schedule 5 CCR**

**CALCULATION OF PUBLIC STAFF'S ADDITIONAL GROSS REVENUE REQUIREMENT - CCR DEFERRAL**

**For the Test Year Ended December 31, 2021**
**(Dollar Amounts Expressed in Thousands)**

| Line No. | Item | Debt | Equity | Total 7/ |
|---|---|---|---|---|
| | | (a) | (b) | (c) |
| | **Calculation of additional gross revenue requirement** | | | |
| 1 | Required net operating income | $4,229 1/ | 7,938 4/ | $12,167 |
| 2 | Net operating income before proposed increase | $4,118 2/ | ($40,818) 5/ | (36,700) |
| 3 | Additional net operating income requirement (L1 - L2) | $111 | $48,756 | $48,867 |
| 4 | Retention factor | 0.9927689 3/ | 0.7609549 6/ | |
| 5 | Additional revenue requirement (L3 ÷ L4) | $112 | $64,072 | $64,184 |

1/ Accounting Exhibit 1, Schedule 4 CCR.
2/ Accounting Exhibit 1, Schedule 4 CCR.
3/ Accounting Exhibit 1, Schedule 1-2 CCR.
4/ Accounting Exhibit 1, Schedule 4 CCR.
5/ Accounting Exhibit 1, Schedule 4 CCR.
6/ Accounting Exhibit 1, Schedule 1-2 CCR.
7/ Column (a) plus Column (b).

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**Public Staff**
**Accounting Exhibit 2**
**Schedule 1**

**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**CALCULATION OF LEVELIZED FEDERAL UNPROTECTED EDIT RIDER CREDIT**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

| Line No. | Item | Year 1 Revenue Requirement (a) | Year 2 Revenue Requirement (b) | Year 3 Revenue Requirement (c) | Total Revenue Requirement (d) |
|---|---|---|---|---|---|
| 1 | Total NC retail regulatory liability to be amortized | ($22,981) 1/ | ($22,981) 1/ | ($22,981) 1/ | |
| 2 | Annuity factor | 2.7334 2/ | 2.7334 2/ | 2.7334 2/ | |
| 3 | Levelized rider EDIT regulatory liability (L1 / L2) | (8,407) | (8,407) | (8,407) | ($25,221) 5/ |
| 4 | One minus composite income tax rate | 76.6497% 3/ | 76.6497% 3/ | 76.6497% 3/ | 76.6497% |
| 5 | Net operating income effect (L3 x L4) | (6,444) | (6,444) | (6,444) | (19,332) |
| 6 | Retention factor | 0.7609549 4/ | 0.7609549 4/ | 0.7609549 4/ | 0.7609549 |
| 7 | Levelized rider EDIT credit (L5 / L6) | ($8,468) | ($8,468) | ($8,468) | ($25,405) |

1/ Bowman Exhibit 3.
2/ Accounting Exhibit 2, Schedule 1(a), Line 6.
3/ One minus composite income tax rate of 23.3503%.
4/ Accounting Exhibit 1, Schedule 1-2, Line 14, Column (d).
5/ Sum of Columns(a) through (e).

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**CALCULATION OF ANNUITY FACTOR FOR EDIT LIABILITY RIDER**
**For the Test Year Ended December 31, 2021**
**(in Thousands)**

**Public Staff**
**Accounting Exhibit 2**
**Schedule 1(a)**

| Line No. | Item | Amount |
|---|---|---|
| | Annuity Factor | |
| 1 | Number of years | 3 1/ |
| 2 | Payment per period | 1 |
| 3 | After tax rate of return (L9) | 6.529% |
| 4 | Present value of 1 dollar over number of years with with 1 payment per year | 2.6471 |
| 5 | 1 plus (interest rate divided by two) | 1.0326 |
| 6 | Annuity factor (L4 x L5) | 2.7334 |

| | | Capital Structure (a) | Cost Rates (b) | Overall Rate of Return 6/ (c) | Net of Tax Rate (d) |
|---|---|---|---|---|---|
| | After Tax Rate of Return | | | | |
| 7 | Long-term debt | 48.00% 2/ | 4.530% 4/ | 2.174% | 1.667% 7/ |
| 8 | Common equity | 52.00% 3/ | 9.350% 5/ | 4.862% | 4.862% 8/ |
| 9 | Total | 100.00% | | 7.036% | 6.529% |

1/ Rider period recommended by Public Staff.
2/ Accounting Exhibit 1, Schedule 4, Line 1, Column (a).
3/ Accounting Exhibit 1, Schedule 4, Line 2, Column (a).
4/ Accounting Exhibit 1, Schedule 4, Line 1, Column (g).
5/ Accounting Exhibit 1, Schedule 4, Line 2, Column (g).
6/ Column (a) times Column (b).
7/ Column (c) times (1 minus combined income tax rate of 23.3503%).
8/ Amount from Column (c).

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**MYRP REVENUE REQUIREMENT CALCULATION**
**For the Rate Year 1 Ended December 31, 2024**
**(Dollar Amounts Expressed in Thousands)**

**Public Staff**
**Accounting Exhibit 3**
**Schedule RY1**

| Line No. | Item | NC Retail, 1st Supplemental Per Company 1/ (a) | Public Staff Recommended PS Adjustment 2/ (b) | Public Staff Recommended Amount after Adjustment (c) | |
|---|---|---|---|---|---|
| | **OPERATING INCOME** | | | | |
| 1 | Deprecia ion Expense | $ 42,099 | $ (13,049) | $ 29,050 | 3/ |
| 2 | Incremental O&M Expense | 16,780 | (13,921) | 2,859 | 3/ |
| 3 | Property Taxes | 629 | (186) | 443 | 3/ |
| 4 | Income taxes impact on deductible expenses | (13,895) | 6,341 | (7,554) | 4/ |
| 5 | Amortization of Investment Tax Credit (ITC) | (52) | (0) | (52) | 7/ |
| 6 | Amortization of Produc ion Tax Credit (PTC) | - | - | - | 7/ |
| 7 | Operating Income (Sum of L1 to L6) | 45,560 | (20,815) | 24,746 | |
| 8 | Retention Factor | 76.09% | 76.10% | 76.10% | 8/ |
| 9 | Operating Income Revenue Requirement (L7/L8) | $ 59,873 | $ (27,353) | $ 32,519 | |
| 10 | **RETURN ON RATE BASE** | | | | |
| 11 | Electric Plant In-Service | $ 1,150,670 | $ (331,727) | $ 818,943 | 5/ |
| 12 | Accumulated Depreciation | (20,825) | 6,259 | (14,566) | 6/ |
| 13 | ITC Net Rate Base Impact | 4 | 0 | 4 | 7/ |
| 14 | PTC Rate Base Impact | - | - | - | 7/ |
| 15 | Total Rate Base (L10-L14) | $ 1,129,850 | $ (325,468) | $ 804,382 | |
| 16 | Return on Rate Base | 9.37% | - | 8.58% | 9/ |
| 17 | Rate Base Revenue Requirement (L15*L16) | $ 105,912 | $ (36,900) | $ 69,013 | |
| 18 | **Cumulative MYRP Revenue Requirement (L9+L17)** | $ 165,785 | $ (64,253) | $ 101,532 | |
| 19 | Incremental MYRP Rate Year Revenue Requirement | $ 165,785 | $ (64,253) | $ 101,532 | |
| 20 | **NC Retail Operations Base Case Revenue Requirement** | $ 5,615,798 | $ (167,516) | 5,448,282 | 10/ 11/ |
| 21 | 4% Annual Increase Test for Rate Years 2 & 3 | | | | |
| 22 | **Total Base Rate Revenue Requirement (L18+L20)** | $ 5,781,583 | $ (231,769) | $ 5,549,814 | |

1/ Per Company Abernathy Supplemental Exhibit 4.
2/ Column (c) minus column (a).
3/ Per Accounting Exhibit 3, Schedule RY1 - Depr & Prop Tax, Lines 1 to 3, Column (c).
4/ Column (c), (L1 + L2 + L3) x 0.233503 x (-1).
5/ Per Accounting Exhibit 3, Schedule RY1 - Plants, Line 7, Column (c).
6/ Per Accounting Exhibit 3, Schedule RY1 - AD, Line 6, Column (c).
7/ Per Accounting Exhibit 3, Schedule RY1 - ITC & PTC, Lines 1 and 2, Column (c).
8/ Per Accounting Exhibit 1, Schedule 1-2, Line 14, Column (d).
9/ Per Accounting Exhibit 1, Schedule 1-2, Line 4, Column (d).
10/ Per Accounting Exhibit 1, Schedules 3 & 3 CCR, Line 4, Column (e).
11/ Company Revenue included in Column (a), Line 20 includes rider revenue.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO MYRP INCREMENTAL CAPITAL PROJECTS**
**For the Rate Year 1 Ended December 31, 2024**
**(Dollar Amounts Expressed in Thousands)**

**Public Staff**
**Accounting Exhibit 3**
**Schedule RY1 - Plants**

| Line No. | Item | NC Retail Total per Application 1/ (a) | Total Public Staff Adjustments 2/ (b) | Total Public Staff Recommended 3/ (c) |
|---|---|---|---|---|
| 1 | Total production plant | $ 346,116 | $ (143,147) | $ 202,969 |
| 2 | Transmission Plant | 149,931 | (59,497) | 90,434 |
| 3 | Distribution Plant | 465,621 | (45,708) | 419,912 |
| 4 | General Plant | 138,600 | (77,071) | 61,529 |
| 5 | Intangible Plant | 50,403 | (6,304) | 44,099 |
| 6 | Nuclear Fuel (Net) | - | - | - |
| 7 | Total plant in service (Sum of L1 to L6) | $ 1,150,670 | $ (331,727) | $ 818,943 |

1/ Per Company Abernathy Supplemental Exhibit 4 WP 1 RB-OM Summary.
2/ Column (c) minus column (a).
3/ Per Public Staff Engineers.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO ACCUMULATED DEPRECIATION**
**For the Rate Year 1 Ended December 31, 2024**
**(Dollar Amounts Expressed in Thousands)**

**Public Staff**
**Accounting Exhibit 3**
**Schedule RY1 - AD**

| Line No. | Item | NC Retail Total per Application 1/ (a) | NC Retail Total Public Staff Adjustments 2/ (b) | NC Retail Total Public Staff Recommended 3/ (c) |
|---|---|---|---|---|
| 1 | Production Reserve | (5,976) | $ 2,950 | $ (3,026) |
| 2 | Transmission Reserve | (2,125) | 649 | (1,475) |
| 3 | Distribution Reserve | (5,053) | 147 | (4,906) |
| 4 | General Reserve | (4,773) | 2,163 | (2,610) |
| 5 | Intangible Reserve | (2,898) | 350 | (2,548) |
| 6 | Total accumulated depreciation (Sum of L1 to L5) | $ (20,825) | $ 6,259 | $ (14,566) |

1/ Per Company Abernathy Supplemental Exhibit 4 WP 1 RB-OM Summary.
2/ Column (c) minus column (a).
3/ Per Public Staff Engineers.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO INVESTMENT TAX CREDIT AND PRODUCTION TAX CREDIT**
**For the Rate Year 1 Ended December 31, 2024**
**(Dollar Amounts Expressed in Thousands)**

**Public Staff**
**Accounting Exhibit 3**
**Schedule RY1 - ITC & PTC**

| Line No. | Item | NC Retail Total per Application 1/ (a) | NC Retail Total Public Staff Adjustments 2/ (b) | NC Retail Total Public Staff Recommended 3/ (c) |
|---|---|---|---|---|
| | Operating Income | | | |
| 1 | Amortization of Investment Tax Credit (ITC) | $ (52) | (0) | (52) |
| 2 | Amortization of Production Tax Credit (PTC) | - | - | - |
| 3 | Total Operating Income Impact (L1 + L2) | $ (52) | $ (0) | $ (52) |
| | Return on Rate Base | | | |
| 4 | ITC Net Rate Base Impact | $ 4 | $ 0 | $ 4 |
| 5 | PTC Rate Base Impact | - | - | 0 |
| 6 | Total Rate Base Impact | $ 4 | $ 0 | $ 4 |

1/ Per Company Abernathy Supplemental Exhibit 4 WP 1 RB-OM Summary.
2/ Column (c) minus column (a).
3/ Per Public Staff Thomas.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO OPERATING EXPENSE,**
**DEPRECIATION AND PROPERTY TAX**
**For the Rate Year 1 Ended December 31, 2024**
**(Dollar Amounts Expressed in Thousands)**

**Public Staff**
**Accounting Exhibit 3**
**Schedule RY1 - Depr & Prop Tax**

| Line No. | Item | NC Retail Total per Application 1/ (a) | Total Public Staff Adjustments 2/ (b) | Total Public Staff Recommended 3/ (c) |
|---|---|---|---|---|
| | Operating Income | | | |
| 1 | Depreciation Expense | $ 42,099 | $ (13,049) | $ 29,050 |
| 2 | Other O&M | 16,780 | (13,921) | 2,859 |
| 3 | Property Tax | 629 | (186) | 443 |
| 4 | Total Operating Income Impact (L1 + L2 + L3) | $ 59,508 | $ (27,156) | $ 32,352 |

1/ Per Company Abernathy Supplemental Exhibit 4 WP 1 RB-OM Summary.
2/ Column (c) minus column (a).
3/ Per Public Staff Engineers, unless otherwise noted.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**MYRP REVENUE REQUIREMENT CALCULATION**
**For the Rate Year 2 Ended December 31, 2025**
**(Dollar Amounts Expressed in Thousands)**

**Public Staff**
**Accounting Exhibit 3**
**Schedule RY2**

| Line No. | Item | NC Retail, 1st Supplemental Per Company 1/ (a) | Public Staff Recommended PS Adjustment 2/ (b) | Public Staff Recommended Amount after Adjustment (c) | |
|---|---|---|---|---|---|
| | **OPERATING INCOME** | | | | |
| 1 | Depreciation Expense | $ 87,697 | $ (18,337) | $ 69,360 | 3/ |
| 2 | Incremental O&M Expense | 8,638 | (6,352) | 2,286 | 3/ |
| 3 | Property Taxes | 4,093 | (925) | 3,168 | 3/ |
| 4 | Income taxes impact on deductible expenses | (23,450) | 5,981 | (17,469) | 4/ |
| 5 | Amortization of Investment Tax Credit (ITC) | (927) | - | (927) | 7/ |
| 6 | Amortization of Produc ion Tax Credit (PTC) | - | - | - | 7/ |
| 7 | Operating Income (Sum of L1 to L6) | 76,051 | (19,633) | 56,418 | |
| 8 | Retention Factor | 76 09% | 76.10% | 76.10% | 8/ |
| 9 | Operating Income Revenue Requirement (L7/L8) | $ 99,943 | $ (25,801) | $ 74,141 | |
| 10 | **RETURN ON RATE BASE** | | | | |
| 11 | Electric Plant In-Service | $ 2,718,457 | $ (556,903) | $ 2,161,554 | 5/ |
| 12 | Accumulated Depreciation | (85,303) | 22,128 | (63,175) | 6/ |
| 13 | ITC Net Rate Base Impact | 397 | - | 397 | 7/ |
| 14 | PTC Rate Base Impact | - | - | - | 7/ |
| 15 | Total Rate Base (L10-L14) | $ 2,633,552 | $ (534,775) | $ 2,098,777 | |
| 16 | Return on Rate Base | 9 37% | - | 8.58% | 9/ |
| 17 | Rate Base Revenue Requirement (L15*L16) | $ 246,869 | $ (66,803) | $ 180,066 | |
| 18 | **Cumulative MYRP Revenue Requirement (L9+L17)** | $ 346,812 | $ (92,604) | $ 254,208 | |
| 19 | Incremental MYRP Rate Year Revenue Requirement | $ 181,027 | $ (76,560) 8/ | $ 152,676 | |
| 20 | **NC Retail Operations Base Case Revenue Requirement** | $ 5,615,798 11/ | $ (167,516) | 5,448,282 | 10/ |
| 21 | Annual Increase % Test for Rate Years 2 & 3 (L19/L20) | 3.2% | | 2.8% | |
| 22 | 4% statutory cap at PS Base Case Revenue for Rate Years 2 & 3 (L20 x 4%) | | | 217,931 | |
| 23 | PS adjustment to 4% statutory cap | | | $ - | |
| 24 | Incremental MYRP Rate Year Revenue Requirement allowed by statute (L19+L23) | | | $ 152,676 | |
| 25 | **Total Base Rate Revenue Requirement (L18+L20+L23)** | $5,962,610 | ($260,120) | $5,702,490 | |

1/ Per Company Abernathy Supplemental Exhibit 4.
2/ Column (c) minus column (a).
3/ Per Accounting Exhibit 3, Schedule RY1 - Depr & Prop Tax, Lines 1 to 3, Column (c).
4/ Column (c), (L1 + L2 + L3) x 0.233503 x (-1).
5/ Per Accounting Exhibit 3, Schedule RY1 - Plants, Line 7, Column (c).
6/ Per Accounting Exhibit 3, Schedule RY1 - AD, Line 6, Column (c).
7/ Per Accounting Exhibit 3, Schedule RY1 - ITC & PTC, Lines 1 and 2, Column (c).
8/ Per Accounting Exhibit 1, Schedule 1-2, Line 14, Column (d).
9/ Per Accounting Exhibit 1, Schedule 1-2, Line 4, Column (d).
10/ Per Accounting Exhibit 1, Schedules 3 & 3 CCR, Line 4, Column (e).
11/ Company Revenue included in Column (a), Line 20 includes rider revenue.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO MYRP INCREMENTAL CAPITAL PROJECTS**
**For the Rate Year 2 Ended December 31, 2025**
**(Dollar Amounts Expressed in Thousands)**

**Public Staff**
**Accounting Exhibit 3**
**Schedule RY2 - Plants**

| Line No. | Item | NC Retail Total per Application 1/ (a) | Total Public Staff Adjustments 2/ (b) | Total Public Staff Recommended 3/ (c) |
|---|---|---|---|---|
| 1 | Total production plant | $579,011 | $ (140,561) | $438,450 |
| 2 | Transmission Plant | 361,486 | (103,362) | 258,124 |
| 3 | Distribution Plant | 1,467,522 | (161,446) | 1,306,076 |
| 4 | General Plant | 249,038 | (143,937) | 105,101 |
| 5 | Intangible Plant | 61,400 | (7,598) | 53,803 |
| 6 | Nuclear Fuel (Net) | - | - | - |
| 7 | Total plant in service (Sum of L1 to L6) | $ 2,718,457 | $ (556,903) | $ 2,161,554 |

1/ Per Company Abernathy Supplemental Exhibit 4 WP 1 RB-OM Summary.
2/ Column (c) minus column (a).
3/ Per Public Staff Engineers.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO ACCUMULATED DEPRECIATION**
**For the Rate Year 2 Ended December 31, 2025**
**(Dollar Amounts Expressed in Thousands)**

**Public Staff**
**Accounting Exhibit 3**
**Schedule RY2 - AD**

| Line No. | Item | NC Retail Total per Application 1/ (a) | NC Retail Total Public Staff Adjustments 2/ (b) | NC Retail Total Public Staff Recommended 3/ (c) |
|---|---|---|---|---|
| 1 | Production Reserve | $ (22,297) | $ 8,068 | $ (14,230) |
| 2 | Transmission Reserve | (8,203) | 2,354 | (5,849) |
| 3 | Distribution Reserve | (27,445) | 1,128 | (26,317) |
| 4 | General Reserve | (18,096) | 9,477 | (8,619) |
| 5 | Intangible Reserve | (9,262) | 1,102 | (8,160) |
| 6 | Total accumulated depreciation (Sum of L1 to L5) | $ (85,303) | $ 22,128 | $ (63,175) |

1/ Per Company Abernathy Supplemental Exhibit 4 WP 1 RB-OM Summary.
2/ Column (c) minus column (a).
3/ Per Public Staff Engineers.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO INVESTMENT TAX CREDIT AND PRODUCTION TAX CREDIT**
**For the Rate Year 2 Ended December 31, 2025**
**(Dollar Amounts Expressed in Thousands)**

**Public Staff**
**Accounting Exhibit 3**
**Schedule RY2 - ITC & PTC**

| Line No. | Item | NC Retail Total per Application 1/ (a) | Total Public Staff Adjustments 2/ (b) | Total Public Staff Recommended 3/ (c) |
|---|---|---|---|---|
| | Operating Income | | | |
| 1 | Amortization of Investment Tax Credit (ITC) | $ (927) | $ - | $ (927) |
| 2 | Amortization of Production Tax Credit (PTC) | | - | - |
| 3 | Total Operating Income Impact (L1 + L2) | $ (927) | $ - | $ (927) |
| | Return on Rate Base | | | |
| 4 | ITC Net Rate Base Impact | $ 397 | $ - | $ 397 |
| 5 | PTC Rate Base Impact | | - | - |
| 6 | Total Rate Base Impact | $ 397 | $ - | $ 397 |

1/ Per Company Abernathy Supplemental Exhibit 4 WP 1 RB-OM Summary.
2/ Column (c) minus column (a).
3/ Per Public Staff Engineer Thomas.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO OPERATING EXPENSE,**
**DEPRECIATION AND PROPERTY TAX**
**For the Rate Year 2 Ended December 31, 2025**
**(Dollar Amounts Expressed in Thousands)**

**Public Staff**
**Accounting Exhibit 3**
**Schedule RY2 - Depr & Prop Tax**

| Line No. | Item | NC Retail Total per Application 1/ (a) | Total Public Staff Adjustments 2/ (b) | Total Public Staff Recommended 3/ (c) |
|---|---|---|---|---|
| | Operating Income | | | |
| 1 | Depreciation Expense | $ 87,697 | $ (18,337) | $ 69,360 |
| 2 | Other O&M | 8,638 | (6,352) | 2,286 |
| 3 | Property Tax | 4,093 | (925) | 3,168 |
| 4 | Total Operating Income Impact (L1 + L2 + L3) | $ 100,428 | $ (25,614) | $ 74,814 |

1/ Per Company Abernathy Supplemental Exhibit 4 WP 1 RB-OM Summary.
2/ Column (c) minus column (a).
3/ Per Public Staff Engineers.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**MYRP REVENUE REQUIREMENT CALCULATION**
**For the Rate Year 3 Ended December 31, 2026**
**(Dollar Amounts Expressed in Thousands)**

**Public Staff**
**Accounting Exhibit 3**
**Schedule RY3**

| Line No. | Item | NC Retail, 1st Supplemental Per Company 1/ (a) | Public Staff Recommended PS Adjustment 2/ (d) | Public Staff Recommended Amount after Adjustment (c) |
|---|---|---|---|---|
| | **OPERATING INCOME** | | | |
| 1 | Deprecia ion Expense | $ 142,367 | $ (30,880) | $ 111,487 3/ |
| 2 | Incremental O&M Expense | 7,133 | (1,293) | 5,840 3/ |
| 3 | Property Taxes | 7,566 | (1,567) | 5,999 3/ |
| 4 | Income taxes impact on deductible expenses | (36,675) | 7,878 | (28,797) 4/ |
| 5 | Amortization of Investment Tax Credit (ITC) | (3,547) | - | (3,547) 7/ |
| 6 | Amortization of Produc ion Tax Credit (PTC) | (4,734) | - | (4,734) 7/ |
| 7 | Operating Income (Sum of L1 to L6) | 112,109 | (25,862) | 86,247 |
| 8 | Retention Factor | 76.09% | 76.10% | 76.10% 8/ |
| 9 | Operating Income Revenue Requirement (L7/L8) | $ 147,328 | $ (33,986) | $ 113,341 |
| 10 | **RETURN ON RATE BASE** | | | |
| 11 | Electric Plant In-Service | $ 4,298,064 | $ (962,437) | $ 3,335,627 5/ |
| 12 | Accumulated Depreciation | (199,885) | 46,230 | (153,655) 6/ |
| 13 | ITC Net Rate Base Impact | $2,733 | - | $2,733 7/ |
| 14 | PTC Rate Base Impact | $1,457 | - | $1,457 7/ |
| 15 | Total Rate Base (L10-L14) | $ 4,102,369 | $ (916,207) | $ 3,186,161 |
| 16 | Return on Rate Base | 9.37% | - | 8.58% 9/ |
| 17 | Rate Base Revenue Requirement (L15*L16) | $ 384,557 | $ (111,197) | $ 273,359 |
| 18 | **Cumulative MYRP Revenue Requirement (L9+L17)** | $ 531,884 | $ (145,183) | $ 386,700 |
| 19 | Incremental MYRP Rate Year Revenue Requirement | $ 185,072 | $ (52,579) | $ 132,493 |
| 20 | **NC Retail Operations Base Case Revenue Requirement** | $ 5,615,798 11/ | ($167,516) | 5,448,282 10/ |
| 21 | Annual Increase % Test for Rate Years 2 & 3 (L19/L20) | 3.3% | | 2.4% |
| 22 | 4% statutory cap at PS Base Case Revenue for Rate Years 2 & 3 (L20 x 4%) | | | 217,931 |
| 23 | PS adjustment to 4% statutory cap | | | $ - |
| 24 | Incremental MYRP Rate Year Revenue Requirement allowed by statute (L19+L23) | | | $ 132,493 |
| 25 | **Total Base Rate Revenue Requirement (L18+L20+L23)** | $6,147,682 | ($312,700) | $5,834,982 |

1/ Per Company Abernathy Supplemental Exhibit 4.
2/ Column (c) minus column (a).
3/ Per Accounting Exhibit 3, Schedule RY1 - Depr & Prop Tax, Lines 1 to 3, Column (c).
4/ Column (c), (L1 + L2 + L3) x 0.233503 x (-1).
5/ Per Accounting Exhibit 3, Schedule RY1 - Plants, Line 7, Column (c).
6/ Per Accounting Exhibit 3, Schedule RY1 - AD, Line 6, Column (c).
7/ Per Accounting Exhibit 3, Schedule RY1 - ITC & PTC, Lines 1 and 2, Column (c).
8/ Per Accounting Exhibit 1, Schedule 1-2, Line 14, Column (d).
9/ Per Accounting Exhibit 1, Schedule 1-2, Line 4, Column (d).
10/ Per Accounting Exhibit 1, Schedules 3 & 3 CCR, Line 4, Column (e).
11/ Company Revenue included in Column (a), Line 20 includes rider revenue.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO MYRP INCREMENTAL CAPITAL PROJECTS**
**For the Rate Year 3 Ended December 31, 2026**
**(Dollar Amounts Expressed in Thousands)**

**Public Staff**
**Accounting Exhibit 3**
**Schedule RY3 - Plants**

| Line No. | Item | NC Retail Total per Application 1/ (a) | Total Public Staff Adjustments 2/ (b) | Total Public Staff Recommended 3/ (c) |
|---|---|---|---|---|
| 1 | Total production plant | $ 1,024,319 | $ (333,005) | $691,314 |
| 2 | Transmission Plant | 555,693 | (175,604) | 380,088 |
| 3 | Distribution Plant | 2,275,977 | (273,539) | 2,002,438 |
| 4 | General Plant | 348,694 | (167,677) | 181,017 |
| 5 | Intangible Plant | 93,382 | (12,613) | 80,769 |
| 6 | Nuclear Fuel (Net) | - | - | - |
| 7 | Total plant in service (Sum of L1 to L6) | $ 4,298,064 | $ (962,437) | $ 3,335,627 |

1/ Per Company Abernathy Supplemental Exhibit 4 WP 1 RB-OM Summary.
2/ Column (c) minus column (a).
3/ Per Public Staff Engineers.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO ACCUMULATED DEPRECIATION**
**For the Rate Year 3 Ended December 31, 2026**
**(Dollar Amounts Expressed in Thousands)**

**Public Staff**
**Accounting Exhibit 3**
**Schedule RY3 - AD**

| Line No. | Item | NC Retail Total per Application 1/ (a) | NC Retail Total Public Staff Adjustments 2/ (b) | NC Retail Total Public Staff Recommended 3/ (c) |
|---|---|---|---|---|
| 1 | Production Reserve | $ (52,232) | $ 15,887 | $ (36,345) |
| 2 | Transmission Reserve | (19,120) | 5,573 | (13,546) |
| 3 | Distribution Reserve | (71,177) | 3,516 | (67,661) |
| 4 | General Reserve | (37,559) | 18,775 | (18,784) |
| 5 | Intangible Reserve | (19,798) | 2,479 | (17,319) |
| 6 | Total accumulated depreciation (Sum of L1 to L5) | $ (199,885) | $ 46,230 | $ (153,655) |

1/ Per Company Abernathy Supplemental Exhibit 4 WP 1 RB-OM Summary.
2/ Column (c) minus column (a).
3/ Per Public Staff Engineers.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO INVESTMENT TAX CREDIT AND PRODUCTION TAX CREDIT**
**For the Rate Year 3 Ended December 31, 2026**
**(Dollar Amounts Expressed in Thousands)**

**Public Staff**
**Accounting Exhibit 3**
**Schedule RY3 - ITC & PTC**

| Line No. | Item | NC Retail Total per Application 1/ (a) | Total Public Staff Adjustments 2/ (b) | Total Public Staff Recommended 3/ (c) |
|---|---|---|---|---|
| | Operating Income | | | |
| 1 | Amortization of Investment Tax Credit (ITC) | $ (3,547) | $ - | $ (3,547) |
| 2 | Amortization of Production Tax Credit (PTC) | (4,734) | - | (4,734) |
| 3 | Total Operating Income Impact (L1 + L2) | $ (8,282) | $ - | $ (8,282) |
| | Return on Rate Base | | | |
| 4 | ITC Net Rate Base Impact | $ 2,733 | $ - | $ 2,733 |
| 5 | PTC Rate Base Impact | 1,457 | - | 1,457 |
| 6 | Total Rate Base Impact | $ 4,190 | $ - | $ 4,190 |

1/ Per Company Abernathy Supplemental Exhibit 4 WP 1 RB-OM Summary.
2/ Column (c) minus column (a).
3/ Per Public Staff Engineer Thomas.

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**DUKE ENERGY CAROLINAS, LLC**
**Docket No. E-7, Sub 1276**
**North Carolina Retail Operations**
**ADJUSTMENT TO OPERATING EXPENSE,**
**DEPRECIATION AND PROPERTY TAX**
**For the Rate Year 3 Ended December 31, 2026**
**(Dollar Amounts Expressed in Thousands)**

**Public Staff**
**Accounting Exhibit 3**
**Schedule RY3 - Depr & Prop Tax**

| Line No. | Item | NC Retail Total per Application 1/ (a) | Total Public Staff Adjustments 2/ (b) | Total Public Staff Recommended 3/ (c) |
|---|---|---|---|---|
| | Operating Income | | | |
| 1 | Depreciation Expense | $ 142,367 | $ (30,880) | $ 111,487 |
| 2 | Other O&M | 7,133 | (1,293) | 5,840 |
| 3 | Property Tax | 7,566 | (1,567) | 5,999 |
| 4 | Total Operating Income Impact (L1 + L2 + L3) | $ 157,066 | $ (33,740) | $ 123,326 |

1/ Per Company Abernathy Supplemental Exhibit 4 WP 1 RB-OM Summary.
2/ Column (c) minus column (a).
3/ Per Public Staff Engineers.