STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1134
DOCKET NO. E-7, SUB 1276

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1134 In the Matter of Application of Duke Energy Carolinas, LLC for Approval to Construct a 402 MW Natural Gas-Fired Combustion Turbine Electric Generating Facility in Lincoln County DOCKET NO. E-7, SUB 1276 In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation	ORDER ACCEPTING STIPULATIONS, GRANTING PARTIAL RATE INCREASE, REQUIRING PUBLIC NOTICE, AND MODIFYING LINCOLN CT CPCN CONDITIONS

HEARD: Wednesday, June 21, 2023, at 7:00 p.m., Burke County Courthouse, Courtroom 1A, 201 South Green Street, Morganton, North Carolina

Thursday, June 22, 2023, at 7:00 p.m., Mecklenburg County Courthouse, Courtroom 5350, 832 East 4th Street, Charlotte, North Carolina

Monday, July 24, 2023, at 7:00 p.m., Forsyth County Courthouse, Courtroom 1A, 200 North Main Street, Winston-Salem, North Carolina

Wednesday, July 26, 2023, at 6:30 p.m. via Videoconference, Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Monday, July 31, 2023, at 6:00 p.m. via Videoconference, Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Monday, August 14, 2023, at 7:00 p.m., Durham County Courthouse, Courtroom 7D, 510 South Dillard Street, Durham, North Carolina

Monday, August 28, 2023, at 2:00 p.m., Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

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

APPEARANCES:

For Duke Energy Carolinas, LLC (DEC):

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

Jason A. Higginbotham, Duke Energy Corporation, 525 South Tryon Street, Charlotte, North Carolina 28202

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

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

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

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

For Carolina Utility Customers Association, Inc. (CUCA):

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

For Carolina Industrial Group for Fair Utility Rates III (CIGFUR):

Christina D. Cress and Douglas E. Conant, Bailey & Dixon, LLP, 434 Fayetteville Street, Suite 2500, Raleigh, North Carolina 27602

Chris S. Edwards, Ward and Smith, P.A., 127 Racine Drive, Wilmington, North Carolina 28406

For North Carolina Sustainable Energy Association (NCSEA):

Ethan Blumenthal and Cassie Gavin, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For Blue Ridge Electric Membership Corporation (Blue Ridge EMC):

Christina D. Cress, Bailey & Dixon, LLP, 434 Fayetteville Street, Suite 2500, Raleigh, North Carolina 27602

Chris S. Edwards, Ward and Smith, P.A., 127 Racine Drive, Wilmington, North Carolina 28406

For Haywood Electric Membership Corporation (Haywood EMC):

Christina D. Cress, Bailey & Dixon, LLP, 434 Fayetteville Street, Suite 2500, Raleigh, North Carolina 27602

Chris S. Edwards, Ward and Smith, P.A., 127 Racine Drive, Wilmington, North Carolina 28406

For Piedmont Electric Membership Corporation (Piedmont EMC):

Christina D. Cress, Bailey & Dixon, LLP, 434 Fayetteville Street, Suite 2500, Raleigh, North Carolina 27602

Chris S. Edwards, Ward and Smith, P.A., 127 Racine Drive, Wilmington, North Carolina 28406

For Rutherford Electric Membership Corporation (Rutherford EMC):

Christina D. Cress, Bailey & Dixon, LLP, 434 Fayetteville Street, Suite 2500, Raleigh, North Carolina 27602

Chris S. Edwards, Ward and Smith, P.A., 127 Racine Drive, Wilmington, North Carolina 28406

For North Carolina League of Municipalities (NCLM):

Ben Snowden, Fox Rothschild LLP, 434 Fayetteville Street, Suite 2800, Raleigh, North Carolina, 27601

For the Commercial Group:

Alan R. Jenkins, Jenkins at Law, LLC, 2950 Yellowtail Avenue, Marathon, Florida 33050

Brian O. Beverly, Young Moore and Henderson, P.A., 3101 Glenwood Avenue, Suite 200, Raleigh, North Carolina 27612

For Sierra Club:

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

For North Carolina Justice Center (NCJC), North Carolina Housing Coalition (NCHC), Southern Alliance for Clean Energy (SACE), Natural Resources Defense Council (NRDC), and Vote Solar (collectively, NCJC, et al.):

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

For NC WARN:

Matthew D. Quinn, Lewis & Roberts, PLLC, Post Office Box 17529, Raleigh, North Carolina, 27609

For Kroger Co. and Harris Teeter LLC, a Division of Kroger Co. (Kroger Co. and Harris Teeter):

Kurt J. Boehm and Jody Kyler Cohn, Boehm, Kurtz & Lowry, 36 East Seventh Street, Suite 1510, Cincinnati, Ohio 45202

Ben M. Royster, Royster and Royster, PLLC, 851 Marshall Street, Mount Airy, North Carolina 27030

For Andale, LLC (Andale):

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

For the Using and Consuming Public:

Tirrill E. Moore and Derrick C. Mertz, North Carolina Department of Justice, 114 West Edenton Street, Raleigh, North Carolina 27603

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

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BY THE COMMISSION: In October 2021, the North Carolina General Assembly enacted N.C. Gen. Stat. § 62-133.16 authorizing the "performance-based regulation" (PBR) of electric public utilities (PBR Statute), which was subsequently signed into law by the Governor. Section 62-133.16 establishes an alternative ratemaking approach that among other things expands upon the traditional historic test year method of setting rates set forth in Article 7 of the Public Utilities Act (Act), Chapter 62 of the North Carolina General Statutes, and authorizes the setting of rates based on a multiyear projection of investments. Further, N.C.G.S. § 62-133.16 requires that an application for PBR include a decoupling ratemaking mechanism, one or more performance incentive mechanisms (PIMs), and a Multiyear Rate Plan (MYRP), including an earnings sharing mechanism (ESM) and proposed revenue requirements and base rates for each of the years that the MYRP is in effect. In conformance with N.C.G.S. § 62-133.16, the Commission adopted Commission Rule R1-17B to implement the requirements of the statute, including a preapplication technical conference on proposed transmission and distribution expenditures.

PROCEDURAL HISTORY

Technical Conference

On September 8, 2022, in Docket No. E-7, Sub 1276, pursuant to Commission Rule R1-17B(c), DEC filed a request to initiate a technical conference regarding projected transmission and distribution projects to be included in its contemplated application for a general rate adjustment.

On September 14, 2022, the Commission issued an Order Scheduling Technical Conference and Setting Procedures for Technical Conference. The Commission's Order established that the Technical Conference would be held in person on November 2, 2022; that DEC should make its Transmission and Distribution (T&D) Information Filing by October 19, 2022; that interested persons could file a petition to intervene in the proceeding and provide notice to the Commission of intent to participate on or before October 18, 2022; and that parties would be allowed to file written comments on DEC's T&D Information Filing on or before November 2, 2022.

By various orders, the Commission granted the intervention of CIGFUR, Haywood EMC, Blue Ridge EMC, Rutherford EMC, Piedmont EMC, NCSEA, NCJC et al., and CUCA. The intervention of the Public Staff – North Carolina Utilities Commission (Public Staff) is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e).

By letter, CIGFUR, the Public Staff, and NCJC et al., respectively, provided notice of their intent to participate in the Technical Conference.

On October 19, 2022, DEC filed its T&D Information Filing. Comments in response to DEC's T&D Informational Filing were filed by the Public Staff, CIGFUR, and NCJC, et al. on November 2, 2022.

On November 2, 2022, the Technical Conference was held before the Commission with Commissioner Kimberly W. Duffley, Presiding; Chair Charlotte A. Mitchell; and Commissioners ToNola D. Brown-Bland; Daniel G. Clodfelter; Jeffrey A. Hughes; Floyd B. McKissick, Jr.; and Karen M. Kemerait.

Application

On December 7, 2022, pursuant to Commission Rule R1-17(a), DEC filed notice of its intent to file a general rate case application that includes a PBR application as authorized under N.C.G.S. § 62-133.16.

On January 19, 2023, DEC filed its Application to Adjust Retail Rates and for PBR and Request for an Accounting Order (Rate Case and PBR Application or Application) pursuant to §§ 62-133, 62-133.16, 62-133.2, 62-134, and 62-135 of the North Carolina General Statutes and Commission Rules R1-17 and R1-17B. In support of the Application, DEC prefiled the direct testimony and exhibits of witnesses Kendal C. Bowman, North Carolina President for Duke Energy; Laura Bateman, Vice President of Carolinas Rates and Regulatory Strategy, and Phillip Stillman, Managing Director of Load Forecasting and Corporate Strategic Regulatory Initiatives, testifying jointly; Quynh Bowman, Rates & Regulatory Strategy Director; Jonathan Byrd, Managing Director of Rate Design and Regulatory Solutions; Steven Capps, Senior Vice President of Nuclear Operations for Duke Energy; Brent Guyton, Director of Asset Management in Customer Delivery; Janice Hager, an outside consultant and President of Hager Consulting; Bradley Harris, Manager, Rates and Regulatory Strategy; Tim Hill, Vice President, Coal Combustion Products Operations, Maintenance, and Governance; Retha Hunsicker, Vice President, Customer Experience Design and Solutions for Duke Energy Business Services, LLC (DEBS);[1] Brandon Lane, Vice President, Real Estate for DEBS; Justin LaRoche, Director of Renewable Development; Daniel Maley, Director, Transmission Compliance Coordination; Laurel Meeks, Director of Renewable Business Development, and Evan Shearer, Principal Integrated Planning Coordinator, testifying jointly as the “Battery Energy Storage Panel;” Dr. Roger Morin, an outside consultant and Principal of Utility Research International; Karl Newlin, Senior Vice President, Corporate Development and Treasurer; John Panizza, Director, Tax Operations for DEBS; Lesley Quick, Vice President of Customer Technology, Advocacy, Regulatory and Business Support within Customer Services for Duke Energy; Morgan Beveridge, Manager Rates and Regulatory Strategy; John Spanos, an outside consultant and President, Gannett Fleming Valuation and Rate Consultants, LLC; Nicholas Speros, Director of Accounting; Jacob Stewart, Director, Health and Wellness; Kathryn Taylor, Rates & Regulatory Strategy Manager; and Bryan Walsh, Vice President of Carolinas Gas Generation. Also, DEC filed supporting Rate Case Information Report Commission Form E-1 (Form E-1).

In summary, DEC requested in its Application and initial direct testimony and exhibits, a base rate increase of approximately $371.5 million, or 7.1%, in its annual

[1] DEBS provides various administrative and other services to DEC and other affiliated companies of Duke Energy.

electric sales, offset by a rate reduction of $10.4 million to refund certain tax benefits, for a net revenue increase of $361.1 million, or 6.9% from its North Carolina retail electric operations, including a rate of return on common equity of 10.4% and a capital structure consisting of 47.0% debt and 53.0% equity. DEC's Application and initial direct testimony and exhibits also sought approval of PBR and a series of rate increases based on DEC's proposed three-year MYRP, and other mechanisms required as part of PBR, with the first rate increase effective February 20, 2023. In addition to the base rate increase of $371.5 million, DEC sought increases to the revenue requirement of $139.8 million, $171.5 million, and $150.3 million in Rate Year 1, Rate Year 2, and Rate Year 3, respectively, for certain projected investments.

DEC submitted evidence in this case with respect to revenue, expenses, and rate base using a test period consisting of the 12 months ending on December 31, 2021, adjusted for certain known changes in revenue, expenses, and rate base through July 31, 2023.[2]

DEC, by its first supplemental direct testimony and exhibits, revised its requested base revenue requirement increase to approximately $434.5 million, offset by a rate reduction of $10.4 million to refund certain tax benefits, for a net revenue increase of $424.1 million, including an increase to the cost of debt to 4.50% based on the average embedded cost of debt financing as of April 30, 2023. DEC also revised its series of rate increases based on DEC's proposed three-year MYRP. DEC's updated MYRP revenue requirements were $165.8 million, $181.0 million, and $185.1 million in Rate Year 1, Rate Year 2, and Rate Year 3, respectively.

DEC, by its second supplemental direct testimony and exhibits, revised its requested base revenue requirement increase to approximately $440.3 million, offset by a rate reduction of $10.4 million to refund certain tax benefits, for a net revenue increase of $429.9 million including an increase to the cost of debt to 4.53% based on the average embedded cost of debt financing as of May 31, 2023. DEC also revised its series of rate increases based on DEC's proposed three-year MYRP. DEC's updated MYRP revenue requirements were $165.9 million, $181.2 million, and $185.3 million in Rate Year 1, Rate Year 2, and Rate Year 3, respectively.

DEC, by its third supplemental direct testimony and exhibits, revised its requested base revenue requirement increase to approximately $466.0 million, offset by a rate reduction of $10.4 million to refund certain tax benefits, for a net revenue increase of $455.6 million, including an increase to the cost of debt to 4.56% based on the average embedded cost of debt financing as of June 30, 2023. DEC also revised its series of rate increases based on DEC's proposed three-year MYRP. DEC's updated MYRP revenue

[2] DEC's Application initially proposed a capital cut-off date of July 31, 2023; however, upon further discussion and agreement with the Public Staff, the parties agreed to, and the Commission's Scheduling Order established, a capital cut-off date of June 30, 2023. The change in capital cut-off was reflected in DEC's supplemental filings.

requirements were \$162.6 million, \$180.0 million, and \$182.8 million in Rate Year 1, Rate Year 2, and Rate Year 3, respectively.

Additional Procedural History

On February 3, 2023, the Public Staff filed a letter in the docket addressed to DEC's counsel stating that it reviewed the Rate Case and PBR Application and determined that additional information was necessary to complete the filing as required by Commission Rule R1-17(f) (February 3, 2023 Public Staff Letter). On February 8, 2023, Duke filed a response to the February 3, 2023 Public Staff Letter stating that it had provided all of the documents expressly identified in the February 3, 2023 Public Staff Letter. DEC further stated that it "does not agree that its Application was incomplete or that the information identified by Public Staff is required under Commission Rule R1-17B(d)(2)j[;]" and also that "while [DEC] acknowledges this difference of opinion, it does not believe that the difference of opinion has any practical impact on this proceeding given that all of the documents requested by Public Staff have now been provided."

On February 16, 2023, the Commission issued an order declaring a general rate case pursuant to N.C.G.S. § 62-197, suspending DEC's proposed new rates for up to 300 days pursuant to N.C.G.S. § 62-133.16, and establishing a 2021 test year period (12-month period ending December 31, 2021).

On March 16, 2023, the Commission issued an order that established discovery guidelines; scheduled four in-person public witness hearings as well as a remote public witness hearing and required that DEC provide public notice thereof; scheduled an expert witness hearing to begin on Monday, August 21, 2023; established a capital cut-off period of June 30, 2023; and established deadlines for the intervention of interested parties and the filing of expert witness testimony (March 16, 2023 Procedural Order).

On April 14, 2023, the Commission issued an order that scheduled an additional remote public witness hearing and required that DEC provide public notice (April 14, 2023 Scheduling Order).

On May 17, 2023, DEC filed a motion requesting that Melissa B. Abernathy, Director of Rates & Regulatory Planning, be allowed to adopt Kathryn S. Taylor's direct testimony and exhibits prefiled with the Commission on January 19, 2023, in full (with the exception of the addition of Abernathy's Introduction section as indicated on page 2, line 1 through page 3, line 11 of the Taylor Direct Testimony). The Commission accepted the substitution by order dated May 25, 2023.

On May 19, 2023, DEC prefiled the supplemental direct testimony and exhibits of witnesses Abernathy; Bateman and Stillman, testifying jointly as the PBR Policy Panel; Beveridge; Q. Bowman; Capps; Guyton; Lane; Maley; the Battery Energy Storage Panel; Walsh; LaRoche; and Martin M. Strasburger, Vice President – Chief Security and Information Security Officer for Duke Energy Corporation (Duke Energy) (May 19, 2023 Supplemental Direct Testimony).

On May 23, 2023, the Commission issued an order that rescheduled the previously scheduled Durham public witness hearing and required that DEC provide public notice (May 23, 2023 Scheduling Order).

On June 15, 2023, DEC filed a motion requesting that Donna T. Council, Senior Vice President, Corporate Real Estate, Aviation, & Business Services for DEBS, be allowed to adopt Brandon Lane's direct testimony and exhibits prefiled with the Commission on January 19, 2023, and supplemental testimony and exhibits prefiled with the Commission on May 19, 2023, in full (with the exception of the addition of Donna T. Council's Introduction section as indicated on page 2, line 1 through page 3, line 19 of the Lane Direct Testimony and page 2, line 1 through line 9 of the Lane Supplemental Testimony). The Commission accepted the substitution by order dated June 28, 2023.

On June 19, 2023, DEC prefiled the second supplemental direct testimony and exhibits of witnesses Abernathy and Q. Bowman (June 19, 2023 Supplemental Direct Testimony).

On June 21, 2023, pursuant to the Commission's March 16, 2023 Procedural Order, DEC filed Affidavits of Publication for the Public Notice of Hearing on Rate Increase Application and stated that the Public Notice had been published in newspapers having general coverage in DEC's service territory. Further, DEC stated that it provided the Public Notice to its retail customers by direct mail starting April 10, 2023, and ending May 4, 2023, and that it posted the Public Notice on its website.

Also, on June 21, 2023, the Commission held a public hearing for the purpose of receiving public witness testimony on DEC's Rate Case and PBR Application at 7:00 p.m. at the Burke County Courthouse in Morganton, North Carolina.

On June 22, 2023, the Commission held a public hearing for the purpose of receiving public witness testimony on DEC's Rate Case and PBR Application at 7:00 p.m. at the Mecklenburg County Courthouse in Charlotte, North Carolina.

On June 28, 2023, pursuant to the Commission's April 14, 2023 Scheduling Order, DEC filed Affidavits of Publication for the Public Notice of Hearing on Rate Increase Application and stated that the Public Notice had been published in newspapers having general coverage in DEC's service territory.

On July 14, 2023, DEC filed a motion seeking to delay the expert witness hearing scheduled to commence on Monday, August 21, 2023, by seven days to Monday, August 28, 2023.

On July 18, 2023, DEC prefiled the additional supplemental direct testimony and exhibits, including the supplemental direct testimony and exhibit of witness Spanos; the second supplemental direct testimony and exhibits of witnesses Council, Walsh, LaRoche, and Maley; and the third supplemental direct testimony and exhibits of witnesses Q. Bowman and Abernathy (July 18, 2023 Supplemental Direct Testimony).

On July 19, 2023, intervenors prefiled expert witness testimony and exhibits, as further detailed below.

Also on July 19, 2023, the North Carolina Electric Membership Corporation (NCEMC) filed a petition with the Commission seeking to intervene in the above-captioned docket or, alternatively, seeking permission to file an amicus curiae brief, which was included with the July 19, 2023 Petition to Intervene. On August 23, 2023, the Commission issued an Order Denying Petition to Intervene of North Carolina Electric Membership Corporation and Allowing Amicus Curiae Status.

On July 24, 2023, the Commission held a public hearing for the purpose of receiving public witness testimony on DEC's Rate Case and PBR Application at 7:00 p.m. at the Forsyth County Courthouse in Winston-Salem, North Carolina.

On July 26, 2023, the Commission issued an order rescheduling the expert witness hearing then scheduled for Monday, August 21, 2023, to commence on Monday, August 28, 2023, and providing additional hearing procedures.

Also on July 26, 2023, the Commission held a remote public hearing for the purpose of receiving public witness testimony on DEC's Rate Case and PBR Application at 6:00 p.m. via Webex.

On July 31, 2023, the Commission held an additional remote public hearing for the purpose of receiving public witness testimony on DEC's Rate Case and PBR Application at 6:30 p.m. via Webex.

On August 1, 2023, the Public Staff filed a letter (August 1, 2023 Public Staff Letter) advising the Commission that its July 19, 2023 prefiled direct testimony incorporated (1) DEC's base case capital spending as presented in its Application; (2) DEC's updated capital spending through April 30, 2023, as presented by in its May 19, 2023 Supplemental Direct Testimony; and (3) DEC's MYRP request. The Public Staff further stated that it was undertaking an investigation and audit of: (1) DEC's updated capital spending through May 31, 2023, as presented in its June 19, 2023 Supplemental Direct Testimony; and (2) DEC's updated capital spending through June 30, 2023, as presented in its July 18, 2023 Supplemental Direct Testimony. The Public Staff noted that it was "undertaking its investigation and audit of DEC's May 2023 and June 2023 updates as expeditiously as possible," however, the Public Staff further explained:

> these updates comprise $350 million and $750 million of capital spend, respectively, for a total capital spend of $1.1 billion for those two months. The magnitude of this spend requires thorough diligence on the part of the Public Staff. Therefore, the Public Staff anticipates filing its supplemental testimony on the Company's May 2023 and June 2023 updates after the start of the hearing, which is scheduled to begin on Monday, August 28, 2023.

The Public Staff, therefore, hereby notifies the Commission, DEC, and other parties in this docket that it anticipates filing its supplemental testimony, addressing both the May 2023 and June 2023 updates, as soon as possible, but no sooner than the start of the hearing on August 28, 2023.

August 1, 2023 Public Staff Letter. The August 1, 2023 Public Staff Letter finally noted that all parties of record were being served with the letter.

On August 4, 2023, DEC prefiled the rebuttal testimony and exhibits of witnesses K. Bowman; Bateman and Stillman, testifying jointly as the PBR Policy Panel; Morin; outside consultant James M. Coyne, Senior Vice President, Concentric Energy Advisors, Inc.; K. Bowman, Quick, and Abernathy, testifying jointly as the COVID Panel; Kevin A. Murray, Vice President of the Project Management & Construction for DEBS; Maley; Guyton; Capps; Walsh; LaRoche; Meeks and Shearer, testifying jointly as the Battery Energy Storage Panel; Council; Stewart; Abernathy; Q. Bowman; Byrd and Beveridge, testifying jointly as the Rate Design Panel; Spanos; Speros; Quick; Newlin; Panizza; Bryan L. Sykes, Director of Rates and Regulatory Planning; Cynthia Klein, Director of Strategic Business Support for DEBS; and outside consultant Jeffrey T. Kopp, Senior Managing Director of the Energy & Utilities Consulting, Burns & McDonnell Engineering Company, Inc.

On August 7, 2023, DEC filed a Notice of Intent to Place Temporary Rates in Effect Subject to an Undertaking to Refund Pursuant to N.C.G.S. § 62-135 and Request for Expedited Approval of Notice and Undertaking which stated that DEC intended to exercise its statutory right to place into effect temporary rates pending a final order by the Commission approving permanent rates. DEC stated that its proposed temporary rates would be effective for services rendered on and after September 1, 2023. DEC further stated in the Notice that the temporary rates sought to be recovered, subject to refund, are based on and consistent with the base rate component as set forth in the July 18, 2023 Supplemental Direct Testimony. For purposes of temporary rates, DEC elected to implement 24.0% of that revenue requirement. Finally, DEC stated that its proposed temporary rates would be implemented subject to an Undertaking to Refund (Undertaking) and that by these rates, DEC would increase its current rates and charges by $46.6 million annually, which represents a temporary rate increase of 0.9%. By order dated August 14, 2023, the Commission accepted DEC's Undertaking and required that DEC provide notice to its customers. Further, the Commission required that DEC refund to customers any amount of temporary rates made effective on and after September 1, 2023, that are finally determined by the Commission to be excessive, plus up to 10.0% interest per annum. On August 18, 2023, DEC filed revised tariffs for implementing temporary rates.

On August 10, 2023, pursuant to the Commission's May 23, 2023 Scheduling Order, DEC filed Affidavits of Publication for the Public Notice of Hearing on Rate Increase Application and stated that the Public Notice had been published in newspapers having general coverage in DEC's service territory.

On August 14, 2023, pursuant to the Commission's March 16, 2023 Procedural Order DEC filed: (1) a list of witnesses to be called during the evidentiary hearing on this matter, the order of the witnesses, and each party's estimated time for cross-examination as gathered by the parties to this proceeding; and (2) a joint motion seeking to excuse DEC witnesses Hunsicker, Strasburger, LaRoche, and Commercial Group witness Chriss from attending the evidentiary hearing. By order dated August 23, 2023, the Commission excused witnesses Hunsicker, Strasburger, LaRoche, and Chriss from attending the evidentiary hearing. These witnesses' prefiled testimony and exhibits were accepted into the record during the course of the evidentiary hearing. Tr. vol. 12, 15.

Also on August 14, 2023, the Commission held a public hearing for the purpose of receiving public witness testimony on DEC's Rate Case and PBR Application at 7:00 p.m. at the Durham County Courthouse in Durham, North Carolina.

Between August 28, 2023, and September 5, 2023, the Commission conducted a hearing for the purpose of receiving expert witness testimony regarding DEC's Application in the above-captioned docket.

On October 11, 2023, parties filed proposed orders and post-hearing briefs.

As is discussed in further detail, infra, the Commission reconvened the evidentiary hearing on October 30, 2023, for the purpose of receiving supplemental testimony expert witness testimony and Commissioner-requested late-filed exhibits into the record.

Intervenors

In addition to the intervenors listed above, subsequent to the Technical Conference and by various orders, the Commission granted the intervention of the Commercial Group, the Sierra Club, Vote Solar, Kroger Co. and Harris Teeter, the Carolinas Clean Energy Business Association (CCEBA), Andale, NC WARN, and NCLM. The North Carolina Attorney General's Office (AGO) is afforded intervention as of right on behalf of the using and consuming public pursuant to N.C.G.S. § 62-20.

On July 19, 2023, intervenors prefiled direct testimony and exhibits as follows: the AGO prefiled the direct testimony and exhibits of witnesses Caroline Palmer, Manager, Strategen; Edward Burgess, Senior Director of Integrated Resource Planning with Strategen; and Nikhil Balakumar, Manager, Strategen; CIGFUR prefiled the direct testimony and exhibits of witness Brian C. Collins, Managing Principal with the firm of Brubaker & Associates, Inc. (BAI); the Commercial Group prefiled the direct testimony and exhibits of witness Steve W. Chriss, Senior Director, Utility Partnerships with Walmart Inc.; CUCA prefiled the direct testimony and exhibits of witnesses Billie S. LaConte, Associate Consultant at J. Pollock, Incorporated; Jeffry Pollock, President of J. Pollock, Incorporated; and David Lyons, Director of Energy of Gerdau and CUCA Chairman; Kroger Co. and Harris Teeter prefiled the direct testimony and exhibits of witness Justin Bieber, Principal for Energy Strategies, LLC; NC WARN prefiled the joint testimony of witnesses William E. Powers, P.E., Principal, Powers Engineering, and Rao Konidena, President, Rakon Energy, LLC; NCJC et al., prefiled the direct testimony and exhibits of witnesses Mark E. Ellis, economic and financial consultant; Genelle Wilson, Senior Associate at RMI; and the joint direct testimony and exhibits of witnesses David G. Hill, Managing Consultant at Energy Futures Group, Inc., and Jake Duncan, Southeast Regulatory Director for Vote Solar; NCSEA prefiled the direct testimony and exhibits of witness Lance D. Kaufman, Lance Kaufman Consulting; Sierra Club prefiled the direct testimony and exhibits of witness Michael Goggin, Vice President at Grid Strategies, LLC; and finally, the Public Staff prefiled the direct testimony and exhibits of witnesses James S. McLawhorn, Director of the Energy Division of the Public Staff; Fenge Zhang, Financial Manager – Electric Section with the Accounting Division of the Public Staff and Michelle Boswell, Director of Accounting for the Accounting Division of the Public Staff, testifying jointly; Roxie McCullar, Certified Depreciation Consultant with the firm of William Dunkel and Associates; Jay B. Lucas, Manager of the Rates and Energy Services Section in the Energy Division of the Public Staff; David M. Williamson, Engineer with the Energy Division of the Public Staff, and Jeff T. Thomas, Engineer with the Energy Division of the Public Staff, testifying jointly as the Public Staff PIMS Panel; David M. Williamson, Engineer with the Energy Division of the Public Staff; Jeff T. Thomas, Engineer with the Energy Division of the Public Staff; Blaise C. Michna, Engineer with the Energy Division of the Public Staff; Jordan A. Nader, Engineer with the Energy Division of the Public Staff; Christopher C. Walters, Associate with BAI; Evan D. Lawrence, Engineer with the Energy Division of the Public Staff; John W. Chiles, Principal in the Transmission Services Group at GDS Associates, Inc.; Tommy Williamson, Jr., Engineer with the Energy Division of the Public Staff; and Dustin R. Metz, Manager of the Electric Section – Operations and Planning in the Energy Division of the Public Staff.

Docket No. E-7, Sub 1134: DEC's Petition to Amend its Lincoln CT CPCN

On June 12, 2017, in Docket No. E-7, Sub 1134, DEC filed an application seeking a Certificate of Public Convenience and Necessity (CPCN) to construct and operate a generating plant for the production of electric power and energy at its existing Lincoln County Combustion Turbine (CT) site (Lincoln CT), located in Lincoln County near Stanley, North Carolina.

On December 7, 2017, pursuant to N.C.G.S. § 62-110.1, the Commission issued an order granting DEC a CPCN for the Lincoln CT with the condition that DEC will not seek cost recovery before the later of December 1, 2024, or the date by which DEC has taken care, custody, and control and placed the unit into commercial operation.

On May 19, 2023, DEC filed a petition to amend the Lincoln CT CPCN to seek cost recovery of the Lincoln CT through rates that will become effective on January 1, 2024. DEC further requested that the Commission consolidate the Lincoln CPCN proceeding with DEC's pending Rate Case and PBR Application.

On July 11, 2023, the Commission issued an order consolidating DEC's petition to amend its Lincoln CT CPCN in Docket No. E-7, Sub 1134 with DEC's Rate Case and PBR Application.

Stipulations

On September 12, 2022, pursuant to N.C.G.S. § 62-69, DEC, Duke Energy Progress, LLC (DEP), the Public Staff, CIGFUR, and Carolina Industrial Group for Fair Utility Rates II (CIGFUR II) filed the Agreement and Stipulation of Partial Settlement regarding the cost of service study (COSS) for consideration by the Commission in Docket Nos. E-2, Sub 1300 and E-7, Sub 1276 (COSS Stipulation). On September 13, 2022, a revision to the COSS Stipulation was filed by the aforementioned parties attaching exhibits which were inadvertently omitted from the version filed the previous day.

On April 27, 2023, DEC, DEP, and the Public Staff filed a Transmission Cost Allocation Agreement and Stipulation of Settlement (TCA Stipulation) for consideration by the Commission in Docket Nos. E-2, Sub 1300 and E-7, Sub 1276. On April 28, 2023, DEC and DEP prefiled the settlement testimony of witness Bateman to support the TCA Stipulation.

On May 4, 2023, DEC, DEP, the Public Staff, the Sierra Club, and NCJC et al. filed an Agreement and Stipulation of Partial Settlement Regarding Low-Income/Affordability Performance Incentive Mechanism and Affordability Issues (Affordability Stipulation) for consideration by the Commission in Docket Nos. E-2, Sub 1300 and E-7, Sub 1276. On May 16, 2023, DEC prefiled the settlement testimony of witnesses Conitsha B. Barnes, Harris, and Quick.

On August 22, 2023, DEC and the Public Staff filed an Agreement and Stipulation of Partial Settlement (Initial Revenue Requirement Settlement), which resolved a number of revenue requirement issues. Also on August 22, 2023, DEC, the Public Staff, and CIGFUR filed an Agreement and Stipulation of Settlement on Performance Incentive Mechanisms, Tracking Metrics and Decoupling Mechanism (PIMS Stipulation). Finally, also on August 22, 2023, DEC and CIGFUR filed an Agreement and Stipulation of Settlement (Power Quality Stipulation).

On August 24, 2023, in support of the PIMS Stipulation, the Public Staff prefiled the joint settlement support testimony of witnesses T. Williamson and D. Williamson and DEC prefiled the settlement support testimony and exhibits of its PBR Policy Panel. Also on August 24, 2023, DEC filed testimony in support of the August 22, 2023 Partial Revenue Requirement Settlement and the TCA Stipulation, including the testimony of witnesses K. Bowman, Abernathy, Beveridge, and Q. Bowman.

On August 25, 2023, DEC and CIGFUR filed an Agreement and Stipulation of Partial Settlement relating to certain industrial rate design issues (OPT-V-Primary Partial Rate Design Stipulation). Also on August 25, 2023, DEC, the Commercial Group, and Kroger Co. and Harris Teeter filed an Agreement and Stipulation of Partial Settlement relating to certain commercial rate design issues (OPT-V-Secondary Partial Rate Design Stipulation, collectively with the OPT-V-Primary Partial Rate Design Stipulation, the Rate Design Stipulations). Further on August 25, 2025, in support of the Rate Design Stipulations, DEC filed the settlement support testimony of its Rate Design Panel.

Relatedly, on August 28, 2023, CIGFUR filed supplemental direct testimony of its witness Collins in support of the OPT-V-Primary Partial Rate Design Stipulation.

On August 28, 2023, DEC and the Public Staff filed an Amended Agreement and Stipulation of Partial Settlement (Amended Revenue Requirement Stipulation), which resolved additional revenue requirement issues between those parties. DEC further filed supplemental settlement support testimony and exhibits of witnesses K. Bowman, Abernathy, Bateman, and Q. Bowman.

Finally, on October 13, 2023, DEC and the Public Staff filed a Supplemental Agreement and Stipulation of Partial Settlement (Supplemental Revenue Requirement Stipulation, collectively with the Initial Revenue Requirement Stipulation and the Amended Revenue Requirement Stipulation, the Revenue Requirement Stipulation), which resolved all issues with respect to the Public Staff's audit of DEC's May and June Supplemental updates. In support of the Supplemental Revenue Requirement Stipulation, DEC filed the settlement support testimony of witness Q. Bowman, and the Public Staff filed the joint settlement support testimony of witnesses Bowell, Zhang, and Metz.

The Commission permitted the parties to file supplemental post hearing briefs and proposed orders responsive to the October 13, 2023 supplemental filings on November 6, 2023.

Public Staff's Supplemental Testimony of Witness D. Williamson

On July 19, 2023, witness D. Williamson, in his prefiled direct testimony stated:

> [d]ue to the ongoing updating of plant-in-service, expenses, and revenues by the Company, the Public Staff cannot yet determine a revenue requirement, and thus I am unable to provide a recommendation regarding revenue apportionment at this time. I intend to file supplemental testimony that will illustrate various approaches to revenue apportionment based on the Public Staff's recommended revenue change as updated through April 2023. However, I note that the Company plans to file its final update through June 2023 on July 18, 2023, and the Public Staff will complete its review of this update and make any necessary additional filings, including jurisdictional and class assignment of the updated Public Staff recommended revenue change, as soon as possible. Moreover, until the Public Staff can provide a final revenue requirement in this case, any class revenue apportionment should be considered preliminary and for illustrative purposes only and should only be viewed as one of many possible approaches to apportioning revenue using the approximate revenue requirement determined by the Public Staff and based on available data at that time.

Tr. vol. 13, 43–44.

Between August 28, 2023, and September 5, 2023, the Commission conducted a hearing for the purpose of receiving expert witness testimony regarding the application of DEC in the above-captioned docket.

During the hearing, on August 29, 2023, counsel for the Public Staff advised the Commission of its intent to file supplemental testimony — including but not limited to the testimony of witness D. Williamson — pertaining to its investigation of DEC's May and June update filings by October 13, 2023. Tr. vol. 8, 14–15.

At the close of the evidentiary hearing, the Presiding Commissioner stated:

> it's my understanding that the Public Staff intends to file supplemental testimony and schedules . . . resolving DEC's May and June updates by October 13th, 2023. We will hold the record open for the purpose of receiving the late-filed exhibits that have been requested by the Commissioners and the supplemental testimony and schedules of the Public Staff on DEC's May and June updates. We will provide all of you with additional time to update your proposed Orders or provide supplemental proposed Orders on the items or matters addressed in the supplemental testimony.

Tr. vol. 16, 422–23.

On October 13, 2023, the Public Staff filed the supplemental testimony and exhibits of witness D. Williamson, which provided the Commission with the Public Staff's revenue requirement apportionment recommendation.

On October 17, 2023, Blue Ridge EMC, Haywood EMC, Piedmont EMC, and Rutherford EMC (collectively, Blue Ridge et al.), and CIGFUR filed a motion to strike the supplemental testimony of witness D. Williamson. On October 23, 2023, Blue Ridge et al. and CIGFUR filed a Second Joint Motion to Strike and Request for Relief. By orders dated October 23, 2023, and October 24, 2023, the Commission denied the motions to strike, but reconvened the hearing on October 30, 2023, for the purpose of allowing the parties an opportunity to cross-examine witness D. Williamson regarding his supplemental testimony and exhibits as well as to allow DEC to present the supplemental rebuttal testimony and exhibits of witnesses Byrd and Beveridge for the purpose of rebutting witness D. Williamson's supplemental testimony and exhibits. Further, the Commission permitted the parties to file supplemental post hearing briefs and proposed orders on November 6, 2023.

Whole Record

The Commission held public witness hearings as noted above. The following public witnesses appeared and testified:

Morganton:	Gray Jernigan.
Charlotte:	Billie Anderson, Janet Labar, David Julian, Beth Henry, Marcia Colson, Ronald Ross, June Blotnick, Nancy Carter, Maria Portone, Michelle Carr, Jessica Finkel, Juanita Miller, Nikita Williams, and Jerome Wagner.
Winston-Salem:	Debra Demske, Anne Garvey, Lei Zhang, Willie Penn, Paulette Smith, and Matthew Mayers.
Durham:	Kara Lynn Sanders, Anne Lazarides, Markus Joseph Kitsinger, Keval Khalsa, Donald Macon Nonini, Andrew Silver, Sherri Zann Rosenthal, Dale Evarts, Stacey Freeman, Zyad Habash, Eleanor Weston, Jennifer Griffith, Lib Hutchby, Martha Pentecost, Sally Jernigan-Smith, Felicia Wang, Carley Tucker, and Shawn Murphy.
Webex:	Dennis Testerman, Sophie Loeb, and Fotini G. Katsanos.

In summary, most public witnesses did not support DEC's proposed rate increase, but public witnesses did commend DEC's economic development efforts. *See generally,* tr. vol. 2–6. More specifically, public witnesses voiced concerns regarding the impact of the rate increase on those living on fixed incomes or experiencing poverty in the current economic environment. Public witnesses also testified regarding DEC's use of fossil fuels, including coal and natural gas power plants, and argued in support of increased renewables. Some public witnesses also voiced concerns regarding DEC's executive compensation. The Charlotte Regional Business Alliance testified that DEC's investments to provide reliable, affordable energy, and build utility infrastructure for businesses is nationally regarded, and that DEC has partnered with various universities, including Historically Black Colleges and Universities to intentionally develop a more diverse workforce and advance more diverse talent into strong leadership. Tr. vol. 2, 28–29.

In addition to the public witness testimony, the Commission received a number of consumer statements of position, all of which were filed in the docket. *See generally,* Docket No. E-7, Sub 1276CS. The public witness testimony and consumer statements of position have been considered by the Commission in its deliberations on DEC's Application.

The testimony and exhibits in this proceeding are voluminous. The Commission has carefully considered all the evidence and the record as a whole. However, the Commission has not attempted to recount every statement of every witness in this Order.

Rather, the Commission has summarized the evidence that is in the record. Likewise, while the Commission has read and fully considered the parties' post-hearing briefs, it has not in this Order attempted expressly to summarize or discuss every contention advanced or authority cited in the briefs.

JURISDICTION

No party has contested the fact that DEC is a public utility subject to the Commission's jurisdiction pursuant to the Public Utilities Act, Chapter 62 of the North Carolina General Statutes. The Commission concludes that it has personal jurisdiction over DEC and subject matter jurisdiction over the matters presented in DEC's Rate Case and PBR Application.

Based upon the foregoing and the entire record in this proceeding, the Commission makes the following

FINDINGS OF FACT

Stipulations

1. On August 22, 2023, DEC and the Public Staff filed the Initial Revenue Requirement Stipulation, which resolved a portion of the base period and MYRP revenue requirement issues in this proceeding. On August 28, 2023, DEC and the Public Staff filed the Amended Revenue Requirement Stipulation, resolving additional revenue requirement issues and leaving as unresolved only the following revenue requirement issues: (1) return on equity; (2) capital structure; and (3) recovery of COVID pandemic-related costs.

2. On September 13, 2022, DEC, DEP, the Public Staff, CIGFUR II, and CIGFUR III (COSS Stipulating Parties) filed the COSS Stipulation. The COSS Stipulation provides that DEC will first allocate production and transmission demand costs to the North Carolina retail jurisdiction using the 12 Coincident Peak (12 CP) method and will allocate production demand costs among the North Carolina retail rate classes using the Modified Average and Excess (Modified A&E) demand method.

3. On April 27, 2023, DEC, DEP, and the Public Staff filed the TCA Stipulation. The TCA Stipulation provides for a pro forma adjustment of approximately $20 million to increase the revenue requirement in the instant proceeding and to decrease the revenue requirement in DEP's rate case proceeding in Docket No. E-2, Sub 1300 (DEP Rate Case).

4. On August 22, 2023, DEC, the Public Staff, and CIGFUR filed the PIMs Stipulation.

5. On August 22, 2023, DEC and CIGFUR filed the Power Quality Stipulation.

6. On May 4, 2023, DEC, DEP, Sierra Club, NCJC, et al., and the Public Staff filed the Affordability Stipulation.

7. On August 25, 2023, DEC and CIGFUR filed the OPT-V-Primary Partial Rate Design Stipulation.

8. On August 25, 2023, DEC, the Commercial Group, and Kroger Co. and Harris Teeter filed the OPT-V-Secondary Partial Rate Design Stipulation.

9. On October 13, 2023, DEP and the Public Staff filed the Supplemental Revenue Requirement Stipulation.

10. The Initial Revenue Requirement Stipulation, the Amended Revenue Requirement Stipulation, the COSS Stipulation, the TCA Stipulation, the PIMs Stipulation, the Power Quality Stipulation, the Affordability Stipulation, the OPT--V--Primary Partial Rate Design Stipulation, the OPT-V-Secondary Partial Rate Design Stipulation, and the Supplemental Revenue Requirement Stipulation are the product of give-and-take settlement negotiations between the respective stipulating parties.

Depreciation

11. As amended by the Revenue Requirement Stipulation, the accelerated retirement dates for coal plants proposed by DEC, except for the Cliffside 5 retirement date which will move to January 1, 2031, and the Allen 1 and 5 retirement date which will move to December 31, 2023, consistent with the rebuttal testimony of DEC witness John Spanos filed on August 4, 2023, are reasonable.

12. The deferral of 75.0% of the impact of accelerating the depreciation of DEC's subcritical coal plants from the current retirement dates to a regulatory asset as agreed upon in the Revenue Requirement Stipulation is reasonable.

13. Any portion of net book value upon the retirement of DEC's subcritical coal-fired plants that will not be recovered through securitization will be recovered with a return over an amortization period to be determined by the Commission in a future rate case proceeding.

14. The corrected depreciation rates set forth by DEC in DEC witness Spanos' rebuttal testimony, subject to an adjustment to decommissioning estimates to use 10.0% contingency and a 5.0% indirect cost adder as agreed upon in the Revenue Requirement Stipulation, are reasonable.

Base Period Plant-Related Items

15. DEC's plant-related capital investments during the test year in its general/intangible, transmission, distribution, fossil/hydro, nuclear, solar, and storage

assets, as adjusted by the Revenue Requirement Stipulation, were prudently and reasonably made, and should be reflected in the revenue requirement.

Grid Improvement Plan Cost Recovery

16. Since DEC's last general rate case, DEC has deferred incremental operation and maintenance expense, depreciation and property taxes associated with its three-year grid improvement plan (GIP), as well as the carrying cost on the investment and the deferred costs at DEC's weighted average cost of capital.

17. DEC proposes to amortize the GIP deferral associated with its GIP investment over an amortization period of three years.

18. The Revenue Requirement Stipulation provides that DEC should be permitted to recover the full balance of its GIP deferral over an amortization period of 18 years, with a debt-only return during the deferral period and rate base treatment during the amortization period.

Coal Ash

19. DEC's request to amortize costs associated with its coal combustion residual (CCR) obligations incurred through June 30, 2023, over a five-year period and to continue the deferral of any CCR costs incurred subsequent to June 30, 2023, is reasonable.

Environmental Compliance Cost Recovery

20. Since DEC's last rate general rate case, DEC has deferred certain costs incurred in connection with compliance with federal and state environmental requirements as it related to CCRs.

21. DEC proposes to amortize $7.284 million of deferred environmental costs related to CCRs over an amortization period of six years which will result in an annual amortization expense of $1.214 million.

Storm Securitization Overcollections

22. Per DEC's Agreement and Stipulation of Partial Settlement with the Public Staff in Docket No. E-7, Sub 1243, DEC agreed to establish regulatory asset or regulatory liability accounts for the purpose of tracking up-front financing costs and servicing and administration fees related to storm securitization.

23. The amortization over three years of the regulatory liability for the over-recovered balance of $0.6 million for storm securitization over collections is just and reasonable.

Cost of Debt

24. The embedded cost of debt of 4.56% as set forth in Section III, Paragraph 1 of the Initial Revenue Requirement Stipulation is reasonable and appropriate for use by DEC in this case.

Accounting Adjustments in Revenue Requirement Stipulation

25. The accounting adjustments set forth in the Initial Revenue Requirement Stipulation, as further described in detail in Q. Bowman Supplemental Partial Settlement Exhibit 2, are the reasonable product of give-and-take negotiations among the parties. The accounting adjustments set forth in the Supplemental Revenue Requirement Stipulation, as further described in detail in Q. Bowman Supplemental Revenue Requirement Stipulation Exhibit 2 and the Public Staff Supplemental and Settlement Accounting Exhibit 1, Schedule 1, are the reasonable product of give-and-take negotiations among the parties.

Supplemental Revenue Requirement Stipulation

26. The accounting adjustments set forth in the Supplemental Revenue Requirement Stipulation are the reasonable product of give-and-take negotiations between the stipulating parties.

Nuclear PTC

27. The nuclear PTC rider agreed to in the Revenue Requirement Stipulation, as further described in DEC witness Bateman's settlement testimony, is the reasonable product of give-and-take negotiations among the parties.

Lead Lag Study

28. DEC agrees to perform a Lead Lag Study before the next general rate proceeding and incorporate the results in that general rate case application in accordance with Section IV of the Initial Revenue Requirement Stipulation.

MYRP Capital Investments

29. DEC's proposed MYRP capital investments, reflecting the projected costs associated with the transmission, distribution, fossil/hydro, nuclear, cybersecurity, solar, and storage, as adjusted in the Revenue Requirement Stipulation, are just and reasonable to all parties in light of the evidence the parties presented, consistent with statutory and regulatory requirements, and appropriate for approval as part of DEC's overall Application in this proceeding.

Reporting Requirements

30. The reporting obligations established in Section IV of the Initial Revenue Requirement Stipulation are just and reasonable.

31. DEC also agreed to provide certain information in its quarterly reliability reports filed in Docket No. E-100, Sub 138A.

Storm Normalization

32. The adjustment to DEC's revenue requirement, calculated using the method approved by the Commission in Docket No. E-7, Subs 1026, 1146, and 1214 to account for anticipated storm expenses based upon a ten-year average of storm costs after removing costs associated with major storms, is approximately $32.225 million.

Payment Navigator and Customer Connect

33. DEC has requested approval for its Payment Navigator program, which is designed to provide support to customers in need of assistance with managing payment of their electric bills, and the request is reasonable.

34. DEC has requested recovery of approximately $92 million associated with the implementation of the Customer Connect platform, which is DEC's customer engagement platform, and the Customer Information System (CIS).

COSS Stipulation

35. The COSS Stipulation between DEC, DEP, CIGFUR II, CIGFUR, and the Public Staff, requires DEC to allocate production demand and transmission demand costs by using the 12 CP allocation method for jurisdictional allocations and the Modified A&E method among North Carolina retail customer classes.

TCA Stipulation

36. The TCA Stipulation establishes a pro forma adjustment to increase the revenue requirement for DEC in the instant proceeding by approximately $20 million on a North Carolina retail basis as well as a corresponding decrease to the revenue requirement for DEP in the DEP Rate Case.

PIMs Stipulation

37. The PIMs Stipulation consists of the following three PIMs: Time Differentiated and Dynamic Rate Enrollment PIM, Reliability PIM, and the Renewables Integration and Encouragement PIM (consisting of Metrics A, B, and C) (collectively, the Settled PIMs). The PIMs Stipulation also provides for three tracking metrics — customer service, beneficial electrification from incremental load of electric vehicles (EVs), and

reporting and analyzing the ten worst performing circuits (collectively, the Settled Tracking Metrics) — and provides a process for DEC to work with the Public Staff to develop tariffs and programs to estimate and update revenue associated with EV sales.

Power Quality Stipulation

38. DEC and CIGFUR filed the Power Quality Stipulation, which contemplates the collaborative development of a proposal for the Commission to consider allowing DEC to analyze power quality issues.

Affordability Stipulation and Customer Assistance Program

39. On May 4, 2023, DEC, DEP, Sierra Club, NCJC, et al., and the Public Staff filed the Affordability Stipulation, pursuant to which DEC and DEP agreed to make shareholder financial contributions totaling $16 million over three years to benefit eligible customers.

40. The Affordability Stipulation supports the Customer Assistance Program (CAP) and the corresponding tariffs associated with the CAP.

Rate Design

41. The objective of DEC's proposed rate design is to recover the revenue requirement while aligning the cost to serve customers within the customer classes and reflecting the costs a customer causes DEC to incur. DEC's proposed rate design allocates the revenue increase between customer classes by rate base amounts.

42. DEC's rate design involves adjustments that are intended to achieve DEC's rate design objective, including a subsidy reduction, a customer migration adjustment, and customer growth and weather normalization adjustments.

43. DEC proposes changes to its residential rate schedules, general service rate schedules, industrial rate schedules, and lighting rate schedules.

44. DEC proposes changes to its service riders, which are offered to reflect the cost of meeting unique or special customer requirements.

45. DEC proposes updated and aligned time of use (TOU) periods across its rate schedules that include time-differentiated pricing for residential and non-residential customers.

46. The OPT-V-Secondary Partial Rate Design Stipulation, entered into by DEC, the Commercial Group, and Kroger Co. and Harris Teeter, provides that the proportion of total revenues recovered through demand charges for the Schedule OPT-V-Secondary sub-class will be increased by 5.0% (relative to current rates) in Rate Year 1 of the MYRP from 37.9% to 42.9%, with a corresponding revenue neutral decrease

to the proposed on-peak, off-peak, and discount energy charges. In Rate Years 2 and 3 of the MYRP, each of the demand and energy charges will be increased by an equal percentage in order to recover the target revenue requirement.

47. The OPT-V-Primary Partial Rate Design Stipulation, entered into by DEC and CIGFUR, provides that any increase in energy charges resulting from an increase in DEC's revenue requirement to be recovered from the OPT-V-Primary sub class, as determined by final Commission order, shall be limited to a percentage that is less than half of the approved overall increase percentage to the OPT-V-Primary, exclusive of any decrements for OPT-V-Primary. The OPT-V-Primary Partial Rate Design Stipulation also provides that DEC agrees to modify the Mid-Peak Demand tiers for the OPT-V-Primary sub-class from 1,000 kW/3,000 kW to 1,000 kW/5,000 kW to better align with the On-Peak Demand tier in the current OPT-V tariff. DEC will also adjust the Mid Peak Demand Charge prices within OPT-V-Primary to achieve similar pricing spreads between the first, second, and third demand tiers. Additionally, DEC agrees to adjust Transmission demand charge pricing in proposed Schedule HLF to achieve a similar pricing spread between voltage classes as compared to Schedule OPT-V, and DEC agrees to set the HLF energy charge equal to the unit cost for OPT-V Large sub-classes. Finally, DEC agrees to modify its proposed economic development rider (Rider ED) to strike the following words: "[T]he New Load shall exclude any curtailable, back-up, or standby service".

Capital Structure, Cost of Equity, and Overall Rate of Return

48. DEC proposed a rate of return on common equity of 10.4%, with a capital structure consisting of 53.0% common equity and 47.0% debt.

49. The overall rate of return and rate of return on common equity must be supported by competent, material, and substantial record evidence; consistent with the requirements of N.C.G.S. § 62-133 considering changing economic conditions; and must balance DEC's need to maintain the safety, adequacy, and reliability of its service with the benefits to DEC's customers to receive safe, adequate, and reliable electric service.

50. Ultimately, the capital structure, rate of return on common equity, and overall rate of return set by this Order must result in just and reasonable rates.

COVID Deferral Recovery

51. The Commission's December 21, 2021 Order in Docket Nos. E-2, Sub 1258 and E-7, Sub 1241 (Deferral Order) approved DEC's request to create a regulatory asset into which to defer incremental COVID pandemic-related costs.

52. In this proceeding, DEC seeks to recover the deferred balance, including accrued carrying costs, of approximately $183 million related to: (1) customer fees waived; (2) bad debt charge-offs; (3) employee stipends to cover unplanned expenses associated with the COVID pandemic; (4) costs related to employee safety; (5) costs related to remote work; and (6) miscellaneous costs, such as employee overtime.

53. DEC identified and calculated two categories of COVID-related savings in the amount of approximately $6.2 million on a North Carolina retail basis related to: (1) reduced printing and postage costs due to the moratorium on customer disconnections; and (2) reduced travel expenses.

54. DEC seeks to recover the deferred balance over a three-year period.

55. DEC requests to continue the deferral of the incremental bad debt for future recovery.

Storm Balancing Account

56. DEC proposed to create a storm balancing account. DEC agreed to withdraw its storm balancing account proposal as part of the Revenue Requirement Stipulation.

Other Deferrals

57. DEC requests to defer the estimated tax benefits, net of costs, associated with the Inflation Reduction Act (IRA) and Infrastructure Investment Job Act (IIJA).

58. DEC has proposed three customer programs for approval by the Commission: (1) the CAP; (2) the Payment Navigator Program; and (3) the Tariffed On-Bill Program.

59. DEC expects to incur incremental operations and maintenance (O&M) costs related to the implementation of the CAP, the Payment Navigator Program, and the Tariffed On-Bill Program, and implementation of the PIMs, including the required PIMs dashboard, and proposed to defer its incremental O&M costs associated with the implementation of the customer programs and PIMs. DEC agreed to withdraw its request to defer its incremental O&M costs associated with the implementation of the customer programs and PIMs as part of the Revenue Requirement Stipulation.

Interconnection CIAC Regulatory Liability Recommendation

60. With respect to DEC's recording of contributions in aid of construction (CIAC) in the context of interconnection agreements (IA) between DEC and third-party interconnection customers, the Public Staff identified an issue and proposed that a regulatory liability be established to record any instances in which DEC incorrectly recovered costs associated with IAs from ratepayers. In the Revenue Requirement Stipulation, DEC and the Public Staff agreed that DEC will not establish a regulatory liability at this time for CIAC.

Quality of Service

61. DEC and the Public Staff presented evidence indicating the adequacy of the electric service provided by DEC.

Tax-Related Items

62. DEC proposes a revision to its previously approved North Carolina excess deferred income taxes (EDIT) rider (EDIT-4 Rider) to reflect additional amounts due to customers.

63. The levelized return rate should reflect a 4.56% embedded cost of debt and the capital structure and rate of return on equity approved by the Commission in this proceeding.

Fuel Cost Voltage Differential

64. It is appropriate for DEC to incorporate fuel cost voltage differential for the prospective billing period fuel rates in DEC's next fuel proceeding to be filed in February 2024, and to remove line losses from base rates at that time.

Equal Percentage Allocation, Base Fuel and Fuel-Related Factors, and Fuel Cost Allocation

65. DEC proposes to continue its use of the equal percentage fuel adjustment allocation methodology.

66. DEC proposes to allocate purchased power capacity costs to North Carolina retail and across North Carolina retail customer classes based on production demand.

Residential Decoupling Mechanism and Earnings Sharing Mechanism

67. DEC's PBR Application includes a residential decoupling mechanism, a ratemaking mechanism intended to break the link between DEC's revenue and the level of consumption of electricity on a per customer basis by its residential customers, as required by N.C.G.S. § 62-133.16 and Commission Rule R1-17B.

68. DEC proposes as a component of the MYRP an ESM, an annual ratemaking mechanism that shares surplus earnings between DEC and its customers during the course of the MYRP, as required by N.C.G.S. § 62-133.16(c) and Commission Rule R1-17B.

Performance-Based Regulation

69. DEC filed its first PBR Application pursuant to N.C.G.S. § 62-133.16 and Commission Rule R1-17B.

Revenue Requirement

70. After giving effect to the portions of the stipulations approved herein and the Commission's decisions on contested issues, the annual revenue requirement for DEC for Rate Years 1, 2, and 3 will allow DEC a reasonable opportunity to recover its operating costs and earn the overall rate of return on its rate base that the Commission has found just and reasonable upon consideration of the findings in this Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-10

Stipulations

The evidence supporting these findings of fact is contained in DEC's verified Application and Form E-1; the stipulations between DEC and the other parties; the testimony and exhibits of DEC witnesses K. Bowman, Q. Bowman, Abernathy, Hager, Bateman, Stillman, Barnes, Harris, and Quick; Public Staff witnesses Zhang, Boswell, McLawhorn, D. Williamson, Thomas, and Metz; CIGFUR witness Collins; and the entire record in this proceeding.

Initial Revenue Requirement Stipulation and Amended Revenue Requirement Stipulation

On August 22, 2023, the Public Staff and DEC filed the Initial Revenue Requirement Stipulation resolving a portion of the revenue requirement issues between the parties. On August 28, 2023, DEC and the Public Staff amended the stipulation to resolve between themselves a substantial number of additional revenue requirement issues. As amended, the Revenue Requirement Stipulation identifies only three unresolved revenue requirement issues (return on equity, capital structure, and recovery of COVID pandemic costs) and one unresolved non-revenue requirement issue (equal percentage fuel adjustment allocation methodology).

DEC witness K. Bowman testified that the Revenue Requirement Stipulation resolves most of the revenue requirement issues between DEC and the Public Staff. Witness K. Bowman stated that the parties fully resolved the recovery of capital projects and related costs to be included in DEC's MYRP. Tr. vol. 7, 109. Witness K. Bowman also testified that the parties reached agreement on the inclusion of plant in service and depreciation rates and agreed to revenue requirement adjustments for the following items: cost of debt; executive compensation; Board of Directors expenses; the Duke Energy Plaza (Plaza); lobbying; sponsorships and donations; incentive compensation; reliability assurance O&M spend; vegetation management O&M; aviation expenses; non-residential credit card fees; end of life nuclear reserve; coal inventory; materials and supply inventory; executive compensation; extra facilities charge (EFC), nuclear levelization costs; production O&M; lighting audit, nuclear production tax credits; and the treatment of various deferrals DEC is requesting to recover. *Id.* at 104, 109. Witness K. Bowman further testified that certain other additional issues were resolved in a manner consistent with the Commission's August 18, 2023 Order Accepting Stipulations, Granting

Partial Rate Increases, and Requiring Public Notice in Docket E-2, Sub 1300 (DEP Rate Case Order), for purposes of settlement only, including: overamortization of regulatory assets, inflation adjustment, deferral of program implementation costs, CIAC regulatory liability recommendation, storm balancing account, and rate case expense. *Id.* at 108.

DEC witness K. Bowman explained that the Revenue Requirement Stipulation shows these accounting and ratemaking adjustments and the resulting effect on the revenue requirement. Witness K. Bowman also testified to DEC's commitment to perform a lead-lag study before its next rate case application and agreement to various reporting obligations. *Id.* at 104. Witness K. Bowman further testified that the Revenue Requirement Stipulation represents a balanced settlement between the stipulating parties on the settled issues, is in the public interest, and should be approved by the Commission. *Id.* at 103.

Sections III and IV of the Initial Revenue Requirement Stipulation and the Amended Revenue Requirement Stipulation outline several accounting and ratemaking adjustments, as well as reporting obligations, to which DEC and the Public Staff agree. The Commission fully discusses these agreed upon issues later in this Order.

COSS Stipulation

On September 13, 2022, the COSS Stipulating Parties filed the COSS Stipulation with the Commission in the instant proceeding and in the DEP Rate Case. Tr. vol. 12, 342. The Commission approved the COSS Stipulation in the DEP Rate Case Order. The COSS Stipulation provides that DEC will first allocate production and transmission demand costs to the North Carolina retail jurisdiction using the 12 CP method and then will allocate production demand costs among North Carolina retail customer classes using the Modified A&E method. *Id.* Because transmission demand does not have average or excess energy components, the transmission demand factors at the customer class level are equivalent to the 12 CP calculation. *Id.* The COSS Stipulation also provides that, for purposes of allocating production demand costs on a jurisdictional basis as well as to North Carolina retail rate classes, DEC will make an adjustment to exclude certain curtailable/interruptible loads if they were not curtailed at the 12 system peak hours during the test year. *Id.* The COSS Stipulation only applies in the current rate case, and the COSS Stipulating Parties are free to advocate for different methodologies in future DEC cases. *Id.* DEC witness Hager testified that the stipulation is reasonable and that the Commission should approve it, noting that it was the result of give-and-take negotiations of parties with diverse views on the appropriate methodologies reaching a settlement. *Id.* at 342–43.

TCA Stipulation

On April 27, 2023, DEC, DEP, and the Public Staff filed the TCA Stipulation in the instant proceeding and in the DEP Rate Case. The Commission approved the TCA Stipulation in the recent DEP Rate Case Order. The TCA Stipulation sets forth the agreement of the parties thereto to a pro forma adjustment of approximately $20 million to increase the revenue requirement in this proceeding and to decrease the revenue requirement in the DEP Rate Case.

The TCA Stipulation calculates a pro forma amount of transmission expense for DEC and transmission revenue for DEP by multiplying the net transfers from DEP to DEC which occurred in 2022 pursuant to the joint dispatch agreement (JDA)[3] by the DEP non-firm transmission rate established in the FERC-approved Joint Open Access Transmission Tariff (OATT) of DEC, DEP, and Duke Energy Florida, LLC (DEF).[4] The TCA Stipulation also provides that the adjustment is for North Carolina ratemaking purposes only and will not change the terms or conditions of the JDA or result in any accounting entries for DEC or DEP. The TCA Stipulation provides that the adjustment will become effective on October 31, 2023, for both DEP and DEC, and will terminate at the sooner of the effective date of rates in DEC's or DEP's next general rate case or the effective date of a full merger of DEC and DEP, unless the Commission orders otherwise.

DEC witness Bateman testified in support of the TCA Stipulation. Tr. vol. 11, 212. Witness Bateman explained that the TCA Stipulation is the result of substantial discovery and extensive negotiation among the stipulating parties and that it reflects a constructive near-term approach to addressing rate disparity concerns arising from the increasing net transfers of energy from DEP to DEC under the JDA. *Id.* at 214. Public Staff witness Metz also testified in support of the TCA Stipulation. Tr. vol. 12, 864–67. Witness Metz testified that the TCA Stipulation addresses the growing level of net transfers and the subsequent rate disparity between DEP and DEC in North Carolina and explained that the adjustment will compensate DEP and DEC ratepayers for the use and annual maintenance of each utility's transmission system for energy transfers under the JDA. *Id.*

PIMs Stipulation

On August 22, 2023, DEC, the Public Staff, and CIGFUR filed the PIMs Stipulation. The PIMs Stipulation reflects an agreement among the stipulating parties regarding certain of the PIMs, tracking metrics, and the EV adjustment to DEC's decoupling mechanism.

The PBR Policy Panel, consisting of DEC witnesses Bateman and Stillman, provided testimony in support of the PIMs Stipulation. Tr. vol. 11, 197. The PBR Policy Panel testified that the resolution reached among the stipulating parties represents a balanced approach to achieving policy goals in DEC's first PBR Application. *Id.* at 201. DEC witness Stillman testified that the Settled PIMs originated from the North Carolina

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[3] The JDA is the framework by which DEC and DEP manage and utilize their electric generation assets jointly to serve their respective retail customers with the most efficient generating plants available on a daily basis and was approved by the Commission as a part of the 2012 merger of Progress Energy, Inc., and Duke Energy. Order Approving Merger Subject to Regulatory Conditions and Code of Conduct, *Application of Duke Energy Corporation and Progress, Inc., to Engage in a Business Combination Transaction and to Address Regulatory Conditions and Codes of Conduct,* Nos. E-7, Sub 986, E-2, Sub 998, (N.C.U.C. June 30, 2012).

[4] DEC OATT Transmission Rate Formula Template Using Form 1-Data Utilizing Cost Data for (Historic Years) with Year-End Average Balances Development of Revenue Requirement OATT, p. 3 of 7 (328 of 1170); DEP OATT Transmission Non-Levelized Rate Formula Template Using Form-1 Data Development of Revenue Requirement, p. 3 of 5 (510 of 1170).

Energy Regulatory Process (NERP) PBR Working Group,[5] were informed by DEC's pre-filing PIM stakeholder process and evolved over discussions among the parties in the instant proceeding. *Id.* at 200. Witness Bateman testified that DEC took a conservative approach in this first PBR Application in order for DEC, the customers, and the Commission to gain experience with the operation and implementation of PIMs. Tr. vol. 11, 187. DEC witness Stillman explained DEC's approach to designing the PIMs around the 1.0% cap set forth in N.C.G.S. § 62-133 and stated that DEC was deliberate in choosing to propose only a select number of PIMs that meet the maximum number of policy goals. *Id.* at 271.

Public Staff witnesses D. Williamson and Thomas provided testimony in support of the PIMs Stipulation. Tr. vol. 14, 315–18. Witnesses D. Williamson and Thomas testified that the PIMs Stipulation benefits ratepayers by providing improved compliance with N.C.G.S. § 62-133 and that each PIM in the stipulation appropriately targets a specific policy goal set forth in N.C.G.S. § 62-133. *Id.* at 318. They further testified that the PIMs Stipulation will benefit ratepayers through improved operational efficiencies, cost savings, and reliability of electric service over the course of the MYRP. *Id.*

Power Quality Stipulation

On August 22, 2023, DEC and CIGFUR filed the Power Quality Stipulation. The Power Quality Stipulation provides that DEC and CIGFUR will collaborate to design a pilot program to install power quality monitoring technology at DEC-owned Transmission to Distribution retail substations or alternatively, another mutually agreed upon alternative in response to the power quality issues raised by CIGFUR in this docket. The Power Quality Stipulation states that DEC shall file a mutually agreed upon pilot power quality program for approval with the Commission within six months of the approval of the Power Quality Stipulation by the Commission.

In testimony supporting the Power Quality Stipulation, DEC witness Stillman testified that DEC and CIGFUR have agreed to collaborate on the development of a power quality equipment pilot and to meet and discuss DEC's potential reliability PIMs before DEC's next rate case. DEC witness Stillman explained that DEC and CIGFUR drafted the Power Quality Stipulation to be responsive to the concerns the Commission expressed in the DEP Rate Case Order. Tr. vol. 11, 210.

Affordability Stipulation

On May 4, 2023, DEC, DEP, Sierra Club, NCJC, et al., and the Public Staff filed the Affordability Stipulation. Tr. vol. 11, 74–75. The Affordability Stipulation obligates DEC to withdraw the affordability PIM proposed in this proceeding. *Id.* at 75. In lieu of the affordability PIM, $16 million of shareholder funds will be dedicated over the next three years to address affordability concerns as follows: $10 million will be contributed to

[5] The NERP was a stakeholder process to examine ways to align utility regulation with the 2019 Clean Energy Plan initiated by Governor Roy Cooper. Tr. vol. 11, 143.

support health and safety repairs that would allow for energy efficiency and weatherization upgrades to homes; and $6 million will be contributed to the Share the Light Fund, which offers customers bill payment assistance. *Id.* at 75–76. In addition, the stipulation obligates DEC to collect and report annually, in Docket No. M-100, Sub 179, the monthly payments ratio, which is the number of residential payments remitted divided by the number of active residential accounts. *Id.* at 76. Finally, the stipulation obligates DEC to establish its CAP as a three-year pilot program and convene a stakeholder engagement process to consider CAP data, metrics, and future CAP program features. *Id.* at 76–77.

OPT-V-Primary Partial Rate Design Stipulation

On August 25, 2023, DEC and CIGFUR filed the OPT-V-Primary Partial Rate Design Stipulation, which provides that any increase in energy charges resulting from an increase in DEC's revenue requirement to be recovered from the OPT-V-Primary sub-class, as determined by final Commission order, shall be limited to a percentage that is less than half of the approved overall increase percentage to OPT-V-Primary, exclusive of any decrements for OPT-V-Primary. The OPT-V-Primary Partial Rate Design Stipulation also provides that DEC agrees to modify the Mid-Peak Demand tiers for the OPT-V-Primary sub-class from 1,000 kW/3,000 kW to 1,000 kW/5,000 kW to better align with the On-Peak Demand tier in the current OPT-V tariff. DEC will also adjust the Mid-Peak Demand Charge prices within OPT-V-Primary to achieve similar pricing spreads between the first, second, and third demand tiers. Additionally, DEC agrees to adjust Transmission demand charge pricing in proposed Schedule HLF to achieve a similar pricing spread between voltage classes as compared to Schedule OPT-V, and DEC agrees to set the HLF energy charge equal to the unit cost for OPT-V Large sub-classes. Finally, DEC agrees to modify proposed Rider ED to strike the following words: "The New Load shall exclude any curtailable, back-up, or standby service."

OPT-V-Secondary Partial Rate Design Stipulation

On August 25, 2023, DEC, the Commercial Group, and Kroger Co. and Harris Teeter filed the OPT-V-Secondary Partial Rate Design Stipulation, which resolves some of the issues in this proceeding among the parties. The OPT-V-Secondary Partial Rate Design Stipulation provides that the proportion of total revenues recovered through demand charges for the Schedule OPT-V-Secondary sub-class will be increased by 5.0% (relative to current rates) in Rate Year 1 of the MYRP from 37.9% to 42.9%, with a corresponding revenue neutral decrease to the proposed on-peak, off-peak, and discount energy charges. In Rate Years 2 and 3 of the MYRP, each of the demand and energy charges will be increased by an equal percentage in order to recover the target revenue requirement.

Supplemental Revenue Requirement Stipulation

On October 13, 2023, DEC and the Public Staff filed the Supplemental Revenue Requirement Stipulation which resolves issues related to the Public Staff audit of DEC's third and fourth update. On that same date, the Public Staff filed the joint supplemental testimony of witnesses Metz, Zhang, and Boswell in support of the stipulation and DEC also filed testimony in support of the Supplemental Revenue Requirement Stipulation.

Discussion and Conclusions

Because not all parties to this docket have adopted the stipulations outlined above, the standards set out by the North Carolina Supreme Court in *State ex rel. Utilities. Commission v. Carolina Utilities Customers Association, Inc.* (*CUCA I*), 348 N.C. 452, 500 S.E.2d 693 (1998) and *State ex rel. Utilities Commission v. Carolina Utilities Customers Association, Inc.* (*CUCA II*), 351 N.C. 223, 524 S.E.2d 10 (2000) govern the Commission's acceptance of the stipulations. In *CUCA I*, the Supreme Court held:

> [A] stipulation entered into by less than all of the parties as to any facts or issues in a contested case proceeding under Chapter 62 should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding. The Commission must consider the nonunanimous stipulation along with all the evidence presented and any other facts the Commission finds relevant to the fair and just determination of the proceeding. The Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes "its own independent conclusion" supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented.

CUCA I, 348 N.C. at 466, 500 S.E.2d at 703.

However, as the Court made clear in *CUCA II*, the fact that not all parties have adopted a settlement does not permit the Court to subject the Commission's order adopting the provisions of a nonunanimous stipulation to a "heightened standard" of review. *CUCA II*, 351 N.C. at 231, 524 S.E.2d at 16. Rather, the Court said that Commission approval of the provisions of a nonunanimous stipulation:

> requires only that the Commission ma[k]e an independent determination supported by substantial evidence on the record [and] . . . satisf[y] the requirements of chapter 62 by independently considering and analyzing all the evidence and any other facts relevant to a determination that the proposal is just and reasonable to all parties.

Id. at 231–32, 524 S.E.2d at 16.

The Commission concludes that the Initial Revenue Requirement Stipulation and the Amended Revenue Requirement Stipulation, the COSS Stipulation, the TCA Stipulation, the PIMs Stipulation, the Power Quality Stipulation, the Affordability Stipulation, the OPT-V-Primary Partial Rate Design Stipulation, the OPT-V-Secondary Partial Rate Design Stipulation, and the Supplemental Revenue Requirement Stipulation result from the give-and-take negotiations between the stipulating parties and represent compromises that are fair and adequate to each party. The Commission has fully evaluated the provisions of these stipulations, the testimony proffered by parties in support of these stipulations cited above, and the dearth of evidence in the record opposing any of these stipulations, and concludes, exercising its independent judgment, that it should accept the stipulations, consistent with the specific discussion and resolution of the issues set forth later in this Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-14

Depreciation

The evidence supporting these findings of fact is contained in DEC's verified Application and Form E-1; the testimony and exhibits of DEC witnesses Spanos, Bateman, Q. Bowman, and Kopp, Public Staff witnesses Lucas and McCullar, NCSEA witness Kaufman; and the entire record in this proceeding.

Spanos Direct Exhibit 1 to DEC witness Spanos's direct testimony is the 2021 DEC Depreciation Study prepared by Gannett Fleming (2021 Depreciation Study). Tr. vol. 9, 188–89; Spanos Direct Ex. 1 (Tr. Ex. vol. 10). Witness Spanos testified that the purpose of the 2021 Depreciation Study was to estimate the most current annual depreciation accruals related to electric plant in service for ratemaking purposes and to determine appropriate average service lives and net salvage percentages for each plant account. *Id.* at 188. In supplemental testimony, DEC witness Spanos provided the Commission with an updated 2021 Depreciation Study. Tr. vol. 9, 225–26; Spanos Supp. Ex. 1 (Tr. Ex. vol. 10). The Updated Depreciation Study accounted for changes to the Lee facility, which was retired as of March 2022 but was not consistently reflected in the initially filed 2021 Depreciation Study presented as Spanos Direct Exhibit 1. *Id.* at 226. Witness Spanos also testified that the weighted net salvage calculation for the Lee facility was updated from -17% to -12% to reflect the more accurate expectation of decommissioning costs. *Id.* at 226–27. Additionally, witness Spanos testified that the updated testimony reflects the proper assignment of the accumulated depreciation to properly match utilization and recovery of assets. *Id.* at 227. Witness Spanos testified that the total depreciation impact for the change in steam production plant is an increase in annual depreciation expense of $11,619,514, which is related to all steam production plants. *Id.* Witness Spanos set forth in his rebuttal testimony the corrected calculation for other Production Plant as of December 31, 2021, and set forth the updated calculation for the Lee steam facility. *Id.* at 228; Spanos Supp. Ex. 1 (Tr. Ex. vol. 10).

Section III, Paragraph 2 of the Amended Revenue Requirement Stipulation provides that the Stipulating Parties agree to use DEC's proposed accelerated retirement dates for its coal plants to set depreciation rates, except for the Cliffside 5 retirement date. Amended Revenue Requirement III.2 (Tr. Ex. vol. 7). The Cliffside 5 retirement date will move to January 1, 2031, which is consistent with DEC's consolidated Carbon Plan and Integrated Resources Plan (CPIRP) filed on August 17, 2023. *Id.* Section III, Paragraph 3 of the Amended Revenue Requirement Stipulation provides that the Stipulating Parties also agree to increase DEC's proposed deferral to a regulatory asset from 50.0% to

75.0% of the impact of accelerating the depreciation of DEC's subcritical coal plants from the current retirement dates. *Id.* Section 5 of S.L. 2021-165 permits securitization of 50.0% of the remaining net book value of subcritical coal plants. The Amended Revenue Requirement Stipulation further provides that amounts not securitized will be recovered with a return over an amortization period to be determined by the Commission in a future rate case. *Id.* Finally, Section III, Paragraph 4 of the Amended Revenue Requirement Stipulation sets forth an agreement by the Stipulating Parties to use the corrected depreciation rates set forth in DEC witness Spanos's rebuttal testimony, subject to an adjustment to the decommissioning estimates to use a 10.0% contingency and a 5.0% indirect cost adder. *Id.*

Summary of Evidence

Retirement Dates for Coal Plants

DEC witness Spanos testified that life span estimates included in depreciation studies are based on informed judgment, incorporating factors for each facility such as facility technology, management plans and outlook for the facility, and estimates for similar facilities of other utilities. Tr. vol. 9, 194. Witness Spanos testified that he used these factors to evaluate DEC's recommended retirement dates and agreed that they were reasonable. *Id.* at 194–95. The 2021 Depreciation Study identified the following retirement dates for DEC's coal plants:

Unit	Probable Retirement Date
Allen 1	December 31, 2023
Allen 5	December 31, 2023
Belews Creek 1	December 31, 2035
Belews Creek 2	December 31, 2035
Cliffside 5	December 31, 2025
Cliffside 6	December 31, 2048
Marshall 1	December 31, 2028
Marshall 2	December 31, 2028
Marshall 3	December 31, 2032
Marshall 4	December 31, 2032

Spanos Supp. Ex. 1 (Tr. Ex. vol. 10).

Witness Spanos testified that since the last approved depreciation rates in DEC's previous rate case, the life spans for the Allen Units were shortened from 2026 to 2023; the Marshall Units were shortened from 2034 to 2028 or 2032; Belews Creek Units were shortened from 2037 to 2035; and Cliffside Unit 5 was shortened from 2032 to 2025. *Id.* at 194–95. Witness Spanos agreed that the new life spans for the units are reasonable and consistent with both DEC's plans as well as industry expectations. *Id.*

In connection with these coal retirement dates, DEC witness Q. Bowman testified that DEC was requesting approval to defer to a regulatory asset 50.0% of the impact of accelerated depreciation for sub-critical coal plants. Tr. vol. 12, 190. Witness Q. Bowman testified that S.L. 2021-165 allows DEC to securitize 50.0% of the remaining net book value of the plants at retirement, and DEC wants customers to benefit from the savings that could potentially be provided through securitization. *Id.* at 190–91. Accordingly, witness Q. Bowman testified that DEC seeks to defer to that regulatory asset 50.0% of the incremental depreciation expense for North Carolina retail customers resulting from the accelerated retirement dates for these coal units in the 2021 Depreciation Study. *Id.* Additionally, witness Q. Bowman testified that DEC seeks permission to defer to this regulatory asset any costs related to obsolete inventory, net of salvage, at the time of retirement. *Id.*

Public Staff witnesses Lucas and McCullar both addressed coal plant retirements and life spans in their testimony. In his direct testimony, witness Lucas recommended using retirement dates from DEC's 2018 Integrated Resource Plan, filed in Docket No. E-100, Sub 157, with the exception of Allen Units 1 and 5. Tr. vol. 13, 126. Witness Lucas testified that he does not dispute the retirement dates established in the Commission's initial Carbon Plan order. Instead, witness Lucas testified that his recommended retirement dates are based on issues of cost and reliability. *Id.* Witness Lucas further testified that if DEC can accelerate depreciation before retirement, customers will not only pay more in the near-term but also that the plants will have less value to securitize in the long-term, thereby muting the benefit of securitization to ratepayers. *Id*. Witness Lucas also testified that Session Law 2021-165 and Commission Rule R8-74 allow securitization of remaining plant value. *Id.* at 128. Witness Lucas further testified that delaying retirement of the dual fuel optionality (DFO) plants will allow for greater use of DFO capital investment. *Id.*

For Allen Units 1 and 5, witness Lucas recommended that for ratemaking purposes only (rather than planning purposes), the Commission keep DEC's retirement date of December 31, 2023, to allow DEC to eliminate fixed O&M expenses for these units. Accordingly, witness Lucas recommended the Commission exclude rate recovery of $7,392,797 after December 31, 2023. *Id.* at 129.

Public Staff witness McCullar proposed depreciation rates based on the final coal plant retirement years provided by witness Lucas. Tr. vol. 15, 224, 231.

NCSEA witness Kaufman did not propose alternative retirement dates from those proposed by DEC, but instead recommended that the Commission authorize a deferral of 50.0% of DEC's return on rate base associated with subcritical coal-fired electric generating facilities to be retired early and 50.0% depreciation expense associated with coal-fired electric plants. Tr. vol. 15, 1158. Witness Kaufman testified that in his view, the total benefits of DEC securitizing early rather than after retirement would save approximately $99 million over ten years. *Id.* at 1160–61. Further, witness Kaufman testified that deferring 50.0% of DEC's return on rate base will preserve the Commission's ability to disallow recovery on any cost of capital expense that exceeds the amounts DEC would have incurred had it securitized early. *Id.* at 1164.

In rebuttal, DEC witness Spanos testified that Public Staff witnesses McCullar and Lucas's proposed retirement dates are longer and not consistent with DEC's plans. Tr. vol. 9, 231. Witness Spanos testified that many other DEC coal-fired power plants either have been or are planned to be retired with life spans of around 40-45 years and that the proposed life spans of DEC's plants are consistent with those of other utilities. *Id.* at 233. Witness Spanos testified that the retirement dates for the coal-fired plants are consistent with informed judgment based on each unit and the expectation within the industry. *Id.* at 233. Witness Q. Bowman testified that DEC also proposes, for ratemaking purposes only, to set customer rates in this proceeding as if the coal plant retirement dates were extended for 50.0% of the plant balances. Tr. vol. 15, 1284. Thus, DEC and the Public Staff are partially aligned in principle but not aligned in methodology. *Id.* DEC believes the depreciation rates at the system level should be set based on the actual planned retirement dates, and that deferrals and regulatory assets should be used thereafter for jurisdictionally specific ratemaking purposes. *Id.* Witness Q. Bowman testified that the methodology is particularly important because securitization of the coal plant balances, which witness Lucas states as a significant reason for his recommendation, is only available for DEC's North Carolina retail jurisdiction. *Id.* Witness Q. Bowman testified, therefore, that deferral and regulatory assets are a more appropriate way to accomplish the effect that witness Lucas is proposing. *Id.* In addition, witness Q. Bowman explained that the retirement dates from DEC's 2018 Integrated Resource Plan utilized by witness Lucas are not reflective of what is included in current customer rates based on DEC's last rate case in Docket No. E-7, Sub 1214, and use of those dates is inappropriate. *Id.* at 1284–85. Finally, witness Q. Bowman explained that S.L. 2021-165 only permits securitization for 50.0% of the remaining net book value for subcritical coal plants, and, therefore, that it is only appropriate to apply this proposed ratemaking treatment to 50.0% of the plant balances. *Id.* at 1285.

Witness Bateman explained that witness Kaufman's proposal has no basis in HB 951's language authorizing securitization of the remaining net book value of early retired subcritical coal generating facilities. Tr. vol. 16, 268. Witness Bateman also explained it would be inappropriate to have current customers, who are benefitting from coal plant generation, not pay the cost for that generation. *Id.* Finally, she noted that witness Kaufman was unable to provide any examples of where his proposal has been implemented. *Id.*

Net Salvage

DEC witness Spanos testified that net salvage is the salvage value received for an asset upon retirement, less the cost to retire or remove the asset. Tr. vol. 9, 196–97, 234. Witness Spanos testified that net salvage must be incorporated in depreciation, as it represents the future cost that is expected to be incurred by DEC. *Id.* at 236. Witness Spanos testified that this calculation approach is consistent with the Uniform System of Accounts (USOA) as well as positions expressed by the National Association of

Regulatory Utility Commissioners (NARUC). *Id.* at 236–38. Witness Spanos testified that the net salvage percentages estimated in DEC's 2021 Depreciation Study were based on informed judgment that incorporated factors such as the statistical analyses of historical net salvage data, information provided by DEC's operating personnel and general knowledge and experience of industry practices, and general industry trends. *Id.*

Regarding net salvage, the parties presented three main topics of disagreement: (1) decommissioning costs (including indirect costs and asbestos); (2) contingency; and (3) escalation of decommissioning costs.

Specific Decommissioning Study Recommendations

A. Indirect Costs

In its Decommissioning Study, DEC included a 10.0% adder for project indirect costs. Public Staff witness Lucas recommended that a 5.0% adder be used instead. Tr. vol. 13, 121. Witness Lucas testified that the previous study filed in DEC's 2019 Rate Case properly used a 5.0% adder, and that DEC only stated that its proposed 10.0% adder was to account for the increase in costs attributable to market conditions. *Id.* Witness Lucas testified that the Decommissioning Study contains a subtotal for dismantlement and environmental costs that is already adjusted for market conditions; thus, an increase in the project indirect percentage amounts to a double counting of these costs. *Id.*

In rebuttal, DEC witness Kopp testified that DEC does have subtotals in decommissioning costs for dismantlement and environmental that are adjusted for market conditions. Tr. vol. 12, 425. However, witness Kopp further testified that those only reflect the costs and market conditions for the direct costs incurred for each of those subtotals, and project indirect costs include a separate set of cost items. *Id.* This separate set of cost items include those costs expected to be incurred by DEC during the dismantlement process that are in addition to the direct costs paid to demolition contractors, such as obtaining permits, construction services such as water and electricity, security labor and facilities, site vehicles, procurement services, legal services, and environmental monitoring. *Id.* at 425–26. Witness Kopp further testified that a minimum of 5.0% indirect costs is typically used on decommissioning cost estimates, but that this is simply the starting point. *Id.* at 426. If the project owner (here, DEC) has insights or experience into expected indirect costs, that input would be taken into consideration. *Id.* For the previous study, DEC did not provide any guidance to change the minimum 5.0% assumption. *Id.* However, since the time of the previous decommissioning study, DEC has decommissioned several power generating facilities, and based on that experience, DEC reported that indirect costs were approximately 11.0% of the direct costs. *Id.* at 426–27. Thus, witness Kopp testifies that a 10.0% indirect cost was a more accurate representation of expected costs. *Id.*

B. Asbestos

Public Staff witness Lucas recommends that the Commission disallow asbestos removal costs for the Bad Creek and Bridgewater hydroelectric plants. Tr. vol. 13, 119–20. The Bad Creek plant was built in the late 1980s and early 1990s, while Bridgewater was completely dismantled and rebuilt in 2010 and 2011. *Id.* Accordingly, witness Lucas testifies that neither plant should contain asbestos because the dangers of asbestos were well known before either plant was built. *Id.* at 120.

Further, witness Lucas notes that the asbestos removal cost for the 99 Islands hydro plant is a 73.0% increase over DEC's previous decommissioning study and recommends that this increase be limited to 16.0%, which is the average increase for asbestos removal at other hydro plants. *Id.*

In rebuttal, DEC witness Spanos testified that witness Lucas fails to properly consider that although Bad Creek went into service in 1991, there were many assets that were part of the initial project in 1977. Tr. vol. 9, 240. DEC witness Kopp also noted that exploration and construction occurred throughout the late 1970s and into the 1980s, with some structures constructed in the early 1980s. Tr. vol. 12, 422. Asbestos-containing materials were still used in construction during this time, and therefore, those assets from before 1986 could have asbestos. *Id.*; tr. vol. 9, 240. Similarly, witness Spanos testified that the Bridgewater hydro facility, while rebuilt in the 2011-2012 timeframe, still maintains some assets from the original plant that were built many years before 1986. Tr. vol. 9, 240; tr. vol. 12, 422–23. Witness Spanos testified that these older assets need to be considered when establishing a decommissioning study. Tr. vol. 9, 240. Witness Kopp testified that the proper removal and disposal of asbestos will be required during decommissioning, so those costs should be included. Tr. vol. 12, 423.

Regarding 99 Islands, witness Kopp testified that some areas that are likely to contain asbestos were not included in the prior decommissioning study. Tr. vol. 12, 424. In addition to the changes in market conditions since the previous study, the quantity of asbestos materials was increased in the current study, reflecting increased asbestos removal and disposal costs at this plant compared to others. *Id.* Witness Kopp noted that witness Lucas provided no support for his recommended percentage, other than applying an average. *Id.*

C. Contingency

DEC's Decommissioning Study includes a 20.0% adder for contingency. Speros Direct Ex. 3 (Tr. Ex. vol. 12). Witness Lucas testified that the Commission approved a 10.0% contingency in its 2017 Rate Case Order.[6] Tr. vol. 13, 121. Witness Lucas further testified that a 20% contingency as proposed by DEC in this case would require

[6] Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, *Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-7, Sub 1146, at 49-50 (N.C.U.C. June 22, 2018) (2017 Rate Case Order).

ratepayers to pay an additional amount for unknown future risks far in advance of when DEC will incur the costs. *Id.* at 122. Accordingly, the Public Staff recommended a 10.0% contingency factor, consistent with the Commission's 2017 Rate Case Order.

In rebuttal, witness Spanos testified that contingency costs are a standard component of decommissioning studies. Tr. Vol. 9, 242. Witness Spanos noted that standard decommissioning studies support a 20.0% contingency factor. *Id.* Witness Spanos also noted that a 10.0% contingency was agreed upon in the previous case, but this was to be reviewed again if an updated decommissioning study was performed. *Id.* Finally, given that contingencies have approached or exceeded 20.0% in many instances in recent years, witness Spanos testified that 20.0% is more appropriate. Witness Kopp also noted that the Decommissioning Study's 20.0% contingency is well-informed by experience. Tr. vol. 12, 429. Witness Kopp testified that decommissioning involves a greater level of unknowns than new construction, and that it is reasonable to expect that the scope of decommissioning can change once actually executed, which would result in cost increases. *Id.* at 431–32. Witness Kopp testified that contingency estimates could be developed with enough accuracy and precision such that a smaller amount of contingency would be reasonable; however, he testified that the cost at which those detailed estimates are derived can be prohibitive, as it is unreasonable to perform exhaustive investigations during the study phase. *Id.* at 433–34. Witness Kopp testified that DEC's decommissioning estimates are reasonable and accurate for the purpose of determining depreciation rates. *Id.* at 434.

D. Escalation of Decommissioning Costs

NCSEA witness Kaufman recommended that decommissioning costs not be escalated when calculating net salvage values. Tr. vol. 15, 1168. Witness Kaufman testified that this practice is unnecessary, is not performed in many depreciation studies, and would result in an excess assignment of decommissioning costs to current customers. *Id.* at 1168–69. Witness Kaufman also noted that these costs are uncertain. *Id.* at 1169. Based on this, witness Kaufman testified that net salvage rates be calculated using original decommissioning costs. *Id.* at 1170.

In rebuttal, witness Spanos explained that witness Kaufman's proposal does not properly reflect the definition of depreciation. Tr. vol. 9, 243. Witness Spanos testified that the total service value, which includes the cost to remove and to decommission, must include costs at the time of retirement. Witness Spanos testified that thus, escalating decommissioning costs, which are in 2022, dollars to the date of retirement for each generating unit matches the concept of depreciation. *Id.* Finally, witness Spanos noted that this approach meets USOA and NARUC definitions of depreciation, which provides that customers should pay through depreciation expense an appropriate share of the terminal costs of removing the asset. *Id.* As such, witness Spanos testified that inflation is a component that authoritative texts recognize as needing to be recovered and built into the overall cost or service value of the asset. *Id.* at 286–87. Additionally, witness Spanos explained that witness Kaufman failed to consider the fact that these assets will be retired in the future and that costs would be as of the date of retirement, which is the definition of "depreciation." *Id.* at 280–81. Witness Spanos further explained that witness Kaufman fails to consider the intergenerational inequities caused by his recommendation or his recommendations' failure to recover cost systematically and rationally. *Id.* at 281. Witness Spanos further explained that over his 37-year career, there have only been rare exceptions, primarily for unique jurisdictional reasons, that escalating decommissioning cost has not been performed as part of a depreciation study that he has conducted. Tr. vol. 10, 70–73.

Net Salvage for Mass Property Accounts

Both the Public Staff and NCSEA propose different net salvage estimates for some accounts. Public Staff witness McCullar and NCSEA witness Kaufman both propose a different net salvage estimate for transmission plant Account 356. Additionally, witness Kaufman proposes different net salvage estimates for distribution Account 373 and general plant Accounts 390, 392, and 396.

Account 356

In DEC's Depreciation Study, DEC proposes a -40.0% net salvage percentage for Account 356 — Overhead Conductors and Devices. In contrast, Public Staff witness McCullar proposes a -30.0% net salvage percentage. Tr. vol. 15, 233. Witness McCullar testified that this is more reasonable than DEC's proposed figures because the Public Staff's estimated future net salvage percentages do not result in an under-recovery of the estimated future costs. *Id.* at 239.

NCSEA witness Kaufman recommended a -31.0% net salvage estimate for Account 356, which is based on a 20-year average of the statistical data, rather than the -40.0% proposed in the 2021 Depreciation Study. *Id.* at 1171.

In rebuttal, witness Spanos testified that neither witness McCullar nor witness Kaufman considers why the cost of removal (COR) is so low for most accounts in the last few years. Tr. vol. 9, 267. Witness Spanos testified that the COR and gross salvage are not always booked/recorded at the same time as the associated retirement. *Id.* Witness Spanos testified that the COR of the associated retirements are not time synchronized. *Id.* As such, witness Spanos testified that witness McCullar's net salvage methodology does not properly assess the true levels of COR. *Id.* Furthermore, witness Spanos notes that the texts cited by witness McCullar support the methodology he uses for DEC's depreciation study. *Id.* at 270. Witness Spanos testified that witness Kaufman's use of a 20-year statistical average fails to consider the proper COR amounts to the associated retirement amounts. *Id.* at 267.

Accounts 373, 390, 392, and 396

For Account 373 — Street Lighting and Account 390 — Structures and Improvements, DEC proposed a -10.0% net salvage rate. For Account 392 — Transportation Equipment and Account 396 — Power Operated Equipment, DEC proposed a 10.0% net salvage rate. NCSEA witness Kaufman recommends using a 20-year average net salvage cost for these accounts. Tr. vol. 15, 1170–71.

In rebuttal, DEC witness Spanos testified that witness Kaufman conducted a 20-year average analysis without looking over the data available to analyze. Tr. vol. 9, 270–71. For Accounts 373 and 390, witness Spanos explained that the most recent data and the overall trend, even when accounting for data from an anomaly year, strongly supports the use of a -10.0% net salvage rate. *Id.* at 271–72. For Accounts 392 and 396, witness Spanos reiterated that it is critical to review the data in order to understand the estimate that is most appropriate for future recovery. *Id.* at 272. Witness Spanos testified that a 10.0% rate is much more likely to be recorded into the future for these accounts.

Other Depreciation Recommendations

Interim Net Salvage Percentage for Steam and Other Production Accounts

NCSEA witness Kaufman proposes a -15.0% interim net salvage rate for steam assets, a 35.0% interim net salvage rate for Other Production assets except Account 343.10, and a 49.0% for Account 343.10. Tr. vol. 15, 1171. DEC recommends -18.0%, -5.0%, and 40.0%, respectively. Tr. vol. 9, 264–65.

Witness Spanos testified that the overall net salvage for most accounts exceeds -15 percent. *Id*. at 265. Further, witness Spanos notes that for the past five years, the net salvage for all steam assets exceeds 20.0%, and for some accounts exceeds 50.0%. *Id.* For Other Production accounts, the data shows that -5.0% is most appropriate except for Account 343.10. *Id.* Thus, witness Spanos testifies that it is unrealistic to expect over the full life cycle of these asset classes that a 35.0% rate will be recorded, as witness Kaufman proposes. *Id.* Finally, for Account 343.10, witness Spanos testified that the high levels of positive salvage relate only to the first stage of rotable part replacements; this salvage rate will not continue in later stages, so increasing salvage values as assets age is unreasonable. *Id.*

Mass Property Service Lives — Survivor Curves

Witness Spanos testified that a mass property account is typically a group of assets for which there will be a range of service lives. Tr. vol. 9, 243. Service lives of these accounts use survivor curves, which provide an estimate of both an average service life and a dispersion of lives or retirements around the average. *Id.* at 244. NCSEA proposes changes to the survivor curves included in the 2021 Depreciation Study for Other Production Account 344.66 — Generators — Solar; transmission Account 354.00 — Towers and Fixtures; distribution accounts 368 — Line Transformers, 368.1 Line Transformers — Storm Securitization, and 369 — Services; and all the Land Rights and Rights of Way accounts. Tr. vol. 15, 1173.

Witness Spanos explained that the primary difference between his analysis and witness Kaufman's analysis in determining the appropriate survivor curves is the understanding of the accounts and the assets within the accounts. Tr. vol. 10, 73. Witness Spanos explained that fieldwork is key to understanding the nature of the account. *Id.* Witness Spanos testified that furthermore, survivor curves are more than a mathematical matching of points; they also involve projecting what future occurrences and how the assets in the account are changing. *Id.*

Account 344.66

Witness Kaufman proposed an alternative survivor curve of 30-S3 for small community solar assets and utility scale solar assets when calculating the expected remaining life for Account 344.66 — Solar Generators. Tr. vol. 15, 1173. Witness Kaufman testified that the 30-S3 curve is the best fitting curve for this distribution and provides a reasonable fit for DEC's actual retirement data. *Id.* at 1173–74. Further, witness Kaufman testified that DEC's proposed retirement curve is 20-S2.5 for community solar facilities and 25-S2.5 for all other solar facilities, which is an unreasonably high level of expected retirement relative to industry expectations. *Id.* at 1174.

In rebuttal, witness Spanos testified that he recommends a 20-S2.5 survivor curve for community solar assets and a 25-S2.5 survivor curve for utility scale solar assets. Tr. vol. 9, 254. Witness Spanos testified that the 20-S2.5 survivor curve and 25-S2.5 survivor curve estimate a maximum life for solar assets in Account 344.66 will be 35 and 45 years respectively. *Id.* Further, witness Spanos testified that there are more causes of retirement than degradation of solar panels and the life characteristics of the related assets — such as the inverters, electronic controls, and framing — have an impact. *Id.* Additionally, witness Spanos testified that the capabilities of the solar sites to store energy, the required upgrades, and wear of the elements will affect the ages. *Id.* In his testimony, witness Spanos reiterated that the process for estimating service lives is based on informed judgment that incorporates a number of factors, including the statistical analysis of historical data. *Id.* at 244. Witness Spanos further testified that the original life tables provide an indication of the percentage of assets that have historically survived to each age for which data is available. *Id.* at 245.

Account 354

In his direct testimony, witness Kaufman proposed that an alternative survivor curve of 75-R2.5 be used when calculating the expected remaining life for Account 354 — Towers and Fixtures. Tr. vol. 15, 1175–76. Witness Kaufman testified that DEC's proposed survivor curve is unreasonable because the older ages of DEC's historic survivor curve represent less than 0.2% of first year exposures and are unlikely to be representative. *Id.* at 1176. Instead, witness Kaufman testified that he recommends that the 75-R2.5 curve be used because it fits ages 0 through 60 well, and these ages are more representative of future retirements. *Id.*

In rebuttal, witness Spanos testified that when considering the overall life cycle and the significant statistical points of the account, the 70-R2.5 curve is a better fit for Account 354. Tr. vol. 9, 253. Further, witness Spanos testified that the transmission towers will have changes in the near future as lines are retired due to generation facilities being retired and many of the lattice towers being changed out to tubular poles. *Id.*

Accounts 368 and 368.10

NCSEA witness Kaufman objected to DEC's proposed 45-R1.5 retirement curve for Accounts 368 and 368.10 — Line Transformers. Tr. vol. 15, 1177. Witness Kaufman noted that the curve flattens at age 50 and follows a linear path until age 60, then exhibits a sharp decline to age 63, resulting in the best fitting curve underestimating retirements in early years. *Id.* Instead, witness Kaufman recommended the 50-R1.5 retirement curve. *Id.*

In rebuttal, witness Spanos testified that DEC's proposed 45-R1.5 survivor curve is a good match to the historical data through age 40 and is consistent with the overall life cycle of the assets recorded in the account through age 68. Tr. vol. 9, 247. Further, witness Spanos testified that the 45-R1.5 curve reflects DEC's future operational plans for Line Transformers, as there will be high retirements for line transformers for the foreseeable future. *Id.* at 247, 249.

Account 369

NCSEA witness Kaufmann objected to DEC's proposed use of a 55-R1.5 curve for Account 369 - Services. Tr. vol. 15, 1178. Instead, witness Kaufman recommended the use of a 65-R1.5 curve. *Id.* at 1178–79. Witness Kaufman notes that the use of a 65-R1.5 curve results in a similar average age as that proposed by DEC, and only deviates marginally from the historical data for ages 40 through 62. *Id.*

In rebuttal, witness Spanos testified that witness Kaufman's statistical analysis is inconclusive, as 70.0% of Account 369 has lasted 60 years; this cannot be expected to continue with low retirement into the future. Further, witness Spanos testified that many services will have increased retirements as overhead services move to underground services, and the increased customer requests for added load due to electronics in the home will increase service replacements. Additionally, witness Spanos testified that witness Kaufman's 65-R1.5 survivor curve unrealistically has a maximum life of 125 years, given that the currently approved life estimate is a 52-R1.5 survivor curve. Tr. vol. 9, 254.

Land Rights and Rights of Way Accounts

In witness Kaufman's direct testimony, he proposed an alternative survivor curve of 132-S6 for Accounts 310, 320, 330, 340, 350, 360, 360.2, 389, and 389.2. Tr. vol. 15,1173. Witness Kaufman testified that the primary cause of retirement for these accounts is abandonment, but rights of way are rarely, if ever, abandoned. *Id.* at 1174.

Witness Kaufman further testified that the low level of retirements means that historic data cannot be used to reliably predict retirement curves after 115 years of age, but it is reasonable to select a retirement curve that at least has a relatively high survival rate to age 115. *Id.* Witness Kaufman accordingly recommends the 132-S6 curve, as it results in a conservatively short expected life because it assumes the steepest retirement rate of all well-fitting curves. *Id.* Witness Kaufman further recommends that all rights of way accounts be analyzed together. *Id.*

In rebuttal, witness Spanos testified that the land rights and rights of way survivor curves proposed by witness Kaufman are unrealistic because the land rights and rights of way accounts are not all the same. Witness Spanos noted that there are some functional land rights and rights of way that have historical data that help understand the past for those categories, but the most important factor is the lives of the related assets. Tr. vol. 9, 256–57. Additionally, witness Spanos testified that the related substation and lines accounts have average lives of 43, 45, 70, 48, and 60 years. *Id.* at 257. All of the life cycles are close to or less than the 115 years of the related rights of way. *Id.*

Discussion and Conclusions

Retirement Dates for Coal Plants

Based on the Revenue Requirement Stipulation and the entire record in this proceeding, the Commission concludes that it is appropriate to adopt the depreciation rates set forth by DEC in Witness Spanos' rebuttal testimony, subject to the adjustments agreed upon in the Revenue Requirement Stipulation. Specifically, DEC's coal plants will be depreciated based on the accelerated retirement dates proposed by DEC, with the exception of the Cliffside 5 retirement date, which will move to January 1, 2031, consistent with DEC's CPIRP filed on August 17, 2023. Additionally, based on the Revenue Requirement Stipulation and the entire record in this proceeding, the Commission concludes that it is appropriate to increase DEC's proposed deferral to a regulatory asset from 50.0%

to 75.0% of the impact of accelerating the depreciation of DEC's subcritical coal plants from the current retirement dates. Using the accelerated retirement dates, while also accomplishing the type of rate mitigation that witness Lucas proposed, strikes a reasonable balance. DEC will be able to recover the 50.0% of the remaining net book value of the subcritical coal plants through securitization, as allowed under HB 951, while recovering the remaining amount, with a return, over an amortization period to be determined in a future rate case.

Based upon the evidence presented, the Commission rejects the securitization proposal of NCSEA witness Kaufman. For the reasons previously stated, the Revenue Requirement Stipulation is a just and reasonable resolution that preserves the ability of DEC to utilize securitization.

Decommissioning Study Recommendations — Indirect Costs, Asbestos, Contingency, and Escalation of Decommissioning Cost

Based on the evidence presented by Public Staff witnesses McCullar and Lucas and DEC witnesses Spanos and Kopp, the Commission finds the specific decommissioning cost adjustments as settled upon in Section III, Paragraph 4(a) of the Amended Revenue Requirement Stipulation, to adjust decommissioning estimates to use a 5.0% indirect cost adder and to adjust decommissioning estimates to use 10.0% contingency are just and reasonable. The Revenue Requirement Stipulation does not include adjustments for asbestos or escalation of decommissioning cost. Based on the evidence presented, the Commission finds that adjustments for these items are not appropriate for determining depreciation rates in this proceeding.

NCSEA is not a signatory to the Revenue Requirement Stipulation and NCSEA witness Kaufman argued for no escalation in decommissioning costs, the Commission finds persuasive the testimony of witness Spanos that the total service value, which includes the cost to remove and to decommission, must include costs at the time of retirement. The escalation of decommissioning costs matches the concept of depreciation supported by authoritative texts like the USOA and NARUC.

Net Salvage for Mass Property Accounts

Account 356

Based on the evidence presented, the Commission finds that the settled-upon net salvage percentages for transmission Account 356 — Overhead Conductors and Devices, established in the depreciation rate in the Revenue Requirement Stipulation, is just and reasonable and should be adopted. With respect to witness Kaufman's net salvage proposal, the Commission finds that his calculation only uses a 20-year statistical average and fails to consider the proper COR amounts to associated retirement amounts. As such, the Commission concludes that the -40.0% net salvage estimate proposed in the 2021 Depreciation Study is just and reasonable and appropriate for use in this case.

Accounts 373, 390, 392, and 396

Based upon the evidence presented, the Commission finds that the settled-upon net salvage percentage for Accounts 373, 390, 392, and 396 established in the depreciation rates in the Revenue Requirement Stipulation, are just and reasonable and should be adopted.

Interim Net Salvage for Percentage for Steam and Other Production Accounts

Based on the evidence presented, the Commission finds that the interim net salvage percentages for steam assets, Other Production assets and account

343.10 (Rotable Parts) used in establishing the depreciation rates in the Revenue Requirement Stipulation, are just and reasonable and should be adopted.

Survivor Curves

Based on the evidence presented, the Commission finds that the survivor curves proposed by DEC and used in establishing the depreciation rates in the Revenue Requirement Stipulation, are just and reasonable and should be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

Base Period Plant-Related Items

The evidence supporting this finding of fact is contained in DEC's verified Application and Form E-1; the Revenue Requirement Stipulation; the testimony and exhibits of DEC witnesses Q. Bowman, Capps, Guyton, Maley, and Walsh; Public Staff witnesses Metz, Thomas, Michna, Lucas, and T. Williamson; the joint testimony of Public Staff witnesses Boswell and Zhang; and the entire record in this proceeding.

Summary of Evidence

Generation Capital Investments

DEC witness Walsh described DEC's fossil/hydro/solar fleet and the operational performance of those generation assets during the test year. Tr. vol. 12, 634–35, 643–44. Witness Walsh testified to the major capital projects undertaken by DEC for maintenance of its fossil, renewable, and solar fleets. *Id.* at 640–41. In testifying on the importance of the traditional fossil fleet to customers in North Carolina, witness Walsh explained that the diversity of the resource and fuel mix and availability of coal generation during the transition away from coal must be strategically managed to ensure the remaining coal fleet can reliably contribute to resource adequacy. Witness Walsh testified that as DEC makes plans to retire its remaining coal fired assets and replace those assets with other resources. DEC must keep these remaining units in efficient working order to support the energy needs of its customers. Witness Walsh explained that DEC will continue to make investments in these assets to ensure that the same reliable cost-effective electricity that customers have counted on for decades remains available while the replacement of those units is developed and implemented. Additionally, witness Walsh testified that the combination of generation resources that replaces coal must be able to provide the same level of reliability that the coal units have and continue to provide. Further, witness Walsh testified that because natural gas is critical to the resource mix, particularly during the winter months and while energy storage capacity is being developed and deployed, DEC will continue to rely on its natural gas fleet as part of the diverse and dispatchable resource mix to ensure the reliability of service to DEC customers. *Id.* at 638–39. Witness Walsh also testified regarding DEC's hydro fleet capital maintenance projects, including two uprate projects at Bad Creek, and DEC's completion of the Maiden Creek and Gaston solar facilities. *Id.* at 641. Finally, witness Walsh testified as to his opinion that DEC has reasonably and prudently operated its fossil/hydro/solar fleet during the test period. *Id.* at 644.

DEC witness Capps described DEC's nuclear generation assets and capital additions made to the fleet since the 2019 Rate Case Order to enhance safety, reliability, and efficiency, preserve performance and reliability of the plants throughout their extended life operations, and address regulatory requirements. Tr. vol. 12, 265–66, 268–70. Witness Capps described how these capital additions are or would be by the capital cutoff date used and useful in safely and efficiently providing reliable electric service to DEC's customers. *Id.* at 271. Witness Capps also testified about the exceptional performance of the nuclear fleet during the test period and initiatives that DEC has undertaken to increase nuclear operational efficiency. *Id.* at 278–80. Witness Capps testified that in comparison to others in the industry DEC's nuclear fleet has a history of top performance including a test period capacity factor of 96.12% which exceeds the average capacity factor for comparable units published in the most recent North American Electric Reliability Council's Generating Unit Statistical Brochure. *Id.* at 280.

Public Staff witnesses Metz, Thomas, and Michna reviewed aspects of DEC's capital investments in its generation fleet. Public Staff witness Metz described his review of DEC's historic costs associated with projects placed in service for the period July 2020 through April 2023 noting that his investigation included multiple site visits to DEC's fleet of generating stations as well as numerous meetings with DEC personnel. *Id.* at 785. Witness Metz did not propose any adjustments to the base case capital investment costs. Public Staff witness Thomas reviewed DEC's capital additions to solar and hydro plants since the 2019 Rate Case Order. Tr. vol. 14, 159–60, 184–85. Aside from recommendations regarding tax incentives for solar and hydro facilities, addressed in Finding of Fact No. 24, witness Thomas did not recommend any adjustments to the base case capital investment costs for the solar and hydro fleets. Public Staff witness Michna reviewed DEC's capital additions for steam generation since the 2019 Rate Case Order and did not propose any adjustments to the base case capital investment costs for the steam facilities. Tr. vol. 15, 44, 60.

Lincoln Pipeline

Public Staff witness Lucas recommended removal of $353,067 of plant-in-service expense for natural gas pipeline improvements necessary for Lincoln County Station Unit 17. Witness Lucas testified that the new pipeline project was built to serve Unit 17 and that the existing pipeline to serve Units 1 through 16 did not require a capacity expansion. Tr. vol. 13, 133.

In DEC witness Kevin Murray's rebuttal testimony, he testified that the pipeline improvements were for the benefit of the entire Lincoln facility and not just Unit 17. Tr. vol. 12, 499.

The Revenue Requirement Stipulation provides that no further adjustment is needed to DEC's Lincoln pipeline costs included in the case. Amended Revenue

Requirement Stipulation § III.11 (Tr. Ex. vol. 7). DEC witness Q. Bowman supported this provision in her settlement supporting testimony. *Id.* at 255.

Transmission and Distribution Base Period Investments — Non-Grid Improvement Plan

In DEC witnesses Guyton and Maley's direct testimonies, they discussed DEC's distribution and transmission investments since its last general rate case. DEC witness Guyton testified that DEC had invested approximately $1.069 billion in new distribution infrastructure since DEC's last rate case, which included investments in DEC's GIP. Witness Guyton testified that non-GIP distribution investments during the base period included targeted reliability and maintenance programs, and customer driven line and substation expansions. Tr. vol. 8, 103. In his direct testimony, witness Maley testified that DEC had spent approximately $463 million in additional transmission infrastructure since its last rate case, the bulk of which was for reliability and capacity improvements. *Id*. at 267–68.

In Public Staff witnesses Lawrence, Metz, and T. Williamson's direct testimonies, they took issue with some of the transmission and distribution capital investments made by DEC since its last rate case, as discussed in more detail below. Specifically, witness Lawrence took issue with the inclusion in rate base of capital associated with EV charging infrastructure and Public Staff witness T. Williamson discussed the Pleasant Garden Circuit Breaker Replacement project (Pleasant Garden Project).

Pleasant Garden Breaker Replacements

In Public Staff witness T. Williamson's direct testimony, he recommended that the Pleasant Garden Project be reclassified from distribution to transmission plant in service. Tr. vol. 15, 129. On rebuttal, DEC witness Guyton testified that he agreed with witness T. Williamson's recommendation to reclassify the Pleasant Garden Project and asserted that DEC had already made the accounting entry necessary to reflect the reclassification. Tr. vol. 8, 190.

Section III, Paragraph 8 of the Amended Revenue Requirement Stipulation specified that reclassification of the Pleasant Garden Project is appropriate. Amended Revenue Requirement Stipulation § III.8 (Tr. Ex. vol. 7).

EV Infrastructure

In Public Staff witness Lawrence's direct testimony, he recommended a $886,130.16 disallowance for costs associated with EV charging infrastructure installed in conjunction with DEC's Electrification Charging Infrastructure (ECI) Project. Tr. vol. 15, 99. Witness Lawrence testified that the program was designed to meet corporate goals and exceeded what was necessary to serve customers. *Id.* at 100. Additionally, witness Lawrence testified that he was unable to determine that the EV charging stations were used and useful. *Id.*

On rebuttal, DEC witness Guyton testified that the EV infrastructure costs were appropriately recoverable because the ECI Project responded to customers' clearly articulated demands and the public interest underlying those demands. Tr. vol. 8, 215. Witness Guyton also testified that the charging infrastructure is used and useful. *Id.* at 193. Specifically, witness Guyton testified that the infrastructure was being used to charge existing DEC plug-in hybrid and electric vehicles. *Id.* Witness Guyton asserted that DEC's EV infrastructure would continue to support the growing number of electric fleet vehicles over the next seven years in alignment with DEC's commitment to electrify its internal fleet. *Id.*

Section III, Paragraph 7 of the Amended Revenue Requirement Stipulation provides that DEC's EV infrastructure in service as of June 2023 that was recommended for removal by Public Staff witness Lawrence should be included in the base period with the limitation that such infrastructure shall only be used for DEC vehicle use. Amended Revenue Requirement Stipulation § III.7 (Tr. Ex. vol. 7).

Easement Forms

In Public Staff witness T. Williamson's direct testimony, he testified that the Public Staff periodically receives inquiries from landowners concerning ambiguity associated with DEC's form easement. Tr. vol. 15, 169. Witness T. Williamson explained that in most instances, DEC's form easement explains that the location of the easement is a function of where DEC's facilities are ultimately installed. *Id.* Witness T. Williamson recommended that DEC: (1) provide landowners a depiction, map, or survey of the proposed easement area as part of the easement documentation to be executed by the landowner; and (2) revise its easement language to describe an unambiguous easement location. *Id.* at 169–70.

DEC Witness Guyton testified that he partly agreed with Public Staff witness T. Williamson's recommendations regarding DEC's easement forms. Tr. vol. 8, 240. Specifically, witness Guyton testified that DEC already provides landowners with a depiction or map of the planned facilities for every project. *Id.* Witness Guyton explained however, that DEC cannot survey the facilities until they have been installed, which necessarily cannot be prior to execution of the easement. *Id.* He also stated that performing surveys would be costly to customers and that, therefore, he disagreed with witness T. Williamson's recommendation to provide a survey of the proposed easement area. *Id.* Witness Guyton further disagreed with witness T. Williamson's recommendation to revise the language on DEC's form easement. Witness Guyton explained that public utility easements are defined by the centerline of the installed facilities and that there are free services available to the public that enable landowners to locate the centerline of public utility facilities. Accordingly, under DEC's current approach, landowners can easily identify the boundaries of DEC's public utility easements. Witness Guyton testified that if DEC revised the form language to describe the easement in the way witness T. Williamson suggested customers would be required to obtain a survey to locate the easement with specificity. *Id.*

After having carefully reviewed the evidence in the record, the Commission directs DEC to continue to provide landowners with a map or depiction of the planned facilities when doing so is appropriate and would not cause confusion. Based on the evidentiary record in this proceeding, for now the Commission declines to direct DEC to modify its practices or forms related to public utility easements as suggested by Public Staff witness T. Williamson.

Mount Holly Building and Other Projects

DEC witness Speros testified that the Mount Holly Technology Center is a multifaceted facility where innovations and technology that are intended to benefit customers and the Duke system are modeled, tested, and evaluated for integration and deployment. Tr. vol. 12, 565.

Public Staff witness Metz testified that he was recommending disallowance of nine Mount Holly projects making up a total disallowance of $8.7 million. *Id.* at 835. Witness Metz also requested that DEC provide a pro forma adjustment in future rate cases to resolve the cost allocation issue for capital projects relating to Mount Holly initiatives as well as similar initiatives benefiting other affiliate companies. *Id.* Witness Metz also noted that he believed the Mount Holly capital projects are for Duke initiatives and learnings that will likely be applied across multiple Duke entities, and it was not appropriate for DEC ratepayers to bear 100.0% of those capital costs. *Id.* at 834–35.

On rebuttal, witness Speros testified that two of the nine projects identified by witness Metz were building renovation projects at Mount Holly. *Id*. at 565. DEC witness Speros testified that two projects identified by the Public Staff are building renovation projects comprising $5.1 million of the Public Staff's total proposed $8.7 million disallowance. *Id.* Witness Speros testified that all of the Mount Holly Building renovation projects are properly recorded to DEC's books. *Id.* at 566. The Mount Holly facility was previously a generation operations facility that was repurposed when the generation operations were no longer necessary, but because the legacy generation building was constructed and recorded to DEC's books it could not easily be moved to another entity from an accounting perspective. *Id.* at 565. Therefore, DEC developed a facility rent charge for the building which is charged to the business units utilizing the facility and then recorded as rent revenue on DEC's books. *Id.* Witness Speros testified that this building rent charge is a reduction in DEC's cost of service, and accordingly, all the Mount Holly building renovation projects are properly recorded to DEC's books. *Id.* at 566.

The remaining seven projects identified by witness Metz, as well as four additional projects identified by DEC, are other non-building related projects. *Id.* at 566. Witness Speros testified that the remaining seven projects are non-renovation projects and should be recorded on the books of DEBS. *Id.* The impact of this adjustment on DEC's request is approximately $572,930. *Id.* Witness Speros also testified that DEC self-identified four additional projects; two of those projects will be recorded on DEBS books, and the other two projects are meter farm related projects and therefore appropriately recorded on DEC's books. *Id.*

Section III, Paragraph 5 of the Amended Revenue Requirement Stipulation provides that the Mount Holly Building Renovation Project should be included in DEC's base period. Amended Revenue Requirement Stipulation § III.5 (Tr. Ex. vol. 7). In addition, Section III, Paragraph 9 of the Amended Revenue Requirement Stipulation provides that the Mount Holly Other Projects will be allocated to all Duke Energy subsidiaries rather than directly assigned to DEC. *Id* § III.9.

526 South Church Street

Public Staff witness Metz testified that the 526 South Church Street building underwent a $7 million switchgear and generator replacement project. Tr. vol. 12, 813–14. Witness Metz testified that the Public Staff recommends cost adjustments related to this project. *Id.* at 826.

In rebuttal, DEC witness Speros testified that the switchgear and generator replacement project is not included in DEC's rate request, and therefore, the adjustment proposed by the Public Staff is unwarranted. *Id.* at 562. Witness Speros further testified that Speros Rebuttal Exhibit 1 details the journal entries associated with the sale of the 526 South Church Street building, and that within the exhibit, the entirety of the 526 South Church Street plant-in-service was removed in January 2023. *Id.* This removal of the plant-in-service removes all projects including the projects identified by witness Metz. *Id.* Accordingly, there are no projects associated with the 526 South Church Street building remaining in DEC's rate request as all activity concluded prior to the capital cutoff in this case. *Id.*

Section III, Paragraph 6 of the Amended Revenue Requirement Stipulation provides that no adjustment is needed for the 526 South Church Street Renovation, as this asset was retired prior to the capital cut-off period in this case and is not included in rates. Amended Revenue Requirement Stipulation § III.6 (Tr. Ex. vol. 7).

Workstation Project

DEC Witness Speros testified that DEC is undertaking a workstation refresh project that entails the complete replacement of workstation hardware and peripherals across Duke Energy. Tr. vol. 12, 563. One-third of workstation hardware is being replaced each year over a three-year replacement cycle. *Id.* The refresh replaces out of warranty computers and associated equipment with updated devices and software to improve productivity, enhance security for the benefit of customers, and reduce the level of O&M maintenance support typically associated with maintaining older workstations. *Id.*

Public Staff witness Metz testified that DEC issued 5,346 out of 14,219 workstations, and recommended disallowance of the workstations not issued to employees, a disallowance of approximately $2.66 million, which would be updated to reflect the number of workstations issued in May and June of 2023. *Id.* at 827.

In DEC witness Speros' rebuttal testimony, he noted that witness Metz did not challenge the prudency of DEC's investment in the workstation refresh project, but rather argued that the workstations should not be included in rates until actually issued to employees. *Id.* at 563. Witness Speros testified that there is a delay from time of purchase to delivery to issuance to employees in order to allow DEC to prepare workstations for integration into the DEC network. *Id.* at 564. However, witness Speros noted that there is no accounting requirement that laptops be issued to employees in order to be included in rates in this case, and he testified that the Public Staff's recommendation sets an arbitrary standard for inclusion of prudently incurred cost in rates. *Id.*

Pursuant to Section III, Paragraph 10 of the Amended Revenue Requirement Stipulation, DEC and the Public Staff agreed that for purposes of this proceeding, DEC will remove new laptop devices not issued to employees as of the capital cutoff date from the revenue requirement. Amended Revenue Requirement Stipulation § III.10 (Tr. Ex. vol.7). The removal will result in a decrease to Plant in Service of $1,811,000 on a North Carolina retail basis. The Public Staff will have the opportunity to assess compliance with this treatment in its audit of DEC's Second and Third Supplemental updates. *Id.*

Discussion and Conclusions

Based on the entire record in this proceeding, the Commission concludes that the costs related to DEC's investments in its fossil, renewable, and nuclear fleet assets as well as its transmission and distribution investments made during the test period, as adjusted by the Revenue Requirement Stipulation, were reasonably and prudently incurred and should be recovered. The Commission also concludes that DEC's EV infrastructure in service as of June 2023 should appropriately be included in the base period as set forth in the Revenue Requirement Stipulation. The Commission further concludes that the adjustment for the Pleasant Garden Project as the Public Staff and DEC agreed in the Revenue Requirement Stipulation is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16-18

Grid Improvement Plan Cost Recovery

The evidence supporting these findings of fact is contained in DEC's verified Application and Form E-1; the Revenue Requirement Stipulation; the testimony and exhibits of DEC witnesses Q. Bowman, Guyton, and Maley; Public Staff witnesses Thomas, Zhang, and Boswell; and the entire record in this proceeding.

Summary of Evidence

DEC witness Maley testified that DEC's GIP is enabling new grid capabilities and that the System Intelligence program has begun deployment of dynamic, smart devices with the ability to remotely locate, sectionalize, and assess damage. Tr. vol. 8, 273. Witness Maley testified that the deployment of remote monitoring and control devices with digital relays supports rapid response to system outages and disturbances to quickly restore power to the maximum number of customers and to enable better management of distributed energy resources. *Id.* DEC installed approximately 800 relays over the 19 months immediately preceding the date on which DEC filed the Application. *Id*. In the period starting June 1, 2020, through December 31, 2021, DEC made North Carolina GIP transmission investments totaling $15 million. *Id.* at 274. Witness Maley testified that DEC completed the North Carolina GIP work scope in its three-year plan by December 31, 2022. *Id.* at 275.

DEC witness Guyton testified that DEC developed its GIP to build grid capabilities needed to address the implications of seven megatrends. These megatrends represent key trends that drive the need to prepare the grid to safely and efficiently distribute the energy which customers depend on in their daily lives. *Id*. at 121. Witness Guyton also testified about the operational benefits associated with the GIP work that DEC had completed as of the filing of the Application. Witness Guyton testified that the GIP projects, which reduce the frequency and impact of outages, are contributing to the improving trends for the System Average Interruption Index (SAIFI) and the System Average Interruption Duration Index (SAIDI). *Id.* at 115. Witness Guyton testified that, as an example, the Self Optimizing Grid program redesigns key portions of the distribution system, transforming it into a dynamic, smart-thinking grid that can automatically reroute power around trouble areas so that power can be quickly restored to the maximum number of customers and line crews can directly and rapidly be dispatched to the source of the outage. *Id.*

Witness Guyton testified that the GIP distribution investments and the North Carolina retail allocated portion of general and intangible plant investments through the December 31, 2021 test period totaled $134 million. *Id.* at 119.

DEC witness Q. Bowman testified that in the 2019 Rate Case Order the Commission approved deferral of certain GIP-related costs for projects placed in service through December 31, 2022 until the costs could be considered for recovery in DEC's next general rate proceeding. Tr. vol. 12, 178–79. With respect to the specific costs that have been deferred, DEC witness Maley testified that DEC has deferred incremental O&M expenses, depreciation, and property taxes associated with the GIP, as well as the carrying cost on the investments and the deferred costs at DEC's weighted average cost of capital. Tr. vol. 8, 275. Witness Q. Bowman testified in her initial direct testimony that by of the end of 2022 DEC will have placed in service investments of approximately $469.6 million on a North Carolina retail basis. Witness Q. Bowman explained that DEC proposes to amortize the GIP regulatory asset of $100.5 million over a three-year period which results in an amortization expense of $33.5 million. Tr. vol. 12, 179. In supplemental testimony, DEC witness Q. Bowman updated the GIP-related costs to replace estimated data with actual amounts incurred through April 30, 2023.[7] *Id.* at 205. Witness Maley testified that DEC proposes to roll these costs into base rates in the current rate case. Tr. vol. 8, 275.

While the Public Staff agreed with DEC's assertion that the Commission approved deferral accounting treatment for the GIP programs, the Public Staff took issue with DEC's calculation of the GIP deferral balance. Tr. vol. 12, 1026–30. Specifically, Public Staff witnesses Zhang and Boswell testified that DEC's inclusion of O&M expenses is outside of the allowable expenses envisioned by the Commission's approval in the 2019 Rate Case Order. *Id.* at 1029. The Public Staff argued that the GIP deferral approved in the 2019 Rate Case Order is restricted to incremental expenses net of operating benefits. Therefore, the deferral does not include overhead or administrative and general costs but may include a reasonable allocation of management and supervision costs. *Id.* Witnesses Zhang and Boswell asserted that some of the O&M expenses included in the deferral were not incremental, that DEC had not determined the amount of any operating benefits, and that the O&M expenses included overhead and administrative and general costs. *Id.* at 1029–30. Public Staff witness Thomas also challenged DEC's inclusion of certain O&M and capital expenses in the GIP deferral balance on these same grounds. Tr. vol. 14, 223–26. As explained by DEC witness Q. Bowman, the Public Staff proposed the following adjustments related to DEC's proposed recovery of the deferred GIP costs: (1) removal of capital and O&M costs, resulting in a reduction to the deferred asset balance of $22.5 million based on the contentions that DEC did not provide support for amounts after March 2022 and that certain of the costs did not meet the criteria for deferral based on 2019 Rate Case Order; and (2) extension of the amortization period to 30 years from DEC's proposed three years. Tr. vol. 15, 1253.

DEC witness Guyton testified on rebuttal that the labor expense deferred for GIP projects was incremental to base labor included in rates since DEC had already reduced the deferral by the amount of installation O&M included in current rates. He asserted that the Public Staff's adjustment to remove O&M for GIP O&M-only projects is not reasonable on the basis that incremental installation is correctly accounted for as O&M. Tr. vol. 8, 196–97. He also disputed Public Staff witness Thomas' position on administrative and general costs and testified that such costs were appropriately included in allocation pools that are added to capital projects in accordance with DEC's accounting practices and cost allocation manual. *Id.* at 195-96. DEC witness Q. Bowman also testified on rebuttal as to DEC's disagreement with the Public Staff's adjustment to remove O&M expenses, with the contention that certain expenses were not appropriately allocated to the GIP projects, and with the contention that 30 years is the appropriate amortization period. Tr. vol. 15, 1253-55.

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[7] The total GIP investment made by DEC as of December 31, 2022, on a North Carolina retail basis is approximately $454 million as shown in the December 2022 NC GIP Biannual Report filed on March 1, 2023, in Docket Nos. E-7, Sub 1214B and E-2, Sub 1219B and Q. Bowman Settlement Exhibit 4.

Section III, Paragraph 12 of the Amended Revenue Requirement Stipulation provides that DEC is permitted to recover the full balance of its GIP deferral over an 18-year amortization period with a debt-only return during the deferral period and rate base treatment during the 18-year amortization period. No intervenor took issue with this provision of the Amended Revenue Requirement Stipulation. The costs associated with the GIP deferral, as settled upon by the Public Staff and DEC, result in a deferred balance on December 31, 2023, of $71.121 million, and an annual amortization expense of $3.951 million, as set forth in DEC witness Q. Bowman Supplemental Partial Settlement Exhibit 4. Q. Bowman Supp. Settlement Ex. 4 (Tr. Ex. vol. 12).

Discussion and Conclusions

The Commission concludes that the evidence presented supports the treatment of the deferred GIP-related costs as agreed to by DEC and the Public Staff in the Revenue Requirement Stipulation and that the treatment strikes a just and reasonable balance between recovery of costs and mitigation of impacts to customers. Therefore, the Commission approves the treatment of DEC's Grid deferral in Section III, Paragraph 12 of the Revenue Requirement Stipulation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

Coal Ash

The evidence supporting this finding of fact is contained in DEC's verified Application and Form E-1; the Coal Combustion Residuals Settlement Agreement approved in the Commission's March 31, 2021 Order in the 2019 Rate Case Order, which accepted the CCR Settlement; the testimony and exhibits of DEC witnesses Q. Bowman and Hill; Public Staff witnesses Zhang, Boswell, and Lucas; and the entire record in this proceeding.

DEC witness Hill provided testimony as to DEC's activities to close ash basins and landfills along with other CCR management units for the period since DEC's last rate case. Tr. vol. 12, 377. Witness Hill testified that the actual and forecasted activities, as well as costs incurred, were reasonable and prudent. *Id.* at 378. Moreover, Witness Hill testified that DEC implemented its plans in accordance with closure and corrective action plans that have been approved by the relevant state environmental agencies (in North Carolina the Department of Environmental Quality and in South Carolina, the Department of Health and Environmental Control). *Id.* at 378–79. Witness Hill testified that DEC has also complied with its obligations under the CCR Settlement. *Id.* at 379.

DEC witness Q. Bowman presented DEC's request to amortize deferred costs associated with the CCRs and to continue deferring costs related to compliance with coal ash regulations. *Id.* at 174. Witness Q. Bowman testified as to the key components of the CCR Settlement, and the associated adjustments made in this case to comply with the CCR Settlement including the use of proceeds from insurance claims to offset CCR compliance costs. *Id.* at 174–77. Witness Q. Bowman explained that the CCR costs sought for recovery are based upon actual costs incurred from February 1, 2020, through June 30, 2022, and updated amounts through May 31, 2023, provided in the supplemental filing made on June 19, 2023. *Id*. at 215. Witness Q. Bowman testified that the cost, less the adjustments, totals approximately $661 million on a system basis and $444 million on a North Carolina retail basis. *Id.* at 176. Witness Q. Bowman testified that DEC's adjustment amortizes the net deferred balance over a five-year period. *Id.* at 177. Witness Q. Bowman also testified that DEC proposes to offset the overamortization for the CCR costs established in the DEC's 2017 Rate Case[8] in the amount of $8.1 million against the CCR Asset Retirement Obligation (ARO) deferral DEC sought recovery of in this case. Witness Q. Bowman testified that the balance sought for recovery in this case is being offset by North Carolina retail customer's share of insurance proceeds, calculated in accordance with the CCR Settlement terms of $169.7 million. *Id.* at 176–77.

Public Staff witness Lucas investigated DEC's management of CCRs, construction and operation of DEC's CCR beneficiation projects, and proceeds from DEC's litigation of CCR insurance claims. Tr. vol. 13,104. After performing a thorough review, witness Lucas concluded that DEC's CCR management practices have been sufficient to prevent unnecessary costs to its customers. *Id*. at 109. Witness Lucas also testified that DEC's construction and operation of its beneficiation project since the last rate case have been sufficient to prevent unnecessary costs to customers. *Id.* at 115. Finally, witness Lucas found that DEC properly credited North Carolina retail customers with proceeds from the insurance litigation. *Id.* at 116.

Public Staff witnesses Zhang and Boswell recommended that the Commission return all overamortizations to customers as a single rider over a period of one year with interest. Tr. vol. 12,1042.

The adjustments recommended by the Public Staff regarding CCR costs were resolved in the Revenue Requirement Stipulation. Section III of the Amended Revenue Requirement Stipulation provides that no further adjustments other than those specifically identified in the stipulation would be made to DEC's base period revenue requirement. In addition, Section III, Paragraph 40(a) of the Amended Revenue Requirement Stipulation provides that the Public Staff and DEC agree that the overamortizations related to coal ash will be netted against the coal ash costs included in the case consistent with the Commission's decision in the DEP Rate Case. Amended Revenue Requirement Stipulation § III.40.a (Tr. Ex. vol. 7).

Based on the entire record in this proceeding, including the testimony cited above as well as the relevant provisions of the Revenue Requirement Stipulation, the Commission concludes that the CCR costs sought for recovery are reasonable and prudent and consistent with the CCR Settlement. The Commission also concludes that DEC has complied with the CCR Settlement and has made the agreed upon adjustments

[8] Application to Adjust Retail Rates, Request for an Accounting Order and to Consolidate Dockets, *Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina*, No. E-7, Sub 1146 (Aug. 25, 2017) (2017 Rate Case).

in this case to reflect that settlement. The Commission approves DEC's applying the overamortization of CCR costs as established in the 2017 Rate Case Order in the amount of $8.1 million against the CCR deferred balance in this case, and the Commission approves the recovery of the net deferred balance over a five-year period. The Commission also approves DEC's request to continue the deferral of any CCR cost DEC incurs subsequent to June 30, 2023, for future recovery consistent with the CCR Settlement.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 20-21

Environmental Compliance Cost Recovery

The evidence supporting these findings of fact is contained in DEC's verified Application and Form E-1; the testimony and exhibits of DEC witness Q. Bowman; and the entire record in this proceeding.

Summary of Evidence

In DEC witness Q. Bowman's direct testimony, she detailed DEC's request to amortize non-asset retirement obligation (ARO) environmental costs over a six-year amortization period. Witness Q. Bowman explained that the Commission's 2019 Rate Case Order granted DEC the authority to continue to defer certain costs incurred in connection with compliance with federal and state environmental requirements as it relates to CCRs. Tr. vol. 12, 178. Witness Q. Bowman testified that a portion of the environmental compliance costs associated with coal ash are related to the continued operation of the active plants and are capitalized to plant in service. *Id.* Witness Q. Bowman stated that by July 31, 2023, DEC placed in service non-ARO environmental compliance investments of $40 million on a system basis since February 1, 2020. Witness Q. Bowman explained that DEC is requesting recovery of actuals beginning February 1, 2020. *Id.* Witness Q. Bowman also provided updated actuals through June 30, 2023, in her third supplemental direct testimony. *Id.* at 224.

Discussion and Conclusion

No party contested DEC's request to amortize its non-ARO costs related to compliance with federal and state environmental requirements for CCRs over a six-year period. The costs associated with the deferred CCR environmental costs result in a deferred balance through June 30, 2023, of $7.284 million and an annual amortization expense of $1.214 million.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 22-23

Storm Securitization Overcollections

The evidence supporting these findings of fact is contained in DEC's verified Application and Form E-1; the testimony and exhibits of DEC witness Q. Bowman; and the entire record in this proceeding.

In DEC's January 27, 2021 Agreement and Stipulation of Partial Settlement with the Public Staff filed in Docket No. E-7, Sub 1243, DEC agreed to establish regulatory asset or regulatory liability accounts for the purpose of tracking up-front financing costs and servicing and administration fees related to storm securitization. In the instant proceeding, DEC proposed to amortize the regulatory liability of $0.6 million for overcollections associated with storm securitizations over a three-year period. Tr. vol. 12, 186, 215; Q. Bowman Supp. Settlement Ex. 4 at E1-10 NC7040 (Tr. Ex. vol. 12). The Public Staff did not oppose this recovery timeframe. No intervenor took issue with this proposal. The Commission concludes that the three-year amortization period is just and reasonable and fair to all parties and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 24

Cost of Debt

The evidence supporting this finding of fact is contained in DEC's verified Application and Form E-1; the Revenue Requirement Stipulation; the testimony and exhibits of DEC witnesses Newlin and Q. Bowman; and the entire record in this proceeding.

DEC witness Newlin testified that DEC's long-term debt cost as of September 30, 2022, was 4.31%, which was the value DEC used to determine the revenue requirement in DEC's Application. Tr. vol. 9, 72. Section III, Paragraph 1 of the Amended Revenue Requirement Stipulation establishes that the embedded cost of debt as of June 30, 2023, shall be used to calculate DEC's revenue requirement. Amended Revenue Require Stipulation § III.1 (Tr. Ex. vol. 7). DEC witness Q. Bowman presented in her supplemental testimony that the embedded cost of debt as of June 30, 2023, is 4.56%. Tr. vol. 12, 131.

No intervenor offered any evidence opposing this provision of the revenue Requirement Stipulation. The Commission therefore concludes that the use of a debt cost of 4.56% per the terms of Section III, Paragraph 1 of the Amended Revenue Requirement Stipulation is just and reasonable to all parties considering all the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

Accounting Adjustments in Revenue Requirement Stipulation

The evidence supporting this finding of fact is contained in DEC's verified Application and Form E-1; the Revenue Requirement Stipulation; the testimony and exhibits of DEC witnesses Q. Bowman, Capps, Council, Quick, Speros, Stewart, and Walsh; Public Staff witnesses Zhang, Boswell, McLawhorn, and Metz; and the entire record in this proceeding.

Incentive Compensation

In DEC witness Stewart's direct testimony, he testified that DEC included in its cost of service incentive compensation at target levels that are assigned or allocated to DEC. *Id.* at 597. Public Staff witnesses Zhang and Boswell testified that incentive compensation related to the Earnings Per Share (EPS) and Total Shareholder Return (TSR) metrics for all employees should be removed from the revenue requirement because these metrics provided a direct benefit to shareholders rather than ratepayers. *Id.* at 1017.

In rebuttal, DEC witness Stewart refuted these contentions asserting that metrics such as EPS and TSR are appropriate for recovery as they benefit customers. *Id.* at 604–06.

The Revenue Requirement Stipulation establishes that DEC employee incentives should be adjusted to remove incentive pay related to EPS and TSR for the top levels of DEC's leadership, but not for the remainder of the employees. Revenue Requirement Stipulation § III.13 (Tr. Ex. vol. 7). No intervenor took issue with this provision of the Revenue Requirement Stipulation, which is consistent with the DEP Rate Case Order. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Duke Energy Plaza

In DEC witness Council's direct testimony, she testified in support of DEC's investment in the Plaza, the new corporate headquarters building located in Charlotte, North Carolina and described Duke Energy's overall real estate strategy and how that strategy evolved during the COVID pandemic. Tr. vol. 12, 319. The Plaza is approximately one million square feet and has the capacity to house more than 4,000 Duke Energy employees. *Id.* at 320. DEC began occupying the building in first quarter 2023 with phased "move-ins" occurring through the third quarter of 2023. *Id.* The total estimated cost of the building through July 31, 2023, was estimated to be approximately $644 million, or $439 million on a North Carolina retail basis, offset by rent revenue received from other affiliates using the building. *Id.* Witness Council testified that prior to the COVID pandemic, the Plaza was not intended to replace the Duke Energy's headquarters but was needed to consolidate office facilities to provide cost savings, promote a more collaborative workplace environment, accommodate growth, and compete for and retain talent.

Id. at 321. Witness Council explained that Duke Energy's previous real estate portfolio included 40-45 year old facilities which were inefficient and well past their useful life, incurring millions of break/fix maintenance costs year over year. *Id.* Furthermore, these facilities were not designed with workplaces that promote collaboration, productivity, or wellness and more than two-thirds of Duke Energy employees were in less than optimal office space with limited lighting, inefficient heating and cooling systems, and furniture, fixtures, and equipment prone to breakage. *Id.* at 321–22. Based on these considerations and supporting analysis, Duke Energy determined that by constructing a new office building it could consolidate its workforce into the new building, reduce its real estate footprint by disposing of five other facilities and generate annual cash savings of approximately $5 million by 2026. *Id.* at 322. Following the COVID pandemic, Duke Energy further revised its real estate strategy and decided it was most cost effective to fully vacate the prior headquarters, the Duke Energy Center, by year end 2021 and consolidate all uptown Charlotte-based employees in one building by designating the Plaza as the new headquarters. *Id.* By divesting five facilities, Duke Energy reduced its real estate footprint from 2.5 million to 1.1 million square feet. *Id.* at 328. Duke Energy implemented a new way of working where only about 10.0% of the workforce reports onsite full-time and are provided dedicated workspaces. *Id.* at 323. Approximately 10.0% work virtually in a non-company location or work in the field the majority of the time. The remaining 80.0% of employees are considered hybrid employees that alternate between working remotely and Duke Energy facilities where shared space is reserved as needed. *Id.*

In DEC witness Council's supplemental testimony, she supported the inclusion in the MYRP of 11 levels (i.e., floors) of the Plaza anticipated to be placed in service after June 30, 2023. *Id.* at 331. In her second supplemental testimony, she revised the Plaza MYRP project to remove one level that was placed in service before the June 30, 2023 capital cut-off date in this proceeding. *Id.* at 336.

Public Staff witness Metz testified that based on his review of the Plaza, DEC did not select the least cost option and selected the most expensive options in terms of projected total project cost and net present value. *Id.* at 797. Witness Metz testified that the least cost option would have been to move forward with a renovation of Duke's 526 South Church Street building which he estimated would have been about half as expensive as the Plaza. *Id.* Witness Metz explained that based on meetings with DEC and targeted discovery he reviewed, including a presentation from the 2016 timeframe, DEC explored four main options for further housing of its Charlotte-area staff: (1) status quo; (2) renovate; (3) re-develop; or (4) build. *Id.* at 797–98. For each option DEC sought competitive proposals, developed an evaluation tool, had internal collaborative discussions, and performed a comprehensive financial analysis, ultimately selecting to build the Plaza. *Id.* at 798. Witness Metz recommended a disallowance for the costs of the Plaza offering three potential ways to calculate the disallowance: (1) calculating a disallowance ratio of 49.4% based on a comparison of the Plaza costs to the renovation project's estimated 2016 cost of approximately $289.2 million; (2) calculating a disallowance ratio of 63.7% based on a comparison of the total cost of the Plaza facility on a market-based recovery basis versus the actual cost of the facility; or (3) an average of multiple data points resulting in a 52.8% disallowance ratio. *Id.* at 805–09. Another option witness Metz offered was for the Commission to apply a general screening criterion and disallow cost recovery for any floors that were not moved into (i.e., used and useful) and not meeting their designed or intended purpose(s). *Id.* at 812.

In DEC witness Council's rebuttal testimony, she responded to Public Staff witness Metz's proposed disallowance of a portion of the Plaza investment and explained the reasons Duke Energy undertook an evaluation of its real estate portfolio beginning in 2014 and the alternatives Duke Energy considered as part of its real estate optimization strategy over the course of the project development. Tr. vol. 16, 376. Witness Council explained that Duke Energy did not consider the status quo or renovate alternatives to be viable options and those options were included in the analysis as the typical "base case" comparisons that the real estate team includes when evaluating real estate alternatives. *Id.* at 377. Witness Council explained further that after initial analysis and consultation with construction experts and architects/design experts, renovation was not deemed a viable option; thus, Duke Energy prudently did not expend valuable resources to further develop and assess the renovation estimate, which would have required additional scope and engineering/structural analysis at a significant cost. *Id.* The renovation option was limited and primarily focused on interior cosmetic aspects and the scope did not address many of the infrastructure issues of the building, so expensive repairs and maintenance costs would continue to be incurred. *Id.* at 377–78. Witness Council also responded that witness Metz's analysis fails to account for other costs and risks that, when added to the project costs, demonstrate that the entire real estate costs (both capital and ongoing O&M) would have been higher if DEC had selected the renovation option and would not have achieved most of DEC's real estate strategic objectives. *Id.* at 378. Finally, she rebutted witness Metz's disallowance methodologies and noted that the majority of the floors in the Plaza are already occupied and in use with the remaining floors scheduled to be moved into over the next few months well before the rates' effective date in this case. *Id.* at 378–79.

The Revenue Requirement Stipulation provides that the stipulating parties agree to remove the DEC North Carolina retail allocation of $50 million system plant in service costs for the Plaza, with $40 million being removed from the base period and $10 million from the MYRP. Amended Revenue Requirement Stipulation § III.14 (Tr. Ex. vol. 7). The parties agreed that all other costs associated with the Plaza should be recoverable subject to the following:

(1) The capital adjustment for the Plaza will flow through the rent expense proforma NC-2150;

(2) The $2.86 million (system basis) will be reflected in the MYRP revenue requirement to account for parking lot revenues for employees and after-hour parking associated with the Plaza parking; and

(3) This agreed upon adjustment covers the costs sought for recovery in the entire base period and MYRP for the Plaza building in this case. No further

> adjustments shall be made to the plant in service costs of the Plaza or changes to the operation and maintenance costs based on the Public Staff's continuing audit of DEC's second and third supplemental updates.

Id. DEC witnesses Abernathy and Q. Bowman supported this provision in their respective settlement supporting testimony. Tr. vol. 12, 135, 239–40. No intervenor took issue with this provision of the Revenue Requirement Stipulation.

The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding. Based on the entire record in this proceeding, the Commission concludes that the capital costs related to DEC's investment in the Plaza through the capital cut-off date, as adjusted by the Revenue Requirement Stipulation, were reasonably and prudently incurred and should be recovered. After having carefully reviewed the entirety of the evidence in the record on DEC's Plaza MYRP project, the Commission finds that the Plaza MYRP project satisfies the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a). The Commission concludes that the evidence supports approval of the Revenue Requirement Stipulation's provisions regarding the Plaza MYRP project. The Commission further concludes that the adjustments for the parking lot revenues for employees and after-hour parking associated with the Plaza parking as the Public Staff and DEC agreed to in the Revenue Requirement Stipulation are reasonable.

Reliability Assurance O&M Adjustment

In DEC witness Walsh's direct testimony, he testified regarding the importance of keeping DEC's remaining coal-fired assets in efficient working order to support customers' energy needs as DEC plans for those units' retirement and explained that DEC will continue to incur costs for these assets as appropriate and prudent to ensure that reliable cost-effective electricity remains available while DEC develops and implements replacement of the coal fleet. Witness Walsh also testified that the fossil units operated efficiently and reliably during the test period. Tr. vol. 12, 638–39, 643.

In DEC witness Walsh's supplemental testimony, he explained the rationale for DEC's pro forma adjustment to O&M expenses for reliability assurance. Witness Walsh stated that the adjustment increased by $5.9 million the test period O&M costs related to planned reliability assurance projects. These additional projects are necessary to maintain reliability of the Belews Creek, Cliffside, and Marshall plants and include winterization projects. Witness Walsh also provided additional details concerning the work identified in the pro forma adjustment for reliability assurance. Witness Walsh stated that the pro forma adjustment reflects costs associated with the "major component" project category, which was identified in late 2022 through the Reliability Threats Analysis. Witness Walsh also stated that DEC intends the work to address large items of equipment that show a clear need of attention in order to maintain reliability of the unit, such as major maintenance and rebuilds of pumps, motors, and large breakers. Witness Walsh testified that the winterization O&M project category is work DEC identified as needed due to Winter Storm Elliott and represents an estimate of the cost of a study of needed repairs and installation of temporary structures to address freeze issues and those projects, such as additional wind breaks and insulation and updated heat trace systems. Witness Walsh testified that the reliability improvements project category represents a deeper level review of system health at the coal stations and typically addresses smaller items that can impact reliability, particularly when combined with other reliability issues. Witness Walsh stated that the operator workaround category is intended to address projects that are needed due to the challenge of utilizing operators to address deficient equipment as a "workaround" and would permit DEC to address such issues directly. Witness Walsh testified that the staffing project category represents DEC's forward projection of costs, primarily salary, benefits, and overhead, accounting for DEC's current understanding of attrition rates, to enable DEC to have adequate resources to operate the coal units until retirement. Witness Walsh also testified that DEC identified the repair hold project category through the Reliability Threat Analysis and that it represents major components that are currently in a repair hold status, do not have a readily available spare, and have long lead times that supply chain challenges have exacerbated. *Id.* at 665–69.

Public Staff witness Metz testified regarding DEC's historic operations of its generating fleet since the 2019 Rate Case Order and other discrete performance metrics over the last decade. Part of his review considered the overall system reliability, service quality, and reasonableness of using DEC's test year O&M costs as a proxy for expected future costs. Witness Metz stated that the primary purpose of his review was to determine whether and how DEC's historic operation of its generation fleet has changed. Witness Metz supported the use of the weighted equivalent availability factor (WEAF) or weighted equivalent unplanned outage factor (WEUOF), as well as other metrics, in reviewing fleet performance and noted that different conclusions are possible depending on the performance metrics one uses. Witness Metz clarified that the intent of the review was not to determine reasonableness or prudence of DEC's historic operations of its fleets. Witness Metz concluded that the performance of DEC's fossil generating fleet has degraded over the last decade, and suggested that if that trend continues, reliability could be impacted, especially as these units must perform in a different manner than originally designed as the generation fleet changes and as DEC removes other generation units from service. Witness Metz also noted DEC's reduction of the level of ongoing generating plant non-fuel O&M expenses, which DEC accomplished in part by reducing staffing, in the years following the test year of the last two DEC's rate cases. *Id.* at 844–54.

Based on the concerns Witness Metz identified with O&M expenses and fleet performance, he recommended several modifications to the adjustment to coal test year O&M expenses (Form E-1, Item 10, NC-2160):[9]

- Since DEC should have already completed the Reliability Threat Analysis and Winterization O&M project work, witness Metz recommended exclusion of the costs related to Reliability Threat Analysis work from any proposed

[9] Pro-forma NC-2160 was filed in DEC's May update.

pro forma adjustment and supported the inclusion of a reduced amount for the Winterization O&M work on a going forward basis. *Id.* at 861–62.

- Since the majority of the costs related to reliability improvements appeared to be capital-related rather than O&M related, and DEC had included a Winterization Capital project in the MYRP, witness Metz recommended exclusion of the Reliability Improvement costs from the pro forma adjustment. *Id.* at 862.

- Since there is no certainty regarding how the expected upcoming closure of DEC's Allen Steam Station will provide synergies or allow for staff relocation to other stations, witness Metz proposed excluding the staffing costs from the pro forma adjustment. *Id.*

- Witness Metz recommended that the Repair Hold category adjustment should be rejected because this category is an attempt to clear a backlog of a larger volume of inventory (spare parts) to be repaired. *Id.* at 863.

In DEC witness Walsh's rebuttal testimony, he described the challenge of optimizing plant investments and maintaining sufficient staffing for the coal-fired assets that DEP will retire in the near future. Witness Walsh stated that the varied timing of these assets' planned retirement dates introduces complexity as to how DEC reliably serves customers while optimizing investments. Witness Walsh explained that DEC must maintain the continued reliability of these units until replacement generation is in place. Witness Walsh explained further that DEC's strategy for addressing this challenge has evolved as circumstances have changed, but with a consistent focus on optimizing investment in the generation fleet based on which units are the most efficient, reliable, and expected to run the most. Most recently, witness Walsh testified that DEC has evaluated how best to ensure that the coal fleet continues to remain reliable up until these units' anticipated retirement, as these assets have run more days than anticipated and therefore required attention and investment. *Id.* at 680–81.

Witness Walsh also responded to witness Metz's specific recommendations regarding the Reliability Assurance pro forma NC-2160. With respect to the major components/Reliability Threat Analysis work, he explained that the Reliability Threat Analysis is not winter storm related and that, therefore, DEC would not have identified this work earlier. Witness Walsh also stated that the winterization O&M work reflected on the pro forma adjustment could not have already been done as it was identified in early 2023 following Winter Storm Elliott. Witness Walsh clarified that the reliability improvements including the operator workarounds work is pure O&M. Witness Walsh also explained that staffing considerations must take location and demographics into account and DEC's staffing models are not based on a percentage allocation between stations but rather on the demographics of the work force at each station. Finally, witness Walsh explained that the repair hold category recognizes the supply chain challenges and the longer time required to complete repairs that DEC faces today, and he disagreed that this work addresses a backlog noting that much of the inventory intended to be addressed came into inventory within the past year. *Id*. at 703–11.

Witness Walsh also responded to witness Metz's testimony regarding fossil fleet performance and O&M investment noting that it is important to view the entire fleet's performance and not focus solely on the coal fleet. Based on the equivalent forced outage factor (EFOF) metric, he stated that DEC's fossil fleet is performing consistent with or better than the industry average, and the natural gas units have exceeded industry average performance. *Id.* at 711–12. Witness Walsh testified that DEC economically dispatches the lowest cost units to serve customers and that the units at the top of the dispatch order need to be the most reliable because they are used the most to serve customers. Witness Walsh noted that the addition of DFO to Cliffside, Belews Creek, and Marshall Stations has increased fuel flexibility for the benefit of customers and that DEC must sufficiently invest in these units to keep the entire fleet reliable. Witness Walsh emphasized that the evaluation of fleet performance and reliability assurance needs have changed over time and will differ between smaller coal units and units with lower gas firing DFO capability as compared to the supercritical coal units, units with higher DFO capability, and natural gas combined cycle units. Witness Walsh concluded that the Reliability Assurance pro forma represents the adjustments that DEC has identified as needed to maintain the coal units in reliable condition. *Id.* at 715–16.

The Revenue Requirement Stipulation provides for inclusion of an additional $4.5 million (North Carolina retail) of annual incremental spend for ongoing O&M for DEC's coal generation fleet for discrete programs and targeted categories that witness Walsh lists in his supplemental and rebuttal testimony and supporting workpapers. The parties agreed that DEC will track and report on an annual basis the actual spend and employee head count for each coal generation station over the MYRP period in a manner to be agreed upon between DEC and the Public Staff. DEC will record any cumulative underspend to a regulatory liability account accrued through the end of the MYRP period (December 2026) and return it to customers in the next general rate case. Amended Revenue Requirement Stipulation §§ III.15, IV.47 (Tr. Ex. vol. 7). DEC witness Q. Bowman supported this provision in her settlement supporting testimony. Tr. vol. 12, 235–36, 243–44.

The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding. DEC has demonstrated that these funds are necessary to maintain the reliability of the coal units until their anticipated retirement. The Public Staff raised valid concerns regarding the performance of the DEC fossil fleet, specifically the coal units, and the Commission recognizes that reviews of performance can have different results depending on the metric the reviewer uses to evaluate it. DEC's tracking and annual reporting of the actual spend and employee head count for each coal generation station over the MYRP period will help to further inform this discussion as these units' retirements approach. The parties' agreement that DEC will record any cumulative underspend to a regulatory liability account accrued through the end of the MYRP period and return it to customers in the next general rate case addresses the concerns the Public Staff raised regarding

O&M spending. In its first annual report, the Commission directs DEC to update the Commission on the agreed upon specifics for the tracking and reporting of the actual spend and employee head count for each coal generation station.

Aviation Expense

In its initial filing, DEC removed 50.0% of corporate-related aviation expenses allocated to DEC in the test period that are not related to aerial patrol. DEC witness Q. Bowman testified that DEC believes these costs were reasonable, prudent, and appropriate to recover from customers but elected to remove them in this case. Tr. vol. 12, 24–25. Public Staff witnesses Zhang and Boswell recommended, in addition to the 50.0% already removed by DEC, removal from DEC's cost of service of additional flight costs that the Public Staff found to be unrelated to the provision of utility service including portions of certain commercial international flights. *Id.* at 1018.

The Revenue Requirement Stipulation removes aviation expenses associated with international flights, in addition to the 50.0% of aviation expenses removed in the Application. Amended Revenue Requirement Stipulation § III.17 (Tr. Ex. vol. 7). No intervenor took issue with this provision of the stipulation which is consistent with the DEP Rate Case Order. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Executive Compensation

In DEC's Application, it removed 50.0% of the compensation of the five Duke Energy executives with the highest level of compensation allocated to DEC. DEC witness Q. Bowman explained that while DEC believes these costs are reasonable, prudent, and appropriate to recover from customers; DEC has, for purposes of this case, made an adjustment to this item. Tr. vol. 12, 166. Public Staff witnesses Zhang and Boswell recommended an adjustment to include the update to Short-Term Incentive Plan actuals paid to the executives and an additional adjustment to remove 50.0% of the benefits of these top five Duke Energy executives, noting that the adjustment was consistent with similar recommendations the Public Staff has made and the Commission has approved in past rate cases. *Id.* at 1014.

Section III, Paragraph 18 of the Amended Revenue Requirement Stipulation provides for removal of 50.0% of the benefits of the five Duke Energy executives with the highest amounts of compensation, in addition to the 50.0% of their compensation DEC removed in the Application. Amended Revenue Requirement Stipulation § III.18 (Tr. Ex. vol. 7). No intervenor took issue with this provision of the stipulation which is consistent with the DEP Rate Case Order. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Charitable Contributions and Sponsorships

In DEC witness Speros' direct testimony, he certified that DEC's cost of service does not include any expenditures for charitable contributions in accordance with the requirement of Commission Rule R12-13(a) as amended. Tr. vol. 12, 534–35. Witness Speros testified that Commission Rule R12-13(a) requires that in every application for a change in rates, a utility must certify in its prefiled testimony that its application does not include certain costs including charitable contributions. *Id.* at 534. Witness Speros further explained that he performed additional reviews of DEC's cost of service to ensure that DEC did not include any costs that Commission Rule R12-13 prohibits in the Application. *Id.* at 535.

Public Staff witnesses Zhang and Boswell recommended an adjustment to charitable contributions of approximately $23,000 to exclude expense amounts paid to the Chambers of Commerce and other donations. Tr. vol. 12, 1023; Public Staff Accounting Ex. 1 at sched. 1, l. 33 (Tr. Ex. vol. 12). Witnesses Zhang and Boswell stated that these expenses should be disallowed because they do not represent actual costs of providing electric service to customers. Tr. vol. 12, 1023.

In witness Speros' rebuttal testimony, he explained that Chambers of Commerce promote business and economic development, which in turn helps to retain and attract customers to DEC's service territory. *Id.* at 560. In addition, funds DEC paid to Chambers of Commerce that DEC does not specify as a donation or lobbying are in fact supporting business or economic development, and DEC properly considers them as utility operating expenses and includes them in DEC's cost of providing electric service to customers. *Id.* Finally, witness Speros noted that $23,000 on a North Carolina retail basis was inadvertently charged to above-the-line accounts rather than below-the-line; he testified that these amounts have been charged against the allowance for mischarges included in the case. *Id.* at 561.

The Revenue Requirement Stipulation establishes that base year revenue requirement will be reduced by $23,000 (North Carolina retail basis) in connection with charitable contributions and sponsorships. Amended Revenue Requirement Stipulation § III.19 (Tr. Ex. vol. 7). No intervenor took issue with this provision of the Revenue Requirement Stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Board of Directors Expenses

With respect to Board of Directors expenses, Public Staff witnesses Zhang and Boswell recommended an adjustment to remove 50.0% of the expenses associated with the Board of Directors of Duke Energy that had been allocated to DEC, similar to the Public Staff's recommendation regarding executive compensation and benefits of the five Duke Energy executives with the highest level of compensation allocated to DEC in the test period. Tr. vol. 12, 1015–16. In his rebuttal testimony, DEC witness Stewart indicated that the law requires DEC to have a Board of Directors and that the costs of being an investor-owned utility, including Board costs, are in fact costs of service. *Id.* at 613. Witness Stewart argued that it is not fair or reasonable to penalize DEC for being an investor-owned utility with attendant requirements to that corporate structure. *Id.*

The Revenue Requirement Stipulation accepts the Public Staff's recommended adjustments to the Board of Directors expenses. Amended Revenue Requirement Stipulation § III.21 (Tr. Ex. vol. 7). No intervenor took issue with this provision of the stipulation, which is consistent with the DEP Rate Case Order. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Lobbying Expenses

In DEC witness Speros' direct testimony, he certified that DEC's cost of service does not include any expenditures for lobbying, political or promotional advertising, political contributions, or charitable contributions in accordance with the requirement of Commission Rule R12-13(a) as amended. Tr. vol. 12, 534–35. Witness Speros further explained that he performed additional reviews of DEC's cost of service to ensure that DEC did not include costs that Commission Rule R12-13 prohibits in the Application. *Id.* at 535.

With respect to lobbying expenses, Public Staff witnesses Zhang and Boswell adjusted O&M expenses to remove additional costs associated with Federal Government Affairs, Governmental Affairs and External Relations, and National Engagements that DEC recorded above the line in the test year. *Id.* at 1018–19. Witnesses Zhang and Boswell stated that Commission Rule R12-12 and the Commission's Order in Dominion Energy North Carolina's 2012 Rate Case[10] (2012 DENC Rate Case Order) justify removal of these expenses. *Id.* at 1018–19.

In DEC witness Speros' rebuttal testimony, he stated that DEC disagrees that any adjustment to remove any additional cost from the cost of service under Commission Rule R12-12 or the Commission's decision in the 2012 DENC Rate Case Order is necessary. *Id.* at 550–51.

The Revenue Requirement Stipulation establishes that while DEC maintains its position that its cost of service in this case did not include any lobbying expenses, for the purposes of settlement, DEC accepted the adjustments proposed by the Public Staff (with agreed upon corrections) for lobbying expenses. Amended Revenue Requirement Stipulation § III.20 (Tr. Ex. vol. 7). No intervenor took issue with this provision of the stipulation, which is consistent with the DEP Rate Case Order. The Commission

[10] Order Granting General Rate Increase, *Application of Virginia Electric Power Company, d/b/a Dominion North Carolina Power, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina,* No. E-22, Sub 479 (N.C.U.C. Dec. 21, 2012).

concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Nuclear End-of-Life Reserve

Public Staff witness Metz recommended that a 5.0% salvage value be applied to nuclear materials and supplies (M&S) inventory for purposes of calculating DEC's end of life nuclear reserve. Tr. vol. 12, 842–43.

In DEC witness Capps' rebuttal testimony, he testified that if DEC receives approval of its requests for subsequent license renewal of its nuclear units, there will be few to no similar technology nuclear plants in operation at the time DEC's units retire in the next 20 years. With few to no similar vintage nuclear or coal plants in operation, the market for the more expensive inventory items such as pumps, motors, and valves will be severely limited or nonexistent. DEC does not expect markets for inventory components at or near market value to exist. Witness Capps indicated that while DEC generally agrees that there may be some small amount of salvage value for nuclear M&S inventory at its end of life, disposal expenses will largely offset any such value. Witness Capps concluded that DEC does not support maintaining a particular salvage value going forward until the retirement of the nuclear units because doing so would reduce DEC's ability to adjust the salvage value for M&S inventory as needed in the future based on changed circumstances. *Id.* at 304.

The Revenue Requirement Stipulation accepts the Public Staff's adjustment to end-of-life nuclear M&S reserve expense, reduced as described in the direct testimony of Public Staff witness Metz. Amended Revenue Requirement Stipulation § III.23 (Tr. Ex. vol. 7). DEC witness Q. Bowman and Public Staff witnesses Zhang and Boswell supported this provision in their settlement supporting testimony. Tr. vol. 12, 237; Public Staff Accounting Ex. 1 at sched. 1, l. 26 (Tr. Ex. vol. 12). The Commission concludes that the adjustment to the nuclear end-of-life reserve established in the Revenue Requirement Stipulation is supported by the evidence presented, is just and reasonable and fair to all, and should be approved.

Coal Inventory

Based on DEC's historical performance, updated coal inventory analysis, and recent coal inventory holdings, Public Staff witness Michna recommended that DEC maintain its current coal inventory of 35 days of 100.0% full load burn and reduce the corresponding DEC adjustment that increased coal inventory to 40 days by $19,301,577 to account for this change. Tr. vol. 15, 46–47.

DEC witness Walsh opposed witness Michna's adjustment. Witness Walsh asserted that the adjustment failed to contemplate the changing market factors impacting a reliable fuel supply, namely the inability of the coal supply chain to timely respond to volatility in coal generation demand and ignored DEC's updated average inventory of

38.8 days. Witness Walsh concluded that it is prudent to increase the target from 35 days to 40 days. Tr. vol. 12, 717, 721–22.

The Revenue Requirement Stipulation accepts the annual 35 full load day burn average to establish the level of coal inventory for purposes of establishing a revenue requirement. Amended Revenue Requirement Stipulation § III.22 (Tr. Ex. vol. 7). DEC witness Q. Bowman and Public Staff witnesses Zhang and Boswell supported this provision in their settlement supporting testimony. Tr. vol. 12, 238; Public Staff Accounting Ex. 1 at sched. 1, l. 13 (Tr. Ex. vol. 12). The Commission concludes that the 35-day coal inventory target proposed in the Revenue Requirement Stipulation (which is consistent with the DEP Rate Case Order) is supported by the evidence presented, is just and reasonable and fair to all, and should be approved.

Credit Card Payment Fees

In DEC witness Quick's direct testimony, she proposed to offer a Fee-Free program for small and medium nonresidential customers who make payments using debit, credit, prepaid, or electric check (Card Payments) to pay their electric bills. Tr. vol. 7, 160. In support of DEC's request, she noted that residential customers have a transaction Fee Free program for Card Payments, which the Commission approved in DEC's last general rate case. *Id.* Witness Quick recounted that nonresidential customers making Card Payments are subject to a convenience fee of $8.50 per payment for payments up to $10,000; for payments in excess of $10,000, the convenience fee is 2.75% of the amount paid. *Id.* at 161. DEC's vendor charges the convenience fee, and DEC receives no portion of it. *Id.* Based on customer feedback and requests, witness Quick proposed in this case to offer the Fee-Free program for Card Payments to nonresidential customers making bill payments up to $3,000. *Id.* at 162–63. DEC, instead of the customer, would pay the vendor the convenience fees for these Card Payments and incorporate the expense into the cost of service for recovery through its base rates. *Id.* at 162.

In Public Staff witnesses Zhang and Boswell's joint testimony, they opposed DEC's proposal to socialize the credit card payment fees for nonresidential customers. Tr. vol. 12, 1019–20. They noted that the current volume of customers who use this method of payment accounts for less than 1.0% of the overall bill pay transactions volume. *Id.* at 1019. Additionally, witnesses Zhang and Boswell distinguished this proposal from the socialization of the residential credit card fees the Commission allowed in the 2019 Rate Case Order by noting that the residential Fee-Free program had the potential to produce reductions in late payments and uncollectibles, but nonresidential customers do not experience the same level of late payments and uncollectibles as residential customers. *Id.* at 1019–20. Therefore, they testified that they found no offsetting benefit of socialization of Card Payment fees for the nonresidential customers to general ratepayers. *Id.* at 1020.

The Revenue Requirement Stipulation establishes that the credit card payment fees for nonresidential customers shall be removed from the revenue requirement in this case. Amended Revenue Requirement Stipulation § III.24 (Tr. Ex. vol. 7). The

Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Vegetation Management O&M

In DEC witness Maley's direct testimony, he described DEC's transmission Integrated Vegetation Management (IVM) Plan and its goal of removing and controlling incompatible vegetation within and along transmission rights of way. Witness Maley indicated that the IVM includes planned corridor work, reactive work, and floor management work, with DEC prioritizing the first two categories based on threat assessments. Witness Maley also indicated that DEC had included an increase in vegetation management costs in its test period pro forma adjustments to account for increased outside labor costs and that this adjustment also covers vegetation management costs associated with the expansion of existing substation sites. Tr. vol. 8, 271–72.

In DEC witness Guyton's direct testimony, he testified that DEC utilized a reliability prioritization model to drive its routine IVM program. The other important components of DEC's vegetation management include the following programs: herbicide management, hazard trees, reactive customer requested activities, and post outage vegetation management activities. Witness Guyton also testified that DEC continues to utilize a five-year cycle for distribution vegetation management in urban areas, a seven-year cycle for distribution vegetation management in mountain areas, and a nine-year cycle for distribution vegetation management in areas categorized as "other" consistent with DEC's 2013 Tree Growth Study. *Id*. at 116–17.

In Public Staff witness T. Williamson's direct testimony, he described DEC's IVM plan and provided a summary of the operation of that plan since 2015. This description included both vegetation within DEC's rights of way and vegetation that lies outside DEC's rights of way. DEC's hazard tree program manages the vegetation which lies outside DEC's rights of way. Witness T. Williamson also recommended changes to DEC's assessment activities which would increase the frequency of its review of distribution lines, and he recommended reductions in one part of the Distribution System Vegetation Management budget and three parts of the Transmission System Vegetation Management budget. Finally, witness T. Williamson recommended changes to the Distribution and Transmission vegetation plan reporting requirements. Tr. vol. 15, 130–51.

In DEC witness Guyton's rebuttal testimony, he addressed Public Staff witness T. Williamson's vegetation plan recommendations and indicated that DEC would consider the recommendations but noted that immediate implementation of the recommendations would have resource and cost implications that DEC needed to evaluate. Witness Guyton further stated that reductions in Distribution Vegetation Management plan budgets would prevent DEC from trimming its full five-year, seven-year, and nine-year mileage targets because DEC's Vegetation Management costs were already higher than those reflected in the budget. Tr. vol. 8, 199–200. Witness Guyton agreed to witness T. Williamson's reporting recommendation. *Id.* at 201–02.

In DEC witness Maley's rebuttal testimony, he addressed Public Staff witness T. Williamson's recommended reductions to the Transmission System Vegetation Management budget. Witness Maley explained his disagreement with two of witness T. Williamson's recommended budget reductions but agreed with one recommendation. *Id.* at 331–34. Witness Maley agreed to witness T. Williamson's reporting recommendation with two exceptions. *Id.* at 354.

No other party presented evidence on these matters.

The Revenue Requirement Stipulation provides for a $3 million (North Carolina retail basis) increase to the test year vegetation management O&M and for adoption of the additional vegetation management reporting requirements recommended by Public Staff witness T. Williamson except as noted in the rebuttal testimony of DEC witness Maley. Amended Revenue Requirement Stipulation §§ III.16 and IV.48 (Tr. Ex. vol. 7). The Commission concludes that these adjustments in the Revenue Requirement Stipulation are supported by the evidence presented and are just and reasonable and fair to all and should be approved.

Extra Facility Charge Revenue

In Public Staff witness Metz's direct testimony, he first explained that EFC revenue applies when a customer requests from the utility a level of service above the standard offer or standard level of service. Witness Metz recommended that DEC's revenue be increased by approximately $4.4 million to reflect an increase in EFC revenue because DEC did not include the EFC revenue in its pro forma adjustments for this proceeding. Witness Metz also recommended that the allocation factor be set to 100.0% North Carolina retail because DEC did not provide the Public Staff the requested information during discovery to determine the appropriate allocation of the EFC revenue for this proceeding. Tr. vol. 12, 837–38.

In rebuttal, DEC witness Q. Bowman testified that DEC did not include a pro forma adjustment for EFC revenue as such an adjustment has not been included as a routine pro forma adjustment in past rate cases. Tr. vol. 15, 1265. Witness Q. Bowman further testified that DEC typically tries to limit pro forma adjustments to those that are routine (i.e., included in every case) and those that are significant in magnitude. *Id.* Witness Q. Bowman maintained that an adjustment to annualize EFC revenues did not meet either of these criteria. *Id.* Witness Q. Bowman testified that should the Commission decide to include this adjustment, the calculation should be modified to account for offsetting incremental EFC O&M expenses which are approximately 15.7% of the EFC revenue and would result in a reduction in revenue requirement of $3.7 million instead of the $4.4 million proposed by the Public Staff. Witness Q. Bowman further stated after meeting with the Public Staff, DEC was able to provide the Public Staff the additional requested information. *Id.* at 1266.

Section III, Paragraph 25 of the Amended Revenue Requirement Stipulation provides that the Stipulating Parties agree to update the EFC revenue to 2023 levels as adjusted in DEC witness Q. Bowman's rebuttal testimony. Amended Revenue Requirement Stipulation § III.25 (Tr. Ex. vol. 7).

Section III, Paragraph 2 of the Supplemental Revenue Requirement Stipulation provides that the Stipulating Parties agree to apply annualized EFC revenue of $310,987 related to the Apex Solar facility to the base period revenue requirement. The Commission concludes that the EFC revenue adjustments in the Revenue Requirement Stipulation are supported by the evidence presented and are just and reasonable and fair to all and should be approved.

Nuclear Levelization Costs

In DEC witness Q. Bowman's direct testimony, she testified that in DEC's 2013 Rate Case Order,[11] the Commission approved an accounting mechanism that levelized certain costs related to nuclear refueling outages. Tr. vol. 12, 169. This adjustment annualizes the amortization expense related to this mechanism incurred during the test period to the latest known and measurable level experienced through the capital cut-off period. *Id.* For this case, DEC witness Q. Bowman provided updated amounts of these costs through the June 30, 2023 capital cutoff date. *Id.* at 223, 225.

Public Staff witness Metz testified that he found two nuclear refueling outages, one at Catawba Unit 2 and the other at Oconee Unit 3, that were atypical, and if not adjusted, would result in an excessive expense being included in rates until DEC files its next general rate case. Tr. vol. 12, 840. Accordingly, he proposed a series of modifications that reduced DEC's associated pro forma by approximately $1.8 million (North Carolina retail basis). *Id.* at 841. Witness Metz testified that he was not taking issue with the outage durations for either outage or the decisions DEC made for the delay; rather, his proposed adjustment reflects his concern with the use of the two outages as the basis for ongoing expected costs for nuclear refueling outage costs in base rates. *Id.*

In rebuttal, DEC witness Q. Bowman testified that DEC disagreed with the Public Staff's recommended adjustment because it is inconsistent with the Agreement and Stipulation filed on June 17, 2013, in the 2013 Rate Case.[12] Tr. vol. 15, 1266. Witness Q. Bowman testified that this stipulation set forth a deferral and amortization recovery mechanism for nuclear outage costs, but she notes that witness Metz contradicts such earlier stipulation by proposing to establish a normalized level of expense going forward rather than amortizing actual, prudently incurred costs consistent with that stipulation. *Id.* Witness Q. Bowman testified that DEC's nuclear levelization adjustment complies with the earlier stipulation while witness Metz's adjustment does not. *Id.* at 1266–67. Witness

[11] *See* Order Granting General Rate Increase, *Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-7, Sub 1026 (N.C.U.C. Sept. 24, 2013) (2013 Rate Case Order).

[12] *See* Application and Request for an Accounting Order, *Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina*, No. E-7, Sub 1026 (Feb. 4, 2013) (2013 Rate Case).

Q. Bowman notes that the Public Staff did not take issue with the costs incurred for nuclear outages but rather only with the calculation of the adjustment. *Id.* at 1267.

Section III, Paragraph 26 of the Amended Revenue Requirement Stipulation provides that the stipulating parties agree to amortize actual nuclear levelization costs incurred with no adjustments. Amended Revenue Requirement Stipulation § III.26 (Tr. Ex. vol. 7). No intervenor took issue with this provision of the Revenue Requirement Stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Marshall O&M Costs

Public Staff witness Michna recommended that the test year non-fuel O&M expense for Marshall Station be adjusted to scale to the 2022 rate of $/MWh of O&M which would reduce Marshall's test year non-fuel O&M by $7.8 million. Witness Michna stated that because the dual fuel operations upgrades at Marshall Station were used and useful for 2022, the 2022 O&M spending should be used to determine the going forward expense instead of the test year. Tr. vol. 15, 58–60.

In DEC witness Walsh's rebuttal, he testified that DEC disagreed with this adjustment. Tr. vol. 12, 723. In DEC witness Q. Bowman's rebuttal, she testified to a calculation error and stated that DEC would work with the Public Staff to resolve the issue. Tr. vol. 15, 1267.

The Revenue Requirement Stipulation provides that no adjustment shall be made to Marshall O&M costs. Amended Revenue Requirement Stipulation § III.27 (Tr.Ex. vol. 7). DEC witness Q. Bowman supported this provision in her settlement supporting testimony. Tr. vol. 12, 243. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Materials and Supplies Inventory

Based on Public Staff witness Lucas' assessment that W.S. Lee Unit 3 is retired and Allen Units 1 and 5 are planned for retirement on or before December 31, 2023, he recommended that DEC's inventory return for Lee Unit 3 and Allen Units 1 and 5 not be included in rates. Tr. vol. 13, 123–24.

In DEC witness Q. Bowman's rebuttal testimony, she testified that DEC partially agreed with witness Lucas' proposed adjustment. Witness Q. Bowman stated that M&S inventory is held at sites until retirement, at which point such inventory is typically recovered through separate regulatory asset treatment or charged against the COR reserve. Witness Q. Bowman stated that DEC agreed with the removal of the Lee Unit 3 inventory balance as the plant was retired in March 2022. Witness Q. Bowman also stated that because inventory balances were charged to COR and included in the net plant portion of rate base as of the cut-off period, and therefore already included in rate base in a different location, it is appropriate to remove them from inventory so as not to double count. Tr. vol. 15, 1250–51.

Witness Q. Bowman did not agree with witness Lucas' proposal to remove inventory costs related to Allen Units 1 and 5 because the plants were not retired as of the capital cut-off date of June 30, 2023, nor were the units expected to be retired by the time of the hearing in the case. Witness Q. Bowman noted that the dismantlement study included in the case includes estimates of inventory amounts remaining at retirement as part of the COR estimates included in the depreciation study but since these units are still operational the inventory balances have not been charged to COR. Witness Q. Bowman clarified that once the units are retired, the inventory will be charged against COR but remain in rate base, just in a different location net plant. As a result, even if the units are retired by the time of the hearing, it would still not be appropriate to remove the inventory from rate base for ratemaking purposes. Tr. vol. 15, 1251–52.

The Revenue Requirement Stipulation provides that the M&S inventory balance associated with Lee Unit 3 as detailed in the testimony of Public Staff witness Lucas and the rebuttal testimony of DEC witness Q. Bowman will be removed. Amended Revenue Requirement Stipulation § III.28 (Tr. Ex. vol. 7). The Revenue Requirement Stipulation also provides that no adjustment is necessary to the M&S inventory costs associated with Allen Units 1 and 5. Amended Revenue Requirement Stipulation § III.29 (Tr. Ex. vol. 7). DEC witness Q. Bowman supported these provisions in her settlement supporting testimony. Tr. vol. 12, 238, 242. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of these issues for purposes of this proceeding.

Allen Unit 4 Costs Deferral

In DEC witness Q. Bowman's direct testimony, she testified that in the 2019 Rate Case Order, the Commission granted DEC authority to establish a regulatory asset for the unrecovered costs associated with Allen Unit 4 at the time of its retirement. Witness Q. Bowman stated that DEC will continue amortization of the regulatory asset at the existing depreciation rates from retirement until an appropriate amortization period is determined in this rate case. Witness Q. Bowman explained that DEC made an adjustment to amortize the remaining regulatory asset, including a reduction for the Buck Coal Plant overamortization from the 2013 Rate Case and an estimated amount of dismantlement costs, net of salvage, over a six-year period. Tr. vol. 12, 179.

Public Staff witness Lucas recommended that the Commission set the Decommissioning Study adder for "project indirects" at 5.0% rather than 10.0% as proposed by DEC and require a 10.0% contingency factor, rather than the 20.0% factor proposed by DEC. Witness Lucas proposed that his decommissioning study recommendations be reflected for Allen Unit 4. Tr. vol. 13, 121–22. Public Staff witnesses Zhang and Boswell made an adjustment to reflect witness Lucas' recommendation to adjust the costs included in the deferral of Allen Unit 4 and did not recommend any change in DEC's proposed six-year amortization period. Tr. vol. 12, 1041–42.

In rebuttal, DEC witness Kopp testified that based on costs actually incurred by DEC on recently completed decommissioning projects, 10.0% is an appropriate number to use for project indirect costs in this case. Tr. vol. 12, 424–27. Witness Kopp also testified that based on the types of activities that will take place during decommissioning, the level of unknowns that would result in potential cost increases, and DEC's experience incurring the contingency costs included in its estimates, a 20.0% contingency is reasonable to use in this case. Tr. vol. 12, 427–35.

In DEC witness Q. Bowman's rebuttal, she explained that the balance for amortization represents the net book value of the plant at retirement including dismantlement costs for the retirement of Allen Unit 4 and an offset of overamortization of the Buck Coal Plant retirement due to the like-kind nature (i.e., both amortizations were due to early retirement of plant). Tr. vol. 15, 1255. Witness Q. Bowman stated that for the reasons discussed in DEC witness Kopp's rebuttal, DEC did not agree with the adjustment for dismantlement expenses. Witness Q. Bowman stated further that it is appropriate to apply the Buck Coal Plant overamortization to the Allen Unit 4 deferral balance because the overamortization was like-kind in nature. Witness Q. Bowman also testified that the appropriate balance to include in rate base is the estimated balance as of December 31, 2023. This deferred plant balance has been in rate base and amortizing at the existing Allen 4 depreciation rate, and therefore it has already been reduced by more than a year's worth of amortization. Tr. vol. 15, 1256.

The Revenue Requirement Stipulation provides for the deferral of Allen Unit 4 costs, subject to adjustment of the decommissioning estimate for contingency and indirect adder for Unit 4, no adjustment to Unit 4 inventory estimate, and to DEC's position on rate base as amortization of Allen Unit 4 is already reflected in the test year. Amended Revenue Requirement Stipulation § III.30 (Tr. Ex. vol. 7). The Revenue Requirement Stipulation also provides that the overamortization related to the Buck Coal Plant retired plant regulatory asset will be netted against the Allen 4 retired plant regulatory asset, as proposed by DEC. Amended Revenue Requirement Stipulation § III.40.a.iii (Tr. Ex. vol. 7). DEC witness Q. Bowman supported these provisions in her settlement supporting testimony. Tr. vol. 12, 241, 256. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Lighting Audit

Public Staff witnesses Zhang and Boswell testified that DEC agreed in a settlement agreement filed on June 17, 2013, in the 2013 Rate Case to change its billing system to ensure that all lighting customers received a revised EFC rate of 1.1% instead of the then-existing 1.7%. Tr. vol. 12, 1039. In the 2013 Rate Case, this Commission ordered that DEC credit any customers continuing to be charged at the 1.7% EFC rate, and that DEC provide a detailed report of the billing corrections. *Id.* at 1040. In their 2013 Rate Case settlement agreement, DEC and the Public Staff agreed to defer the costs associated with conducting this audit. *Id.* Now, in this rate case, DEC seeks recovery of the estimated $656,000 in deferred costs associated with the lighting audit that was incurred between 2013 and 2015. *Id.*

Witnesses Zhang and Boswell testified that the customers who benefitted from the lighting audit were those who received credits in the two-year timeframe following the Commission's 2013 Rate Case Order. Tr. vol. 12, 1040. However, they testified that customers since that timeframe have not benefitted from the lighting audit. *Id.* Further, DEC filed rate cases in 2017 and 2019 but did not seek recovery of its lighting audit costs in those cases, both of which were closer in time to when the costs were incurred than the current rate case. *Id.* Given how much time has passed, witnesses Zhang and Boswell testified that allowing DEC to recover from current customers the costs incurred between 2013 and 2015 would cause significant intergenerational equity issues. *Id.* at 1040–41. Thus, while the Public Staff did not take issue with the prudency of the lighting audit costs, the Public Staff recommended denying DEC's request to recover those costs. *Id.* at 1041.

In rebuttal, DEC witness Q. Bowman testified that DEC opposed the Public Staff's proposed adjustment and noted that DEC acknowledged that it did not bring its lighting audit costs up for recovery sooner. Tr. vol. 15, 1257. Witness Q. Bowman testified that this delay in seeking recovery does not invalidate the fact that the costs are reasonable, were prudently incurred, and should be recoverable. *Id.* Moreover, she testified that there has been no return accrued on this balance, and thus, the delayed timing has no impact on the amount requested for recovery. *Id.* Witness Q. Bowman further testified that if intergenerational equity is a concern, the Public Staff could have chosen to net the full deferral of $656,028 against the overamortization amounts which have already been collected from customers to better align the timing, rather than proposing a disallowance of reasonable and prudent costs. *Id.*

In the Revenue Requirement Stipulation, the stipulating parties agree that DEC will remove from rate base $656,028 in deferred costs associated with the lighting audit incurred between 2013-2015 and will not seek to recover those deferred costs. Amended Revenue Requirement Stipulation § III.31 (Tr. Ex. vol. 7). The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

IIJA for Hydroelectric Plants

Public Staff witness Thomas recommended that the costs of certain MYRP hydroelectric projects be reduced by the hydroelectric incentives for which those projects were likely eligible under the IIJA. Tr. vol. 14, 186–87. Witness Thomas identified several projects in an exhibit to his direct testimony and recommended a total reduction in costs for those projects of approximately $37.9 million throughout the MYRP. *Id.* at 233.

In DEC witness Klein's rebuttal testimony, she opposed witness Thomas's recommendations and described DEC's approach to pursuing IIJA funds. Tr. vol. 15, 1213. Witness Klein testified that IIJA programs are highly competitive, and therefore, it is not possible to project with any degree of confidence whether DEC will be selected for an IIJA award or the grant amount that will be awarded. *Id.* at 1222. In addition, witness Klein explained that under DEC's internal prioritization framework, DEC pursues IIJA funds for programs that will provide the greatest benefits to customers, and DEC uses its prioritization framework to identify priority IIJA programs based on the resources and costs that would be required to pursue funds. Witness Klein testified that DEC has also used its prioritization framework to identify IIJA programs for which DEC is not directly eligible but may have opportunities to partner with eligible entities in a joint or supporting capacity. *Id.* at 1218. Regarding the specific hydroelectric incentive projects identified by Public Staff witness Thomas, witness Klein testified that as hydroelectric incentives under the IIJA are subject to cost caps and funds have only been appropriated for fiscal year 2022, it is not certain that funds for these projects will be available after 2022. *Id.* at. 1224. Witness Klein also testified that multiple developments within individual FERC -licensed hydroelectric projects are treated as a single hydroelectric facility for IIJA -eligibility purposes, and therefore, only one IIJA incentive payment may be made to each hydroelectric facility per fiscal year. *Id.* at 1225.

The Revenue Requirement Stipulation establishes that, for the hydroelectric projects identified in Public Staff's testimony for which Duke has previously submitted IIJA applications, the base period and MYRP revenue requirement will be adjusted based on Public Staff's recommendation to incorporate assumed receipt of such IIJA grants, net of costs incurred, with deferral of any variance to the revenue requirement once actual IIJA funding amounts are known, including the impact should DEC not receive the funding. For hydroelectric projects for which DEC did not apply for IIJA funds, the stipulation provides that no adjustment shall be made to the MYRP revenue requirement and that the Public Staff will not seek to disallow costs in DEC's next general rate case for the hydroelectric MYRP projects (identified in Thomas Exhibit 17) that meet both of the following conditions: (1) are either under the Catawba-Wateree FERC license or the East Fork Tuckasegee FERC license; and (2) have capital cost estimates less than $16.7 million.

Overamortizations

In its Application, DEC requested permission to apply expiring overamortizations as an offset to the deferral balances of costs that DEC believed were similar in nature, but which may not yet have been approved by the Commission. The requested offsets include: (1) the CCR ARO; (2) rate case expenses; (3) application of the overamortization of severance costs to rate case expenses; and (4) application of the overamortization of the Buck early retired coal plant to the Allen Unit 4 early retired coal plant. Application at E1-10 (Tr. Ex. vol. 12).

In DEC witness Q. Bowman's direct testimony, she supported adjustment NC5010 which removes from the test period the costs the amortization of various regulatory assets or liabilities that have been approved by the Commission in previous general rate case proceedings. Tr. vol. 12, 177. Witness Q. Bowman testified that the amortization period for the items removed will expire before proposed new rates are effective and thus should not be included in test period expenses on which new rates are based. *Id.* Witness Q. Bowman explained that overamortizations of the regulatory assets and liabilities have been applied to like kind expense recovery in this case. *Id.* Witness Q. Bowman also testified that DEC intends to apply the overamortization of Buck Coal Plant regulatory assets against the Allen Unit 4 plant regulatory asset allowed in the 2019 Rate Case Order, as an example. *Id.* at 179.

In Public Staff witnesses Zhang and Boswell's direct testimony, they recommended that the Commission remove DEC's proposed overamortization offsets and return the expiring amortizations to customers as a single rider over a period of one year with interest. Tr. vol. 12, 1024–25. Witnesses Zhang and Boswell explained that currently regulatory assets are handled on a case-by-case basis with the recovery period determined by the Commission based on the specifics of the item to be recovered. *Id.* at 1042. They testified that by offsetting the expiring amortizations against continuing amortizations, DEC is overriding the Commission's approved terms for recovery of the individual regulatory assets. *Id.* Witnesses Zhang and Boswell testified that the Public Staff recommends returning the overamortizations to ratepayers through a one-year rider with interest which allows for the refund to customers while maintaining the terms of the Commission's previous approvals of the remaining regulatory assets. *Id.*

In rebuttal, DEC witness Q. Bowman described each of the expired amortizations that DEC is proposing to offset against like costs: (1) coal ash;[13] (2) rate case costs; (3) severance; and (4) early retirement of coal plants. Tr. vol. 15, 1299–1303. Witness Q. Bowman explained how DEC's proposed treatment of the expiring amortizations is consistent with the 2017 Rate Case Order. *Id.* at 1297–98. Witness Q. Bowman stated that, in the 2017 Rate Case Order, the Commission previously addressed continuing amortizations of expired regulatory assets and liabilities in the context of coal ash costs. *Id.* Witness Q. Bowman further stated that in that order the Commission concluded:

> With regard to DEC's CCR costs from 2018 forward, DEC witness McManeus testified that DEC is requesting to establish a regulatory asset/liability account and defer to this account the portion in annual rates that is more than DEC's actual costs, or the amount in annual rates that is less than DEC's actual costs. In essence, the asset/liability account would be a tool used to true-up the difference in DEC's next general rate case. The Commission agrees with DEC's recommended approach, not only for CCR costs, but also for all cost deferral accounts . . . . Rather, the Company should continue to record all amounts recovered as deferred costs in the

[13] The overamortization of coal ash costs is separately addressed later in this Order.

specific regulatory asset account established for those deferred costs until the Company's next general rate case.

Id. at 1298.

DEC witness Q. Bowman also disagreed with the Public Staff's assertion that by offsetting the expiring amortizations against continuing amortizations DEC is overriding the Commission's approved terms for recovery of the individual assets. *Id.* at 1297. Witness Q. Bowman maintained that DEC has complied with the 2017 Rate Case Order, and DEC has continued the amortization of the expired regulatory assets and liabilities. witness Q. Bowman also stated in the context of this rate case, DEC is applying those overamortizations to the deferral balances of costs that are similar in nature, in compliance with the Commission's 2017 Rate Case Order. *Id.* at 1298–99.

DEC witness Q. Bowman also explained the impact upon rates should the Commission adopt DEC's proposed treatment. *Id.* at 1299. Witness Q. Bowman testified that DEC's approach reduces deferred balances being addressed in the current case and thereby reduces the base rate revenue requirement all the while protecting the customers from the rate volatility created by a significant one-year rider. *Id.*

Section III, Paragraph 40(a) of the Amended Revenue Requirement Stipulation provides that (1) the overamortizations related to prior coal ash costs will be netted against coal ash costs included in this case; (2) the overamortizations related to prior rate case costs will be netted with rate case costs included in this case; (3) the overamortization related to the Buck Coal Plant retired plant regulatory asset will be netted against the Allen Unit 4 retired plant regulatory asset; and (4) the overamortization of the severance regulatory asset established in the 2019 Rate Case will be refunded through a one-year rider with interest. This provision of the stipulation is consistent with the Commission's ruling in the DEP Rate Case Order.

The Commission has reviewed the evidence and considered the testimony of the witnesses and determines that for purposes of this proceeding, it is reasonable and appropriate to offset most but not all of DEC's previously approved regulatory assets that have been overamortized against other regulatory assets in accordance with Section III, Paragraph 40(a) of the Amended Revenue Requirement Stipulation. No intervenor took issue with this provision of the stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Inflation Adjustment

DEC, through witness Q. Bowman's direct testimony and exhibits, adjusted its annual non-labor and non-fuel O&M costs to reflect the increase in costs during the test period that occurred due to inflation. *See* tr. vol. 12, 169. In supplemental direct testimony, witness Q. Bowman testified that this inflation adjustment was updated to reflect inflation factors through April 30, 2023. *Id.* at 203.This inflation adjustment factor was subsequently updated in witness Q. Bowman's second and third supplemental direct testimony, and in her Settlement Testimony, consistent with the DEP Rate Case Order, to arrive at a rate of 12.76%. *Id.* at 213, 223, 233, 242, 249, 255; Q. Bowman Supp. Settlement Ex. 4 at 109 (Tr. Ex. vol. 12).

In Public Staff witnesses Zhang and Boswell's direct testimony, they recommended that the Commission adjust DEC's inflation factor to reflect a five-year average inflation rate through April 30, 2023. Tr. vol. 12, 1011. Witnesses Zhang and Boswell further recommended that the inflation adjustment be modified to reflect the Public Staff's recommended adjustments removing aviation expenses, Board of Directors expenses, rent expense, and sponsorships and donations. *Id.* Finally, they testified that the Public Staff did not find it appropriate to calculate ongoing rates for a minimum of the next three years based on years in which inflation was abnormally high. *Id.* at 1012.

In rebuttal, DEC witness Q. Bowman opposed the Public Staff's recommended adjustment. Tr. vol. 15, 1287. Witness Q. Bowman testified that DEC's proposal does not project inflation of O&M expenses but instead accounts for the impacts of inflation that have already been incurred from the test period to the end of the update period. *Id.* at 1288. Witness Q. Bowman further testified to DEC's methodology for calculating an inflation factor stating that it has not changed from previous rate cases. *Id.* Witness Q. Bowman testified that the Public Staff's assertion that any non-payroll O&M expenses updated beyond December 2021 would include impacts related to inflation is incorrect, and she explained that any O&M expenses that are updated through pro forma adjustments are excluded from the inflation adjustment. *Id.* at 1287–88. Witness Q. Bowman cited data from the U.S. Bureau of Labor Statistics that shows a continual upward trend for all inflation metrics. *Id.* at 1290. Further, witness Q. Bowman testified that while DEC disagrees with the Public Staff's adjustments removing certain expenses related to aviation, sponsorships, donations, lobbying, and Board of Directors expenses, DEC agrees that it would be appropriate to adjust the total O&M subject to inflation for that amount to the extent that there are adjustments made to those expenses. *Id.* at 1291.

The Amended Revenue Requirement Stipulation accepts DEC's proposed inflation adjustment. Revenue Requirement Stipulation § III.40.b (Tr. Ex. vol. 7). No intervenor took issue with this provision of the stipulation which is consistent with the DEP Rate Case Order. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Rate Case Expenses

DEC witness Q. Bowman testified that in the current proceeding, DEC included adjustment NC5020 related to rate case costs, and amortized, over a three-year period the rate case costs incurred and projected to be incurred for this docket, as well as costs incurred after the cut-off in the last rate case which have not yet been brought forth for recovery. Her testimony explained that overamortizations associated with severance costs approved in the 2019 Rate Case and rate case costs from prior cases were used to offset the amount requested for recovery in this case. Tr. vol. 12, 177–78, 204.

Public Staff witnesses Zhang and Boswell explained that they removed: (1) DEC's adjustment to include additional rate case expenses from the 2019 Rate Case Order that exceed the amount agreed to in the first partial settlement entered into by DEC and the Public Staff in the 2019 Rate Case (2019 First Partial Settlement); (2) the adjustment to include the unamortized portion of rate case expense in rate base; and (3) DEC's inclusion of overamortized regulatory assets to offset rate case expense. Regarding the additional costs from the 2019 Rate Case, witnesses Zhang and Boswell testified that the 2019 First Partial Settlement reflected an agreed upon amount for 2019 Rate Case expenses and that this amount was ultimately incorporated into the revenue requirement approved by the 2019 Rate Case Order. As such, the Public Staff asserted that it is inappropriate to include the 2019 Rate Case costs beyond those included in the Commission-approved revenue requirement from a general rate case that has been closed and in which DEC did not request that additional costs be considered before the Commission issued its final order. Tr. vol. 12, 1024–25.

Regarding DEC's adjustment to include the unamortized balance of rate case expense in rate base, witnesses Zhang and Boswell testified that the amortization of rate case expense should reflect a normalization of the costs associated with the filing of a rate case based on an average of the number of years between rate case filings. In this case, witnesses Zhang and Boswell stated that rate case expense does not rise to the level of being extraordinary in nature and as such does not require rate base treatment. As with other overamortizations in this proceeding witnesses Zhang and Boswell asserted that the overamortized amounts from the rate case expense and severance costs should be flowed back to ratepayers as a one-year rider and not used to offset other amounts. *Id.* at 1025.

In DEC witness Q. Bowman's rebuttal testimony, she asserted that DEC is not precluded from collecting additional amounts incurred from the 2019 Rate Case based on the 2019 First Partial Settlement. In her view, the 2019 First Partial Settlement does not contain any language capping rate case costs at a maximum amount or prohibiting DEC from asking for additional reasonably and prudently incurred actual expenses in a future rate case. While the amounts agreed to in the 2019 First Partial Settlement were based upon information available at the time the agreement was reached, witness Q. Bowman stated that DEC's costs were ultimately higher as the proceedings for that case were delayed and extended for reasons which could not have been foreseen, and the Public Staff has made no assertion or forecasted any evidence showing that the additional 2019 Rate Case expenses were not reasonably and prudently incurred. Tr. vol. 15, 1270–72.

In response to the Public Staff's recommendation that the unamortized rate case costs for this proceeding be removed from rate base, witness Q. Bowman explained that DEC's investors have advanced the funds to cover these reasonably and prudently incurred utility costs, and as such DEC should be allowed to earn a return on this asset to reflect the earnings expected from its investors during the amortization period. *Id.* at 1270.

In the DEP Rate Case Order, the Commission approved DEP's request to recover rate case costs incurred from DEP's 2019 Rate Case which were above and beyond those provided for in the DEP 2019 First Partial Settlement with the Public Staff, denied DEP's request to include the unamortized balance of rate case expense in the rate base, and determined that the amortization period for which the rate case expense should be recovered is three years as this aligns with the MYRP time frame. DEP Rate Case Order, 204–05.

In Section III, Paragraph 40(f) of the Amended Revenue Requirement Stipulation, DEC and the Public Staff agreed on the following: (1) that DEC shall recover the remaining unamortized rate case expenses from Docket Nos. E-7, Sub 1146 and E-7, Sub 1214; (2) that DEC shall recover the additional rate case expense requested for Docket No. E-7, Sub 1214 in this proceeding; (3) that the rate case expense balance shall be netted against all rate case expense overamortization from the prior cases; and (4) that the unamortized rate case expense balance will not be included in the rate base. In addition, DEC and the Public Staff agreed that the actual rate case expenses for the present case will reflect prudently incurred costs through the filing of the proposed order and any remaining costs will not be included for recovery from ratepayers either in a future rate case nor included in the unamortized balance for this case. No intervenor took issue with this provision of the stipulation. Further, in the Supplemental Revenue Requirement Stipulation DEC and the Public Staff agreed that the DEC may update its rate case expense with expense incurred through the date of filing of supplemental proposed orders with all such expenses subject to audit by the Public Staff.

The Commission concludes that the collective Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

The Commission concludes that these adjustments in the collective Revenue Requirement Stipulation are supported by the evidence presented and are just and reasonable and fair to all and should be approved.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 26

Supplemental Revenue Requirement Stipulation

The evidence supporting this finding of fact is contained in DEC's verified Application and Form E-1; the Supplemental Revenue Requirement Stipulation; the testimony and exhibits of Public Staff witnesses Metz, Zhang, and Boswell; DEP witness Q. Bowman; and the entire record in this proceeding.

The Initial Revenue Requirement Stipulation and the Amended Revenue Requirement Stipulation involves a comprehensive resolution between the stipulating parties of a majority of the revenue requirement issues in this case. Because these stipulations were entered into before the Public Staff had completed its audit of DEC's third and fourth update of costs, these stipulations provide expressly that they do not prevent the Public Staff from completing its audit of DEC's updates or making proposed adjustments to the updated revenue requirements based on the audit. The Public Staff completed its audit of the updates in October 2023, and the Public Staff and DEC entered into the Supplemental Revenue Requirement Stipulation, filed on October 13, 2023, in which the parties agreed to certain further minor adjustments to the revenue requirement. The Supplemental Revenue Requirement Stipulation lists seven areas of agreement between DEC and the Public Staff. Supp. Revenue Requirement Stipulation (Tr. Ex. vol.17).

Allen 230 kV Transformer Project

DEC and the Public Staff agreed that DEC shall remove from rate base the Allen 230 kV Transformer Project, for purposes of this proceeding only. The removal will result in a decrease of $5,024,146 in Plant in Service on a system basis but moves the project to MYRP Rate Year 1 and adjusts the MYRP revenue requirement accordingly. *Id.*

Apex Solar Additional Facilities Charge

DEC and the Public Staff agreed to apply annualized extra facilities revenue of $310,987 related to the Apex Solar facility to the base period revenue requirement. *Id.*

Durham Main Spill Prevention, Control and Countermeasure (SPCC) Project

DEC and the Public Staff agreed that DEC will reclassify from distribution to transmission plant the $2,834,492 system amount related to a portion of the Durham Main SPCC project that is included in the base period. The stipulating parties also agreed to remove from rate base costs related to a portion of the Durham Main SPCC that was prematurely closed to plant resulting in a decrease of $751,724 from Plant in Service in the base period on a system basis. The stipulating parties further agreed that this portion of the Durham Main SPCC project was eligible to have been included in the MYRP; however, as part of settlement, the stipulating parties agreed that no adjustment will be made to the MYRP revenue requirement in connection with this portion of the Durham Main SPCC project. *Id.*

Rosman SS – Quebec Project

DEC and the Public Staff agreed that DEC will reclassify the $418,751 system amount related to the Rosman SS — Quebec 44 kV OCB Replacement project from Distribution FERC to Transmission FERC. *Id.*

Misenheimer Solar

DEC and the Public Staff agreed that DEC will remove $853,150 from Plant in Service on a system basis related to the Misenheimer Solar project. *Id.*

Ernst & Young (E&Y) Contract

DEC and the Public Staff agreed that for reporting purpose only, DEC, along with DEP, will track and report in the next base rate case the following information on a system and allocated basis: (1) test period labor costs included in the revenue requirement in this rate case that were impacted by the E&Y contract, including payroll, labor, fringe benefits, pensions & benefits, incentives, outside services, and employee expenses (for employee expenses, the Stipulating Parties will consult to determine) as well as any additional categories DEC has included in its calculation of the $15 million savings over the next five years; and (2) the actual costs incurred under the E&Y contract. For purposes of reporting of both savings and costs, the allocations assumed in this rate case would also be utilized for reporting (i.e., allocations between capital O&M, service company and operating company; and operating company and retail). *Id.*

On October 13, 2023, the Public Staff filed the joint supplemental settlement testimony of witnesses Metz, Zhang, and Boswell in support of the Supplemental Revenue Requirement Stipulation. According to the Public Staff witnesses, the most important benefits that the stipulation and the agreed upon adjustments provide are: (1) an aggregate reduction in DEC's proposed revenue increase in this proceeding; and (2) the avoidance of litigation between the parties on the settled issues and the associated increased accumulation of rate case expense recovery from ratepayers. Tr. vol. 17, 33–34. The Public Staff further testified that the Commission should approve the Supplemental Revenue Requirement Stipulation because of these benefits to ratepayers. *Id.* at 34. Finally, DEC witness Q. Bowman testified that DEC believes the Supplemental Revenue Requirement reflects a fair, just and reasonable resolution of the issues it addresses. *Id*. at 25.

The Commission concludes that the adjustments in the Supplemental Revenue Requirement Stipulation are supported by the evidence presented and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 27

Nuclear PTC

The evidence supporting this finding of fact is contained in DEC's verified Application and Form E-1; the Amended Revenue Requirement Stipulation; the testimony and exhibits of DEC witnesses Abernathy, Bateman, and Panizza; Public Staff witness Metz; and the entire record in this proceeding.

DEC requested an accounting order to authorize deferral of all impacts associated with the IRA. Tr. vol. 12, 95–96. DEC witness Abernathy testified in support of DEC's deferral request. Witness Abernathy explained that because there remains uncertainty surrounding the estimated benefits DEC will receive from the IRA, DEC is requesting an accounting order authorizing it to defer any difference between realized and estimated impacts included in this filing, net of costs. *Id.* at 96.

DEC witness Panizza's testimony explained how DEC did not account for any impacts associated with nuclear PTCs in the base case revenue requirement due to it being uncertain as to when DEC will be able to monetize nuclear PTCs. *Id.* at 517. Witness Panizza reiterated how DEC's request for an accounting order authorizing a deferral is appropriate. *Id.* at 518.

The Public Staff recommended that DEC begin providing the benefits of the expected nuclear PTCs to customers in Rate Year 1. *Id.* at 927–29. Witness Metz testified that by seeking a deferral of all of the benefits, DEC shifted the full benefit of the nuclear PTCs to the future resulting in current system users (who are benefiting from the nuclear PTCs) not receiving the resulting cost reductions. *Id.* at 927.

In DEC witness Abernathy's rebuttal testimony, she testified that none of the MYRP nuclear projects will increase nuclear output during the MYRP period. Witness Abernathy also explained that under N.C.G.S. § 62.133-16(c)(1)a, the MYRP revenue requirement must be based on the costs, net of savings, of specific capital investments. Tr. vol. 16, 228. For this reason, DEC did not include an estimate for nuclear PTCs in DEC's MYRP revenue requirement or adjust the base case revenue requirement to account for nuclear PTCs. *Id.* Further, in his rebuttal testimony DEC witness Panizza noted that the Public Staff's suggestions seemed to overlook the complexities and uncertainties of the IRA's tax credits. In particular, witness Panizza testified that witness Metz's recommendation appeared to be based on a misunderstanding of the nuclear production tax credit and its calculation. Tr. vol. 15, 1198. Witness Panizza commented that witness Metz did not make a specific disallowance recommendation nor did he indicate that DEC should in any of the rate years in the MYRP period reflect a specific dollar amount of NPTC credit to customers. *Id.* at 1186.

In DEC witness Bateman's supplemental settlement testimony, she testified that the nuclear PTC rider agreed upon in the Revenue Requirement Stipulation provides more structure to DEC's plan to provide the benefits of nuclear PTCs to customers. Tr. vol. 11, 216–17. The rider will be effective beginning January 1, 2025, and flow back $50 million (North Carolina retail) in 2025 and $100 million (North Carolina retail) in 2026, subject to adjustments from the Commission under certain specified conditions. Witness Bateman explained that the nuclear PTC rider will result in a standardized annual process that will assess and confirm the amount of nuclear PTCs previously generated and monetized or used per the terms of the Amended Revenue Requirement Stipulation. *Id*. at 217. Witness Bateman noted that the annual process will allow the benefit of the nuclear PTCs to be distributed in multiple tranches, each over a four-year period, which will extend the timeframe over which the benefit of the nuclear PTCs will be realized by customers. *Id*. Witness Bateman also testified that DEC will track the amounts of nuclear PTCs for inclusion by establishing a regulatory asset/liability account for nuclear PTCs to allow for the deferral of any variance to actuals including a return at DEC's last authorized WACC, net of taxes. Witness Bateman explained that upon monetization or use, the amounts will be deferred to the regulatory asset/liability account, net of costs, and net of any amounts already included in the rider. A return will accrue on the regulatory asset/liability beginning upon the monetization or use of the nuclear PTCs until amounts are included in the rider with a levelized WACC return. *Id*. at 217–18. At the evidentiary hearing, witness Panizza responded to questions from Commissioners regarding the $50 million and $100 million to be returned to customers in the first two years of the proposed nuclear PTC rider. Tr. vol. 15, 1200. Witness Panizza explained that nuclear PTCs differ from traditional PTCs (like solar) because they include a phaseout of the credit, which is not part of the traditional PTC framework. The phaseout is based upon a calculation of the gross receipts the nuclear producer obtains from the generation of electricity from nuclear sources. The phaseout begins once the gross receipts level hits $25 per MWh, proceeds ratably down to $43.75 per MWh, and then is zero. *Id.* at 1201–02. Witness Panizza explained that DEC is awaiting IRS guidance to define gross receipts for purposes of calculating the phaseout, if it becomes applicable to DEC under the rules ultimately established by the IRS. Witness Panizza testified that the $50 and $100 million included in the proposed rider was a reasonable estimate that allows DEC to begin the flowback of nuclear PTC's pending finalization of the IRS guidance. Witness Panizza noted that the rider provides for subsequent mechanisms to ensure that customers receive the full amount of the credit. *Id.* at 1203–04. Witness Panizza also clarified that DEC incurs transactional costs associated with monetizing PTCs and stated that the rider would return the PTCs to customers net of those costs. *Id.* at 1205–07.

Discussion and Conclusion

Section III, Paragraph 33 of the Amended Revenue Requirement Stipulation provides that the parties agree to file with the Commission and support a standalone rider to refund deferred benefits of nuclear PTCs to customers. The rider will be effective beginning January 1, 2025, and flow back $50 million (North Carolina retail) in 2025 and $100 million (North Carolina retail) in 2026, subject to certain adjustments from the Commission. Thereafter, the rider will be updated annually on October 15 of each year starting in 2026. DEC will identify nuclear PTCs generated and monetized in accordance with the IRA to return to customers such amounts evenly over a four-year amortization period with a levelized return at DEC's last authorized weighted average cost of capital (WACC), net of tax, with such updates being effective the following January 1. The rider, as proposed, will continue until all nuclear PTCs monetized or used are returned to customers.

No intervenor took issue with this provision of the Amended Revenue Requirement Stipulation. The Commission concludes that the Amended Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 28

Lead Lag Study

The evidence supporting this finding of fact is contained in DEC's verified Application and Form E-1; the Revenue Requirement Stipulation; the testimony and exhibits of DEC witness Speros; Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

As part of its filing in this case, DEC submitted a lead-lag study that was performed by Ernst & Young, LLP, and approved in the Commission's 2019 Rate Case Order. Tr. vol. 12, 531; Speros Direct Ex. 2 (Tr. Ex. vol. 12). The lead-lag study was used to analyze transactions throughout the year to determine the number of days between the time services are rendered and payment is received (revenue lag) and the number of days between the time expenditures are incurred and payment is made for such services (expense or payment lead). Tr. vol. 12, 532. Public Staff witnesses Zhang and Boswell recommended that DEC prepare and file a fully updated lead-lag study in its next general rate case. *Id.* at 1010–11.

In DEC witness Speros' rebuttal testimony, he stated that DEC plans to pursue a merger of the DEC and DEP utilities in the next rate case and will work with the Public Staff to determine if the timing of the next lead-lag study makes more sense before or after that case. *Id.* at 560.

The Revenue Requirement Stipulation incorporates DEC's agreement to perform a lead-lag study before the next general rate case proceeding and incorporate the results of that study in DEC's next rate case application. No intervenor took issue with this provision of the stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 29

MYRP Capital Investments

The evidence supporting this finding of fact is contained in DEC's verified Application and Form E-1; the Revenue Requirement Stipulation; the testimony and exhibits of DEC witnesses Abernathy, Bateman, Maley, Guyton, Capps, Walsh, and LaRoche; Battery Energy Storage Panel witnesses Meeks, Shearer, Strasburger, and Murray; Public Staff witnesses Thomas, Chiles, Metz, Michna, T. Williamson, Nader, Zhang, and Boswell; AGO witness Burgess; NCJC, et al. witnesses Hill and Duncan; Sierra Club witness Goggin; NC WARN witnesses Powers and Konidena; and the entire record in this proceeding.

In its Application, DEC identified capital spending projects projected to be placed in service during the MYRP period. These projects consist of transmission and distribution projects and investments, solar and battery storage, and fossil, hydro, and nuclear investments.

Transmission

DEC witness Maley testified in support of the MYRP transmission projects. Regarding future needs, witness Maley testified that while DEC has worked hard to maintain the system and reliably meet customer needs, it must do more to improve the state's energy infrastructure to meet the challenges and opportunities that lie ahead. Tr. vol. 8, 264. Witness Maley testified that DEC designed its MYRP to address those future challenges and opportunities. *Id.* Witness Maley testified that the MYRP transmission projects include investments in the following categories: system intelligence, hardening and resiliency, transformer and breaker upgrades, and capacity and customer planning. *Id.* at 278.

Witness Maley testified that DEC selected and grouped targeted reliability improvements in the following MYRP projects, based on the areas that provide the greatest value to customers: system intelligence, vegetation management, transmission line hardening and resiliency, substation hardening and resiliency, transformer upgrades, breaker upgrades, and capacity and customer planning. *Id.* at 280. Witness Maley explained that although these seven proposed MYRP investments are the same as those DEC presented in the November 2, 2022, MYRP technical conference, DEC had refined some of the location details and informed the Cost Benefit Analysis (CBA) with those details. *Id.*

In witness Maley's direct testimony and accompanying exhibits, he described the estimated costs of DEC's proposed MYRP transmission projects. *Id.* at 279.

In witness Maley's supplemental direct testimony, he provided an update on the cost estimates applicable to transmission projects that DEC included in its MYRP based on certain criteria agreed upon with the Public Staff. *Id.* at 300. Witness Maley identified additional transmission MYRP project locations that DEC added to the MYRP after filing his direct testimony and identified those that it removed along with the reasons behind such changes. *Id.* at 301. Witness Maley provided updated project cost estimates for certain transmission MYRP projects including explanations for the basis for such updated cost estimates. *Id.* Witness Maley explained that his direct testimony included 306 transmission projects at the location/task level totaling $1.79 billion and his supplemental direct testimony included 305 projects at the location/task level totaling $2.03 billion, which represented an overall net increase of $246.8 million. *Id.*

In witness Maley's second supplemental direct testimony, he provided a further update on the cost estimates applicable to transmission projects that DEC included in its MYRP. *Id.* at 312. Witness Maley also identified those transmission project locations that DEC removed from the MYRP after filing his direct and supplemental direct testimony along with the reasons behind such changes. *Id.*

DEC witness Maley's Direct Second Supplemental Exhibit 1 provides the total updated costs of the proposed MYRP Transmission projects as follows:

(1) Breakers – $375,814,508;

(2) Capacity and Customer Planning – $521,982,230;

(3) Substation Hardening and Resilience – $362,637,115;

(4) System Intelligence – $136,841,787;

(5) Transmission Line Hardening and Resilience – $329,361,344;

(6) Transformers – $177,369,201; and

(7) Vegetation Management – $85,291,177.

Maley 2d Supp. Ex. 1 (Tr. Ex. vol. 9).

The modifications to the proposed MYRP transmission projects described in witness Maley's supplemental direct testimony, second supplemental direct testimony, and accompanying exhibits, resulted in an updated estimated capital cost to DEC's proposed MYRP Transmission projects of $1.99 billion. Tr. vol. 8, 313.

Public Staff Witness Metz testified to multiple concerns with the transmission MYRP projects, including DEC's provision of project documentation and insufficient staffing levels to complete the projects on schedule. Tr. vol. 12, 790–95, 901. Witness Metz recommended reducing the project estimate contingency components by half arguing that DEC failed to justify the high contingency amount DEC budgeted for the projects. *Id.* at 912–15. Witness Metz also recommended the removal of certain transmission projects from the MYRP based on the analysis of Public Staff witness Chiles. *Id.* at 867–68. In particular, witness Chiles recommended removal of the Boyds to Trinity Ridge project. Tr. vol. 15, 207.

AGO witness Burgess critiqued DEC's transmission planning and made several recommendations. Witness Burgess recommended that the Commission require DEC to conduct a study on the costs and benefits of grid-enhancing technologies (GETs). *Id.* at 322. Witness Burgess described GETs as technologies that can enhance transmission planning and operations by increasing the real-time transfer capacity of the existing transmission network helping to maximize both cost-efficiency and renewable integration. *Id.* at 315. Witness Burgess also recommended that DEC engage in regional transmission planning and asserted that regional planning could potentially displace projects in the MYRP. *Id.* at 333–36. Finally, witness Burgess recommended that DEC pursue all funding options for transmission projects that are part of the IRA. *Id.* at 328.

Sierra Club witness Goggin recommended that the Commission require DEC to file a proactive transmission plan for all transmission expansion and upgrades needed to accommodate the interconnection of all new renewable resources required by 2035 under the Carbon Plan. *Id.* at 1145. Witness Goggin also recommended that the Commission direct DEC to use a "multi-value approach to planning [] transmission so that the identified upgrades meet needs related to public policy, economics, reliability, expanded interconnection with neighboring Balancing Authorities, and other categories of benefits…." *Id.* at 1118.

NC WARN witnesses Powers and Konidena expressed concern with the "high apparent cost of" proposed upgrades to several transmission lines that are "listed in Table P-3 of Appendix P to the Carbon Plan." *Id.* at 1094.

Witness Maley addressed testimony from Public Staff witnesses Metz and Chiles. Specifically, he: (1) responded to witness Metz's testimony related to project documentation; (2) spoke of each MYRP project witnesses Metz and Chiles challenged by rebutting the justifications presented for the challenge and explaining why the projects are necessary and appropriate for inclusion in the MYRP; (3) addressed witness Metz's concerns regarding staffing levels; (4) countered the argument that the Commission should reduce contingency components of the estimates for all MYRP transmission projects by 50.0%; and (5) explained the basis for the contingency component of DEC's transmission projects. Tr. vol. 10, 322–35. Witness Maley agreed to remove the Boyds to Trinity Ridge project from DEC's MYRP. *Id.* at 356.

Witness Maley also addressed testimony of witnesses for the AGO, the Sierra Club, and NC WARN. Witness Maley stated that he disagreed with AGO witness Burgess recommendations. *Id.* at 392–93. Also, witness Maley disputed witness Burgess' recommendations because they require activities already underway or that should be considered in the CPIRP or in the North Carolina Transmission Planning Collaborative (NCTPC). *Id.* Witness Maley further stated that the Commission has already noted in its Carbon Plan Order that it "expects Duke to pursue all potential tax incentives or federal funding." *Id*. Witness Maley countered that new requirements imposed in this proceeding that circumvent resource planning and transmission planning are not reasonable. *Id.*

In witness Maley's rebuttal testimony, he responded that Sierra Club witness Goggin's recommendations regarding transmission planning would fit better in the CPIRP than within a rate case proceeding. *Id.* at 393. Witness Maley explained that Duke Energy stated in the March 15, 2023, NCTPC Transmission Advisory Group presentation that it is pursuing the integration of a multi-value strategic transmission planning study into the local transmission planning process. *Id.* at 393–94. Since DEC is already pursuing this in the NCTPC, witness Maley testified that any further requirement is unnecessary. *Id.* In response to questions from Commissioner Kemerait and Chair Mitchell, DEC witness Maley also testified that the recommendations by Sierra Club witness Goggin, such as multivalued strategic transmission, were already being evaluated in the NCTCP process, and the update was included in the Carolinas Resource Plan filed on August 17, 2023. Tr. vol. 9, 15–24.

Witness Maley testified that the estimated costs included in the MYRP for the projects identified by NC WARN witnesses Powers and Konidena included the most up to date available information and were appropriate based on the scope of work for the projects. Witness Maley also noted that their concerns would be more appropriately addressed in the CPIRP proceedings. *Id.* at 369.

The Revenue Requirement Stipulation includes a $351 million reduction in DEC's projected MYRP capital on a system basis in connection with the Public Staff's testimony regarding insufficient project documentation. It states that DEC will remove the costs of the Boyds to Trinity Ridge project as agreed to in the rebuttal testimony of witness Maley. It also includes a 50.0% reduction to the contingency amounts of the transmission projects as recommended by Public Staff witness Metz and removal of 50.0% of corrected one-time installation O&M from the MYRP. The stipulation also establishes that the transmission MYRP projects identified in Exhibits 1 and 2 of DEC witness Abernathy's August 24, 2023 settlement testimony and the supplemental and rebuttal testimonies of DEC witness Maley are appropriate for inclusion in the MYRP except as modified by the terms of the stipulation. Revenue Requirement Stipulation (Tr. Ex. vol. 7). Based on the entire record in this proceeding, the Commission finds that DEC's proposed transmission projects as discussed above and adjusted in the Revenue Requirement Stipulation are reasonable and shall be included in the MYRP for recovery.

The only parties that opposed portions of DEC's transmission projects included in the MYRP but not resolved through the Revenue Requirement Stipulation and other settlements are the AGO, as indicated by the testimony filed by AGO witness Burgess, the Sierra Club, as indicated by the testimony filed by Sierra Club witness Goggin, and NC WARN, as indicated by the testimony filed by NC WARN witnesses Powers and Konidena.

The Commission encourages DEC to continue evaluating and utilizing GETs as potential alternative solutions to identified transmission needs as appropriate, but the Commission agrees with DEC witness Maley's assertion that the recommendations of AGO witness Burgess and Sierra Club witness Goggin regarding transmission planning are designed to change DEC's decision-making regarding the types of transmission projects it undertakes. The Commission finds that the appropriate proceeding for consideration of GETs and other changes to transmission planning is the CPIRP or other proceedings. The Commission further finds that the concerns of NC WARN witnesses Powers and Konidena, as addressed by DEC witness Maley, do not justify any modifications to the transmission projects in the MYRP.

N.C.G.S. § 62-133.16(c)(1)(a) provides that for the first year of an MYRP, the

> base rates … shall be fixed in a manner prescribed under G.S. 62-133 … plus costs associated with a known and measurable set of capital investments, net of operating benefits, associated with a set of discrete and identifiable capital spending projects to be placed in service during the first rate year.

The same provision specifies:

> [s]ubsequent changes in base rates in the second and third rate years of the MYRP shall be based on projected incremental Commission-authorized capital investments that will be used and useful during the rate year and associated expenses, net of operating benefits, including operation and maintenance savings, and depreciation of rate base associated with the capital investments, that are incurred or realized during each rate year of the MYRP period.

N.C.G.S. § 62-133.16(c)(1)(a).

After having carefully reviewed all the evidence in the record, the Commission concludes that the evidence demonstrates that the proposed MYRP transmission projects satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a). The Commission further concludes that the evidence supports approval of the Revenue Requirement Stipulation's provisions regarding these transmission projects and that the transmission MYRP costs thereunder are just and reasonable and consistent with the public interest.

Distribution

DEC witness Guyton described the discrete and identifiable capital spending projects associated with DEC's distribution system proposed to be placed in service for each rate year of the MYRP. His testimony included the reason for, scope of, timing for (projected in-service month and year), and operating benefits of each project. Tr. vol. 8, 100. Witness Guyton testified that DEC's proposed MYRP distribution and other projects covered in his testimony total $2.7 billion and included the $2.3 billion in distribution MYRP projects discussed at the T&D technical conference held on November 2, 2022, as well as $0.4 billion in other non-T&D MYRP projects. *Id.* at 107. The other MYRP project categories include DEC's allocated share of the costs of enterprise communications and enterprise systems as well as facilities and fleet electrification infrastructure. *Id.* These other projects are closely aligned with the distribution business or enabling the grid capabilities. *Id.*

While discussing the preliminary findings in the ongoing Climate Risk and Resilience Study (CRRS) of the Carolinas transmission and distribution system, witness Guyton testified that the preliminary findings of the CRRS reinforce the benefits of the proposed MYRP projects, and that the additional headroom provided by capacity upgrades and improvements accommodates customer load growth and generation, but also increases resilience to the effects of extreme heat. *Id.* at 129. Witness Guyton testified that targeted undergrounding, distribution hardening and resiliency, and hazard tree removal increase resilience to the impact of wind and storms which are likely to increase in frequency and strength due to climate change. *Id.* Witness Guyton also testified that Duke Energy implemented Integrated Systems Operations Planning (ISOP) to leverage increasing amounts of data, such as the propensity of customers to adopt solar and purchase EVs, when planning future projects. *Id.* at 105. Witness Guyton testified that when appropriate the distribution projects will take advantage of new processes and technologies that will aid in the delivery of the energy goals and requirements of North Carolina. *Id.* As such, he stated that the proposed MYRP projects and the grid capabilities that are achieved through these projects will serve as a foundation to support future technologies and will result in significant customer benefits particularly in the areas of reliability and resiliency. *Id.* at 106.

With respect to reliability, witness Guyton stated that DEC anticipates fewer and shorter outages as a result of programs such as Self-Optimizing Grid (SOG), Targeted Underground (TUG), and distribution automation. *Id.* Regarding resiliency, the MYRP projects will provide increased protection against physical/cyber-attacks and severe weather impacts. Increases in capacity and voltage regulation and management will accommodate increasing amounts of Distributed Energy Resources (DERs) and EVs. *Id.* Enhanced automation and control and situational awareness will enable DEC to operate the grid more efficiently and support new customer programs, which will provide customers more options to control their energy usage and decrease their energy costs. *Id.* Witness Guyton testified that DEC will spread its proposed distribution MYRP projects across its service territory and retail customer classes to provide equitable access to these benefits. *Id.* The programs in DEC's MYRP projects make the grid more flexible and adaptable. Automation and control technologies will help generate and capture large volumes and types of data which was not previously available. *Id.* Witness Guyton asserted that these benefits are helpful not only for DEC's Grid Operators but also for its Planning Engineers as they analyze and model DEC's grid for future improvements and capabilities using ISOP toolsets like Morecast and Advanced Distribution Planning. *Id.* Witness Guyton indicated that grid technologies will continue to and will be integrated into new solutions to address changing customer needs. *Id.* at 106–07.

Witness Guyton testified that distribution projects included in the MYRP total $2,718,439,578 in estimated capital investment and fall into four investment categories: (1) Substation and Line MYRP projects which total estimated capital costs of $1.847 billion and comprise most of the distribution MYRP project costs; (2) Retail and System Capacity Projects which total estimated capital costs of $0.256 billion and include the traditional identification and execution of capacity projects to support traditional loads as well as DERs and EVs; (3) Hazard Tree Removal Projects which total estimated capital costs of $0.039 billion and consist of the traditional identification and execution of hazard tree removal which is performed in conjunction with normal trimming cycles; (4) the Integrated Volt Var Control (IVVC)/Voltage Regulation Management Projects which total estimated capital costs of $0.196 billion and represent the work performed to establish control of distribution equipment to optimize delivery voltages and power factors and facilitate addition of DERs and EVs; and (5) non-distribution MYRP projects which total estimated capital cost of $0.4 billion and include DEC's allocated share of the cost for the Advanced Distribution Management System, enterprise communications and systems, as well as facilities and fleet electrification infrastructure. *Id.* at 107–09.

Witness Guyton testified that the Substation and Line MYRP projects are geographically based and include a combination of ongoing work necessary for safe and reliable service and the work necessary to deliver essential grid capabilities that DEC has identified to address the megatrends and support the clean energy transition. *Id.* at 130–31. DEC's Distribution MYRP consists of the following ten programs:

(1) SOG Program, also known as the smart-thinking grid, redesigns key portions of the distribution system and transforms it into a dynamic self-healing network that isolates grid issues and limits customer impacts to hundreds versus thousands of customers. The total capital cost for this program is $270.8 million;

(2) Distribution Automation Program targets the lateral segments of the grid and focuses on modernizing single-use fuses with automated devices

capable of intelligently resetting themselves for reuse. The total capital cost for this program is $28.4 million;

(3) Capacity Upgrades and Improvements Program consists of the same work that DEC has always performed to serve its new and existing customers. The total capital cost for this program is $522.3 million;

(4) Hardening and Resiliency – Laterals Program focuses on the lateral sections or tap lines which branch from the main feeder lines and feed neighborhoods, businesses, and commercial/industrial customers. The total capital cost for this program is $436.5 million;

(5) Hardening and Resiliency – Public Interference Program improves reliability by targeting DEC's most outage prone overhead backbone power line sections most impacted by vehicle accidents and determining the proper hardening and resiliency solution to reduce the number of outages customers experience. The total capital cost for this program is $96.1 million;

(6) Hardening and Resiliency – Storm Program consists of improvements to locations of the distribution grid that DEC has identified through analysis of historical outage data as being more vulnerable to outage impacts from extreme weather events. The total capital cost for this program is $51.3 million;

(7) Long Duration Interruption Program relocates segments of main overhead feeder lines in hard-to-access areas to improve accessibility for utility trucks. The total capital cost for this program is $23.1 million;

(8) TUG Program improves reliability by strategically identifying DEC's most outage prone overhead power line sections and relocating them underground to reduce the number of outages customers experience. The total capital cost for this program is $193.7 million;

(9) Hazard Tree Removal Program maintains or improves reliability by identifying and removing dead, structurally unsound, dying, diseased, leaning, or otherwise defective trees that could strike electrical lines or equipment of the distribution system from outside the maintained right of way. The total capital cost for this program is $71.6 million; and

(10) Distribution Infrastructure Integrity Program identifies and mitigates risk factors such as end-of-service equipment, technology obsolescence, and damaged in-service distribution equipment. The total capital cost for this program is $447.4 million. *Id.* at 132–36.

Witness Guyton testified that DEC's description of its distribution MYRP programs and associated exhibits reflect the detailed project information required by Commission Rule R1-17B. *Id.* at 137. The projected annual net O&M benefits that Commission Rule R1-17B(d)(2)k requires reflect the operational O&M savings offset by the incremental cost to operate the new technology. *Id.* at 138. The O&M savings stem from fewer outages resulting from reliability improvements and the reduction in vegetation management resulting from the undergrounding of overhead lines, for example, in the TUG program. *Id.* DEC netted these savings with the ongoing O&M costs associated with maintaining the added equipment installed under the SOG and Voltage Regulation programs. *Id.*

In witness Guyton's supplemental direct testimony, he identified distribution MYRP project locations that DEC either added to or removed from the MYRP period and explained the reasons for such changes. *Id.* at 157. Witness Guyton provided updated project cost estimates applicable to distribution projects that are included in DEC's MYRP based upon certain criteria to which DEC and the Public Staff agreed. *Id.* Witness Guyton testified that his direct testimony included 76 distribution projects (comprised of 602 distribution sub-projects at the location/task level) totaling $2.7 billion, while his supplemental direct testimony included 78 distribution projects (comprised of 680 sub-projects at the location/task level) totaling $3.1 billion representing an overall net increase of $337.6 million across all the distribution MYRP projects. *Id.* at 157–58.

Witness Guyton summarized the supplemental MYRP as follows: (1) DEC added two new Enterprise Application MYRP projects including the Geospatial Information System Replacement project, totaling $30.6 million, and the Grid Hosting Capacity project, totaling $6.7 million; (2) DEC added one project/task, totaling $4.8 million, for Closed Loop Fault Isolation Service Restoration; (3) DEC added 29 project locations, totaling $75.3 million, in the Communications MYRP Projects for a South Carolina location that was added in the supplemental filing; (4) DEC added 15 project locations, totaling $31.3 million, in the Communications MYRP Projects, and removed nine project locations, totaling $16.3 million, to reflect updates that have occurred in the project development life cycle; (5) DEC added four project locations, totaling $1.7 million, in the IVVC MYRP Projects; (6) DEC added 18 project locations, totaling $56 million, to the Retail System Capacity MYRP Projects, while DEC also removed another 18 projects from the Retail System Capacity MYRP Projects; (7) DEC added 6 project locations, totaling $62 million, in the Substation and Line MYRP Projects; and (8) DEC added one project location for Hazard Tree. *Id.* at 160–62. Witness Guyton also testified that supply chain constraints on transformers had near-term impacts on DEC's planned TUG work and, consequently, DEC removed TUG work scope from the Substation and Line projects. *Id.* at 168, 230. Witness Guyton described cost updates to 441 total distribution MYRP projects. *Id.* at 164. Witness Guyton also explained that at the time of DEC's Application, the distribution MYRP projects were at various stages of the project management lifecycle under DEC's Project Management Center of Excellence (PMCoE) standards. *Id.* at 165. Under the PMCoE approach, as a project moves through the development cycle, DEC continues to refine the costs and project schedules based on project development, detailed design, and construction planning. *Id.* at 165–66.

Witness Guyton explained that when the Substation and Line projects were initially identified, a spreadsheet cost estimate was constructed based on past work scope completed for similar assets at similar locations primarily based on engineering analysis and data driven models *Id.* at 167. Planning and engineering activities that occurred after the filing of DEC's Application and engaged in as part of the PMCoE process provided the opportunity to refine the scope of work and cost estimates on 155 of the total 290 Substation and Line sub-projects at the location/task level in the MYRP based on actual circuit and equipment and site conditions. *Id.*

Guyton Supplemental Exhibit 1 identifies the total estimated capital costs of the Distribution MYRP projects to be $3,056,048,092. Guyton Supp. Ex. 1 (Tr. Ex. vol. 9).

Public Staff witness Metz testified to multiple concerns with the distribution MYRP projects including DEC's provision of project documentation and insufficient staffing levels to complete the projects on schedule. Tr. vol. 12, 790–95, 901. Witness Metz recommended reducing the project estimate contingency components by one-half, arguing that DEC failed to justify the high contingency amount DEC budgeted for the projects. *Id.* at 912–15. Public Staff witness Lawrence recommended removal of the ECI Project that would support the deployment of electric vehicles to DEC facilities and the homes of select DEC employees from the MYRP on the basis that its costs were not sufficiently developed. Tr. vol. 15, 95. Public Staff witness T. Williamson recommended the TUG Program continue to focus on circuit segments that experience a relatively high number of outages and that DEC use analytics to determine whether TUG is the most cost-effective solution for that segment. *Id.* at 122.

NCJC, et al. witnesses Hill and Duncan made several recommendations related to DEC distribution planning. First, they recommended that the Commission initiate a working group to redesign DEC's CBA methodologies for selection of MYRP projects and that the Commission initiate an investigation into distribution system planning. Tr. vol. 15, 861, 863. Witnesses Hill and Duncan also recommended that the Commission require DEC to conduct non-wire pilot projects and that DEC update its MYRP cost estimates to account for federal funds available through the IRA and IIJA. *Id.* at 842–43.

In his rebuttal testimony, DEC witness Guyton responded to the Public Staff's distribution related MYRP testimony and to NCJC, et al. witnesses Hill and Duncan's testimony. Tr. vol. 8, 172–73. Specifically, he: (1) responded to witness Metz's testimony related to project documentation; (2) discussed the methodologies and procedures DEC used to develop cost and contingency estimates for distribution projects; (3) countered the argument that the Commission should reduce contingency components of the estimates for all distribution projects in the MYRP by 50.0%; (4) addressed witness Metz's concerns regarding staffing levels; (5) responded to witness Lawrence's recommendation to remove the ECI Project from the MYRP; and (6) agreed that DEC would continue to utilize events per mile to determine which circuit segments are appropriate for TUG and that DEC would continue to perform cost benefit analyses on TUG projects with greater than a half mile of overhead conductor removed. *Id.* at 182–86, 204–18, 222–27, 238.

The Revenue Requirement Stipulation included certain modifications to DEC's MYRP distribution projects. Those modifications include: (1) a $351 million reduction in DEC's projected MYRP capital on a system basis in connection with the Public Staff's testimony regarding insufficient project documentation; (2) a 50.0% reduction to the contingency amounts of the distribution projects as recommended by Public Staff witness Metz; (3) removal of the costs of the ECI Project; and (4) removal of 50.0% of corrected one-time installation O&M from the MYRP. The stipulation also establishes that the distribution MYRP projects identified in Exhibits 1 and 2 of DEC witness Abernathy's August 24, 2023 settlement testimony and supplemental and rebuttal testimonies of DEC witness Guyton are appropriate for inclusion in the MYRP except as modified by the terms of the stipulation. Revenue Requirement Stipulation (Tr. Ex. vol. 7).

The Revenue Requirement Stipulation did not address the concerns raised by NCJC, et al. witnesses Hill and Duncan.

In response to the recommendations of NCJC, et al. witnesses Hill and Duncan, witness Guyton testified that the recommendations fail to acknowledge activities that are already underway and for which Commission approval is therefore unnecessary. Tr. vol. 8, 240–41. Witness Guyton asserted that the recommendation of NCJC, et al. that the Commission initiate a working group to update DEC's CBA methodologies is unnecessary since DEC has demonstrated the current methodology and no other intervenor disputed the current methodology or its usefulness in the current rate case. *Id.* at 241. Witness Guyton contends that witnesses Hill and Duncan also do not acknowledge specific improvements in the CBA methodology DEC used in the current rate case that DEC made in response to stakeholder feedback in DEC's last rate case. *Id.* Witness Guyton also asserted that the non-wire pilot projects witnesses Hill and Duncan suggest are unnecessary because DEC has already initiated other non-wire pilot projects. *Id.* Witness Guyton points out that their recommendation that the Commission initiate distribution system planning is not necessary because the Commission has already initiated the ongoing ISOP stakeholder engagement efforts. *Id.* Similarly, witness Guyton asserts that their recommendation to require DEC to update MYRP cost estimates to account for federal funds available through the IRA and IIJA is unnecessary as DEC is actively pursuing grant funding opportunities for the benefit of customers. *Id.* at 242. Witness Guyton further noted that witness Abernathy testified that DEC's request that the Commission issue an accounting order authorizing deferral of all IRA and IIJA impacts including benefits and costs should be addressed in a future filing. *Id.*

The Commission gives significant weight to the compromise agreements reflected in the Revenue Requirement Stipulation. The Commission is not persuaded that the recommendations of NCJC, et al. witnesses Hill and Duncan related to DEC's proposed MYRP distribution projects are necessary at this time. The majority of the recommendations of witnesses Hill and Duncan are related to distribution system planning that should be considered in other proceedings such as the CPIRP proceeding. With respect to witnesses Hill and Duncan's recommendation that the Commission require DEC to update its distribution MYRP investments to account for available federal funds, the Commission notes that the record demonstrates that DEC is pursuing such funds and re-emphasizes its direction to DEC to pursue such funds. As discussed later in this Order, impacts associated with the IIJA and IRA will be deferred, and the Commission declines to adopt Witness Hill and Duncan's recommendation related thereto.

After having carefully reviewed all the evidence in the record on DEC's distribution MYRP proposal in this docket, and based on that evidence, the Commission finds that DEC's distribution MYRP projects, as adjusted in the Revenue Requirement Stipulation, satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a). The Commission further concludes that the evidence supports approval of the Revenue Requirement Stipulation's provision regarding these distribution MYRP projects.

Nuclear

DEC witness Capps testified in support of the nuclear projects DEC included in the proposed MYRP, the process DEC used to select the projects, and the method by which DEC calculated projected costs for the projects. Tr. vol. 12, 281–86. Witness Capps explained that DEC selected the projects based on their value in maintaining safe and reliable operation of the nuclear stations and on a high level of confidence in their cost estimates and schedule. Witness Capps stated that DEC based the projected costs on its long-range nuclear planning tool, which it updates regularly. *Id.* at 281. Witness Capps presented additional details regarding nuclear fleet-wide projects and the projects DEC planned for each of DEC's nuclear stations. *Id.* at 283–86; Application at 16 (Tr. Ex. vol.7). Witness Capps concluded that DEC prudently and reasonably selected these projects as they will enable DEC to maintain the fleet in reliable and efficient condition for customers' benefit. *Id.* at 283. Witness Capps' Direct Exhibit 1 provided additional details regarding projected cost, schedule, scope, and justification for each nuclear MYRP project. Capps Direct Ex. 1 (Tr. Ex. vol. 12).

In DEC witness Capps supplemental direct testimony, he updated the information on the MYRP nuclear projects. Witness Capps supported nine additional nuclear projects that DEC proposed to include in its MYRP and explained why DEC removed six nuclear projects from the MYRP. Tr. vol. 12, 307–10. Witness Capps explained the basis for updating MYRP project costs as agreed upon with the Public Staff and the method by which DEC developed the updated project costs. *Id.* at 310–12. Witness Capps' Supplemental Exhibits 1 and 2 provided updated in-service dates and projected costs for the nuclear MYRP projects. Capps Supp. Ex. 1–2 (Tr. Ex. vol. 12).

Public Staff witness Metz discussed the Public Staff's review of DEC's initial and supplemental MYRP filings and updates. Witness Metz testified that the Public Staff initiated multiple sets of discovery and participated in multiple meetings with DEC on the MYRP. Tr. Vol. 12, 867. Witness Metz testified to multiple concerns with the nuclear MYRP projects, including DEC's provision of project documentation and insufficient staffing levels to complete the projects on schedule. *Id.* at 790–95, 901. Witness Metz recommended reducing the project estimate contingency components by half, arguing that DEC failed to justify the high contingency amount DEC budgeted for the projects. *Id.* at 912–15.

In DEC witness Capps' rebuttal testimony, he noted that no individual nuclear MYRP project received objections by the Public Staff or any party on the basis of need, scope, cost, or schedule. *Id.* at 289, 297. Witness Capps also responded to witness Metz's testimony related to project documentation. *Id.* at 296–302. Finally, witness Capps testified to DEC's ability to execute the nuclear MYRP projects within the three-year time period. *Id.* at 302–03.

Based on the entire record in this proceeding, the Commission finds that DEC's projected nuclear MYRP capital investments, as adjusted by the Revenue Requirement Stipulation, satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a) and will be used and useful in the appropriate rate year. The Commission notes that no party offered any evidence to challenge any of the nuclear MYRP projects on the basis of need, scope, cost, or schedule. Therefore, the Commission concludes the evidence supports approval of the Revenue Requirement Stipulation's provisions regarding the nuclear MYRP projects.

Fossil/Hydro

In DEC witness Walsh's direct testimony, he outlined the projected natural gas, coal, and hydroelectric capital investments DEC included in the MYRP. Witness Walsh described DEC's prioritization process for identification of the projects to include in the MYRP. *Id.* at 645–46. Witness Walsh explained that DEC applied its project management guidelines for project scope development and cost estimation. *Id.* at 646. Witness Walsh presented additional details regarding the MYRP projects proposed for the natural gas, coal, and hydro generation fleets. *Id.* at 650–55; Application at 16 (Tr. Ex. vol. 7). Witness Walsh testified that DEC is undertaking the Clemson Hydrogen project to develop hydrogen generation technology as part of Duke Energy's transition to a cleaner energy future. Tr. vol. 12, 651, 655. Witness Walsh also testified to the importance of keeping DEC's remaining coal fired assets working efficiently to support customers' energy needs as DEC plans for those units' retirement and explained that DEC will continue to incur costs for these assets as appropriate and prudent to ensure that reliable cost-effective electricity remains available while DEC develops and implements replacement of the coal fleet. Witness Walsh noted that due to the continued importance of natural gas to DEC's resource mix, particularly during winter months and while DEC is developing and deploying energy storage capacity, DEC will continue to rely on its natural gas fleet as part of the diverse and dispatchable resource mix. *Id.* at 639. Witness Walsh concluded that DEC's decision to invest in these projects is prudent and reasonable as they will enable DEC to continue to provide safe, reliable, and affordable service to customers. *Id.* at 650. Witness Walsh's Direct Exhibit 1 provided additional details regarding projected cost, schedule, scope, and justification for each fossil/hydro MYRP project. Walsh Direct Ex. 1 (Tr. Ex. vol. 12).

In DEC witness Walsh's supplemental direct testimony, he supported the additional fossil and hydro projects that DEC proposed to include in its MYRP. Tr. Vol. 12, 657–59. Witness Walsh explained why certain projects that DEC removed from the MYRP were determined to be no longer necessary. *Id.* at 660. Witness Walsh explained the basis for updated MYRP projected costs as agreed upon with the Public Staff and the method by which DEC developed the updated project costs. *Id.* at 661–62. Witness Walsh's Supplemental Exhibits 1 and 2 provided updated in-service dates and projected costs for the fossil and hydro MYRP projects and cost, schedule, scope, and reasoning information for the newly added fossil and hydro projects. Walsh Supp. Ex. 1–2 (Tr. Ex. vol. 12).

In witness Walsh's second supplemental direct testimony, he provided an additional update on the fossil and hydro projects included in the MYRP to support DEC's third supplemental update filing. Witness Walsh explained the removal of one project that had been postponed beyond the MYRP period and updates to cost estimates for three other projects. Tr. vol. 12, 672. Witness Walsh's Second Supplemental Exhibit 1 provided an updated list of the fossil and hydro MYRP projects with these changes reflected. Walsh 2d Supp. Ex. 1 (Tr. Ex. vol. 12).

Public Staff witnesses Metz, Thomas, and Michna reviewed DEC's proposed fossil, hydro, and nuclear MYRP projects. Public Staff witness Metz testified that the Public Staff reviewed DEC's initial and supplemental MYRP filings and updates, initiated multiple sets of discovery, and participated in several meetings with DEC on the MYRP. Tr. vol. 12, 867. Witnesses Metz, Michna, and Thomas testified to multiple concerns with the fossil and hydro MYRP projects, including DEC's provision of project documentation and insufficient staffing levels to complete the projects on schedule. *Id.* at 790–95, 901. Witness Metz recommended removing from the MYRP all projects which did not include supporting documentation sufficient to satisfy Commission Rule R1-17B(d)(2)(j). *Id*. at 872. Witness Metz also recommended reducing the project estimate contingency components by half, arguing that DEC failed to justify the high contingency amount DEC budgeted for the projects. *Id.* at 912–15. Witness Metz recommended removal of the Clemson Hydrogen Project based on seven factors: (1) lack of a supporting economic analysis; (2) DEC's inability to provide documentation until after the filing of its CPIRP; (3) DEC forcing hydrogen into its 2022 Carbon Plan model; (4) the uncertainty as to whether the project will be approved in South Carolina, where it is located; (5) the cost of energy associated with a hydrogen project; (6) the lack of demonstration of need for the project and its impact on rates; and (7) the fact that only DEC ratepayers would pay all the project costs though the project would benefit other Duke Energy entities. *Id.* at 880–86.

Public Staff witness Thomas testified that he reviewed the proposed hydro MYRP projects. Witness Thomas recommended that the Mountain Island dam seismic project be removed from the MYRP based on the project schedule indicating an in-service date beyond the MYRP period and a lack of cost support. Tr. vol. 14, 190. Witness Thomas also recommended removing some O&M costs associated with hydroelectric plants that had documented cost savings. *Id.* at 189.

Witness Michna reviewed the proposed coal MYRP projects. Witness Michna agreed with DEC's philosophy of prioritizing unit reliability and resource adequacy in capital spending decisions. Tr. vol. 15, 69.

In DEC witness Walsh's rebuttal testimony, he responded to witness Metz's testimony related to project documentation. Tr. vol. 12, 685–93. Witness Walsh testified that the Clemson Hydrogen project is needed for DEC to begin to gain operational experience with hydrogen fuel. Further, witness Walsh explained that this operational experience will allow DEC to continue to pursue this potentially pivotal fuel option and incorporate hydrogen into the resource mix for the future and to produce benefits for DEC customers. *Id.* at 694. Witness Walsh also clarified that the modeling completed for the Clemson Hydrogen project was based upon but separate from the 2022 Carbon Plan modeling; described the 2022 Carbon Plan modeling assumption of hydrogen availability for long-term planning purposes; explained that the Clemson modeling process was more complex and took more time than originally anticipated but that DEC subsequently provided production cost information for the project to the Public Staff; and noted that the project will not require a certificate from the Public Service Commission of South Carolina to be constructed. *Id.* at 694–98. Witness Walsh agreed with witness Thomas that the Mountain Island project should be removed from the MYRP as it is not expected to go in service before 2027. *Id.* at 698–99. Witness Walsh disagreed with witness Thomas' recommendation regarding O&M costs associated with certain hydro MYRP projects explaining that any initial projections of savings contained in project Evaluator documents were not intended to be relied upon as actual annual ongoing O&M savings. *Id.* at 700. Finally, witness Walsh testified to DEC's ability to execute the fossil/hydro MYRP projects within the three-year time period. *Id.* at 702.

The Revenue Requirement Stipulation provides that the costs of the Clemson Hydrogen project will be removed from the MYRP. Amended Revenue Requirement Stipulation § III.38.b (Tr. Ex. vol. 7). DEC witness Abernathy supported this provision in her settlement supporting testimony. Tr. vol. 12, 134. The Amended Revenue Requirement Stipulation provides that the costs of the Mountain Island Dam Seismic project will be removed from the MYRP as agreed to in DEC's rebuttal testimony. Amended Revenue Requirement Stipulation § III.38.c (Tr. Ex. vol. 7). DEC witness Abernathy supported this provision in her settlement supporting testimony. Tr. vol. 12, 135.

Based on the entire record in this proceeding, the Commission finds that DEC's proposed natural gas, coal, and hydro MYRP projects, as adjusted by the Revenue Requirement Stipulation, satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a). DEC demonstrated that these projects are primarily in the normal course of business for maintaining the fossil and hydro fleets for reliability, safety, and regulatory compliance. In addition, DEC provided substantial evidence regarding the continued importance of the coal and natural gas fleets to its ability to continue to provide reliable service to customers and the need to continue to invest in the coal fleet until its retirement and in the natural gas fleet to reliably manage the transition away from coal. The Commission further concludes that the evidence supports approval of the Revenue Requirement Stipulation's provisions regarding these fossil/hydro projects. Specifically, the Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of the Clemson Hydrogen and Mountain Island dam seismic projects for purposes of this proceeding.

Lincoln CT

On May 19, 2023, DEC petitioned the Commission for an Order Amending CPCN to update the commercial operation and cost recovery date for the Lincoln CT Unit 17 to January 1, 2024. Tr. vol. 12, 492. DEC stated that the requested amendment would provide an additional 400 MW of dispatchable generation leading into the 2024 winter season.

The Public Staff opposed DEC's request. Witness Lucas testified that DEC's proposed change would move the warranty expiration date from December 1, 2026, to January 1, 2026. Witness Lucas further testified that this change would create disproportionate risks for ratepayers if Lincoln CT Unit 17 were to experience operational problems between those two dates. Tr. vol. 13, 133. Witness Lucas testified that if the Commission did adopt DEC's proposed commercial operation and cost recovery date of January 1, 2024, then the Public Staff's recommendation is that the Commission not allow cost recovery of any repairs or replacements between January 1, 2026 and December 1, 2026. *Id.* at 134.

In DEC witness Murray's rebuttal testimony, he testified that DEC's proposal to amend the CPCN is a "creative, efficient, and effective way for DEC to increase generation capacity in time for the winter season through a relatively straightforward administrative process with minimal costs." Tr. vol. 12, 495. Witness Murray also explained that DEC confirmed with Siemens Energy, Inc., the developer of the project, that the unit can be safely placed into service on January 1, 2024. *Id.* at 500–01. Witness Murray noted that Public Staff witness Lucas did not identify any operational issues with Lincoln CT that would support the Public Staff's concerns about changing the commercial operation date. *Id.* at 495. Additionally, witness Murray also noted that the Commission found the Lincoln CT was consistent with DEC's 2016 IRP and will provide enhanced reliability, low turn-down, fast ramp rate, and efficient dispatch capability for the DEC system. *Id.* at 468–70. In response to questions from Commissioner Duffley, Public Staff witness Lucas testified that DEC has sufficient capacity without the Lincoln CT Unit 17 for winter 2024. Tr. vol. 13, 183–84. Witness Lucas also testified that while DEC's confidential briefing regarding the Lincoln CT did not allay the Public Staff's initial concern, DEC's agreement to move the in-service date from January 1, 2024, to November 1, 2024, did ameliorate it enough for the Public Staff to agree to settle the issue. *Id.* at 186–87.

Section III, Paragraph 39 of the Revenue Requirement Stipulation provides that the parties agree to recommend that the Commission revise the Lincoln CT CPCN to modify the in-service date to November 1, 2024, for purposes of calculating the MYRP revenue requirement. No intervenor took issue with this provision in the Revenue Requirement Stipulation. The Commission concludes that DEC and the Public Staff's joint recommendation regarding the commercial operation and cost recovery date for Lincoln CT provides a reasonable resolution of this issue and accepts the modification to the Lincoln CT CPCN that the Commission granted in Docket No. E-7, Sub 1134 changing the in-service date for the facility to November 1, 2024, as agreed to by DEC and the Public Staff and reflected in in the Revenue Requirement Stipulation.

Cybersecurity

In DEC witness Strasburger's Supplemental Direct Testimony, he provided support for DEC's information technology (IT)/operational technology (OT) Cybersecurity project proposed in the MYRP. Tr. vol. 12, 617–20. Witness Strasburger explained that the purpose of the IT/OT Cybersecurity project is to ensure safe and sustainable operations through proactive and effective cybersecurity design, implementation and operation of critical energy systems and their underlying technology. *Id.* Witness Strasburger testified that the IT/OT Cybersecurity project will update OT governance and risk and compliance standards and processes, implement a new OT specific asset, patch and vulnerability management system, and deliver new OT cybersecurity threat logging and monitoring capabilities. *Id.* The project will also focus on expanding monitoring and threat response capabilities and will introduce proactive elements to reduce cybersecurity risks. *Id.* Witness Strasburger noted that his Strasburger Exhibit 1 contained information regarding the IT/OT Cybersecurity project required by Commission Rule R1-17B(d)(2)j.(i)-(iii). Witness Strasburger further testified that as DEC continues to see increased cyber threats against operational assets, including potential geopolitical threats, cybersecurity becomes a larger component of DEC's energy transition and grid protection initiatives, and that the Commission should approve the MYRP IT/OT Cybersecurity project. *Id.*

No other party offered any evidence regarding DEP's MYRP Cybersecurity project.

After having carefully reviewed the entirety of the evidence in the record on DEC's MYRP IT/OT Cybersecurity project, the Commission finds that the IT/OT Cybersecurity MYRP project, as adjusted by the Revenue Requirement Stipulation, satisfies the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a). DEC demonstrated that cybersecurity is becoming an increasingly critical component of its energy transition and grid protection initiatives, and that the IT/OT Cybersecurity project is reasonably necessary. Additionally, no party offered evidence to the contrary. The Commission further concludes that DEC put forth a reasonable plan to implement the IT/OT Cybersecurity project within the prescribed time period.

Battery Storage

DEC proposes a portfolio of nine MYRP battery energy storage projects. Tr. vol. 9, 126. The portfolio consists of nine discrete and identifiable battery energy storage projects: (1) Lowgap; (2) Monroe; (3) Frieden; (4) Novant Health; (5) Nebo; (6) Rich Mountain; (7) Longtown; (8) Farr's Bridge; and (9) Allen. *Id.* DEC witnesses Meeks and Shearer (Battery Energy Storage Panel) testified and detailed the projected cost, schedule, and scope for each MYRP project, as well as the rationale supporting each project as required by Commission Rule R1-17B(d)(2) j. *Id.* at 127–28; *see also* Battery Energy Storage Panel Exhibit 1. The Battery Energy Storage Panel submitted supplemental direct testimony explaining that DEC had removed two projects, Novant Health and Rich Mountain, from the proposed MYRP. *Id.* at 140. According to the Battery Energy Storage Panel, the proposed investments represent near-term investments that will play an integral role in the next phases of the energy transition. *Id.* at 125. The Battery

Energy Storage Panel explained further that the microgrid projects included in the proposed MYRP provide potential reliability improvement solutions for geographically isolated feeders and circuits facing unique reliability challenges with limited options for traditional mitigation improvements. *Id.* at 127. Evidence contained in Battery Storage Panel Exhibits 1-2 includes detailed information regarding projected cost, schedule, scope, and rationale supporting the investments. *Id.* at 124. Battery Energy Storage Panel Exhibit 2 also contains anticipated project timelines, including projected in-service month and year for each proposed project as required by Commission Rules R1-17B(d)(2) j. *Id.* Battery Energy Storage Panel Exhibit 3 provides a program summary of the battery energy storage project portfolio that were presented at the T&D Technical Conference. *Id.* Battery Energy Storage Panel Exhibit 4 includes the CBAs for projects presented at the T&D Technical Conference. *Id.* Finally, Battery Energy Storage Panel Exhibit 5 outlines the methodology that DEC employed in developing the CBAs outlined in Battery Energy Storage Panel Exhibit 4. *Id.*

The Battery Energy Storage Panel described the expected benefits associated with each proposed battery project including unique bulk power services. *Id.* at 127–28. The Battery Energy Storage Panel explained further that battery resources are uniquely capable of serving multiple grid functions across generation, transmission, and distribution systems. *Id.* at 125. The Battery Energy Storage Panel testified that the Frieden project allows DEC to provide bulk system benefits from a distribution interconnection point and explore the value of solar smoothing. *Id.* at 127–28. In addition, the proposed Monroe project utilizes existing interconnection infrastructure, thereby reducing development costs and project timelines. The Battery Energy Storage Panel also explained that the Nebo, Longtown, and Farr’s Bridge microgrid projects are reliability projects located on feeders and circuits with unique reliability challenges and limited options for traditional outage mitigation improvements; thus, these projects improve reliability and resiliency, and speed restoration times for circuits in those areas. *Id.* at 127. The Battery Energy Storage Panel highlighted that upon completion, the proposed Allen project will represent the largest battery installation that DEC has installed. The Battery Energy Storage Panel explained further that the proposed Allen project will: (1) provide bulk system services including energy arbitrage and ancillary services with a grid scale battery system; (2) maximize existing interconnection rights and land availability at a retiring coal facility; and (3) capture the added benefit of an additional 10.0% Investment Tax Credit adder. *Id.* at 127, 130.

Public Staff witness Thomas examined and provided testimony addressing DEC’s proposed battery energy storage portfolio. Witness Thomas did not adjust the cost of battery storage projects included in DEC’s proposed MYRP, but recommended removal of certain microgrid projects and recommended allocation of microgrid costs to distribution only. Tr. vol. 14, 174, 179. Witness Thomas questioned whether the microgrid batteries would provide significant production plant services and testified that project costs should therefore “be allocated 100.0% to distribution.” *Id.* at 174. As a further recommendation regarding microgrid projects, witness Thomas recommended removing three projects — the Nebo, Lowgap, and Farr’s Bridge projects — from the MYRP because these projects had benefit cost ratios “well below one, indicating that the project is not cost-effective" *Id.* at 180–82. Finally, witness Thomas recommended that "DEC consider adding additional battery storage at the retired Allen coal plant in the near future" because DEC recently retired Allen Units 2, 3, and 4 which provided approximately 704 MW of winter capacity and had plans to retire Allen Units 1 and 5 which provide an additional 426 MW of winter capacity. *Id.* at 179. In light of those retirements, witness Thomas testified that there is significant potential to add more than 50 MW of storage capacity in that area through the generator replacement interconnection process. *Id.* at 179–80. Witness Thomas also testified about the higher cost of microgrids compared to grid-scale batteries (75.0% higher on a dollar per kW basis and 61.0% higher on a dollar per kilowatt-hour basis). *Id.* at 177–78.

The Battery Energy Storage Panel submitted rebuttal testimony disagreeing with witness Thomas' recommendations to remove the Farr's Bridge, Lowgap, and Nebo microgrids from DEC's proposed MYRP. Tr. vol. 9, 151, 161. Furthermore, the Battery Energy Storage Panel disagreed with witness Thomas's recommended modifications to DEC's proposed cost allocation methodology for the battery storage projects included in this case. *Id.* at 161. The Battery Energy Storage Panel also contended that witness Thomas ignored the many qualitative and quantitative benefits that the proposed microgrids can provide to customers: customers benefit from both qualitative and quantitative benefits. *Id.* at 150, 156. To that end, the Battery Energy Storage Panel stated that the proposed microgrids will cost-effectively address difficult reliability challenges and provide bulk system benefits that justify production cost allocation. *See Id.* at 157–58. The Battery Energy Storage Panel highlighted that the projects represent the most optimal solutions for feeders facing unique or chronic reliability challenges with limited options for traditional outage mitigation improvements. *Id.* at 152. The Battery Energy Storage Panel further testified that DEC is open to exploring a second project at the Allen site, but the proposed 50 MW project in the MYRP maximizes existing land availability and has already been studied through the large generator interconnection process. *Id.* at 163.

During the hearing, in response to Presiding Commissioner Duffley's questions, the Battery Energy Storage Panel explained DEC's approach to choosing microgrid projects over stand-alone battery projects. *See id.* at 168–70. Specifically, witness Meeks testified that DEC's microgrid projects are strategically sited to solve a grid need that was previously unable to be solved with past technology options, and the microgrids increase reliability and resiliency in areas with reliability needs. *Id.* at 169. Further, when those projects are not needed for local reliability and resiliency, they can be dispatched to the benefit of the bulk system. *Id.* Witness Shearer testified that this also benefits the battery itself, as it allows the battery to "stretch its legs" by providing bulk system benefits on a day-to-day basis rather than sit idly waiting for a reliability event to occur. *Id.* at 170. Witness Shearer also analogized a microgrid to a "Swiss Army knife," testifying that microgrids offer benefits where traditional solutions fall short. *Id.* at 175. Public Staff witness Thomas testified that the Public Staff would work with DEC to understand the operational benefits of microgrids and would review cost allocation in future general rate cases. Tr. vol. 14, 255–59. Regarding the Allen site project, the Panel testified during the hearing that the Allen battery was sized based on available land and transmission hosting capacity, and the battery's siting at a coal facility derives a higher ITC value to offset the cost to customers. *Id.* at 172.

As part of the Revenue Requirement Stipulation, the Stipulating Parties agreed that aside from the provisions laid out in the Revenue Requirement Stipulation, no further adjustments will be made to DEC's base period or MYRP revenue requirement based on the Public Staff's positions as presented in its initial testimony. Revenue Requirement Stipulation (Tr. Ex. vol. 7). Accordingly, the Stipulating Parties agree to use the allocation factor by plant classification of the microgrid projects as proposed by DEC. *Id.* Additionally, the Stipulating Parties agreed to the removal of the Lowgap project from the MYRP. *Id.* During the expert witness hearing, Public Staff witness Thomas explained that only the Lowgap microgrid costs were removed, but that the allocation of the remainder of the microgrids was as DEC had proposed. Tr. vol. 14, 255. Witness Thomas testified that FERC Order 898 may have an impact on how battery costs are allocated in the future, potentially rendering functional cost allocation discussions moot. *Id.* at 263.

After careful review of all the evidence in the record on DEC's MYRP proposal in this docket, and based on that evidence, the Commission finds that DEC's Battery Storage MYRP projects, as adjusted by the Revenue Requirement Stipulation, satisfy the standard set forth in N.C.G.S. § 62-133.16(c)(1)(a). The Commission further finds and concludes that approval of the Revenue Requirement Stipulation's provisions regarding the Battery Storage MYRP projects are appropriate and supported by competent, substantial, and material evidence in the record, and that the Battery Storage MYRP costs thereunder are just and reasonable and consistent with the public interest and subject to a prudence review in DEC's next general rate case. The Commission notes that the concerns and recommendations raised by witness Thomas based on his analyses regarding the higher cost of microgrids over grid-scale storage and microgrid cost-allocation merit consideration in future rate cases. The Commission also notes witness Thomas' recommendation that DEC consider adding additional battery storage capacity at the Allen site and DEC's willingness to explore a second project at the Allen site if there is land availability at the site. Further, in future rate cases, the Commission directs DEC to present detailed evidence demonstrating that completed MYRP microgrids have provided production plant services before allocating new microgrid costs to both production and distribution categories. Finally, the Commission directs DEC to investigate increased storage capacity at the Allen site and to report on its findings in its next general rate case proceeding.

Solar

DEC witness LaRoche provided testimony supporting the 2026 Solar Procurement Program Investment (2026 Solar Investment) that is included in DEC's MYRP, as well as in support for DEC's request for a 35-year depreciation life for the 2026 Solar Investment and for future solar facilities. Tr. vol. 12, 438-49. Witness LaRoche described the 2026 Solar Investment as a procurement of 165 MWs of solar, which will result in multiple projects being selected as part of the 2022 Solar Procurement Program (2022 SP Program) Request for Proposals (RFP), with projected in-service dates of

June 1, 2026. *Id.* at 442. Witness LaRoche stated that to identify the 2026 Solar Investment, DEC examined the solar pipeline for discrete and identifiable solar projects that would be placed in service within the MYRP period, and as part of this process, DEC considered the solar investments that will result from the 2022 SP Program. *Id.* at 442–43. Additionally, he testified that DEC's Initial Carbon Plan identified the need for new solar resources to reliably serve DEC's projected customer load. *Id.* at 441. Witness LaRoche also stated that S.L. 2021-165 was a "key driver" of the 2026 Solar Investment as that statute requires DEP and DEC to take all reasonable steps to achieve 70.0% carbon emission reductions by 2030 and carbon neutrality in North Carolina by 2050. *Id.* at 440. Further, witness LaRoche identified that the 2022 SP Program RFP aligns with the Carbon Plan solar targets. *Id.* at 441. In addition, DEC's most recent Initial Carbon Plan, filed with the Commission, also identified the need for new solar resources to reliably serve DEC's projected customer load. *Id.*

In witness LaRoche's first supplemental testimony, he testified to an agreement reached between DEC and the Public Staff describing updates associated with the proposed solar projects contained in DEC's MYRP. *Id.* at 452. Witness LaRoche stated that DEC has identified an early winner that is part of the 2026 Solar Investment. *Id.* Additionally, witness LaRoche provided the Commission with an update on the 2026 Solar Investment to reflect the selection of a proposal from the 2022 SP Program RFP. *Id.* Witness LaRoche testified that DEC updated the cost estimate for the 2026 Solar Investment to reflect the reduced MW capacity and DEC's revenue requirement. *Id.* at 456.

In DEC witness LaRoche's second supplemental testimony, he updated the 2026 Solar Investment to reflect the selection of a market participant and proposal for the 2022 SP Program RFP. *Id.* at 462. Witness LaRoche testified that the market participant selected has: (1) performed all required environmental studies; (2) secured required county permit approval; and (3) completed interconnection studies and obtained a fully executed IA. *Id.* at 463. Further, the market participant selected has requested and received a CPCN for the 2026 Solar Investment, and DEC intends to file a CPCN transfer application by the end of 2023. *Id.* As a result, the 2026 Solar Investment cost estimates and revenue requirements for the proposed MYRP have been updated. *Id.* at 463–64. Witness LaRoche testified that the 2026 Solar Investment can reasonably be placed in-service by June 2026. *Id.* at 464.

Public Staff witness Thomas recommended reducing the system level in-service costs of the facility and the associated network upgrades to $70,799,273, a reduction of approximately $123 million. Tr. vol. 14, 167. Further, witness Thomas recommended a proportional reduction to the annual O&M thereby reducing the annual O&M cost to $653,739. *Id.*

DEC witness LaRoche testified in his rebuttal testimony that DEC agrees with the Public Staff's solar investment-related recommendations. Tr. vol. 12, 451. Specifically, DEC's supplemental direct testimony updated the projected in-service costs (including associated network upgrade costs) and projected annual net O&M to reflect selected winners resulting from the 2022 SP Program. *Id.* Consistent with witness Thomas' recommendation, DEC updated the projected in-service costs to $70,799,273. Furthermore, witness LaRoche testified that the projected annual O&M was updated to $481,246, an amount lower than the Public Staff's recommended value. *Id.*

After having carefully reviewed the evidence in the record on DEC's Solar MYRP proposal in this docket, and based on that evidence, the Commission finds that DEC's solar MYRP projects, as adjusted by the Revenue Requirement Stipulation, satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a).

MYRP Implementation

Public Staff witness Metz testified to his concern regarding DEC's ability to complete the proposed MYRP projects within the three-year MYRP period. Based on his review of DEC's historic and projected 2023 staffing, witness Metz asserted that DEC does not have a plan to increase staffing for planned MYRP projects while continuing to perform traditional work of the utility. *Id.* at 901–10.

In DEC witness Murray's rebuttal testimony, he reviewed DEC's holistic and comprehensive approach to project planning and execution, while noting that neither the Public Staff nor any party recommended disallowance or rejection of any MYRP project based on generalized project execution risks or challenges. *Id.* at 481. Witness Murray discussed how Duke Energy's PMCoE creates a common framework for managing projects across the enterprise and how DEC has successfully implemented prudent management processes historically. *Id.* at 482–83.

While acknowledging that MYRP project execution will not be easy and that there likely will be unforeseen challenges that require DEC to in some cases modify planning MYRP projects to maximize benefits for customers, he explained that MYRP project execution is not a challenge that is fundamentally different than challenges inherent in DEC's historic capital project implementation. Witness Murray disagreed with the Public Staff's suggestion that DEC is not well prepared to successfully execute these projects. *Id.* at 481.

DEC witness K. Bowman also responded to witness Metz's concerns regarding DEP's ability to execute certain MYRP projects. Tr. vol. 7, 98. Witness K. Bowman testified that DEC is confident in its ability to execute the MYRP projects and acknowledged DEC's obligation, as confirmed by the Commission, to continually assess the MYRP projects and ensure that customer benefits are maximized throughout the execution phase. *Id.* Witness K. Bowman explained that although DEC will encounter unforeseen challenges and circumstances in all instances DEC will leverage its execution experience to maximize benefits for customers. *Id.*

After review of the evidence presented by DEC's various generation, transmission, and distribution witnesses, as well as the evidence presented by DEC regarding its processes, procedures, and project management experience the Commission finds that

DEC has the obligation to prudently and reasonably implement the MYRP in a manner that benefits its customers. Any modification to the implementation of MYRP projects will be reported by DEC on a quarterly basis, as required under Commission Rule R1-17B(h)(2) and will be subject to audit in future base rate case proceedings. While the Commission recognizes the risk about which the Public Staff is concerned, the Commission determines on the evidence presented that DEC has demonstrated a reasonable plan to complete the MYRP projects within the prescribed time periods.

MYRP Project Documentation

DEC provided support for its MYRP projects through its Application, direct, supplemental, settlement, and rebuttal testimony of the DEC witnesses discussed below, as well as at the November 2022 Transmission and Distribution Technical Conference. Furthermore, the Public Staff conducted substantial discovery regarding the projects DEC proposed in its MYRP.

The Public Staff critiqued DEC's project documentation for MYRP projects. Specifically, witness Metz testified that the Public Staff implemented a screening process to review and identify project documents received. Tr. vol. 12, 872. Witness Metz stated that the Public Staff received insufficient or no project documentation for a number of MYRP projects, which raised concerns of undue risk placed on customers if projects lacking full documentation are being planned and included in rates. *Id.* at 873–79. Witness Metz recommended removing projects from DEC's MYRP that did not include supporting documentation sufficient to satisfy Commission Rule R1-17B(d)(2)(j). *Id.* at 872. Witness Thomas also recommended the removal of approximately $63 million of hydroelectric projects from the MYRP citing a failure to satisfy Commission Rule R1-17B(d)(2)(j) due to a lack of documentation. Tr. vol. 14, 189. Witness Michna further recommended the removal of approximately $41 million of steam generation projects from the MYRP citing a failure to satisfy Commission Rule R1-17B(d)(2)(j) due to a lack of documentation. Tr. vol. 15, 67.

The various DEC operational witnesses all provided testimony supporting their respective projects. DEC witness Murray specifically responded to the Public Staff's critiques regarding the level and amount of project documentation DEC provided. Witness Murray testified that DEC has in place well-defined project management practices, and the complexity of a project drives the level of project documentation with more complex projects generating much more documentation than recurring, routine projects. *Id.* at 487. As it relates to the timing, witness Murray testified that project documentation is created in the ordinary course of business. Witness Murray explained that as a project advances through DEC's Project Stage Gating process associated documents also advance and develop to include greater detail and a more defined scope. *Id.* Witness Murray also testified that it was reasonable to expect a range of project documentation available based on the factors noted above, namely, timing, complexity, and gating stage. *Id.* at 488.

During the hearing, Public Staff witness Metz testified that the Revenue Requirement Stipulation included a commitment between the Public Staff and DEC to work on a project documentation framework for MYRP projects in future rate cases as first mentioned above. Tr. vol. 12, 983–85. Witness Murray agreed with counsel for DEC that the goal of that commitment in the Revenue Requirement Stipulation is to develop an agreed upon structure for making the audit process of MYRP projects more efficient. *Id.* at 985. Witness Murray further agreed that he felt reasonably comfortable that DEC and the Public Staff can develop an efficient structure for review of project documentation that will aid the Public Staff in its review in future MYRP cases. *Id.*

Section IV, Paragraph 42 of the Amended Revenue Requirement Stipulation requires DEC to work with the Public Staff before filing its next PBR Application to attempt to establish agreed upon MYRP project documentation guidelines.

Section III, Paragraph 34 of the Amended Revenue Requirement Stipulation provides that the projected MYRP capital should be reduced by $351 million on a system basis in connection with the Public's Staff's disallowance based on the Public Staff's contention of insufficient project documentation. Amended Revenue Requirement Stipulation § III.34 (Tr. Ex. vol. 7). No intervenor took issue with these provisions of the Revenue Requirement Stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of these issues for purposes of this proceeding.

MYRP Project Contingency

In Public Staff witness Metz's testimony, he recommended the Commission reduce DEC's project contingency by half for all projects not identified for removal by the Public Staff by the appropriate rate year. Tr. vol. 12, 914–15. Witness Metz testified that DEC provided a detailed list, by project, of total project contingency costs. Witness Metz noted that each project type had a different percentage of contingency costs applied. *Id.* at 913. Witness Metz explained that the Public Staff's recommended adjustment would include project contingencies in rates for prospective years which would incentivize DEC to complete projects at or under budget. *Id.* at 915.

DEC witness Murray addressed witness Metz's contingency recommendation. Witness Murray testified that the projects included in DEC's MYRP include contingency amounts that are prudent and in line with industry practice and noted that contingency only represents 9.91% of DEC's total planned project spend. *Id.* at 490. Witness Murray also testified that DEC's PMCoE provides guidance on project contingency and contingency levels are set for each project based on specific execution risks and vary based on the project development timeline. *Id.* at 490–91.

Section III, Paragraph 35 of the Amended Revenue Requirement Stipulation provides that DEC will reduce its total contingency amounts included in the MYRP by 50.0%. Amended Revenue Requirement § III.35 (Tr. Ex. vol. 7). No intervenor took issue with this provision of the Revenue Requirement Stipulation, which is consistent with the

DEP Rate Case Order. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Allowance for Funds Used During Construction

Public Staff witnesses Zhang and Boswell testified that DEC appeared to include allowance for funds used during construction (AFUDC) as part of its costs for MYRP projects. Tr. vol. 12, 1048. They expressed concern that DEC may recover AFUDC while simultaneously recovering capital costs from customers. *Id.* at 1047. Witnesses Zhang and Boswell recommended removal of DEC's AFUDC for MYRP projects and requested that DEC provide in its rebuttal testimony: (1) its methodology and supporting calculations for AFUDC included in projects; (2) a detailed description of how DEC calculated AFUDC amounts for each MYRP project, including how DEC accounted for the recovery of projects in given rate years; and (3) supporting workpapers for accrual amounts for each project. *Id.* at 1048–49.

DEC witness Abernathy clarified that DEC's MYRP estimates include an amount of AFUDC that is expected to accrue on each capital project from the project start date until the in-service date. Tr. vol. 16, 221. Witness Abernathy explained that there is no overlap of the AFUDC accrual, and the return is included in DEC's revenue requirement calculation because the revenue requirement calculation starts with the in-service date and is based on the total balance projected to be placed in-service. *Id.* at 221–22.

Section III, Paragraph 36 of the Amended Revenue Requirement Stipulation provides that DEC's AFUDC calculation will be included in the MYRP. No intervenor took issue with this provision of the Revenue Requirement Stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Installation O&M

In DEC witness Abernathy's direct testimony, she testified that DEC included one-time, incremental O&M costs in the revenue requirement calculation. Tr. vol. 12, 93. Witness Abernathy explained that these costs, provided by the respective operations witnesses, flow through the revenue requirement calculation according to the date of the one-time O&M expense not a project's in-service date. *Id.*

Public Staff witness Metz recommended removal of all DEC's one-time, incremental O&M expenses from the MYRP. *Id.* at 922. Witness Metz stated that the test year also included a level of O&M expenses associated with the completion of capital projects, and he expressed concern that DEC overestimated its level of one-time O&M. *Id.* at 918–19.

In DEC witness Bateman's rebuttal testimony, she responded to witness Metz's recommendation. Witness Bateman testified that the Public Staff's proposal seeks to adjust test year expenses in a manner that is neither authorized by the PBR Statute nor consistent with the Commission's rules. Tr. vol. 16, 255–57. Witness Bateman explained that as some test year costs will decrease, others will increase, and that it is DEC's responsibility to balance non-MYRP impacts. *Id.* at 257.

Section III, Paragraph 37 of the Amended Revenue Requirement Stipulation provides that 50.0% of corrected, one-time installation O&M should be removed from the MYRP revenue requirement. No intervenor took issue with this provision of the Revenue Requirement Stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 30-31

Reporting Requirements

The evidence supporting these findings of fact is contained in DEC's verified Application and Form E-1; the Revenue Requirement Stipulation; the testimony and exhibits of DEC witnesses Maley, Guyton, Abernathy, and Byrd; Public Staff witnesses Metz, Thomas, T. Williamson, Lawrence, and Nader; and the entire record in this proceeding.

AFUDC on MYRP Capital Projects Reporting

In DEC witness Abernathy's Settlement Testimony, she explained that the Revenue Requirement Stipulation provides that the DEC calculated AFUDC is included in the MYRP subject to reporting obligations agreed to with the Public Staff. Tr. vol. 12, 135. These reporting requirements were included in the Revenue Requirement Stipulation.

EV Reporting

In Public Staff witness Lawrence's testimony, he recommended the following reporting requirements for EV charging stations installed by DEC: (1) Location (site name and address); (2) Installation date; (3) Charging station type (L2, DCFC, etc.); (4) Maximum charging station output rating; (5) Capital cost per charging station; (6) Number of uses; (7) Average duration of use; and (8) Average energy delivered per use. Tr. vol. 15, 101–02. In addition to this reporting, DEC should also maintain the load profile for each station. DEC should make the first report beginning no later than 180 days after the Commission's final order in this docket and subsequent report every six months thereafter until the Commission's final order in DEC's next rate case. *Id.*

In DEC witness Guyton's rebuttal testimony, he stated that DEC agrees in part with the reporting items. Witness Guyton stated items one through five are part of the normal project documentation, and DEC can provide them. Tr. vol. 8, 218. However, for items six through eight, as well as the request of a load profile per station, such reporting items are not achievable. *Id.* DEC witness Guyton explained that charging infrastructure varies in technology and capabilities as well as installation set up. Not all charging stations have the capability to record and transmit number of sessions, time of use, or energy delivered before developing a load profile. *Id.* Further, DEC cannot rely upon meter data to provide an overall look as the installation approach varies from site to site. For example, leveraging existing building panel capacity when available to reduce installation costs places charging stations on the building meter. *Id.* at 218–19. In cases where building capacity is not available a separate transformer and meter specific for the charging stations is installed. However, a separate meter cannot provide individual station data as recommended. *Id.*

Rider ED

In DEC witness Byrd's direct testimony, he explained that DEC is proposing a new rider that will improve competitiveness for attracting and retaining customers that are adding jobs and making capital investments in DEC's service territory. Tr. vol. 10, 106. Witness Byrd testified that this new Economic Development Rider (Rider ED) affords greater flexibility to tailor benefits based on both electric grid and regional economic benefits associated with the participant's investment and load characteristics. *Id.*

In Public Staff witness Nader's testimony, he stated that DEC's Rider ED adheres to the principles of the Commission's Order Adopting Guidelines for Job Retention Tariffs, *Investigation of Changes Occurring in the Electric Utility Industry and the Regulatory and Policy Implications of Such Changes, including Proposals for Innovative Rates and Mechanisms, and Proposed Interim Guidelines for Self-Generation Deferral Rates*, No. E-100, Sub 73 (N.C.U.C. Dec. 8, 2015). Tr. vol. 13, 766–69. Witness Nader stated that the Public Staff is reasonably satisfied that the costs and benefits of Rider ED are balanced, fair, and in the public interest. *Id.* Witness Nader recommended that the Commission require annual reporting of the impacts of Rider ED to ensure the rider remains in the Public Interest. *Id.* at 769. At a minimum, he testified that DEC should report the gross level of incentives paid, the number of recipients, the amount of investment, load, and jobs associated with the incentives, and an overall marginal cost analysis of Rider ED to determine if the gross level of incentives paid exceeds the marginal cost to serve the gross pool of participants. *Id.*

In his rebuttal testimony, DEC witness Byrd testified that within certain limits, DEC agrees that some annual reporting is reasonable with respect to the impacts of Rider ED. Tr. vol. 10, 214. For example, DEC could report on the total number of jobs, total capital investment, or other such characteristics contained in the applications for customers currently taking service under Rider ED provided such information can be appropriately anonymized to preserve confidentiality. *Id.*

CIAC Reporting

In Public Staff witnesses Zhang and Boswell's joint direct testimony, they stated that DEC was booking CIAC related to IA inconsistently. Witnesses Zhang and Boswell recommended that the Commission order DEC to review its CIAC policy to ensure that DEC properly accounts for CIAC and report the results of that review in the next general rate case. Tr. vol. 12, 1005–06. In rebuttal, DEC witness Speros testified in opposition to the Public Staff's contention that DEC was booking its CIAC related to IAs inconsistently but stated that DEC did not oppose in principle reporting to the Commission on its CIAC policy in the next general rate case. Tr. vol. 13, 545–50.

Quarterly Reliability Reporting

In Public Staff witness T. Williamson's testimony, he recommended that the Commission require DEC to include the number of Major Event Days (MEDs) and non-MEDs that DEC experiences during a reporting period in its quarterly reliability report filed in Docket No. E-100, Sub 138A. Tr. vol. 15, 171.

In DEC witness Guyton's rebuttal testimony, he testified that DEC agreed to add the information requested by Public Staff witness T. Williamson to its quarterly reports. Tr. vol. 8, 239.

Vegetation Management Reporting

In Public Staff witness T. Williamson's testimony, he recommended that the Commission extend DEC's vegetation management-related semi-annual filing requirement that is already in effect through the end of DEC's proposed MYRP period, aligning with DEP's report sunset in 2026. Tr. vol. 15, 149–50. Witness T. Williamson also recommended the Commission require DEC to include additional metrics in its semi-annual Vegetation Management Program Performance report. Witness T. Williamson's recommended additions included the following for distribution-related vegetation management reporting: (1) for distribution vegetation management herbicide, add actuals, target, and variance for spending and miles; (2) for distribution vegetation management hazard tree programs, add actuals for spending and tree counts; and (3) for distribution vegetation management reactive/demand events, add the number of events worked annually. *Id.* at 150–51. In his rebuttal testimony, DEC witness Guyton agreed with these reporting requirements. Tr. vol. 8, 202.

In addition, Public Staff witness T. Williamson recommended the Commission require the following changes to DEC's report on its vegetation management performance filed semi-annually in the 2019 Rate Case docket: (1) for transmission vegetation management trimming, add actuals, target, and variance for spending and miles; (2) for transmission vegetation herbicide, add actuals, target, and variance for spending and miles; (3) for transmission vegetation management hazard tree programs, add actuals for spending and tree counts for removal; and (4) for transmission vegetation management reactive/demand events, add the number of events worked annually. Tr. vol. 15, 150–51.

In witness Maley's rebuttal testimony, he stated that DEC did not take issue with these reporting requirements subject to two clarifications, those being that: (1) the transmission vegetation management trimming program focuses on removal as the primary function, and DEC interprets this reporting requirement as requesting the O&M portions of planned corridor work; and (2) that transmission vegetation herbicide is tracked as the amount of vegetation sprayed in acres as opposed to miles due to varying corridor widths and shared corridors, and DEC therefore proposes to report by acres rather than miles. Tr. vol. 8, 354.

Discussion and Conclusions

The Amended Revenue Requirement Stipulation establishes certain reporting obligations. Specifically, in Section IV, Paragraph 43 DEC agrees to track and report on AFUDC accrued on MYRP capital projects and for the Public Staff and DEC to discuss the scope and content of such reporting. In Section IV, Paragraph 44, DEC agrees to report the EV reporting requirements discussed by Public Staff witness Lawrence, and to further discuss with the Public Staff those items noted by DEC witness Guyton as unfeasible with the understanding that those items will be reported by DEC when doing so becomes possible. Section IV, Paragraph 45 obligates DEC to report on Rider ED subject to agreement of the stipulating parties regarding the scope and content of the report. Section IV, Paragraph 46 obligates DEC to report on the CIAC issue in its next general rate case application. Section IV, Paragraph 47 addresses a reporting on reliability O&M as discussed by Public Staff witness Metz and above in this Order, and Section IV, Paragraph 48 obligates DEC to report on certain Vegetation Management reporting requirements as discussed by Public Staff witness T. Williamson except for reporting on the two issues noted in the rebuttal testimony of DEP witness Maley. Additionally, witness Guyton agreed to add information to DEC's reliability reporting.

No other party offered any evidence addressing the reporting obligations outlined in the Amended Revenue Requirement Stipulation or addressed above. The Commission concludes that the reporting obligations agreed upon in Section IV of the Amended Revenue Requirement Stipulation and addressed above are reasonable. Based upon the record evidence and consistent with the Amended Revenue Requirement Stipulation, the Commission finds and concludes that the reporting obligations outlined in Section IV of the Amended Revenue Requirement Stipulation are approved as well as the additional reporting requirement addressed herein.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 32

Storm Normalization

The evidence supporting this finding of fact is contained in DEC's verified Application and Form E-1; the testimony and exhibits of DEC witness Q. Bowman; and the entire record in this proceeding.

In prior DEC rate cases, including the 2013 Rate Case, the 2017 Rate Case, and the 2019 Rate Case, the Commission has approved a calculation of "storm normal" expenses based upon a ten-year average of storm costs, after reducing the costs associated with major storms, to include in rates. Witness Q. Bowman explained the methodology for the calculation of storm normal in this case. Tr. vol. 12, 185–86. The resulting amount to include in rates per DEC's calculation is approximately $32.225 million. Q. Bowman Supp. Settlement Ex. 4 (Tr. Ex. vol. 12).

No party disputes DEC's methodology for calculation of storm normal expenses to include in rates, and DEC witness Q. Bowman testified that the Public Staff's calculation is consistent with the methodology used by DEC. Tr. vol. 15, 1276.

Accordingly, the Commission finds that the appropriate North Carolina retail normalized annual level of storm costs to include in DEC's rates in this case is $32.225 million.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 33-34

Payment Navigator

The evidence supporting these findings of fact is contained in DEC's verified Application and Form E-1; the Revenue Requirement Stipulation; the testimony and exhibits of DEC witnesses Q. Bowman and Quick; and the entire record in this proceeding.

In DEC witnesses Q. Bowman's direct testimony, she stated that DEC proposed several new programs in this rate case to benefit customers, including the CAP, the Tariffed On-Bill program, and the Payment Navigator program that DEC witnesses Harris and Quick also discussed in their testimony. If the Commission approves each program, DEC requests permission to establish a regulatory asset and defer to the account the incremental implementation and administration O&M costs related to the programs. Tr. vol. 12, 191–92.

DEC witness Quick described DEC's Affordability Ecosystem in her direct testimony. The Affordability Ecosystem is a multi-pronged approach to assist customers who have challenges in affording to pay their electric utility bills. The Affordability Ecosystem includes products and services, including bill pay assistance and weatherization programs, and DEC equips its customer service team to inform customers about opportunities to address their affordability challenges. Tr. vol. 7, 130–31. Consistent with DEC's Affordability Ecosystem, witness Quick requested approval of the Payment Navigator program, which DEC specifically designed to comprehensively support not only low-income customers in arrears on their bills, but all customers seeking assistance in managing their electric utility bills. *Id.* at 133. The Payment Navigator program is based on a pilot that DEC tested with customers seeking support in paying their electric bills. *Id.* at 133–34. As witness Quick described, in accordance with the Payment Navigator program, DEC proactively contacts customers who are struggling with arrearages to invite them to speak with a Payment Navigator specialist. A Payment Navigator specialist is a call center agent trained to empathetically handle more complex calls assisting customers who have fallen behind in their bills, and the specialist can take the necessary time to work with customers on obtaining the assistance they need. *Id.* Based on the customer's situation, the Payment Navigator specialist may tailor a unique set of recommendations to assist the customer in becoming current on payments and provide longer-term guidance on how to ease the customer's electric energy burdens by connecting the customer to assistance funding, referring them to energy efficiency or demand side management options, or enrolling them in programs like Budget Billing, Pick Your Own Due Date, and more. *Id.* at 134.

DEC witness Quick also testified that Payment Navigator would complement the CAP that DEC witness Harris described. Witness Quick noted that CAP will directly benefit customers by reducing their monthly electric energy burden through a bill discount. After a customer enrolls in CAP DEC can continue to work with the customer to understand the customer's needs and analyze what other products and services (such as Share the Light, Budget Billing, energy efficiency offerings, weatherization, and payment plans) are available to support the customer over the longer term. *Id.* at 135–36.

Witness Quick concluded by requesting that the Commission approve the Payment Navigator program and associated costs, which she estimated to be $4 million over the next three years. Witness Quick noted that the deferral request that DEC witness Q. Bowman describes in her testimony addresses the associated incremental O&M costs that the $4 million estimate includes. Witness Quick testified that DEC would not defer any capital costs associated with the program. *Id.* at 136.

No party contested the implementation of the Payment Navigator program.

Customer Connect

In its Application, DEC requested recovery of the approximately $92 million North Carolina retail allocated capital investment associated with implementation of its Customer Connect project, the new customer engagement platform, and CIS. Tr. vol. 12, 407, 417. DEC witness Hunsicker testified that in November 2021, DEC implemented the Customer Connect platform including a CIS, which is a system that manages the billing, accounts receivable, and rates for DEC as a central repository for all customer information. *Id.* at 407–08. Witness Hunsicker explained that a CIS links the consumption and metering process to payments, collections, and other downstream processes, including additional work order requests such as service connections and disconnections, outages, and trouble requests. A CIS also manages customer profiles and integration of data to provide a holistic view of the customer and it should enable expected customer capabilities. *Id.* at 408–09. Witness Hunsicker explained that DEC developed its previous CIS almost 30 years ago and the system could not efficiently support new capabilities, and thus required complex add-ons and manual performance of some complex billing functions. *Id.* at 407.

Witness Hunsicker explained that Customer Connect benefits customers by providing a modern, configurable billing system that allows DEC to keep pace more efficiently with changing customer expectations and needs. Improvements with Customer Connect include a customer-centric data model and more holistic customer data analytics capabilities which allow DEC to better know its customers and the usage needs across the entire Duke Energy footprint and provide a more customized experience. Witness Hunsicker explained that, since she first testified to the need for Customer Connect in the 2017 Rate Case, DEC has kept stakeholders informed of the status of the implementation, and while no complex, enterprise-wide CIS implementation is without challenges, its Customer Connect implementation benchmark metrics compare favorably to industry benchmarks. *Id.* at 408.

No party contested DEC's request to recover its costs related to Customer Connect.

Discussion and Conclusions

No parties opposed DEC's requests related to Payment Navigator or Customer Connect. In *State ex rel. Utilities Commission v. Intervenor Residents of Bent Creek/Mt. Carmel Subdivisions*, 305 N.C. 62, 75–77, 286 S.E.2d 770, 778–79 (1982), the North Carolina Supreme Court held that the Commission can accept the uncontested evidence of a public utility regarding the reasonableness of its costs as satisfying the utility's burden of proof on the question of cost recovery. The Commission concludes that DEC has met its burden of showing that its proposals related to Payment Navigator and Customer Connect are just and reasonable.

Further, the Commission concludes that DEC's requested recovery of costs associated with its Customer Connect project is just and reasonable to all parties considering the evidence presented.

Finally, the Commission approves implementation of Payment Navigator and recognizes and appreciates the work of DEC to undertake this effort during the COVID pandemic and to devote resources and expertise to connecting customers with assistance during the crisis. The Commission recognizes the customer benefits that arise, particularly in the context of those customers most in need, when DEC (and its affiliates) apply their specialized knowledge and resources in direct support of the customers. The Commission encourages DEC to continue to partner with assistance agencies across its service area and to proactively contact struggling customers to direct them to contact a Payment Navigator specialist for assistance in managing their electric utility bills.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 35

COSS Stipulation

The evidence supporting this finding of fact is contained in DEC's verified Application and Form E-1; the COSS Stipulation; the testimony and exhibits of DEC witness Hager; Public Staff witnesses McLawhorn and D. Williamson; CIGFUR witness Collins; and the entire record in this proceeding.

Summary of Evidence

DEC Direct Testimony

Cost of Service Study Overview

In DEC witness Hager's testimony, she described the purpose of a COSS and how costs are assigned pursuant to such study. Witness Hager explained that the COSS is used to align the total costs incurred by DEC in the test period with the jurisdictions and customer classes responsible for those costs. Tr. vol. 12, 344. Using the principle of cost causation, the COSS assigns or allocates DEC's revenues, expenses, and rate base to the regulatory jurisdictions and to customer classes that caused such costs to be incurred. *Id.* at 344–45. Costs are first grouped according to their function. *Id.* at 346. Functions include production (generation), transmission, distribution, and customer service, billing, and sales. *Id.* Functionalized costs are then classified based on the utility operation or service being provided and the related causation of the costs. *Id.* Typical classifications include demand, energy, and customer-related costs. *Id.* Finally, the functionalized and classified costs are allocated or directly assigned to the proper jurisdiction and customer class based on the way the costs are incurred, i.e., based on cost causation principles. *Id.* at 346–47. Once all costs and revenues are assigned the COSS identifies the return on investment that DEC earned for each customer class during the test period, and these returns can then guide rate design. *Id.* at 345.

The COSS Stipulation

On September 13, 2022, DEC, DEP, the Public Staff, CIGFUR II, and CIGFUR (COSS Stipulating Parties) filed the COSS Stipulation with the Commission. Tr. vol. 12, 342. The COSS Stipulation provides that production and transmission demand costs are first allocated to the North Carolina retail jurisdiction using the 12 CP method, and then production demand costs are allocated within North Carolina retail rate classes using the Modified A&E method. *Id.* Because transmission demand does not have average or excess energy components the transmission demand factors at the customer class level are equivalent to the 12 CP calculation. *Id.* The COSS Stipulation also provides that, for purposes of allocating production demand costs on a jurisdictional basis as well as to North Carolina retail rate classes, DEC will make an adjustment to exclude certain curtailable/interruptible loads if they were not curtailed at the 12 system peak hours during the test year. *Id.* By its terms, the COSS Stipulation only applies in the current rate case, and the COSS Stipulating Parties are free to advocate for different methodologies in future DEC cases. *Id.* DEC witness Hager testified that the COSS Stipulation is reasonable and that the Commission should approve it noting that it was the result of the give-and-take inherent in coming to a settlement among parties with diverse views on the appropriate methodologies. *Id.* at 342–43. The COSS Stipulating Parties urge the adoption of the stipulation in this case as a fair and reasonable methodology for the allocation of costs. COSS Stipulation (Tr. Ex. vol. 7).

The 12 CP Method

Under the COSS Stipulation, the 12 CP method will be used to allocate production and transmission demand-related costs to the North Carolina retail jurisdiction. *Id.* Witness Hager testified that in the 2019 Rate Case, DEC recommended and the Commission approved the summer coincident peak (Summer CP) method to allocate the fixed portion of production and transmission demand-related costs. Tr. vol. 12, 351. However, DEC now believes it is appropriate to move from Summer CP to 12 CP which utilizes the average of the test year's 12 monthly peaks. *Id.* Witness Hager testified that DEC's integrated resource planning period has shifted away from an emphasis solely on summer peaks, and by averaging the 12 monthly peaks the 12 CP method is less volatile than a single coincident peak. *Id.* at 351–52. Witness Hager further testified that the 12 CP method is regularly used by other utilities and has been approved by state commissions and the FERC. *Id.* at 352.

The Modified A&E Method

The COSS Stipulation also proposes a Modified A&E method to allocate production demand costs across North Carolina retail customer classes. COSS Stipulation (Tr. Ex. vol. 7). DEC witness Hager testified that the Modified A&E method adopted under the COSS Stipulation 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 demand-related costs. Tr. vol. 12, 358. The excess demand is the excess of a rate class's non-coincident peak (NCP) demands over its average demands. Under this method, all groups of customers are allocated some portion of the production plant investment and fixed expenses related to the generation of power. *Id.* at 358. A rate class's coincident peak demand is the class's load at the time of the system's peak demand, while a rate class's NCP is the maximum demand regardless of the time of occurrence. *Id.* Witness Hager explained that each customer class's non-coincident demand likely occurs at different times. *Id.* Witness Hager noted that the Modified A&E method is a commonly accepted method of allocating demand-related production costs used in several jurisdictions and is a reasonable method for allocating demand-related production costs to the North Carolina retail classes in this case. *Id.* at 359. However, DEC modified the method to conform the A&E allocators to the 12 CP method used at the North Carolina retail jurisdictional level. *Id.*

Removal of Certain Curtailable/Interruptible Loads

DEC witness Hager testified that historically DEC has allocated production fixed costs based on the demands served at its peak hour. *Id.* at 360. Witness Hager also testified that aligning firm load with firm capacity to serve that load is more consistent with the principle of cost causation than the previous method. *Id.* DEC does not plan for, and does not purchase capacity for, the curtailable load of customers. *Id.* Since DEC can curtail customers who take interruptible service so that their load does not contribute to the system peak interruptible load does not factor in to how much the utility must invest in capacity to meet the system peak. *Id.* If the utility curtails all possible curtailable load in the test year during system peaks there is no need for adjustments as revenues and loads both reflect only firm load. *Id.* However, there can be a mismatch between revenues and loads if there is some non-firm load in the test year peaks. *Id.* at 360–61. Accordingly, DEC removed non-curtailed non-firm load present during the test year peaks where its presence would create a mismatch with revenues. *Id.* at 361. This adjustment ensures a matching of firm load with firm load revenues. *Id.* This practice is also consistent with FERC precedent. *Id.* Witness Hager testified that this proposed method will eliminate the volatility of having load in one test year and out in the next test year. *Id.* at 363.

Adjustments were made to remove certain curtailable load at both the North Carolina retail jurisdiction level with the 12 CP method, as well as at the North Carolina retail rate class level with the Modified A&E method. *Id.* The demand-related transmission costs were allocated to rate classes based on 12 CP demand without adjustment for curtailable load. *Id.*

Distribution Costs

DEC witness Hager testified that most distribution investments are identified and then directly assigned to the state in which they are located. *Id.* at 363. Distribution costs identified as customer-related are allocated using customer allocation factors, and the remainder are designated as demand-related and allocated to customers based on NCP demand allocators. *Id.*

NCP allocators are developed to account for the different levels of the distribution system where customers may take service. *Id.* at 364. Witness Hager explained that NCP allocators are developed by taking the ratio of the non-simultaneous peak demands of the customers in each class whenever that peak occurred during the test period and comparing that to the sum of all customers' non-simultaneous peak demands. *Id.* Witness Hager noted that several different NCP allocators are developed to account for the different levels of the distribution system where customers may take service (primary, secondary, etc.). *Id.* For example, only the NCP demand of customers taking service at secondary voltage is included in the development of the NCP allocator used to allocate secondary distribution lines and poles. *Id.*

Further, witness Hager testified that NCP allocators are used for demand-related distribution investment because distribution facilities serve individual neighborhoods, rural areas, or commercial districts; they do not function as a single integrated system in meeting system peak demand. *Id.* The individual distribution system serving an area must be able to meet the peak demand in the area it serves whenever the peak occurs. *Id.* Accordingly, Witness Hager testified that contribution to NCP is the appropriate measure of determining customers' responsibility for costs because it best measures the factors that drive investment to support that part of the system. *Id.*

Energy Allocators

DEC witness Hager testified that energy-related costs, such as fuel costs and variable production costs at generating stations, reflect the variable cost of producing, transmitting, and delivering electricity. *Id.* at 365. Witness Hager also testified that these costs are allocated using DEC's kilowatt-hour of generation and deliveries during the test period. *Id.* Finally, witness Hager explained that kilowatt-hour sales information is collected and adjusted for the level of losses attributable to each class and jurisdiction to determine the level of kilowatt-hour at the generator attributable to that class or jurisdiction. *Id.*

Customer Allocators

DEC included operating expenses in FERC accounts 901–917 for allocation as customer-related costs that include meter reading, billing and collection, and customer information and services. Tr. vol. 12, 365. DEC has also included in this category a portion of distribution costs that it has identified as customer-related, such as meters and service drops (FERC accounts 369 and 370) and a portion of transformers (FERC account 368). *Id.* A portion of costs for distribution lines and poles (FERC accounts 364–367) were also identified as customer related. *Id.* The remaining distribution plant and associated costs were classified as demand-related, except for FERC account 363, Energy Storage Equipment – Distribution. *Id.* at 365–66.

While DEC had no battery storage units in plant in service in the 2021 test year, DEC projections for the MYRP years include the costs to install battery storage facilities. *Id.* at 366. DEC witness Hager testified that storage battery equipment functionalized to production (FERC Account 348) is allocated across customer classes using the production demand allocator. Battery storage equipment that is functionalized to distribution (FERC account 363) is allocated across customer classes using gross distribution plant excluding batteries. *Id.* This approach recognizes that batteries provide benefits to or support different sections of the electrical system. *Id.*

Witness Hager testified that a portion of distribution costs related to FERC accounts 364-68 including costs of poles, towers, fixtures, overhead and underground conductors, and transformers are customer related. *Id.* at 366. NARUC discusses using two methods for allocating these customer-related distribution costs: the Minimum System Method and the Zero-Intercept Method. *Id.* Witness Hager testified that both methods recognize that some portion of the distribution system is necessary to serve customers regardless of whether the customers take any energy from the system. *Id.* at 367. The Minimum System Method seeks to determine the minimum size distribution system that can be built to serve the minimum load requirements of customers. *Id.* This method develops the cost of the minimum set of distribution assets that are needed to serve customers and allocates those costs based on the number of customers. *Id.* The Zero-Intercept Method, according to witness Hager, similarly allocates a portion of the same distribution accounts on the basis of the number of customers and seeks to identify the portion of distribution plant that is associated with no load using regression techniques. *Id.*

Witness Hager testified that DEC incorporated the Minimum System Method into its COSS and testified that this was appropriate for the allocation of customer-related distribution costs. *Id.* Witness Hager explained that the Zero-Intercept Method is a more complex and time consuming methodology. *Id.* Witness Hager further explained that the Minimum System Method, which is sound and consistent with cost causation, produces results that are not materially different from the Zero-Intercept Method. *Id.* DEC's Minimum System Study allowed DEC to classify the distribution system into customer-related and demand-related portions. *Id.* at 367–68. Witness Hager testified that because every customer requires some minimum amount of wires, poles, and other distribution infrastructure every customer "causes" DEC to install some amount of distribution assets. *Id.* at 368. The concept used by DEC in developing its Minimum System study was to consider what distribution assets would be required if every customer had only a minimum level of usage. *Id.* This allows DEC to assess how much of its distribution system is installed simply to ensure that electricity can be delivered to each customer. *Id.* Once minimum system costs are identified distribution costs over this amount and direct assignments of those extra costs are determined to be driven by demand. *Id.*

Witness Hager testified that the PBR Statute requires the use of the minimum system methodology to allocate distribution costs between customer classes. *Id.* at 368–69.

Public Staff Testimony

Public Staff witness McLawhorn testified in support of the COSS Stipulation and discussed the stakeholder process that led to that settlement. Witness McLawhorn discussed the Commission's 2019 Rate Case Order, in which the Commission adopted the Second Agreement and Stipulation of Partial Settlement (2019 Rate Case). Tr. vol. 12, 739. The 2019 Rate Case Partial Settlement provided for an analysis of various cost of service methodologies in which DEC and DEP agreed to consult with the Public Staff and interested parties to analyze and develop cost of service studies based upon specific criteria, including the analysis of the various strengths and weaknesses of each respective methodology, and to file the resulting COSS with the Commission before DEC filed its next rate case. *Id.* at 739–40. As witness McLawhorn described, the stakeholders met several times throughout 2021 holding the final meeting on November 16, 2021. *Id.* at 740. On January 25, 2022, DEC and DEP filed the results of the COSS in Docket Nos. E-2, Sub 1219 and E-7, Sub 1214, as the Commission required. *Id.* Although the stakeholder process did not result in a consensus as to the appropriate cost of service allocation methodology to utilize, it helped certain parties arrive at the COSS Stipulation that is before the Commission in this case. *Id.* In response to Commissioner Duffley's question about the use of non-coincident peak demand, Public Staff witness McLawhorn testified that it was not his preference to use non-coincident peak but reiterated both the

Public Staff's support for the COSS stipulation and the settlement being a give-and-take between the different stipulating parties. *Id*. at 982–83.

Public Staff witness D. Williamson also testified in support of the COSS Stipulation, including the results of his investigation on how the COSS influences the way DEC's base rate charges will reflect the requested revenue requirement changes. Tr. vol. 13, 16. As witness D. Williamson explained, it is important that the utility consider all costs in the COSS to ensure that it is reasonably able to recover its full cost to serve all customers, while also ensuring that all jurisdictions and customer classes bear the appropriate responsibility for the respective costs they impose upon the system. *Id.* at 34–35. In discussing the 12 CP methodology for jurisdictional allocations and the Modified A&E methodology for NC retail allocations, witness D. Williamson confirmed that the use of different cost of service allocation methodologies may be unusual for a general rate case in North Carolina, but use of two methodologies does occur in some other jurisdictions. *Id.* at 38. In sum, witness D. Williamson recommended approval of the COSS Stipulation and DEC's use of the methodologies to which the parties agreed in the COSS Stipulation. *Id.* at 51.

CIGFUR Testimony

CIGFUR witness Collins filed testimony in support of the COSS Stipulation. Witness Collins testified that the COSS Stipulation is reasonable and that the Commission should approve it in its entirety. Tr. vol. 15, 957. Witness Collins also testified that both the 12 CP and Modified A&E methodologies are theoretically sound, reflect principles of cost causation as required by N.C.G.S. § 62-133.16(a)(1) and (b), and should be used for ratemaking in this proceeding. *Id.* at 951–52, 957. Witness Collins further testified that DEC has appropriately allocated distribution system costs to customer classes in a manner consistent with N.C.G.S. 62-133.16(b) which requires the use of minimum system methodology by an electric public utility for the purpose of allocating distribution costs. *Id.* at 952. Witness Collins additionally testified about the relation between the excess component of the Modified A&E method as it relates to additional capacity requirements. *Id.* at 960.

CUCA Testimony

CUCA is not a party to the COSS Stipulation and was not involved in the settlement negotiations. *Id.* at 444. Witness Pollock testified that he disagreed with the use of the Modified A&E method for allocation of production plant and related expenses and the 12 CP method for allocation of transmission plant and related expenses because DEC has been and will continue to be a summer-peaking utility. *Id.* Nevertheless, CUCA witness Pollock testified that CUCA was accepting the results of DEC's COSS consistent with the COSS Stipulation for the purpose of this proceeding only. *Id*.

The Commercial Group Testimony

The Commercial Group is not a party to the COSS Stipulation. However, Commercial Group witness Chriss testified that for the purposes of this rate case, the Commercial Group does not oppose DEC's proposed production capacity cost allocation methodology. Tr. vol. 15, 1010, 1020.

Discussion and Conclusions

Although the COSS Stipulation is not unanimous no other party to this proceeding has proposed an alternative cost of service methodology.

Based upon the evidence presented in this case, including the evidence offered in support of the stipulation as discussed hereinabove, the Commission approves the COSS Stipulation. The Commission notes that the use of the diversified non-coincident peak demand to calculate the excess allocation portion of the Modified A&E methodology is a departure from both the method approved currently for DEC as well as the A&E method applied in South Carolina. Therefore, the Commission directs DEC to provide a more detailed justification for the use of an NCP demand over a coincident peak demand for any cost allocation purpose in future rate cases.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 36

TCA Stipulation

The evidence supporting this finding of fact is contained in DEC's verified Application and Form E-1; the TCA Stipulation; the testimony and exhibits of DEC witnesses Abernathy, Maley, K. Bowman, and Bateman; Public Staff witness Metz; and the entire record in this proceeding.

As explained by DEC witness Maley, the Red Zone Expansion Plan (RZEP) transmission projects (RZEP Projects) included in DEC's MYRP consist of transmission upgrades needed to enable interconnection of additional solar generation on the DEC transmission system. Tr. vol. 8, 294–96. DEC witness Abernathy testified as to the revenue requirement sought by DEC for the RZEP Projects which involved allocation of all RZEP costs to DEC. In light of concerns expressed by the Public Staff in the Initial Carbon Plan proceeding regarding the imbalance of transmission costs being incurred between DEC and DEP associated with the interconnection of new generation, DEC presented (but did not propose) an alternative allocation of RZEP costs as between DEC and DEP based on respective retail transmission demand load ratio share. Tr. vol. 12, 97–99. Witness Abernathy testified that DEC did not support this allocation but included the calculation in the event the Commission determined that such an allocation was more appropriate in light of the concerns of the Public Staff. *Id.*

While the Public Staff found merit in DEC's alternative proposal Public Staff witness Metz recommended a different proposal that focused on the net energy transfers between DEP and DEC. *Id.* 864–67. Public Staff witness Metz explained that the Public Staff's alternative proposal utilizes the non-firm transmission rate from the FERC-approved OATT of DEC, DEF, and DEP which incorporates capital and ongoing O&M costs of the DEC and DEP transmission systems. Witness Metz testified that DEC's alternative allocation only considers a discrete portion of each utility's system and does not consider the O&M costs. The OATT, which is updated annually and listed on the OASIS website, provides an established calculation for transmission system capital and O&M costs that is transparent and easily verifiable. *Id.*

DEC, DEP, and the Public Staff resolved their differences on this issue and, as set forth in the TCA Stipulation, agreed to a pro forma adjustment of approximately $20 million to increase the revenue requirement in the instant proceeding and a corresponding decrease to the revenue requirement in the DEP Rate Case.

DEC, DEP, and the Public Staff agreed to calculate the pro forma amount of transmission expense for DEC and transmission revenue for DEP by multiplying the net transfers from DEP to DEC under the JDA in 2022 by the DEP non-firm transmission rate from the FERC-approved Joint OATT of DEP, DEC and DEF. The stipulation makes clear that the adjustment is for North Carolina ratemaking purposes only and will neither change the terms or conditions of the JDA nor result in any accounting entries for DEC or DEP. The TCA Stipulation provides that the adjustment will become effective on October 31, 2023, for both DEC and DEP and will terminate at the sooner of the effective date of rates in DEC's or DEP's next general rate case or the effective date of a full merger of DEC and DEP unless the Commission orders otherwise. TCA Stipulation § II (Tr. Ex. vol. 7).

DEC witness Bateman testified in support of the TCA Stipulation. Tr. vol. 11, 212. Witness Bateman testified that the TCA Stipulation is the result of substantial discovery and extensive negotiation among the stipulating parties and that it reflects a constructive near-term approach to addressing rate disparity concerns arising from the increasing net energy transfers from DEP to DEC under the JDA. *Id.* at 214. In DEC witness Abernathy's supplemental direct testimony, she also supported the update to the RZEP Alternative Allocation Method, consistent with the TCA Stipulation. Tr. vol. 12, 122.

At the evidentiary hearing, DEC witness Bateman explained that the TCA Stipulation was agreed to by DEC, DEP, and the Public Staff to address concerns of cross subsidization and rate disparity between DEP and DEC. Tr. vol. 11, 231. DEC witness Bateman testified that the TCA Stipulation supports that goal and results in rates that are just and reasonable and that reduce cross subsidization. *Id.*

The Commission concludes that the TCA Stipulation itself, along with the expert testimony discussed above, is credible evidence and is entitled to substantial weight in the Commission's ultimate determination on this issue. The Commission notes that this holding is consistent with the Commission's decision on this issue in the recent DEP Rate Case Order. No party offered evidence opposing the TCA Stipulation, and the Commission concludes that the TCA Stipulation, as supported by the testimony cited above, establishes a reasonable method to align costs with cost causation principles. Utilization of this method appropriately balances DEC and DEP benefits to the least cost dispatch of their respective systems. Accordingly, the Commission concludes that the provisions of the TCA Stipulation are in the public interest and are just and reasonable to all parties in this proceeding. Therefore, the TCA Stipulation is approved for the purposes of DEC's Application in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 37

PIMs Stipulation

The evidence supporting this finding of fact is contained in DEC's verified Application and Form E-1; the PIMs Stipulation; the testimony and exhibits of DEC witnesses Bateman and Stillman; Public Staff witnesses D. Williamson and Thomas; AGO witness Balakumar; NCJC et al. witness Wilson; CUCA witness Pollock; CIGFUR witness Collins; and the entire record in this proceeding.

DEC initially proposed the following PIMs in its Application: (1) Peak Load Reduction; (2) Low-Income/Affordability; (3) Reliability; and (4) Renewables Integration and Encouragement. *Id.* 162–70.

According to DEC, as filed, the Peak Load Reduction PIM encouraged DEC to reduce peak load, based on the estimated winter peak kW reduction resulting from new customer enrollment in DEC's dynamic and time differentiated rate programs. *Id.*

DEC testified that the Low-Income/Affordability PIM provided incentives for DEC to encourage voluntary contributions to its existing "Share the Light" Fund, which provides financial assistance to customers who are struggling to pay their energy bills, through a structure that establishes graduated shareholder contributions and shareholder bonus matching contributions to fund health and safety repairs for low-income residences based upon target levels of contributions to the Share the Light Fund. *Id.*

According to the testimony of DEC, the Reliability PIM will hold DEC accountable to maintain service reliability as measured by SAIDI (excluding MEDs). This PIM features graduated penalties that DEC must distribute to customers for failure to maintain SAIDI below tiered threshold levels based upon historic averages adjusted for statistical confidence levels and increased outages due to additional grid work that DEC expects during the MYRP. *Id.*

DEC testified that the Renewables Integration and Encouragement PIM involves three metrics to incent and reward DEC. The DERs Integration Metric A will provide graduated rewards to DEC for exceeding targets for the number of net-metered DER customers interconnected to the DEC system. *Id.* at 168. The Large Customer Renewable Program Encouragement Metric B will provide an incentive for DEC to design, obtain approval of, and subscribe customers to new renewable programs that meet these customers' desires for access to clean energy resources. *Id.* at 169. The Residential

Customer Shared Solar Program Encouragement Metric C will encourage DEC to subscribe residential customers to new shared solar programs. *Id.* at 170.

In addition to the PIMs, DEC also proposed three tracking metrics in the areas of customer service, carbon dioxide emissions, and beneficial electrification. The proposed customer service tracking metric would support maintaining adequate levels of customer service per N.C.G.S. § 62-133.16(d)(2)j. *Id.* at 184. The proposed carbon dioxide emissions tracking metric would report progress towards compliance with the carbon dioxide reduction requirements of S.L. 2021-165 and the Carbon Plan. *Id.* at 184–85. Finally, the third metric would report on incremental load from EVs. *Id.* at 185.

In supplemental testimony filed by the PBR Policy Panel on May 19, 2023, DEC witnesses Bateman and Stillman withdrew DEC's Low-Income/Affordability PIM. *Id.* at 193.

Public Staff witnesses D. Williamson and Thomas expressed concerns with each PIM, beginning with the metric DEC proposed in the Peak Load Reduction PIM. Tr vol. 14, 287. The Public Staff testified that TOU customers have complete control over whether they act on price signals and shift their load, and enrollment in TOU rates does not directly correlate to winter peak load reductions across DEC's footprint. The Public Staff noted that DEC's TOU report suggests a modest winter peak load reduction for customers who could be presumed to be early adopters or have a greater awareness of energy usage, but there is no guarantee that this level of winter peak load reductions will occur with greater enrollment. *Id.* at 288–89.

Regarding the Reliability PIM, which targets reliability by tracking DEC's SAIDI score, the Public Staff testified to their concern with the Reliability PIM as originally filed. The Public Staff explained that the benchmarking for the tiered performance structure proposed by DEC was based on five years of historical SAIDI data and consideration of any expected advancements in reliability that will occur as a result of grid investments included in the proposed MYRP is foreclosed. In addition, the Public Staff expressed the concern that the five years of historical performance data included data that was collected before DEC's GIP investments were placed into service. *Id.* at 290–91. The Public Staff acknowledged that the Reliability PIM as revised by DEC witnesses Bateman and Stillman's May 19, 2023 supplemental testimony addressed these concerns. *Id.* at 291.

Finally, the Public Staff testified as to concerns with the Renewables Integration and Encouragement PIM. *Id.* at 291–94. With respect to Metric A, the Public Staff testified that Net Energy Metering (NEM) adoption is largely outside of DEC's control, that NEM adoption has been steadily increasing over time as individual customers make individual financial decisions, that two recent Commission orders that have not been incorporated into the forecast or financial structure of this proposed PIM that have the potential to skew the adoption rates above what DEC has already forecast, and that the new NEM rate schedules involve customer enrollment in certain TOU rates which links this metric to the Peak Load Reduction PIM. *Id.* at 291–92. The Public Staff explained that DEC's revised incentive tier structure that incorporates a three-year rolling average of net metered interconnections measured in each rate year of the MYRP alleviated the Public Staff's concerns. *Id.* at 292. With respect to Metrics B and C, the Public Staff expressed concerns that DEC has complete control over all renewable program capacity available to large customers and that a capacity limit that is set below anticipated enrollment requests could result in DEC easily surpassing the enrollment thresholds. Additionally, the Public Staff testified that existing large customer programs have been popular without an incentive. *Id* at 293–94*.* The Public Staff noted that performance data on which Metrics B and C are based are linked to new programs, and there is therefore insufficient data for determining whether a financial incentive is necessary. *Id.*

In light of the Public Staff's concerns, the Public Staff proposed two modified PIMs in response to the PIMs DEC proposed. The Public Staff proposed a TOU Enrollment PIM and a Renewable Interconnections PIM, which involve a modification to DEC's proposed Peak Load Reduction PIM and a new PIM proposal, respectively. *Id.* at 294.

CIGFUR witness Collins' direct testimony expressed concern regarding DEC's proposed Reliability PIM. Tr. vol. 15, 986. Witness Collins proposed expanding the Reliability PIM to include a metric for measuring and ensuring the maintenance of adequate power quality and the avoidance of power quality incidents. *Id.*at 987.

AGO witness Balakumar proposed a Carbon Reduction PIM as an alternative to Metrics B and C of DEC's proposed Renewables and Integration PIM. *Id.* at 292. Witness Balakumar expressed concern that the PIMs Stipulation does not incentivize DEC to lower emissions at least cost. *Id.* at 292–93.

NCJC, et al. witness Wilson proposed three illustrative PIM concepts to address incentivize reduced fuel costs, incentivize investments in non-wires alternatives, and penalize failing to maximize federal savings opportunities. *Id.* at 918–32. Witness Wilson's proposed fuel cost PIM would attempt to manage and reduce fuel costs and volatility and incent DEC to reduce its reliance on fuel over time. *Id.* at 924.

CUCA witness Pollock proposed a rate competitiveness PIM. *Id.* at 438–41. Witness Pollock's proposed rate competitiveness PIM would reward or penalize DEC for changes in the competitive ranking of its electric service rates as compared to peer utilities in the Southeast region. *Id.* at 438. Witness Pollock testified that the PIM would address all of the costs that directly impact electricity rates and not simply fuel. *Id.* at 441.

DEC witnesses Bateman and Stillman explained how the carbon reduction requirement in N.C.G.S. § 62-110.9 is an aggregate requirement on DEC and DEP, meaning that the law does not require DEC to independently reduce its carbon dioxide emissions by 70.0%. Tr. vol. 16, 306–07.

DEC, the Public Staff, and CIGFUR resolved their differences of opinion on PIMs proposed in this proceeding, for the purpose of settlement, in the PIMs Stipulation. PIMs Stipulation, Tr. vol. 7, 39–40.

DEC's PBR Policy Panel provided testimony in support of the PIMs Stipulation. Tr. vol. 11, 198. The PBR Policy Panel testified that the resolution reached with the Public Staff and CIGFUR represents a balanced approach to achieving policy goals in DEC's first PBR Application. *Id.* at 201. DEC witness Stillman testified as to how the settled PIMs originated from the NERP PBR Working Group, were informed by DEC's prefiling PIM stakeholder process, and evolved over discussions with the stipulating parties. *Id.* at 200. DEC witness Stillman explained DEC's approach to designing the PIMs around the 1.0% cap in N.C.G.S. § 62-133.16 and stated that DEC deliberately chose only a select number of PIMs that meet the maximum number of policy goals. Tr. vol. 16, 271.

Public Staff witnesses D. Williamson and Thomas also provided testimony in support of the PIMs Stipulation. Tr. vol. 14, 315–19. Witnesses D. Williamson and Thomas testified that the PIMs Stipulation benefits ratepayers by providing improved compliance with N.C.G.S. § 62-133.16 and that each PIM in the stipulation appropriately targets a specific policy goal from N.C.G.S. § 62-133.16. *Id.* at 318. Public Staff witnesses D. Williamson and Thomas further testified that the PIMs Stipulation will benefit ratepayers through improved operational efficiencies, cost savings, and reliability of electric service over the course of the MYRP. *Id.*

The PIMs Stipulation contains the three PIMs described below; the PIMs are described with specificity, including thresholds, tiers, penalty and reward amounts, and projections of costs in PBR Policy Panel Settlement Exhibits 1, 3, and 4. Tr. vol. 12, 68; PBR Policy Panel Settlement Ex. 1, 3, 4 (Tr. Ex. vol. 11).

Time Differentiated and Dynamic Rate Enrollment PIM

DEC witness Stillman testified that the Peak Load Reduction PIM was renamed as the Time Differentiated and Dynamic Rate Enrollment PIM (TOU Enrollment PIM) and was revised to provide DEC with a $5 incentive for every new customer enrolled in an eligible program. Tr. vol. 11, 202–03. Witness Stillman also testified that this PIM targets and advances operational efficiency and cost savings, and it encourages DEC to design and seek approval of dynamic and time-differentiated rate designs. *Id.* at 203. Witness Stillman further testified that this PIM is an upside only PIM with a shared savings-like structure that would distribute 30.0% of the total peak reduction joint benefit to DEC and 70.0% to customers. *Id.* at 162.

At the expert witness hearing, witness Stillman further explained that the purpose behind this PIM is to encourage DEC to expand the use of TOU rates to help address peak load growth. *Id.* at 260–63. This TOU Enrollment PIM should encourage customers to adapt to new rate designs and subsequently shift their usage from high to low usage periods. *Id.* at 260. Witness Stillman testified that current subscribership to these programs is low so one of the purposes behind this PIM is to encourage more customers to subscribe to TOU programs. *Id.* at 165. In response to concerns about insufficient data to measure impact on load due to enrollment in TOU programs, witness Stillman testified that the PIMs Stipulation addresses this concern, and he explained that DEC will conduct a broader Evaluation, Measurement, and Verification study on system benefits once there is sufficient participation in DEC's TOU rate schedules to achieve statistical significance. Tr. vol. 16, 278.

Reliability PIM

DEC witness Stillman offered direct settlement testimony in support of DEC's Reliability PIM, which is designed to target and advance reliability of electric service per N.C.G.S. § 62-133.16(a)(8). Tr. vol. 11, 203. DEC's Reliability PIM would be measured by SAIDI excluding MEDs. As originally proposed, DEC's Reliability PIM provided for graduated penalties based on DEC's failure to maintain SAIDI below certain threshold tiers which would be based upon five-year historic averages, adjusted for statistical confidence levels and anticipated increased outages due to expected grid work. *Id.* at 174.

In the PBR Policy Panel's supplemental testimony, witness Stillman explained that, following discussions with the Public Staff and other parties, DEC agreed to revise the metric for this PIM account for projected SAIDI improvement during the MYRP period due to expected grid investments. *Id.* at 192–93.

Renewables Integration and Encouragement PIM

DEC witness Stillman testified that DEC designed Metric A of the Renewables Integration and Encouragement PIM to incent rooftop solar and to provide DEC with an incentive to determine the most effective way to encourage adoption. *Id.* at 168–69. This metric was modified as part of the PIMs Stipulation to base the incentive tiers on the three-year rolling average of net metered interconnections. *Id.* at 205. Metric A would provide an incentive of up to $6 million to DEC if the number of net metered interconnections for each rate year exceeds the applicable preceding three-year rolling average by at least 25.0%. *Id.* at 176–77.

As filed, Metric B of the Renewables Integration and Encouragement PIM supports large commercial and industrial customers, educational institutions, and local governments who have corporate goals related to electricity and are increasingly seeking access to renewable energy and programs. *Id.* at 169; tr. vol. 16, 288–89. As witness Stillman explained, DEC proposed this component of the Renewables Integration and Encouragement PIM in response to recommendations of the NERP PBR Working Group and stakeholders who participated in PIM stakeholder sessions in the summer of 2022. Tr. vol. 11, 169. DEC witness Stillman provided settlement testimony explaining that the only difference between Metric B as proposed by DEC and finalized in the PIMs Stipulation is the revised incentive tiers. *Id.* at 199.

Metric C of the Renewables Integration and Encouragement PIM in the PIMs Stipulation is based on the recommendations of the Public Staff, addresses utility-scale interconnections, and is designed to increase operational efficiency by incentivizing interconnections above DEC's estimated annual limits. *Id.* at 206. This PIM includes incentive tiers and minimum MW thresholds for utility-scale interconnections for each

MYRP rate year. *Id.* Public Staff witnesses Thomas and D. Williamson provided joint settlement testimony explaining that Metric C's performance thresholds were revised to correspond with the most recent data provided in DEC's proposed CPIRP filed in Docket No. E-100, Sub 190 on August 17, 2023. Tr. vol. 14, 316.

Tracking Metrics

DEC witness Stillman provided direct testimony stating that DEC selected the tracking metrics it proposed to quantitatively measure and monitor outcomes and utility performance that, although not tied to financial incentives or penalties, address DEC's progress in furthering important policy goals. Witness Stillman further stated that tracking metrics can provide useful information in evaluating potential future PIMs. Tr. vol. 11, 158.

In the PIMs Stipulation, the stipulating parties agreed to three tracking metrics. The first agreed upon tracking metric is the proposed metric on customer service as DEC proposed in its initial testimony. DEC witness Stillman testified that under the customer service tracking metric DEC will provide a quarterly update during the rate year of the rolling 12-month call center answer rate and the average speed of answer. *Id.* at 208. Witness Stillman testified that this tracking metric is appropriate because customers often communicate with DEC about service and billing issues by telephone, it allows greater public access to the data, and it supports maintaining adequate levels of customer service. *Id.*

The second tracking metric is beneficial electrification of EVs as DEC initially proposed. Witness Stillman explained that this metric requires DEC to report beneficial electrification from estimated incremental load from EVs, and it will provide data in an area of material public policy interest. *Id.*at 208–09.

The third tracking metric in the PIMs Stipulation requires DEC to provide an annual Circuit Performance Report that identifies ten circuits with the worst combined score of SAIDI, SAIFI, and Customer Average Interruption Duration Index (CAIDI), and further requires DEC to include an analysis of the cause of each circuit's performance. *Id.* at 209. DEC witness Stillman testified that this tracking metric will provide information and analysis that supports the importance of DEC's reliability to its customers and to DEC. *Id.*

Discussion and Conclusions

Upon review of the testimony of DEC, the Public Staff, and CIGFUR witnesses regarding the PIMs Stipulation, the Commission concludes that the PIMs Stipulation is the product of give-and-take negotiations between DEC, CIGFUR, and the Public Staff to achieve PIMs and tracking metrics that are consistent with N.C.G.S. § 62-133.16 and that it strikes an appropriate balance.

The Commission must give full consideration to a non-unanimous stipulation itself, along with all evidence presented by non-stipulating parties in determining whether the stipulation's provisions should be accepted. *See CUCA I*, 348 N.C. at 466*;*

CUCA II, 351 N.C. at 231. The Commission has considered the testimony of the parties to this proceeding on the PIMs, as cited above, and notes that some of the non-stipulating parties' recommendations and modifications are addressed by the PIMs Stipulation. For example, with the inclusion of the annual Circuit Performance Report tracking metric, certain intervenor recommendations on reliability PIMs are accounted for outside of an express PIM and that data on reliability and circuit performance will be gathered as a result. PIMs Stipulation § III.2 (Tr. Ex. vol. 7).

As this is the second electric PBR Application considered by the Commission, and the second set of PIMs to be adopted by the Commission, the Commission concludes that it is reasonable and appropriate to take measured steps to implement PIMs and tracking metrics as allowed for under N.C.G.S. § 62-133.16. The PIMs and the tracking metrics set forth in the PIMs Stipulation achieve this measured approach and are balanced, reasonable, and consistent with the requirements of the PBR Statute, encourage behavior that is sought by customers, and could provide meaningful operational and financial benefits to customers. Therefore, the Commission concludes that the PIMs Stipulation is entitled to substantial weight and that the PIMs and tracking metrics set forth in the PIMs Stipulation should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 38

Power Quality Stipulation

The evidence supporting this finding of fact is contained in DEC's verified Application and Form E-1; the Power Quality Stipulation; the testimony and exhibits of DEC witness Stillman; CIGFUR witness Collins; and the entire record in this proceeding.

In CIGFUR witness Collins' direct testimony, he testified regarding DEC's Reliability PIM. Witness Collins testified that the Reliability PIM should be expanded to include power quality protections. Tr. vol. 15, 953–54. Witness Collins recommended that the Reliability PIM should include a metric for measuring and ensuring adequate power quality is maintained and power quality incidents are avoided and that DEC should provide evidence indicating a range of voltage variability which will allow for sensitive digital equipment to continue to operate on the system. *Id.* at 987.

DEC witness Stillman explained in rebuttal testimony that DEC's Reliability PIM included a reasonable baseline for measuring DEC's reliability using historical averages. While witness Stillman explained that DEC would not incorporate CIGFUR witness Collins' recommended changes to the Reliability PIM, witness Stillman testified that DEC would continue to explore additional areas for alignment with CIGFUR. Tr. vol. 16, 285.

The Power Quality Stipulation provides that DEC and CIGFUR will collaborate to design a pilot program which will install power quality monitoring technology at DEC-owned Transmission to Distribution retail substations or, alternatively, discuss another mutually agreed upon alternative in response to the power quality issues CIGFUR raised in this docket. The Power Quality Stipulation requires DEC to file the mutually agreed upon pilot power quality program for approval by the Commission within six months of approval of the Power Quality Stipulation. In addition, the Power Quality Stipulation provides an agreed upon definition for Momentary Average Interruption Frequency Index – Event (MAIFIe). DEC and CIGFUR assert that the Power Quality Stipulation is responsive to the concerns expressed in the Commission's recent DEP Rate Case Order. Tr. vol. 7, 45–46.

The Commission notes that the pilot program as contemplated by the Power Quality Stipulation filed in this docket provides interested parties an opportunity to review and provide comments and that is subject to approval by this Commission. The Commission acknowledges that power quality is of importance to CIGFUR and reiterates its opinion that a well-designed pilot program focused on improving power quality for individual customers and for the entire system has merit and could provide benefits for all ratepayers. As such, the Commission approves the Power Quality Stipulation and directs DEC to file, within six months of this order, an application for a power quality pilot program in a new docket. The application should include information regarding the parameters for a feasibility review, participant eligibility, and cost.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 39-40

Affordability Stipulation and Customer Assistance Program

The evidence supporting these findings of fact is contained in DEC's verified Application and Form E-1; the Affordability Stipulation; the testimony and exhibits of DEC witnesses Barnes, Harris, Bateman, Stillman, and Quick; Public Staff witnesses D. Williamson and Thomas; CIGFUR witness Collins; and the entire record in this proceeding.

Summary of Evidence

Low-Income/Affordability PIM

DEC's PBR Policy Panel testified in support of DEC's proposed Low-Income/Affordability PIM. Tr. vol. 11, 162. The PBR Policy Panel testified that the Low-Income/Affordability PIM would: (1) target and advance cost savings; (2) reduce low-income energy burdens; and (3) encourage carbon reductions. *Id.* at 165–66. The PBR Policy Panel also testified that the proposed PIM would advance the identified policy goals by providing DEC with an incentive to promote voluntary contributions to the Share the Light Fund. *Id.* at 166. However, pursuant to the Affordability Stipulation filed with the Commission on May 4, 2023, DEC formally withdrew its proposal for a Low-Income Affordability PIM. *Id.* at 75–76. The parties to this Stipulation include DEC, DEP, Sierra Club, NCJC et al., and the Public Staff.

Public Staff witnesses Thomas and D. Williamson testified that the Public Staff was a party to the Affordability Stipulation and supports DEC's withdrawal of the Low-Income/Affordability PIM. Tr. vol. 14, 282.

Customer Assistance Program

DEC's Application requested approval of the CAP and two new tariffs, the CAP Rider and the Customer Assistance Recovery Rider (CAR Rider). DEC witnesses Harris and Quick provided testimony addressing the CAP proposal. DEC witness Quick described DEC's Affordability Ecosystem as a multi-pronged approach to assist customers who face electric utility bill affordability challenges. Tr. vol. 7, 130. Witness Quick explained that bill payment assistance represents one product or service that can be used as part of the Affordability Ecosystem. *Id*. at 130–31. Witness Quick further testified that the CAP program proposal will be a critical component in the Affordability Ecosystem. *Id.* at 131.

Witness Harris testified that the CAP proposal, initially developed as part of the Low-Income Affordability Collaborative (LIAC), is designed to assist low-income customers who face affordability challenges. Witness Harris described the program structure, framework, and reasoning behind the program. Tr. vol. 11, 114–17. Under the CAP, eligible customers would automatically receive a $42 monthly bill credit for a 12-month period. *Id.* at 115.

Regarding CAP eligibility, witness Harris explained that customers who are eligible for and receive funds from either the Low-Income Energy Assistance Program (LIEAP) or the Crisis Intervention Program (CIP) would qualify for assistance under the CAP. *Id.* at 115. DEC would automatically enroll eligible customers into the CAP using a list of customers provided by the North Carolina Department of Health and Human Services. *Id.* at 119. Moreover, DEC could re-enroll customers in the CAP for another 12 bill cycles if they are re-certified as LIEAP or CIP eligible after expiration of the initial enrollment. *Id.* at 125.

Witness Harris testified that in addition to the $42 bill credit on the participants' next 12 monthly bills, DEC will also refer CAP customers to other income-qualified weatherization and energy efficiency services that can assist customers with reducing energy usage. *Id.* at 114. DEC would spread the costs for the $42 CAP credit among all customer classes, excluding lighting schedules, through the CAR Rider. *Id.* at 121. Residential customers would pay approximately 86.0% of the CAR Rider, on a per kilowatt-hour basis, with non-residential customers paying the approximately 14.0% remaining on a per bill basis. *Id.* The CAR Rider would have a rolling recovery factor that DEC would true-up annually to reflect the actual amount of CAP credits paid. *Id.* at 117.

Public Staff witness D. Williamson testified that the proposed CAP would provide a direct subsidy to qualifying low-income customers to reduce their electric bills on the premise that these customers will be more likely to avoid chronic arrears and eventual service disconnection. Tr. vol. 13, 27. Witness D. Williamson acknowledged that the CAP proposal would create a subsidy from non-participating customers to an estimated 64,000 low-income residential customers. However, witness D. Williamson highlighted that in the past this Commission has found some cross-subsidies to be reasonable when it serves to preserve load and customers for the overall benefit of the utility system. *Id.* at 28. Furthermore, witness D. Williamson noted that the Commission placed a special focus on affordability issues in the 2019 DEC and DEP rate cases leading to the LIAC and comprehensive rate design study that produced the CAP proposal. *Id.* at 28–29. Witness D. Williamson also acknowledged that DEC has attempted to address this cross-subsidy by applying a design principle that customers receiving the CAP on average should still on average pay more than the marginal cost of service. *Id.* at 29. Witness D. Williamson testified that he reviewed the supporting information on this applied design principle and confirmed that it has modeled the monthly credit to on average ensure that CAP recipients will pay an amount above their marginal cost of service. *Id.* Witness D. Williamson further testified that he believes the Commission continues to have the same level of discretion as it did in the 2019 DEC Rate Case to determine whether a rate or program offering is just and reasonable and within the public interest, including the ability to determine if a certain level of cross-subsidy is allowable. *Id.* at 29–30.

CIGFUR witness Collins testified that the costs of the proposed CAP that DEC would recover though the CAR Rider should only be recovered from residential customers and that the creation of a new cross-subsidy benefitting residential customers at the expense of non-residential customers contradicts the express directive of the PBR Statute to minimize interclass cross-subsidization to the greatest practicable extent possible by the end of the MYRP period. Tr. vol. 15, 963.

Affordability Stipulation

On May 4, 2023, DEC, DEP, Sierra Club, NCJC, et al., and the Public Staff filed the Affordability Stipulation which was the result of extensive negotiations and compromise among the stipulating parties. Tr. vol. 11, 74–78. Pursuant to the terms of the Affordability Stipulation, DEC will withdraw the Low-Income/Affordability PIM, and instead a shareholder contribution of $16 million to benefit income-eligible customers will be made as follows: $10 million in support of health and safety repairs that would allow for energy efficiency and weatherization upgrades to homes, and $6 million for the Share the Light Fund which offers customers bill payment assistance. *Id.* at 75–76. In addition, DEC and DEP agree to collect and annually report the monthly payments ratio which is the number of residential payments remitted divided by the number of active residential accounts. DEC and DEP will file this data annually in Docket No. M-100, Sub 179. *Id.* at 76. Furthermore, pursuant to the terms of the Affordability Stipulation, DEC would establish its CAP program as a three-year pilot. *Id.* If the Commission approves the CAP, DEC agrees to convene a stakeholder engagement process to consider CAP data, metrics, and future CAP program features. *Id.* at 77.

DEC's Affordability Panel and Public Staff witness D. Williamson each provided testimony supporting the Affordability Stipulation. *Id.* at 71–78; tr. vol. 13, 31–33. The Affordability Panel testified that the Affordability Stipulation demonstrates DEC's commitment to affordability and its low-income customers and is in the public interest. Tr. vol. 11, 77. Considering all testimony and evidence along with the Affordability

Stipulation, the Commission finds that the provisions of the Affordability Stipulation are reasonable and should be approved for the following reasons.

The Commission gives significant weight to the testimony of the Affordability Panel and Public Staff witness D. Williamson regarding the Affordability Stipulation and DEC's CAP proposal. As Public Staff witness D. Williamson and DEC witness Harris highlighted in their testimony, the Commission has broad authority to set rates in the public interest. Tr. vol. 13, 30; tr. vol. 11, 85–86, 93–94. The question of whether the Commission should approve the CAP proposal and corresponding tariffs as outlined in the Affordability Stipulation is largely a public policy issue requiring a balancing of costs and benefits to DEC customers. The Commission established the LIAC in the 2019 Rate Case Order and tasked the collaborative with addressing affordability issues for low-income residential customers.

The PBR Statute emphasizes reducing interclass subsidies and reducing low-income energy burdens. Section 62-133.16(b) requires the minimization of interclass subsidies to the greatest extent practicable by the end of the MYRP period. Further, N.C.G.S. § 62-133.16(d)(1) requires the Commission to consider whether the PBR Application, in its entirety, "assures that no customer or class of customers is unreasonably harmed" by the proposal. Section 62-133.16(d)(2) provides that the Commission may consider whether the PBR Application "reduces low-income energy burdens." The Commission concludes that DEC reasonably designed the CAP proposal to meet and balance these statutory directives.

The Commission finds that the Affordability Stipulation advances the objective of reducing low-income energy burdens without causing unreasonable harm to any customer or class of customers. The Commission gives substantial weight to the DEC testimony that: (1) although the CAP causes a small interclass subsidy, residential customers primarily fund it; and (2) there is potential for the program to put downward pressure on rates for all customers by having fewer stranded costs from disconnected accounts and arrearages which would otherwise be passed on to the general body of ratepayers in the next general rate case.

The Commission approves the CAP as a limited-term pilot which will allow the Commission, the Public Staff, DEC, and other parties to examine over time whether the CAP credit meets the public policy objectives and whether the CAP results in rates that are unreasonably discriminatory or preferential to certain customer classes. As such, the Commission finds that it is reasonable for DEC to launch the CAP as a pilot and implement the corresponding tariffs associated with the CAP proposal for a period of three years as set forth in the Affordability Stipulation.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 41-47

Rate Design

The evidence supporting these findings of fact is contained in DEC's verified Application and Form E-1; the OPT-V-Primary Partial Rate Design Stipulation; the OPT-V-Secondary Partial Rate Design Stipulation; the testimony and exhibits of DEC witnesses Beveridge and Byrd; Public Staff witnesses D. Williamson and Nader; Commercial Group witness Chriss; Kroger Co. and Harris Teeter witness Bieber; CIGFUR witness Collins; AGO witness Palmer; CUCA witnesses Pollock and Lyons; NC WARN witnesses Powers and Konidena; and the entire record in this proceeding.

Objectives of Rate Design

DEC witness Beveridge testified that he used the cost of service information prepared by DEC and examined by DEC witness Hager to design rates. Tr. vol. 10, 129. Witness Beveridge also testified that he reviewed and considered the rates of return across the customer classes derived from the COSS when designing rates. *Id.* at 130. Finally, witness Beveridge noted that he reviewed DEC's Advanced Metering Infrastructure (AMI) data to examine customers' usage characteristics, determine relationships between energy and demand, and examine bill impacts from changes in rate design and pricing. *Id.*

Witness Beveridge stated that one objective of DEC's proposed rate design is to achieve the necessary increase in rates to collect the total revenue requirement. *Id.* Witness Beveridge also testified that another DEC objective is to further align revenues with the cost to serve customers across rate classes and rate schedules. *Id.* Witness Beveridge further noted that DEC's goal is to design rates that reflect the costs each customer causes DEC to incur based on their usage characteristics. *Id.* at 130–31. With respect to the rate increases proposed in this case, witness Beveridge explained that the base rate increase has been allocated to the rate classes by base rate amounts. *Id.* at 133. Finally, witness Beveridge asserted that this allocation methodology distributes the increase equitably to the classes while maintaining each class deficiency or surplus contribution to return. *Id.*

In DEC witness Byrd's direct testimony, he testified that DEC, as ordered by the Commission, participated in a year-long Comprehensive Rate Design Study (CRDS) with over fifty external stakeholders to develop DEC's future pricing and rate design options. *Id.* at 87. Following this engagement, DEC proposed several rate design changes to incorporate stakeholder requests and input. *Id.* at 88.

DEC witness Beveridge testified in detail regarding changes that DEC proposes to the residential rate schedules, the general service and industrial rate schedules (including SGS, LGS, I, and OPT-V schedules), and to the lighting schedules. *Id.* at 136–60. Witness Beveridge also testifies in detail regarding the proposed revisions to DEC's service riders which are offered to reflect special customer needs and requirements. *Id.* at 160–65. His testimony describes how the riders have been revised to better reflect cost of service. *Id.*

Having considered the record evidence on the issue of rate design, the Commission concludes that the objectives of DEC's rate design (which are to: (1) achieve the necessary increase in rates to collect the total revenue requirement; (2) further align revenues with the cost to serve customers across DEC's rate classes and rate schedules; and (3) design rates that reflect the costs each customer causes DEC to incur) are reasonable. Further, the Commission concludes that DEC's proposed allocation of the approved revenue increase to the customer classes is reasonable to all parties considering the evidence presented and is approved for the purposes of this proceeding. Moreover, it is reasonable and equitable to apply the same basic rate design and revenue requirement allocation approach in this case as was approved and implemented pursuant to the DEP Rate Case Order, and it would not be beneficial to apply inconsistent rate design principles as between DEP and DEC when there is no evidence supporting such a decision. Finally, for the foregoing reasons, the revisions to the rate schedules and to the service riders proposed by DEC in this proceeding are reasonable and are approved as proposed, unless otherwise addressed by the OPT-V-Secondary Partial Rate Design Stipulation, the OPT-V-Primary Partial Rate Design Stipulation, or otherwise specifically noted hereinafter in this Order.

Subsidy Reduction

DEC evaluated rates of return across customer classes emanating from DEC's COSS for all MYRP rate years. *Id.* at 132. DEC witness Beveridge testified that the historical per books rate of return indices as measured by the ratio of class rate of return to retail rate of return, show that over a lengthy period residential customers have been subsidized. *Id.* He testified that this historical subsidy has been near or beyond the range of reasonableness which DEC defines as class rates of return within 10.0% of DEC's North Carolina retail rate of return. *Id.* at 132–33. He also testified that an updated comparison through the test period now shows significant convergence of the class rate of return over all classes towards the band of reasonableness demonstrating the success of the strategy of gradually reducing the subsidy/excess through general rate case proceedings. *Id.* at 133.

DEC witness Beveridge explained that, in designing rates, the base rate increase was allocated to the rate classes by rate base amounts, and he further stated that this allocation method distributes the increase equitably to the classes while maintaining each class's deficiency or surplus contribution to return. *Id.* DEC witness Beveridge also testified that in this proceeding DEC is also recommending a variance reduction of 10.0% to gradually help reduce interclass subsidies to better align each rate class to the average rate of return. *Id.*

CIGFUR witness Collins testified that the Commission approved 25.0% subsidy reductions in the last 2017 and 2019 Rate Cases. Tr. vol. 15, 964–65. Witness Collins instead recommended that a 25.0% subsidy reduction is the minimum level of interclass subsidy reduction permissible for this rate case. *Id.* at 965. He further opined that an increase to a 50.0% or even 100.0% subsidy reduction would be more consistent with the law. *Id.* at 965. Witness Collins also claimed that OPT customers are subsidizing other rate classes by approximately $85.4 million under current rates, that the proposed 10.0% subsidy reduction does not adequately correct this cross-subsidization, and that general service customers are also paying a significant subsidy. *Id.* Witness Collins also stated that DEC's proposed 7.8% increase to OPT customers will continue exacerbating "the large subsidy already being paid by these customers." *Id.* at 966. Finally, witness Collins recommended that OPT customers should receive only a 2.1% increase to eliminate the subsidy. *Id.*

CUCA witnesses Pollock and Lyons challenge DEC's proposed 10.0% subsidy reduction. Witness Pollock testified that DEC's proposal would not move all classes 10.0% closer to cost, and for some classes, the interclass subsidies would increase. *Id.* at 442. Witness Lyons testified that DEC's proposal is both inadequate and a missed opportunity to reduce interclass subsidization to the greatest extent practical under HB 951, and he urges the Commission to move rates more aggressively toward cost. *Id.* at 416–17.

In his initial testimony, Public Staff witness D. Williamson testified that though DEC used a 10.0% subsidy reduction target rather than the 25.0% reduction used in the past, his review of DEC witness Beveridge's exhibits and revenue calculations and workpapers indicates that a 10.0% target reduction is appropriate to mitigate the potential for significant rate shock in the MYRP. Tr. vol. 13, 51.

On rebuttal, witness Beveridge testified that the proposed 10.0% subsidy reduction balances the requested rate increases that no rate class receives a disproportionate increase due to the proposed changes to the cost of service methodology which results in a shift of costs among between rate classes. Tr. vol. 10, 187. Specifically, witness Beveridge explained that if DEC had employed a 25.0% subsidy reduction, the proposed increase to the Lighting class would increase from 28.0% to 38.0% and would be disproportionately high. *Id.* at 187–88. Witness Beveridge stated that DEC's 10.0% subsidy reduction proposal applies the concept of gradualism to align revenues collected from each class with cost causation from DEC's cost of service, but DEC does not intend it to signal that DEC will limit future subsidy reductions to 10.0%. *Id.* at 188.

During the expert witness hearing, in response to cross examination by counsel for Blue Ridge EMC, et al., witness Beveridge reiterated that it has always been a priority for DEC to reduce interclass cross subsidization to the extent it can. *Id.* at 264–65. Further, witness Beveridge acknowledged that S.L. 2021-165 was a change in the law that required DEC to reduce interclass subsidization to the greatest extent practicable, but that the change in the law did not change DEC's overall goal of reducing interclass cross subsidization as quickly as possible within each rate proceeding, which has been demonstrated over time. *Id.* at 265. Witness Beveridge asserted that a 10.0% reduction variance is appropriate and strikes the right balance when considering cost causation along with the goal of minimizing interclass cross subsidization, which meets S.L. 2021-165 while also appropriately implementing gradualism. *Id.* at 304–05.

In response to cross-examination by the Public Staff regarding subsidies, witness Beveridge testified that DEC balanced the potential for interclass cross subsidization along with additional potential issues like unreasonable harm, unreasonable prejudice, and avoiding rate shock when apportioning revenues in this case. Tr. vol. 11, 46. Witness Beveridge further testified that the Commission should also consider these additional factors in determining revenue apportionment in this case. *Id.* at 47.

In Public Staff witness D. Williamson's supplemental testimony, he presented the Public Staff's recommended distribution of revenues to retail customer classes based on the results of the Modified A&E cost of service methodology. Tr. vol. 17, 40. Witness D. Williamson testified that he utilized DEC's E-1, Item 45A to develop a distribution framework incorporating the overall base revenues, expenses, net income, and rate base for the test year. *Id.* at 42. Witness D. Williamson then applied this framework to the adjusted present and proposed revenues, expenses, and rate base provided by Public Staff witnesses Zhang, Boswell, and Metz to develop the Public Staff's recommended revenue changes by retail rate class for each MYRP year. The Public Staff's recommended total revenue change (in thousands) by rate year is as follows:

	Public Staff Recommended Revenue Requirement under Present Rates (Base)	Public Staff Recommended Change in Revenue Requirement (Incremental)	Public Staff Recommended Change in Revenue Requirement (Cumulative)
Base Case	$5,427,913	$146,502	$5,574,415
Rate Year 1		$117,126	$5,691,541
Rate Year 2		$164,650	$5,856,191
Rate Year 5		$151,235	$6,007,425

Id. at 41.

Witness D. Williamson used this information to assign the revenues and credits to individual customer classes. Witness D. Williamson stated that he did not exclusively rely on the Modified A&E methodology but also applied the Public Staff's four basic revenue assignment principles to guide revenue apportionment by each retail rate class. *Id.* at 42–43. As described by witness D. Williamson, the four principles are: (1) any revenue increase assigned to any customer class is limited to no more than two percentage points greater than the overall jurisdictional revenue percentage increase to avoid rate shock; (2) class rates of return are maintained within a +/- 10.0% band of reasonableness relative to the overall North Carolina rate of return; (3) all class rates of return move closer to parity with the overall North Carolina rate of return; and (4) subsidization among the customer classes is minimized. *Id.* Witness D. Williamson also testified that while DEC's proposed fixed 10.0% subsidy reduction is one possible approach to reduce class cross-subsidization, the Public Staff instead focused primarily on the four rate design principles. *Id.* at 48. Witness D. Williamson noted that this approach involves independently moving each rate class closer to rate of return parity (based on a band of reasonableness index between 0.9 and 1.1). *Id.* Witness D. Williamson also stated that because some classes are already within this band there is no need for additional movement toward the band, while other classes may need more movement toward the band. *Id.*

In the Rate Design Panel's supplemental rebuttal testimony, they disagreed with the Public Staff's proposed allocation of revenue to the retail classes. *Id.* at 146. The Rate Design Panel noted that witness D. Williamson stated in his initial testimony that DEC's proposed 10.0% variance reduction was appropriate to mitigate rate shock. *Id.* They also noted that the Public Staff had previously applied the same four revenue assignment principles to arrive at the exact same allocation methodology as DEP in Docket No. E-2, Sub 1300 despite not agreeing with the proposed revenue amount. *Id.* at 146–47. The Rate Design Panel further testified that no basis exists in this case supporting the use of a methodology other than the one proposed and approved in the DEP case, and they also noted that DEC had reasonably relied on the approach described in D. Williamson's initial testimony, which was consistent with the proposed variance reduction in the DEP Rate Case. *Id.* at 147. Furthermore, the Rate Design Panel explained that the revenue requirement allocation recommended by witness D. Williamson differed from that of DEC and all other intervenors and results in substantially different percentage increases to customer classes than those litigated over the course of the evidentiary hearing. *Id.* Also, the Rate Design Panel described the Public Staff's proposed methodology as not being replicable and as utilizing an unreasonable level of subjective determination. Specifically, they testified that the Public Staff did not define or employ a precise, replicable process that could be applied to revenue requirement values other than their own. *Id.* at 147-48. Additionally, the Rate Design Panel testified that the Public Staff did not provide clear guidance on how to apply their allocation principles to any other revenue requirement the Commission may order, and DEC believes that a precisely defined and scalable process for revenue allocation is crucial to provide transparency into the range and direction of potential outcomes as well as to allow informed debate over the course of rate case proceedings. *Id.* at 148. The Rate Design Panel then reiterated that DEC's proposed approach balances the requested rate increase, is consistent with previous proceedings, applies the concept of gradualism, and is consistent with S.L. 2021-165. *Id.* at 149.

At the reconvened evidentiary hearing, witness D. Williamson acknowledged that different revenue requirements will produce different rates of return and percent increase changes for customer classes if the Public Staff's method is used. *Id.* at 72. Witness D. Williamson also noted that if another party offered a different revenue requirement for use under the Public Staff's method, the Public Staff could enter that and provide their results for that recommendation. However, he acknowledged that the Public Staff would "need a number of different supporting inputs to go along with th[e] revenue requirement." *Id.* at 73. Finally, witness D. Williamson explained that the Public Staff's approach to revenue apportionment was "surgical," as opposed to DEC's flat 10.0% variance reduction, to achieve the necessary movement between class rates of return while avoiding rate shock. *Id.* at 76.

The Rate Design Panel restated their position that replicating the Public Staff's subjective apportionment methodology for any other approved revenue requirement would be impossible. *Id.* at 159–60. Witness Byrd testified that based on the Rate Design Panel's review of D. Williamson's apportionment approach, DEC would be unsure of how to apportion revenues using the Public Staff's approach to any revenue amount other than that recommended by the Public Staff. *Id.* at 160. The Rate Design Panel also emphasized the importance of having a formulaic, non-subjective approach to revenue apportionment capable of being applied across a wide range of revenue requirements while producing consistent outcomes; they further stated that DEC's allocation methodology fulfills this purpose. *Id.* at 172–73. They noted that this allows any party involved in the proceeding to verify that DEC has complied with the Commission's prescribed revenue requirement. *Id.* at 162. In contrast, they asserted that the Public Staff's recommended approach is optimized to one specific revenue requirement and applies a high level of individual subjective judgment; they explained that if multiple rate designers applied the Public Staff's approach it is likely that each would produce different answers, which would introduce significant controversy and challenge DEC's compliance with the Commission's final order. *Id.* at 161–62. Finally, the Rate Design Panel acknowledged that while methodological inputs, such as DEC's 10.0% variance reduction, are discretionary, they asserted that DEC's process of implementing the rate increase is formulaic, as opposed to the Public Staff's process, which requires the application of individual discretion and is thus open to interpretation. *Id.* at 173–74.

Based on the evidence in the record, the Commission agrees that a variance reduction of 10.0% is reasonable for application in this proceeding. This approach balances the requested rate increases so that no rate class receives a disproportionate increase, is consistent with the approach taken in the DEP Rate Case proceeding and other proceedings where the Commission has approved more formulaic revenue apportionment methods, applies the concept of gradualism to limit rate shock, and is consistent with S.L. 2021-165 by allocating the base revenue requirement using principles of cost causation. In reaching this conclusion, the Commission gives significant weight to the testimony of witness Beveridge that a 10.0% subsidy reduction helps move toward eventual rate parity and minimize interclass subsidization, including but not limited to the historic subsidization of the residential class, while considering and incorporating other important factors. Additionally, the Commission recognizes that witness Collins' argument in support of a greater variance reduction raises a legitimate concern but concludes that a variance reduction is not the only issue that a utility must consider when designing rates.

The Commission also gives significant weight to the initial testimony of Public Staff witness D. Williamson which stated that a 10.0% variance reduction is appropriate in this case to mitigate potential rate shock. Thereafter, the Public Staff altered its suggested revenue requirement allocation methodology in its supplemental testimony and the Commission gives little to no weight to the supplemental testimony of Public Staff witness

D. Williamson. The Commission, after full consideration of DEC's rebuttal testimony and that of the other involved parties, as well as the evidence presented in the evidentiary hearing, finds that the 10.0% variance reduction approach proposed by DEC is reasonable for this proceeding. The Commission gives substantial weight to the testimony provided by the Rate Design Panel that DEC would be unable to implement the Public Staff's proposed approach for revenue allocation in a consistent, replicable manner given its reliance on subjective judgment. The Commission notes that, while subjective judgments are an inherent aspect of determining the revenue requirement and its allocation (e.g., the 10.0% variance reduction), it is the Commission's responsibility to apply such discretion, based on its review and analysis of evidence and testimony provided during the rate case proceeding itself, when making such subjective decisions. Further, the Commission agrees with DEC that the *process of implementing* its decisions when allocating revenues should be a precise, objective, and replicable process to prevent unnecessary controversy and delay as DEC develops its compliance rates. To be clear, the Commission does not find fault with the Public Staff's four revenue assignment principles as outlined in the initial testimony of Public Staff witness D. Williamson, but the Commission concludes that the Public Staff's proposed approach in its supplemental testimony does not provide the precision, objectivity, or verifiability required to ensure the revenue allocation process is transparent during the compliance period. The Commission finds that DEC's proposed 10.0% variance meets such requirement. Accordingly, the Commission concludes that a 10.0% subsidy reduction is just and reasonable and consistent with the PBR Statute, moves rates closer to cost for all customer classes, is less likely to lead to rate shock than a larger subsidy reduction, and is methodologically appropriate.

Migration Adjustment

DEC witness Beveridge testified that DEC is recommending migration adjustments based on an annual savings threshold of 10.0% or more for customers under 1,000 kW, and 5.0% or more for customers at or above 1,000 kW. Tr. vol. 10, 134, 175. Witness Beveridge explained that this recommendation is due to the introduction of new tariffs, the redesign of other tariffs, and the ability of DEC's new billing system to compare rates and suggest the best rate. *Id.* at 134. DEC's proposed migration adjustment for the Residential class, which is primarily due to the redesign and reopening of Schedule RT, are approximately $9.2 million in Rate Year 0. *Id.* at 135. DEC does not propose a migration adjustment for the Residential rate class in Rate Years 1, 2, or 3 since under the MYRP's Residential Decoupling Mechanism Rider such an adjustment is not necessary. *Id.* For the General Service class, the proposed migration adjustments, which are cumulative not incremental, are $10.1 million, $11.4 million, $14.1 million, and $17.1 million for Rate Years 0, 1, 2, and 3, respectively. *Id.* Witness Beveridge testified that these migration adjustment requests are primarily driven by migration to TOU-Critical Peak Pricing Schedule SGSTC and the redesigned TOU demand (TOUD) Schedule OPT-V, which will allow customers to respond more efficiently to price signals. *Id.* Beveridge Exhibits 4, 4_1, 4_2, and 4_3 provided the requested migration amounts. *Id.*; Beverage Settlement Ex. 4–4-3 (Tr. Ex. vol. 11).

In response to cross examination from counsel for CUCA, witness Beveridge noted that rate migration is expected to increase when rate design changes especially around rate cases. *Id.* at 272. Rate migration is a revenue loss to DEC, and DEC would not meet the original total revenue requirement anticipated in its rate design if it is not addressed. *Id.* Witness Beveridge testified that the migration adjustment, which was approved in the DEP Rate Case as well as DEC's previous Rate Case, helps DEC accurately reflect its test period billing determinants to reach the revenue requirement needed in this case. *Id.* at 274–75, 277; tr. vol. 11, 57. Witness Beveridge further stated that migration adjustments are narrow adjustments specifically reflecting revenue loss due to customer savings caused by a customer moving to new rates; in contrast, "decoupling" is a much broader term that can include other things like weather, customer growth, or changes in use, among other things. Tr. vol. 10, 276–77; tr. vol. 11, 57.

The Commission concludes that DEC's proposed migration adjustment is just and reasonable considering the evidence in this proceeding. The Commission therefore accepts DEC's proposed migration adjustments and finds they should be approved as DEC proposed them for the purposes of this proceeding.

Customer Growth and Weather Normalization

DEC witness Beveridge testified that he provided the retail sales and number of customers to DEC witness Q. Bowman for use in calculating the pro forma adjustment for growth in customers. Tr. vol. 10, 126. Witness Beveridge explained that to arrive at the appropriate number of customers served and the attendant annualized sales levels at the end of the test period, DEC used a combination of regression analysis and a customer-by-customer approach. *Id.* Witness Beveridge also noted that the customer growth data was adjusted for weather through a weather normalization adjustment that was incorporated into the regression analysis for the Residential class and into the usage analysis for the General Service and Industrial classes. *Id.* at 127. Weather adjustments were not used in the regression analysis for the Lighting or Building construction schedules since usage on these schedules generally does not change due to weather. *Id.* The weather normalization is reflected in Adjustment NC1050 Normalize for weather as discussed in DEC witness Q. Bowman's testimony. *Id.*; *see* tr. vol. 12, 164–65.

In witness Beveridge's supplemental direct testimony, he testified that DEC had agreed with the Public Staff to periodically update the Customer Growth Analysis to extend the results to the end of the pro forma period. Tr. vol. 10, 177. As such, witness Beveridge stated that DEC had updated the Customer Growth Analysis, and DEC witness Q. Bowman's Supplemental Partial Settlement Exhibit 4 pro forma NC 1040 demonstrates actual amounts through June 30, 2023. *Id.; see* Q. Bowman Supp. Settlement Ex. 4 (Tr. Ex. vol. 12).

The Commission concludes that DEC's proposed weather normalization and customer growth adjustments are reasonable in light of the evidence presented.

Updated Time of Use Periods

DEC witness Byrd, in his direct testimony, testified that DEC is proposing updated and aligned TOU periods across its tariffs that contain time-differentiated pricing for residential and non-residential customers. Tr. vol. 10, 88–89. Specifically, DEC is proposing to refresh TOU periods as follows (peak periods do not include weekends or holidays):

- On-Peak (Summer) – 6:00 p.m. – 9:00 p.m.;
- On-Peak (Non-Summer) – 6:00 a.m. – 9:00 a.m.;
- Discount (Summer) – 1:00 a.m. – 6:00 a.m.;
- Discount (Non-Summer) – 1:00 a.m. – 3:00 a.m. and 11:00 a.m. – 4:00p.m.;
- Summer consists of the months May – September; and
- Non-Summer consists of the months October – April.

Id. at 90. Witness Byrd testified that the impacted rate schedules include the redesigned RT schedule and the redesigned OPT-V schedule. *Id.* at 97. Schedules RSTC, RETC, and SGSTC already use these proposed periods and will not be impacted. *Id.*

Witness Byrd explained that DEC's existing TOU periods, which were established decades ago, are no longer appropriate and increasingly do not align with DEC's current and anticipated system needs. *Id.* at 91. Witness Byrd also stated that the new TOU periods will benefit customers and advance several policy goals. *Id.* at 97. Specifically, witness Byrd testified that the new TOU periods will properly align price signals to cost differences that exist across different seasons and hours thereby encouraging peak load reduction and efficient system usage; provide the opportunity for economic use of new technologies such as smart energy management devices, energy storage, and EVs; and encourage flexible consumption during times of low system costs providing incentives for distributed energy resource adoption. *Id.* Witness Byrd notes that the TOU periods proposed were taken directly from observations of the Cost Duration Model (CDM) and were discussed and evaluated at length with stakeholders during the CRDS. *Id.* at 91–92. Moreover, witness Byrd noted that the proposed TOU periods have already been approved by the Commission for three of DEC's current tariffs: RSTC, RETC, and SGSTC. *Id.* at 91.

AGO witness Palmer recommended that DEC shift its proposed Summer On-Peak period one hour earlier to 5:00 to 8:00 p.m., claiming that this Summer On-Peak period would better reflect system costs during each year of the CDM output (2021, 2026, and 2030). *Id.* at 367–68. Witness Palmer was particularly concerned with DEC's use of the 2030 CDM output and argued that DEC should not weigh it as heavily as the 2021 and

2026 outputs when designing current rates since it is farthest in the future and therefore the most uncertain. *Id.* at 368.

CUCA witness Pollock testified that DEC's proposed peak hours are unsupported by its analysis, and he did not characterize the results as being closely aligned. *Id.* at 452. Additionally, witness Pollock states that the CDM understates the costs assigned to on-peak hours, and he characterized the CDM as a usage-based, rather than a cost-causation, model. *Id.* Witness Pollock also explained that the proposed Discount period is problematic because the duration is exceedingly short (only five hours during the Summer months and seven non-consecutive hours during the Winter months) and creates a disincentive for large electricity consumers that operate "24x7" to shift load from high-cost periods. *Id.* at 454. Witness Pollock recommended that the Commission reject DEC's proposed TOU periods. *Id.* However, he noted that if the Commission opted to refresh the TOU periods, he would recommend Summer On-Peak and Discount periods be expanded to eight hours (1:00 p.m. to 9:00 p.m. for Summer On-Peak, 12:00 a.m. to 8:00 a.m. during the Summer, and 9:00 a.m. to 5:00 p.m. during the Winter for Discount). *Id.* at 454–55. Witness Pollock testified that creating 8-hour rating periods would allow manufacturers to schedule entire work shifts to the Discount period, when costs are low, thereby avoiding the high-cost hours. *Id.* at 455.

In DEC witness Byrd's rebuttal testimony, he disagreed with the AGO's position that DEC should shift the Summer On-Peak period to 5:00 to 8:00 p.m. *Id.* at 189. Witness Byrd reiterated that DEC discussed and evaluated the proposed 6:00 to 9:00 p.m. Summer On-Peak period at length with stakeholders during the CRDS; DEC based the proposal on observations from the CDM; and the peak period balances several factors including system costs through 2030 and customer experience. *Id.* at 190. Further, witness Byrd testified that while the CDM values 5:00 to 6:00 p.m. higher than the 8:00 to 9:00 p.m. hour in 2021, the difference becomes very narrow by 2026 and certainly by 2030. *Id.* at 189. DEC included 2021 to demonstrate that as more solar is added to the system the afternoon peak shifts later and later; this trend will continue as new resource plans call for ever greater amounts for solar. *Id.* at 189–90. Moreover, witness Byrd contended that if the Commission adopted witness Palmer's recommendation to shift the Summer On-Peak period to 5:00 to 8:00 p.m., customers on Rate Schedules RSTC, RETC, and SGSTC would experience a change in TOU periods after having only been on these rate schedules for a short period. *Id.* at 190–91. As such, given the recent approval of Rate Schedules RSTC, RETC, and SGSTC, shifting the Summer On-Peak period to 5:00 to 8:00 p.m. would presumably alter these customers' expectations of TOU period stability and durability, which could impact customer confidence in making investments or changing behavior based on TOU periods. *Id.* at 191 Finally, witness Byrd recommended that the proposed 6:00 to 9:00 p.m. Summer On-Peak period better aligns with the anticipated increased levels of solar generation on the system, as contemplated in the Carbon Plan, which will shift the net peak to later in the afternoon. *Id.*

In response to witness Pollock, witness Byrd testified that TOU periods should be based on system costs, as DEC has proposed, and should not be designed primarily to accommodate the usage patterns of a particular class of customers. *Id.* at 191–92.

Further, witness Byrd observed that witness Pollock's recommendations include hours that are clearly outside the peak window and challenging for customers to respond to. *Id.* at 192–93. Regarding witness Pollock's suggestion that manufacturers can schedule work shifts to his proposed Discount periods, witness Byrd opined that most customers across all classes, including manufacturers, would find it easier to avoid DEC's proposed on-peak periods than witness Pollock's proposed periods. *Id.* at 193–94. Witness Byrd also testified that DEC's proposed TOU periods, unlike those proposed by witness Pollock, might actually encourage operational adjustments for manufacturers. *Id.* at 194. Additionally, witness Byrd explained that designing rates to shift the fixed costs of production and transmission assets away from a class of customers that use them would be contrary to sound rate design principles and would unfairly burden all other customer classes. *Id.* at 195. Witness Byrd testified that if the Commission were to approve witness Pollock's proposed periods for DEC, the difference between DEC's and DEP's TOU periods would create an unwieldy and confusing set of price signals both for system planning and supporting customers on TOU rate schedules. *Id.* at 196–97.

During the expert witness hearing, the Rate Design Panel responded to cross-examination from CUCA's counsel regarding the TOU periods. *Id.* at 290–99. Witness Byrd reiterated that the redesign of the TOU periods was developed to send price signals consistent with usage in order to better reflect cost causation as well as providing price signals that would help customers with flexible loads better control their bills. *Id.* at 292. Witness Byrd also testified that the TOU rates were designed to accommodate customers using a wide variety of distributing-energy technologies such as generation or storage technologies. *Id.* at 296–97. Further, witness Byrd noted that EVs were one of the many technologies and customer uses considered as DEC designed its proposed TOU rate schedules, but customers using a wide variety of energy technologies would benefit from them. *Id.* at 297.

During cross-examination by NCLM's attorney, witness Beveridge acknowledged that the change in DEC's cost of service methodology, combined with efforts to reduce interclass cross subsidization, had large impacts on the Lighting class. *Id.* at 301–02. However, witness Beveridge also acknowledged that a 10.0% variance reduction accomplishes S.L. 2021-165's goal of minimizing interclass subsidies to the greatest extent practicable while still appropriately implementing gradualism. *Id.* at 304–05.

In response to Commissioner questions, the Rate Design Panel noted that the TOU rates were designed to reflect system costs, to be very durable in anticipation of additional solar generation in future years, and to allow customers to plan and make related investments. Tr. vol. 11, 61–62. The Rate Design Panel also noted that DEC anticipates the number of customers using TOU rate schedules to increase over time, which was also a consideration in designing the periods. *Id.* at 63.

The Commission declines to adopt witness Palmer's recommended change to shift the Summer On-Peak period to 5:00 to 8:00 p.m. DEC witness Byrd offered convincing testimony that it would not be reasonable to shift the Summer On-Peak period to 5:00 to 8:00 p.m. given that the CRDS analyzed the 6:00 to 9:00 p.m. Summer On-Peak period, DEC based the proposal on the CDM, and the Commission has already approved the Summer On-Peak period for DEC's Rate Schedules RSTC, RETC and SGSTC. Furthermore, the Commission gives significant weight to witness Byrd's testimony regarding the importance of alignment between the DEC and DEP TOU periods. The Commission also finds that in addition to ensuring proper price signals and encouraging customer adoption of new technologies, the evidence strongly indicates that DEC's modernized TOU periods will improve price and cost causation alignment.

The Commission also declines to adopt witness Pollock's recommended changes. Witness Byrd offered convincing testimony that operational changes to avoid higher cost periods would be just as or more easily avoided under DEC's proposed TOU rates. Further, the evidence suggests that adjusting TOU rates to shift the fixed costs of asset use away from the manufacturing class, at times when the manufacturing class is using those same assets, would violate sound rate design principles and unfairly burden other customer classes. Accordingly, the Commission concludes that DEC's new TOU periods should be approved as proposed.

Residential Rate Design

The residential rate class includes the following rate schedules: Residential Service Schedule RS; Residential Service Electric Water Heating and Space Conditioning Schedule RE; Residential Service, Energy Star Schedule ES; Residential Service, Time of Use Schedule RT; Residential Service, Time of Use with Critical Peak Pricing Schedule RSTC; and Residential Service, All Electric Customers with Time of Use and Critical Peak Pricing Schedule RETC. Tr. vol. 10, 138.

Witness Beveridge testified that Schedule RS is the basic residential service rate schedule available to all residential customers. *Id.* Schedule RE provides a lower price for higher usage in non-summer months and is available to qualifying residential customers with electric water heating and space conditioning. *Id.* Schedule ES provides a 5.0% discount on energy charges for customers that meet the qualifications of the Energy Star program. *Id.* Schedule RT is a residential TOU schedule with a demand charge. *Id.* Schedules RSTC and RETC went into effect in October 2021 and are new residential TOU schedules with Critical Peak Pricing, with Schedule RETC available to customers that meet the eligibility requirements of Schedule RE. *Id.*

DEC witness Byrd testified that DEC is proposing to reopen and revise the RT rate schedule based upon the new TOU periods, as discussed above. *Id.* at 98, 138–39. DEC is proposing that the demand structure for Schedule RT be modified to include two parts: (1) a demand charge component for the highest on-peak demand; and (2) a demand charge component for the highest demand regardless of TOU period. *Id.* Further, regarding the seasonality of rates for residential customers, DEC is proposing to reduce seasonal pricing, which differentiates between winter and summer, for residential customers. *Id.* at 98. Witness Byrd testified that DEC believes such changes are appropriate given the increasing importance of resources to cover both winter and summer peaks, and the updated TOU periods provide adequate pricing signals based on seasonal system loads, as the On-Peak, Off-Peak, and Discount pricing time periods are differentiated by season. *Id.*

Witness Beveridge also testified that DEC is proposing to increase the kilowatt-hour tier level in non-summer months from 350 kWh to 800 kWh for Schedules RE and ES. *Id.* at 139. Witness Beveridge stated that the proposed tier level better reflects the lower cost of service at higher utilization rates by improving correlation between load factor and average price and will align with the standard residential rate schedule in DEP's Schedule RES. *Id.* at 139–40. DEC is also proposing to align the definitions of summer and non-summer months across all rate schedules, with summer months comprising of May through September and non-summer months comprising of October through April. *Id.* at 140. Witness Beveridge noted that this change will affect residential Schedule RE, ES, and RT. *Id.* Beveridge Exhibits 5, 5_1, 5_2, and 5_3 illustrate the impact of the proposed rates for each of the proposed rate years. *Id.* at 141; Beveridge Direct Ex. 5–5_3 (Tr. Ex. vol. 11).

Witness Beveridge further testified that DEC is not proposing to increase the residential Basic Customer Charge in this case. Tr. vol. 10, 141. The present and proposed Basic Customer Charge rates are provided in Beveridge Exhibits 6, 6_1, 6_2, and 6_3. *Id.*; Beveridge Direct Ex. 6–6_3 (Tr. Ex. vol. 11).

Finally, witness Beveridge testified that DEC is proposing to broaden the applicability of residential rates to include detached garages, barns, or other structures that are at the same service address as a separate, primary residential account. Tr. vol. 10, 141–42. The current policy is to serve these structures on a small general service schedule if the structure is not used for cooking and sanitation. *Id.* at 142. Witness Beveridge testified that this change was being proposed in response to customer feedback regarding bills on a commercial rate for what customers believed to be residential usage. *Id.* Based on this feedback, DEC believes it is appropriate to include detached garages, barns, and other structures on residential rates if those structures are on the same premise as the residential unit and are primarily used for residential, rather than business purposes. *Id.* To this end, DEC has proposed clarifying language in its residential rate schedules.

AGO witness Palmer testified that Schedule RS, comprised of a basic customer charge and a flat energy charge, fails to send accurate price signals to residential customers, thereby causing the utility to incur more costs during peak hours, which may result in the need for additional infrastructure and future customer rate increases. Tr. vol. 15, 391. Witness Palmer also proposed exploring other avenues for expanding residential TOU rates, such as adopting simple TOU rates (comprised of energy and fixed monthly charges but not a demand charge) as a default rate as is the case in some other jurisdictions. *Id.* at 391–92. Witness Palmer also noted that it may be more appropriate to do so after gathering additional information on the potential impact to low-income and other vulnerable populations before shifting to a default TOU rate for residential customers. *Id.* at 392.

Public Staff witness D. Williamson testified that while he recommended approval of DEC's proposal to allow detached garages, barns, and other structures on the same residential premise to be served under a residential rate schedule, he also proposed that DEC be required to notify customers through a bill insert or separate mailing of the change. Tr. vol. 13, 65.

In rebuttal, the Rate Design Panel noted that while DEC's proposed Schedules RS and RE do not contain time-varying prices, they still provide meaningful incentives for customers to conserve energy or invest in energy efficiency through Demand-Side Management and Energy Efficiency Programs offered by DEC. Tr. vol. 10, 212. The panel noted that several other Residential TOU rate options are available to customers that provide price signals which encourage grid beneficial consumption and help customers reduce costs. *Id.* Regarding a default residential TOU rate, the Rate Design Panel testified that DEC does not agree with this proposal at this time. *Id.* While DEC agrees that encouraging TOU rate adoption and supporting price-responsive consumption plans is beneficial to customers and the grid, DEC prefers to encourage voluntary adoption and leave the choice to switch to TOU rates with the customer. *Id.* at 212–13. The Rate Design Panel testified that default TOU rates bypass the opportunity to encourage new behaviors or technologies that increase price-responsiveness that voluntary adoption provides, and accordingly may result in less beneficial grid behaviors even though TOU adoption is accelerated. *Id.* Additional considerations for TOU adoption are best reserved for the future after the trends and impacts of the newly proposed rate design can be better evaluated. *Id.*

Based on the evidence provided in this proceeding, the Commission declines to adopt AGO witness Palmer's proposed default TOU rate for residential customers. Witnesses Byrd and Beveridge provided compelling testimony indicating that adoption of a default residential TOU rate for all customers would not necessarily promote price-responsive consumption behaviors. The Commission concludes that residential customer adoption of TOU rates should remain voluntary, as customers themselves are better suited to determine whether a TOU rate is best for their usage profile.

In light of the parties' testimony and all the evidence presented, the Commission concludes that DEC's proposed rate design for the residential rate class, including the Public Staff's proposed modifications to which DEC agreed, is just and reasonable. The Commission agrees with witnesses Beveridge and Byrd that the proposed TOU changes are appropriate to address both winter and summer peaks. Further, the Commission agrees that the decision to switch to a TOU rate should remain voluntary. Additionally, the Commission finds and concludes that DEC's proposal to increase the kilowatt-hour tier level in non-summer months from 350 kWh to 800 kWh for Schedules RE and ES, as well as the changes to the definitions of summer and non-summer months across all rate schedules, is just and reasonable and in the public interest. Finally, the Commission concludes that DEC's proposal to allow detached garages, barns, and other structures on the same residential premise to be served under a residential rate schedule is just, reasonable, and in the public interest. The Commission directs DEC to notify all affected customers of the change through a bill insert or separate mailing.

Non-Residential Rate Design

The basic non-residential rate schedules are Small General Service (SGS), Large General Service (LGS), and Industrial Service (I). *Id.* at 143. SGS is available to non-residential customers up to 75 kW; LGS is available to non-residential customers above 75 kW; and Schedule I is available to customers in the manufacturing sector. *Id.* at 143–44. These rate schedules have non-TOU, tiered energy charges and a demand charge applicable above 30 kW. *Id.* at 144.

DEC's non-residential TOU schedules are Optional Power Service, Time of Use with Voltage Differential Schedule OPT-V; Optional Power Service, Time of Use, Energy-Only (Pilot) Schedule OPT-E; Small General Service, Time of Use with Critical Peak Pricing Schedule SGSTC; Parallel Generation Schedule PG; and Hourly Pricing for Incremental Load Schedule HP. *Id.* at 144. The majority of DEC's non-residential TOU customers are under OPT-V, which has seven pricing classifications based on voltage (Secondary, Primary, Transmission) and size (Small, Medium, and Large). *Id.* Schedule OPT-E is a legacy pilot for customers previously under closed Schedules OPT-I and OPT-G. *Id.* Schedule SGSTC is a critical peak pricing (CPP) rate, available to customers up to 75 kW, that went into effect in October 2021. *Id.* Schedule PG is available to customers operating power generating facilities in parallel with DEC and contains provisions for standby service. *Id.* Schedule HP is an hourly pricing rate available to customers with a contract demand of at least 1,000 kW. *Id.* DEC also offers Building Construction Service Schedule BC for temporary service; Traffic Signal Service Schedule TS; and Unmetered Signs Schedule S, only available in the Nantahala area. *Id.*

DEC witness Beveridge testified that DEC, in addition to designing energy and demand rates to recover the proposed revenue increase, is proposing to:

- Increase the Basic Customer Charge for all GS and I rate schedules;
- Redesign the energy charge tiers for SGS, LGS, and I;
- Redesign the TOU periods for OPT-V;
- Redesign Schedule HP;
- Modify billing demand and minimum bill provisions;
- Modify standby service requirements;
- Update the industry classification system used to determine Industrial customers;

- Close Schedule PG to new participants; and
- Terminate Schedule OPT-E.

Id. at 145.

Increase to Basic Customer Charge

In DEC witness Beveridge's direct testimony, he described the proposed rate design for the GS and I rate schedules. *Id.* at 145–48. Witness Beveridge testified that DEC is proposing to increase the Basic Customer Charge for all GS and I classes to better reflect the cost of serving these customers. *Id.* at 145–46. Specifically, witness Beveridge stated that DEC proposes to increase the Basic Customer Charge rates at approximately the rate class revenue increase percentage for Rate Year 0, rounding to the nearest whole dollar. *Id.* at 146. This increase will move Basic Customer Charge rates in the direction of customer unit costs while minimizing the percentage increase in bills for customers with low monthly usage. *Id.* Finally, witness Beveridge states that DEC proposes keeping the Basic Customer Charge at the proposed rate for all rate years. *Id.*

Based on all the evidence presented, the Commission finds that DEC's proposed increase to the Basic Customer Charge is just and reasonable. The Commission therefore approves DEC's proposal to increase the Basic Customer Charge for all GS and I classes.

Energy Charge Tiers

DEC witness Beveridge testified that DEC is proposing to modify the energy charge structure of Schedule SGS in order to make the rate design more understandable and easier to calculate, as informed by CRDS stakeholder discussions. *Id.* at 146. The current structure aligns price tiers with customer load factor, particularly when the range of customer demands is large, but the availability requirements for SGS (loads below 75 kW) limit the customer base to a narrow range of customer demands. *Id.* Witness Beveridge testified that similar price objectives and outcomes can be achieved with a simpler declining block tier structure, and DEC proposes a three-tier declining block energy charge based on: (1) first 3,000 kWh; (2) next 6,000 kWh; and (3) over 9,000 kWh. *Id.* at 146–47. Witness Beveridge claims that this structure achieves a comparable correlation between average price and customer load factor while simplifying the description and calculation of the rate schedule. *Id.* at 147.

Witness Beveridge testified that DEC also proposes modifying the energy charge tier levels of Schedule LGS and I to simplify and align the rate designs of these two related schedules. *Id.* at 147. Currently, though both schedules have declining block tiers based on kilowatt-hour usage per max kW demand, the number of tiers and the tier levels differ between the schedules; therefore, DEC proposes to align the rate designs by reducing the number of tiers to five and setting the tiers at the same usage levels. *Id.* The proposed tiers are: (1) first 3,000 kWh for the first 125 kWh per kW; (2) over 3,000 kWh for the first

125 kWh per kW; (3) first 6,000 kWh for the next 275 kWh per kW; (4) over 6,000 kWh for the next 275 kWh per kW; and (5) all kilowatt-hours over 400 kWh per kW.

Witness Beveridge testified that for the proposed rates for Schedules SGS, LGS, and I, DEC determined that the small shift in revenue from energy to demand of about 1.0% was justified by the unit cost study and resulted in more equitable impacts across customers on all three rate schedules. *Id.* at 148.

Based on all the evidence presented, the Commission finds that DEC's proposed modifications to energy charge tiers are just and reasonable. The Commission therefore approves the proposed changes to the Schedule SGS energy charge tiers.

OPT-V TOU Periods

Witness Beveridge testified that DEC proposes to modify Schedule OPT-V to modernize the TOU periods and update the demand charge structure to better reflect cost causation. *Id.* at 148. DEC witness Byrd testified noted that Schedule OPT-V is the only rate schedule impacted by this demand structure change. *Id.* at 99–101.

Witness Byrd stated that as the TOU periods transition to the three time-period structure, the non-residential demand structure must also change to maintain and improve upon the price structure alignment with system costs to help provide actionable price signals to customers with flexible loads or enabled technology. *Id.* at 99. Accordingly, DEC proposed a three-part structure consisting of the following components: (1) a Base Demand Charge designed to recover distribution costs which DEC would apply to the higher of either a customer's highest maximum demand across all periods over the previous 12 months or 50.0% of the Contract Demand; (2) a Mid-Peak Demand Charge designed to recover off-peak and discount allocation of production and transmission costs which DEC would apply to a customer's maximum demand during off-peak or on-peak periods while excluding discount periods; and (3) a Peak Demand Charge designed to recover peak allocation of production and transmission costs resulting from the customer's contribution to system demand during peak hours which DEC would apply to a customer's measured on-peak demand. *Id.* at 99–100. Witness Byrd testified that this three-part demand structure will improve price transparency and better align with cost causation based on both the size and timing of customer demands. *Id.* at 100. Witness Byrd noted that the relative recovery of costs between each part of this proposed change was determined by using the CDM to maintain cost causation linkage and remain aligned with the methodology used to set TOU energy charges. *Id.* Witness Byrd also testified that this demand structure is meant to work in tandem with the proposed TOU periods which govern both energy and demand charges. *Id.*

Additionally, witness Byrd testified that in response to stakeholder feedback during the CRDS DEC evaluated the alignment of bills and pricing to cost causation. *Id.* at 101. Witness Byrd stated that this analysis showed that shifting a portion of fixed cost recovery from energy charges to demand charges improved cost causation alignment across a wide spectrum of customer energy usage profiles with minimal impact to customer bills.

Id. Witness Byrd stated that as a result of this evaluation DEC witness Beveridge proposed pricing that reflects slightly higher recovery through demand charges for TOU rates. *Id.*

Witness Beveridge testified that DEC also proposes aligning prices across the three OPT-V size classifications for Secondary and Primary voltages. *Id.* at 148. He noted that the proposed three-part demand structure, described above, provides the opportunity and flexibility to achieve similar pricing outcomes that were previously achieved through separate pricing classifications based on size. Specifically, witness Beveridge explained that the proposed Mid-Peak Demand Charge has a three-tiered declining block structure which effectively yields a correlation between customer demand and the average price of demand such that larger customers pay a lower average price. *Id.* at 148–49. Witness Beveridge further stated that by setting the Mid-Peak Demand Charge tiers to the current Schedule OPT-V size classifications, DEC can design rates that result in similar average prices while minimizing bill impacts and cross-subsidization across voltage and size classifications. *Id.* at 149. This allows for pricing alignment across the three size classifications for Secondary and Primary voltages. *Id.*

Witness Beveridge also testified that DEC proposed a minimum contract demand of 75 kW for new customers served under OPT-V in order to better delineate between rate classes and rate classes for small (up to 75 kW) versus large (75 kW or greater) business customers. *Id.* at 149. Schedule SGSTC, effective since October 2021, is available as a modern TOU-CPP rate schedule specifically designed for small business. Witness Beveridge noted that the rate design and cost of service for Schedule SGSTC is more appropriate for small business customers than Schedule OPT-V. *Id.* at 149–50. Witness Beveridge also stated that the minimum demand requirement for OPT-V will help ensure it remains an attractive and appropriate cost of service rate class for larger business customers. *Id.* at 150.

Commercial Group witness Chriss testified regarding DEC's proposed OPT-V rate design. Tr. vol. 15, 1023–28. Witness Chriss stated that DEC has not fully aligned the proposed OPT-V demand charges with underlying demand-related costs, as the proposed demand charges are well below their respective unit rates per DEC's COSS results. *Id.* at 1026. Witness Chriss also stated that Commercial Group, for the purposes of this proceeding, is not opposed to DEC's proposed rate levels for OPT-V at DEC's proposed revenue requirements. *Id.* at 1028. However, Witness Chriss also explained that if there is a decrease from the proposed revenue requirement, they should be applied proportionately to the energy charges to bring these charges closer to their cost of service-based levels. *Id.* at 1028.

Kroger Co. and Harris Teeter witness Bieber testified that DEC's proposed rate design for the OPT-V-Secondary rate schedules would cause the proportion of revenues recovered through demand charges to decrease relative to current rates, resulting in demand charges that are understated relative to demand-related costs under DEC's COSS. *Id.* at 1067. Witness Bieber further stated that despite its assertions that shifting revenue recovery to demand charges for OPT-V by up to 5.0% was justified by the unit cost study and is expected to result in more equitable bill impacts, DEC has not proposed to increase revenue recovery through demand charges for the OPT-V-Secondary rate schedules. *Id.* at 1068. Witness Bieber recommended that the proportion of OPT-V-Secondary revenues recovered through demand charge be increased in Rate Year 1 of the MYRP by 5.0%, from 37.9 to 42.9%, with a corresponding revenue neutral decrease to the proposed on-peak, off-peak, and discount energy charges. In Rate Years 2 and 3, witness Bieber proposed that the incremental revenue requirement be recovered through increases to the demand charges while maintaining his recommended Rate Year 1 energy charges at a constant level. *Id.* at 1074–75.

AGO witness Palmer recommended that DEC increase cost recovery through energy charges and correspondingly decrease demand charges for all OPT-V schedules and Rate Schedule HLF. *Id.* at 372–73. Witness Palmer claimed that changes in the power system justify increases to energy charges rather than decreases, as DEC is proposing, in order to send improved price signals. *Id.* at 373. Witness Palmer also stated that DEC's decision to introduce time-varying demand demonstrates the temporal nature of system costs and that high load factor customers are not consuming in a way that is beneficial or less costly to the system. *Id.* at 376. Witness Palmer testified that DEC's proposed energy charges do not currently send a reasonable price signal as some energy charges are set below the marginal energy cost. *Id.* at 378. This sends particularly inefficient price signals and fails to adequately compensate net metering customers. *Id.* at 379. Witness Palmer explained that while setting rates to marginal costs would be warranted, she instead recommends a more modest energy rate increase of 15.0% and corresponding decreases to demand charge cost recovery in the interest of gradualism. *Id.* at 382. Finally, witness Palmer recommended that DEC introduce a CPP rate option for commercial and industrial customers with demands over 75 kW, since TOU tariffs like OPT-V are not precise enough to target peak critical peak events while a CPP tariff can provide simplicity, stable prices throughout the year, and incentivize customer adoption of technologies that provide grid benefits while typically only requiring customers to respond to a small number of critical peak events. *Id.* at 386–87.

Public Staff witness D. Williamson recommended that DEC notify current OPT-V customers of the 75 kW minimum contract demand threshold for OPT-V and alternative rate schedules available to them through a bill insert or separate mailing. Tr. vol. 13, 65.

The Rate Design Panel, responding to Commercial Group witness Chriss' claim that DEC has not fully aligned proposed OPT-V demand charges with underlying demand-related costs, agreed that the proposed demand charges are not fully aligned with DEC's cost of service, but also noted that DEC has, in fact, proposed greater recovery through demand charges than exists in current rates. Tr. vol. 10, 204. Additionally, the Rate Design Panel notes that witness Chriss' position supports DEC's rejection of AGO witness Palmer's proposal to increase energy charges and decrease demand charges by a corresponding amount. *Id.* However, they also noted that DEC must balance alignment to cost causation with gradualism and that DEC's approach avoids adverse impacts to lower load factor customers. *Id.* Furthermore, the Rate Design Panel disagreed with witness Chriss' recommendation to apply revenue decreases to the energy charges, while also noting that DEC is willing to balance lowering energy and demand as appropriate to meet the revenue requirement, ensure that both low and high load factor customers are treated equitably, and provide that changes in cost recovery occur gradually over time. *Id.*

In response to witness Bieber's recommendation that the proportion of OPT-V-Secondary revenues recovered through its demand charge be increased by 5.0% in Rate Year 1 of the MYRP, the Rate Design Panel testified that DEC carefully considered gradualism and impacts to both low and high load factor customers when designing specific demand and energy charges for OPT-V. *Id.* at 197–98. The Rate Design Panel stated that DEC sought to balance adjustments toward unit cost with bill impacts for customers. *Id.* at 198. Further, they note that voltage classes for OPT-V had very different starting points for demand revenues, with more opportunity and priority to shift recovery to demand charges for the Primary and Transmission sub-classes than for the Secondary sub-class, and that such adjustments can be accomplished with minimal bill impacts for customers. *Id.*

The Rate Design Panel testified that DEC does not agree with AGO witness Palmer's recommendations. *Id.* The Rate Design Panel noted that DEC, in contrast to witness Palmer's recommendation to increase cost recovery through energy charges, instead proposed a modest increase in fixed cost recovery through demand charges since they align with cost of service as much of DEC's costs to provide service are fixed. *Id*. The Rate Design Panel also stated that demand charges both improve alignment to cost causation across the range of customer load factors and provide meaningful price signals that encourage beneficial customer behavior. *Id.* at 198–99. The Rate Design Panel claimed that witness Palmer's suggestion would penalize higher load factor customers who require less costs to serve per unit of energy, create more subsidization between customers with varying load factors, and reward inefficient use of system resources. *Id.* at 199. The Rate Design Panel also stated that Witness Palmer's proposal would be counterproductive by weakening price signals at peak times while DEC's proposed rate designs would incentivize reduced demand during system stress. *Id.* at 200. The Rate Design Panel, in response to witness Palmer assertion that DEC's time-varying demand rates demonstrate that high-load factor customers do not consume in a manner that is beneficial to the system, acknowledged that load factor is not the single determining factor for distinguishing cost causation between customers but testified that all else being equal, customers with higher load factors have lower per unit costs than lower load factor customers. *Id.* at 201.They stated that DEC's proposed rate design is an attempt to balance this with other rate design factors, and witness Palmer's proposal ignores efficiencies associated with higher utilization of fixed assets. *Id.* In response to witness Palmer's claim that DEC's proposed energy prices are below average marginal costs, the Rate Design Panel noted that natural gas prices have sharply declined since 2021–2022 making witness Palmer's fuel cost comparisons invalid. However, they do state that DEC will review final pricing in compliance rates to address this general concern. *Id.* at 203. Finally, regarding witness Palmer's recommendation for a CPP rate, the Rate Design Panel testified that DEC's rate design proposals in this case offer suitable alternatives for customers with loads above 75 kW, and stakeholders to the CRDS generally favored new

HP options such as the one proposed in this proceeding, over CPP options, making the addition of a CPP feature unnecessary. *Id.* at 203–04.

The Rate Design Panel accepted the Public Staff's recommendation to notify affected customers of the 75 kW minimum contract demand threshold for OPT-V. *Id.* at 205.

Under the OPT-V-Primary Partial Rate Design Stipulation, DEC and CIGFUR agreed that any increase in energy charges resulting from an increase in DEC's revenue requirement recovered from the OPT-V-Primary sub-class, as determined by final Commission order, should be limited to a percentage that is less than half of the approved overall increase percentage to OPT-V-Primary exclusive of any decrements for OPT-V-Primary. *Id.* at 230; OPT-V-Primary Partial Rate Design Stipulation (Tr. Ex. vol. 7). DEC also agrees to modify the Mid-Peak Demand tiers for the OPT-V-Primary sub-class from 1,000 kW/3,000 kW to 1,000 kW/5,000 kW to better align with the On-Peak Demand tier in the current OPT-V tariff. DEC also agreed to adjust the Mid-Peak Demand Charge prices within OPT-V-Primary to achieve similar pricing spreads between the first, second, and third demand tiers. *Id.* at 230–31. In the Rate Design Panel settlement testimony, they testified that the terms of the OPT-V-Primary Partial Rate Design Stipulation do not result in interclass subsidies, improve alignment with cost of service, and streamline designs across sizes and delivery voltages. *Id.* at 232. CIGFUR witness Collins stated, in his settlement testimony, that the terms of the OPT-V-Primary Partial Rate Design Stipulation have no impact on the interclass allocation of revenues and do not cause interclass subsidies. Tr. vol. 15, 995. Witness Collins also testifies that the terms of the stipulation enhance alignment between price and cost of tariff rates for both the OPT-V-Primary class and new Schedule HLF customers. *Id.* at 997.

Under the OPT-V-Secondary Partial Rate Design Stipulation, DEC, the Commercial Group, and Kroger Co. and Harris Teeter agreed that DEC should increase the proportion of total revenues recovered through demand charges for the Schedule OPT-V-Secondary sub-class by 5.0% (relative to current rates) in Rate Year 1 of the MYRP, from 37.9% to 42.9%, with a corresponding revenue neutral decrease to the proposed on-peak, off-peak, and discount energy charges. In Rate Years 2 and 3 of the MYRP, each of the demand and energy charges will be increased by an equal percentage in order to recover the target revenue requirement. Kroger Co. and Harris Teeter also agreed to withdraw their proposal that DEC study and propose a multi-site aggregate commercial rate and agreed that they do not oppose the Revenue Requirement Stipulation and PIMs Stipulation. Revenue Requirement Stipulation, PIMs Stipulation (Tr. Ex. vol. 7). In the Rate Design Panel settlement testimony, they testified that the terms of the OPT-V-Secondary Partial Rate Design Stipulation do not result in interclass subsidies, are in line with cost of service, and are more consistent with the shift to demand charge cost recovery than the demand charge rates DEC originally proposed for OPT-V-Primary. Tr. vol. 10, 233.

Based on the testimony and the evidence presented in this proceeding, the Commission concludes that DEC's proposed rate design for the OPT-V-Primary and

OPT-V-Secondary sub-classes, including the modifications agreed to in the OPT-V-Primary Partial Rate Design Stipulation and OPT-V-Secondary Partial Rate Design Stipulation, is just and reasonable. The Commission further concludes that DEC's proposed Basic Customer Charge increases strike an appropriate balance to provide rates that accurately reflect cost causation, minimize subsidization, and provide proper price signals to customers in the OPT-V rate classes, while also moderating the impact of such increase on lower-usage customers. The Commission directs DEC to notify current customers of the new contract demand threshold for OPT-V through a bill insert or separate mailing.

Furthermore, the Commission concludes that the OPT-V-Primary Partial Rate Design Stipulation and OPT-V-Secondary Partial Rate Design Stipulation are the products of arm's-length negotiations between parties who took opposing positions on these subjects in their pre-filed testimony. The Commission also finds that OPT-V-Primary Partial Rate Design Stipulation and OPT-V-Secondary Partial Rate Design Stipulation reduce the number of contested issues regarding rate design before the Commission that require resolution. The Commission concludes that both stipulations address only intra-class issues, not interclass issues, and focus on increasing the amount of fixed cost recovery through demand charges as opposed to energy which is consistent with DEC's COSS. The Commission gives substantial weight to the testimony of the Rate Design Panel and finds that neither stipulation results in any interclass subsidies, that the impact on customers within the class are slight, and the stipulation improves alignment between customer rates and cost causation. The Commission notes that no party presented any evidence that the OPT-V-Primary Partial Rate Design Stipulation and OPT-V-Secondary Partial Rate Design Stipulation result in any interclass subsidization, involve interclass allocation of revenue requirement, or are not in alignment with DEC's COSS. Therefore, the Commission concludes that the OPT-V-Primary Partial Rate Design Stipulation and OPT-V-Secondary Partial Rate Design Stipulation are reasonable and should be approved.

The Commission notes that the OPT-V-Primary Partial Rate Design Stipulation and OPT-V-Secondary Partial Rate Design Stipulation provisions concerning their respective energy rates only apply to these particular proposed rates in this specific rate case proceeding. These provisions do not bind DEC to any particular rate design structure in future rate cases and do not limit DEC's ability to study alternative rate designs.

The Commission declines to adopt witness Palmer's recommended modifications to DEC's proposed rate designs. The Commission gives substantial weight to the Rate Design Panel's testimony regarding the appropriateness of increasing the level of fixed costs recovered through demand charges and concludes that doing so will improve alignment between customer rates cost causation across the range of customer load factors while also providing meaningful price signals. In contrast, the Commission finds that witness Palmer's proposal would likely result in subsidization between customers with varying load factors while also weakening price signals for customers in the OPT-V class. The Commission also rejects witness Palmer's request that it require DEC to create a CPP rate for the OPT-V class at this time given the availability of DEC's existing, updated, and proposed TOU and hourly pricing options.

Schedule HP

DEC witness Byrd testified that during the CRDS stakeholders expressed an interest in certain changes to yield a more flexible marginal price rate with expanded availability. *Id.* at 104. Accordingly, DEC proposed a redesigned Hourly Pricing rate designed to provide broader customer access to marginal pricing. *Id.* The revised tariff will have features that encourage customers to be consistently price-responsive during times of grid constraints to retain that expanded access to marginal pricing. *Id.* The tariff is available to all customers with load greater than 1,000 kW. *Id.* DEC proposes to reestablish Customer Baseline Loads (CBL) every four years based on the customer's 12-month usage history including modifications to reflect customer price-responsiveness during periods of grid constraints. *Id.* The CBL defines the level above which all kilowatt-hours will be billed at hourly marginal energy prices. *Id.* The CBL would be maintained or adjusted downwards, if mutually agreeable to DEC and the customer, to the extent the customer consistently reduces loads during times when grid constraints result in rationing charges within the hourly prices. *Id.* at 105. Witness Byrd also noted that DEC will include a margin adder of $6 per MWh to account for day-ahead pricing uncertainty and provide some fixed cost recovery from marginal energy purchases. *Id.* Witness Byrd noted that the durability and scalability of the redesigned Schedule HP allows DEC to provide customers greater exposure to marginal prices. *Id.* Witness Byrd testified that DEC proposes to eliminate the participation cap given the improved scalability of the program after its redesign. *Id.* Witness Byrd also testified that pricing changes under the redesigned Schedule HP will be effective for existing customers, but the requirement for automatic CBL reestablishment will not apply unless and until a customer requests an update of their CBL for any reason. This grandfathering provision is specified in the proposed Schedule HP tariff. *Id.* at 106.

CUCA witnesses Pollock and Lyons opposed DEC's proposal to increase the Schedule HP Incentive Margin to $6 per MWh claiming that a 20.0% increase is unsupported and excessive. Tr. vol.15, 417, 455. Instead proposed maintaining the current Incentive Margin of $5 per MWh. *Id.* Witness Pollock claimed that the Incentive Margin is designed to compensate DEC for the risk that projected hourly prices which are set the day before at 4:00 p.m., may vary from actual daily marginal energy costs. *Id.* at 455. Witness Pollock also asserted that DEC has not provided any analysis demonstrating that it is experiencing increased price forecast risk to justify the proposed increase. *Id.* Additionally, witness Pollock disagreed with DEC's proposed Incremental Demand change which he characterized as being designed to recover distribution related costs associated with incremental load, i.e., load in excess of the CBL. *Id.* at 455–56. Witness Pollock noted that not all HP customers take service at distribution voltages and that the Incremental Demand charge would be excessive for HP customers taking service at transmission voltage. *Id.* at 456. Accordingly, witness Pollock recommended pegging the Incremental Demand charge to the proposed Base Demand charges in the Optional TOU rates. *Id.* at 456. Finally, witness Pollock testified that DEC's attempt to provide more broadly available customer access to marginal pricing is commendable since it would provide them with immediate and significant incentives to respond to price signals and thus be beneficial to both them and other customers. *Id.* However, he opposed DEC's proposal to reestablish Schedule HP's CBL every four years claiming this would be counterproductive and disincentivize customers from permanently committing to real-time price responsiveness during times of grid constraint. *Id.* at 456–57. Instead, he recommended that DEC make an additional 15 MW block of service available under Schedule HP allowing customers to make a one-time decision to switch from standard to hourly pricing while also mitigating potential revenue erosion which DEC may experience due to customer migration. *Id.* at 457.

Public Staff witness Nader recommended that the implementation date for Schedule HP be set to January 1, 2024, when proposed rates are effective or following the Commission's order in this proceeding. Tr. vol. 12, 764. Further, he expressed general support for the proposed modifications but encouraged DEC to consider reducing the contract demand limit for Schedule HP to below 1,000 kW prior to the next rate case. *Id.* at 763. Witness Nader noted that while marginal energy prices are volatile and primarily of value to sophisticated customers limiting access to LGS customers with contract demands over 1,000 kW should not be DEC's goal. *Id.* Furthermore, he noted that enabling a larger number of customers to be responsive to marginal prices would likely improve DEC's ability to mitigate future resource investment needs, particularly given the support expressed by CRDS stakeholders for such expanded access to marginal price rates. *Id.* at 763–64.

In the Rate Design Panel's rebuttal, they addressed CUCA witnesses Pollock and Lyons' opposition to the Incentive Margin. Tr. vol. 10, 206–08. The Rate Design Panel noted that the Schedule HP incentive margin has been set at 0.5 cents per kWh for nearly 30 years, and an increase of 0.1 cents per kWh is appropriate in order to address the impact of inflation and ensure alignment with DEP's similar proposal. *Id.* at 206–07. They also noted that while the Incentive Margin does offset the risk inherent in offering hourly prices, it also provides a degree of fixed cost recovery from Schedule HP customers for usage above their CBL which ensures that all customers in the rate class contribute appropriately to fixed cost recovery. *Id.* at 207–08. Regarding the Incremental Demand charges, the Rate Design Panel noted that they are designed to recover both transmission and distribution plant costs whereas the Base Demand Charges on Schedule OPT-V only recover distribution costs, i.e., they are not comparable prices. *Id.* at 208. The Rate Design Panel testified that DEC does, however, agree with witness Pollock's suggestion that Incremental Demand Charges should consider customers' mode of delivery and explained that the proposed Schedule HP tariffs reflect this by listing separate prices for transmission and distribution customers. *Id.* They also explained that DEC, in consideration of gradualism, proposed equal Incremental Demand Charges across all rate years in order to limit the increase of charges to the class average percent increase though DEC does intend for these prices to diverge eventually once the charge for transmission customers reaches DEC's target of 50.0% of the unit cost demand. *Id.* at 208–09. In response to witness Pollock's recommendation to reject the reestablishment of CBLs every four years, the Rate Design Panel noted that this provision is specifically intended to expand access to marginal cost pricing while mitigating the potential for subsidization contrary to witness Pollock's assertion. *Id.* at 209. Furthermore, they testified that DEC's proposed Load Response Adjustment provision addresses witness Pollock's claim that reestablishing the CBL every four years removes customers' incentive to permanently commit to real time price responsiveness since it provides them an opportunity to maintain a lower CBL over time by demonstrating load responsiveness during periods of capacity constraints. This would, according to the Rate Design Panel, provide more, not less, of an incentive for customers to commit to real-time price responsiveness than the tariff currently provides. *Id.* at 209–10. Finally, regarding witness Pollock's recommendation to make up to 15 MW of service available to new customers on Schedule HP without requiring CBL reestablishment, the Rate Design Panel noted that the changes to Schedule HP were proposed in order to create an equitable and durable rate design that supports expanded customer participation and access to marginal pricing. DEC thus does not propose or support a cap to participation or load for Schedule HP. *Id.* at 210.

Further, in rebuttal testimony, the Rate Design Panel agreed with witness Nader's implementation date for Schedule HP but disagreed with his suggestion to allow customers with contract demand below 1,000 kW to receive service under Schedule HP. *Id.* at 205. They expressed concern that offering marginally priced energy which can be volatile to customers below one megawatt may have unintended consequences, noting that OPT-V is an appropriate option for customers in this size category. *Id.* at 206. The Rate Design Panel testified that DEC is open to exploring expanded marginal pricing options in future proceedings. *Id.*

During the expert witness hearing, the Rate Design Panel addressed CUCA's concerns regarding Schedule HP. *Id.* at 277–90. Witness Beveridge reiterated that the Incentive Margin serves both as a buffer against hourly pricing forecast errors and a margin covering costs for customers in the class. *Id.* at 278–79. Witness Beveridge also testified that the 0.6 cents per kWh Incentive Margin was determined in part for both DEC and DEP by analyzing and comparing historical prices from 2018 to 2020 across both utilities. *Id.* at 282. Witness Byrd responded to CUCA's assertion that the mandatory reset of the CBL every four years "rob[s] the benefit of these rates" from customers. *Id.* at 287. Witness Byrd testified that characterizing the reset in this way is not accurate, noting that incremental load initially comes on without the need for DEC to incur additional capital investment. However, over time, the electricity system's marginal capacity becomes smaller making it appropriate for customers with non-price responsive load, which is load that drives the need for additional system investments, to contribute towards the embedded costs of the infrastructure they use. *Id.* at 286–87. Witness Byrd further noted that the CBL reset was specifically designed to provide the flexibility required to provide expanded marginal pricing access by enabling the recovery of embedded costs from customers with non-responsive load while also ensuring that price signals are accurate for customers that have the ability to respond to them. *Id.* at 287–88. Witness Byrd also testified that customers who are responsive to price signals will be able to keep their CBL low and may be able to lower it if they demonstrate a high level of responsiveness. *Id.* at 290. Finally, in response to witness Pollock's recommendation to create a category providing up to 15 MW of incremental service without a mandatory reset, witness Byrd noted that the proposed CBL reset was expressly designed so that such a cap was not required and that imposing such a cap would effectively create a rate similar to other less scalable existing rate designs offered by DEC and DEP. *Id.* at 289.

Based on all the evidence in this proceeding, the Commission finds and concludes that Schedule HP, as proposed by DEC, is just and reasonable. The Commission gives significant weight to the Rate Design Panel's testimony indicating that the Incentive Margin serves a dual purpose as a buffer on forecast calculations as well as a margin for the recovery of fixed costs. The Commission also gives weight to the fact that the Incentive Margin was designed in alignment with DEP's Incentive Margin, which was previously approved in the most recent DEP Rate Case Order. The Commission also gives weight to the Rate Design Panel's testimony indicating that there are other available options for customers with demand less than 1,000 kW, such as OPT-V. Furthermore, the Commission concludes that the proposed design changes to schedule HP effectively balance providing expanded access to marginal prices against the need to recover embedded costs, provide effective price signals that encourage beneficial system behaviors, and mitigate the likelihood of subsidization. The Commission gives significant weight to the Rate Design Panel's testimony regarding the four-year CBL reset and concludes that many of the benefits of Schedule HP are reliant on its inclusion, as designed, in the rate. The Commission gives little weight to CUCA witness Pollock's testimony regarding the CBL and declines to adopt his recommendation to create a capped 15 MW block not subject to the quadrennial reset. Finally, the Commission finds witness Nader's proposed implementation date, to which DEC agreed, to be reasonable. Accordingly, Schedule HP is hereby approved with a January 1, 2024 implementation date.

Billing Demand and Minimum Bill Provisions

DEC witness Beveridge testified that DEC is requesting to modify the Determination of Billing Demand provisions and eliminate the Minimum Bill provision under Schedule OPT-V based on the proposed three-part demand structure discussed above. *Id.* at 150. Witness Beveridge stated that the proposed rate design offers adequate provision for minimum bills primarily due to the Base Demand Charge described above. Specifically, witness Beveridge testified that DEC is seeking to modify the Determination of Billing Demand for Schedules SGS, LGS, and I to increase the minimum billing demand from 50.0% to 70.0% of the maximum demand from the previous 12 months in tandem with the elimination of the Minimum Bill provision for these rate schedules. *Id.* at 151. DEC is also proposing to increase the ramp-up period for the minimum billing demand provision based on contract demand from three months to 12 months for Schedules SGS, LGS, I, and OPT-V. *Id.* Witness Beveridge testified that this proposed change would achieve the Commission-directed alignment of minimum bill provisions by making the contract demand ramp up period the same for both DEC and DEP. *Id.*

No intervenor took issue with this proposal. Accordingly, based on all the evidence in this proceeding, the Commission concludes that the billing demand and minimum bill provisions proposed by DEC are just and reasonable and are hereby approved.

Standby Service Requirements

Witness Beveridge testified that with the proposed demand and TOU window restructuring DEC is recommending the elimination of the Standby Charge for generation with planning capacities below 60.0% for customers on a TOU-demand schedule. *Id.* at 151. Related provisions in Schedule PG, HP, SCG, and Rider NM have been modified to reflect this change. *Id.* Commercial Group witness Chriss testified that CUCA supported DEC's proposed changes to the Standby Charge and recommended that the Commission approve DEC's proposal. Tr. vol. 15, 1029.

No intervenor took issue with this proposal. Accordingly, based on all the evidence in this proceeding, the Commission finds and concludes that the standby service requirements proposed by DEC are just and reasonable and are hereby approved.

Industrial Customer Classifications

Witness Beveridge testified that DEC is proposing edits to Schedule I and to Service Regulations specifying that the North American Industry Classification System (NAICS) will be used for industry classification including eligibility for service under Schedule I and for rider rate classification. Tr. vol. 10, 152. Witness Beveridge noted that NAICS was developed to replace the Standard Industrial Classification (SIC) codes and is the official classification system of the United States government. *Id.* Witness Beveridge also stated that DEC transitioned to NAICS after the implementation of the Customer Connect billing system and that there are no notable changes or impacts from this change. *Id.*

No intervenor took issue with this proposal. Accordingly, based on all the evidence in this proceeding, the Commission finds and concludes that the use of NAICS for industry classification is just and reasonable and accordingly is approved.

Close Schedule PG

Witness Beveridge testified that Parallel Generation Schedule PG is a general service TOU-demand schedule for customers operating generation systems in parallel with DEC but that there are only six customers on this schedule and there have been no new participants since 2015. *Id.* at 153. Thus, DEC is requesting to close Schedule PG to new participants as an alternative to redesigning the rate to make it consistent with the new TOU periods and demand charge structure. *Id.* at 153–54. DEC also proposes equal percentage rate increases for energy and demand charges under this schedule in order to recover the revenue increase based on the COSS for each rate year. *Id.* at 154. Witness Beveridge explained that DEC also proposes to increase the Standby Charge by the same percentage as the overall revenue increase in Rate Year 0, from $1.7235 to

$1.83, as justified by the unit cost study. *Id.* The proposed Standby Charge would apply to all rate years and would continue to apply to standby service provisions in other parallel generation tariffs, including Schedule HP, Rider NM, proposed Rider NSC, and Rider SCG. *Id.*

No intervenor took issue with this proposal. Accordingly, based on all the evidence in this proceeding, the Commission finds and concludes that the closure of Schedule PG to new participants is just and reasonable and accordingly is approved.

Terminate Schedule OPT-E

DEC witness Beveridge testified that Schedule OPT-E is a legacy general service TOU pilot rate schedule with 20 customers and has been closed to new participants since January 2012. *Id.* at 155. DEC requests to terminate Schedule OPT-E rather than redesigning the rate with new TOU periods given the availability of multiple alternative rate schedules. *Id.* Witness Beveridge stated that Schedule OPT-E has sufficiently served as a gradual transition for customers previously under Schedules OPT-I and OPT-G and that continuation of the schedule would yield inequitable outcomes. *Id.* If approved, current OPT-E customers will be notified of the upcoming termination via email or other means of communication as available and given an opportunity to select an alternative rate schedule. *Id.* If a customer does not respond the customer will be automatically transferred to either SGS or LGS, based on their usage and contract demand, and effective with the start of the customer's next billing month after the effective date of termination. *Id.*

No intervenor took issue with this proposal. Accordingly, based on all the evidence in this proceeding, the Commission finds and concludes that the termination of Schedule OPT-E is just and reasonable and accordingly is approved.

High Load Factor Tariff

Witness Byrd testified that stakeholders in the CRDS expressed interest in rate options reflecting cost causation differences between loads of varying load factors because higher load factors generally correspond to more efficient use of grid resources. *Id.* at 110–11. Accordingly, DEC proposes a High Load Factor tariff, Schedule HLF, which provides a simple cost of service-based pricing structure for customers with very high load factors. *Id.* at 111. The proposed HLF rate is based on demand and energy pricing determined by the COSS and includes a high level of fixed cost recovery from demand charges. *Id.* Witness Byrd testified that Schedule HLF is not TOU-based since participating customers are assumed to have consistent loads with little seasonal or daily variation and that do not or cannot vary by time of day. *Id.* The rate structure consists of a Basic Customer Charge, a single demand rate, and a single energy rate for all energy consumed as shown in Byrd Exhibit 7. *Id.;* Byrd Direct Ex. 7 (Tr. Ex. vol. 11). Fixed costs are predominantly recovered through the demand charge which is higher than the demand charges on DEC's other general service tariffs. *Id.* Demand charges are based on a billing demand defined as the highest of: (1) the highest demand in the billing month;

(2) 90.0% of the highest demand during the preceding 11 months; (3) 75.0% of contract demand; or (4) 1,000 kW. *Id.* Witness Byrd notes that while the rate does not explicitly limit participation to high load factor customers DEC expects that low load factor customers who otherwise qualify for this rate will not find it attractive due to its pricing design. *Id.* at 112.

Public Staff witness Nader acknowledged that DEC proposed Schedule HLF directly in response to CRDS stakeholders. Tr. vol. 12, 765. Witness Nader concurred with witness Byrd noting that the schedule will be less ideal for customers with low and moderate load factors, but other rate options are available to them more appropriately fit their needs. *Id.*

CIGFUR witness Collins expressed concern with Schedule HLF's energy charge of 2.66 cents per kWh, which is significantly higher than the unit energy cost of 2.16 cents per kWh provided in DEC's unit cost study. Tr. vol. 15, 967. Witness Collins testified that as a result of this it appears that the charges for HLF are not based strictly on cost of service. *Id.* at 968. Furthermore, he expressed concern that the proposed demand charges contain significant interclass subsidy levels in Schedule HLF. *Id.* Accordingly, witness Collins recommended that demand, energy, and customer charges in HLF be based as closely on cost of service without subsidies to the greatest extent practicable to ensure that customers receive appropriate price signals and encourage their adoption of the proposed rate. *Id.* at 969. Witness Collins also noted that an appropriate way to test the validity of Schedule HLF's rate design would be that industrial customers with higher-than-average load factors should see savings from Schedule HLF as compared to their current tariff. *Id.*

In the Rate Design Panel's rebuttal, they testified that DEC designed Schedule HLF based on its unit cost study and with consideration for expected savings and migration. Tr. vol. 10, 210. DEC performed a migration analysis when setting HLF prices to ensure higher-than-average load factor customers could save on the rate without a major migration and cost shift to remaining OPT customers. *Id.* at 211. The Rate Design Panel also noted that, based on witness Collins' testimony, DEC's proposed rate design is appropriate as DEC's analysis of potential customers found many could save at least 2.0% on Schedule HLF under its proposed pricing for the base year. *Id.* The Rate Design Panel finally testified that the new HLF rate was designed to balance various factors including migration, cost of service, and gradualism all of which are necessary to ensure against unreasonable cost shifts to the OPT class. *Id.*

Under the OPT-V-Primary Partial Rate Design Stipulation, DEC and CIGFUR agreed that DEC will modify Schedule HLF's demand charges for transmission-served customers so they are consistent with the demand charge pricing spreads in Schedule OPT-V. Additionally, DEC agreed to set the Schedule HLF energy charge equal to the unit cost for OPT-V-Secondary Large, Primary Large, and Transmission sub-classes. *See* OPT-V-Primary Partial Rate Design Stipulation (Tr. Ex. vol. 7); *see also* tr. vol. 10, 231.

The Commission reiterates its conclusion that the OPT-V-Primary Partial Rate Design Stipulation is reasonable and in the public interest. Accordingly, the Commission approves the High Load Factor Tariff subject to the relevant stipulations as described in the OPT-V-Primary Partial Rate Design Stipulation.

Lighting

DEC provides outdoor lighting service under the following rate schedules: Outdoor Lighting Service Schedule OL, Street and Public Lighting Service Schedule PL, and Nonstandard Lighting Service (Pilot) Schedule NL. Tr. vol. 10, 156. Rates under Schedule OL and PL contain three categories: Existing Pole, New Pole, and New Pole Served Underground categories. The New Pole and New Pole Served Underground rate category prices are based on the corresponding Existing Pole rate plus a fixed adder. *Id.*

Witness Beveridge testified that DEC proposes to increase all Existing Pole rates, excluding LED fixtures on Schedule OL, by a consistent percentage to achieve the proposed revenue increase. *Id.* Witness Beveridge noted that in order to better align LED fixture rates on Schedule OL to Schedule PL, DEC is proposing to increase Existing Pole rates for LED fixtures on Schedule OL by 20.0% less than the percentage increase for non-LED fixtures. *Id.* Witness Beveridge also stated that DEC proposes increases for both the New Pole and New Pole Served Underground new pole adder fees, from $6.49 to $7.37 per month in Rate Year 0, or alternatively to increase the new pole adder incrementally in Rate Years 1-3 (to $6.93 per month, $7.15 per month, and $7.37 per month for Rate Years 1, 2, and 3, respectively). *Id.* at 156–57. Witness Beveridge stated that this proposed rate increase was determined by applying the Extra Facilities rate of 1.0% per month to DEC's total cost to install a new standard 30-foot wooden pole. *Id.* Additionally, Witness Beveridge testified that DEC is proposing to establish a new tariff for Outdoor Lighting Service Regulations (OLSR) and to increase the minimum contract term for lighting fixtures on distribution poles from three years to five years. *Id.* at 157. This new tariff is designed to provide clarity on DEC's outdoor lighting policies and alignment with DEP policies. The template for the proposed OSLR was based on the corresponding DEP tariff. *Id.* Witness Beveridge explained that the new minimum contract term is meant to attract customers who want lighting service long-term, enable DEC to recover more of the costs it incurs serving lighting customers, and to minimize the attrition DEC is currently experiencing in this customer class. *Id.* at 158. Finally, he testified that DEC is proposing to add two new low-wattage LED fixtures to Schedules OL and PL, in part due to the ongoing increases to LED efficiency, creating the need to offer lower wattage products so maintain certain lumen outputs *Id.* Rates for these new LED fixtures were determined using the most recent COSS and in consideration of current prices for comparable fixtures under Schedules OL and PL, and prices were scaled from the Rate Year 0 price for each subsequent Rate Year (1, 2, and 3) of the MYRP based on the incremental year-over-year proposed rate increase for LED fixtures for each rate schedule. *Id.* at 159.

In Public Staff witness D. Williamson's direct testimony, he testified that he generally supports the proposed changes to DEC's various rate schedules but proposed one modification. Tr. vol. 13, 65. Specifically, witness D. Williamson recommended that DEC be required to notify all lighting customers of the change to lighting services, rate schedules, and service regulations by bill insert or separate mailing. *Id.* The Rate Design Panel testified that DEC accepts the Public Staff's proposal and is willing to notify Lighting customers of these changes via a bill insert or separate mailing. Tr. vol. 10, 214.

Considering the parties' testimony and the evidence the parties presented, the Commission finds that DEC's proposed rate design for the Lighting class, with the modification Public Staff witness D. Williamson recommended and DEC agreed to, is just and reasonable for the purposes of this proceeding.

Riders

DEC witness Beveridge testified that DEC proposes to modify a series of service riders. *Id.* at 160. First DEC proposes to modify Net Metering Rider NM and Small Customer Generator Rider SCG to reflect the proposed change in standby service requirements as discussed above in "Standby Service Requirements." *Id.* Further, DEC is proposing to close Rider NM to new participants and terminate Standby Generator Control Rider SG. *Id.* Witness Beveridge noted that DEC is requesting approval to adopt a new Economic Development Rider, Rider ED, and to close the existing Economic Development (Rider EC) and Economic Redevelopment (Rider ER). *Id.* at 110.

Witness Beveridge testified that DEC is also proposing a new net metering rider for non-residential customers, Rider NSC, and explained the adoption of this rider is the basis for its request to close Rider NM to new participants. *Id.* at 160. Witness Beveridge stated that existing participants would continue receiving service under Rider NM for ten years, until December 31, 2033, at which point they would be required to transition to the proposed Rider NSC or another applicable tariff for parallel generation. *Id.* at 160–61.

Witness Beveridge noted that participation in Rider SG, after the introduction of Power Share Rider PS in 2009 and impacts from changes to regulations in 2016, fell to 11 customers and curtailable demand of less than 2 MW (0.4% of DEC's large business demand response portfolio). *Id.* at 161. However, witness Beveridge testified that Rider SG, which relies on manual processes and obsolete metering technology, remains the most administratively burdensome demand response program for DEC and that these administrative challenges are costly and have led to repeated billing delays. *Id.* Additionally, he noted that Rider SG's terms are no longer adequate to incent system beneficial behavioral changes. *Id.* Witness Beveridge testified that Rider PS is an available alternative to Rider SG for customers with at least 100 kW of curtailable demand and that many current Rider SG participants would benefit if they switched. *Id.* at 161. However, he noted that not all existing participants would meet the curtailable demand eligibility criteria and thus some would not qualify to participate in Rider PS. *Id.* at 161–62. DEC proposes to inform affected customers of the pending request to close Rider SG, and if the termination request is approved by the Commission, DEC will communicate the decision and subsequent impacts to Rider SG participants as quickly as practicable. *Id.* at 162. Witness Byrd also noted that Rider SG participants eligible to participate in Rider PS will need to opt-in during the November-December 2023 enrollment period to transition on the effective Rider SG termination date and avoid interruption in demand response program participation. Otherwise, customers will not be able to join Rider PS until the March 2024 alternate enrollment period. *Id.*

In DEC witness Byrd's direct testimony, he stated that DEC is proposing new service riders Rider ED and Nonresidential Solar Choice Rider (Rider NSC) to expand the rate options available to customers. *Id.* at 89. Witness Byrd testified that Rider ED and Rider NSC were designed based on discussions with stakeholders during the CRDS. *Id.* at 103, 106.

Witness Byrd testified that Rider ED will be available to customers: (1) with new load exceeding 1,000 kW with a minimum load factor of 40.0%; (2) that have applied for and received economic assistance from either the state or local government or another public agency; and (3) that meet certain employment and investment minimums relative to the size of the new load. *Id.* at 107. However, witness Byrd stated that new loads which primarily serve EV charging needs are exempted from Rider ED's employment and load factor requirements and that qualifying customers may participate if their new load sizes are above 500 kW. *Id.* Additionally, he also noted that existing customers considering plant investments with possible relocation outside of DEC's service territory may qualify for Rider ED by meeting the investment and employment thresholds, but their new load calculation would exclude reductions associated with the removal of historic equipment or processes. *Id.* Witness Byrd stated that in light of new Rider ED, DEC proposes to close its existing Rider EC and Rider ER to new applicants, but that customers currently served by them will continue to take service under these riders until completion of their existing contracts. *Id.* at 110.

Witness Byrd testified that Rider ED contains several improvements to Rider EC that will help attract and retain customers that make capital investments and add jobs in DEC's service territory. *Id.* at 106–07. Witness Byrd also explained that Rider ED will provide more flexibility for customers to tailor benefits based on both electric grid and regional economic benefits associated with the participant's investment and load characteristics, as shown in Byrd Exhibit 7. *Id.* at 106; Byrd Direct Ex. 7 (Tr. Ex. vol. 7). Witness Byrd stated that Rider ED will consider the following criteria in developing appropriate benefit levels on an individual customer basis: peak monthly demand; average monthly load factor; DEC's incremental costs to serve; the number of new fulltime employees; an economic multiplier; and the total new capital investment of the customer. *Id.* at 108. Witness Byrd further testified that unlike Rider EC, under which participants are required to begin taking credits 18 months after the first date service is supplied under the contract (ramp up period), Rider ED allows participants to wait to take credits until 36 months after the first date of service, in recognition that some industries require significant start-up time for new facilities and that an 18-month ramp up period may constrain their ability to take advantage of the Rider's benefits. *Id.* Witness Byrd also noted that unlike Rider EC, which provides benefits that steadily decline over a five-year period on a rigid schedule, Rider ED allows benefits for up to ten years with possible differences across the years as determined by the project merits. *Id.* Witness Byrd further stated that DEC would, for example, require projects receiving greater levels of benefits for longer periods to meet higher thresholds of investment and employment. *Id.* Also, witness Byrd explained that Rider ED provides a reduction of up to 75.0% of the applicable demand charges on the monthly bill, while Rider EC in comparison, provides a reduction in total charges, excluding certain riders and Extra Facilities fees. *Id.* at 109. Overall, witness Byrd claimed that Rider ED will enable DEC to improve its ability to assist North Carolina and its local communities when they compete for projects. Finally, Rider ED will allow DEC to attract and retain customers adding jobs and making capital investments in its service territory, which ultimately reduces the prices all customers pay while promoting the prosperity of citizens and businesses in North Carolina. *Id.* at 106, 109.

In Public Staff witness Nader's direct testimony, he testified that Rider ED is in the public interest and not unduly discriminatory, should assist with keeping jobs in economically distressed communities and that the Public Staff is reasonably satisfied that its costs and benefits are balanced and fair. Tr. vol. 12, 767–68. Witness Nader explained that he based his determination on the fact that DEC is targeting new investment in load, employment, and economic activity for communities that the state has already designated as economically distressed. *Id.* at 767. Witness Nader also stated that requiring participants to demonstrate that they have received state or local assistance helps balance the costs to non-participants against the benefits to participants. *Id.* Moreover, witness Nader testified that retaining jobs is critical given the competitive pressures manufacturing and large energy customers experience, and Rider ED as proposed should assist with keeping jobs in economically distressed communities. *Id.* at 767–68. Witness Nader also noted that Rider ED's longer ramp-up period and extended period of access to the incentive should help ensure that system load and employment will remain in communities for some time. *Id.* at 768. Finally, witness Nader testified that the Public Staff recommended that to ensure that Rider ED continues to be in the public interest the Commission should require annual reporting of the impacts of Rider ED. *Id.* at 769. Witness Nader explained that DEC should report, at minimum, the gross level of incentives paid, the number of recipients, the amount of investment, load, and jobs associated with the incentives, and an overall marginal cost analysis of Rider ED to determine if the gross level of incentives paid exceeds the marginal cost to serve the gross pool of participants. *Id.*

In rebuttal testimony, the Rate Design Panel testified that DEC agrees that some annual reporting, within certain limits, is reasonable with respect to Rider ED's impacts. Tr. vol. 10, 214. For example, the Rate Design Panel noted that DEC could report on the total number of jobs, total capital investment, or other characteristics contained in Rider ED customer applications, provided that such information can be appropriately anonymized to preserve confidentiality. *Id.*

Under the OPT-V-Primary Partial Rate Design Stipulation, DEC and CIGFUR agree that DEC will modify proposed Rider ED to strike the following words: "[T]he New Load shall exclude any curtailable, back-up, or standby service." OPT-V-Primary Partial Rate Design Stipulation (Tr. Ex. vol. 7).

With respect to Rider NSC, witness Byrd testified that as a result of DEC's proposed new TOU periods and the new three-part demand charge structure, DEC proposes the new Rider NSC to implement several changes for non-residential customers who seek to pursue self-generation through NEM. *Id.* at 102. Witness Byrd stated that Rider NSC also requires all future NEM customers to take service under a general service or industrial rate schedule that includes TOU periods. *Id.* Witness Byrd explained that because DEC's TOU periods include the proposed modified demand charge structure, including them in this rider ensures price alignment with system utilization and cost causation for larger customers and systems. *Id.* Additionally, witness Byrd stated that DEC is proposing an increase to the size limit of customer generation installations under Rider NSC, to either the lesser of 100.0% of the customer's contract demand or 5,000 kW (i.e., 5 MW) for customer-owned systems. Witness Byrd also notes that DEC, in accordance with N.C.G.S. § 62-126.3(14), does not propose increasing the system size limit for leased generation facilities. *Id.* at 102–03. Witness Byrd testified that such changes are appropriate, as the new TOU periods and three-part demand structure will provide cost recovery assurance for fixed costs. *Id.* Finally, he stated that energy exported would be netted against energy usage by TOU period on a monthly basis, with excess energy not used to offset billed usage credited to the customer at an average avoided cost rate calculated using the Net Excess Energy Credit calculation proposed by DEC and DEP in Docket No. E-100, Sub 175. *Id.* at 103.

With the advent of Rider NSC, witness Byrd testified that DEC is proposing that all new non-residential NEM applications take service under Rider NSC and that current Rider NM be frozen to new customers beginning on January 1, 2024. *Id*. Accordingly, witness Byrd explained that existing non-residential NEM customers served under Rider NM would continue to receive service under it until they request service under Rider NSC or until December 31, 2033, at which point all non-residential NEM customers receiving service under Rider NM will be moved to Rider NSC or another appropriate tariff, as available at that time. *Id.*

Regarding Rider NSC, Public Staff witness Nader recommended eliminating DEC's proposed 5-MW cap on nameplate capacity and instead allowing customers to generate up to their contract demand. Tr. vol. 12, 770, 772. Witness Nader testified that by requiring all non-residential NEM customers to subscribe to a TOU schedule and the proposed three-part demand structure, the full fixed cost of service should be recovered regardless of system size, thereby mitigating the risk for material cross-subsidization. *Id.* at 771. Witness Nader also argued that large non-residential customers that seek to install on-site generation will be subject to the capital funding limitations of their own businesses, serving as another limitation to prevent generation in excess of site load from being installed. *Id.* Although witness Nader stated that DEC's concerns regarding reliability due to installed capacity limit increases are valid, he also testified that large customers siting generation behind the meter has the potential to mitigate congestion and defer system upgrade costs. He noted that DEC's concerns could be addressed, at the cost of the generator, though upgrades to customer generator controls and improved communication between customer generators and DEC's distribution network. *Id.* at 771–72.

AGO witness Palmer recommended that customers have the option to enroll in Rider NSC for a contract term of up to five years, with the option for annual renewal thereafter. Tr. vol. 15, 388. Witness Palmer explained that providing an option for customers to enroll for a term length of up to five years balances the need to provide rate certainty for customers investing in distributed resources with the imperative to ensure that tariffs adapt to reflect evolving grid dynamics. *Id.* at 388–89. In support of her proposal, she stated that in Docket No. E-100, Sub 180, DEC sought a ten-year term for its residential NEM tariffs. *Id.* at 389.

NC WARN witnesses Powers and Konidena testified that DEC does not provide evidence to support its claim that the proposed Rider NSC ensures price alignment between system utilization and cost causation and that discussions of the proposed tariff changes with stakeholders, whose knowledge regarding NEM varies widely, cannot substitute for a formal and rigorous application proceeding. *Id.* at 1109–10. Accordingly, NC WARN proposed having a separate DEC application that would address the proposed revisions to the NSC tariff. *Id.* at 1111.

On rebuttal, the Rate Design Panel testified that it did not agree with Public Staff witness Nader's recommendation to eliminate Rider NCS's 5 MW cap. Tr. vol. 10, 215. The Rate Design Panel explained that the 5 MW limit strikes a reasonable balance between stakeholders' requests for larger system sizes and DEC's concerns regarding grid operations and reliability. *Id.* The Rate Design Panel also noted that DEC's proposed 5 MW limit for Rider NSC represents a 500.0% increase over the current limit. *Id.* Moreover, the panel testified that DEC's proposed Schedule HP would allow customer generating systems above the 5 MW limit. *Id.* Importantly, the Rate Design Panel explained that large NEM systems require interconnection studies to manage the complexity they introduce to the electricity grid given the unpredictability of their output to it. *Id.*

In response to AGO witness Palmer's recommendations with respect to Rider NSC, the Rate Design Panel testified that it did not agree with her recommendation. *Id.* at 216. Specifically, the Rate Design Panel explained that in Docket No. E-100, Sub 180, DEC stated that the basic design and structure of the residential NEM tariffs would remain unchanged for ten years in order to provide consistency and predictability for NEM customers. *Id.* However, DEC sought, and the Commission approved, a minimum original contract term of one year consistent with the proposed Rider NSC language. *Id.* The Rate Design Panel stated that in short rate design stability is a separate matter from contract duration, and that witness Palmer's proposal to extend the original contract term would not provide the benefits she described. *Id.*

Finally, the Rate Design Panel disagreed with NC WARN witnesses Powers and Konidena's proposal to include a separate application process for the non-residential NEM tariff revisions. *Id.* at 217. The Rate Design Panel noted that NC WARN, along with a number of other intervenors in this case, participated in the CRDS, and they stated that NEM was extensively studied and discussed, as directed by the Commission in the 2019 Rate Case Order, throughout the year-long process. *Id.* The Rate Design Panel disagreed with NC WARN's assertion that the CRDS discussions involved stakeholders of widely varied knowledge levels and encouraged the Commission to give considerable weight to the process, which was open, collaborative, formal, and thorough, as well as being supported by several sophisticated and well-informed stakeholders involved in this proceeding. *Id.* at 218–19. Further, the Rate Design Panel testified that customers and other stakeholders have had ample opportunity to consider the proposed net energy metering changes through the CRDS process and in this proceeding. *Id.* at 219. They also noted that no stakeholder or participant opposed the nonresidential NEM ideas presented as part of the CRDS Roadmap of the Roadmap itself in the 2017 Rate Case. *Id.* at 220. Finally, the Rate Design Panel asserted that the CRDS successfully built stakeholder support for non-residential NEM changes that the Commission should neither delay implementation of widely supported changes nor should it create a separate docket to relitigate a recently concluded and successful process, and that to do so would be both inefficient and unnecessary. *Id.* at 220–21.

The Rate Design Panel also addressed cross-examination from NC WARN regarding net metering and Rider NSC during the expert witness hearing. Tr. vol. 11,15–35. The Rate Design Panel provided testimony reaffirming the robustness of the CRDS process. *Id.* at 23–26. They also testified that Rider NSC's design is meant to send prices that reflect system costs across a wide range of different usage profiles among nonresidential customers. *Id.* at 32.

On redirect examination, witness Byrd testified that the Rider NSC proposed in this case is similar to the Rider NSC that was approved in the DEP Rate Case Order. *Id.* at 51. Witness Byrd also testified that a single process was used to develop Rider NSC in both this case and the DEP Rate Case. *Id.*

Based on all the evidence in the record of this proceeding, the Commission concludes that DEC's proposed new Rider ED, with the reporting obligation witness Nader suggested and DEC agreed to and also including the amendment, is reasonable and should therefore be approved. The Commission views DEC's proposed Rider ED as an effort to attract economic development in North Carolina and concludes that implementation of the rider is in the public interest. As with other economic development tariffs this Commission has previously approved, approval of Rider ED is based in part on an evaluation of the expected economic benefits resulting from the tariff. The Commission has considered the goal of attracting new economic development in North Carolina as well as the impact of Rider ED on non-participating ratepayers and concludes that Rider ED strikes the appropriate balance between the two. The Commission gives substantial weight to DEC witness Byrd's testimony that Rider ED will result in broad state and regional benefits by enabling DEC to assist North Carolina and local communities when competing for projects, and Rider ED represents an improvement over Rider EC. The Commission also gives substantial weight to Public Staff witness Nader's testimony that Rider ED is not unduly discriminatory, that costs to non-participants against the benefits to participants are balanced fairly, and that it improves on the previous economic development riders DEC has offered. Therefore, the Commission approves DEC's proposal to close Rider EC and Rider ER to new participants and to terminate the old riders once all existing customers have concluded their terms.

The Commission also concludes, based on all the evidence in this proceeding, that DEC's proposed new Rider NSC is reasonable and should therefore be approved. The Commission finds that Rider NSC is appropriate given DEC's new TOU periods and non-residential three-part demand structure, and it will help ensure price alignment with system utilization and cost causation, both for nonresidential customers using NEM systems and all customer classes. In arriving at this conclusion, the Commission gives significant weight to the testimony of DEC witness Byrd. Furthermore, the Commission is not persuaded by Public Staff witness Nader's testimony in support of his recommendation that DEC eliminate the 5 MW cap on nameplate capacity. The Commission also gives substantial weight to the operational and reliability concerns expressed by DEC and accepts witness Byrd's explanation that by increasing the cap from the existing 1 MW to 5 MW, DEC will gain more experience with larger systems and that this experience would provide valuable information to both it and the Commission regarding the operational and reliability challenges and mitigative measures that could be adopted in future proceedings to guide additional increases to, or the removal of, NEM system generation capacity limits. Therefore, the Commission does not accept witness Nader's recommendation to remove the 5 MW limit under Rider NSC. Additionally, the Commission declines to adopt AGO witness Palmer's recommendation regarding the Rider NSC's contract and renewal terms, as it is not convinced that they would provide the customer benefits described in her testimony. Regarding the recommendation of NC WARN witnesses Powers and Konidena to open a new proceeding for Rider NSC, the Commission finds that it is not necessary, nor appropriate, to do so since the issue has already been adequately litigated in both this and the earlier DEP general rate case. Furthermore, the Commission notes its general disapproval towards opening new dockets to relitigate specific issues, except when extraordinary circumstances justify the additional time and expense of doing so, that are more appropriately resolved in general rate cases such as this proceeding. The Commission also notes its satisfaction with the CRDS, which convened a wide range of stakeholders to inform and guide DEC's rate design process. Finally, the Commission finds it reasonable to freeze Rider NM to new customers as of January 1, 2024, and allow existing NEM customers to continue service under Rider NM until they request service under Rider NSC or until December 31, 2033.

In summary, the Commission concludes, based on all the evidence presented, that DEC's riders are just and reasonable, subject to the OPT-V-Primary Partial Rate Design Stipulation, and are hereby approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 48-50

Cost of Capital

The evidence supporting these findings of fact is contained in DEC's verified Application and Form E-1; the testimony and exhibits of the public witnesses; DEC witnesses Morin, Newlin, and Coyne; Public Staff witness Walters; CUCA witness

LaConte; NCJC, et al. witness Ellis; Commercial Group witness Chriss; CIGFUR witness Collins; and the entire record in this proceeding.

Cost of Equity Capital

Summary of Evidence

DEC's rate of return expert, Dr. Roger Morin, recommended a rate of return on common equity of 10.4% with a capital structure consisting of 53.0% common equity and 47.0% debt. The recommendations of intervenor expert rate of return witnesses are as follows:

Public Staff Witness Walters	9.55%[14]
CUCA Witness LaConte	9.4%[15]
NCJC, et. Al Witness Ellis	6.15%

Neither Commercial Group witness Chriss nor CIGFUR witness Collins, performed an independent expert rate of return on common equity analysis. Rather, both witnesses confined their rate of return testimony to commenting on average rates of return awarded to electric utilities over various time periods.

As is often the case with rate of return on common equity, the testimony is voluminous. Below, the Commission summarizes the prefiled testimony of the various witnesses and addresses testimony received at the hearings.

DEC Direct Testimony

DEC witness Morin explained that the regulatory framework under which a regulated entity's rates should be set is that the entity should have a fair opportunity to recover its prudently incurred costs, including taxes and depreciation, plus a fair and reasonable return on its invested capital. The allowed rate of return must necessarily reflect the cost of the funds obtained, that is, investors' return requirements. In determining a company's required rate of return, the starting point is investors' return requirements in financial markets. A rate of return can then be set at a level sufficient to permit a company the fair opportunity to earn a return commensurate with the cost of those funds. Tr. vol. 7, 202. Witness Morin noted that while the cost of debt is observable in the marketplace, the cost of equity — that is, investors' required rate of return on this source of financing — is more difficult to estimate. *Id.* Witness Morin concluded that the Commission's decision should allow DEC to earn a rate of return on common equity that is commensurate with returns on investments in other firms having corresponding risks;

[14] Witness Walters recommends a 20-basis point downward adjustment in rate of return on equity, to 9.35%, if DEC's MYRP is approved, and 9.55% otherwise.

[15] Witness LaConte recommends a 20-basis point downward adjustment in rate of return on equity, to 9.20%, if the MYRP is approved, and 9.4% otherwise.

sufficient to assure confidence in DEC's financial integrity; and sufficient to maintain DEC's creditworthiness and ability to attract capital on reasonable terms. *Id.* at 204.

Witness Morin reiterated that the aggregate return required by investors is "the cost of capital," which he described as "the opportunity cost, expressed in percentage terms, of the total pool of capital employed by the utility." *Id.* Witness Morin noted that public utilities (or their publicly traded parent companies) must compete for capital, and that the price of capital is set in the same manner as it is set for other input factors of production — by supply and demand. *Id.* at 205.

Witness Morin testified that the focus is and must be on the investor and the investor's expectations. As witness Morin explained, "[t]he market required rate of return on common equity, or cost of equity, is the risk-adjusted return demanded by the equity investor. Investors establish the price for equity capital through their buying and selling decisions in capital markets." *Id.* at 207.

In estimating a fair rate of return on common equity for DEC, witness Morin applied three cost of capital methodologies: the Discounted Cash Flow (DCF) methodology, the Capital Asset Pricing Model (CAPM) methodology, and the Risk Premium methodology, all of which are market-based methodologies designed to estimate the return required by investors on the common equity capital committed to DEC. *Id.* at 209. Witness Morin stressed that multiple methodologies must be employed in the estimation of the cost of equity. As he noted:

> No one single method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data.
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> . . .
>
> As a general proposition, it is extremely dangerous to rely on only one generic methodology to estimate equity costs. The difficulty is compounded when only one variant of that methodology is employed. It is compounded even further when that one methodology is applied to a single company. Hence, several methodologies applied to several comparable risk companies should be employed to estimate the cost of common equity.

Id. at 209–10.

Witness Morin noted that the three methodologies he utilized, DCF, CAPM, and Risk Premium, are "broad generic market-based methods available to measure the cost of equity," and are all "accepted and used by the financial community and firmly supported in the financial literature." *Id.* at 210. Witness Morin utilized two sub-variants of each broad methodology, for a total of six studies.

In DEC witness Morin's direct testimony, he recommended a rate of return on common equity (ROE) of 10.4%, which was the average of mathematical results from the six cost of capital studies he conducted and he provided the below comparison:

Method	Direct ROE
DCF Value Line Growth*	9.3%
DCF Analysts Growth*	9.3%
CAPM*	11.0%
Empirical CAPM*	11.2%
Historical Risk Premium*	10.8%
Allowed Risk Premium	10.5%

*Rate of return on common equity estimate includes an adjustment for flotation costs.

Id. at 195.[16]

In DEC witness Morin's direct testimony, he also surveyed the current risk environment, describing a paradigm shift in the electric utility industry's risk profile. Witness Morin described a "perfect storm" environment, in which "the industry is experiencing declining demand growth, rising operating costs, rising capital costs, while at the same time the industry is beset by lower allowed returns," and noted that as a result "[i]t is not surprising that investor risk perceptions have escalated" in this setting. *Id.* at 256.

Witness Morin attributed this increase in industry risk to four major challenges facing electric utilities: (1) declining growth in energy consumption due to improvements in energy science and productivity; (2) the need for record amounts of capital to replace aging infrastructure, improve reliability, and deliver renewable generation; (3) higher business risks, including the emergence of "prosumers," that is, customers (residential, commercial, industrial) who are both consumers and producers as a result of the increase in distributed generation; and (4) rising operating costs due to rising inflation and supply chain bottlenecks. *Id.* at 257–60. Witness Morin concluded with the observation that "[g]iven the new paradigm shift in the industry, it is transparent that state regulatory support, including adequate returns on equity, will be instrumental to ensure ongoing capital attraction in the utility sector at reasonable costs." *Id.* at 260.

[16] Witness Morin updated his analyses in his rebuttal testimony, which is discussed further below. As he indicated, the inputs to various individual analyses did change, but his overall recommendation of 10.4% did not.

Finally, witness Morin surveyed economic conditions in North Carolina. Witness Morin considered key macroeconomic factors such as GDP growth, employment data, and household income levels in North Carolina and DEC's service territory relative to the aggregate U.S. economy. *Id.* at 261. Witness Morin opined that the economic conditions remain highly correlated with national conditions, such that they were reflected in the analyses used to determine the cost of equity. *Id.* at 263. Witness Morin noted that economic conditions in North Carolina continue to improve from the COVID pandemic, and they continue to be strongly correlated to conditions in the broader U.S. economy. *Id.* at 268. Witness Morin further noted that unemployment at the state level continues to fall and remains highly correlated with national rates of unemployment, and that GDP growth also remains well correlated with U.S. GDP growth. *Id.* Median household income in North Carolina has grown at a rate consistent with the rest of the U.S. and remains strongly correlated with national levels. *Id.* at 268–69. Witness Morin concluded that "the correlations between state-wide measures of economic conditions noted by the Commission in Docket No. E-22, Sub 479 remain strongly in place and, as such, they continue to be reflected in the models and data used to estimate the cost of equity capital." *Id.* at 269.

Intervenor Testimony (rate of return experts)

The intervenor rate of return on common equity expert witnesses generally criticized DEC witness Morin's analysis that resulted in his recommended 10.4% rate of return on common equity. In addition, they performed their own analyses as outlined below.

Direct Testimony of Public Staff Witness Walters

Public Staff witness Walters used the same proxy group of electric utilities relied on by DEC witness Morin. Tr. vol. 14, 54. Witness Walters performed DCF, Risk Premium, and CAPM analyses for his proxy groups of electric utilities. *Id.* at 44. Witness Walters developed his DCF growth rate by relying on a consensus of professional securities analysts' earnings growth estimates, averaging the growth rate forecasts from Yahoo Finance, S&P Capital IQ Market Intelligence (MI), and Zack's. *Id.* at 58. Public Staff witness Walters recommended a rate of return on common equity of 9.35% if the Commission grants DEC's MYRP and PBR Application. *Id.* at 19, 93, 99. In the absence of an MYRP, witness Walters recommended a rate of return on common equity of 9.55% based on a capital structure of 52.0% common equity and 48.0% long-term debt. *Id.* at 53, 93, 123.

Public Staff witness Walters applied the DCF model, Risk Premium Model, and CAPM, with his analyses yielding the following results:

Discounted Cash Flow — 9.20% Recommended DCF Result

	Mean	Median
Constant Growth – Consensus Analyst	9.96%	9.87%
Constant Growth – Sustainable Growth Rate	9.02%	8.72%
Multi-Stage Growth	8.56%	8.41%

Risk Premium Model — 9.90% Recommended Risk Premium Result

Projected Treasury Yield (3.70%)	9.78%	
	A-rated	Baa-rated
13-week Average Utility Bond Yield	9.94%	10.28%
26-week Average Utility Bond Yield	9.95%	10.26%

Capital Asset Pricing Model — 9.40% Recommended CAPM Result

	Current VL Beta	Historical VL Beta	Current MI Beta
D&P Normalized Method	8.76%	8.10%	8.40%
Risk Premium Method	10.60%	9.66%	10.10%
FERC DCF	10.42%	9.51%	9.93%

Id. at 70, 77, 89.

In witness Walters' DCF analysis, he used the average of the weekly high and low stock prices of the utilities in the proxy group over a 13-week period ending on June 9, 2023. *Id.* at 56. For his constant growth model, he used the most recently paid quarterly dividend as reported in Value Line and an expected growth rate based on a consensus of professional securities analysts' earnings growth estimates as a proxy for investors' dividend growth rate expectations. *Id.* at 57–58. For his sustainable growth model, he estimated the long-term growth rate based on DEC's current market-to-book ratio and on Value Line's three- to five-year projections of earnings, dividends, earned returns on book equity, and stock issuances. *Id.* at 62. witness Walters' Multi-Stage growth model relied on inputs from three growth periods: (1) a short-term growth period consisting of the first five years; (2) a transition period, consisting of the next five years (six through ten); and (3) a long-term growth period starting in year 11 and extending into perpetuity. *Id.* at 64. For the short-term growth period, witness Walters relied on the consensus of analysts' growth projections described above in relationship to his constant growth DCF model. *Id.* For the transition period, witness Walters reduced or increased the growth rates by an equal factor reflecting the difference between the analysts' growth rates and the long-term sustainable growth rate. *Id.* For the long-term growth period, witness Walters assumed each company's growth would converge to the maximum sustainable long-term growth rate. *Id.* Lastly, while not witness Walters typical practice, he provided DCF models using historical growth inputs, which resulted in DCF estimates ranging from 7.77% to 9.33%. *Id.* at 70–71.

Witness Walters' risk premium model is based on two estimates of an equity risk premium: the difference between the regulatory commission-authorized returns on common equity and (1) contemporary U.S. Treasury Bonds; and (2) contemporary Moody's "A" rated utility bond yields. *Id.* at 72. Witness Walters evaluated these premia over the period of 1986–2021 on an overall average and rolling five- and ten-year basis. *Id.* In addition, he evaluated the average spread between Treasury bonds and A- and Baa-rated utility bonds. *Id.* at 75. Finally, witness Walters added what he deems an appropriate premium in the third quartile of the rolling five-year average risk premia (6.08%) to his projected Treasury bond yields (3.7%), which produces a return on equity of 9.78%. *Id.* at 75–76. Witness Walters applies a similar methodology to utility bond yields to estimate an equity risk premium of 4.67%. *Id.* at 76. Witness Walters adds this to the 13- and 26-week average A- and Baa-rated utility bond yields. *Id.*

Witness Walters' CAPM analysis used Blue Chip Financial Forecasts' projected 30-year U.S. Treasury bond yield of 3.70% for the risk-free interest rate. *Id.* at 79. Witness Walters used the Value Line beta estimates of 0.88, the historical average Value Line beta since 2014 of 0.76, and the adjusted beta estimates provided by Market Intelligence's Beta Generator Model of 0.82 for his proxy group. *Id.* at 80–81. To derive estimates of the market risk premium (MRP), witness Walters used two general approaches: a risk premium approach and a DCF approach. Witness Walters also considered the normalized MRP of 5.50% with the normalized risk-free rate of 3.89% as recommended by Kroll. *Id.* at 82. For his risk premium approach, witness Walter added the historical arithmetic average real market return of 8.90% to the consensus Consumer Price Index forecast of 2.40%, before subtracting the 3.70% projected risk-free rate, to arrive at 7.81%. *Id.* at 83. Witness Walters used two versions of the constant growth DCF model to develop his DCF-based estimate of the MRPs. *Id.* at 83–85. Witness Walters used the 7.60% average of his estimated MRPs of 7.0% and 8.2%. *Id.* at 83–84. Witness Walters testified that as his average expected market return of 10.73% exceeds the long-term market expectations of several financial institutions, his MRPs are reasonable, if not high-end estimates. *Id.* at 84–86.

Witness Walters concluded that the appropriate equity cost rate for DEC based on companies in his proxy group is in the 9.20% to 9.90% range, recommending the midpoint of 9.55%. *Id.* at 90. However, witness Walters testified that DEC's PBR Application would shift risk from shareholders to ratepayers by reducing regulatory lag. *Id.* at 92. As such, he recommended a 9.35% rate of return on common equity, should the Commission grant DEC's MYRP and PBR Application. *Id.* at 92–93. Witness Walters also testified as to current capital market conditions as of the date of his testimony. Witness Walters stated that the authorized rates of return on common equity for electric utilities have declined over the last several years. *Id.* at 20.

Direct Testimony of CUCA Witness LaConte

CUCA Witness LaConte testified that a fair and reasonable rate of return on common equity should be based on accepted methodologies. The inputs and assumptions used should consider current financial and economic realities, such as DEC's financial strength and credit rating, rates of return on common equity authorized by state regulatory commissions, and financial risk. Tr. vol. 15, 623. Witness LaConte referenced principles established by the U.S. Supreme Court for determining a fair return on capital for regulated monopolies. *Id.* at 623–24. Witness LaConte also highlighted DEC's stable credit outlook as per Moody's latest credit report and noted that DEC's proposed 10.4% return on equity and 53.0% equity ratio are overstated compared to the national average authorized return on equity for vertically integrated electric utilities, which ranged from 9.53% to 9.74% between 2019 and 2023. *Id.* at 624–26.

Witness LaConte further discussed how financial risk, defined as variability in income, is influenced by the regulatory climate. *Id.* at 626–32. Witness LaConte argued that DEC's proposed MYRP would reduce its business and financial risk, as it allows for automatic rate adjustments over a three-year period to account for infrastructure investments. *Id.* at 627–30. Witness LaConte pointed out that DEC has adjustment clauses in place that reduce its income variability and lower its financial risk. *Id.* at 630. If the Commission approves the MYRP, witness LaConte testifies that her recommended 9.4% rate of return on equity should be reduced by 20 basis points to 9.2%. *Id.* Witness LaConte concluded by stating that the persistently higher inflation rate in North Carolina, compared to the national rate, places an additional burden on customers, making an increase in DEC's return on equity imprudent at this time. *Id.* at 633.

Witness LaConte calculated a range of return on equity for DEC using a combination of methodologies: DCF analysis, two CAPMs, and a Risk Premium method. The results of these analyses produced an average return on equity of 9.43%. *Id.* at 634. First, her DCF analysis involved the use of a proxy group of 16 companies and was based on the average, historical 30-day stock price, dividends adjusted for growth, and earnings growth estimates from three sources. *Id.* at 639. Witness LaConte employed a single-stage DCF combined with the low, mean, and high estimated growth rate for each utility, resulting in three estimated rates of return on equity: 8.37% (low estimate), 9.54% (mean estimate), and 10.58% (high estimate). *Id.* Witness LaConte utilized two CAPM models, using the average of the betas for each company in the proxy group and two estimates of the market risk premium: a historical MRP of 5.5% and a projected MRP of 5.6%. *Id.* at 640–41. Her CAPM analyses resulted in an estimated return on equity of 8.99% using the historical MRP and 9.08% using the projected MRP. *Id.* at 642. Finally, witness LaConte employed a Risk Premium method to estimate the required return on equity as the sum of a bond yield plus a risk premium yield. *Id*. Witness LaConte compared the authorized rates of return on equity for electric utilities since 1986 to the risk-free rate at the time the rate of return on equity was authorized, resulting In a return on equity of 10.03% when a projected 30-year Treasury yield of 4.30% is used. *Id.* at 642–43. Witness LaConte calculated that the outputs of her models resulted in an average rate of return on equity of 9.43%, which supports her recommended rate of return on equity of 9.4% for DEC. *Id.* at 643–44.

Additionally, witness LaConte offered a critique of witness Morin's proposed rate of return on equity of 10.4% for DEC. *Id.* at 645–54. Witness LaConte claimed witness Morin uses an incorrect MRP of 7.3% in his CAPM analysis, which overstates the risk premium. *Id.* at 646. In the Empirical CAPM (ECAPM), witness LaConte challenged witness Morin's estimated beta as too high. *Id.* at 648–50. Witness LaConte further criticized witness Morin's Risk Premium method, claiming that it overstates the equity risk premium. *Id.* at 650–52. Discussing the DCF method, witness LaConte testified that witness Morin uses improper estimated growth rates. *Id.* at 652. Witness LaConte further criticized witness Morin's inclusion of a flotation cost adjustment. *Id.* at 647–48.

Direct Testimony of NCJC, et al. Witness Ellis

NCJC, et al. witness Ellis recommended a rate of return on common equity of 6.15%, based on the minimum required to maintain DEC's current A2 credit rating. *Id.* at 687. Witness Ellis criticized DEC witnesses for their conflation of the rate of return on capital and the cost of capital, arguing that such confusion has led to excessive authorized returns. *Id.* at 695–97. Witness Ellis testified that his analysis relies on the premise that rate of return on common equity and capital structure are interrelated and cannot be determined separately. *Id.* at 816–21.

Witness Ellis' analysis relies on the DCF and CAPM to estimate the cost of capital. *Id.* at 691. His analysis yielded the following results: (1) Multi-Stage Discounted Cash Flow: 6.63% and (2) Capital Asset Pricing Model: 6.06%. *Id.* at 693.

Witness Ellis opined that the multi-stage DCF model should be used instead of the constant growth DCF model because it allows for more realistic cash flow projections, yielding more accurate results. *Id.* at 744. Witness Ellis testified that his CAPM analysis eliminates the upward biases seen in Witness Morin's CAPM analysis. *Id.* at 788.

Witness Ellis testified that rate of return on common equity and capital structure are interrelated and must be addressed together. *Id.* at 816–21. Witness Ellis recommended along with his 6.15% rate of return on common equity that the Commission set DEC's capital structure at 58.8% equity and 41.2% debt and indicated that this combination would maintain DEC's credit rating. *Id.* at 687.

Intervenor Testimony (other experts)

As noted above, both Commercial Group witness Chriss and CIGFUR witness Gorman provided rate of return on common equity-related testimony but did not perform any rate of return on common equity analysis.

Direct Testimony of Commercial Group Witness Chriss

While Commercial Group witness Chriss did not provide a rate of return on common equity analysis in his testimony, he testified that DEC's proposed rate of return on common equity was significantly higher than rates of return previously approved by the Commission from 2019 to the present. *Id.* at 1013–14. Likewise, witness Chriss indicated that DEC's proposed rate of return on common equity is significantly higher than most reported rate of return on common equity decisions by utilities commissions from 2019 to the present. *Id.* at 1015–16. Witness Chriss testified that according to S&P Global Market Intelligence, 148 decisions were rendered during that time frame, with results ranging from 7.36% to 10.60%, with the median authorized rate of return on equity at 9.50%. *Id.* at 1015. Removing distribution-only utilities and distribution service rates from the analysis, he testified that the average rate of return on common equity for vertically integrated utilities authorized from 2019 through the time of his direct testimony filing was 9.62%. *Id.* at 1016.

Direct Testimony of CIGFUR Witness Collins

CIGFUR witness Collins recommended that the Commission reject DEC's proposed return on equity of 10.4% in favor of something significantly less. *Id.* at 980. Witness Collins testified that for vertically integrated utilities, the authorized rate of return on common equity was around 9.39% in 2021, 9.52% in 2022, and currently holds around 9.64% for 2023. *Id.* at 979. Witness Collins testified that DEC's requested rate of return on common equity is significantly above the current market cost of equity for an electric utility based on recent evidence. *Id.* at 977. Witness Collins further testified that the proposed 10.4% rate of return on common equity significantly exceeds the authorized rates of return on equity for other regulated utilities companies, which have been sufficient to maintain credit and provide utilities access to capital under reasonable terms and prices. *Id.*

DEC Rebuttal Testimony

DEC presented two rebuttal witnesses — witness Morin and witness Coyne.

Rebuttal Testimony of DEC Witness Morin

In DEC witness Morin's rebuttal testimony, he responded to criticism by intervenor rate of return on equity witnesses and commented upon deficiencies in their analyses. While he testified that he agrees with several of the views and procedures presented by witness Walters and witness LaConte, he noted that their recommendations understate the appropriate rate of return on equity for DEC. Tr. vol. 7, 305, 339. Particularly, he reasoned that their recommendations lie outside of the zone of currently authorized rates of return on common equity for vertically integrated electric utilities in the United States, which have averaged 9.73% so far in 2023 and have trended upward in more recent decisions in response to the surge in interest rates and inflation. *Id.* at 305, 336, 339. Witness Morin further noted that neither witness Walters nor witness LaConte explained why or how DEC's cost of equity capital has decreased since it was awarded a rate of return on common equity of 9.6% in its last rate case in 2021, given a surge in interest rates and inflation that each of them acknowledged in their testimony. *Id.* at 377.

Witness Morin further disputed the contentions of witnesses Walters and LaConte that the adoption of a performance-based ratemaking statute in North Carolina, including multiyear rate plans, should result in a lower rate of return on common equity for DEC. *Id.* at 297. Witness Morin noted that the peer group of electric utilities also includes other risk-mitigating mechanisms, taken into account in the use of the proxy group's financial data. *Id.* at 298. As such, further adjustment on the basis that an MYRP reduces risk amounts to double counting and should be rejected. *Id.* Witness Morin noted further that the Commission had already addressed this issue by rejecting any downward adjustment in two recently decided cases: (1) Order Approving Partial Settlement Agreement and Stipulation, Deciding Contested Issues, Approving Water and Sewer Investment Plan, Granting Partial Rate Increases, and Requiring Customer Notice, *Application by Aqua North Carolina, Inc., for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All Its Service Areas in North Carolina and for Approval of a Water and Sewer Investment Plan*, No. W-218, Sub 573 (N.C.U.C. June 5, 2023) (2023 Aqua Rate Case Order); and (2) Order Approving Partial Settlement Agreement and Stipulation, Deciding Contested Issues, Granting Partial Rate Increase, Approving Water and Sewer Investment Plan, and Requiring Customer Notice, *Application by Carolina Water Service, Inc. of North Carolina for Authority to Adjust and Increase Rates and Charges for Water and Sewer Utility Service in All Service Areas of North Carolina and Approval of a Three-Year Water and Sewer Investment Plan*, No. W-354, Sub 400 (N.C.U.C. Apr. 26, 2023) (2023 CWS Rate Case Order). *Id.* at 300.

In his introductory comments, witness Morin referenced two factors which he indicated were entirely ignored by the intervenor rate of return on equity witnesses. First, referring back once again to the 2023 Aqua and CWS Rate Case Orders, he noted that the Commission in both cases awarded the applicable water utility a rate of return on common equity of 9.8%. Witness Morin testified that there is a hierarchy of risk among different types of utilities, and water utilities are considerably less risky than vertically integrated electric companies, for the simple reason that the water utilities are not afflicted with the risk of generation (particularly, as is the case with DEC, nuclear generation). *Id.* at 302.

Second, witness Morin noted that while the intervenor witnesses generally acknowledge that capital market conditions since DEC's rates were last set have been characterized by increases in interest rates and inflation, particularly in the last year or so, the analyses performed by those witnesses resulted in a lower rate of return on equity than awarded by the Commission in DEC's last case. *Id.* at 302–03. Witness Morin indicated that the Commission-authorized rate of return on equity in 2021 was 9.6%, when the yield on the 30-year Treasury bond was 2.16%; in contrast, at the time of his rebuttal testimony analysis the 30-year Treasury bond yield had risen to 4.02%, an increase of 186 basis points. *Id.* at 303. Witness Morin commented that the intervenor witnesses' failure to increase their recommended rate of return on equity in the face of rising interest rates defied reason and logic and indicated to him that their recommendations lacked credibility. *Id*.

Witness Morin additionally challenged the findings of the intervenors individually. While he noted that they shared quite a bit of common ground in their analyses, witness Morin testified that Public Staff witness Walters' recommended rate of return on common equity lies outside of the zone of currently authorized rates of return on common equity for vertically integrated utilities and opined that if his results were amended to reflect proper data inputs to the financial models, his results would exceed 10.0%. *Id.* at 303–05. Witness Morin offered the following six points of disagreement. *Id.* at 306.

Witness Morin criticized witness Walters' reluctance to accept flotation costs, explaining that the parent-subsidiary relationship does not eliminate the cost of stock issuance. *Id.* at 307–10. Witness Morin disagreed with witness Walters' DCF technique, explaining that his sustainable growth rate approach was illogical and inconsistent with empirical evidence. *Id.* at 310–13. Witness Morin testified that witness Walters' multi-stage DCF should not be given any weight by the Commission, as it is predicated on the idea that utilities grow at the same rate as the general macro-economy. *Id.* at 314–15. Witness Morin wholly rejected witness Walters' use of the historical Value Line beta estimates and Vasicek-adjusted betas, explaining that their use is not standard and the extent to which market participants rely on them is unclear. *Id.* at 319–21. Witness Morin argued that witness Walters' CAPM underestimates the appropriate cost of capital. *Id.* at 326–27. In challenging witness Walters' risk premium analysis, witness Morin testified that it fails to recognize the inverse relationship between risk premium and interest rates. *Id.* at 327. Finally, witness Morin disagreed with witness Walters' criticisms of his testimony, noting that nothing presented would cause him to alter any of his recommendations or methodologies. *Id.* at 335.

While witness Morin agreed with parts of CUCA witness LaConte's analysis, he identified six specific areas of disagreement. *Id.* at 336–37. Witness Morin explained that witness LaConte's recommended rate of return on common equity is outside the zone of currently authorized rates of return on common equity for vertically integrated electric utilities in the United States, noting that in 2023 the average authorized return on equity in the vertically integrated electric utility industry is 9.73%. *Id.* at 339. Witness Morin asserted that witness LaConte's dividend yield calculations are understated by ten basis points because she multiplies the spot dividend yield by one half the expected growth rate rather than one, thus deviating from the standard textbook methodology. *Id.* at 340. Witness Morin raised concern with witness LaConte's DCF growth model, finding her failure to include an allowance for issuance expense understates her DCF by 20 basis points. *Id.* at 340–41. Combined with his disagreement on the dividend yield, witness

Morin thus testified that witness LaConte's DCF results were understated by 30 basis points.

While he agreed with parts of witness LaConte's CAPM analysis, witness Morin argued that witness LaConte's risk-free rate assumption is out of date, and as a result, too high. *Id.* at 341–42. At the time of witness Morin's rebuttal testimony (filed August 4, 2023), interest rates had fallen to 3.9% from 4.3% as of his direct testimony. *Id.* However, at the hearing on August 28, 2023, witness Morin testified that U.S. Treasury bond yields had risen from 3.9% to 4.3% in the span of approximately the prior week. *Id.* at 400–01. Witness Morin also testified that witness LaConte's adopted historical risk premium is incorrect and confounded the utility risk premium with the MRP, creating a serious error in her historical MRP. *Id.* at 342. Witness Morin further criticized witness LaConte's exclusion of an ECAPM analysis. *Id*. at 343. With regard to witness LaConte's risk premium estimate, witness Morin criticized her failure to account for the inverse behavior between the allowed risk premium and the level of interest rates, as well as her failure to adjust for the flotation cost allowance. *Id.* at 344–45.

Witness Morin wholly rejected the testimony of NCJC, et al. witness Ellis, describing his approach as "non-mainstream, far-fetched, and unorthodox for both methods he uses to estimate the cost of capital." *Id.* at 351. Witness Morin described witness Ellis' recommendation as draconian and described the adverse consequences to DEC's creditworthiness, financial integrity, capital raising ability, and its customers, should the Commission adopt it. *Id.* at 350–51. Witness Morin also identified witness Ellis' inconsistencies and contradictions, such as his challenging the validity of the same consensus economic forecasts he relies on to make his recommendations. *Id.* at 353. Witness Morin challenged witness Ellis' differentiation of cost of capital and rate of return and dismissed his position on the use of Market-to-Book ratios in utility regulation. *Id.* at 354–55. In addition to challenges to witness Ellis's recommendations, witness Morin offered a myriad of criticisms to the application of his methodologies. Witness Morin explained that witness Ellis' misuse of geometric averages rather than arithmetic averages produces results clearly contrary to the most basic financial theory. *Id.* at 356–57. Witness Morin further identified multiple other instances where witness Ellis' methods deviate from academic state of the art practices, including his rejection of the constant growth DCF analysis and his condemnation of Value Line beta estimates. *Id.* at 362–63.

Witness Morin highlighted the limited analysis performed by Commercial Group witness Criss and CIGFUR witness Collins. *Id.* at 368–69. Witness Morin testified that witnesses Criss and Collins determined their recommendations merely by averaging what other regulators have allowed in 2022. *Id.* at 369–70. Witness Morin criticized the circular nature of their recommendations and noted the large deviations among the utilities included in their proposed averages. *Id.* Witness Morin encouraged the Commission to disregard their testimonies as not germane and to exercise a mind of its own rather than relying on the actions of other Commissions. *Id.* at 370.

Finally, witness Morin provided updated results (including flotation costs) from his various methodologies:

Method	Original ROE	Updated ROE
DCF Value Line Growth	9.3%	9.8%
DCF Analysts Growth	9.3%	10.0%
CAPM	11.0%	10.8%
Empirical CAPM	11.2%	10.9%
Historical Risk Premium	10.8%	10.4%
Allowed Risk Premium	10.5%	10.3%

Id. at 372. Witness Morin stated that his risk-free rate had dropped from 4.3% to 3.9%, which lowered the results in his CAPM, ECAPM, and Risk Premium analyses. *Id.* at 371. This impact was offset slightly by an increase in electric utility betas, from 0.89 to 0.91. *Id.* Witness Morin noted, however, that higher dividend yields (a component of the DCF model) resulted in higher DCF results. *Id.* at 372. The input revisions did not change his overall recommended rate of return on equity result of 10.4%. *Id.*

Rebuttal Testimony of DEC Witness Coyne

DEC witness Coyne's rebuttal testimony critiqued Public Staff witness Walters' analysis. Witness Coyne opined that witness Walters placed undue reliance on models with analytical results that are inconsistent with the current capital market environment, and that witness Walters' reliance upon flawed assumptions and unreasonably low results biased his recommendation downward. Tr. vol. 16, 130. In his testimony summary, witness Coyne noted that he had fundamental concerns with the Walters analysis because it failed basic tests of logic along with certain specific methodological issues. *Id.* at 163–64.

A. Overview of Witness Coyne's Criticisms

In terms of basic tests of logic, witness Coyne testified that it was counter-intuitive to conclude that DEC's cost of equity capital had decreased since the Commission authorized a rate of return on equity of 9.6% in DEC's previous rate case, when from that time long-term government and utility bond yields have increased by 162 to 207 basis points. *Id.* at 140, 160, 163. Witness Coyne noted further that witness Walters' recommendation would place DEC's cost of capital in the bottom tenth percentile of rates of return on equity authorized for vertically integrated electric utilities over the past 12 months, but that there is no basis to conclude that DEC was that much less risky than its peers. *Id.* at 140. This is particularly the case as returns allowed over the past 12 months were authorized under capital market conditions that reflect substantially lower interest rates, and, therefore, understate the cost of equity in the current capital market environment. *Id.*

Witness Coyne also critiqued witness Walters' methodologies, and indicated that certain of his analytic results were below any rate of return on common equity authorized for a vertically integrated electric utility in at least 40 years, and, therefore, failed the basic test of comparability. *Id.* at 140–41.

B. Criticism of Witness Walters' DCF Analyses

Witness Coyne noted that witness Walters uses two DCF models, a constant growth DCF model (using both analysts' projected earnings growth and sustainable growth rates) and a Multi-Stage DCF (MSDCF) model. *Id.* at 141. Witness Coyne noted that while the theory behind the sustainable growth model assumes that future earnings will increase as the retention ratio increases, academic research was to the contrary, and indicates that future earnings growth is actually associated with high, rather than low payout ratios. *Id.* at 142–43.

Witness Coyne indicated that the results for the sustainable growth model and the MSDCF model were so low as to fail to meet the *Hope* and *Bluefield* standards for a fair return. *Id.* Witness Coyne testified that these model results should therefore be disregarded; yet witness Walters nevertheless relied upon them to arrive at his ultimate DCF recommendation of 9.20%, which is roughly the midpoint between all of his DCF analytic results. *Id.* at 142, 144. Witness Walters' DCF estimate also forms the low end of his rate of return on common equity range, and disregarding these results and relying on witness Walters' constant growth model using analyst growth rates would result in a DCF range of 9.87% to 9.96%, increasing the low-end of witness Walters' recommended range by 67 to 76 basis points. *Id.* at 144.

C. Criticism of Witness Walters' CAPM Analyses

In commenting upon witness Walters' CAPM analyses, witness Coyne noted that he uses unconventional CAPM methodologies, with results far removed from any reasonable estimate of DEC's cost of equity capital. *Id.* at 145. Witness Coyne identified witness Walters' use of Vasicek-adjusted Beta coefficients from S&P Global Market Intelligence (MI) and his application of historical beta coefficients as being among these unconventional approaches. *Id.* at 146–47.

Witness Coyne testified that that he was not aware of any regulatory commission that has accepted the use of Vasicek adjusted beta coefficients, and that the Vasicek adjustment methodology requires more inputs and calculations and is more susceptible to subjective judgment than are the beta coefficients independently reported by Value Line, or other sources such as Bloomberg that use the Blume adjustment methodology. Witness Coyne concluded that the MI Beta Generator Model and the Vasicek adjustment generally is susceptible to subjective variability based upon size and selection of the comparable group used in the adjustment. Adjusted beta coefficients from Value Line, however, are well understood, independently reported, and easily verifiable; therefore, they are not exposed to these criticisms. *Id.* at 146.

Witness Coyne also criticized witness Walters' use of historical beta coefficients. Witness Coyne noted that beta is a measure of relative risk in the CAPM analysis, and that Value Line Beta coefficients for utilities increased substantially in connection with the COVID pandemic and have remained elevated ever since. *Id.* at 147. The five-year period over which Value Line Beta coefficients are calculated includes returns that both predate the pandemic and are now three years removed from the pandemic's onset, which suggests that betas for the proxy group employed by both witness Walters and witness Morin are being affected by factors other than the pandemic. *Id.* Witness Coyne concluded that since electric utility betas have remained at elevated levels, it appears that electric utilities have not served as a safe haven for investors over the past five years, and that this shift may also be attributable to the market's recognition of the complex challenges facing the industry in response to climate change, transitioning to a lower carbon generation mix, grid modernization, and shifting consumer preferences. *Id.*

In addition, witness Coyne took issue with witness Walters' use of the Duff & Phelps (Kroll) MRP in his CAPM analysis. Witness Coyne noted in his Figure 7 that witness Walters' Kroll market premium analysis resulted in a rate of return on common equity so low as to be below any rate of return on common equity authorized for a vertically integrated electric utility since 2022, and that two of the three results were below any rate of return on common equity authorized in the last 40 years. *Id.* at 149–50. Witness Coyne demonstrated that there was no relationship between the Kroll recommended equity risk premium and the risk-free rate, whereas academic studies have shown that the two are inversely related. *Id.* at 148. Witness Coyne recommended that witness Walters' CAPM results based upon the Kroll MRP be disregarded. *Id.* at 150. Doing so would result in witness Walters' CAPM range increasing to 9.51% to 10.60%, with a midpoint of 10.06%, 66 basis points above witness Walters' stated CAPM estimate of 9.40%. *Id.*

D. Criticism of Witness Walters' Risk Premium Analyses

Witness Coyne noted that witness Walters' Risk Premium analysis understates the required risk premium as it fails to adequately reflect the inverse relationship between the Equity Risk Premium and bond yields. *Id.* at 152. Witness Coyne testified that there is a clear inverse relationship between the risk premium and bond yields, but that witness Walters ignored this relationship and substituted his own judgment as to the appropriate risk premium, resulting in an understatement of the results. *Id.* Witness Coyne suggested that based upon witness Walters' other inputs to the Risk Premium Model, including a risk-free rate of 3.7%, an appropriate risk premium would be 6.34%, leading to a cost of equity of 10.08%, rather than witness Walters' estimate of 9.78%. *Id.* at 154–55. Similarly, witness Coyne suggested that the cost of equity based on utility bond yields should be 10.21%, rather than witness Walters' estimate of 9.94%. *Id.* at 156.

In sum, witness Coyne indicated that after correction for methodological errors, witness Walters' rate of return on common equity range would have encompassed witness Morin's 10.4% rate of return on common equity recommendation. *Id.* at 160.

Law Governing the Commission's Decision on Rate of Return on Equity

Rate of return on equity is often one of the most contentious issues to be addressed in a rate case. The baseline for establishment of an appropriate rate of return on common equity is the constitutional constraints established by the decisions of the United States Supreme Court in *Bluefield Water Works & Improvement Co. v. Public Service Commission*, 262 U.S. 679 (1923), and *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) which establishes:

> To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting [an ROE], the Commission must still provide the public utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital.

Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, *Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-7, Sub 1146, at 49-50 (N.C.U.C. June 22, 2018); *see also State ex rel. Utils. Comm'n v. Gen. Tel. Co. of the SE*, 281 N.C. 318, 370, 189 S.E.2d 705, 738 (1972). As the North Carolina Supreme Court held in *General Telephone*, these factors constitute "the test of a fair rate of return declared" in *Bluefield* and *Hope*. *Id.*

The rate of return on equity is, in fact, a cost — the return that equity investors require represents the cost to the utility of equity capital. In his dissenting opinion in *Missouri ex rel. Southwestern Bell Telephone Co. v. Missouri Public Service Commission*, 262 U.S. 276 (1923), Justice Brandeis remarked upon the lack of any functional distinction between the rate of return on equity (which he referred to as a "capital charge") and other items ordinarily viewed as business costs, including operating expenses, depreciation, and taxes:

> Each is a part of the current cost of supplying the service; and each should be met from current income. When the capital charges are for interest on the floating debt paid at the current rate, this is readily seen. But it is no less true of a legal obligation to pay interest on long-term bonds . . . and it is true also of the economic obligation to pay dividends on stock, preferred or common.

Id. at 306 (Brandeis, J., dissenting). Similarly, the United States Supreme Court observed in *Hope*, "[f]rom the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business . . . [which] include service on the debt and dividends on the stock." *Hope*, 320 U.S. at 591, 603.

The North Carolina Supreme Court has long recognized that the Commission's subjective judgment is a necessary part of determining the authorized rate of return on common equity. *See, e.g., State ex rel. Utils. Comm'n v. Public Staff-N.C. Utils. Comm'n*, 323 N.C. 481, 490, 374 S.E.2d 361, 369 (1988). Likewise, the Commission has noted that such determination is not made by application of any one simple mathematical formula:

> Throughout all of its decisions, the [United States] Supreme Court has formulated no specific rules for determining a fair rate of return, but it has enumerated a number of guidelines. The Court has made it clear that confiscation of property must be avoided, that no one rate can be considered fair at all times and that regulation does not guarantee a fair return. The Court also has consistently stated that a necessary prerequisite for profitable operations is efficient and economical management. Beyond this is a list of several factors the commissions are supposed to consider in making their decisions, but no weights have been assigned.
>
> The relevant economic criteria enunciated by the Court are three: financial integrity, capital attraction and comparable earnings. Stated another way, the rate of return allowed a public utility should be high enough: (1) to maintain the financial integrity of the enterprise; (2) to enable the utility to attract the new capital it needs to serve the public; and (3) to provide a return on common equity that is commensurate with returns on investments in other enterprises of corresponding risk. These three economic criteria are interrelated and have been used widely for many years by regulatory commissions throughout the country in determining the rate of return allowed public utilities.
>
> In reality, the concept of a fair rate of return represents a "zone of reasonableness." As explained by the Pennsylvania commission:
>
> > There is a range of reasonableness within which earnings may properly fluctuate and still be deemed just and reasonable and not excessive or extortionate. It is bounded at one level by investor interest against confiscation and the need for averting any threat to the security for the capital embarked upon the enterprise. At the other level it is bounded by consumer interest against excessive and unreasonable charges for service.
> >
> > As long as the allowed return falls within this zone, therefore, it is just and reasonable. . . . It is the task of the commissions to translate these generalizations into quantitative terms.
>
> Charles F. Phillips, Jr., The Regulation of Public Utilities, 3d ed. 1993, pp. 382 (notes omitted).

Order Granting General Rate Increase, *Application of Carolina Power & Light Co., d/b/a Progress Energy Carolinas, Inc., for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-2, Sub 1023, at 35-36 (N.C.U.C May 30, 2013), *aff'd, State ex rel. Utils. Comm'n v. Cooper,* 367 N.C. 444, 761 S.E.2d 640 (2014) (2013 DEP Rate Case Order).

Moreover, in setting rates the Commission must not only adhere to both the United States and North Carolina Constitutions, but as held by the North Carolina Supreme Court, it must set rates as low as possible consistent with constitutional law. *Public Staff*, 323 N.C. at 490, 374 S.E.2d at 370. Further, the North Carolina General Assembly has provided that the Commission must also set rates employing a multi-element formula set forth in N.C.G.S. § 62-133. The formula requires consideration of elements beyond just the rate of return on common equity element, and it inherently necessitates that the Commission make many subjective determinations, in addition to the subjectivity required to determine the rate of return on common equity. The subjective decisions the Commission must make as to each of the elements of the formula can and often do have multiple and varied impacts on all of the other elements of the formula. In other words, the formula elements are intertwined and often interdependent in their impact to the setting of just and reasonable rates.

The fixing of a rate of return on the cost of property used and useful to the provision of service (as determined through the end of the historic 12-month test period prior to the proposed effective date of a requested change in rates and adjusted for proven changes occurring up to the close of the expert witness hearing or projected in accordance with the provisions of N.C.G.S. § 62-133.16(c)(1)(a) is one of several interdependent elements of the statutory formula to be used in setting just and reasonable rates. N.C.G.S. § 62-133(b)(4) provides, in pertinent part, that the Commission shall:

> [f]ix such rate of return on the cost of the property . . . as will enable the public utility by sound management [1] to produce a fair return for its shareholders, considering changing economic conditions and other factors . . . [2] to maintain its facilities and services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and [3] to compete in the market for capital funds on terms that are reasonable and that are fair to its customers and to its existing investors.

N.C.G.S. § 62-133(b)(4) (emphasis added).

The North Carolina Supreme Court has interpreted the above-emphasized language as requiring the Commission to make findings regarding the impact of changing economic conditions on customers when determining the proper rate of return on common equity for a public utility. *State ex rel. Utils. Comm'n v. Cooper (Cooper I)*, 366 N.C. 484, 495, 739 S.E.2d 541, 548 (2013). The Commission must exercise its subjective judgment so as to balance two competing rate of return on common equity-related factors — the economic conditions facing DEC's customers and DEC's need to attract equity financing on reasonable terms in order to continue providing safe and reliable service. 2013 DEP Rate Case Order at 35–36. The Commission's determination in setting rates pursuant to N.C.G.S. § 62-133, which includes the fixing of the rate of return on common equity, always takes into account affordability of public utility service to the using and consuming public. The impact of changing economic conditions on customers is embedded in the analyses conducted by the expert witnesses on rate of return on common equity, as the various economic models widely used and accepted in utility regulatory rate-setting proceedings take into account such economic conditions. 2013 DEP Rate Case Order at 38. Further,

> [t]he Commission always places primary emphasis on consumers' ability to pay where economic conditions are difficult. By the same token, it places the same emphasis on consumers' ability to pay when economic conditions are favorable as when the unemployment rate is low. Always there are customers facing difficulty in paying utility bills. The Commission does not grant higher rates of return on common equity when the general body of ratepayers is in a better position to pay than at other times . . . .

Id. at 37.

Economic conditions existing during the modified test year, at the time of the public hearings, and at the date of the issuance of the Commission's order setting rates will affect not only the ability of the utility's customers to pay rates but also the ability of the utility to earn the authorized rate of return during the period the new rates will be in effect. However, in setting the rate of return on common equity, just as the Commission must assess the impact of economic conditions on customers' ability to pay for service, it likewise must assess the effect of regulatory lag on DEC's ability to access capital on reasonable terms. The Commission sets the rate of return on common equity considering both of these impacts taken together in its ultimate decision fixing a utility's rates.

Thus, in summary and in accordance with the applicable law, the Commission's duty under N.C.G.S. § 62-133, as well as N.C.G.S. § 62-133.16, is to set rates as low as reasonably possible to the benefit of the customers without impairing DEC's ability to attract the capital needed, at reasonable rates, in order to provide safe and reliable electric service and recover its cost of providing service.

Discussion and Conclusions

Two basic issues relating to rate of return on common equity are presented in this case. First, the Commission must, based upon the evidence presented, select the appropriate rate of return on common equity for DEC. Second, the Commission must determine whether a downward adjustment to that rate of return on common equity is appropriate in light of North Carolina's adoption of PBR, in particular, the potential for an MYRP, and the Commission's approval of DEC's PBR Application, as modified by this Order. For the reasons set forth herein, the Commission determines that: (1) the appropriate rate of return on common equity to be awarded to DEC in this case is 10.1%; and (2) downward adjustment to otherwise applicable rate of return on common equity is not warranted in view of (a) the widespread acceptance of alternative regulation throughout the United States; indeed DEC witness Bateman indicated that alternative regulation was the "norm", *see* tr. vol. 16, 252, 254, 340, and (b) a comparison of North Carolina's alternative regulation program as promulgated by the PBR Statute and other states' alternative regulation. The Commission is persuaded that that comparison shows that North Carolina's alternative regulatory program is, from the utility's standpoint, no less risky than other jurisdictions. The Commission notes also that it rejected downward adjustment only a few months ago in the DEP Rate Case, as well as in two water utility cases.[17] Intervenors in this case who advocate for downward adjustment have presented no arguments or evidence that persuades the Commission that these precedents should not be followed; to the contrary, the Commission reaffirms those precedents and chooses to follow them.

Setting the Rate of Return on Common Equity

Introduction

As is the norm, the expert witnesses for DEC, the Public Staff, and other intervenors differ widely in their conclusions with regard to their rate of return on equity recommendations.[18] As is also typical of rate of return on equity testimony, the various expert witnesses rely on many of the same models to inform their cost of equity estimates. However, the results of these models vary due to differences of opinion on the appropriate inputs and implementation. As more fully set forth below, the Commission has weighed and considered the resulting outputs in order to narrow the range of reasonable outcomes. Further, as in Docket No. E-2, Sub 1300, the Commission has followed its long-standing practice to consider and place weight on multiple models in order to protect against any one model's skewing the outcome in times when it may be less indicative of the true cost of capital.

The models estimating DEC's required rate of return on equity fall into three main categories, DCF, CAPM, and RPM. DEC witness Morin, Public Staff witness Walters, and

[17] *See* Order Approving Partial Settlement Agreement and Stipulation, Deciding Contested Issues, Approving Water and Sewer Investment Plan, Granting Partial Rate Increases, and Requiring Customer Notice, *Application by Aqua North Carolina, Inc. for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All Its Service Areas in North Carolina and for Approval of a Water and Sewer Investment Plan*, No. W-218, Sub 573, at 62 (N.C.U.C. June 5, 2023) (2022 Aqua Rate Case Order); Order Approving Partial Settlement Agreement and Stipulation, Deciding Contested Issues, Granting Partial Rate Increase, Approving Water and Sewer Investment Plan, and Requiring Customer Notice, *Application by Carolina Water Service, Inc. of North Carolina for Authority to Adjust and Increase Rates and Charges for Water and Sewer Utility Service in All Service Areas of North Carolina and Approval of a Three-Year Water and Sewer Investment Plan*, No. W-354, Sub 400, at 43-44 (N.C.U.C. April 26, 2023) (2022 CWS Rate Case Order).

[18] The Commission places little weight on the rate of return on equity testimony of Commercial Group witness Chriss and CIGFUR witness Collins as neither actually performed any rate of return on equity analysis, beyond looking to average authorized rate of return on equity awards by utility commissions, including this Commission. While looking to such industry average data can be beneficial, it does not substitute for the rigorous analysis the law and the Commission demand in setting the allowed rate of return on equity.

CUCA witness LaConte employ versions of all three, while NCJC et al. witness Ellis bases his recommendation on the DCF and CAPM models.

In this case, the Commission considered the application of these models in the context of the witnesses' testimony and other evidence, in order to ensure that its rate of return on equity conclusion of 10.1% is adequately supported by the evidentiary record. However, the Commission first will discuss — and reject — the recommendations of witness Ellis. In sum, both his individual model results and his overall recommendation of a rate of return on equity of 6.15% show that witness Ellis' cost of equity estimate is an outlier, entitled to no weight, and should be rejected. Aside from being more than 300 basis points below any rate of return on equity ever approved by this Commission for DEC, a rate of return on equity at that level, is scarcely 150 basis points above DEC's embedded cost of debt, a premium that is clearly insufficient to compensate investors for the added risks associated with equity ownership relative to a debtholder's claim on the same enterprise. Worse, DEC witness Newlin testified that that the interest rate DEC could expect today in issuing a 30-year bond is 5.72%. Tr. vol. 16, 85. This is a mere 43 basis points below witness Ellis' rate of return on common equity recommendation of 6.15%. The Commission finds it inconceivable that an investor would make an equity investment in DEC to realize a 6.15% expected return when that same investor could obtain a much less risky return merely 43 basis points lower simply by purchasing bonds issued by DEC. The Commission does not believe that a 6.15% rate of return on common equity will allow DEC to attract equity capital on reasonable terms, which is the essence of the *Bluefield/Hope* test.

The Commission will now consider each cost of capital model in turn.[19]

Discounted Cash Flow Model

The Constant Growth DCF results of the expert witnesses (excluding any adjustment for flotation costs) are as follows:

DEC – Morin	Analysts Growth	9.75%
	Value Line Growth	9.61%
Public Staff – Walters	Average	9.96%
	Median	9.87%
CUCA – LaConte	Low	8.37%
	Mean	9.54%
	High	10.58%

Tr. vol. 14, 59; tr. vol. 15, 639; *see* Morin Rebuttal Ex. 3, Ex. 4 (Tr. Ex. vol. 8).

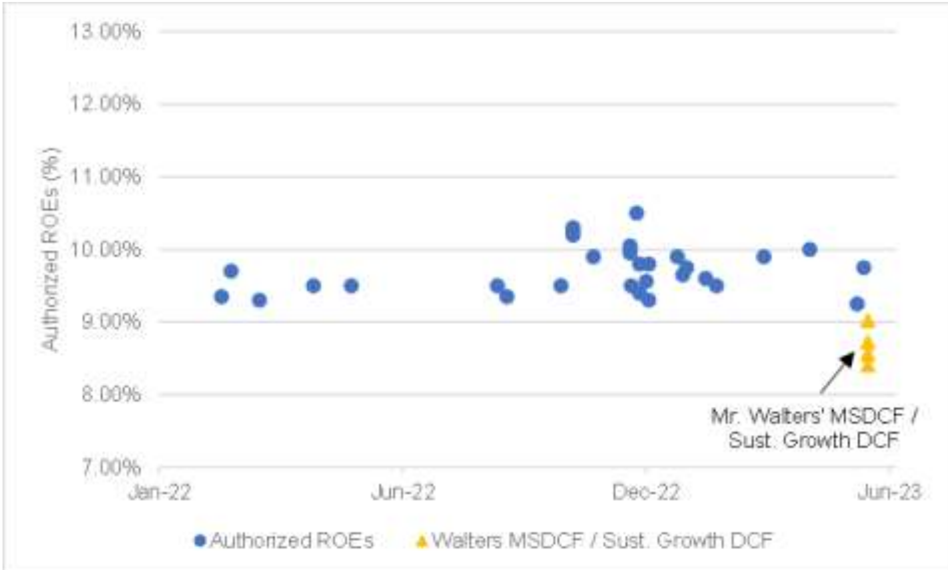
[19] The Commission notes that the following pages strip out witness Morin's proposed flotation cost adder in addressing his models.

Notably, witness Morin agreed with witness Walters' implementation of what he terms the conventional constant growth method. With regard to witness LaConte's DCF implementation, witness Morin offered a correction in terms of the appropriate dividend yield to use, namely that the current yield should be increased by a full year's growth. Tr. vol. 7, 339. The Commission accepts this correction. Adjusting for this error increases witness LaConte's DCF results by ten basis points. *Id.* at 341. The average of witness LaConte's DCF results then is 9.60%, and her result utilizing the average expected growth rate is 9.64%. As such, the Commission determines that the range of DCF results utilizing the constant growth method is approximately 9.6% to 9.9%. This range is based on evidence that is credible, probative, and entitled to substantial weight.

Witness Walters, however, utilized two additional growth measures. Tr. vol. 14, 61-69. First, he performed a DCF calculation using the constant growth methodology, but with "sustainable" growth rates, derived from Value Line, rather than analyst growth rates. Second, he performed a Multi-Stage DCF analysis. In this analysis, he used the same analyst growth rates that he used in his constant growth application for the first stage, but in his terminal stage (third stage) he used consensus projected GDP growth estimates. In the second stage he transitioned the first stage growth rates to the third stage GDP rate using a straight linear trend. The results he obtained from these alternative analyses are as follows: (1) Sustainable Growth: 9.02% to 8.72%; and (2) Multi-Stage DCF: 8.56% to 8.41%. The Commission declines to accept any of these results, for the following reasons.

First, the Commission notes that witness Walters employed the same two methodologies in the DEP Rate Case but did not in that case rely upon the model outputs. DEP Rate Case Order at 159. In this case, however, witness Walters evidently did rely on these model outputs, as his final DCF recommendation clearly includes these low results. Witness Walters made no explanation for this change of position in his pre-filed direct testimony, nor any adequate explanation in his live testimony. Indeed, his testimony seeking to explain the reversal focuses on the source of the increase in his constant growth DCF results, but the Commission finds that increased growth expectations of the magnitude cited by witness Walters are well within the realm of reasonableness. Tr. vol. 14, 131–33. The Commission takes this into account to discount the validity of the outputs witness Walters derived from these models.

Second, as witness Coyne points out, these results fail to pass *Bluefield/Hope* standards, in that they do not meet the test of comparable return, i.e., that the return must be comparable to those available to investors in firms with commensurate risk. Tr. vol. 16, 137. Figure 4 to witness Coyne's testimony displayed graphically that these model results are below all authorized rates of return on equity for vertically integrated electric utilities since 2022:



Tr. vol. 16, 139.

Witness Coyne testified that these model results should therefore be disregarded; the Commission agrees.

Third, the Commission agrees with both witnesses Morin and Coyne, who criticized witness Walters' application of the sustainable growth and Multi-Stage DCF models. Witness Morin indicates that witness Walters' application of the sustainable growth methodology contains a logical contradiction, in that the method requires an explicit assumption on the rate of return on equity expected from retained earnings that produce future growth. In this case, the assumed rate of return on common equity is 11.19%, which is far in excess of witness Walters' opinion that DEC's cost of equity capital is 9.55%. As witness Morin notes, "[t]hat simply cannot be." Tr. vol. 7, 312.

As for the Multi-Stage DCF model, witness Morin noted that witness Walters' application of the model in this case contained a logical flaw, which he indicated was the Achilles' heel of the methodology — witness Walters' failure to recognize that as growth expectations fall, stock prices fall, but dividend yields rise (i.e., that changes in the growth rate are inversely related to the dividend yield). *Id.* at 316. Since the model output results from the sum of dividend yield and growth, but the two are interrelated, adjusting one variable without commensurately adjusting the other will lead to an artificially low result.

Witness Morin also testified that witness Walters' application of the Multi-Stage DCF also suffered from other flaws. Noting that the DCF model requires as an input growth expectations of investors, he indicated that it was difficult to accept that investors would believe that every company would grow at the long-term GDP rate witness Walters used (4.3%), which witness Morin labeled as merely generic in nature and does not account for the different risks and prospects of the peer group companies or for the entire utility industry. *Id.* at 315. Witness Morin commented further that when witness Walters' estimate of inflation (2.0% – 2.3%) is taken into account, the generic 4.3% GDP growth rate becomes essentially zero in inflation-adjusted terms. Witness Morin concluded that he found it hard to believe that investors would assume the risk of buying utility stocks in that circumstance, and that they would be better off buying far less risky bonds. *Id.* at 315–16.

During his live testimony at the hearing, witness Coyne expanded upon these observations. Witness Coyne testified that witness Walters' substitution of the 4.3% GDP growth rate for his proxy group of companies, which is generally much lower than analyst growth rates between 6.0% and 7.0% were for these same companies, would result mathematically in lower model outputs. Tr. vol. 16, 189. But, he added, that "intuitively" it made no sense to use a long-term growth rate for a company like DEC capped at GDP estimates, because companies like DEC need to make considerable investments. Witness Coyne noted that the electric industry was at a turning point:

> [D]ecarbonizing your systems and building of a new and modern grid, substituting solar and wind for . . . fossil fuel resources are going to take considerable investments. Those investments will drive earnings growth much greater than GDP. I've looked at this issue many times, and every time I've looked at earnings growth for utilities in relationship to GDP, I find that, historically, their earnings and dividends growth routinely exceed GDP growth.
>
> . . .
>
> What you have to do to understand the earnings potential of a Company is to look at what's driving its rate base growth, what's going on the economy of the service area, how fast can you expect it to grow income and earnings.

Id. at 189–91. Witness Walters' "generic" GDP-based growth rate simply does not reflect the real world expected growth of a utility like DEC.

Accordingly, the Commission determines that neither the sustainable growth methodology nor the Multi-Stage DCF should be accorded any weight in this case, just as witness Walters himself accorded them no weight in the DEP Rate Case.

Capital Asset Pricing Model (CAPM)

Capital Asset Pricing Model – Standard Application[20]

The fundamental premise of the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities, which is a fundamental paradigm of finance. Tr. vol. 7, 224. Formulaically, the CAPM is expressed as the sum of (1) the risk-free rate and (2) a risk premium calculated as the product of (a) market risk (referred to as beta (β)) and (b) the market risk premium, which itself is the return on the market as a whole less the risk free rate:

$$K = RF + \beta \times (RM - RF)$$

where: K = investors' expected return on equity

RF = risk-free rate

RM = return on the market as a whole

β = beta, the systematic risk (i.e., change in a security's return relative to that of the market)

Id. at 224–25. Accordingly, solving for "K" (cost of capital) requires three input variables: the risk-free rate, beta, and the market risk premium (MRP, also called the equity risk premium (ERP)).

Risk-Free Rate

The risk-free rate for CAPM purposes is typically the expected yield on long-term US Treasury bonds, as the risk of default on those bonds is negligible and their long-term nature mirrors the investment horizon similar to that of common stock. *Id.* at 226; tr. vol. 14, 79. Each of witnesses Morin, Walters, and LaConte derived their risk-free rate in this manner. In addition, each of the witnesses utilized projected, as opposed to current, yields in connection with their selection of the risk-free rate, which the Commission agrees is an acceptable measure for purposes of this case, especially in light of DEC witness Morin's advocacy for a risk-free rate lower than prevailing market rates at the time of the hearing. Current rates on 30-year Treasury bonds as of the hearings in this case were higher than projected yields, *see, e.g.,* tr. vol. 8, 67; tr. vol. 16, 196, so were the Commission to employ current yields as the risk-free rate that would, all else being held

[20] The Commission also has considered the Empirical CAPM, as discussed below. The ECAPM, according to witness Morin, corrects for the fact that the CAPM under-predicts observed returns when beta is less than 1.0, which is typical for utility stocks.

constant, result in a cost of equity calculation higher than the those estimated by the rate of return experts.

In their final analyses, witness Morin used 3.9% as his risk-free rate in his rebuttal testimony; witness Walters used 3.7%; and witness LaConte used 4.3% (witness Morin's rate from his direct testimony). For purposes of its consideration of required rate of return on equity in this case, the Commission will accept all of these reflections of the risk-free rate.

Beta

Modern financial theory as expressed in the CAPM posits that investors can diversify away from all company-specific risks, leaving only market risk, also known as systemic risk. Tr. vol. 7, 230; tr. vol. 14, 78. Systemic risk is represented by the symbol "beta" (β); the beta coefficient measures the change in a security's return relative to that of the market, and, therefore, measures the degree to which a particular stock shares the risk of the market as a whole. Tr. vol. 7, 230. A beta of 1.0 signifies a security that has systemic risk equal to the market as a whole. A security with a beta of greater than 1.0 signifies that it is riskier than the market as a whole, while, conversely, a security with a beta of less than 1.0 is less risky than the market as a whole. As a general proposition, utility betas have typically been less than 1.0.

Securities analysts, such as Value Line or Bloomberg, calculate betas, and the use of these betas for utilities is a standard means of estimating cost of equity in utility rate cases. Each of witnesses Morin, Walters, and LaConte utilized current Value Line betas for their proxy group companies and averaged the resulting values, as follows: Morin (rebuttal testimony): 0.91; Walters: 0.88 (average) and 0.89 (median); and LaConte: 0.85.

Witness Coyne notes that "current Value Line beta . . . [is] a well-regarded source investors rely on", Tr. vol. 16, 202, and witness Morin testified:

> Value Line betas are widely used and well known to investors. Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors. Value Line is a widely followed, reputable source of financial data that is frequently used by professional regulatory economists in regulatory proceedings dealing with the cost of capital.

Tr. vol. 7, 362. The Commission agrees. Accordingly, for purposes of its consideration of rate of return on common equity in this case, the Commission will accept these betas as noted above, ranging from 0.85 to 0.91.

However, as Witness Walters did in the DEP Rate Case, he employed two additional calculations of beta: (1) a historical calculation using Value Line betas since 2014, and (2) a beta calculation using S&P's Market Intelligence Beta Generator

(MI). The Commission rejected these beta measures in the DEP rate case and does so again here. *See* DEP Rate Case Order at 161.

Witness Coyne testified that he had never seen a rate of return expert utilize historical betas going back ten years. Tr. vol. 16, 202. Witness Coyne noted that while cost of capital is forward looking, rate of return on common equity analysis sometimes requires historical data to provide the basis for forward looking estimates, and beta calculation is one such instance. However, he indicated, for beta calculation “the standard compromise is to look to five years of history, and that’s how Value Line approaches it.” *Id.* Witness Coyne continued that to go back ten years, to 2014, means that:

> [Y]ou’re basically suggesting that the industry risk profile in 2014 is representative of what the industry risk profile is today from an investor standpoint.
>
> And I can’t think of an investor that thinks that way because so much has changed that’s fundamental to the utility industry in terms of decarbonization and need to modernize the grid, fundamental changes in how consumers consume electricity and gas for that matter. All these issues are pointed out in analyst reports and credit rating reports that suggest that 10 years is pretty old when it comes to looking at the electric industry.

Id. at 203. And, as witness Morin noted, “[t]he whole point of this proceeding is to estimate investors’ current and expected returns. There is certainly nothing current and expected in witness Walters’ stale historical betas going almost ten years all the way back to 2014.” Tr. vol. 7, 319. The Commission agrees that using stale betas is the incorrect approach, and, accordingly, will disregard witness Walters’ results based upon the stale betas.

The MI Beta Generator uses Vasicek adjusted betas. Witness Coyne noted that the Vasicek adjustment is used in academic circles but is not used in his experience in regulatory proceedings, and he knows of no regulator that has adopted this approach. Tr. vol. 16, 203–04. Certainly witness Walters did not cite any such use, and the Commission notes that the Florida Public Service Commission (PSC) has expressly rejected it. Order Granting in Part and Denying in Part Florida City Gas’ Petition for Certain Rate Increases, *Petition for Approval of Rate Increase and Request for Approval of Depreciation Rates by Florida City Gas*, *supra*, No. 20220069-GU, at 43 (Fla. P.S.C. June 9, 2023). The Florida PSC found that the method was subject to bias, which was also witness Coyne’s critique. Tr. vol. 16, 204. The Commission agrees and accepts the rationale provided by witnesses Coyne and Morin for rejecting the Vasicek adjusted betas from Market Intelligence.

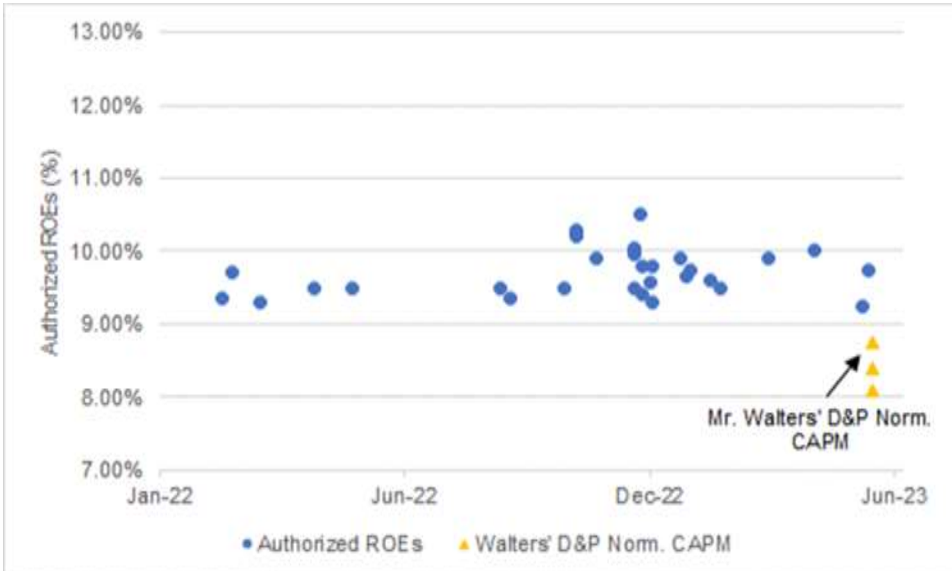
Market Risk Premium

Witness Morin utilized the same MRP in his updated rebuttal analysis as he had in his direct testimony, indicating that it had remained unchanged at 7.3%. Tr. vol. 7, 371. His MRP calculation was the average between two approaches he described in his direct testimony: an historical approach and a prospective approach. First, he used the Kroll 2022 SBBI Yearbook, a well-known and highly regarded source, to show that that the overperformance of a broad market sample of stocks over the income component of long-term government bonds was 7.4%. *Id.* at 231–32. Second, he examined Value Line's dividend yield and growth forecasts for the stocks in the S&P 500 stock index (i.e., for the broad US economy) and calculated based upon the risk-free rate an implied market risk premium of stocks over bonds of 7.2%. *Id.* at 237–38.

Witness Walters used three measures of MRP, the first two of which were very similar to the methodologies employed by witness Morin. Witness Walters, using the Kroll 2023 SBBI Yearbook (which had not been available when witness Morin performed his direct MRP analysis) calculated the MRP on that basis to be 7.81%. Tr. vol. 14, 83. Witness Walters also utilized a variant of the prospective approach followed by witness Morin but combining the S&P 500 analysis with an analysis based upon a FERC-prescribed adjustment to come up with an MRP estimate of 7.6%. Both witness Morin, Tr. vol. 7, 322, and witness Coyne, Tr. vol. 16, 198–99, agree with this approach, and witness Coyne characterized it and the historical approach as "more mainstream." *Id.* at 200.

The third Walters MRP approach, which he called the "normalized" Kroll analysis, resulted in an MRP of 5.5%. Tr. vol. 14, 88. Witness Walters indicated that Kroll developed this MRP estimate by employing its own inputs, *id.*, but witness Morin criticized it on this basis: "[T]he Kroll forecast lacks transparency and is only as good as its input assumptions and input data which are not only invisible but also quite unpredictable." Tr. vol. 7, 323. In addition, as witness Coyne points out, the opaque Kroll methodology is at odds with other available empirical evidence. Witness Walters demonstrated that there was no relationship between the Kroll recommended equity risk premium and the risk-free rate, whereas academic studies have shown that the two are inversely related. Tr. vol. 16, 148–49.

In addition, witness Coyne demonstrated graphically in Figure 7 to his rebuttal testimony that the Kroll normalized approach produces results that are far below all rate of return on common equity for vertically integrated electric utilities since 2022, and in two cases below any rate of return on common equity authorized in at least 40 years:



Id. at 149–50. As such, like witness Walters' use of the Multi-Stage DCF model, his use of Kroll's 5.5% MRP fails the test of *Bluefield/Hope*, in that it does not meet the test of comparable return, i.e., that the return must be comparable to those available to investors in firms with commensurate risk. *Id.* at 137. The Florida PSC also found witness Walters' use of the Kroll MRP to be "unreasonable" and rejected it. Order Granting in Part and Denying in Part, *supra*, No. 20220069-GU, at 43 (Fla. P.S.C. June 9, 2023). This Commission agrees and gives witness Walters' employment of the Kroll normalized MRP no weight in this case.

Witness LaConte also used an MRP of 5.5%. While the other inputs witness LaConte used in her CAPM calculation are acceptable, this unreasonably low MRP results in CAPM output results (8.99% and 9.08%) that are also unreasonably low and do not meet the Bluefield/Hope comparability test. Witness LaConte did not provide an alternative MRP calculation, and, for the above stated reasons, the Commission rejects her CAPM estimate. In his rebuttal testimony, witness Morin recalculates witness LaConte's CAPM using an MRP of 6.5%, which corrects for an error in witness LaConte's testimony in which she cited his 7.4% historical MRP, but used a different figure in her calculations. Tr. vol. 7, 424. The result of this calculation is 9.825% excluding flotation cost adjustments. The Commission gives substantial weight to this corrected estimate.

CAPM Conclusion

The rate of return on common equity witnesses' CAPM results acceptable to the Commission are as follows:

- Morin (without flotation costs): 10.6%, based upon a 3.9% risk free rate, current Value Line betas, and an MRP of 7.3% being the average of his two MRP calculations;

- Walters Method 1: 10.6%, based upon a 3.7% risk free rate, current Value Line betas, and an MRP of 7.81% based on his risk premium method;

- Walters Method 2: 10.42%, based upon a 3.7% risk free rate, current Value Line betas, and an MRP of 7.6% based upon his FERC DCF method; and

- LaConte (Corrected): 9.825%, based upon a 4.3% risk free rate, current Value Line betas, and an MRP of 6.5% based upon the corrected average MRP.

Giving equal weight to the CAPM calculations supported by the intervening witnesses' acceptable inputs (10.51% for Walters, 9.825% for Laconte), the CAPM-based range is thus 10.16%-10.6% which the Commission concludes is a reasonable outcome for the standard CAPM model.

Empirical CAPM

In this case, DEC witness Morin supported inclusion of an ECAPM result. The ECAPM, according to witness Morin, corrects for the fact that the CAPM under-predicts observed returns when beta is less than 1.0. Public Staff witness Walters took issue with witness Morin's use of an adjusted beta as published by Value Line because the adjustments made in his ECAPM model are mathematically the same as adjusting beta. Tr. vol. 14, 108–09. In rebuttal, witness Morin testified that adjusted betas and ECAPM correct different problems, and that as a result, both are needed. Tr. vol. 8, 331–33. CUCA witness LaConte opposed the ECAPM, calling it unnecessary. Tr. vol. 16, 649–50. NCJC, et. al. witness Ellis opposed the ECAPM on the grounds that it is not used elsewhere in finance and is not supported by updated research. *Id.* at 797–99. Witness Morin contended the ECAPM is discussed in most finance textbooks and provided specific examples. Tr. vol. 7, 365–66.

The Commission agrees with witness Walters' contention that mathematically, the Blume adjusted betas provided by Value Line achieve the same end. However, it is persuaded by witness Morin's testimony that both adjustments are needed because they correct for different things.

Although the intervening witnesses did not calculate an ECAPM result, applying the ECAPM adjustment to the acceptable inputs used in the CAPM section above results in an average ECAPM based on the inputs of witnesses Walters and LaConte of approximately 10.4%. As witness Morin's ECAPM calculation, as adjusted for removal of flotation costs, is 10.7%, the Commission concludes an ECAPM-based estimate of the rate of return on equity of 10.4% to 10.7% is reasonable.

Risk Premium Model (RPM)

The RPM, like the CAPM, applies a premium over the risk-free rate demanded by investors to compensate them for investing in securities that are of higher risk.

DEC witness Morin utilized two variations of this approach. The first compares actual returns of the S&P Utility Index with contemporaneous Treasury yields and applies the risk-free rate. As with his other methods, he also applied a flotation cost adjustment. His second RPM represents the historical premium of allowed rate of return on common equity to the risk-free rate. This method does not employ a flotation cost adjustment. The indicated results from witness Morin's updated rebuttal analysis are 10.2% (without flotation costs) for his historical risk premium approach and 10.3% for the allowed rate of return on common equity risk premium approach.

Witnesses Walters and LaConte also employed the RPM, but their application of the model is flawed in that neither gave sufficient weight to the inverse relationship between the equity risk premium and bond yields. Correcting for this error, the DEC witnesses re-calculated their RPM results to be 10.08% to 10.39% for witness Walters, Tr. vol. 16, 157, 205, and 10.5% for witness LaConte. Tr. vol. 7, 344. The Commission is persuaded that the DEC witnesses have correctly identified this deficiency in the intervenor witnesses' application of the RPM, and so will utilize the results, as corrected, in its assessment.

Morin: Historical Risk Premium (without flotation costs)	10.2%
Morin: Allowed Risk Premium	10.3%
Walters: Projected 30-Year Treasury Yield, as corrected	10.08%
Walters: 13-Week Avg. Moody's A Utility Bond Index, as corrected	10.21%
Walters: 26-Week Avg. Moody's A Utility Bond Index, as corrected	10.21%
Walters: 13-Week Avg. Moody's Baa Utility Bond Index, as corrected	10.39%
Walters: 26-Week Avg. Moody's Baa Utility Bond Index, as corrected	10.38%
LaConte: Bond Yield + Risk Premium, as corrected	10.5%

Tr. vol. 7, 344, 372; tr. vol. 16, 157.

The average of witness Walters' corrected RPM results using Treasury yields, A-rated utility bonds, and Baa-rated utility bonds is approximately 10.22%. As such, the range of RPM-based rate of return on equity estimates is 10.2% to 10.5%. The Commission has in the past relied on the RPM to assess the cost of equity capital. It finds the range of 10.2% to 10.5% to be credible and appropriate in fixing the rate of return on common equity to be authorized in this case.

Indicated Range Prior to Adjustments

As discussed above, the Commission has determined:

- The appropriate range of DCF results is from 9.6% to 9.9%;
- The appropriate range of CAPM and ECAPM results is 10.16% to 10.70%; and
- The appropriate range of RPM results is from 10.2% to 10.5%.

In light of the foregoing, the Commission has identified a zone of reasonableness of 9.99% to 10.37%, reflecting the average of the ranges identified above. The approximate midpoint of this range is 10.18% — which is nearly identical to the rate of return on common equity recommendation of witness Morin, without regard to flotation costs. Within this range of reasonableness, the Commission in its discretion, determines that an allowed rate of return of common equity of 10.1% before considering flotation costs or adjustment for MYRP is supported by the evidence in the record.

In DEC witness Newlin's rebuttal testimony, he alluded to recently awarded rate of return on common equity for vertically integrated electric utilities in the southeast:

Table 2: Authorized ROE Comparison of Peer Utilites in the Southeast since 2020

Regulated Utility	State	Docket/Case No.	Year of Order	Current Authorized ROE
Virginia Electric and Power	NC	E-22, Sub 562	2020	9.75%
Dominion South Carolina	SC	2020-125-E	2021	9.50%
Duke Energy Progress	NC	E-2, Sub 1219	2021	9.60%
Alabama Power Company	AL	reported by S&P, under RSE mechanism	2022	11.91%(1)
Georgia Power	GA	44280	2022	10.50%(2)
Florida Power & Light	FL	20210015 - ROE Trigger	2022	10.80%(3)
Duke Energy Florida	FL	20220143-EI	2022	10.10%(4)
Tampa Electric Co.	FL	20220122-EI	2022	10.20%(5)
Duke Energy Progress	SC	2022-254-E	2023	9.60%
Average				**10.22%**

Source: S&P Capital IQ, Past Rate Cases pulled on June 26, 2023.

(1) Alabama Power has a formula rate mechanism that allows for annual adjustments, and they have a variety of mechanisms to allow for the inclusion of new plant. Under this mechanism, they are allowed a relatively high ROE (S&P reported 11.91% in year 2022) that is balanced against limited annual rate adjustments with certain caps.

(2) Authorized retail ROE set under the 2022 Alternative Rate Plan approved by the Georgia Public Service Commission and evaluated against a range of 9.50% to 11.90%. Any retail earnings above 11.90% will be shared with Georgia Power retaining 20%, 40% applied to reduce regulatory assets, and 40% directly refunded to customers.

(3) ROE Trigger increased authroized ROE to a midpoint of 10.80% from 10.60%

(4) Originally approved ROE band was 8.85% to 10.85%. The ROE band will increase by 25 basis points beginning in 2023 as a result of the average 30-year U.S. Treasury rate increasing by more than 50 basis over a six-month period.

(5) Originally approved ROE band was 9.00% to 11.00%. The ROE band will increase by 25 basis points beginning in 2023 as a result of the average 30-year U.S. Treasury rate increasing by more than 50 basis over a six-month period.

Tr. vol. 16, 42. The Commission notes that all of the 2022 rate of return on common equity authorizations listed are in excess of 10.0%. Witness Coyne was involved in the rate cases that led to the Florida Power & Light's (FPL) 10.8%, and Georgia Power Company's

(GPC) 10.5% authorized rates of return on common equity.[21] Witness Coyne indicated during his live testimony in this case that FPL and GPC are utilities that look very much like DEC in terms of their risk profiles, their storm exposure, their generation mix, and the decarbonization pressures they face. Tr. vol. 16, 179–80. Witness Coyne noted further that the average authorized rate of return on common equity for the utilities on Table 2 is 10.2%, which is squarely within the reasonable range of cost of equity capital for DEC indicated by the Commission's analysis.

The Commission is well aware that DEC is in competition for equity capital with other utilities such as FPL and GPC. Utilities must obtain capital from investors, and they seek capital from investors in competitive markets. As DEC witness and Treasurer Karl Newlin testified:

> The Company competes for capital in the open market, and must appeal to debt and Duke Energy's equity investors to attract the capital it needs. As Dr. Roger Morin, a leading expert on utility finance, indicates, "[t]he … prices of debt capital and equity capital are set by supply and demand, and both are influenced by the relationship between the risk and return expected for those securities and the risks expected from the overall menu of available securities." Morin, Roger A., Modern Regulatory Finance (PUR Books LLC 2021), at 27. Investors have a variety of investment opportunities available to them, and require a return commensurate with the risk they incur. They will invest elsewhere if they feel the expected return provided by a company is inadequate, and lower credit quality weakens a company's attractiveness as an investment opportunity relative to companies with higher credit quality and similar return profiles.

Tr. vol. 9, 59–60. In his live testimony, witness Morin explained the concept, saying, "[u]tilities are in perfect competition for investor savings." Tr. vol. 7, 457–58. The Commission takes this into account when establishing DEC's authorized rate of return on common equity, and will next examine the proposed adjustments offered by the witnesses.

Flotation Cost Adjustment

Flotation costs are the expenses of issuing equity, such as printing fees, underwriter fees, attorney fees, and other similar fees. *Id.* at 249. DEC, itself, does not issue equity; instead, equity issuances are made by its publicly traded parent, Duke Energy.

Duke Energy issued no equity during the test year. Duke Energy forecasts there will be no common equity issued from 2023 through 2027. *Id.* at 465. DEC witness Morin

[21] Witness Coyne also testified, that these rate of return on common equity authorizations were accompanied by equity ratios of 59.6% (FPL) and 56.0% (GPC), far higher than the 53.0% equity ratio sought by DEC. Tr. vol. 16, 180.

testified that he was aware that Duke Energy had publicly stated that it did not intend to issue new equity before 2027. *Id.* at 395. Based on similar evidence, the Commission declined to allow recovery of flotation costs in the DEP rate case. The Commission similarly declines to allow recovery of flotation costs in this case.

The recovery of flotation costs is not allowed under North Carolina law where there is no evidentiary support. 2022 Aqua Rate Case Order at 61-62. The North Carolina Supreme Court in *State ex rel. Utilities Commission v. Public Staff*, 322 N.C. 689, 370 S.E.2d 567 (1988), reversed and remanded the rate of return on common equity portion of the Commission's Order dated October 31, 1986, Docket No. E-7, Sub 408 for Duke Power Company. The Supreme Court directed the Commission on remand to reconsider the proper rate of return on Duke Power's common equity and also support its conclusion on flotation costs with specific findings. There was no evidence in that case that Duke Power intended to issue new stock for the next three or four years. On remand, the Commission issued its second E-7, Sub 408 Order, reassessed the evidence, and issued new findings of fact and conclusions. The Commission concluded that 13.2% was a fair rate of return on Duke Power's equity and there was a 0.1% increment in the approved 13.2% rate of return on common equity to cover future stock issuance costs. On the second appeal, the Supreme Court held that the Commission's inclusion of the "stock" issuance increment is not supported by substantial evidence in view of the whole record. *State ex rel. Utils. Comm'n. v. Public Staff*, 331 N.C. 215, 218 (1992). The Supreme Court concluded the Commission's inclusion of a 0.1% rate of return on common equity increment for purported future financing costs in the approved rate of return on common equity was not based upon substantial evidence in view of the whole record. The Supreme Court stated:

> As we noted on the first appeal, an 0.1% upward increment in Duke's rate of return on common equity costs ratepayers $ 4.2 million annually in additional rates. Historically, Duke's average costs per issuance of stack was $ 3.2 million. In light of the whole record on this issue, particularly in the absence of any evidence that Duke intended to issue stock in the immediate future, there is simply no substantial evidentiary support for the Commission's addition of a 0.1% increment to Duke's rate of return on common equity to cover future stock issuance costs.

Id. at 221-22.

The Supreme Court further stated and ruled:

> On the first appeal of this case, we questioned whether the record supported any adjustment whatever in the rate of return for purported future stock issuance, or financing costs. We said:
>
> > Since no evidence was introduced that Duke intends to issue new stock for the next three or four years, and because there was no evidence regarding the probable cost of a prospective issuance, we

> question whether the record supports any financing cost adjustment. *State ex. rel. Utilities Commission v. Public Staff*, 322 N.C. at 700, 370 S.E.2d at 574 (emphasis added). We are not satisfied, for the reasons alluded to in our first opinion, that the record supports no such adjustment in the common equity rate of return.

Id. at 221 (emphasis added).

As in that case, there was and is no plan to issue equity in the present case. Accordingly, there is no evidence to support DEC's request to increase its rate of return on common equity by 20 basis points for flotation costs. The end result is that the Commission finds and concludes that rate of return on common equity of 10.1% without upward adjustment for flotation costs is appropriate.

Downward Adjustment Due to MYRP

N.C.G.S. § 62-133.16(c)(1)(a) requires the Commission to consider any increased or decreased risk to either the electric public utility or its ratepayers that may result from having an approved MYRP.

Public Staff witness Walters and CUCA witness LaConte both made specific mathematical downward adjustments of 20 basis points in their rate of return on equity recommendations to account for what they perceive as the less risky environment DEC now operates in as a result of the passage of the PBR Statute. Witness Walters' downward adjustment reduced his recommended return on equity 9.55% to 9.35%. Tr. vol. 14, 92–93. Witness LaConte's downward adjustment reduced her recommended return on equity from 9.4% to 9.2%. Tr. vol. 15, 630. Inasmuch as the Public Staff's recommendation is more fully explained in witness Walters' testimony, the Commission will address it, but the same factors described in this discussion apply with equal force to the recommendations of witness LaConte.

The actual quantification of the recommended downward adjustment was not performed by Public Staff witness Walters at all. Instead, he simply adopted the Public Staff's methodology applied in the recent water utility cases, the 2022 Aqua Rate Case Order and the 2022 CWS Rate Case Order. In footnote 38 of his direct testimony, witness Walters linked to the Public Staff testimony filed in those two water utility cases to support quantification, noting that the "Public Staff has previously argued that approval of multiyear mechanisms that reduce the risk borne by water and wastewater utilities should result in a 20-basis point reduction in the allowed ROE." *Id.* at 92. The Commission did not accept the Public Staff position in either of the proceedings cited by witness Walters, and this downward adjustment is contrary to Commission's reasoning in the Orders in the 2023 Aqua Rate Case Order and the 2023 CWS Rate Case Order. Further, there is substantial evidence introduced in this case supporting DEC's position that no downward adjustment is warranted. Accordingly, as it did based on virtually identical evidence in the DEP Rate Case, the Commission rejects the downward adjustment theory.

In the Commission's 2022 CWS Rate Case Order, the Commission addressed and rejected the Public Staff's requested 20 basis point downward adjustment in otherwise applicable rate of return on common equity:

> [T]he Commission is persuaded that this type of mechanism is prevalent across the country and within the proxy group. Although a WSIP is intended to reduce regulatory lag, the existence of similar mechanisms across the country and in the states where the proxy group utilities operate indicates that the comparative risk reduction associated with a WSIP[][22] for CWSNC, in this case, is zero.

2023 CWS Rate Case Order at 43.[23]

The Commission's conclusion is in line with witness Morin's academic work on this subject, which is summarized in his most recent book, Modern Regulatory Finance, published in late 2021. Tr. vol. 7, 297–98. Witness Morin summarized the reasons why he asserts the presence of risk-mitigating mechanisms should not result in a reduction in the cost of equity in his rebuttal testimony.

Witness Morin asserts that the rate of return on equity in a rate case is being set based upon a proxy group of comparable companies, and the use of a proxy group takes into account similar risk mitigating mechanisms that are pervasive in the industry, so "the addition of any discreet (sic) adjustment would be unwarranted double counting of the effect of these mechanisms." *Id.* at 297. In sum he states that the "current market data reflects or embeds the presence of risk mitigators." *Id.* Second, he states that empirical studies in peer-reviewed academic journals have examined the impact of risk mitigators on the cost of equity, and the results show that there is no impact. *Id.* at 298. Third, risks that are diversifiable are not considered relevant in cost of capital estimates for investors, because by definition they can be eliminated through diversification, and risk mitigators are in fact diversifiable. *Id.*

Beyond witness Morin's academic approach, the Commission is persuaded that DEC has proven, by the greater weight of the evidence, that the impact of alternative ratemaking mechanisms like the PBR Statute is already incorporated into the analysis and a downward adjustment in otherwise applicable rate of return on common equity would indeed be inappropriate "double counting."

DEC's PBR Policy Panel Rebuttal Exhibits 1 and 2 illustrate the prevalence of alternative ratemaking mechanisms. DEC's PBR Policy Panel Rebuttal Exhibit 1 is a map demonstrating that alternative ratemaking mechanisms are widespread throughout the United States. Tr. vol. 16, 251; PBR Policy Panel Rebuttal Ex. 1 (Tr. Ex. vol. 16). In fact,

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[22] A "WSIP" (Water and Sewer Investment Plan) is the water utility analog to an MYRP for electric utilities.

[23] The Commission reiterated this holding, in identical language, in its 2023 Aqua Rate Case Order at 62.

of the 51 jurisdictions depicted (50 states plus the District of Columbia), only five have no alternative ratemaking mechanism in place. By contrast, 36 (over 70.0%), have two or more such mechanisms, including North Carolina, which has two (MYRP and decoupling). The other 11 states have a single mechanism, either a future test year or specific capital trackers. The exhibit validates DEC witness Bateman's observation that in the United States:

> [A]lternative ratemaking regulation is the norm and, therefore, contrary to Public Staff and the intervening witnesses' assertions, implementation of a MYRP does not warrant a reduction to the Company's ROE since this change simply makes North Carolina's ratemaking practices more aligned with the rest of the country. Notably, every single company in Public Staff Witness Walters's proxy group (which is the same as DEC Witness Morin's) operates either entirely or partially in states that have adopted alternative regulation.

Tr. vol. 16, 252–53.

PBR Policy Panel Rebuttal Exhibit 2 shows the 23 electric utility holding companies in witness Morin's peer group used in connection with his rate of return on common equity recommendation and the alternative ratemaking mechanisms in the applicable jurisdiction. *Id.* at 251. This exhibit illustrates witness Bateman's assertion that "every single company in Public Staff witness Walters' proxy group (which is the same as DEC witness Morin's) operates either entirely or partially in states that have adopted alternative regulation." *Id.*

DEC witness Bateman compared the alternative ratemaking mechanisms available in North Carolina under the PBR Statute with similar mechanisms available in other jurisdictions. Witness Bateman stated that "the focus should not be on whether DEC has a MYRP, but rather, how the North Carolina PBR framework compares to alternative regulation in other states in terms of risk to the utility." *Id.* at 253. Witness Bateman asserted that "North Carolina's framework places more risk with the utility than the frameworks in some other states." *Id.* Witness Bateman provided numerous examples of how North Carolina's framework places risk on the utility. As an example, she compared states with formula rates and riders for significant capital investments that allow for true-ups of costs increases to North Carolina's PBR mechanism under which she contends electric utilities bear "all the risk of and financial impact associated with cost increases on projects in between rate cases." *Id.* Witness Bateman also stated that unlike the PBR Statute many other states' MYRP mechanisms provide for fully forecasted growth of both capital and associated O&M expense. *Id.* Finally, she noted that ESM in North Carolina's PBR Statute is asymmetrical in that it assures that customers receive 100.0% of earnings once the utility's earnings exceed its allowed rate of return on common equity by 50 basis points, but the utility does not receive an earnings boost if it underearns. *Id.* at 254; *see also* PBR Policy Panel Rebuttal Ex. 1 (Tr. Ex. vol. 16). Witness Bateman concluded her review with the observation that a downward adjustment to the rate of return on common equity goes against Commission precedent. Tr. vol. 16, 254.

DEC witness Coyne emphasized the importance of a comparative basis for the cost of equity, stating that the Company's risk should be evaluated relative to its peers, and noting that rate structures are only one factor among many that equity investors consider. *Id.* at 157. As demonstrated in his Rebuttal Exhibit 3, a majority of witness Walters' proxy group companies utilize various rate structures and mechanisms to mitigate regulatory lag, making DEC's regulatory structures no different from an investment perspective. *Id.*

The Commission concludes that substantial evidence supports the reasonableness of a rate of return on equity of 10.1% without a downward adjustment due to the MYRP. The Commission is persuaded by the evidence that similar types of mechanisms are prevalent across the industry as well as within the proxy group. The Commission is also persuaded that elements of the North Carolina statute are distinguishable as compared to other jurisdictions, as pointed out by witness Bateman, in terms of allocation of risk between utility and customers. The Commission is mindful that one of the objectives of the MYRP is to reduce the lag in recovery experienced by the utilities, which, in theory, benefits the utility. However, the Commission concludes that given the utility has entered a capital-intensive period of time as it manages the transition of its system, it is critical that the utility be in a position to access capital on reasonable terms and the Commission concludes that the availability of the MYRP makes DEC competitive in terms of its ability to access capital on reasonable terms.

The end result is that the Commission finds and concludes that an rate of return on common equity of 10.1% without downward adjustment is appropriate.

Cooper I *Factors and Ultimate Conclusion Regarding Cost of Equity Capital*

Regarding the obligation in accord with the holding in *Cooper I* to inform its determination of a rate of return on equity within that range, the Commission must address the impact of changing economic conditions on customers.

In this case, all parties had the opportunity to present the Commission with evidence concerning changing economic conditions as they affect customers. The testimony of DEC witness Morin and Public Staff witness Walters addresses changing economic conditions at some length. Witness Morin provided detailed data concerning changing economic conditions in North Carolina, as well as nationally, and concluded that the North Carolina-specific conditions are “highly correlated” with conditions in the broader national economy. As such, witness Morin testified that changing economic conditions, both nationally and specific to North Carolina, are reflected in his rate of return on common equity estimates.

Public Staff witness Walters generally agreed with DEC witness Morin that as of the time of the filing of his testimony, economic conditions had improved in North Carolina. As the Commission has noted, customer impact due to changing economic conditions is embedded in rate of return on equity expert witness analyses. Witness Morin’s analysis, which the Commission credits and to which the Commission gives weight, also indicates that even though the North Carolina and U.S. economies have contracted, economic conditions in North Carolina continue to be highly correlated to conditions nationally, and, therefore, continue to be reflected in the analyses used to determine the rate of return on equity.

The Commission concludes that based upon the evidence presented in this case, the econometric data relied upon by rate of return on equity expert witnesses captures the effects and impacts of changing economic conditions upon customers and the Commission concludes that based on the evidence presented in this case, it does.

Based upon the general state of the economy and the need for the continuing affordability of electric utility service, and after weighing and balancing factors affected by the changing economic conditions in making the subjective decisions required, the Commission concludes that the rate of return on common equity of 10.1% will not cause undue hardship to customers even though some will struggle to pay the increased rates.

Indeed, affordability, especially for low-income customers, was a special focus of DEC and the intervening parties to this proceeding. As noted above, the Commission established the LIAC in its April 16, 2021 Order in the 2019 Rate Case and tasked the LIAC with addressing affordability issues for low-income residential customers. The efforts of the LIAC are apparent in this case and include the Affordability Stipulation as previously discussed in this Order. The provisions in the Affordability Stipulation, which includes the development of the CAP pilot, directly benefit customers with the least ability to pay in the current economic environment. In addition, as previously discussed in this Order, through the Payment Navigator program proposed in this proceeding, DEC will work closely with customers in need of assistance with managing bills and will connect those customers with sources of support and funding, based on the unique situation of the customer. While these programs will not ease the burden that electricity rates will place on certain of DEC's customers, the Commission expects these programs to provide a meaningful level of support to eligible customers. The Commission takes these facts into account in approving the 10.1% return on equity. However, the Commission also concludes, based on the evidence of record, that efforts to address energy burden and support for customers needing assistance with their bills are continuing to evolve. The LIAC allowed DEC and its stakeholders to generate data that illustrates the depth and breadth of the challenge in North Carolina. Work must continue to reach these customers and provide meaningful support both in terms of assisting customers to use energy more efficiently so that bills are reduced and in terms of providing support to those customers when they are in need of bill assistance. The Commission recognizes the difficulties attendant to solving for these issues but emphasizes that the utility must continue to work with community partners and the LIAC in this work. As has been previously expressed by this Commission, the electric utilities must pursue every opportunity presented by federal funding made available by the IRA and other federal legislation to support customers in need. The Commission has confidence that DEC, the Public Staff and stakeholders will identify such opportunities for customers and will develop programs that take advantage of every federal dollar that is available for customer support.

Considering the changing economic conditions and their effects on DEC's customers, the Commission recognizes the financial difficulty that an increase in DEC's rates may create for some of DEC's customers, especially low-income customers. The Commission is mindful that as shown by the evidence, relatively small changes in the rate of return on common equity have a substantial impact on a utility's base rates. Therefore, the Commission has carefully considered changing economic conditions and their effects on DEC's customers in reaching its decision regarding DEC's approved rate of return on common equity.

The Commission also recognizes that provisions in S.L. 2021-165 may intensify the risks facing DEC as it continues to navigate the challenges associated with the change in the mix of electric generating resources and with new load patterns, including ensuing the continued reliable operation of the electric system, and to work toward the requirements of N.C.G.S. § 62-110.9. As DEC witness K. Bowman asserted:

> [I]t is simply indisputable that the tasks currently before the Company — implementing the energy transition within the construct of the Carbon Plan while simultaneously evolving nearly every aspect of its business and pursuing a complex merger — are unprecedented, imposing new and unique execution risks on the Company across all phases and aspects of its business that are inarguably more far-reaching and complex than anything the Company has ever pursued in the past.

Tr. vol. 7, 87.

The need to invest significant sums to serve its customers requires DEC to maintain its creditworthiness in order to compete for large sums of capital on reasonable terms. In addition, as recent years have demonstrated, macroeconomic, geopolitical, extreme weather, public health, and other exogenous events beyond DEC's control may necessitate and indeed have necessitated the need for DEC to access and invest significant sums during atypical and volatile market conditions. The Commission takes note of DEC witness Newlin's testimony that particularly in light of DEC's present credit metrics, rate of return on equity is one predicate (capital structure being another predicate, discussed in detail below) to the level of creditworthiness necessary to efficiently access the capital markets on reasonable terms during all market cycles, including periods of high volatility, which access ultimately lowers borrowing costs passed through to customers during such time. Tr. vol. 9, 61; tr. vol. 16, 41. Witness Newlin testified that high credit quality will benefit customers. Witness Newlin explained that if the credit profile of DEC is weakened, customers might pay less in rates in the short-term, but DEC would face higher debt borrowing costs in the long-term that will be passed through to customers. Tr. vol. 16, 55–56. Witness Newlin testified that "it would be risky to do that [weaken DEC's credit profile] because I can see — you know, mathematically, you might get some near-term savings, but longer term, I believe it'd be greater cost to customers." *Id.* at 56.

The Commission must weigh the impact of changing economic conditions on DEC's customers against the benefits that those customers derive from DEC's ability to provide safe, adequate, and reliable electric service 24/7/365, regardless of macroeconomic, geopolitical, environmental, and public health events. Safe, adequate, and reliable electric service is essential to the well-being of the people, businesses, institutions, and economy of North Carolina. The Commission is mindful of the burden that electricity rates will place on many of DEC's customers and the contribution of the rate of return on common equity to those rates, but the Commission must balance the burden against DEC's being in a position to access capital: (1) on reasonable terms, and (2) in moments when DEC most needs capital in order to provide reliable service.

The Commission concludes in the exercise of its independent judgment and discretion that a 10.1% rate of return on common equity is supported by the evidence and should be adopted. The hereby approved rate of return on common equity appropriately balances the benefits received by DEC's customers from DEC's provision of safe, adequate, and reliable electric service in support of the well-being of the people, businesses, institutions, and economy of North Carolina (which benefits are symbiotically linked to DEC's ability to compete in the capital markets to access capital on reasonable terms that will be fair to ratepayers and that will ultimately benefit ratepayers) with the difficulties that some of DEC's customers will experience in paying DEC's adjusted rates. The Commission further concludes that a 10.1% rate of return on common equity will allow DEC to compete in the market for equity capital, providing a fair return on investment to its investor-owners. Accordingly, the Commission concludes, taking into account changing economic conditions and their impact on customers, that the approved rate of return on common equity will result in the lowest rates constitutionally permissible in this proceeding.

Capital Structure

Summary of Evidence

In DEC witness Newlin's direct testimony, he proposed using a capital structure of 53.0% members' equity and 47.0% long-term debt. Tr. vol. 9, 68. Witness Newlin testified that DEC's "specific debt/equity ratio will vary over time, depending on a variety of factors, including among other things, the timing and size of capital investments and payments of large invoices, debt issuances, seasonality of earnings, and dividend payments to the parent company." *Id.* at 69. As of December 31, 2021, DEC's capital structure was 53.1% common equity and 46.9% long-term debt. *Id.*

Witness Newlin discussed the current credit ratings and forecasted capital needs of DEC and emphasized the importance of DEC's continued ability to meet its financial objectives. *Id.* at 59. Witness Newlin noted that DEC faces substantial capital needs over the next several years so as to provide cost-effective, safe, reliable, and increasingly cleaner electric service to its customers well into the future, so DEC must therefore appeal to debt and Duke Energy's equity investors to attract the capital it needs. *Id.* at 72–73. Witness Newlin explained that investors — both debt and equity — have a variety of investment opportunities available to them and require a return commensurate with the risk they incur, warning that they will invest elsewhere if they feel the expected return provided by a company for a given amount of risk is inadequate. *Id.* at 59–60, 76. Witness Newlin further explained that lower credit quality weakens a company's attractiveness as an investment opportunity relative to companies with higher credit quality and similar return profiles. *Id.* As such, witness Newlin testified it is critically important that DEC maintain strong, investment-grade ratings to assure its financial strength and flexibility and ensure access to capital on reasonable terms. *Id.* at 60, 71.

Discussing DEC's financial objectives, witness Newlin addressed specific objectives that support financial strength and flexibility, including maintaining 53.0% common equity for DEC on a financial capitalization basis; ensuring timely recovery of prudently incurred costs; maintaining sufficient cash flows to meet obligations; and maintaining a sufficient return on equity to fairly compensate shareholders for their invested capital. *Id.* at 60. Witness Newlin further testified that the ability to attract capital (both debt and equity) on reasonable terms is vitally important to DEC and its customers, and each of these specific objectives helps DEC both to maintain its investment-grade credit ratings and to meet its overall financial objectives. *Id.* at 60–61.

Intervenor witnesses disputed witness Newlin's recommendation. Public Staff witness Walters testified that DEC's proposed 53/47 capital structure exceeded the equity ratio for all proxy group companies. Tr. vol. 14, 49. Witness Walters also noted that the 53/47 recommendation was inconsistent with DEC's observed capital structure at various points in time. *Id.* at 53. Witness Collins testified that the 53/47 proposal exceeded the average capital structure authorized by other utility commissions. Tr. vol. 15, 976–77. The witnesses' capital structure recommendations were as follows: Walters — 52/48, tr. vol. 14, 53; LaConte — 51.55/48.45, tr. vol. 15, 658.

NCJC, et al. witness Ellis took a different tack, recommending a capital structure of 58.8% equity and 41.2% debt. Tr. vol. 15, 693, 826. As noted above in connection with the Commission's discussion of rate of return on common equity evidence, witness Ellis testified that rate of return on common equity and capital structure are interrelated and must be addressed together. *Id.* at 816–22. Accordingly, his 58.8/41.2 capital structure recommendation goes hand-in-hand with his 6.15% rate of return on common equity recommendation. *Id.* at 829–30. Witness Ellis indicated that this combination would minimize customer costs while meeting investor return expectations. *Id.*

In DEC witness Newlin's rebuttal testimony, he took issue with the intervenor witness recommendations. Witness Newlin observed that witness Walters' reliance on capital ratios of proxy group companies was misplaced, because the proxy companies are all publicly traded holding companies, not utility operating companies. Tr. vol. 16, 21. Witness Newlin testified that it is inappropriate to compare DEC's capital structure to the holding company capital structures, because the risk profiles are very different. *Id.* at 22. The appropriate comparison is to other utility operating companies. *Id.* Witness Newlin noted that witness Coyne performed that comparison for witness Morin's proxy group, which was the same proxy group used by witness Walters, and presented the results in

Coyne Rebuttal Exhibit JMC-4. *Id.* at 23. The results show that the average capital structure for operating utilities is 52.94% equity to 47.06% debt — consistent with DEC's proposal. *Id.* Witness Newlin pointed to the Commission's previous rejection of the use of parent company structures as opposed to operating company structures in determining the operating utility's appropriate equity/debt ratio. *Id.* at 25–26.

Witness Newlin further testified that witness Walters' comparisons of DEC's proposed capital structure with DEC's actual capital structure at a specific point in time are inappropriate. *Id.* at 25. Witness Newlin explained that it is reasonable to expect DEC's capital structure to fluctuate above and below the target equity ratio, and that merely selecting a point in time is not representative of how DEC intends to capitalize its business in the long-term. *Id.* at 25–26. Moreover, the specific points in time utilized by witness Walters rely on a surveillance report which includes current maturities of long-term debt which are excluded for ratemaking purposes. *Id.*

Witness Newlin also evaluated the testimony of witness LaConte, arguing that her recommendation, which is based on the average authorized common equity ratios for the period 2020 through 2023, is overly simplistic and misleading. *Id.* at 28. Witness Newlin pointed out that witness LaConte's Exhibit BSL-12, used to substantiate her recommendation, fails to acknowledge the upward trend in authorized equity ratios over the same period. *Id.* at 28–29. Using the same proxy group of companies relied upon by witness LaConte, witness Newlin demonstrated that authorized equity ratios for rate cases decided in 2020–2021 was 50.61%, while those decided in 2022–2023 rose nearly 200 basis points to 52.59%. *Id.* Moreover, witness Newlin noted that the average authorized equity ratio for the proxy group over the past 12 months was 53.80%, which is higher than DEC's requested 53.0%. *Id.* at 29.

Witness Newlin further criticized witness LaConte's Exhibit BSL-12 for cherry-picking data and excluding certain companies from her proxy group, which could skew her results. *Id.* at 31. For instance, Oklahoma Gas & Electric, which has an authorized equity ratio of 53.37%, was excluded from her proxy group; this omission could have raised witness LaConte's calculated average. *Id.* Witness Newlin also points out that LaConte Exhibit BSL-12 includes data regarding authorized rates of return on equity for selected utilities and compares that data to DEC's requested rate of return on equity. However, witness Newlin argues that because of a rising trend in authorized rates of return on equity, witness LaConte's reliance on stale data for her averages makes her presentation inapplicable to DEC today. *Id.* at 32. Witness Newlin also criticized witness LaConte for including distribution-only utilities in her rate of return on common equity and overall rate of return analyses, which he considers an inappropriate comparison to a vertically integrated electric utility such as DEC. *Id.*

Witness Newlin also criticized witness Ellis' 6.15% rate of return on equity and 58.8% equity layer recommendation, noting that with an authorized rate of return on equity that low DEC would not be able to effectively compete for capital. *Id.* at 40. This is especially the case because a comparison of rates of return on equity recently awarded to southeastern utilities shows that DEC will be severely disadvantaged by such a low authorized rate of return on equity. Witness Newlin presented a table showing alternate authorized rates of return on equity comparisons of southeastern utilities. *Id.* at 42.

Finally, witness Newlin provided an overview of market dynamics since DEC's last rate case, noting the dramatic changes in economic conditions, including persistently high inflation, geopolitical issues like the war in Ukraine, and bank failures. *Id.* The Federal Reserve has responded to inflation by dramatically raising short-term interest rates, and long-term rates have also spiked and remain volatile. *Id.* at 43. Witness Newlin noted that this heightened level of market volatility and uncertainty has led to an unprecedented number of zero issuance days in the primary debt capital markets. *Id.* Witness Newlin stressed the value during these times of high credit quality and strong investment-grade credit ratings, which allow companies to not only access the market, if needed, but also provide flexibility to wait for more optimal market conditions. *Id.* In his testimony summary, witness Newlin noted that DEC's existing strong investment grade credit ratings constitute a form of insurance against downgrades that will be the likely consequence of weakening DEC's financials and noted further that downgrades only work to the detriment of DEC and its customers. *Id.* at 49.

DEC witness Coyne rebutted witness Walters' arguments about the DEC's risk profile and its impact on the cost of equity. *Id.* at 157–59. Witness Coyne emphasized that the cost of equity should be comparable to returns available to investors in firms with similar risk and reasoned that witness Walters has not demonstrated that DEC is less risky than the proxy companies due to its rate structures. *Id.* at 158. Witness Coyne further challenged witness Walters' reliance on credit ratings as a measure of risk to equity, arguing that it doesn't reflect the full range of risk borne by equity investors. *Id.* at 158–59. Lastly, witness Coyne criticizes witness Walters' comparison of DEC's proposed capital structure to the proxy companies at the holding company level, arguing that it's more appropriate to compare at the operating company level, where DEC's requested 53.0% is nearly identical to the mean of the proxy company operating subsidiaries' capital structures at 52.94%. *Id.* at 159.

Discussion and Conclusions

For the reasons set forth herein, the Commission approves DEC's proposed capital structure of 53.0% equity and 47.0% long-term debt.

The Commission is not persuaded by witness Ellis' recommendation. In the Commission's view, his testimony on capital structure is far outside the mainstream, just as it was for rate of return on common equity. While the Commission appreciates — and no party disputes — witness Ellis's point that capital structure and rate of return on equity are related, the Commission is concerned that an authorized rate of return on equity so low, even if connected to a high equity ratio, will render DEC at a severe disadvantage when competing for capital. The Commission is concerned that DEC will not find many equity investors willing to invest in an electric utility that operates nuclear plants and faces significant challenges and capital needs with respect to spearheading

S.L. 2021-165's energy transition with a 6.15% rate of return on equity, no matter what the equity ratio.

Turning next to the recommendations of the other witnesses, the Commission notes while witnesses Walters and LaConte support a capital structure at or near the stipulated equity layer from DEC's prior rate case, their testimony is flawed. As to witness LaConte, DEC witness Newlin's rebuttal testimony effectively demonstrates that her testimony, based on the average authorized common equity ratios for the period 2020 through 2023, is overly simplistic in that it fails to acknowledge the upward trend in authorized equity ratios over that period. Tr. vol. 16, 28–29. Witness Newlin's testimony, which the Commission credits, demonstrates that authorized equity ratios for rate cases decided in 2020–2021 was 50.61%, while those decided in 2022–2023 rose nearly 200 basis points to 52.59%, and further that the average authorized equity ratio for the proxy group over the past 12 months was 53.80%, which is higher than DEC's requested 53.0%. *Id.* at 28–29.

As for witness Walters, much of his testimony in support of lowering the equity layer from DEC's request is premised upon comparisons to the capital structures of publicly traded holding companies. The Commission has repeatedly rejected the use of holding company capital structures in the past. *See, e.g.,* Order Granting General Rate Increase and Approving Amended Stipulation, Application of Duke Energy Carolinas LLC for an Increase in and Revisions to Its Rates and Charges Applicable to Electric Utility Service in North Carolina, No. E-7, Sub 909, at 27-28 (N.C.U.C. Dec. 7, 2009). Moreover, witness Coyne persuasively establishes that DEC's proposed 53/47 capital structure is right in line with the capital structures of the utility operating companies that are subsidiaries of the holding companies in witness Morin's proxy group, which is the same as witness Walters' proxy group. *See* Coyne Rebuttal Ex. 4 (Tr. Ex. vol. 16).

In any event, as the Commission held in the DEP Rate Case Order that the seemingly slight difference between DEC's 53/47 proposal and the intervenor witnesses' 52/48 proposal masks consequential impacts. *See* DEP Rate Case Order at 176 Those impacts persuade the Commission that 53/47 is the optimal structure that appropriately balances affordability and DEC's access to capital on reasonable terms. With DEC's credit metrics as stressed as they are, further downward pressure in the form of a reduced equity layer and increased debt is decidedly not in the best interests of either DEC or its customers. Witness Newlin, referring to this passage in the DEP Rate Case Order, testified that exactly the same considerations apply to DEC. Tr. vol. 9, 101–02.

Thus, for example, the increase by Moody's in its downgrade threshold, from an FFO/Debt ratio[24] of 20.0% to 21.0%, impacts both DEP and DEC. Tr. vol. 16, 20; DEC Rebuttal Ex. KWN-3 – KWN-4 (Tr. Ex. vol. 16). The increase in the downgrade threshold means that while in the past Moody's had forecast "a potential downgrade in the

[24] The FFO/Debt ratio, or, in Moody's parlance "preworking capital cash flow to debt" or "CFO pre-WC to debt," is a measure of cash flow, and is the most significant metric utilized by Moody's in assessing credit quality.

Company's credit rating if the FFO/Debt metric stayed below 20.0% on a sustained basis, it was now forecasting a potential downgrade if the metric stayed below 21.0% on a sustained basis." Tr. vol. 16, 20. By this action Moody's raised the bar on DEC, heightening the fragility of its credit metrics. This heightened fragility is exacerbated, as witness Newlin further testified, by the rating agencies' desire that rated utilities maintain a "cushion" of about 100 basis points above the downgrade threshold (so, in DEC's case, to an FFO/Debt ratio of about 22.0%) so as to provide additional protection to the credit rating — and, therefore, to debt investors — with respect to exogenous events beyond the control of the issuer. *Id.* at 19–20, 36, 73, 76.

The credit stressors led by DEC are in some respects being felt industry wide. In his direct testimony, witness Morin referenced the "perfect storm" facing electric utilities like DEC: (1) slowing or even declining electricity growth in energy consumption; (2) at a time in which record amounts of new capital must be raised to replace aging infrastructure, improve reliability, and deliver renewable generation; (3) coupled with the need to implement a transition away from fossil fuel (particularly coal) and toward renewables, including electrification of the transportation sector; and (4) and layering on further the need to build new transmission infrastructure to strengthen the grid against weather events increasing in frequency and ferocity, as well as new renewable generation resources. Tr. vol. 7, 256.

DEC is not immune from these industry-wide considerations, and, to the contrary, faces multiple risks on multiple fronts including risks associated with investment and new technologies; risks associated with operating a system that must be on 24/7/365 with new types of generation, including increasing amounts of solar; and risks associated with getting the retirement of existing coal generation just right. These risks all highlight the execution and operational risks facing DEC in connection with the mandates of S.L. 2021-165. Witness K. Bowman addressed this issue as well, as noted in the return on equity discussion above. Moving forward, these risks impose upon DEC the obligation to navigate a fast-changing landscape to secure ready access to capital upon reasonable terms, to ensure that it can make the necessary capital investments to ensure reliable and affordable service to its customers.

Witness Morin noted that the "A" rating minimizes the revenue requirement and is the most cost effective bond rating. Tr. vol. 8, 59–60. The Public Staff, however, through the testimony of witness Walters, posited that DEC can maintain its present bond ratings at a 52.0% equity ratio, even coupled with his recommended rate of return on equity of 9.35%. Tr. vol. 14, 98–100. However, DEC witness Newlin countered that witness Walters' analysis fails to capture all the relevant factors, and that witness Walters' rate of return on common equity and capital structure recommendations "would weaken the quantitative and qualitative aspects" of DEC's credit quality. Tr. vol. 16, 48.

Witness Newlin pointed out that the Walters analysis mixes apples and oranges, because it purports to perform an FFO/Debt calculation using S&P's methodology, but then applies the result to the Moody's downgrade threshold (21.0%). *Id.* at 77. However, the two ratings agencies follow different methodologies in assessing credit quality and

FFO/Debt. *Id.* at 77–78. In particular, S&P uses a family rating based upon its evaluation of Duke Energy as a whole, encompassing all of its utility operating subsidiaries (including DEC, but also, for example, DEP, DEF, Duke Energy Ohio, etc.). The S&P downgrade threshold based on its family rating methodology is an FFO/Debt ratio of 12.0%, *Id.* at 52, but a calculation using S&P's methods purporting to show that DEC's FFO/Debt ratio is 21.3%, which is the result witness Walters derives, does not mean that S&P's evaluation of the Duke family will not result in a potential downgrade. Accordingly, witness Newlin appropriately took issue both with the overall way in which witness Walters performed his calculation and with the implications that witness Walters drew from the calculation. *Id.* at 57–58.

Moody's, on the other hand, performs its FFO/Debt calculation on an individual issuer basis, which is why DEC and DEP (and other operating utilities in the Duke family) receive individual Moody's credit opinions with individual ratings and individual FFO/Debt analyses. As witness Newlin observed, the Moody's analysis focuses "on each issuer . . . [and] its cash flows, its credit profile as the entity, the issuer." *Id.* at 54. It is for this reason that witness Newlin recommends that the Commission "focus on the Moody's metric . . . when adjudging risk to credit quality." *Id.* Moody's simply has "more specific criteria and methodology when taking a look at . . . what the credit ratings and the overall credit quality and credit profile of the Company is when it seeks to raise capital." *Id.* And focusing on the Moody's metric reveals that DEC is currently operating with little or no cushion above the 21.0% downgrade threshold. *Id.* at 79. As witness Newlin testified, DEC is operating "right at that cut line" and there is no margin for error. Tr. Vol. 9, 112–13. The Commission agrees.

Operating right at the cut line makes the potential for downgrade more than a theoretical issue. DEC needs some margin for error — in part because of the "cushion" concept witness Newlin discussed in his testimony, but also because of the credit stressors Moody's itself has identified in its most recent DEC credit opinion issued in May 2023. DEC Rebuttal Ex. KWN-4 (Tr. Ex. vol. 16). The credit opinion notes that DEC's "historically strong financial overage metrics have declined materially in recent years," with the main drivers of the decline being coal ash spending (which DEC must seek recovery of in a general rate case, as there is no rider mechanism for coal ash spend, meaning that these costs are particularly susceptible to regulatory lag), unusually severe storms (which also create regulatory lag), the negative cash flow impacts of tax reform, and — importantly for this case — massive investment in new generation and grid modernization needed to implement the energy transformation mandated by S.L. 2021-165. Tr. vol. 16, 80–82.

Witness Newlin noted in his testimony that to ensure reliable and cost-effective service, and to fulfill its obligations to serve customers, DEC must continuously plan and execute major capital projects, and must be able to operate and maintain its business without interruption and refinance maturing debt on time, regardless of financial market conditions, even (and perhaps especially) in times of market volatility. Tr. Vol. 9, 61. Customers benefit from DEC's financial strength, because its strong investment-grade credit ratings provide DEC with greater access to the capital markets on reasonable terms during such periods of volatility. *Id.* at 60.

As witness Newlin did with respect to DEP in the most recent DEP rate case, he likened the flexibility derived from DEC's existing strong investment grade credit ratings as "a form of insurance against negative ratings action that could potentially be a consequence of weakening the Company's financials," and noted that downgrades only "work to the detriment of DEC *and* its customers." Tr. vol. 16, 49 (emphasis in original). Witness Newlin cautioned against the Commission's taking action to weaken this insurance policy, "perhaps with unintended consequences." *Id.* As the Commission did in the DEP Rate Case Order, it agrees with witness Newlin and finds that now is decidedly not the time to weaken DEC's credit profile and invite a credit downgrade. DEC must attract capital on reasonable terms in order to finance investment needed for the continued reliability of the system. Weakening DEC's capital structure or awarding too-low of rate of return on common equity will make attraction of necessary capital that much more difficult — and certainly more expensive.

Accordingly, the Commission accepts witness Newlin's recommendation that DEC's capital structure be composed of 53.0% equity and 47.0% long-term debt.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 51-55

COVID Deferral Recovery

The evidence supporting these findings of fact is contained in DEC's verified Application and Form E-1; the testimony and exhibits of DEC witness Q. Bowman and DEC's COVID Panel; Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

Deferral Docket

In August of 2020, DEC and DEP (together, Duke) jointly petitioned the Commission for approval of orders for regulatory accounting purposes authorizing both companies to establish a regulatory asset to account for incremental costs resulting from the unprecedented COVID pandemic and declared State of Emergency, so that such costs could be deferred pending further action by the Commission in the next general rate cases filed by DEC and DEP. Joint Petition of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC for Approval of Accounting Orders to Defer Incremental COVID-19 Expenses, *Joint Petition of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC for Approval of Accounting Order to Defer Incremental Expenses as a Result of COVID-19*, Nos. E-2, Sub 1258, E-7, Sub 1241 (N.C.U.C. Aug. 7, 2020) (COVID Deferral Docket). DEC and DEP each requested permission to create a regulatory asset to defer costs associated with customer fees waived, bad debt expenses, employee stipends and safety-related costs, remote work costs, and other costs including overtime and related call center costs.

The Public Staff filed comments in the COVID Deferral Docket opposing Duke's request, arguing among other things that Duke had not substantiated a need for a deferral of the costs enumerated, and recommending the Commission deny the request. Further, the Public Staff stated that if the Commission allowed Duke to defer costs, Duke should offset such costs with COVID-related savings such as federal tax credits and reductions in operating expenses.

In the COVID Deferral Docket, the Commission granted the request to defer incremental costs and waived customer fees associated with the COVID pandemic for recovery in a future proceeding in its December 21, 2021 Order Approving Deferral Request (Deferral Order). The Commission noted the unique nature of the request, the severity of the ongoing pandemic, and the fact that many of the actions taken by Duke were in part due to government mandates imposed upon Duke, which were intended to ease both the financial and public health impacts of the pandemic on North Carolina and its citizens who might likely have been displaced from their homes. Deferral Order at 13.

The Commission determined that it would be patently unfair to penalize Duke by not allowing an opportunity to justify recovery of these costs in a future rate case and the Commission concluded that the costs allowed to be recovered may be amortized over a period of time determined in a future rate case.

Although the Commission allowed Duke to include carrying costs on the deferred amounts for accounting purposes, the Commission concluded that the rate of that return, if any, and the amount to which that return would be applied would be subject to determination in DEC and DEP's future rate cases.

Summary of Evidence

DEC Direct and Supplemental Testimony

In the present proceeding, DEC seeks recovery of its deferred incremental COVID-related costs. In her direct testimony, DEC witness Q. Bowman explained that DEC deferred and requests to recover: (1) customer fees waived; (2) bad debt charge-offs; (3) employee stipends to cover unplanned expenses associated with the COVID pandemic; (4) costs related to employee safety; (5) costs related to remote work; and (6) miscellaneous costs, such as employee overtime. Tr. Vol. 12, 180–81. Witness Q. Bowman maintained that the costs included in the deferral are reasonable and prudent costs that were incurred as DEC provided its essential public service during the pandemic. *Id.* at 182.

In DEC witness Quick's direct testimony, she explained the efforts DEC undertook to support its customers throughout the pandemic and the return to normal billing practices. Tr. Vol. 7, 136–40. Witness Quick explained that DEC suspended service disconnections, fees for card payments, walk-in pay location payments, late payment charges, and fees for insufficient funds. *Id.* at 136–37. Witness Quick also detailed how DEC worked with assistance agencies and customers on an individual basis to connect qualifying customers with assistance funding where possible. *Id.* at 137. Witness Quick further described DEC's expanded outreach campaign efforts and, in particular, detailed the ways in which DEC adapted its customer operations resources to provide a more tailored experience for customers and utility assistance agencies. *Id.* at 137–38.

DEC witness Speros testified in support of DEC's bad debt calculation. Tr. vol. 12, 539–41. Witness Speros explained that the moratorium on disconnections and late payment fees led to an increase in the number and amounts of past due accounts outstanding, which in turn led to increased bad debt expense. *Id.* at 540. Witness Speros testified that the deferred bad debt expense was calculated as the total amount of incremental bad debt expense exceeding the amount already being recovered in base rates from the period starting in March 2020 through the July 31, 2023 capital cut-off date in this case. *Id.* at 540. Witness Speros also explained that DEC is continuing to incur impacts to business operations from the pandemic, namely that charge-offs related to COVID delinquencies are ongoing and will continue going forward. *Id.* at 541.

Witness Q. Bowman testified that DEC's additional deferred expenses include employee safety-related costs, costs for remote work, employee stipends, and other miscellaneous costs. *Id.* at 180–82. Witness Q. Bowman further explained that DEC provided, and will continue to provide, employees with the appropriate personal protective equipment, and DEC incurred additional incremental costs for increased cleaning and sanitation supplies, health care, as well as for testing and temperature checks. *Id.* at 181–82. For those employees who could work from home, witness Q. Bowman testified that DEC incurred additional costs for remote work, including costs for expanded conference line capacity, increased network bandwidth, other required information technology improvements, expanded video conferencing licenses, and increased company cellular telephone and data usage. *Id.* at 182. Lastly, for certain eligible employees, witness Q. Bowman stated that DEC provided a one-time cash payment of $1,500 to help with unplanned expenses associated with COVID. Witness Q. Bowman also clarified that DEC seeks to recover other expenses related to overtime costs needed to implement COVID guidelines to ensure employee safety and due to increased call volume at call centers as a result of DEC resuming normal billing practices. *Id.*

Witness Q. Bowman testified that the proposed new rates requested in this proceeding include recovery of costs deferred from March 2020 through July 2023. *Id.* at 182–83. Further, the adjustment normalizes revenues for waived late fees that will be collected going forward, amortizes the deferred costs over a three-year period, adjusts test year expenses to include certain incremental employee costs that were previously deferred, and includes the deferral balance, net of one year of amortization and deferred taxes, in rate base. *Id.* In her third supplemental direct testimony, witness Q. Bowman updated DEC's amortization amount for the COVID deferral to include actual amounts realized through June 30, 2023. *Id.* at 224.

Public Staff Direct and Supplemental Testimony

In Public Staff witnesses Zhang and Boswell's direct testimony, they recommended that the Commission adjust DEC's revenue requirement to remove certain components of DEC's proposed COVID deferral. *Id.* at 1032–33. First, witnesses Zhang and Boswell recommended that the Commission remove the costs associated with DEC's employee stipends on the basis that the one-time payment was unverified and constituted goodwill on the part of DEC. *Id.* at 1033.

Next, witnesses Zhang and Boswell recommended that the Commission remove certain O&M expense savings that DEC stated it experienced through COVID against the COVID deferral. Witnesses Zhang and Boswell stated that DEC offset these savings against reduction in customer load, unfavorable weather, and excess storm costs, which the Public Staff claims were not the cause of the savings. *Id.* at 1033.

Witnesses Zhang and Boswell noted that DEC received the following credits and delayed payments as a result of the pandemic: (1) Employee Retention Credit (ERC), and (2) delayed payment of employer portion of social security tax. *Id.* at 1034–35. The witnesses explained that Section 2301 of the Federal Coronavirus Aid, Relief, and Economic Security Act (CARES Act) created a refundable ERC of up to $5,000 per eligible employee taken against the employer's share of the social security tax on qualified wages paid from March 13, 2020, through December 31, 2020. *Id.* at 1034. Under the Federal CARES Act, businesses received a delay in payment of the employer portion of social security tax. The Public Staff witnesses stated that the delayed payment of taxes is an interest-free amount of additional working capital available to DEC, and therefore made an adjustment to decrease the COVID deferral. *Id.* at 1034–35.

Finally, witnesses Zhang and Boswell removed DEC's return on the COVID deferral. Witnesses Zhang and Boswell testified that DEC's return represented approximately 12.0% of the overall COVID deferral. The witnesses testified that it would be inappropriate for DEC to earn a return on costs for which all other utilities regulated by the Commission did not seek a deferral. *Id.* at 1035. Additionally, the witnesses expressed concerns regarding the types of charges deferred reiterating the same concerns the Public Staff expressed in its comments filed in the COVID Deferral Docket. *Id.* at 1032–33.

Witnesses Zhang and Boswell recommended that the remainder of the COVID deferral be amortized over a 12-year period. *Id.* at 1036. Regarding DEC's reserve percentage and incremental bad debt calculations, the Public Staff did not make any adjustments but testified that they were unable to determine and compute a reasonable provision for the reserve and incremental bad debt. Witnesses Zhang and Boswell stated that DEC's Form E-1, Item-20 was incorrect and misleading as it inflated the bad debt expense and provision for reserve amounts since North Carolina and South Carolina had different governmental mandates during COVID. *Id.* at 1037. The witnesses also testified that DEC's approach to the estimation and calculation of bad debt expense appeared to utilize a higher risk of customers being past due. Witnesses Zhang and Boswell also expressed concern about the impact of DEC's Systems, Applications, and Products in Data Processing (SAP) billing system, which they stated skewed DEC's charge-off analysis. *Id.* at 1037–38.

Witnesses Zhang and Boswell also recommended adjustments to DEC's proposed ongoing COVID costs for call center overtime and DEC's proposed impact on other revenue related to customer fees waived for the 2021 test period. The witnesses disagreed with DEC's assertion that its call center costs have increased and recommended removal of overtime costs for the call center. They instead testified that based on the Public Staff's review of the call center volumes and labor costs, including overtime, over the last five years, the volume and costs has been steady, with costs and volume declining in 2021 and 2022. *Id.* Witnesses Zhang and Boswell testified that they also adjusted other revenue related to customer fees waived for the 2021 test period to reflect a normalized annual level of customer fees waived utilizing a two-year average based on actual revenue collected in years 2018 and 2019 to better represent the customer fees to be collected by DEC in the future. *Id.* at 1039.

DEC Rebuttal Testimony

On rebuttal, the COVID Panel testified to provide further detail and context for DEC's pandemic response and COVID-related costs incurred. Tr. vol. 13, 208. The COVID Panel stated that the vast majority of the deferred costs DEC seeks to recover result directly from customer inability to pay and the governmental response to that inability to pay. They explained that nonpayment ordinarily would have been met by discontinuance of service, but actions both of the Governor of North Carolina and the Commission removed service disconnection as an option for DEC. *Id.* at 209.

Witness Q. Bowman detailed DEC's initial and ongoing response as an essential service provider. Witness Q. Bowman explained DEC's actions in response to Federal, State, and Commission direction, including Governor Cooper's executive orders and the Commission's moratorium on disconnections. *Id.* at 211–12. Witness Q. Bowman also provided a brief background on the COVID Deferral Docket and the Commission's Deferral Order, which approved DEC and DEP's request to establish a regulatory asset for the purposes of deferring the incremental costs associated with the COVID pandemic for final determination in a future rate case. *Id.* at 213–14. Witness Q. Bowman stated that the Deferral Order also required DEC to periodically file reports to update the Commission concerning the actual amounts deferred. *Id.* at 214. DEC witness Quick detailed the ways in which DEC adapted its customer support operations to serve the unique needs of customers associated with the pandemic. *Id.* at 219–21.

DEC witness Abernathy included in her portion of the prefiled COVID Panel rebuttal testimony a chart detailing the deferred costs as of June 30, 2023: based on DEC's third supplemental filing:

Deferred Incremental COVID Costs	$ in Millions	% of Total
Customer fees waived	$45.7	28.6%
Bad debt expense	$99.9	62.6%
Employee safety related costs	$7.3	4.6%
Costs for remote work	$0.9	0.6%
Employee stipends	$1.1	0.7%
Other (primarily call center costs)	$4.6	2.9%
Total Incremental COVID Costs deferred	$159.6	100.0%
Accrued carrying costs	$23.3	
COVID Deferral projected balance as of rates effective	$182.9	

Id. at 227.

According to DEC, the requested $182.9 million in deferred incremental COVID-related costs translates to approximately 136 basis points, excluding any impacts from lost revenues. *Id.* at 226. Witness Abernathy testified that as of the filing of the third supplemental testimony (July 18, 2023) the projected balance as of the date rates would go in effect, including carrying charges, is approximately $182.9 million. *Id.* at 227. Witness Abernathy explained that over 91.0% of the deferred costs are attributable to waived customer fees and bad debt expenses. Witness Abernathy noted that these incremental costs were primarily the result of government-issued moratoriums imposed on DEC. *Id.* at 229. Witness Quick explained that DEC waived approximately $46 million in customer fees, launched extensive outreach campaigns to bring awareness of the available customer assistance, expanded the eligibility for the Winter Moratorium and extended its length from February 2021 until the end of March 2022. *Id.* at 219–20. The COVID Panel testified that the remaining categories of expense are also clearly pandemic-related, in that they were incurred in order for DEC, as a provider of an essential service, to fulfill its obligation to continue operation 24 hours a day, seven days a week despite the pandemic.

The COVID Panel testified regarding the challenges faced by DEC's customer service representatives, who ordinarily would work in call centers but had to transform themselves into a virtual workforce working from their homes. They noted that costs associated with these challenges are captured in the employee stipends, which were distributed to hourly-paid call center employees costs related to the pandemic.[25] *Id.* at 221–22. Witness Quick explained that the stipends served as means of retaining essential employees, as witness Quick noted, DEC "recognized the importance of retaining employees, especially its frontline employees, like call center specialists who interfaced with customers daily." *Id.* at 221. The COVID Panel testified that DEC also incurred costs related to remote work generally, such as expanded conference line capacity, increased network bandwidth, other required information technology improvements, expanded video conferencing licenses, and increased company cellular telephone and data usage. *Id.* at 228.

Regarding regulatory treatment of COVID costs in other jurisdictions, the COVID Panel testified that as of the time the reply comments were filed in the COVID Deferral Docket (November 30, 2020) commissions in 32 states and the District of Columbia had permitted cost deferral in response to requests from regulated utilities subject to their jurisdiction. They stated that since then, several state commissions have begun to allow recovery of deferred costs. They noted that the Georgia Public Service Commission recently permitted recovery of approximately $25 million in deferred COVID-related costs

[25] The COVID Panel also noted that call center-related costs are also captured in the "call center" category, which relates to incremental increases in workload and the need to retain outside vendors as the centers began to "return to normal" following the easing of the shutdown moratoriums. Tr. vol. 13, 1277–79.

over a three-year amortization period.[26] *Id.* at 215. Moreover, in response to the Public Staff's arguments that no other North Carolina regulated utilities sought a COVID deferral, witness Q. Bowman explained that both DEP and DEC sought, and received, deferrals in North Carolina. *Id.* at 217. DEC and DEP accounted for the overwhelming majority of outstanding debt for all utilities in North Carolina and considering the size of both utilities as well as the magnitude of personnel and infrastructure needed to provide safe reliable electric service witness Q. Bowman explained that it is not surprising that DEC and DEP sought deferrals. *Id.* at 217–18. Additionally, witness Q. Bowman explained that other utilities like Piedmont Natural Gas Company, Inc. and Public Service Company of North Carolina significantly reduced their exposure to the negative impacts of COVID through existing regulatory mechanisms that are not similarly available to DEC or DEP. *Id.* at 218.

In response to the Public Staff's testimony that DEC's request for cost recovery of incremental deferred COVID-related costs should be reduced because DEC has not offset these costs with COVID savings, the COVID Panel testified that the Deferral Order requires only that DEC track the costs being deferred. The Panel did note that in South Carolina, DEC was required to track and report quarterly both COVID-related savings and net lost revenues (NLRs) on a South Carolina retail basis in 2020. *Id.* at 232–33. The Panel stated that because of this South Carolina requirement, DEC has tracked incremental savings due to COVID and provided these amounts to the Public Staff. They explained that DEC's estimates included two categories of expenses that resulted in financial savings attributable to the COVID pandemic. First, DEC experienced reduced employee expenses as compared to budget, primarily related to reductions or elimination of travel and expenses associated with normal operations while DEC's employees were required to work remotely and adhere to travel restrictions. Second, DEC experienced reduced printing and postage costs while the various government-imposed moratoriums were in place and DEC was not disconnecting customers and thus not mailing required notifications. *Id.* at 233–34.

The COVID Panel stated that in 2020, DEC estimated approximately $6.2 million, on a North Carolina retail basis, in O&M expense savings attributable to COVID. DEC estimated NLRs in 2020 to be approximately $47 million, on a North Carolina retail basis, compared to budget. They further stated that these O&M expense reductions assisted DEC in avoiding seeking a deferral request for the NLRs. *Id.* at 234. The COVID Panel maintained that the negative impact of NLRs was ignored by the Public Staff in its testimony. *Id.* at 235.

The COVID Panel also addressed the assistance provided by the federal CARES Act. Regarding the delay in payment of the social security tax for the period April through December 2020, the COVID Panel noted that this was only a temporary deferral from the government and was fully paid by December 31, 2022. *Id.* at 235–36. They stated that although the Public Staff believes that DEC should have offset the COVID deferral for the

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[26] *See* Order Adopting Settlement Agreement as Modified, *Georgia Power Company's 2022 Rate Case*, No. 44280 (G.P.S.C. Dec. 30, 2022); *see also* Direct Testimony of Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston, and Michael B. Robinson on behalf of Georgia Power Company, Georgia Power Company's 2022 Rate Case, No. 44280, at 46–47 (June 24, 2022).

working capital impacts of the delay in payment, witnesses Boswell and Zhang also included in its recommendation reduction for Duke Energy Business Services (DEBS) payroll. The COVID Panel explained that DEC received no carrying cost benefit from the social security delayed payment associated with DEBS payroll, as it was recognized on the DEBS balance sheet (i.e., deferred) to a long-term liability account and was ultimately paid by DEBS. *Id.* at 236. The COVID Panel stated that DEC filed for federal employee retention credits (ERCs) under the CARES Act and that all claims have been filed attributable to its operations from March 13, 2020, through September 30, 2021. The COVID Panel contended that even if these benefits to DEC should be netted against costs, they should in that case also be netted against NLRs. The Panel maintained that these benefits do not overcome NLRs even when added to the $6.2 million DEC estimates is COVID-related savings. *Id.* at 237.

Witness Abernathy maintained that the Public Staff's recommendation is one-sided and asymmetrical in its focus on DEC's apparent savings but omits any discussion of NLRs. *Id.* at 239–40. Witness Abernathy explained that in 2020, DEC faced challenges in addition to the pandemic, such as mild weather that also resulted in substantially lower than projected revenues. Witness Abernathy also testified concerning increased expense due to higher-than-normal storm restoration costs. Witness Abernathy testified that when faced with the prospect of revenue loss and in keeping with its focus on managing O&M expenses for the benefit of customers, DEC, as a routine part of its business, identifies and implements a suite of cost mitigation measures. *Id.* at 240.

Witness Abernathy testified that total O&M cost reductions for 2020 amounted to $44 million on a North Carolina retail basis. *Id.* at 240–41. Witness Abernathy further testified that revenue impacts from lower volumes and mild weather amounted to $83 million on a North Carolina retail basis, and when added to an additional impact ($26 million) related to storm costs, the total is $109 million, an amount that was not contested by any party. *Id.* Witness Abernathy then observed that "revenue impacts plus storm costs on the one hand, and the cost savings on the other, are opposite sides of the same coin — but, as shown by my illustration, the reduced revenues and storm impacts ($109 million) outstrip cost savings ($44 million) by a significant amount — approximately $65 million." *Id.*

In response to the Public Staff's testimony regarding incremental call center costs, the COVID Panel explained that although average workload hours decreased during the Commission-ordered disconnection (Q2 and Q3 2020), DEC could not capture the potential savings associated with reduced workload during this timeframe in light of the uncertainty of when DEC would return to normal, making it such that reducing staffing would not have been prudent; and its view that reducing staffing in the short term, only to have to restaff a few months later, would not have been cost-effective. DEC witness Quick clarified that while overall call volume declined in 2021 and 2022, the average handling time per call increased as DEC's customers experienced changing needs following the return to normal. *Id.* at 224–25.

Witness Abernathy also testified regarding Public Staff's O&M savings disallowance. Witness Abernathy explained the various ways in which DEC instituted cost efficiency measures across the enterprise to respond to both the COVID pandemic and mild weather and increased expense due to higher-than-normal storm restoration costs. *Id.* at 238–40. Witness Abernathy clarified that DEC updated its data through December 2021, which showed that 2021 O&M expenses actually ended the year unfavorable to budget and did not result in any savings. However, witness Abernathy testified that the Public Staff ignored DEC's update and used data from August 2021, which showed an over statement of approximately $20 million in North Carolina retail savings. *Id.* at 238–39. Witness Abernathy also noted that for bad debt expense, the Public Staff only expressed concerns with DEC's calculation and the reserve percentages used. *Id.* at 230.

Witness Abernathy also addressed the Public Staff's exclusion of DEC's carrying charges. *Id.* at 242. Witness Abernathy testified that in the face of the COVID pandemic, DEC incurred costs of providing service that were unanticipated and at a level that was not being recovered in existing rates (incremental bad debt expense, incremental O&M expense, no late payment fees due to government moratoriums) and, therefore, it had to utilize investor-supplied funds to pay for such costs. *Id.* With specific regard to late fees, witness Abernathy rebutted the Public Staff's contention that the interest has already been accounted for. Witness Abernathy explained that, "[T]he late payment fee represents the financing costs [DEC] has incurred if it is paid and collected when the fee is due. Because in this case, [DEC] was not able to collect those fees when they were due, additional financing costs were incurred." *Id.* at 244. Thus, witness Abernathy testified that DEC incurred additional prudent and reasonable financing costs related to the cash that it borrowed but has not yet recovered from customers, therefore it is entitled to a return on the deferred costs related to late fees. *Id.* at 245.

Witness Speros provided additional testimony in support of DEC's bad debt expense and calculation. Witness Speros explained that the moratorium on disconnections and the suspension of late fees, enacted through Executive Orders of Governor Cooper as well as Commission Orders to mitigate the impact of the pandemic on customers, had an adverse impact on the level of DEC's bad debt expense. *Id.* at 246. Witness Speros testified to the process that DEC undertook to develop its bad debt reserve percentages, explaining that the reserve percentages are calculated by taking the net charge-off amounts divided by the aged receivable balance utilizing the historical data from 2018 and 2019. *Id.* at 249. Witness Speros explained that DEC reviews the aging schedules and works with various internal teams to determine if there are any unusual changes or fluctuations in collections and write-offs that could impact the reserve calculation, and that based on these reviews, DEC determines if the balance in the loss reserve is reasonable as stated or if an adjustment is required. Witness Speros also testified that DEC compiles quarterly data on aged receivables, the balance of the loss reserve, and the current write-offs compared to forecast are then summarized and discussed with management. *Id.* at 249–50. Witness Speros clarified how customers on payment plans are treated for purposes of charge-off accounting. *Id.* at 250. Witness Speros stated that customers on payment plans are actively working with DEC and are therefore viewed as having less risk of charging off than the typical delinquent customer. Witness Speros noted that consistent data is available related to payment plans and a more accurate assessment can be taken by looking at the trends of customer defaults on their payment plans. Witness Speros explained that the percentage is calculated using the dollars defaulted on payment plans divided by total dollars of payment plans. *Id.* Witness Speros further detailed DEC's methodology for calculating its bad debt reserve, explaining that DEC's bad debt reserve calculation utilizes data of customers that are actually past due. Witness Speros explained that the only estimate related to customers not yet past due are in the current category of aged receivables, which are reserved at 0.3% and comprise a very small portion of the overall reserve. Witness Speros testified that the increase in charge-offs DEC saw in late-2022 and into 2023 confirm that its estimates were correct. *Id.* at 252.

Witness Speros also testified regarding DEC's SAP billing system. Witness Speros testified that alongside the implementation of Customer Connect, DEC changed how aged receivables are reported. *Id.* at 253. Witness Speros explained that this methodology shifted the reported aged receivables by four days in DEC's aging categories. Witness Speros clarified that the four-day shift is less than 1.0% of each category. *Id.* Witness Speros also stated that continuation of the COVID deferral, as requested, will ensure that customers pay only for the incremental bad debt expense that is actually incurred, since the deferral will be credited for amounts recovered from customers. *Id.*

Witness Abernathy also testified regarding DEC's request to continue the deferral of bad debt expense until the next rate case. Witness Abernathy noted that if the Commission does not approve continuation of the bad debt expense deferral, then test year bad debt expense should be increased by approximately $61 million to reflect a current level of bad debt expense using 2022 actual expense. *Id.* at 246.

Testimony Presented at the Expert Witness Hearing

At the expert witness hearing, Public Staff witnesses Zhang and Boswell responded to questions from Commissioners about their retail O&M savings reductions to the COVID deferral. Witness Boswell testified that the Public Staff relied upon data provided by DEC that included employee expenses and postage savings, and the differential between what was included for DEC's actual versus budgeted expenses for 2020 and 2021. Tr. vol. 12, 1059. The Commission requested that witnesses Zhang and Boswell file a late-filed exhibit that lists each of the O&M accounts and the corresponding confidential amount included in the Public Staff's offset to the COVID deferral. *Id.* at 1060. The late-filed exhibit was filed on October 13, 2023.

In response to a question on DEC's proposal to continue the COVID deferral, witness Boswell testified that the Public Staff did not recommend continuation of the deferral. *Id.* at 1060. Witness Boswell testified that DEC's bad debt expense that is being projected is subjective and includes both North and South Carolina. Witness Boswell stated that is inappropriate to include South Carolina within that calculation. *Id.* Witness

Boswell also expressed concern about DEC's change in the number of days for which uncollectibles are calculated. *Id.* The Public Staff testified, however, that they did not make an adjustment for the percentage calculation of uncollectibles included in this case. *Id.* at 1061.

The COVID Panel also responded to questions from Commissioners related to DEC's deferral request and addressed the Public Staff's recommendation regarding continuation of the bad debt deferral. Witness Abernathy began by explaining that if the continued deferral is not granted, DEC's test year expenses would need to be adjusted by approximately $61 million to represent a level of 2022 bad debt expense. Witness Abernathy also provided the final amount of the requested deferral in this proceeding — $182.9 million through DEC's third supplemental update. Tr. vol.13, 267–68. Witness Abernathy also explained that the carrying costs DEC included in the deferral are calculated at its currently approved weighted average cost of capital from when DEC incurred the cost, through the effective date of rates in this proceeding. *Id.* at 269. Witness Abernathy stated that DEC has carried the deferral on its books for more than three years, starting in March of 2020. Witness Abernathy further stated that DEC would continue to carry this deferral on its books until the costs are fully recovered; thus, DEC has proposed a three-year recovery period. *Id.* at 269–70.

Witness Quick testified concerning the types of costs included in the call center costs. *Id.* at 270. Witness Quick stated that the volume of calls decreased during the disconnection moratoriums. However, when DEC started to return to normal practices, customers started calling and call specialists saw increased workloads. *Id.* at 270–71. Witness Quick explained that "workload is really a combination of volume multiplied by average handle time." *Id.* at 271. Witness Quick continued to explain that once DEC began disconnecting customers for nonpayment, due to the nature of many customers' situations at that time, it took specialists longer to complete the calls as they worked with customers to connect them with agency assistance and other support, such as payment arrangements. *Id.* at 271–72. In response to a question regarding bad debt in North Carolina versus South Carolina, the COVID Panel explained that while South Carolina did have a lower bad debt expense, South Carolina did not have an Executive Order implementing a disconnection moratorium. *Id.* at 276.

Discussion and Conclusions

In the Deferral Order, the Commission expressly granted DEC's request that "estimated incremental costs of utility service that are proximately caused by the pandemic may be deferred pending a final determination on cost recovery in a future rate case," and also held that its decision was, "without prejudice to the right of any party to take issue with the amount, if any, of the deferred costs to be allowed for ratemaking purposes, if such costs are included in future rate filings." Deferral Order at 13. In determining the amount of cost recovery, the Commission must evaluate the totality of the circumstances.

The Commission recalls that during the state of emergency government officials were taking all necessary steps to slow the spread of the coronavirus by requiring people to social distance and stay at home to the greatest extent possible. The health and safety of North Carolina communities were affected by the efforts of all residents to stay home and socially distance to slow the spread of the coronavirus. Governmental actions were also implemented to help prevent hospitals from being overwhelmed with patients and to preserve human life. The seriousness of the circumstance was unprecedented. The Commission recognizes that it was crucial for DEC, as a provider of an essential service, to fulfill its obligation to its customers to continue operations 24 hours a day, seven days a week despite the pandemic. This vital requirement for DEC to continue to provide its customers essential electric utility service during this unprecedented event cannot be overemphasized. The Commission recognizes that DEC met its obligation to the Commission and the citizens of North Carolina. The Commission recognizes that for DEC to provide electric utility service to the citizens of North Carolina during the pandemic necessitated certain DEC employees to perform their job duties in the same manner as prior to the declaration of the state of emergency. As a result, many of DEC's employees were not allowed the option to work from home to protect the health and safety of themselves and their families.

Government officials, including this Commission, sought to aid North Carolina citizens amidst a turbulent and challenging economic environment by issuing a state of emergency and various mandates and moratoriums. During the height of the turmoil caused by the pandemic, customers benefitted from the governmental mandates to waive customer fees and discontinue disconnections for nonpayment. The pandemic lasted much longer than anyone anticipated. Businesses, families, and individuals benefitted from these mandates, particularly households that were struggling with financial issues resulting from the pandemic. Further, DEC, at this Commission's direction, provided customers with new, more favorable payment options and worked to connect eligible customers with available financial assistance from new and existing federal and state programs.

In reaching its decision concerning cost recovery of the incremental COVID-related expenses, the Commission must determine: (1) the appropriate amount of cost recovery of the deferred expenses in this proceeding; (2) the COVID-related savings; (3) whether a return should be allowed on the deferred amount during the deferral period and on the unamortized balance during the amortization period; (4) the amortization period for cost recovery; and (5) the timing of when amortization of the deferred balance should begin.

In reaching its decision concerning cost recovery of the incremental COVID-related expenses, the Commission gives significant weight to the fact that the deferred costs at issue in this case were not discretionary on the part of DEC and that in the COVID Deferral Docket, DEC sought and received approval to defer the costs at issue. Further, the Commission gives significant weight to the fact that the Public Staff, which extensively audited the deferred costs, did not find any of the costs to be unreasonable in amount and did not find that any of the costs were unrelated to the COVID pandemic. As it did in the COVID Deferral Docket, the Public Staff primarily argues that COVID costs should be offset with certain COVID savings. The Commission notes that in the DEP Rate Case, the Public Staff recommended disallowance of the employee stipends and the increased call center costs but did not specifically object to cost recovery of any other category of DEP's deferred COVID-related costs. As set forth in prefiled testimony and discussed herein, the Public Staff's position and recommendations to the Commission concerning cost recovery of the COVID deferral in the DEC rate case is similar but a more refined than its approach in the DEP Rate Case.

After careful consideration, the Commission concludes based upon the evidence presented that recovery in rates of DEC's deferred COVID-related costs pertaining to customer fees waived, bad debt expense, employee safety related costs, costs for remote work, stipends, and other COVID-related costs (primarily call center costs) and carrying costs during the deferral period and the amortization period are just and reasonable and should be approved. The Commission determines that it is appropriate to reduce these allowed costs by certain COVID-related expense savings for employee travel expenses, printing, and postage costs. Further, the Commission determines a three-year amortization period beginning when rates become effective for this proceeding is appropriate. Finally, the continuation of the COVID deferral for bad debt expenses as requested by DEC is appropriate and in the best interest of customers and therefore the Commission approves the continuation of the deferral. The Commission also concludes that DEC, on a monthly basis until the next general rate case, should credit any payments received which are associated with the deferred bad debts. The Commission sets forth its reasons for these conclusions below.

Regarding the amount of costs deferred, DEC witness Abernathy testified that as of the filing of the third supplemental testimony on July 18, 2023, the projected balance of deferred incremental COVID costs as of the date rates would go in effect increased to approximately $182.9 million, the Commission acknowledges that no party has challenged whether the expenses for which DEC now seeks recovery pursuant to the Deferral Order were COVID-related expenses. Instead, the fundamental disagreements between DEC and the Public Staff are: (1) whether certain deferred COVID expenses are appropriate for recovery from ratepayers; (2) whether the deferred COVID expenses should be offset by certain savings; and (3) whether a return on the deferred costs during the deferral period and on the unamortized balance during the amortization period should be allowed.

The Commission notes that as indicated in the chart above provided by witness Abernathy, over 91.0% of the deferred costs were incurred from waived customer fees and bad debt expense. The Commission concludes that these two costs resulted directly from governmental action, including mandates from the Commission, and are appropriate for recovery from customers. Specifically, at the onset of the COVID pandemic the Governor issued a proclamation of a state of emergency (Executive Order No. 116), and subsequent orders of the Governor and of the Commission imposed a moratorium upon DEC's ability to disconnect customers for nonpayment and required waiver of customer fees ordinarily imposed in connection with nonpayment, such as late fees, reconnection fees, and return check charges. As a consequence of these governmental actions, DEC was unable to use its customary tools to timely collect payments from customers. DEC's ability to charge certain customer fees such as late fees, reconnection fees, and returned check charges encourage customers to pay their monthly bills. Disconnection of electric service is a strong incentive for the customers to timely pay their bills. The COVID Panel testified that the moratorium on disconnections and the suspension of late fees had an adverse impact on the level of bad debt expense such that DEC realized an increase in the number of past due accounts that ultimately caused a significant increase in bad debt expense. The Commission acknowledges the testimony of DEC witness Speros, which described DEC's methodology for calculating the bad debt reserve. The Commission determines that DEC's methodology for calculating its bad debt reserve for including in the deferral is appropriate and consistent with the methodology approved in the recent DEP Rate Case Order.

In this proceeding, DEC seeks to recover the difference between the level of bad debt expense currently in rates and the amount of bad debt expense above that level resulting from actions taken during the pandemic. The Commission acknowledges that denial of the recovery of deferred waived customer fees and bad debt expense would deny DEC recovery of costs incurred for complying with Executive and Commission Orders. DEC was expected to continue to provide normal, uninterrupted electric service 24 hours per day, seven days a week, to all customers during this unprecedented event. Moreover, DEC was expected to continue to provide service to its customers who were not paying for such service for an extended period of time. The Commission concludes that these incremental bad debt expenses are reasonable for recovery from customers.

With respect to employee safety-related costs, the Commission acknowledges that DEC incurred costs to provide its employees with the appropriate personal protective equipment to facilitate the continuation of work for customers in a safe manner. Additionally, DEC incurred incremental costs associated with cleaning supplies, healthcare, as well as testing and temperature checks. To provide essential electric service, many of DEC's employees were not allowed the option to work from home. The Commission recognizes that those employees had to be furnished with protective gear, cleaning/sanitizing supplies, and COVID testing services and nursing case management. Thus, the Commission concludes that these employee safety related costs are reasonable and prudent costs for recovery from customers.

Regarding the costs of remote work, in order to facilitate employees working remotely to protect their health and safety during the pandemic, DEC incurred incremental costs associated with expanded conference line capacity, increased network bandwidth, other required information technology improvements, expanded video conferencing licenses, and increased company cellular telephone and data usage. As previously mentioned, DEC was expected to continue to provide normal, uninterrupted electric service to all its North Carolina customers throughout the COVID pandemic. The costs included in DEC's remote work expenses allowed DEC to transition those employees that could safely work at home to remote work and facilitated DEC's seamless, uninterrupted and undiminished provision of service to customers during the pandemic and also provided DEC the foundation for a new approach that allows certain employees to work remotely. The Commission recognizes that DEC's costs related to remote work originated because of the COVID pandemic. The Public Staff did not include any testimony disputing the accuracy or prudence of these costs. Thus, the Commission concludes that it is appropriate to recover from customers the one-time, deferred costs of remote work.

DEC also provided certain eligible call center employees with a one-time cash payment of $1,500 to help with unplanned expenses associated with the COVID pandemic. In this case, the Public Staff did not dispute the amount of the costs but opposed the inclusion of these costs claiming they were goodwill and should not be allowed for recovery. DEC witness Quick testified that the stipends were important in retaining employees, especially frontline employees, like call center specialists who interfaced with customers daily. DEC stated that these stipends were targeted towards hourly employees with a focus on retaining this critical part of the workforce during this unprecedented time. DEC further stated that a loss of this workforce or significant portions of it would have likely led to considerable declines in customer service at a time when such declines could have had a significant impact on customers. The Commission recognizes that stipends in combination with alternative work schedules may have been necessary to accommodate this critical workforce. The Commission understands witness Quick's response that verifying use of the stipends during the pandemic would have created a hardship on employees and had an adverse impact on the intended purpose of the stipends — which purpose was employee retention. Therefore, the Commission concludes that the one-time $1,500 stipends provided by DEC to certain hourly employees should be recovered from customers.

DEC witness Q. Bowman testified that the other category of deferred costs includes overtime to implement COVID guidelines to ensure employee safety and increased costs due to expected increased call volume at call centers when normal billing practices resume. Public Staff witnesses Boswell and Zhang contended that expenses associated with call center overtime should not be included in the ongoing COVID deferral given that the amount sought by DEC for call center overtime was not above the amounts already included in DEC's cost of service. Witness Quick disputed the Public Staff's findings explaining that the average workload volume for call center post COVID is significantly higher as compared to the pre-COVID call center hours per quarter. As a result of ongoing pandemic-related customer challenges, call center average quarterly workload has increased by roughly 11,000 hours more per quarter compared to 2019. Furthermore, the Commission acknowledges witness Quick's confirmation that the costs associated with COVID-related policy changes are appropriately reflected in the COVID deferral and are not included in DEC's internal O&M labor and vendor charges. The Commission agrees with witness Quick's assertion that workload increased significantly with the return to normal operations as the discussions with customers were longer and more complex; and the ongoing nature and impact of this increased workload is properly included in the COVID-deferral. Therefore, the Commission concludes that these other COVID-related costs (primarily call center costs) should be recovered from customers.

Regarding COVID-related cost savings, the COVID Panel contends that the Deferral Order required only that DEC track the costs being deferred, but that nonetheless

DEC was required to track and report COVID savings (specifically, reduced employee expenses such as reductions or elimination of travel and expenses associated with normal operations while employees were required to work remotely and adhere to travel restrictions, and reduced printing and postage costs) and NLRs on a South Carolina retail basis for 2020 and therefore did, and provided to the Public Staff, the incremental COVID savings and NLRs at a system level to which it applied allocation factors to derive the South Carolina retail amounts. According to the COVID Panel, DEC's COVID savings were largely realized in 2020 in the amount of approximately $6.2 million on a North Carolina retail basis, while DEC estimated the NLRs related to reduced load and demand in 2020 to have been approximately $47 million on a North Carolina retail basis, thereby more than offsetting the savings reductions that the Public Staff suggests.

The Commission recognizes that DEC is not requesting rate recovery of the NLRs related to the COVID pandemic. Witness Abernathy explained that the COVID pandemic significantly reduced economic activity throughout the state and country, resulting in unforeseeable reductions in customer demand, which led to NLRs, meaning that fixed costs of service were not being recovered by DEC. DEC was able to employ cost mitigation efforts and use those savings to partially offset the impacts of the NLRs, leading to its decision to not request deferral of the NLRs in the COVID Deferral Docket or recovery of NLRs in this case. Witness Q. Bowman explained that when faced with the prospect of revenue loss, DEC as a routine part of its business and in keeping with its focus on managing its O&M costs for the benefit of customers, identifies and implements a suite of cost mitigation measures. Witness Abernathy testified that further complicating the picture in 2020, the prospect of revenue loss arose not only from the pandemic but also from mild weather. Witness Abernathy noted that DEC responded to twin threats to its revenue stream, both the pandemic and mild weather, by instituting cost efficiency measures. Witness Abernathy maintained that DEC did everything that it could to reduce costs and, as a result, avoided the need to request a deferral of the NLRs. However, DEC was not able to offset both the incremental costs due to the COVID pandemic, and the other unfavorable impacts in 2020, including the NLRs due to the pandemic. The end result is that DEC determined the deferral of incremental COVID-related costs was required and requested, and the Commission gave its approval to that deferral. Moreover, DEC relied upon that deferral and the expected recovery of all prudently incurred cost in limiting the scope of the deferral to exclude NLRs. Witness Abernathy contended that none of the cost saving measures discussed above have been — or should be — used to offset the COVID pandemic-related incremental costs.

Witness Abernathy testified that two categories of savings were identified: (1) reduced employee expense related to reduction or elimination of travel; and (2) reduced printing and postage costs as a result of the disconnect moratoriums ordered by the Commission. The Commission concludes that these cost savings identified by DEC are directly attributable to the pandemic and should offset the amount of deferred COVID-related expenses.

At the expert witness hearing, the Commission requested a late-filed exhibit from the Public Staff regarding its breakdown of recommended adjustments to DEC's COVID deferral balance. The Public Staff filed Confidential Late-Filed Exhibit 2 which has an extensive listing of O&M expense accounts with a comparison by account of actual to budgeted amounts for 2020 and 2021. The late-filed exhibit also provides a comparison of actual to budgeted interest expense and labor expense by account. Public Staff Late-Filed Ex. 2 (Tr. Ex. vol. 17).

The Commission recognizes that the issue of COVID-related cost savings is intertwined with the issue of cost savings resulting from the mitigation measures taken by DEC to address NLRs. Furthermore, various events occurring in 2020 are entwined in the analysis — lower volumes due to the COVID pandemic and mild weather, and storm restoration costs. DEC, through witness Abernathy's testimony, maintained that none of DEC's cost saving measures to mitigate NLRs should be used to offset the incremental COVID-related costs. Witness Abernathy also maintained that savings related to the federal government assistance for which DEC filed ERCs and was granted a carrying cost benefit related to the delayed payment of the employer portion of social security tax fall far short of offsetting the total impacts from NLRs. Additionally, the tax benefit from the delayed payment of employer portion of social security taxes was a temporary deferral of those taxes and was fully paid by DEC by December 31, 2022. Finally, as witness Abernathy explained a portion of the delayed tax benefit is associated with DEBS to which DEC received no carrying cost benefit from the delayed payment of social security taxes. In reaching its conclusion regarding the treatment of savings in this case, the Commission gives significant weight to the testimony of witness Abernathy that expense savings resulting from DEC's normal cost mitigation measures to offset revenue shortfalls related to mild weather and in this case, the pandemic, should not be used to offset COVID-related expenses.

Further, the Commission is persuaded by the testimony of witness Abernathy that savings related to the federal government assistance for which DEC filed and received ERCs should not be used to offset the expenses included in the COVID deferral. The Commission gives weight to the testimony of witness Abernathy that the ERC payments are attributable to operations from March 13, 2020 through September 30, 2021, a period that covers the height of the NLR impact on DEC. Regarding the delayed payment of the employer portion of the social security tax, the Commission determines that such benefit was simply a temporary deferral from the government and such expense was ultimately paid by DEC in December 2022 and should not be netted against COVID-related costs. Further, the delayed tax benefit is associated with DEBS which provided no carrying cost benefit to DEC should also not be netted against DEC's COVID-related costs. In sum, the Commission concludes that cost mitigation efforts that were employed in 2020 and 2021 to offset NLRs, ERC benefits, and the cost savings associated with the carrying cost benefit related to the delayed payment of employer portion of social security tax should not be netted against the deferred COVID-related costs.

The Commission also approves DEC's request to recover approximately $23 million in accrued carrying costs on the deferred costs and authorizes a return on the unamortized balance of the COVID-related costs during the amortization period. In reaching this decision, the Commission is conscious of the fairness and equity factors inherently at play in considering how to appropriately balance the difficulties experienced by both the utility and ratepayers throughout the pandemic. The Commission agrees with DEC that the deferred costs were fronted by DEC's investors and the costs should properly bear a return at DEC's weighted average cost of capital to ensure that DEC and its investors are made whole.

The Public Staff recommended denial of any return on the allowed deferred expenses stating that the Public Staff believes that it would be inappropriate to allow DEC to earn a return on costs for which all other utilities regulated by the Commission did not seek a deferral. Additionally, the Public Staff argued that the interest has already been accounted for in the $45.7 million late payment fees of the deferred expenses at issue in this proceeding, and to allow an additional return would unfairly allow DEC to collect interest upon interest.

In responding to these points, DEC stated that a number of utilities sought and received deferrals across the country and some have already begun cost recovery. In North Carolina, DEC and DEP were the utilities that faced, and still face, the greatest amounts of bad debt resulting from the COVID pandemic. Indeed, the Commission's own COVID pandemic reports prove out that DEC's bad debt in North Carolina alone was several times that of water and gas utilities. In addition, as witness Q. Bowman explained utilities like Piedmont Natural Gas and Public Service Company of North Carolina, Inc. were able to reduce their exposure to the pandemic through existing regulatory mechanisms. The same mechanism was not available to DEC. As for interest on late payment fees, the Commission gives weight to witness Abernathy that interest has not been accounted for through the category of late payment fees in that DEC was unable to collect the late payment fees when they were due and that additional financing costs were incurred. Therefore, late payment fees are appropriately included in the deferred amount and should receive the carrying costs during the deferral period and the amortization period.

The Commission also gives significant weight to the fact that the COVID deferral is the result of mandates from the Governor and Orders of this Commission. Furthermore, DEC took immediate action to mitigate the hardship to customers and to ensure the continued provision of the essential electric service to all of its customers in North Carolina. Those actions included waiving all disconnections for customers who did not pay their electric bills and waiving customer late payment fees, return check charges, reconnections fees, and residential customers' electronic payment fees. Customers were served, even when unable to pay, and DEC carried customer balances for many months and years in some cases. As a result of those mandates DEC had to use investor supplied funds to pay the incremental COVID costs. Part of the prudently incurred cost of the COVID deferral includes the use of investor capital, which means that the investor typically receives a return on that investment until the balance has been fully recovered. In this case, DEC customers have been provided the benefit of delayed payments for COVID-related costs. The Commission finds that DEC's response during the critical emergency and the governmental mandates provide the support for recovery of the COVID-related costs, including the carrying costs during the deferral period. DEC upheld its obligation, and the Commission concludes that DEC is entitled to recover its accrued carrying costs. The Commission finds that the recovery of approximately $23 million of accrued carrying costs on the deferred costs during the deferral period as well as a carrying cost during the amortization period is appropriate.

The Commission concludes that it is appropriate that cost recovery for the approved deferred COVID-related costs occur over a three-year amortization period, coincident with the three-year MYRP period. In determining the reasonable and appropriate amortization period for the COVID-related costs, the Commission also gives weight to witness Abernathy's testimony that DEC has carried the deferral on its books for more than three years, starting in March of 2020 and that DEC would continue to carry this deferral on its books until the costs are fully recovered. The Commission finds that the 12-year amortization period advocated by the Public Staff in its proposed order is unreasonably long. Further, the Commission determines that amortization of the deferred COVID-related costs should begin upon the effective date of new rates in this proceeding.

Regarding DEC's request to continue its deferral for incremental bad debt expense, the Commission determines that since DEC is still incurring incremental bad debt expense, it is appropriate for DEC to continue to defer those costs incurred after June 30, 2023. The Commission concludes that DEC's request to continue the deferral of the incremental bad debt, for future recovery, is just and reasonable, and should be approved. The Commission also concludes that DEC should credit any payments associated with the deferred bad debts to the COVID deferred account on a monthly basis through the next general rate case. Furthermore, the Commission concludes that DEC should file a report with the Commission on a semiannual basis stating the actual amounts of additional incremental bad debt expense recorded to the COVID deferral and the associated payments received with respect to the deferred bad debts.

Finally, the Commission notes that its decision on deferral of the COVID-related costs is based on the particular facts of this case, and in particular, the unprecedented circumstances related to the pandemic, and should not be cited or relied on as precedent for future cost deferral decisions. The Commission evaluated the totality of the pandemic, taking into consideration the governmental mandates which removed DEC's tools to control bad debt expense, the necessity for DEC to provide uninterrupted electric service during the duration of the pandemic, even when many customers were not paying their bills, and the benefit to customers and North Carolina as a whole of the governmental mandates. Considering all these factors and the entire evidence of record, the Commission concludes that its decision set forth herein is the most reasonable, fair, and equitable outcome for both customers and shareholders with respect to the COVID pandemic.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 56

Storm Balancing Account

The evidence supporting this finding of fact is contained in DEC's verified Application and Form E-1; the Revenue Requirement Stipulation; the testimony and exhibits of DEC witness Q. Bowman; Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

Summary of Evidence

DEC witness Q. Bowman testified as to DEC's request for approval of a new methodology for tracking storm costs incurred. Tr. vol. 12, 192. Witness Q. Bowman explained that Adjustment NC7010 establishes an average amount of incremental storm costs included in customer rates. *Id.* Witness Q. Bowman testified that under DEC's proposal, each year, if the incremental storm expenses are over the average amount in rates, the difference would be deferred to a "storm balancing account;" if the incremental storm expenses are under the average amount in rates, the difference would be contributed to the account. Witness Q. Bowman testified that if the average amount included in customer rates approximates the average amount of storm expense going forward, the balancing account balance should fluctuate around zero and not require additional funding. *Id.* Witness Q. Bowman further stated that if the account does require additional funding, this could be evaluated in a future rate case or storm securitization proceeding. *Id.* Witness Q. Bowman testified that the storm balancing account would allow DEC to recover its actual costs for storm restoration efforts and ensure that DEC does not make or lose money related to its storm restoration efforts. *Id.*

Public Staff witnesses Zhang and Boswell disagreed with DEC's proposal to create a storm balancing account and stated that creating such an account would only serve to transfer all risk from DEC to ratepayers, including placing unaudited costs into a deferral for recovery. *Id.* at 1021-23. The Public Staff stated that DEC already has ample opportunities to recover storm costs, whether that be through storm normalization, securitization, or deferrals, all of which may allow DEC to reasonably and appropriately recover actual audited storm costs. *Id.* at 1022.

DEC witness Q. Bowman testified on rebuttal that the Public Staff accurately summarized DEC's intent in proposing the storm balancing account. Tr. vol. 15, 1277. Witness Q. Bowman explained that the Commission should implement a mechanism that results in DEC's neither making nor losing money because of storm restoration efforts. *Id.* Witness Q. Bowman responded to the Public Staff's assertion that the storm balancing account would transfer risks from the utility to ratepayers and would include unaudited costs for recovery. *Id.* at 1278. Witness Q. Bowman testified that the base level of storm expense that must be exceeded before DEC can request deferral has in practice been inequitable to DEC as the base level of storm expense is greater than the amount of storm normal expense included in base rates, which results in that difference being borne by shareholders. *Id.* Witness Q. Bowman stated that it is DEC's position that these storm restoration expenses are a cost of service of the regulated utility that are reasonably and prudently incurred and should be recovered from customers. *Id.* at 1279.

Witness Q. Bowman also responded to the Public Staff's second assertion and explained that the deferral of the amounts to the balancing account does not preclude those amounts from being subject to audit or review by the Public Staff or the Commission. *Id.* at 1280. Witness Q. Bowman testified that deferrals, by their nature, are unaudited amounts when initially recorded, but that when the amounts in the balancing account are put forth for recovery or return to customers in a future case or securitization, the activity and related balance will be subject to audit for reasonableness and prudency. *Id.*

Discussion and Conclusions

In Section III, Paragraph 40(e) of the Amended Revenue Requirement Stipulation, DEC agreed to withdraw its request for a storm balancing account in this proceeding. No intervenor took issue with this provision of the Stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 57-59

Other Deferrals

The evidence supporting these findings of fact is contained in DEC's verified Application and Form E-1; the Revenue Requirement Stipulation; the testimony and exhibits of DEC witnesses Abernathy, Bateman, Stillman, Q. Bowman, Panizza, and Klein; Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

IIJA/IRA

By Application and through the direct and rebuttal testimony of witness Abernathy, DEC requests to defer the estimated tax benefits, net of costs, associated with the IRA and IIJA. Tr. vol. 12, 95–96; tr. vol. 16, 231.

With respect to the IRA, DEC witness Panizza discussed the solar MYRP project and the battery energy storage MYRP projects that are eligible for either ITC or Production Tax Credits (PTC) made available under the IRA. Tr. vol. 12, 507. Witness Abernathy explained how DEC estimated the IRA benefits based on the best information available and that DEC's intention is for customers to receive the full benefit (net of costs) of the tax credits. *Id.* at 95–96.

Public Staff accounting panel witnesses Boswell and Zhang testified in support of the requested deferral treatment of the IRA impacts. *Id.* at 1049–50. Similarly, Public Staff witness Nader provided testimony recommending that the Commission treat the impacts associated with the IIJA consistent with those related to the IRA. *Id.* at 760.

Regarding the IIJA, DEC witness Klein responded to the Public Staff's recommendations and provided an overview of DEC's approach to identifying and pursuing federal loans and grants that may be available under the IIJA, including under the Grid Resilience and Innovative Partnerships (GRIP) Program. Tr. vol. 15, 1214–22. Witness Klein also described DEC's rigorous prioritization methodology for determining which opportunities it should pursue, and witness Klein reiterated that DEC pursued every available opportunity to obtain funds under the IIJA as directed by the Commission. *Id.* Witness Klein responded to Public Staff witness Thomas' testimony about the status of funding for DEC's hydroelectric projects and clarified the eligibility requirements provided in the IIJA. *Id.* at 1224. Witness Abernathy also testified that DEC "agrees [with the Public Staff] that a deferral of IIJA impacts is appropriate and support[s] the recommendation for the Commission to approve an accounting order to defer any incremental revenue requirement impacts, including benefits and costs related to IIJA, and that they be addressed in a future rate case." Tr. vol. 16, 231.

Based on the foregoing, the Commission concludes that DEC's request for an accounting order authorizing deferral of all IRA and IIJA related impacts, net of costs, as well as any difference between realized and estimated impacts included in DEC's filing is reasonable and should be approved.

Customer Assistance Program, Payment Navigator Program, and the Tariffed On-Bill Program

In DEC witness Q. Bowman's direct testimony, she explained that DEC has proposed several new programs in this case to benefit customers, including the CAP, Tariffed On-Bill program, and the Payment Navigator program (Customer Programs) and that DEC would incur certain implementation and administration costs that were not included in the test period, and which are not known and measurable at this point. Tr. vol. 12, 191–92. Witness Q. Bowman stated that should the Commission approve the Customer Programs, DEC requests permission to establish a regulatory asset and defer to the account the incremental implementation and administrative O&M costs related to the programs for future recovery in rates. *Id.* Witness Q. Bowman also testified that DEC is proposing PIMs as part of its PBR Application and that DEC requests to defer to this regulatory asset the implementation costs for the PIMs, including, without limitation, certain costs relating to marketing, administration, and the PIMs dashboard. *Id.*

DEC witnesses Bateman and Stillman testified that the PIMs dashboard had a capital cost estimate of $540,000, with estimated annual O&M costs of approximately $100,000, with DEC proposing to allocate 56.77% of these costs to DEC's North Carolina retail customers. Tr. vol. 11, 183.

Public Staff witnesses Zhang and Boswell testified that the proposed deferral of the costs associated with the implementation of the proposed Customer Programs and PIMs fails to meet either prong of the Commission's two-prong test for deferrals, and therefore DEC's request should be denied. Tr. vol. 12, 1045. Public Staff witnesses Zhang and Boswell further testified that because PIMs are designed to protect ratepayers and are required for approval of an MYRP, PIMs are part of DEC's normal course of business and should also be denied on that basis. *Id.* at 1045–46.

In witness Q. Bowman's rebuttal testimony, she responded to the Public Staff's recommendation to deny DEC's request on the basis of the deferral test. Tr. vol. 15, 1304–06. Witness Q. Bowman testified that DEC's request is being included as a part of its general rate case proceeding and is not an "out of period" cost subject to the Commission's two-prong deferral test. *Id.* at 1305. Witness Q. Bowman explained that even though the costs of implementing these programs are known and measurable, DEC did not adjust operating expenses in this case to include these incremental costs which are not captured in the historic test period. *Id.* Witness Q. Bowman clarified that while PIMs will become a part of DEC's normal course of business as a result of the MYRP, the costs of that new normal course of business have not been included in operating expenses for recovery from customers. *Id.* at 1305–06. Thus, witness Q. Bowman explained that creation of a regulatory asset for deferral of the costs would allow DEC to postpone recovery of these costs until the Customer Programs are implemented and benefitting customers. *Id.* at 1306.

In Section III, Paragraph 40(c) of the Amended Revenue Requirement Stipulation, DEC agreed that it would not defer costs relating to the Customer Programs or costs associated with PIMs. The Commission notes that this resolution is consistent with the resolution of the issue in the recent DEP Rate Case. The Commission agrees with witness Q. Bowman's rebuttal testimony that the fact that deferral requests in general rate case proceedings are not subject to the Commission's two-prong deferral test. However, the Commission accepts the agreement reached in the Revenue Requirement Stipulation. To the extent that there are ongoing O&M expenses associated with implementation of the PIMs and customer programs, DEC may seek cost recovery of actual expenses incurred during a future test period in its next general rate case. No intervenor took issue with this provision of the Revenue Requirement Stipulation, and the Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 60

Interconnection CIAC

The evidence supporting this finding of fact is contained in DEC's verified Application and Form E-1; the Revenue Requirement Stipulation; the testimony and exhibits of DEC witness Speros; Public Staff witnesses Metz, Zhang, and Boswell; and the entire record in this proceeding.

Public Staff witnesses Zhang and Boswell testified that during the course of the Public Staff's investigation into both the DEC and DEP rate cases, the Public Staff discovered that DEC was booking CIAC related to IAs inconsistently. Tr. vol. 12, 1005. Witnesses Zhang and Boswell testified that in general, an IA developer is responsible for network upgrades when connecting to DEC's network, not the ratepayer. *Id.* Witnesses

Zhang and Boswell further testified that DEC changed its booking procedures for the fees received for interconnections at the beginning of 2022. *Id.* The Public Staff witnesses asserted that they were unable to determine whether ratepayers have been harmed, and if DEC's new procedures will alleviate the issues. *Id.* Therefore, the Public Staff recommended that the Commission order DEC to produce all entries related to the IAs for all plant, depreciation, and collections so the Public Staff can determine whether ratepayers have been held harmless. *Id.* at 1005–06. Additionally, the Public Staff recommended that a regulatory liability be established to record any instances in which DEC incorrectly recovered costs associated with IAs from ratepayers, to be flowed back to ratepayers with interest at DEC's weighted average cost of capital in DEC's next general rate case. *Id.* at 1006. Witnesses Zhang and Boswell testified that since DEC had full control over its accounting systems and should have booked the amounts correctly, any items found to have been booked that should have been recovered from ratepayers should not be credited to the regulatory liability. *Id.* Witnesses Zhang and Boswell recommended that the Commission order DEC to review its CIAC policy and report the results of that review in the next general rate case. *Id.*

DEC witness Speros took exception to the Public Staff's recommendations and argued that the establishment of a regulatory liability has not been justified in this case. *Id.* at 546. Witness Speros explained that DEC has taken a number of steps to ensure CIAC associated with IAs is appropriately recorded on DEC's books. *Id.* at 547. Witness Speros stated that this process begins with DEC's monthly reconciliation of associated liability accounts. *Id.* For transmission projects, a monthly journal entry is made to credit capital projects for customer deposits based upon the cost incurred. *Id.* For distribution projects, quarterly journal entries are made to credit the capital projects for customers based upon costs incurred. *Id.* Witness Speros stated that DEC's project controls organization and finance organizations then work together to ensure that the current list of IA projects is appropriately analyzed so that proper journal entries are made, whether a debit or credit to the construction project. *Id.* Moreover, witness Speros explained that DEC continually works to improve its accounting processes, including the process for recording CIAC associated with IAs. *Id.* Witness Speros commented that since 2019, DEC has taken steps to improve the processes in place for recording CIAC associated with IAs and made recent modification in 2022. *Id.* at 547–48. Witness Speros also explained that DEC has not been able to identify any interconnection costs associated with CIAC that ratepayers should not have been charged in DEC's last general rate case. *Id.* at 549. Witness Speros testified that if the Commission were to adopt a regulatory liability for the purpose of reconciling any instances where IA costs have been incorrectly booked, that regulatory liability should record both credits and debits. *Id.* at 549. Witness Speros testified that any amounts related to the Public Staff's CIAC concerns are not material in this case, given that the vast majority of DEC customers opt for a monthly facilities charge. *Id.*

Witness Speros also testified that the Public Staff's broad-based recommendation to order DEC to produce all entries related to IAs for all plant, depreciation, and collections is unnecessary to demonstrate that DEC's procedures are working properly. *Id.* at 548. In the alternative, DEC offered to work with the Public Staff in a collaborative fashion to facilitate their review and help identify information that would best provide a reasonable and efficient evaluation. *Id.* DEC also did not oppose in principle reporting to the Commission on its CIAC policy in the next general rate case. *Id.* at 550.

No other intervenors raised an issue regarding DEC's accounting for CIAC associated with IAs.

The Revenue Requirement Stipulation identifies the CIAC issue as resolved. Per the Stipulation, the Stipulating Parties agree to settle this issue on the same terms as it was resolved in the DEP Rate Case. In the DEP Rate Case Order, the Commission directed DEP to continue its work with the Public Staff regarding the documentation of its processes related to the recording of CIAC and to report on the CIAC issue in its next general rate case. Accordingly, the Stipulating Parties in this case agree that it is not necessary to establish a regulatory liability at this time for CIAC in this case. *See* Revenue Requirement Stipulation (Tr. Ex. vol. 7).

Based upon all of the evidence presented, the Commission concludes that the Revenue Requirement Stipulation is just and reasonable with respect to the IA-related CIAC issue. Accordingly, DEC will not be required to establish a regulatory liability for the recording of IA-related CIAC. DEC shall continue its work with the Public Staff regarding the documentation of its processes related to the recording of IA-related CIAC and shall report on the CIAC issue in its next general rate case application as required by the Revenue Requirement Stipulation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 61

Quality of Service

The evidence supporting this finding of fact is contained in DEC's verified Application and Form E-1; the testimony and exhibits of DEC witnesses Guyton, Maley, Quick, and K. Bowman; Public Staff witness T. Williamson; and the entire record in this proceeding.

DEC witnesses Guyton and Maley testified to the performance of the DEC transmission and distribution systems during the base period. Witness Maley testified that DEC's transmission system is reliable and well-maintained, and that DEC is seeking to continue transmission investments to facilitate the conversion of the transmission system to meet future demands. Witness Maley further indicated that DEC utilizes the SAIDI and SAIFI metrics to measure outage durations and that these metrics over the base period showed a downward trend in outages (and therefore an upward trend in reliability). Witness Maley indicated that the transmission system also utilizes an Outages per Hundred Miles per Year — Sustained Automatic (OHMY-SA) metric which has further demonstrated the reliability of the DEC transmission system. Tr. vol. 8, 269–71. Witness Guyton testified that DEC's operational investments since its last rate case have allowed it to meet its operational performance and customer satisfaction goals and that it is providing safe and reliable service. *Id.* at 113–16. Witness Guyton also cited DEC's SAIDI and SAIFI scores as indicative of increasing system reliability in the form of reduced customer outages. Witness Guyton attributed this improvement in outage experience to ongoing grid improvements such as SOG improvements as well as ongoing vegetation management activities. *Id.* at 114–16.

In Public Staff witness T. Williamson's direct testimony, he testified that overall, the quality of service provided by DEC to its North Carolina retail customers, on average, is adequate given minor improvements in shorter-term non-MED SAIDI. Tr. vol. 15, 154–67. Witness T. Williamson also engaged in an in-depth analysis of DEC's service quality in which he examined various aspects of DEC's performance in initiating new service, providing normal day-to-day service, and restoration of service after outage events. *Id.* at 151–70. Witness T. Williamson also summarized various consumer statements of position filed with the Commission relative to this rate case. *Id.* at 168–70.

Regarding the initiation of new service, witness T. Williamson indicated that new service installations have steadily increased from 2015 through 2022 and that DEC's average percentage of installations completed within 20 days averaged 94.7%. Witness T. Williamson also noted that DEC was completing new residential service installations in a consistent manner and is providing customers with a reasonable expectation as to the amount of time it will take DEC to provide initial service to new residential dwellings. *Id.* at 152–53. Regarding day-to-day service, witness T. Williamson testified that from 2017 through 2022, non-MED SAIDI shows a downward trend (lower the SAIDI score, the shorter the outage duration for customers) and the non-MED SAIFI trend is relatively flat with a slight upward move (higher the SAIFI score, the more frequently customers experience outages). Witness T. Williamson also testified that while DEC has seen improvements in non-MED SAIDI and SAIFI during the 2017-2022 timeframe, DEC's longer-term trend from 2014-2022 demonstrates a relative decrease in service quality and a less favorable trend for ratepayers. Witness T. Williamson testified that these trends may be reflective of the initiation of the GIP and continued investments in DEC's transmission and distribution systems, though it is too soon to draw broad conclusions. *Id.* at 155.

Witness T. Williamson further testified that service reliability as measured by ASAI[27] during the 2014 through 2022 timeframe, has held steady at 99.97%. *Id.* at 159. With respect to restoration of service after an outage, witness T. Williamson testified that DEC's Estimated Time to Restoration for service outages was met in 96.0% of MED outages. *Id.* at 167.

In DEC witness Quick's direct testimony, she testified that in addition to DEC's primary responsibility of providing safe and reliable service, DEC understands that its customer base has diverse service needs and strives to recognize and accommodate them where possible. Tr. vol. 7, 122–23. Witness Quick outlined the steps that DEC is

[27] ASAI is the ratio of the total number of customer hours that service was available during a given time period to the total number of customer hours demanded. Algebraically, this ratio is represented as follows: ASAI= 1 – (SAIDI/8760).

taking to continue to improve customers' experiences and satisfaction. *Id.* With respect to DEC's customer care operations, witness Quick explained that they are designed and continuously enhanced to ensure that customer inquiries are answered promptly and accurately. Customer calls are either processed in the Interactive Voice Response (IVR), allowing customers to self-serve, or by a call center specialist. *Id.* Witness Quick also described how DEC uses social media channels to inform customers about reliability updates in their area and changes that could impact their bills. Additionally, in an emergency or major storm, DEC uses social media to communicate essential information to customers, making proactive posts to quickly warn as many customers as possible and engage with customers who have storm- or outage-related questions. *Id.* at 124.

Witness Quick also testified about the programs that DEC supports to help customers with the affordability of electric utility service. Witness Quick noted the energy efficiency programs that help reduce energy usage and provide weatherization assistance. *Id.* at 125–26. Witness Quick also detailed DEC's numerous efforts to support customers during the unprecedented COVID pandemic. One example she gave was DEC's expansion and extension of the Winter Moratorium, a period from November until March every year where qualified customers are protected from disconnection for nonpayment. DEC ensured the Winter Moratorium remained in place from November 2020 until March 2022, protecting approximately 53,000 eligible customers from disconnection during the initial and subsequent COVID pandemic waves. Another example was the outreach campaigns to municipal leadership, community stakeholders, Chambers of Commerce, state agencies, food banks, and churches where DEC communicated with customers to promote options for assistance and contacting DEC. *Id.* at 139–44.

Witness Quick further testified about recent digital enhancements to improve service to customers. Witness Quick relayed that after receiving customer feedback, DEC improved its website by making interaction operations easier to locate in January 2022. Additionally, she described an interactive Transmission Map that details transmission projects planned across North Carolina, a planned vegetation management map, a feature alerting customers to estimated call wait times, the ability for customers to start and stop service online, and a digital, and a self-service enrollment option for payment arrangements. Moreover, witness Quick highlighted that DEC's digital enhancements made it easier for customers to report service interruptions. Witness Quick also testified that DEC offers a free mobile app that allows residential and small business customers to easily manage their account from anywhere in the United States. Witness Quick stated that since making these changes, customers are reporting higher satisfaction with their web experiences. *Id.* at 155–66.

In DEC witness K. Bowman's supplemental settlement testimony, she testified that the Revenue Requirement Stipulation is a fair compromise that serves customers' interests by allowing DEC to recover the investments required to safely and reliably provide high quality electric service to customers, all while advancing the state's energy policy goals. *Id.* at 111.

Discussion and Conclusions

In recognition of the policy of the State of North Carolina “to promote adequate, reliable and economical utility service” codified at N.C.G.S. § 62-2(2) and in accordance with the Commission’s general supervisory authority established in N.C.G.S. § 62-32, and recognizing that the Commission found DEC’s service quality to be “good” in the 2019 Rate Case Order and that the performance metrics for service rendered have not declined and, in some cases, have improved since that rate case, as is reflected in witness T. Williamson’s testimony, the Commission concludes, based on the record in this proceeding, that the quality of service provided by DEC is good. No other party presented evidence on DEC’s service quality.

Additionally, no other party presented evidence critical of DEC’s quality of service. Based on the foregoing, the Commission concludes that DEC provides adequate service to customers.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 62-63

Tax-Related Items

The evidence supporting these findings of fact is contained in DEC’s verified Application and Form E-1; the testimony and exhibits of DEC witness Q. Bowman; Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

In its Application, DEC proposes to revise the EDIT-4 Rider to return an additional $17.1 million for unprotected federal EDIT and $5.9 million for deferred revenues to customers over the remaining 2.4 years of the total five years to return the unprotected federal EDIT approved in the prior rate case. The two-year period for Deferred Revenues under EDIT-3 expired in June of 2023; therefore, DEC is proposing to flow the additional amounts back to customers over the remaining life of the EDIT-4 Rider in lieu of creating a new decrement rider.

DEC witness Q. Bowman supports this revision to the EDIT-4 Rider in her direct testimony and in Q. Bowman Exhibit 3. Tr. vol. 12, 188. The Public Staff agrees with DEC’s proposal to flow back the incremental amount to customers on a levelized basis; however, the Public Staff proposed to flow back the incremental amount to customers over three years instead of over the remaining EDIT rider term. Tr. vol. 15, 1306. Additionally, the levelized return rate used by the Public Staff reflects DEC’s 4.53% cost of debt rate and a return on equity of 9.35% with a 48.0% debt and 52.0% equity capital structure. *Id.*

In witness Q. Bowman’s third supplemental testimony, she updated DEC’s cost of debt to 4.56% as of June 30, 2023, and recalculated the proposed changes to the EDIT-4 Rider accordingly. Tr. vol. 12, 220–22. In the Revenue Requirement Stipulation, the stipulating parties agreed to update the cost of debt to the actual cost of debt as of June 30, 2023, 4.56%. Revenue Requirement Stipulation § III.1 (Tr. Ex. vol. 7).

Based on the foregoing, the Commission concludes that DEC's proposal to revise the EDIT-4 Rider to return additional unprotected federal EDIT to customers over the remaining life of the EDIT-4 Rider, as supported by the Public Staff, is just and reasonable and should be approved. Further, the Commission finds and concludes that the levelized return rate should be based on the 4.56% embedded cost of debt agreed to by the stipulating parties in the Revenue Requirement Stipulation and the capital structure and rate of return on equity approved by the Commission in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 64

Fuel Cost Voltage Differential

The evidence supporting this finding of fact is contained in DEC's verified Application and Form E-1; the Revenue Requirement Stipulation; the testimony and exhibits of DEC witness Sykes; Public Staff witness Lucas; and the entire record in this proceeding.

Public Staff witness Lucas recommended in his testimony that voltage differentiated fuel rates be used by DEC, as they are used by DEP. Witness Lucas stated that such rates reflect the fact that less generation and fuel consumption is required for customers that receive service at higher voltages. Witness Lucas further testified that recent changes in North Carolina law, that being the passage of N.C.G.S. § 62-133.16 regarding PBR, support the Public Staff's position with regard to the cost causation principle. Tr. vol. 13, 140–42. Specifically, Public Staff witness Lucas recommended DEC incorporate voltage differential for the prospective billing period fuel rates in DEC's next fuel proceeding to be filed in February 2024, with rates taking effect on September 1, 2024; however, he clarified that this recommendation should not affect the Experience Modification Factor fuel rates established in the 2024 fuel proceeding. *Id.* at 147.

In DEC witness Sykes's rebuttal testimony, he stated that DEC did not agree with Public Staff witness Lucas's recommendation, and instead proposed to incorporate voltage differential into fuel rates prior to a merger of the two utilities in a future general rate case proceeding. Tr. vol. 12, 624–25. In support for DEC's proposal, DEC witness Sykes explained that DEC's affiliate, DEP, followed this same approach in its 2012 general rate case proceeding in Docket No. E-2, Sub 1023, where DEP proposed, and the Commission approved, to begin recovering voltage differential through the annual fuel proceeding simultaneously with the effective date for new rates in that general rate case. In the case of DEP, the timing of the transition of voltage differential from the general rate case and the annual fuel proceeding aligned, which is what witness Sykes therefore proposed to do in a future general rate case prior to a merger of DEC and DEP. *Id.*

In the Revenue Requirement Stipulation, DEC agreed to incorporate fuel cost voltage differential for the prospective billing period fuel rates in DEC's next fuel proceeding to be filed in February 2024, and to remove line losses from base rates at that time. No intervenor took issue with this provision of the stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of the fuel cost voltage differential rate issue for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 65-66

Equal Percentage Allocation, Base Fuel and Fuel-Related Factors, and Fuel Cost Allocation

The evidence supporting these findings of fact is contained in DEC's verified Application and Form E-1; the testimony and exhibits of DEC witnesses Hager, Q. Bowman, and Sykes; Public Staff witnesses Lucas, McLawhorn, Zhang, and Boswell; CIGFUR witness Collins; and the entire record in this proceeding.

Equal Percentage Fuel Allocation Adjustment Allocation Methodology

In its Application and Form E-1, DEC allocated its proposed fuel rates amongst the retail customer classes using the equal percentage fuel adjustment methodology.

Public Staff witness Lucas testified that DEC currently allocates fuel cost adjustments to customer classes based on an equal percentage change, meaning that fuel and fuel-related costs are recovered using a uniform percent increase or decrease per rate class such that each rate class will, on average, experience the same average monthly percent increase or decrease as the overall fuel and fuel-related costs change. Tr. vol. 13, 136. He testified that the Public Staff first supported the use of the equal percentage fuel adjustment allocation methodology in DEP's 2008 fuel adjustment proceeding, Docket No. E-2, Sub 929. He cited several reasons for the Public Staff's agreement to the equal percentage fuel adjustment allocation methodology including uncertain economic times and the large increase in fuel costs. *Id*. at 136–37. He noted that the equal percentage fuel adjustment allocation methodology assisted industrial customers financially during the Great Recession and during a period of unprecedented increases in coal prices at the expense of other customers. *Id*.

Public Staff witness Lucas testified that since 2012, in Docket No. E-7, Sub 1002, DEC has allocated fuel cost increases on an equal percentage basis to each of its customer classes as allowed by Session Law 2007-397. *Id*. at 135–38. He indicated that DEC switched to the equal percentage fuel adjustment allocation methodology because large customers believed that moving to equal percentage fuel adjustments would aid in load retention during the economic conditions at the time. *Id*. However, witness Lucas also testified that the distortion created by the equal percentage fuel adjustment allocation methodology shifts fuel costs away from industrial customers and onto other customer classes. *Id*. at 174–76. He explained that, for this reason, it is the Public Staff's recommendation that the Commission should not allow DEC to make equal percentage fuel adjustments moving forward. *Id*.

Witness Lucas recommended that the Commission require DEC eliminate the equal percentage fuel adjustment allocation methodology in its next fuel proceeding to be filed in February 2024 with rates taking effect on September 1, 2024. *Id*. at 147.

Witness Lucas also testified that DEC should use voltage differentiated fuel rates to reflect the fact that less generation and fuel consumption is required for customers that receive service at higher voltages. *Id*. at 141. Witness Lucas recommended that DEC implement voltage differentiation in fuel rates in its next fuel proceeding to be filed in February 2024 with rates taking effect on September 1, 2024. *Id*. at 147. DEC and the Public Staff agreed to this recommendation in their Amended Revenue Requirement Stipulation filed on August 28, 2023.

Witness Lucas also explained that since DEC's last general rate case N.C.G.S. § 62-133.16(b) now requires the Commission to allocate the utility's total revenue requirement among customer classes based on the cost causation principle and minimize cross subsidies "to the greatest extent practicable." *Id*. at 142–45, 181–82. He noted that the statute defines the cost causation principle to mean "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." *Id*. at 142.

Witness Lucas presented the current fuel rates adjusted to remove the equal percentage allocation method. *Id*. at 36. As set forth in Lucas Table 6, the rates in cents per kilowatt-hour, excluding the regulatory fee, are 2.3345 for Residential customers, 2.3387 for General customers, and 2.3326 for Industrial customers. *Id*. at 145.

CIGFUR witness Collins testified in support of the equal percentage fuel adjustment methodology. Tr. vol. 15, 973. He stated that the equal percentage fuel adjustment methodology has been approved without objection by any party in every annual fuel charge adjustment proceeding since 2008 and that the method has served ratepayers well and should continue to be utilized. *Id.* at 972. He further opined that the equal percentage fuel adjustment methodology levelizes over time any harsh impacts and results in equal percentage increases or decreases to all customers, which are fair, just, and reasonable. *Id.* at 973. He further argues that additional capital costs, rather than only fuel costs, are now recovered in the fuel charge adjustment proceedings and the continuation of the equal percentage fuel adjustment methodology is appropriate due to the significant subsidization of between certain customer classes. *Id.*

On cross-examination during the evidentiary hearing, DEC witness Beveridge stated that DEC's proposed revenue apportionment assumed continued use of the equal percentage fuel adjustment methodology to allocate fuel and fuel-related costs. Tr. vol. 10, 257.

Discussion and Conclusions

In CIGFUR's post-hearing brief, CIGFUR argues that N.C.G.S. § 62-133.16(b) is inapplicable to the DEC's fuel and fuel-related charge adjustment rider, which is facilitated by the Commission pursuant to N.C.G.S. § 62-133.2 and Commission Rule R8-55. CIGFUR particularly contends that the provisions of N.C.G.S. § 62-133.16(b) do not apply to the fuel rider, because N.C.G.S. § 62-133.16(g) makes it clear that the fuel rider operates independently and must be considered separately from DEC's PBR Application. CIGFUR Post-Hearing Brief at 8.

CIGFUR next asserts that

> It would constitute an absurd result if the purported interclass cross-subsidy the Public Staff alleges is caused by the equal percentage method of allocating fuel and non-fuel (i.e., "fuel-related") costs was eliminated in the name of compliance with N.C.G.S. § 62-133.16(b) (which does not even apply to the Fuel Rider), while the same customer classes that purportedly benefit from the equal percentage allocation methodology are simultaneously and substantially subsidizing other customer-classes in base rates.

Id. at 8–9. CIGFUR offers its recommendation on what it deems to be more appropriate times when the Commission could reevaluate the equal percentage fuel adjustment methodology. However, CIGFUR contends that until the base rates paid by retail customer classes are at parity (i.e., each respective customer class is fully paying the costs allocated to it based upon the Commission's approved COSS) that eliminating the equal percentage fuel adjustment methodology will be counter-productive to minimizing retail class cross subsidies "to the greatest extent practicable" consistent with N.C.G.S. § 62-133.16(b).

Finally, CIGFUR argues that if the Commission eliminates the equal percentage fuel adjustment methodology it will be engaging in "impermissible single-issue ratemaking" because "it seeks to address a purported 'cross-subsidy' from other customer classes to certain non-residential classes of customers, while simultaneously ignoring the substantial subsidy in base rates being provided by those same non-residential customers to other classes of customers." *Id*. at 10.

After careful review of all evidence in the record in this proceeding and based on this evidence, the Commission concludes that it is no longer appropriate to allocate fuel and fuel-related costs, as defined by N.C.G.S. § 62-133.2, to retail customer classes using the equal percentage fuel adjustment methodology. In reaching this conclusion, the Commission gives substantial weight to the testimony of Public Staff witness Lucas — particularly that the distortion created by the equal percentage fuel adjustment allocation methodology shifts fuel costs away from industrial customers and onto other customer classes and the credible opinion provided by witness Lucas that the equal percentage fuel adjustment allocation methodology should be discontinued for this reason. The Commission finds that it is appropriate to require DEC to discontinue use of the equal percentage fuel adjustment methodology its next fuel rider proceeding to be filed with the Commission in February 2024.

The Commission has given due consideration to the arguments proffered by CIGFUR in its post-hearing brief and finds them to be without merit. With respect to the impermissible single-issue ratemaking argument, the Commission notes that objections based upon single-issue ratemaking typically arise outside of general rate case proceedings.

> Single-item rate adjustments outside general rate cases throw the base rates out of balance. Historically, the Commission has, with a few limited exceptions, disallowed the use of single-factor rate riders or cost recovery adjustments outside of a general rate case because it is unlawful to do so.

Order Addressing the Impacts of HB 998 on North Carolina Public Utilities, *Implementation of House Bill 998 – An Act to Simplify the North Carolina Tax Structure and to Reduce Individual and Business Tax Rates*, No. M-100, Sub 138 (N.C.U.C. May 13, 2014). Here, the Commission's determination to direct DEC to discontinue use of the equal percentage fuel adjustment methodology is based upon its full review of all cost of service components viewed through both traditional, historic test year principles pursuant to N.C.G.S. § 62-133 and future projections consistent with performance-based ratemaking as authorized by the General Assembly pursuant to N.C.G.S. § 62-133.16. Such thorough and holistic consideration is the antithesis of single-issue ratemaking.

The Commission is also not persuaded by CIGFUR's assertion that N.C.G.S. § 62-133.16(g) requires the Commission to consider the fuel rider separately from DEC's PBR Application. The Commission concludes that the purpose and intent of N.C.G.S. § 62-133.16(g) is to make clear that the PBR Statute does not "limit or abrogate the existing rate-making authority of the Commission[.]" It is not, as CIGFUR would have the Commission interpret, to limit the Commission's authority related to or analyses of appropriate cost allocation methodologies. The Commission has existing authority under N.C.G.S. § 62-133.2(f), the statute that governs the fuel rider proceeding, to determine the appropriate cost allocation methodology of fuel rates in a rate case. Therefore, the Commission is acting within its authority by applying cost-causation principles to fuel costs and determining the appropriate cost allocation methodology within this general rate case.

Finally, the Commission is persuaded by the testimony of Public Staff witness Lucas that it is appropriate for DEC to implement voltage differentiation in fuel rates in its next fuel proceeding consistent with the Amended Revenue Requirement Stipulation.

Base Fuel and Fuel-Related Cost Factors

Witness Q. Bowman testified that DEC made an adjustment (Adjustment No. NC2010) to test period fuel expense to match the fuel clause revenues included in pro forma Adjustment No. NC1010. Tr. vol. 12, 165. Witness Q. Bowman explained that by matching the expenses to the revenue, the adjustment ensures that no increase is requested in this proceeding related to fuel and fuel-related costs that are recoverable through the fuel clause. *Id.*

In witness Q. Bowman's supplemental direct testimony, she explained that DEC had updated pro forma Adjustment No. NC2010 to correct a formula error in DEC's original Application. *Id.* at 202.

Also in witness Q. Bowman's supplemental direct testimony, she testified that DEC had made a new adjustment (Adjustment No. NC2020) to adjust the nonfuel component of purchased power expense to reflect the impacts of the Stipulation Regarding the Proper Methodology for Determining the Fuel Costs Associated with Power Purchases from Power Marketers and Others reached with DEP, DEC and the Public Staff in Docket No. E-7, Sub 1282. *Id.* Based on the stipulation, witness Q. Bowman testified that during the test year, 15.0% of energy costs from these power purchases is the appropriate percentage to be deemed as non-fuel costs and appropriate for cost recovery through base rates. *Id.*

The only party that submitted evidence in this proceeding using fuel rates other than those approved in Docket No. E-7, Sub 1263 was the Public Staff. Public Staff witness Lucas presented theoretical fuel rates, based on rates proposed in Docket No. E-7, Sub 1282 with the equal percentage adjustments removed and with voltage differentiation. Witness Lucas did not propose such rates be implemented in this case. Tr. vol. 13, 145–46. The Commission concludes for purposes of this proceeding that matching fuel expense to fuel clause revenue as set forth in DEC adjustment NC2010, so that no increase is granted in this proceeding related to fuel and fuel related costs, is just and reasonable to all parties in light of all the evidence presented.

Fuel Cost Allocations

In DEC's previous general rate case, the parties agreed on production plant as an appropriate allocation factor for purchased power capacity costs. Tr. vol. 12, 369. Under N.C.G.S. § 62-133.2(a2)(2), the Commission shall determine how these costs shall be allocated in a general rate case for the electric public utility. Therefore, this proceeding is the appropriate forum for the Commission to reconsider the appropriate cost allocation methodology for such costs, which are to be requested for cost recovery in DEC's annual fuel proceeding.

Witness Hager testified that DEC is proposing that the Commission use production demand as the more appropriate factor to allocate purchased power capacity costs to North Carolina retail and across North Carolina retail customer classes. *Id*. Witness Hager testified that allocation based on production demand is more appropriate than production plant because purchased power capacity costs that are not recovered through the fuel clause are allocated on production demand. *Id.* Witness Hager testified that the change towards allocation based on production demand would align all purchased capacity costs under the same allocator. *Id.* Additionally, most production plant is allocated on production demand, except for jurisdiction-specific amounts that are not related to purchase power costs. *Id.* at 369–70.

No party offered testimony opposing DEC's recommendation.

Section 62-133.2(a2)(2) of the North Carolina General Statutes requires the Commission to determine how capacity costs should be allocated in a general rate case for the electric public utility. Therefore, this proceeding is the appropriate forum for the Commission to reconsider the appropriate cost allocation methodology for such costs, which are to be requested for cost recovery in DEC's annual fuel proceeding. Based upon the evidence presented in this case, the Commission finds and concludes that the same production demand allocation method approved for production demand costs in this case using the 12 CP methodology at NC retail and the Modified A&E methodology for NC retail classes is the most appropriate methodology for allocating purchased power capacity costs in DEC's annual fuel proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 67-68

Residential Decoupling Mechanism and Earnings Sharing Mechanism

The evidence supporting these findings of fact is contained in DEC's verified Application and Form E-1; the testimony and exhibits of DEC witnesses Abernathy, Bateman, and Stillman; Public Staff witnesses D. Williamson and Thomas; AGO witness Palmer; and the entire record in this proceeding.

Summary of Evidence

DEC's PBR Application seeks approval of PBR through the proposed three-year MYRP beginning on January 1, 2024 and ending December 31, 2026. DEC witness Bateman testified that in addition to the three-year MYRP, which includes an ESM, DEC's PBR Application also includes PIMs and a decoupling mechanism for the residential customer class. Tr. vol. 11, 146. Witness Bateman explained that the PBR approach and DEC's PBR Application better align customer and state policy goals with utility revenues and performance than traditional ratemaking. *Id.* at 148.

Residential Decoupling Mechanism

DEC witness Abernathy provided direct testimony on DEC's proposed decoupling mechanism, which is a ratemaking mechanism intended to break the link between an electric public utility's revenue and the level of consumption of electricity on a per customer basis. The following Rate Schedules are affected by the decoupling mechanism: RS, RE, ES, RT, RSTC, and RETC, along with any new residential rate schedules approved by the Commission during the Plan Period. Tr. vol. 12, 100. Witness Abernathy explained how the annual and monthly target revenue per customer would be calculated for Rate Years 1, 2 and 3, as well as how DEC plans to estimate the number of residential customers for each month for each rate year. Witness Abernathy's testimony also discussed how the difference between target residential revenues and actual residential revenues would be deferred and include a carrying charge, and that deferral amount would be adjusted to account for DSM/EE NLRs and incremental EV revenues. Lastly, witness Abernathy testified about how the Decoupling Rider will work and DEC's reporting obligations with respect to the deferred balance. *Id.* at 100–09.

AGO witness Palmer advocated for applying a lower carrying cost rate on the decoupling deferral amount and placing a hard cap of 3.0% on surcharges. Tr. vol.15, 409–10. Witness Palmer explained that a hard cap would limit rate increases and promote cost containment. *Id.* at 409. AGO witness Palmer asserted that DEC's proposal to exclude EV sales from its decoupling mechanism is not in the public interest and that the adjustment to exclude EV sales contains numerous unsubstantiated adjustments that cannot be verified. *Id.* at 398–400. Witness Palmer also asserted that there is no link between this proposal and the goal of advancing EV adoption. *Id.* Witness Palmer concluded that DEC's method for calculating EV sales is not accurate and recommended that the Commission reject DEC's proposal. *Id.* at 401–06.

Public Staff witness Nader testified that N.C.G.S. § 62-133.16 authorizes the Commission to approve a residential decoupling mechanism designed to break the link between revenues and the consumption of electricity. Witness Nader also testified that the statute also provides the utility with an opportunity to exclude rate schedules or riders associated with EV charging from sales calculations for purposes of the mechanism. Tr. vol. 12, 772. The Public Staff expressed only one concern regarding DEC's proposed decoupling mechanism. Witness Nader objected to how DEC determined the estimate of EV sales for the calculation and recommended that the decoupling mechanism not include DEC's proposed "Incremental EV Revenue Adjustment". *Id.* at 774. Witness Nader asserted that the estimate was speculative, and that the decoupling mechanism should only include the adjustment for EV sales when more accurate EV sales data are available. *Id.* Witness Nader recommended that the estimated monthly kilowatt-hour per EV should be updated regularly based on the data collected within the Commission-approved EV Make-Ready Program. In the interim, witness Nader recommended that DEC use metered data that is filed in DEC's First Status Report on Make Ready Credit Programs. *Id.* at 775.

In response to AGO witness Palmer's suggestion to institute a 3.0% hard cap on the amounts the utility is able to collect from customers, "decoupling cap," witness Bateman testified that there is no basis for a cap in the statute, that a cap has only been authorized in a few states, and that there is no cap on the recovery of DSM/EE NLRs. Tr. vol. 16, 265–66. Witness Bateman offered further support for the exclusion of EV sales from the decoupling mechanism. *Id.* Witness Bateman testified that adjusting the decoupling mechanism for EV sales allows the utility to retain incremental net revenues driven by EV growth, thereby directly connecting EV growth with net revenues. Witness Bateman further explained that precluding DEC from including an EV adjustment within the decoupling and ESM calculations would eliminate an important incentive for the utility to encourage EV adoption and grow EV sales in between rate case filings, which is actually contrary to the requirements of N.C.G.S. § 62-133.16 to encourage beneficial electrification. *Id.* at 264–65.

The PIMs Stipulation between DEC, the Public Staff, and CIGFUR provides that DEC is permitted to exclude all EV sales from its decoupling mechanism subject to two conditions. PIMs Stipulation (Tr. Ex. vol. 7). First, DEC, the Public Staff, and CIGFUR agreed to work together to develop and file EV tariffs and programs to estimate and update the revenue associated with residential EV sales in DEC's service territory, consistent with the testimonies of DEC witnesses Byrd and Abernathy and Public Staff witness Nader within 90 days of the Commission's order approving the PIMs Stipulation. *Id.* Second, pursuant to the PIMs Stipulation DEC is required to update the estimate of 180 kWh proposed by Public Staff witness Nader with actual, DEC-specific EV usage data in each future decoupling mechanism rider proceeding. *Id*. In addition, the PIMs Stipulation provides for a tracking metric for beneficial electrification from incremental load EVs. *Id.*

DEC witnesses Bateman and Stillman explained the agreement to exclude all residential EV sales from the decoupling mechanism resolves contested issues between the parties and provides a process for DEC to work with the Public Staff to develop tariffs and programs to estimate and update revenue associated with EV sales. Tr. vol. 11, 201–02. Witnesses Bateman and Stillman explained that the tracking metric to report beneficial electrification from incremental load of EVs from estimated incremental load from EVs is consistent with N.C.G.S. § 62-133.16(c)(2)'s provision to encourage EVs by excluding EV charging from the decoupling mechanism. *Id.* at 208–09. In addition, they stated that Governor Cooper's Executive Order 246, signed on January 7, 2022, sets goals to increase the number of zero emission vehicles in our state by 2030. *Id*. They assert that the residential EV tracking metric will provide important data about an area with material policy interest. *Id*. Witnesses Bateman and Stillman concluded that the conditions associated with tracking and estimating DEC's proposal to exclude incremental residential EV sales from the decoupling mechanism "are reasonable and will result in a transparent process for updating EV revenue estimates before the Commission." *Id.* at 14.

In witness Abernathy's supplemental direct testimony, she further explained that the PIMs Stipulation (also approved in the DEP Rate Case Order) agreed and clarified that DEC and DEP will obtain data that will help them to better estimate revenue associated with incremental residential EVs. Tr. vol. 12, 124. Witness Abernathy explained that the agreed upon method entails using data from the Department of Transportation to derive the number of residential EVs in DEC's service territory and then applying the flat residential tariff rate to the average monthly EV usage amount to derive the amount of residential EV sales to exclude from the decoupling mechanism. *Id.* at 123. Finally, witness Abernathy stated that pursuant to the PIMs Stipulation, within 90 days of a Commission order in this proceeding, DEC will file tariffs or programs, and further using the data from those tariffs and programs, will refine the analytics to update the number of EVs and the usage assigned to each vehicle. Tr. vol. 11, 201–02.

Earnings Sharing Mechanism

DEC witnesses Abernathy and Bateman testified in support of the ESM, which is a component of the MYRP. Tr. vol. 11, 145–47; tr. vol. 12, 109–10. Witness Abernathy explained that if DEC's adjusted earnings exceed the authorized rate of return on common equity established by the Commission in this rate case plus 50 basis points, those excess earnings, including a return calculated at the weighted average cost of capital, will be distributed to customers over a 12-month period via the annual ESM Rider. Tr. vol. 12, 109.

Witness Abernathy testified that for purposes of the ESM calculation, DEC will adjust earnings for weather, DSM/EE incentives, PIMs, and EV sales. *Id.* at 110.

At the evidentiary hearing, witness Bateman testified that the ESM allocates risk away from customers and onto DEC, since the ESM distributes to customers 100.0% of earnings in excess of 50 basis points above the authorized rate of return on common equity on an annual basis, without a corresponding ability for DEC to collect additional revenue from customers if the utility is underearning. Tr. vol. 11, 150.

Also, as noted above, witness Bateman explained that if the Commission precluded DEC from including an EV adjustment within the ESM calculations, DEC's residential EV sales would be decoupled from the utility's margin, thus eliminating an important incentive for the utility to encourage EV adoption and grow EV sales in between rate case filings.

Discussion and Conclusion

In general, the Commission concludes that the residential decoupling mechanism and the ESM proposed by DEC are consistent with the PBR Statute and with the Commission's rules. Further, the Commission concludes that DEC's proposal to exclude EV sales from the decoupling mechanism and the ESM, as modified by the PIMs Stipulation, is reasonable and should be approved. The Commission gives substantial weight to the testimony of the DEC witnesses who explained that residential EV sales section of the PIMs Stipulation is consistent with the spirit and intent of N.C.G.S. § 62-133.16(c)(2) to encourage EV sales and who explained the process that will be utilized to arrive at an estimate of EV sales that addresses the objections of the Public Staff to DEC's initial proposal.

The Commission finally notes that it will thoroughly review the EV tariffs and programs DEC files within 90 days of this order and will consider stakeholder positions as appropriate.

The Commission does not find it appropriate, for the reasons articulated by DEC witnesses Bateman and Abernathy, to impose a decoupling cap, or authorize a lower carrying cost on the decoupling deferral amount. The Commission notes that the TCA Stipulation provides that the $20 million adjustment in the revenue requirement agreed to in the TCA Stipulation will be included in the ESM for DEC.

The Commission notes that Commission Rule R1-17B(h)(1) provides for the filing of quarterly earnings reports that require certain enumerated information. The Commission directs DEC to work with the Public Staff to develop a quarterly reporting form for DEC's earnings that will enable the Commission to analyze the information and determine the appropriate application and operation of the ESM Rider. As part of this review, DEC and the Public Staff shall review the requirements of Commission Rule R1-17B(h)(1) and recommend any necessary changes.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 69

Performance-Based Regulation

The evidence supporting this finding of fact is contained in DEC's verified Application and Form E-1; the testimony and exhibits of DEC witnesses Abernathy, Bateman, and Stillman; Public Staff witnesses D. Williamson and Thomas; AGO witness Balakumar; NCJC et al. witness Wilson; CUCA witness Pollock; and the entire record in this proceeding.

Summary of Evidence

DEC's PBR Application seeks approval of PBR through the proposed three-year MYRP beginning on January 1, 2024, and ending December 31, 2026.[28] DEC witness Bateman testified that in addition to the three-year MYRP, which includes an ESM, DEC's PBR Application includes a residential decoupling mechanism, PIMs, and tracking metrics. Tr. vol. 11, 145. Witness Bateman explained that the PBR approach, in general, and DEC's proposed MYRP better align customer and state policy goals with utility revenues and performance than under a traditional ratemaking construct. *Id.* at 148.

The Commission notes, as the Public Staff points out, that the PBR Statute represents a substantial supplement to the existing law related to electric public utilities, such as DEC, and provides DEC with a cost recovery framework that represents a fairly significant departure from the traditional cost recovery paradigm that has served North Carolina's electric utilities and their customers well for many decades. Discussed

[28] DEC seeks MYRP cost recovery for capital projects which will be placed into service during the so-called "Gap Period"; that is, the time period between the capital cut-off (June 30, 2023) and the start of Rate Year 1 (January 1, 2024). For the reasons articulated by DEP in its post-hearing brief filed in the DEP Rate Case proceeding, the Commission concludes that it has the authority to approve cost recovery for MYRP projects entering service during the Gap Period and that DEC properly included a full year's revenue requirement for MYRP projects that are placed in service during the Gap Period.

below are four new concepts allowed for the first time in North Carolina under the PBR Statute.

First, electric public utilities in North Carolina are entitled to file a MYRP, which is "a ratemaking mechanism under which the Commission sets base rates for a multiyear period that includes authorized periodic changes in base rates without the need for the electric public utility to file a subsequent general rate application . . . ." N.C.G.S. § 62-133.16(a)(5). This approach is a departure from the adjusted historic test year and authorizes certain projections of cost in the setting of rates.

Second, electric public utilities, such as DEC, are now allowed to utilize a decoupling mechanism. Under the PBR Statute's decoupling mechanism, DEC is authorized to "defer to a regulatory asset or liability account the difference between the actual revenue and the target revenue for the residential class" and this variance will result in an annual adjustment to the residential customer classes' bills. *Id.* § 133.16(c)(2).

Third, the PBR Statute creates an ESM, which allows the electric public utility to elect to file a new rate case under N.C.G.S. § 62-133 in the event its weather-normalized earnings fall below the authorized rate of return on equity and requires the utility to refund to customers all weather-normalized earnings in excess of the authorized rate of return plus 50 basis points. *Id.* § 133.16(c)(1).

Fourth, the PBR Statute requires that the utility implement at least one performance incentive mechanism, which is "a ratemaking mechanism that links electric public utility revenue or earnings to utility performance in target areas consistent with policy goals . . . ." *Id.* § 133.16(a)(6). PIMs are intended to encourage the types of behavior about which customers care, provide DEC with the opportunity to earn a reward to be collected from customers, and expose DEC to payment of penalties which are refunded to customers (subject to a cap). *Id.* § 133.16(c)(4).

While certain of the mechanisms established in the PBR Statute are new to North Carolina, aspects of the law are familiar and well-known to the Commission. For example, the responsibility "[t]o make reasonable and just rates" has been the obligation of the Commission's predecessors since the 19th century. *See, e.g.,* 1899 N.C. Sess. Laws, ch. 164, § 2. The requirement that rates be "fair both to the electric public utility and to the customer," set forth in N.C.G.S. § 62-133.16(d)(1)(a) mirrors the charge in N.C.G.S. § 62-133(a) that "the Commission shall fix such rates as shall be fair both to the public utilities and to the consumer." Moreover, N.C.G.S. § 62.133-16 explicitly preserves the Commission's existing ratemaking authority, providing: "[n]othing in this section shall be construed to [ ] limit or abrogate the existing ratemaking authority of the Commission . . . ." N.C.G.S. § 62-33.16(g) (omission denoted via brackets and ellipses). And, significantly, the Commission has long been required to consider risks both to the electric utility and to its customers, as it is well-established policy in North Carolina "to provide fair regulation of public utilities in the interest of the public" as well as "to promote adequate, reliable and economical utility service to all of the citizens and residents of the State." N.C.G.S. § 62-2(1), (3).

When reviewing a PBR Application, the PBR Statute requires the Commission to consider whether a PBR Application:

(1) Assures that no customer or class of customers is unreasonably harmed and that the rates are fair both to the electric public utility and to the customer;

(2) Reasonably assures the continuation of safe and reliable electric service; and

(3) Will not unreasonably prejudice any class of electric customers and result in sudden substantial rate increases or "rate shock" to customers.

N.C.G.S. § 62-133.16(d)(1).

Elsewhere in this Order the Commission has ruled upon the specific requests of DEC regarding costs to be recovered, as well as the rate of return that DEC has an opportunity to earn. In approving costs for recovery and establishing the rate of return, the Commission has applied well-established law in attempt to put the utility in a position to maintain its system and level of service, in view of the very real challenges that lie ahead for DEC, to earn a fair return, in view of current economic conditions, and to compete in the marketplace for capital on reasonable terms and at times when a capital need arises. The Commission has considered the impact of changing economic conditions on customers, recognizing that certain of the utility's customers will struggle to afford electric utility service, and has endeavored to establish rates that achieve the foregoing objectives most economically. In addition, elsewhere in this Order, the Commission has considered the potential for prejudice to customer classes and accepts the cost allocation methods, as well as certain of the rate designs, proposed by the utility and modified by the various stipulations to be reasonable and not prejudicial to any customer class.

In addition to the requirements for consideration by the Commission set forth in N.C.G.S. § 62-133.16(d)(1), the PBR Statute provides guidance on other considerations the Commission may undertake, including, for example, whether the PBR application "reduces low-income energy burdens;" whether the PBR application "encourages DERs"; whether the PBR application "encourages utility-scale renewable energy and storage"; and whether the PBR application "encourages peak load reduction or efficient use of the system." N.C.G.S. § 62-133.16(d)(2). The Commission notes, for example, that the PIMs Stipulation, discussed in detail elsewhere in this Order, involves PIMs that are intended to increase numbers of customers enrolled in time-differentiated rates, to increase the number of net-metered interconnections, to encourage the interconnection of utility scale generation above DEC's estimated annual limits, and to enable large commercial and industrial customers to achieve clean/carbon free energy objectives. Each of these PIMs aligns with the considerations established in N.C.G.S. § 62-133.16(d)(2). The tracking metrics, agreed upon by the parties to the PIMs Stipulation, pertain to customer service, reliability and "beneficial electrification," all of which should inform the future development of PIMs that align with the guidance set forth in N.C.G.S. § 62-133.16(d)(2). In addition, elsewhere in this Order, the Commission discusses the CAP pilot proposed by DEC and other assistance programs in this proceeding, aimed at providing customers in need of assistance with bill payment, as well as the Affordability Stipulation, which is intended to provide additional relief for customers who will struggle to afford the cost of electricity. These provisions of the PBR Application, as modified by the stipulations, align with the considerations of § 62-133.16(d)(2). Throughout the course of this proceeding, DEC has worked with parties to the proceeding to refine the elements of its PBR Application to better conform to the requirements of N.C.G.S. § 62-133.16(d)(1) and to more closely align with the guidance set forth in N.C.G.S. § 62-133.16(d)(2).

For the foregoing reasons, and as discussed in greater detail throughout this Order, the Commission concludes that DEC's PBR Application, as modified by the stipulations and this Order, results in just and reasonable rates, is in the public interest, and is consistent with the criteria established in N.C.G.S. § 62-133.16.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 70

Revenue Requirement

The evidence supporting this finding of fact is contained in DEC's verified Application and Form E-1; the Revenue Requirement Stipulation; the TCA Stipulation; the Supplemental Revenue Requirement Stipulation; the testimony and exhibits of DEC witnesses Q. Bowman and Abernathy; Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

The Revenue Requirement Stipulation, the TCA Stipulation, and the Supplemental Revenue Requirement Stipulation provide for certain accounting adjustments that parties have agreed upon and the Commission has approved in this Order. The stipulation issues that impact the revenue requirement in the Revenue Requirement Stipulation and the TCA Stipulation are detailed in Q. Bowman Supplemental Partial Settlement Exhibit 2 which provides sufficient support for the annual revenue required on the issues agreed to in the Revenue Requirement Stipulation. Q. Bowman Supp. Settlement Ex. 2 (Tr. Ex. vol. 12). The stipulation issues that impact the revenue requirement in the Supplemental Revenue Requirement Stipulation are in Q. Bowman Supplemental Revenue Requirement Stipulation Exhibit 1. Q. Bowman Supp. Revenue Requirement Stipulation Ex. 1 (Tr. Ex. vol. 17).

After giving effect to the approved stipulations and the Commission's decisions on the Unresolved Issues, as discussed herein, the Commission finds that DEC should recalculate the required annual revenue requirement consistent with the Commission's findings herein within ten days of the issuance of this Order. DEC is further directed to file with the Commission the final revenue requirements for Rate Years 1, 2, and 3 in the same format as Q. Bowman Supplemental Partial Settlement Exhibit 1. The Commission directs DEC to work with the Public Staff to verify the accuracy of the calculations, and the filing should reflect the corrections identified by DEC and agreed upon by the Public Staff.

The Commission concludes the annual revenue requirement for DEC for Rate Years 1, 2, and 3, which reflect the approved stipulations and the Commission's decisions on unresolved issues, will allow DEC a reasonable opportunity to recover its operating costs and earn the overall rate of return on its rate base that the Commission has found just and reasonable upon consideration of the findings in this Order.

IT IS, THEREFORE, ORDERED as follows:

1. That the Initial Revenue Requirement Stipulation, the Amended Revenue Requirement Stipulation, the COSS Stipulation, the TCA Stipulation, the PIMs Stipulation, the Affordability Stipulation, the OPT-V-Primary Partial Rate Design Stipulation, the OPT-V-Secondary Partial Rate Design Stipulation, the Power Quality Stipulation, and the Supplemental Revenue Requirement Stipulation are accepted and approved, as detailed in this Order;

2. That the depreciation rates proposed by DEC in this case, which are based on the 2021 Depreciation Study and amended by the Revenue Requirement Stipulation, with such agreed upon amendments proposed by intervenors, including (1) accelerated retirement dates for coal plant assets except for Cliffside 5; and (2) corrected depreciation rates set forth in DEC witness Spanos' rebuttal testimony, subject to an adjustment to decommissioning estimates to use 10.0% contingency and a 5.0% indirect cost adder, shall be, and are hereby approved;

3. That DEC's request for an accounting order for approval to defer to a regulatory asset 75.0% of the impact of accelerating the retirement of DEC's subcritical coal plants, as agreed upon in the Revenue Requirement Stipulation, preserving DEC's ability to recover 50.0% of the net book value of the subcritical plants through securitization, shall be, and is hereby approved;

4. That the remaining net book value of DEC's subcritical coal plants at retirement shall be recovered with a return over the amortization period determined by the Commission in a future rate case;

5. That DEC's plant-related capital investments in the base period fossil, renewable, storage, nuclear fleet assets, as adjusted in the Revenue Requirement Stipulation, shall be included in rates for the base period;

6. That DEC's transmission and distribution investments made during the test period, as adjusted by the Revenue Requirement Stipulation, shall be included in rates for the base period;

7. That DEC's GIP investments shall be included for recovery in DEC's rates;

8. That in accordance with the Revenue Requirement Stipulation, DEC is permitted to recover the full balance of its GIP deferral over an 18-year amortization period, with a debt-only return during the deferral period and rate base treatment during the 18-year amortization period;

9. That DEC shall recover the balance of the CCR deferral, net of the overamortization, over a five-year amortization period with reduced financing costs during the amortization period calculated based on (1) DEC's cost of debt as approved in this Order adjusted as appropriate to reflect the deductibility of interest expense; (2) a rate of return on common equity 150 basis points lower than the rate of return on common equity as approved in this Order; and (3) a capital structure of 48.0% debt and 52.0% equity as set forth in the CCR Settlement;

10. That DEC shall amortize non-ARO environmental compliance costs over a six-year period;

11. That DEC shall amortize the regulatory liability for overcollections associated with storm securitization over a three-year period;

12. That the agreed upon accounting adjustments outlined in the Revenue Requirement Stipulation shall be, and are hereby, approved;

13. That DEC shall establish the nuclear PTC rider, effective January 1, 2025, as provided in the Revenue Requirement Stipulation;

14. That DEC shall track and report on an annual basis the actual spend and employee head count for each coal generation station over the MYRP period in a manner to be agreed upon by DEC and the Public Staff. DEC shall update the Commission within six months of the issuance of this Order on the manner upon which DEC and the Public Staff have agreed to the tracking and reporting of the actual spend and employee head count for each coal generation station;

15. That DEC shall record any cumulative underspend less than $4.5 million (North Carolina retail) of annual incremental spend for ongoing O&M for DEC's coal generation fleet for discrete programs and targeted categories to a regulatory liability account accrued through the end of the MYRP period (December 2026) and return the underspend to customers in the next general rate case;

16. That DEC shall perform a lead-lag study before its next general rate proceeding and incorporate the results of that study in its next general rate case filing;

17. That DEC's proposed MYRP, reflecting the projected costs associated with the Transmission, Distribution, Fossil/Hydro, Nuclear, Cybersecurity, Solar, and Storage and Duke Energy Plaza capital investments, as adjusted by the Revenue Requirement Stipulation, as reflected in Abernathy Supplemental Settlement Exhibits 1 and 2, is just and reasonable and adopted in its entirety;

18. That DEC is allowed to modify the conditions to the Lincoln CT CPCN to move the in-service date to November 1, 2024, for purposes of calculating the MYRP revenue requirement;

19. That DEC has demonstrated a reasonable plan to timely complete the MYRP projects;

20. That DEC shall consult with the Public Staff before filing its next PBR Application to attempt to establish agreed upon MYRP project documentation guidelines;

21. That DEC shall track and report on AFUDC accrued on MYRP capital projects and consult with the Public Staff regarding the scope and content of the report;

22. That DEC shall develop and file EV tariffs and programs to estimate and update the revenue associated with residential EV sales in DEC's service territory within 90 days of the Commission's order in this docket, and DEC shall update the kilowatt-hour per EV estimate proposed by Public Staff witness Nader with actual, DEC-specific EV usage data in each future decoupling rider proceeding;

23. That DEC shall consult with the Public Staff to develop a report on Rider ED. DEC shall file its first report on Rider ED no later than one year from the date of this Order;

24. That DEC shall report on the issue of CIAC related to IAs in its next rate case application;

25. That DEC shall consult with the Public Staff to develop a report on reliability O&M as the Public Staff proposed. DEC shall file its first report on reliability O&M no later than one year from the date of this Order;

26. That DEC shall report on Vegetation Management as agreed upon in the Revenue Requirement Stipulation;

27. That DEC's request to establish the Payment Navigator program shall be, and is hereby approved;

28. That DEC shall be allowed to recover its costs to implement Customer Connect;

29. That the COSS Stipulation shall be, and is hereby approved;

30. That in its next general rate case, DEC shall provide a comprehensive justification for the use of a NCP demand instead of a coincident peak demand for any cost allocation purpose;

31. That the PIMs Stipulation is consistent with N.C.G.S. § 62-133.16 and Commission Rule R1-17B, achieves a measured balance between encouraging behavior and risk/reward to utility shall be, and is hereby approved;

32. That the Power Quality Stipulation is approved, and DEC shall file an application for such a pilot program, or agreed upon alternative, in a separate proceeding within six months of this Order;

33. That consistent with the Affordability Stipulation, DEC's proposed CAP is hereby approved as a three-year pilot;

34. That DEC's proposed CAP and CAR Riders shall be, and are hereby approved as part of the three-year pilot;

35. That the shareholder financial contributions, detailed in the Affordability Stipulation, shall be, and are hereby approved;

36. That the revisions to rate schedules, as proposed by DEC or as otherwise modified herein shall be, and is hereby approved;

37. That the revisions to the service riders, as proposed by DEC or otherwise specifically modified herein, including Rider ED and Rider NSC shall be, and are hereby approved;

38. That DEC shall notify all SGS customers, via bill insert or separate mailing, that customers may now elect a residential rate schedule for detached garages, barns, and other structures on the same residential premise currently served under a residential rate schedule;

39. That DEC shall notify GS and I customers of the 75 kW minimum contract demand threshold for OPT-V, through bill insert or separate mailing;

40. That DEC shall notify lighting customers of the changes to lighting services and the establishment of an Outdoor Lighting Service Regulations tariff, through bill insert or separate mailing;

41. That DEC's rates during the MYRP Rate Period shall reflect a rate of return on common equity of 10.1%, an embedded cost of debt of 4.56%, and a capital structure consisting of 53.0% common equity and 47.0% long-term debt, for a rate of return of 7.496%;

42. That DEC shall be allowed to recover all its requested deferred COVID-related costs, including customer fees waived, bad debt charge-offs, employee stipends, costs related to employee safety and remote work, call center costs, and the accrued carrying costs during the deferral period netted against the COVID-related savings related to printing, postage and employee travel, over a three-year amortization

period. DEC shall also be entitled to earn a return on the unamortized balance during the three-year amortization period, which shall begin on the effective date of the rates approved in the proceeding;

43. That DEC's request to continue the deferral of bad debt expenses related to the impact of the COVID pandemic is hereby approved. That any payments associated with bad debt amounts should be credited to the COVID deferral account on a monthly basis through the next general rate case proceeding. That DEC should report on a semiannual basis the actual amounts recorded to the COVID deferral and the payments received;

44. That DEC's withdrawal of its request for an accounting order for the storm balancing account consistent with the Revenue Requirement Stipulation shall be, and is hereby approved;

45. That DEC is allowed to recover the remaining unamortized rate case expenses from the 2017 and 2019 Rate Cases as well as the additional rate case expense requested for the 2019 Rate Case in this proceeding. Such costs shall be netted against all rate case expense overamortization from the prior cases and amortized over a three-year period, and shall not be included in rate base;

46. That DEC is hereby allowed to recover over a three-year period rate case costs related to the present proceeding, including actual rate case costs through the date that the proposed order is filed;

47. That the following treatment with respect to overamortizations of regulatory assets shall be, and hereby is approved for purposes of this proceeding:

a. The overamortization of rate case expense from DEC's prior rate cases should be applied against rate case costs being requested in this proceeding;

b. The overamortization of severance costs from the Commission's 2019 Rate Case Order should be refunded to customers through a one-year rider with interest; and

c. The overamortization of early retired plant should be applied against the outstanding rate base balance for the Allen Unit 4 early retired coal plant authorized in the 2019 Rate Case Order;

48. That if DEC receives revenue for any deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, DEC shall continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until DEC's next general rate case for a determination of the appropriate ratemaking treatment of such overamortizations;

49. That DEC is allowed to collect in rates its North Carolina Retail normalized annual level of storm costs in the amount of approximately $32.225 million;

50. That DEC's request for an accounting order to defer any incremental revenue requirement impacts, including benefits and costs, associated with the IRA and the IIJA, shall be, and is hereby approved;

51. That the agreement in the Revenue Requirement Stipulation that it is not necessary to establish a regulatory liability at this time for CIAC is reasonable; however, DEC shall report on the issue of how CIAC is recorded in the context of IAs in its next general rate case application as required by the Revenue Requirement Stipulation;

52. That the Commission finds DEC's provision of electric service to be adequate;

53. That DEC's proposed revisions to its previously approved EDIT-4 Rider to reflect additional amounts due to customers, shall be, and is hereby approved, and that the levelized return rate shall be based on an embedded cost of debt of 4.56% and the capital structure and rate of return on common equity approved by the Commission in this proceeding;

54. That DEC shall use base fuel rates, exclusive of the equal percentage fuel adjustment allocation methodology, in its 2024 annual fuel adjustment proceeding;

55. That the production demand allocation method approved for production demand costs using the 12 CP method at NC retail and the Modified A&E method for NC retail classes is the most appropriate method for allocating purchased power capacity costs in DEC's annual fuel proceedings;

56. That DEC's proposed residential decoupling mechanism is consistent with N.C.G.S. § 62-133.16 and Commission Rule R1-17B, and the proposed tariff for the associated rider, shall be, and is hereby approved;

57. That DEC's proposed ESM, as modified by the TCA Stipulation, is consistent with N.C.G.S. § 62-133.16 and Commission Rule R1-17B, and the proposed tariff for the associated rider, shall be, and is hereby approved;

58. That DEC shall file the final annual revenue requirements for Rate Years 1, 2, and 3 consistent with the Commission's findings and rulings herein within ten days of the issuance of this Order in the same format as Q. Bowman Supplemental Partial Settlement Exhibit 1. DEC shall work with the Public Staff to verify the accuracy of the calculations;

59. That DEC shall file schedules (North Carolina Retail Operations — Statement of Rate Base and Rate of Return, Statement of Operating Income, and Statement of Capitalization and Related Costs) with the Commission within

ten days of the issuance of this Order, summarizing the gross revenue and the rate of return that DEC should have the opportunity to achieve based on the Commission's findings and determination in this proceeding;

60. That DEC is authorized to adjust its rates and charges in accordance with the Initial Revenue Requirement Stipulation, Amended Revenue Requirement Stipulation, the TCA Stipulation, the Supplemental Revenue Requirement Stipulation, and findings in this Order effective for service rendered on and after the following date after the Commission issues an Order accepting the calculations required by Ordering Paragraph No. 58;

61. That within 30 days of this Order, DEC shall file for Commission approval all rate schedules designed to comply with this Order, accompanied by calculations showing the revenues that will be produced by the rates for each schedule; and

62. That DEC shall submit a proposed customer notice to the Commission for review and approval, and upon approval of the notice by the Commission, shall give appropriate notice of the approved rate increase by mailing the notice to each of its North Carolina retail customers during the billing cycle following the effective date of the new rates.

ISSUED BY ORDER OF THE COMMISSION.

This the 15th day of December, 2023.

NORTH CAROLINA UTILITIES COMMISSION

A. Shonta Dunston

A. Shonta Dunston, Chief Clerk

Commissioner Daniel G. Clodfelter resigned from the Commission effective November 15, 2023, and did not participate in this decision. Commissioner ToNola D. Brown-Bland resigned from the Commission effective December 1, 2023, and did not participate in this decision.

Commissioner Jeffrey A. Hughes concurs in part and dissents in part.

Commissioner Floyd B. McKissick, Jr., dissents in part.

DOCKET NO. E-7, SUB 1276

Commissioner Jeffrey A. Hughes, concurring in part and dissenting in part:

With the exception of the rate of return on common equity and allowing recovery of the accrued carrying costs incurred on the incremental COVID-related costs during the deferral period and a return during the amortization period, as to which I dissent, I concur in the majority's Order. I concur with the Commission's decision to accept the Affordability Stipulation, but I write separately in support of the adoption of affordability tracking mechanisms, which the Commission declined to require in the Order.

I. Affordability Tracking Mechanisms

I write separately to outline my concern about the Order leaving out any metrics relating to customer affordability. While I support the PIMs and Affordability Stipulations, I am concerned that the negotiations behind them may have inadvertently resulted in leaving out customer affordability metrics from DEC's list of PIMs and tracking metrics. In the recent DEP Rate Case, the Commission accepted the Affordability and PIMs Stipulations and also added two affordability tracking metrics. I supported that approach, which was not counter to either of the stipulations and provided the Commission and the Public with transparent information on this important subject. Additionally, I note that DEC witness K. Bowman testified that affordability is one of the four components that guided DEC in preparing its Application:

> . . . I discuss the following core components of the Company's filing: (1) a continued balanced transition away from coal to achieve a cleaner energy future; (2) operational excellence; (3) enhancing the customer experience; and (4) affordability and proposals to assist our customers most in need. Tr. vol. 7, 53.

The Order identifies and requires at least a PIM or a tracking metric for each of the other core components identified by witness K. Bowman with the noticeable exception of customer affordability. In my view, implementing tracking mechanisms to better inform DEC's and the Commission's understanding of the low-income energy burden and the impact of different measures is a worthwhile investment. DEC has made progress in this area with the Affordability Stakeholder Process and EE programs. While I was pleased to see that DEC acknowledged affordability as a worthy policy goal in its initial PIMs proposals, I agree with the Public Staff that having an affordability PIM as DEC proposed is premature. However, there is ample evidence that introducing affordability tracking mechanisms would be useful, and it would have been my preference for the Commission to order DEC to add the same tracking metrics that were added in the DEP Rate Case Order.

II. Rate of Return on Common Equity and COVID Deferral-Accrued Carrying Costs and Return on Deferred Balance

I cannot approve a 10.1% rate of return on common equity or DEC's request for recovery of the accrued carrying costs incurred on the incremental COVID-related costs during the deferral period and a return during the amortization period, and I respectfully dissent on these two issues.

Each of the rate of return of common equity witnesses presented a range of rate of return of common equity values, which given the number of models used and the numerous assumptions, resulted in a wide band of potential rates of return of common equity supported by the evidence in this proceeding. Given the reduced revenue risk and financial attributes of North Carolina's new rate setting paradigm, I feel strongly that a rate of return of common equity in the 9.8 to 9.9% range balances fairness to DEC with fairness to customers, while not negatively impacting DEC's access to or cost of capital. A rate of return of common equity of 9.9% would have reduced the total North Carolina retail revenue requirement by approximately $92 million over the MYRP period.

Concerning the COVID costs, I note that DEC witness Abernathy testified that over 91% of the deferred incremental COVID-related costs are attributable to waived customer fees and bad debt expenses. Although many of DEC's customers were not directly responsible for these costs, I am willing to accept the majority's decision to allow DEC to recover from customers all the incremental COVID-related costs DEC incurred because these special measures were taken to protect the public health for all North Carolina citizens during the State of Emergency. However, I would find that refraining from allowing DEC to recover its accrued carrying costs during the deferral period and a return on the COVID deferred balance during the amortization period, as was done in the DEP Rate Case, strikes a reasonable balance. Such a decision in this proceeding would have reduced DEC's annual North Carolina retail revenue requirement by roughly $16 million (roughly $48 million over the MYRP period).

/s/ Jeffrey A. Hughes
Commissioner Jeffrey A. Hughes

DOCKET NO. E-7, SUB 1276

Commissioner Floyd B. McKissick, Jr., dissenting in part:

I dissent from the Order's resolution of recovery of the deferred COVID-related costs with respect to the $1.1 million in employee stipends provided by DEC to certain eligible employees. In direct testimony, DEC witness Q. Bowman stated that DEC provided certain eligible employees a one-time cash payment of $1,500 to help with unplanned expenses associated with the COVID pandemic. The Public Staff did not dispute the amount of the employee stipends but opposed recovery of these costs stating that the one-time payment to the employees was unverified and constituted goodwill on the part of DEC. In rebuttal testimony, the COVID Panel testified that DEC's customer service representatives who ordinarily would work in call centers had to transform themselves into a virtual workforce working from their homes which presented challenges for these employees. The COVID Panel stated that the stipends were distributed to hourly-paid call center employees to assist with these challenges and to certain other hourly employees to retain a critical part of DEC's workforce during this unprecedented time. The majority concluded that the one-time stipend of $1,500 that DEC provided to certain hourly employees should be recovered from customers. I disagree.

I note that in the DEP Rate Case Order, the Commission denied DEP's requested recovery of the employee stipends stating that usage of the stipends was not verified by DEP and that employees were free to spend the funds as they pleased, without oversight by DEP.

I do not believe that DEC has provided in this proceeding any additional substantiation of its stipend costs than that provided by DEP in the DEP Rate Case. Therefore, I believe the Commission's conclusion in this proceeding should be the same as in the DEP Rate Case. I understand that it would have been difficult during the height of the pandemic for DEC to take the time necessary to work directly with the eligible employees on each employee's specific needs to accomplish their job duties during the challenges presented by the pandemic. I also understand that it may have been time consuming for DEC to review documentation provided by the employees and to determine whether the expenses were reasonable and prudent prior to dispensing the stipends to its eligible employees. However, I believe DEC could have instructed its employees when the stipends were distributed that they would be required to account for the use of their $1,500 stipend in some reasonable documented manner and that such documentation would be reviewed by the employee's supervisor to ensure that the funds were indeed used to assist the employee to work remotely from home effectively. That documentation and review process would have established a mechanism to ensure accountability by employees and the utility as well as the oversight by the Commission that is missing in both the DEP and DEC rate case proceedings. Otherwise, the stipend could have been used by an employee to buy toys and clothes for their children or for other similar purposes that were unrelated to facilitating the employee's ability to work from home.

In this proceeding concerning the cost recovery issue of employee stipends provided by DEC, I support the same decision reached by the Commission in the DEP Rate Case Order that usage of the stipends was not verified by DEC and that employees were free to spend the funds as they pleased, without oversight, and thus the Commission should have determined these costs should be excluded from cost recovery of deferred COVID expenses.

/s/ Floyd B. McKissick, Jr.
Commissioner Floyd B. McKissick, Jr