STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1329
DOCKET NO. E-7, SUB 1355

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1329 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 DOCKET NO. E-7, SUB 1355 In the Matter of Application by Duke Energy Carolinas, LLC for Accounting Order Regarding Level 2 Charging Infrastructure	)	ORDER ACCEPTING STIPULATIONS IN PART, GRANTING PARTIAL RATE INCREASE, GRANTING ACCOUNTING ORDER, AND REQUIRING PUBLIC NOTICE

HEARD: Tuesday, April 7, 2026, at 6:30 p.m., via Webex Videoconference

Tuesday, April 28, 2026, at 7:00 p.m., Burke County Courthouse, 201 South Green Street, Morganton, North Carolina 28655

Wednesday, April 29, 2026, at 7:00 p.m., Mecklenburg County Courthouse, 832 East Fourth Street, Charlotte, North Carolina 28202

Wednesday, May 6, 2026, at 7:00 p.m., Forsyth County Courthouse, 175 North Chestnut Street, Winston-Salem, North Carolina 27101

Tuesday, June 3, 2026, at 7:00 p.m., Durham County Courthouse, 501 South Dillard Street, Durham, North Carolina 27701

Tuesday, July 7, 2026, at 10:00 a.m., North Carolina Utilities Commission, Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27603

BEFORE: Commissioner Floyd B. McKissick, Jr., Presiding; Chairman William M. Brawley; and Commissioners Tommy Tucker and John W. Gajda.

APPEARANCES:

For Duke Energy Carolinas, LLC (DEC):

Jack E. Jirak and Kathleen H. Richard, Duke Energy Corporation, 410 South Wilmington Street, Raleigh, North Carolina 27601

Camal O. Robinson, Duke Energy Corporation, 525 South Tryon Street, Charlotte, North Carolina 28202

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

Brian L. Franklin, McGuireWoods LLP, 201 North Tryon Street, Suite 3000, Charlotte, North Carolina 28202

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

Brandon F. Marzo, Melissa Oellerich New, and Joshua Warren Combs, Troutman Pepper Locke LLP, 600 Peachtree Street, NE Suite 3000, Atlanta, Georgia 30308

Lawrence B. Somers, Lawrence B. Somers, PLLC, Post Office Box 44, Cary, North Carolina 27512-0044

For Amazon Data Services, Inc. (Amazon):

Robert B. Josey, Nelson, Mullins, Riley & Scarborough LLP, 301 Hillsborough Street, Suite 1400, Raleigh, North Carolina 27603

Weston Adams, III, Nelson, Mullins, Riley & Scarborough LLP, 1320 Main Street, Suite 1700, Columbia, South Carolina 29201

For Andale, LLC (Andale):

Weston Adams, III, Nelson, Mullins, Riley & Scarborough LLP, 1320 Main Street, Suite 1700, Columbia, South Carolina 29201

Robert B. Josey, Nelson, Mullins, Riley & Scarborough LLP, 301 Hillsborough Street, Suite 1400, Raleigh, North Carolina 27603

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

Christina D. Cress, Ward and Smith, P.A., 127 Racine Drive, Wilmington, North Carolina 28403

Peter H. Ledford, Ward and Smith, P.A., 751 Corporate Center Drive, Suite 300 (27607), Post Office Box 33009 Raleigh, North Carolina 27636-3009

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

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

For Environmental Defense Fund (EDF):

Benjamin W. Smith, Kilpatrick Townsend & Stockton LLP, 4208 Six Forks Road, Suite 1400, Raleigh, North Carolina 27609

For Google LLC (Google):

Heather D. Fennell, Brooks, Pierce, McLendon, Humphrey & Leonard, LLP, 150 Fayetteville Street, Suite 1700, Raleigh, North Carolina 27601

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

Kurt J. Boehm and Jody Kyler Cohn, Boehm, Kurtz & Lowry, 425 Walnut Street, Suite 2400, Cincinnati, Ohio 45202

For Microsoft Corporation (Microsoft):

Ben Snowden and Karen M. Kemerait, Fox Rothschild LLP, 301 Hillsborough Street, Suite 1120, Raleigh, North Carolina 27603

For the North Carolina Attorney General's Office (AGO):

Reita Coxton-Shanaghan, North Carolina Department of Justice, 114 West Edenton Street, Raleigh, North Carolina 27603

For North Carolina Home Builders Association (NCHBA):

Peter H. Ledford and Alexandra E. Ferri, Ward and Smith, P.A., 751 Corporate Center Drive, Suite 300, Raleigh, North Carolina 27607

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

David L. Neal, Nick Jimenez, Munashe Magarira, and Hannah Klaus, Southern Environmental Law Center, 136 East Rosemary Street, Suite 500, Chapel Hill, North Carolina 27514

For the North Carolina Sustainable Energy Association (NCSEA):

Ethan Blumenthal, Justin T. Somelofske, and William N. Greene, 4441 Six Forks Road, Suite 106-250, Raleigh, North Carolina 27609

For Nucor Steel Lexington (Nucor):

Joseph R. Briscar and Shaun C. Mohler, Stone Mattheis Xenopoulos & Brew, PC, 1025 Thomas Jefferson Street, Northwest, Suite E-3400, Washington, District of Columbia 20007

For Walmart Inc. (Walmart):

Carrie H. Grundmann, Stephanie U. Eaton, and Nelson McKown, Spilman Thomas & Battle, PLLC, 110 Oakwood Drive, Suite 500, Winston-Salem, North Carolina 27103

Steven W. Lee, 1100 Bent Creek Blvd., Suite 101, Mechanicsburg, Pennsylvania 17050

For the Using and Consuming Public:

Lucy E. Edmondson, Nadia L. Luhr, Anne M. Keyworth, Jennifer T. Harrod, William E. H. Creech, William S.F. Freeman, and Thomas J. Felling, the Public Staff – North Carolina Utilities Commission (Public Staff), 4326 Mail Service Center, Raleigh, North Carolina 27699

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BY THE COMMISSION: On July 8, 2025, DEC filed a Motion Requesting a Limited Waiver of Rule R1-17B(c) of the Rules of Practice and Procedure of the North Carolina Utilities Commission. DEC requested that it be permitted to file its request to initiate a technical conference at least 30 days before filing a notice of intent to file a general rate case application that included a performance-based regulation (PBR) application as authorized under N.C. Gen. Stat. § 62-133.16 (PBR Statute) due to the Commission's ongoing consideration of proposed changes to Commission Rule R1-17B(c). On July 10, 2025, the Commission issued an Order Granting Motion for Limited Waiver of Commission Rule R1-17B(c) (R1-17B(c) Order). The R1-17B(c) Order directed DEC to file its request to initiate a technical conference at least 30 days before filing a notice of intent to file a general rate case that included a PBR application.

On October 20, 2025, pursuant to Commission Rule R1-17(a) and the Commission's Order issued July 10, 2025, DEC filed notice of its intent to file a general rate case application that includes a PBR application as authorized under the PBR Statute.

On November 20, 2025, DEC filed its Application to Adjust Retail Base Rates and for Performance-Based Regulation, and Request for an Accounting Order (PBR Application), supported by a Rate Case Information Report Form E-1 (Form E-1), and direct testimony and exhibits. As required by the PBR Statute and Commission Rule R1-17B, DEC's PBR Application included a residential decoupling rate-making mechanism (RDM), performance incentive mechanisms (PIMs) and tracking metrics, and a Multiyear Rate Plan (MYRP)[1], including an earnings sharing mechanism (ESM).

PROCEDURAL HISTORY

The following is a summary of the most pertinent filings by DEC, the parties, and procedural orders issued by the Commission.

By various orders, the Commission granted the intervention of AGO, Amazon, Andale, CIGFUR III, CUCA, EDF, Google, Harris Teeter, Microsoft, NCHBA, NCJC, et al., NCSEA, Nucor, and Walmart. The intervention of the Public Staff is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e).

On October 24, 2025, pursuant to N.C.G.S. § 62-69, DEC, Duke Energy Progress, LLC (DEP, and together with DEC, Duke), the Public Staff, Carolina Industrial Group for Fair Utility Rates II (CIGFUR II), CIGFUR III, and CUCA filed an Agreement and Stipulation of Partial Settlement regarding the cost of service study (COSS Stipulation) for consideration by the Commission in Docket Nos. E-7, Sub 1329, and E-2, Sub 1380.

On November 20, 2025, DEC filed its PBR Application, Form E-1, and the direct testimony and exhibits of the following witnesses: Kendal C. Bowman, North Carolina President for DEC and DEP; Laura A. Bateman, Vice President of Carolinas Rates and Regulatory Strategy for DEC, and S. Renee Farmer, Rates and Regulatory Strategy

[1] "MYRP" is used herein to refer generally to a multiyear rate plan, which is one of the three required components of PBR. "MYRP1" refers to the three-year MYRP approved by the Commission as part of PBR1 and "MYRP2" refers to the two-year MYRP proposed as part of PBR2.

Director for DEC (appearing as a panel); Melissa B. Abernathy, Director of Rates & Regulatory Planning for DEC; Bennett D. Fogg, General Manager of Engineering for Transmission in Power Grid Operations for DEP; Brent C. Guyton, Director of Distribution Asset Management in Power Grid Operations for DEC; Thomas P. Haaf, Senior Vice President of Nuclear Operations for Duke Energy Corporation (Duke Energy); John Samuel Holeman III, Vice President of Grid Integration Strategy for DEC; Justin C. LaRoche, Director of Renewables Development for Duke Energy; Graham C. Tompson, Director of Renewable Business Development for Duke Energy; Bryan P. Walsh, Vice President of Renewables Generation and Lake Services for DEC; Timothy S. Hill, Vice President of Coal Combustion Products for Duke Energy Business Services, LLC (DEBS); Lesley G. Quick, Vice President of Customer Technology, Advocacy, Regulatory and Business Support within Customer Services for DEC; Shannon Caldwell, Director of Human Resources Operations for DEBS; LaWanda M. Jiggetts, Rates & Regulatory Strategy Director for DEC; Nicholas G. Speros, Director of Electric Utility and Infrastructure Accounting of the Carolinas for DEBS; Janice D. Hager, President of Janice Hager Consulting, LLC; Jonathan L. Byrd, Managing Director of Rate Design and Regulatory Solutions for DEBS; Bryan L. Sykes, Director of Rates & Regulatory Planning for DEP; John J. Spanos, President of Gannett Fleming Valuation and Rate Consultants, LLC; Melissa Culbreth, Vice President of Financial Planning & Analysis for DEBS; Michael P. Callahan, Senior Vice President and Treasurer for DEBS; and James M. Coyne, Senior Vice President at Concentric Energy Advisors.

On November 24, 2025, the Commission issued an order which declared the proceeding to be a general rate case, suspended the proposed new rates, established the test year period as ending December 31, 2024, and advised that an order scheduling hearings and requiring public notice would be issued at a later date.

On November 26, 2025, CIGFUR III filed a Motion to Deem Performance-Based Regulation Application Incomplete or, in the Alternative, to Reject Performance-Based Regulation Application (Motion to Deem Performance-Based Regulation Application Incomplete), contending that DEC's PBR Application was incomplete because it proposed a two-year MYRP rather than a three-year MYRP as CIGFUR III argued was required by the PBR Statute and Commission Rule R1-17B.

On December 15, 2025, DEC filed a Response in Opposition to CIGFUR III's Motion, arguing pursuant to N.C.G.S. § 62-133.16(f), a PBR application "shall remain in effect for a plan period of not more than 36 months," sets an outer limit rather than a mandatory floor and that DEC's proposed two-year MYRP complies with all applicable requirements.

On December 16, 2025, 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 January 27, 2026, that DEC should make its Transmission and Distribution (T&D) Information Filing by January 20, 2026, and that parties would be allowed to file written comments on DEC's T&D Information Filing on or before January 26, 2026.

On January 9, 2026, the Commission issued its Order Denying CIGFUR III's Motion to Deem Performance-Based Regulation Application Incomplete, concluding that

the PBR Statute allows utilities to request a MYRP lasting fewer than 36 months and that DEC's PBR Application, which included a request for a MYRP of two years could not fail for lack of a proposed third rate year.

On January 12, 2026, CIGFUR III filed a Notice regarding Technical Conference Participation, indicating that it would not be presenting at the Technical Conference, but that counsel would appear and be available to answer any questions from the Commission.

On January 14, 2026, DEC filed a Motion for Substitution of Witness and Adoption of Testimony requesting to substitute Thomas J. Heath, Jr., DEBS' Corporate Finance Director, as the sponsor of the prefiled direct testimony of witness Callahan. The Commission entered an order allowing the substitution of witness Callahan with witness Heath and for witness Heath to adopt the direct testimony of witness Callahan on January 20, 2026.

On January 15, 2026, the Commission issued its Order Scheduling Hearings, Establishing Procedural and Filing Requirements, and Requiring Public Notice (Scheduling Order). The Scheduling Order scheduled public witness hearings in Morganton, Charlotte, Winston-Salem, and Durham, North Carolina on April 28, April 29, May 6, and May 12, 2026, respectively, as well as a remote public witness hearing via Webex on April 7, 2026. Further, the Scheduling Order set the relevant test period to be used by all parties as the twelve-month period ending December 31, 2024, with appropriate adjustments. The Scheduling Order also scheduled an expert witness hearing to begin on July 7, 2026. The Commission directed, among other instructions, DEC and the Public Staff to confer and file a proposed Public Notice with the Commission.

On January 20, 2026, the Commission issued an Errata Order correcting errors in the Scheduling Order regarding certain filing deadlines.

Also on January 20, 2026, DEC filed its T&D Information Filings. CIGFUR III and NCJC, et al. each filed comments in response to DEC's T&D Informational Filing on January 26, 2026.

On January 21, 2026, the Public Staff and DEC filed a Joint Expedited Motion for Procedural Relief, requesting Commission approval to deviate from the approved template for public notice and including a proposed Public Notice.

On January 22, 2026, the Commission issued its Order Approving Public Notice, approving the Joint Expedited Motion and DEC's proposed Public Notice. The Commission directed DEC to publish the Public Notice once a week for two successive weeks, mail the Public Notice to customers no later than 30 days in advance of the first set hearing, and to make a copy of the Public Notice prominently available on its website.

Also on January 22, 2026, the Commission issued its Order Canceling Technical Conference, canceling the January 27, 2026 Technical Conference due to a forecasted winter storm and the declaration of a State of Emergency by Governor Joshua H. Stein pursuant to Executive Order No. 31 (Winter Storm Fern), with the Technical Conference to be rescheduled by further order of the Commission.

On January 30, 2026, the Commission issued its Order Rescheduling Technical Conference and Setting Procedures for Technical Conference. The Commission's order rescheduled the Technical Conference for March 9, 2026, and directed parties to file written comments on DEC's T&D Information Filing on or before March 6, 2026.

On February 3, 2026, CIGFUR III filed a Motion for Reconsideration of the Presiding Commissioner's January 9, 2026 Order denying its motion regarding DEC's PBR Application.

On February 12, 2026, DEC filed the supplemental direct testimony and exhibits of witnesses Jiggetts, Abernathy, Fogg, Guyton, Haaf, Holeman, LaRoche, Tompson, and Walsh.

On February 16, 2026, DEC filed its response to CIGFUR III's Motion for Reconsideration of the Commission's Order denying its motion regarding DEC's PBR Application.

On March 5, 2026, DEC filed updated T&D Information Filing documents with the Commission.

On March 9, 2026, a Technical Conference was held before the Commission with Commissioner Floyd B. McKissick, Jr., Presiding; Chair William M. Brawley; and Commissioners Tommy Tucker, Donald van der Vaart, and John W. Gajda.

On March 12, 2026, DEC and DEP filed a Joint Motion to Establish New Dockets and Consolidate Request for Accounting Order with Pending Rate Cases. The Motion requested the Commission to open new dockets specific to DEC's and DEP's requests to establish a regulatory asset for the remaining net book value of the Level 2 (L2) public charging infrastructure currently pending in Docket Nos. E-2, Sub 1197 and E-7, Sub 1195 and to consolidate the newly established dockets with DEC's rate case pending in this docket and DEP's rate case pending in Docket No. E-2, Sub 1380.

On March 18, 2026, the Commission entered an Order Denying CIGFUR III's Motion for Reconsideration of the Commission's January 9, 2026 order denying CIGFUR III's Motion for Reconsideration pertaining to the sufficiency of DEC's PBR Application.

On March 27, 2026, DEC and DEP filed a MYRP1 Project Status Exhibit.

In April, May, and June of 2026, the Commission held five public hearings as scheduled by the Scheduling Order for the purpose of receiving public witness testimony.

On April 6, 2026, DEC filed its Affidavits and Certification of Publication for the Public Notice of Application for General Rate Increase and Public Hearings, as required by the Commission's January 15, 2026 Order Scheduling Hearings, Establishing Procedural and Filing Requirements, and Requiring Public Notice.

On April 20, 2026, DEC filed a Clarification Regarding Consolidation with Accounting Order Request. DEC clarifies that its request for an accounting order regarding the remaining net book value of L2 public charging infrastructure deployed

under the Phase I Electric Transportation Pilots, which was filed in Docket No. E-7, Sub 1355, is intended to be consolidated with DEC's general rate case proceeding pending in this docket, Docket No. E-7, Sub 1329.

On April 22, 2026, DEC filed the supplemental direct testimony of Jonathan Byrd and supplemental direct testimony and exhibits of Melissa Culbreth. Also on April 22, 2026, DEC filed the second supplemental testimony and exhibits of witnesses Melissa B. Abernathy and LaWanda M. Jiggetts.

On May 1, 2026, DEC filed supplemental direct exhibits of Jonathan Byrd.

On May 8, 2026, the Commission entered an Order Rescheduling Public Witness Hearing in Durham, North Carolina, and Requiring Supplemental Customer Notice.

On May 26, 2026, DEC filed a motion to substitute witness Jacob S. Colley, Managing Director of Regulatory Planning, Compliance, and Vulnerable Customer Support, as the sponsor of the Direct Testimony and Exhibits prefiled by witness Quick on November 20, 2025. On June 4, 2026, the Commission entered an Order Accepting Substitution of Witness Lesley G. Quick and Allowing Adoption of Testimony by Witness Jacob S. Colley.

On May 29, 2026, the Public Staff's Energy Division filed the following sets of direct testimonies and exhibits: Evan D. Lawrence, Engineer; Erik G. Fernandez, Caleb A. Hill, and Tommy Williamson, Jr., Engineers (the Public Staff PIMs Panel); Dustin Metz, Director; Jay B. Lucas, Manager of the Rates and Energy Services Section; Jeff Thomas, Manager of the Operations Section; Caleb A. Hill and Leah M. M. Weaver, Engineers (the Public Staff Renewables Panel); David M. Williamson and Erik G. Fernandez, Engineers (the Public Staff Rates Panel); Jeff Thomas and Tommy Williamson, Jr. (the Public Staff Distribution Panel); Patrick A. Fahey, Public Utilities Regulatory Analyst; Jay B. Lucas, Leah M. M. Weaver, and Dr. Jethro Ssengonzi, Engineer (Public Staff Large Load Panel); Barry S. Brown, Syed Imam, Desiree Manfull, and Hemanth Meda, Public Utility Regulatory Analysts, and Fenge Zhang, Public Utility Regulatory Analyst Manager (the Public Staff Accounting Panel); and Dustin Metz and Jeff Thomas (the Public Staff Policy Panel). The Public Staff also filed on its behalf the direct testimonies and exhibits of Roxie McCullar, Consultant, William Dunkel and Associates; and Christopher C. Walters, Principal with Brubaker & Associates, Inc.

Also on May 29, 2026, EDF filed the joint direct testimony and exhibits of Timothy M. Lenell and Karan Pol; the AGO filed the direct testimony and exhibits of Edward Burgess, Founding Partner of Current Energy Group LLC (CEG), Daniel Cassara, Consultant with CEG, and Justin Brant, Senior Manager with CEG; NCJC, et al., filed the direct testimony and exhibits of Steven Kihm, President of Narrative 804, LLC, and John D. Wilson, Vice President of Grid Strategies, LLC; Microsoft filed the direct testimony and exhibits of Isaac Gabel-Frank, Co-CEO of Gabel Associates, Inc.; NCHBA filed the direct testimony and exhibits of Christopher W. Millis, Chief of Staff and Director of Regulatory Affairs for NCHBA, Aaron P. Lange, Director of Operations for Arden Group, LLC, and Laura T.W. Olive, Director in the Energy and Natural Resources practice at National Economic Research Associates, Inc.; Google filed the direct testimony and exhibits of

Dr. Carolyn A. Berry; CIGFUR III filed the direct testimony of Brian C. Collins, Managing Principal at Brubaker & Associates, Inc.; Harris Teeter filed the direct testimony and exhibits of Justin Bieber, Principal for Energy Strategies, LLC; CUCA filed the direct testimony and exhibits of Billie S. LaConte, Energy Advisor and Associate Consultant at J. Pollock, Incorporated, and Shawn McGlothlin, Associate with J. Pollock, Incorporated; Walmart filed the direct testimony and exhibits of Steve W. Chriss, Group Director, Utility Partnerships at Walmart; and NCSEA filed the direct testimony and exhibits of Albert Lin, OG Finance Lab.

Also on May 29, 2026, the Electrification Coalition filed Comments on DEC's PBR Application.

On June 3, 2026, DEC filed its Affidavit and Certification of Publication of the Supplemental Notice of Application for General Rate Increase and Public Hearings, as required by the North Carolina Utilities Commission's May 8, 2026, Order Rescheduling Public Witness Hearing in Durham, North Carolina, and Requiring Supplemental Customer Notice.

On June 8, 2026, Microsoft filed its Request That the Commission Open a Separate Docket to Address a Large Load Tariff (LL Tariff) and, in the Alternative, Motion for Leave to File Rebuttal Testimony. On June 11, 2026, Public Staff filed its response to Microsoft's Motion. Microsoft filed a Reply in support of its request that the Commission open a separate docket to address the LL Tariff, and, in the alternative, a motion for leave to file rebuttal testimony.

On June 12, 2026, CIGFUR III filed a Motion for Leave to File Supplemental Testimony. Also on June 12, 2026, Public Staff objected to CIGFUR III' s Motion for the reasons set forth in its response (filed on June 11, 2026) to the motion filed by Microsoft in this proceeding on June 8, 2026.

On June 18, 2026, the Commission entered an Order Denying Microsoft and CIGFUR III's Motions for Leave to File Rebuttal and Supplemental Testimony, but referred the request to open a separate parallel docket to the Chairman for the Commission to take the request under advisement.

On June 19, 2026, DEC filed the rebuttal testimony and exhibits of DEC's witnesses Bowman; Abernathy; Coyne; Heath; Timothy J. Duff, Managing Director, Large Load Strategy & Enablement for DEBS; Colley; Guyton; Fogg; Justin Teckenbrock, General Manager of Enterprise Information Solutions; Haaf; Walsh; LaRoche; Tompson; Jiggetts; Caldwell; David J. Wathen, Senior Managing Director, Southeast Work & Rewards Region Leader for Willis Towers Watson (WTW); Hager; Speros; Spanos; Jeff Kopp, Senior Managing Director of the Energy & Utilities Consulting department of Burns & McDonnell Engineering Company, Inc.; Culbreth; Sykes; the joint rebuttal testimony and exhibits of witnesses Bateman and Farmer; and the joint rebuttal testimony and exhibits of witnesses Byrd and Morgan Beveridge, Director of Rates and Regulatory Planning for DEBS.

On June 22, 2026, DEC filed the rebuttal testimony and exhibits of witness Sykes.

On July 2, 2026, DEC filed an Agreement and Stipulation of Partial Settlement (Partial Stipulation) between DEC and Public Staff.

On July 6, 2026, NCHBA filed a Settlement Agreement and Partial Stipulation on the Distribution Line Extension Plan (DLEP) between DEC, NCHBA, and Public Staff (DLEP Stipulation). DEC also filed an Agreement and Stipulation of Settlement of Storm Costs (Storm Cost Stipulation) between DEC and Public Staff. Also on July 6, 2026, Public Staff filed Joint Settlement Testimony of Dustin Metz, Fenge Zhang, and Jeff Thomas.

Also on July 6, 2026, Harris Teeter filed a Motion to Excuse witness Justin Bieber, which was granted by Commission order on July 7, 2026.

On July 7, 2026, DEC filed the Settlement Testimony and Exhibits of witnesses Jiggetts, Byrd, and Beveridge in support of the Partial Stipulation.

Also on July 7, 2026, NCHBA filed a Motion to Excuse Witnesses Aaron P. Lange and Laura T.W. Olive and CUCA filed a Motion to Excuse Witness Shawn McGlothin. The Commission granted NCHBA and CUCA's motions to excuse on July 8, 2026.

On July 7, 2026, the expert witness hearing commenced.

At the outset of the July 7, 2026, hearing, DEC made an oral motion to excuse DEC witness Culbreth, stating that no parties objected to her excusal. At the hearing, on July 8, 2026, the Presiding Commissioner orally denied DEC's motion to excuse witness Culbreth. On July 9, 2026, during the hearing, counsel for DEC renewed its oral motion to excuse witness Culbreth, which the Presiding Commissioner then granted orally. The Commission entered an Order Granting Motion to Excuse Witness Culbreth on July 16, 2026.

On July 8, 2026, Public Staff filed Joint Settlement Testimony on Storm Costs of Dustin Metz, Fenge Zhang, and Jeff Thomas.

On July 9, 2026, Persistence Analytics Group LLC filed a Public Comment Regarding DEC's LL Tariff, Cost Causation, Grid Upgrade Allocation, and Ratepayer Protection.

Also on July 9, 2026, DEC filed an Agreement and Stipulation of Settlement on the Direct Current Fast Charging (DCFC) Pilot Program (DCFC Stipulation) between DEC, Public Staff, and Walmart.

On July 13, 2026, DEC filed the Settlement Testimony of witnesses Byrd and Beveridge in support of the DCFC Stipulation. Also on July 13, 2026, Walmart filed the Settlement Testimony of Steve W. Chriss in support of the DCFC Stipulation.

On July 14, 2026, NCSEA filed a Motion to Excuse Witness Albert Lin, Walmart filed a Motion to Excuse Witness Steve W. Chriss, CUCA filed a Motion to Excuse Witness Billie LaConte, and NCHBA filed a Motion to Excuse Witness Christopher W. Millis.

The Commission granted NCSEA, Walmart, CUCA, and NCHBA's motions to excuse on July 15, 2026.

On July 15, 2026, DEC filed a Motion to Excuse Witness Justin A. Teckenbrock and the AGO filed a Motion to Excuse Witness Daniel Cassara. The Commission granted DEC and the AGO's motions to excuse on July 15, 2026.

From July 14, 2026, through August 10, 2026, DEC filed fourteen Late-Filed Exhibits, including one Joint Late-Filed Exhibit with the Public Staff on July 27, 2026.

From July 16, 2026, through July 20, 2026, Public Staff filed four Late-Filed Exhibits.

On July 17, 2026, DEC filed a Comprehensive Revenue Requirement Agreement and Stipulation of Settlement (Comprehensive Settlement) between DEC and the Public Staff, CIGFUR III, CUCA, NCSEA, and Walmart (collectively, Stipulating Parties), along with a Motion to Delay Continuance of Evidentiary Hearing. Also on July 17, 2026, the Commission entered an Order Granting Motion to Delay Continuance of Evidentiary Hearing.

On July 20, 2026, CIGFUR III filed the Settlement Testimony of Brian C. Collins. Also on July 20, 2026, DEC filed an Amended Comprehensive Settlement adding Microsoft as a Stipulating Party. DEC filed a Second Amended Comprehensive Settlement adding Andale as a Stipulating Party. DEC also filed a Third Amended Comprehensive Settlement adding EDF as a Stipulating Party. No substantive changes were made to the Comprehensive Settlement in any of the amended versions — instead, such amended versions only added additional Stipulating Parties. For purposes of this Order, the Comprehensive Settlement refers to the settlement as amended. Additionally, on July 20, 2026, DEC filed Settlement and Supplemental Settlement Testimony of DEC's witnesses Bowman; Colley; Heath; Coyne; Jiggetts; Abernathy; Byrd and Beveridge; and Bateman. The Public Staff also filed the Joint Comprehensive Settlement Testimony of Metz, Zhang, Thomas, and Fahey.

Also on July 20, 2026, CIGFUR III filed a Motion to Excuse Witness Brian C. Collins from providing further live testimony on the limited supplemental testimony witness Collins filed in support of the Comprehensive Settlement. The Commission granted CIGFUR III's motion to excuse on July 21, 2026.

On July 21, 2026, DEC filed a Motion to Excuse Witnesses: Guyton, Fogg, Haaf, Walsh, LaRoche, Tompson, Sykes, Caldwell, and Wathen. On July 22, 2026, the Commission granted DEC's motion in part and denied in part, granting excusal of DEC witnesses Guyton, Fogg, Haaf, LaRoche, Tompson, Sykes, Caldwell, and Wathen and denying excusal of DEC witness Walsh.

Also on July 21, 2026, Google filed a Letter in Support of ¶ 15 (LL Tariff) of the Comprehensive Settlement and stated that it had reviewed the entirety of the Comprehensive Settlement and did not object to any of its remaining provisions.

On July 22, 2026, the Commission entered an Order Requiring Response from Non-Participating Parties Regarding Objections, if any, to the Comprehensive Stipulation.

Also on July 22, 2026, Amazon filed a Letter in Support of ¶ 15 of the Comprehensive Settlement, EDF filed the Settlement Testimony of Timothy M. Lenell and Karan Pol, and Nucor Steel filed a Letter Responding to the Order Requiring Response from Non-Participating Parties Regarding Objections, if any, to the Comprehensive Stipulation, stating that it does not object to the Comprehensive Settlement.

On July 23, 2026, EDF filed a Motion to Excuse Witnesses Lenell and Pol. The Commission granted EDF's motion to excuse on July 23, 2026.

Also on July 23, 2026, the AGO and NCJC, et al. filed Letters Responding to the Order Requiring Response from Non-Participating Parties Regarding Objections, if any, to the Comprehensive Stipulation.

Also on July 23, 2026, DEC filed the Fourth Amended Comprehensive Settlement adding Harris Teeter as a Stipulating Party.

On July 24, 2026, DEC filed an Agreement and Stipulation of Settlement on Performance Incentive Mechanisms and Tracking Metrics (PIMs Settlement) between DEC and Public Staff. The Public Staff also filed the Joint Settlement Testimony on Performance Incentive Mechanisms of Erik G. Fernandez, Caleb A. Hill, and Tommy Williamson, Jr.

Also on July 24, 2026, DEC filed a Motion to Excuse Witness S. Renee Farmer, which the Commission granted on July 27, 2026.

On August 12, 2026, the Commission issued an Order Requesting Comments on a model rate schedule, the proposed LL Tariff provisions that each of the Public Staff and DEC submitted in this docket, and other large load issues as specified therein (Order Requesting Comments). The Order Requesting Comments provided that parties may file initial comments by September 9, 2026, and reply comments by September 25, 2026.

On August 17, 2026, the Carolinas Clean Energy Business Association (CCEBA) filed a Petition to Intervene for the purpose of providing comments in response to the Commission's Order Requesting Comments. On August 19, 2026, CIGFUR II and CIGFUR III (collectively, CIGFUR) filed a letter opposing CCEBA's intervention. The Commission denied CCEBA's petition to intervene on the grounds it was not timely and allowed CCEBA amicus curiae status on August 21, 2026.

On August 28, 2026, DEC filed its summary of stakeholder feedback regarding LL Tariffs consistent with the Commission's Order Requesting Comments.

On September 3, 2026, the Corporate Energy Buyers Association (CEBA) filed a Motion for Amicus Curiae Status and a Motion for Admission Pro Hac Vice for the purpose of providing comments in response to the Commission's Order Requesting Comments, which was granted by Commission order on September 4, 2026.

On September 4, 2026, parties filed proposed orders and briefs.

On September 9, 2026, parties filed initial comments in response to the Commission's August 12, 2026 Order Requesting Comments.

Also on September 9, 2026, Digital Reality Trust, L.P. (Digital Realty) filed a Petition to Intervene Out of Time (Digital Realty Petition) for the purpose of providing comments in response to the Commission's Order Requesting Comments. The Commission denied Digital Realty's Petition on the grounds it was not timely and allowed Digital Realty amicus curiae status on September 24, 2026.

On October 6, 2026, parties filed reply comments or letters in lieu of reply comments in response to the Commission's August 12, 2026 Order Requesting Comments. DEC also submitted an Agreement and Stipulation of Settlement of Large Load Tariff (LLT Stipulation) among DEC, DEP, the Public Staff, Amazon, Andale, CIGFUR, Google, and Microsoft that DEC and DEP discussed in their joint reply comments.

On October 12, 2026, Walmart filed a motion for leave to file supplemental comments regarding the LLT stipulation, which motion was denied by Commission order issued on October 20, 2026.

Also on October 12, 2026, the Commission issued an Errata Order, which corrected its July 7, 2026, order to include admitting Harris Teeter witness Bieber's prefiled testimony and exhibits into the record.

Performance-Based Regulation Application

In summary, DEC requested in its PBR Application and initial direct testimony and exhibits, a net base rate revenue increase of approximately $595 million, which represents an overall increase in its retail revenues of approximately 8.9%, including a rate of return on common equity (ROE) of 10.95% and a capital structure consisting of 47% debt and 53% equity. DEC's PBR Application and initial direct testimony and exhibits also sought approval of PBR, and a series of rate increases based on DEC's proposed two-year MYRP2, and other mechanisms required as part of PBR, with the first rate increase proposed to take effect January 1, 2027. DEC sought incremental increases to the revenue requirement of $132 million in Rate Year 1 and $274.9 million in Rate Year 2.

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, 2024, adjusted for certain known changes in revenue, expenses, and rate base. DEC's proposed capital cut-off period was March 31, 2026.

Public Witness Hearings

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

Morganton: La'Meshia Whittington, Sanja Whittington, Nathan Huret, Brooke Melton, Sarah Wilder, Jamie Thompson, Lynda Garabaldi, Robert Gray Jernigan, Pamela Harrison, Emma Corpening, Doris Crute, Christopher Griffin,

Kamicia Griffin, Doyle Brown, Cynthia Reilly, MacGregor VanBeurden, and Jessica Sanchez

Charlotte: Catherine Butler, Harry Taylor, Joseph Baxter, Katie Rothweiler, Shannon Bradley, Veleria Levy, Tommy George, Kolbi Blackburn, Ana Clemmer, Ana Diaz, Adam Frers, Maryann Sanders, Jared Yerg, Jeanna Hoffman, Trinity Maeshack, William Burton-Edwards, Robert McCutcheon, June Blotnick, Marjorie Storch, Yasir Faras Tamir-El, Amethyst Fernandez, Nancy Carter, Susanna Chen, Martha Zziwa, Rachel Rader, Jessica Holtzapple, and Brian Kennedy

Winston-Salem: Stacy Smith, Albert Gayzik, Cassi Choi, Victor Duarte, Gary Purgason, William Blake Stewart, Jeanette Kelley, Paulette Smith, Jesse Epperson, Sharlee Hainesworth, Annette Hayes, Debra Demske, Amy Taylor North, Matthew Mayers, David Fairall, Henry Fansler, John Calhoun, Lauralei McCarver, Joel Wooten, Chuck Slipetsky, Sandra Stinson, Blondia Ferrell, Betsy Johnson, Kara Larrabee, Waltena Robinson, Carol Ann Krebs, Deborah Gibbs, Misty Gabriel, Carly Diaz, and Sharon Black

Durham: Paul Baer, Dan Jewell, Carolina Spencer Sparks, Ted Spencer, LaTosha Gibson, Christopher Latham, Anali North Martin, Marth Henderson, Michelle Carter, Savannah Hutko, Irene Cygan, Lib Hutchby, Wendy Michener, Ash Voss, Aidan Paul, Matt Killmon, Charles Pettee, Darrion Smith, Michelle Lesher, Alexandria Kupsky, Kasey Kinsella, Robert Sotolongo, Margo MacDonald, Justin Powers, Victoria Polischak, Danielle Hallett, Kristen Viera, Alexander Robichaud, Bobby Jones, Brittany Phillips, Lisa Beasley, Lindsey Bradsher, Leslie St Dre, Colin Dornemann, William Israel, Aidan Loretz, John Midyette, Gregory Williams, Lindsay Savelli, Maya Ghanem, Jennifer Griffith, Stephanie Gans, Robby Roudon, Elisabeth Pethybridge, Rani Patel, Juhi Modi, Joel Hornstein, Shriram Raghu, Sherri Zann Rosenthal, Loftin Wilson, Pablo Friedmann, Deron Burton, Weini Girmai, Barjron Zenelaj, Mark Miller, Jane MacNeela, Sophia Barron, Hannah Teasley, Olive Burress, Tomas Robinson, and Wendy Warren Merritt

Virtual: Rick Martin, Lauren Carlin, and Charles Fieselman

In summary, nearly all public witnesses stated their opposition to DEC's proposed rate increase. *See generally*, tr. vols. 1-5. A limited number of witnesses commended DEC's economic development efforts, including individuals testifying on behalf of Catawba County Economic Development Corporation, Central Piedmont Community College, and the Charlotte Regional Business Alliance. Tr. vol. 2, 32-35, tr. vol. 3, 18-21, 68-72. Public witnesses voiced concerns regarding the impact DEC's proposed rate increase will have on residential ratepayers living on fixed incomes and those experiencing financial hardship in an inflated economic environment. Some witnesses testified that they currently forgo spending on healthcare and groceries to pay their power bills, or that they anticipate forgoing this spending if DEC's requested rate increase takes effect. Other witnesses testified to the strain the requested rate increase will place on their local businesses.

Public witnesses also testified that DEC's executive compensation and profits are excessive. Further, public witnesses expressed concerns with the corporation's conduct, including DEC's mishandling of coal ash. Lastly, many public witnesses also testified against DEC's investments in new natural gas generation facilities and its reliance on coal-fired generation and instead expressed their support for renewables.

Public witnesses also expressed specific concerns pertaining to data center demand growth. Witnesses testified that residential customer classes should not experience a greater percentage increase in their rates than industrial customer classes, as DEC had proposed. Public witnesses also communicated strong opposition to any cross-subsidization of electrical infrastructure development caused by data centers and argued that data centers should pay for all costs they cause. Public witnesses also testified against DEC constructing fossil-fuel fired generating infrastructure to supply data centers with power, stating their opposition to the pollution and natural resource strain that would result from this power supply strategy. Instead, some public witnesses testified that data centers should supply their own power using renewables.

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 (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 PBR Application.

WHEREUPON, the Commission makes the following

FINDINGS OF FACT

Stipulations

1. On October 24, 2025, DEC, DEP, the Public Staff, CIGFUR II, CIGFUR III, and CUCA (COSS Stipulating Parties) filed the COSS Stipulation. The COSS Stipulation provides that DEC will continue to allocate production and transmission demand costs to the North Carolina retail jurisdiction using the Twelve Coincident Peak (12 CP) method and will allocate production demand costs among the North Carolina retail rate classes using the modified Average and Excess (A&E) Demand Method (Modified A&E Method).

2. On July 2, 2026, DEC and the Public Staff filed the Partial Stipulation, which resolved a portion of the base period and MYRP revenue requirement issues in this proceeding.

3. On July 6, 2026, DEC and the Public Staff filed the Storm Cost Stipulation, which resolved storm cost recovery related issues between DEC and Public Staff.

4. On July 6, 2026, NCHBA filed the DLEP Stipulation between DEC, NCHBA, and Public Staff regarding DEC's DLEP and contribution in aid of construction (CIAC) policy.

5. On July 9, 2026, DEC filed the DCFC Stipulation, among DEC, Public Staff, and Walmart, establishing an electric vehicle (EV) DCFC Pilot Program available for electric service used by a commercial customer to operate public-facing DCFC facilities.

6. On July 17, 2026, DEC, the Public Staff, CIGFUR III, Walmart, NCSEA, and CUCA filed the Comprehensive Settlement. The Comprehensive Settlement was subsequently amended on July 20, 2026, to add Microsoft, Andale, and EDF as Stipulating Parties, and was further amended on July 23, 2026, to add Harris Teeter as a Stipulating Party. The Comprehensive Settlement resolved all outstanding revenue requirement issues in this proceeding as between the Stipulating Parties. By the terms of the Comprehensive Settlement, all Stipulating Parties also supported the earlier partial revenue requirement settlements executed between DEC and the Public Staff — namely, the Partial Stipulation filed on July 2, 2026, and the Storm Cost Stipulation filed on July 6, 2026.

7. On July 24, 2026, DEC and the Public Staff filed the PIMs Settlement.

8. The Comprehensive Settlement, the Partial Stipulation, the COSS Stipulation, the DLEP Stipulation, the Storm Cost Stipulation, the DCFC Stipulation, and the PIMs Settlement, are the product of give-and-take settlement negotiations between the respective stipulating parties.

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

9. In its rebuttal testimony, DEC voluntarily lowered its ROE request to 10.48%, citing affordability concerns raised by customers, the Public Staff, and intervenors. In the Comprehensive Settlement, the Stipulating Parties agreed to an allowed ROE of 9.80% and a capital structure consisting of 53.0% common equity and 47.0% long-term debt.

10. After filing the PBR Application, DEC updated its cost rate for long-term debt. As of March 31, 2026, the embedded cost of DEC's long-term debt is 4.57%, which is reasonable and appropriate for use in this proceeding.

11. The Comprehensive Settlement's stipulated ROE of 9.80% and capital structure composed of 53% common equity and 47% long-term debt, when factoring in the embedded cost of DEC's debt (4.57%), results in an overall rate of return under the Comprehensive Settlement of 7.34%.

12. The resulting overall rate of return of 7.34% is reasonable and appropriate for use in this proceeding.

13. In light of the Comprehensive Settlement as a whole, the ROE and capital structure approved by the Commission appropriately balances the benefits received by DEC's customers from DEC's provision of safe, adequate, and reliable electric service with customer affordability.

14. The capital structure, ROE, and overall rate of return set by this Order result in just and reasonable rates.

Depreciation

15. DEC's 2024 DEC Depreciation Study prepared by Gannett Fleming (2024 Depreciation Study) as originally proposed, adjusted to reflect the Public Staff's proposed adjustments, including recommended adjustments to the 2024 Decommissioning Study (except that a 10% contingency factor shall be applied in lieu of the contingency percentages proposed by either DEC or Public Staff), as stipulated, is just and reasonable for purposes of this proceeding.

16. It is reasonable for DEC to use good faith estimates reflecting a 10% contingency factor for purposes of the settlement schedules and for DEC's depreciation consultant, in a compliance filing, to apply the agreed-upon assumptions in his model to develop the final depreciation rates to be implemented by DEC.

17. The exclusion of asbestos decommissioning costs related to the Bad Creek and Bridgewater hydroelectric plants from the 2024 Depreciation Study, as reflected in the proposed depreciation rates of Public Staff witness McCullar, is the reasonable product of negotiations among the Stipulating Parties and is just and reasonable for purposes of this proceeding.

18. DEC's proposal to defer 100% of the impact of accelerating the depreciation of DEC's subcritical coal plants resulting from the 2021 Depreciation Study to a regulatory asset for future securitization, for an annual deferral of $13.956 million on a North Carolina retail basis, as permitted by Session Law 2025-78 (S.L. 2025-78), is reasonable.

Base Period Plant-Related Items

19. DEC's plant-related capital investments during the test year as updated through the capital cut-off date in its general/intangible, transmission, distribution, fossil/hydro, nuclear, solar, and storage assets, as adjusted by the Partial Stipulation and the Comprehensive Settlement, are the reasonable product of give-and-take negotiations and should be included in the revenue requirement.

Base Period Accounting Adjustments

20. The accounting adjustments set forth in the Partial Stipulation and Comprehensive Settlement, as further described in detail in Jiggetts Comprehensive Settlement Exhibits 2 and 3, are the reasonable product of give-and-take negotiations among the Stipulating Parties. DEC's uncontested request to amortize the net deferred regulatory fees over a two-year period (pro forma NC5030) and its request in Docket No. E-7, Sub 1355 to establish a regulatory asset for the remaining net book value of its Level 2 public charging infrastructure are just and reasonable.

Federal Funding

21. DEC's request to recover the deferred revenue requirement impacts, including benefits and costs, associated with the Inflation Reduction Act (IRA) and the Infrastructure Investment and Jobs Act (IIJA) grants, net of costs to pursue the grants, over a two-year period is just and reasonable.

22. It is just and reasonable for DEC to continue to defer incremental costs related to pursuing grant funding, with any incremental costs relating to grants that are not ultimately received to remain in a regulatory asset account to be recovered in a future rate case.

23. It is just and reasonable that, if DEC is successful in obtaining a grant, DEC record the grant amount received, net of the associated incremental costs to achieve the grant, as an offset to the capital project receiving the grant. If the capital project receiving the grant was in service as of March 31, 2026, or is a MYRP2 project approved in this case, DEC should also defer the depreciation and return amounts related to the net grant amount to a regulatory liability to return to customers in a future rate case; provided, however, that DEC's accounting for the Department of Energy (DOE) grant for the Belews Creek Coal Reliability Assurance Initiative shall be governed by Section II. 20 of the Comprehensive Settlement.

Coal Ash

24. DEC's request to recover costs associated with its coal combustion residual (CCR) obligations incurred from July 1, 2023, through March 31, 2026, over an eight-year period and to continue the deferral of any CCR costs incurred subsequent to March 31, 2026, is reasonable.

Storm Costs

25. The adjustment to DEC's revenue requirement, calculated using the method approved by the Commission in Docket Nos. E-7, Sub 1026, E-7, Sub 1146, E-7, Sub 1214, and E-7, Sub 1276, to account for anticipated storm expenses based upon a 10-year average of storm costs after removing costs associated with major storms, is approximately $34.194 million.

26. Per DEC's Agreement and Stipulation of Partial Settlement with the Public Staff in Docket No. E-7, Sub 1243 (2020 Storm Securitization), and DEC's Amended Agreement and Stipulation of Settlement in Docket Nos. E-7, Sub 1325 and E-2, Sub 1370 (2024 Storm Securitization), 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.

27. The amortization over two years of the regulatory liability for the over-recovered balance of approximately $152,000 for storm securitization servicing and administration fees, and the amortization over two years of the regulatory asset for the under-recovered balance of approximately $118,000 for upfront bond issuance costs related to storm securitization are just and reasonable.

28. Per the Storm Cost Stipulation, the Hurricane Helene over-securitization amount is the amount per DEC's filing in this case ($141.557 million overcollection plus $12.639 million return on the overcollection), using DEC's proposed incremental calculation for purposes of the Hurricane Helene over-securitization amount in this case only.

29. The Storm Cost Stipulation includes Winter Storm Fern incremental storm costs of $99.910 million (net of the applicable storm deductible) in the revenue requirement, subject to audit by the Public Staff and a final true-up based on actual reasonable and prudent costs determined under the traditional method in DEC's next general rate case.

30. The Storm Cost Stipulation includes the Hurricane Helene over-securitization amount, netted against the Winter Storm Fern incremental storm costs, resulting in a $54.287 million credit to customers, to be amortized over 18.75 years with the unamortized balance included in rate base.

31. Per the Storm Cost Stipulation, DEC and the Public Staff agree that the Winter Storm Fern incremental costs will not incur any carrying costs.

32. Per the Storm Cost Stipulation, DEC agrees to use the traditional method for calculating the incremental storm operations and maintenance costs for 2026 through DEC's next general rate case.

33. In its initial application, DEC proposed to establish a storm reserve. DEC agreed to withdraw its storm reserve proposal as part of the Storm Cost Stipulation.

Multiyear Rate Plan 2 Capital Investments

34. DEC's proposed MYRP2 capital investments, reflecting the projected costs associated with transmission, distribution, grid planning & integration (GP&I), fossil/hydro, nuclear, solar, and storage, as adjusted in the Partial Stipulation and Comprehensive Settlement, are the reasonable product of give-and-take negotiations among the parties and appropriate for approval as part of DEC's PBR Application in this proceeding.

Cost Allocation

35. The COSS Stipulation between DEC, DEP, CIGFUR II, CIGFUR III, CUCA, and the Public Staff requires DEC to first allocate production demand and transmission demand costs to the North Carolina retail jurisdiction by using the 12 CP allocation method and will then allocate production demand and transmission demand costs among the North Carolina retail rate customer classes using the Modified A&E Method.

36. The cost allocation methodologies used in DEC's cost of service study (COSS), including the methods for allocating production demand and transmission demand costs in accordance with the COSS Stipulation and the use of the minimum system methodology for the purpose of allocating distribution costs between customer classes in accordance with the PBR Statute, are just and reasonable for purposes of this proceeding.

Distribution Line Extension Plan

37. DEC, the Public Staff, and NCHBA agreed on the extent to which grid improvements upstream from a new residential real estate development may be treated as construction costs, to amend DEC's DLEP as set forth in the DLEP Stipulation, which, in part, extends the revenue credit from three years to five years for the initial extension

of distribution facilities for both residential and nonresidential service and facilities within a residential real estate development, and agreed on a letter template with explanatory details for CIAC charges.

38. The Public Staff and NCHBA agreed that with respect to CIAC obligations arising within a specific residential real estate development pursuant to DEC's DLEP, including without limitation single-phase and three-phase line extensions, the CIAC calculation shall be performed on a cumulative, development-wide basis limited to the subject residential real estate development.

Rate Design

39. 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.

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

41. DEC proposed a 25% reduction in variance from present rates of return by class, subject to a 3% cap on any class increase relative to the retail average. The annualized base and total revenue at present and proposed rates is reflected in Byrd-Beveridge Comprehensive Settlement Exhibit Nos. 2, 2_1, and 2_2; the Class COSS results are reflected in Byrd-Beveridge Comprehensive Settlement Exhibits Nos. 4, 4_1, and 4_2. The Comprehensive Settlement did not change DEC's proposed rate design methodology.

42. The proposed rate design, as reflected in the Byrd-Beveridge Comprehensive Settlement Exhibits, is just and reasonable.

43. DEC proposed changes to its residential rate schedules, general service rate schedules, industrial rate schedules, and lighting rate schedules. DEC also proposed changes to its service riders, which are offered to reflect the cost of meeting unique or special customer requirements.

44. DEC proposed, consistent with principles of gradualism, Basic Customer Charge increases of 7.7% for Schedule LGS, 9.5% for Schedule I, and 8.8% for Schedule OPT-V. The Comprehensive Settlement does not change DEC's proposed increases to the Basic Customer Charge.

45. DEC proposed to close Schedule ES to new residential customers effective January 1, 2027. The Public Staff proposes to reduce the Schedule ES discount from 5% to 2.5% beginning January 1, 2028, to mitigate any rate shock. Schedule ES will close on March 31, 2029, and remaining customers will transition to either Schedule RE or Schedule RS.

46. Pursuant to the DCFC Stipulation, DEC has agreed to establish a DCFC Pilot Rate (DCFC Pilot) that is available for electric service used by a commercial customer to operate public-facing DCFC facilities.

Customer Growth and Large Load Interconnection Facilities

47. The Comprehensive Settlement provides that the revenues in DEC's customer growth pro forma and the corresponding interconnection facilities for three specific large load customers shall be included in the case and that the resulting net benefit of $19.5 million shall be allocated to all customer classes.

48. Aside from the facilities for the above-referenced three specific large load customers, the Stipulating Parties agree to remove from this case the specific interconnection facilities identified by the Public Staff in its direct testimony and agreed to by DEC in rebuttal, resulting in a reduction in rate base of $173.2 million on a system basis.

49. DEC agrees to establish a process for future rate cases to update the capital additions for customer interconnection facilities and the associated revenue for such customers through the same period, subject to any changes directed by the Commission in a future proceeding.

COVID Bad Debt Deferral Recovery

50. The Commission's Order Accepting Stipulations, Granting Partial Rate Increase, Requiring Public Notice, and Modifying Lincoln CT CPCN Conditions, *Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation*, No. E-7, Sub 1276, at 273 (N.C.U.C. Dec. 15, 2023) (Sub 1276 Order) approved DEC's request to continue to defer incremental bad debt for future recovery.

51. The Comprehensive Settlement allows DEC to recover the deferred bad debt balance in this case to include actual deferral amounts from July 1, 2023, through June 30, 2026, plus an estimated deferral amount of $12 million for the period from July 1, 2026, through December 31, 2026, less a one-time impairment of $17 million removed in June 2026.

52. It is reasonable and appropriate for DEC to continue to defer the difference between actual bad debt expense and the amount in customer rates for the period from July 2026 through December 2026, subject to a $12 million cap.

53. It is reasonable and appropriate that the deferral include a debt only return during the deferral period, with no rate base treatment (no return) during the amortization period. DEC should recover the deferred balance over a five-year period.

54. If the actual deferral for July 2026 through December 2026 is less than $12 million, it is reasonable and appropriate for DEC to defer the difference and return it to customers in the next rate case.

Lead Lag Study

55. In accordance with the Sub 1276 Order, DEC prepared an updated lead-lag study and has incorporated the results of this study into its PBR Application in this rate case, and the lead-lag study is reasonable and appropriate for use in this proceeding.

Reporting Requirements

56. The reporting obligations established in Section II, ¶ 18 and Section IV, ¶ 1 of the Comprehensive Settlement are appropriate.

57. The reporting obligations established in Section IV of the Partial Stipulation, as modified by Section III of the Comprehensive Settlement, are appropriate.

Affordability

58. Under the Comprehensive Settlement, DEC agreed to make shareholder financial contributions totaling $10 million. The contribution will support both bill assistance through the Share the Light Fund and health and safety repairs through the Helping Home Fund to help facilitate access to low-income weatherization programs. DEC shall file, beginning April 1, 2028, an annual report with the Commission documenting the disbursement of shareholder contributions and the number of customers assisted, as set forth in the Comprehensive Settlement.

Riders

59. The Nuclear Production Tax Credit (PTC) Rider established in Docket No. E-7, Sub 1276 returns to customers the benefits of nuclear PTCs under the IRA. Expanding the rider to include other available PTCs, such as those for solar and hydroelectric resources, and renaming it the PTC Rider will allow customers to receive the benefits of those additional credits.

60. The expansion of the PTC Rider as agreed to in the Partial Stipulation is just and reasonable. Under the Partial Stipulation, DEC will add back non-outage incremental Operation and Maintenance (O&M) for prevailing wages to the test year and discontinue all prevailing wage deferrals effective January 1, 2027, and other incremental costs not in customer rates to achieve the tax credit benefits may still be netted in the PTC Rider subject to determination of reasonableness in a future PTC Rider proceeding.

61. The Existing DSM Program Rider (EDPR) recovers only the costs of DSM programs that predate 2007, is relatively small and will continue to decline, and has resulted in an over-collection of $1.2 million or less in each of the past five years.

62. The elimination of the EDPR and recovery of the associated costs in base rates, as agreed to in the Partial Stipulation, are just and reasonable.

63. Certain regulatory assets and liabilities previously approved by the Commission have been over-amortized, resulting in a net over-recovery that should be returned to customers.

64. The establishment of a new tranche of DEC's Regulatory Asset and Liability (RAL) Rider, Rider RAL-2, to refund to customers over a two-year period the net over-amortization of expired regulatory assets and liabilities, as agreed to in the Partial Stipulation, is just and reasonable.

65. Consistent with the Partial Stipulation, DEC has withdrawn the pension rider proposed in its initial application, and it is just and reasonable that no pension rider be established in this proceeding.

Carrying Costs

66. Annual compounding of the return accrued during the deferral period for the COVID bad debt, CCR, and Hurricane Helene (post-securitization bond issuance) deferrals, as agreed to in the Partial Stipulation, is just and reasonable.

67. The use of annual compounding when accruing a return, if applicable, on deferrals (both regulatory assets and liabilities) and riders through DEC's next two general rate cases, which may be achieved either by applying monthly compounding at a discounted rate or by applying annual compounding at the annual rate, as agreed to in the Partial Stipulation, is just and reasonable.

Quality of Service

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

Base Fuel and Fuel-Related Factors

69. The Stipulating Parties agree to work together on a proposal to finalize DEC's fuel treatment in its compliance filing to update the base fuel factors to reflect the Commission's Order in Docket No. E-7, Sub 1334.

70. The Stipulating Parties agree that DEC will not seek to true-up any additional fuel and fuel related costs incurred prior to January 1, 2025, that are not already included in the current DEC fuel rider, or in the pending DEC fuel rider, Docket No. E-7, Sub 1334, for rates effective September 1, 2026.

71. The Stipulating Parties agree to meet and discuss the appropriate calculation of interest under N.C.G.S. § 62-133.2.

Residential Decoupling Mechanism and Earnings Sharing Mechanism

72. DEC's PBR Application includes an RDM, a rate-making 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 the

PBR Statute and Commission Rule R1-17B. As a component of the Comprehensive Settlement, only sales under the EV tariff will be included in the calculation to exclude EV sales margin from the RDM and ESM.

73. DEC's PBR Application includes an ESM, an annual rate-making 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. As a component of the Comprehensive Settlement, DEC has agreed to calculate the ESM using a 13-month average rate base and the Commission-approved target capital structure, and to maintain separate ESMs for DEC and DEP. The separation of the ESMs includes expenses and rate base that will be allocated on a revenue basis, and blended capital structures and rate base will be used to calculate individual utility results.

Performance Incentive Mechanisms

74. The PIMs Settlement consists of the following four PIMs: Time Differentiated and Dynamic Rate Enrollment PIM, Reliability PIM, Facilities Study PIM, and Vegetation Management PIM (collectively, Settled PIMs). The PIMs Settlement also provides for the following tracking metrics – customer service with the addition of major digital channel customer interactions and beneficial electrification from incremental load of EVs, as well as additional non-tracking metric reporting obligations. The PIMs Settlement also requires DEC to host a PIMs Workshop prior to filing its next PBR rate case.

Multiyear Rate Plan Refund Rider

75. 72.76. It is just and reasonable to implement the MYRP Refund Mechanism and Rider under which DEC will refund customers if approved MYRP2 projects are delayed or not completed during their expected rate year. The MYRP Refund Mechanism is designed to measure the actual costs and in-service dates for MYRP2 projects compared to the projected costs and in-service dates included in rates. The Stipulating Parties propose to apply a factor to this delta based upon project completion percentages using both number of projects and dollars, to determine the amount to be refunded pursuant to the MYRP Refund Rider on an annual basis.

76. The MYRP Refund Rider is a fair and reasonable mechanism to address concerns raised by the parties regarding MYRP1 project execution and impacts on customers of delayed and canceled projects.

Performance-Based Regulation

77. DEC's PBR Application, as modified by DEC's rebuttal testimony, the Partial Stipulation, the Comprehensive Settlement, and the PIMs Settlement, will result in just and reasonable rates, is in the public interest, and is consistent with the criteria established in the PBR Statute and Commission Rule R1-17B.

Revenue Requirement

78. After giving effect to the stipulations approved herein, the annual revenue requirement for DEC for Rate Years 1 and 2 will allow DEC to recover its operating costs

and a reasonable opportunity to 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.

Large Loads, Data Centers, and the DC Schedule

79. Duke is experiencing significant anticipated load growth from new XL Customers (as defined hereinbelow) seeking to interconnect and obtain service on Duke's system. DEC and DEP combined have approximately 7.9 GW of potential large load customer loads in the advanced development phase, including signed Energy Services Agreement (ESA) contracts for 6.7 GW of new load attributable to new large load customers from March 2024 through April 2026 in North Carolina and South Carolina. Data centers represent 92% of the 6.7 GW of load covered by ESAs.

80. Driven primarily by the recent proliferation of data centers, the rapid and unprecedented increase in new customer demand that is contracting, or seeking to contract, with Duke's operating companies for electric service imposes unprecedented planning, operational, and financial risks, from which existing ratepayers must be protected.

81. Serving these new data center customerswill require DEC and DEP to invest billions of dollars in its generation, transmission, and distribution assets, all of which will take years to construct.

82. If the potential data center customer load fails to materialize in whole or in part, terminates its contractual obligations early, or leaves DEC's system before the new assets can reasonably be absorbed by existing ratepayers or fully recovered from the exiting data center customer(s), the fixed costs of the new infrastructure, much of which has a useful life of 30 years or longer, could be unfairly and unreasonably shifted to other North Carolina retail ratepayers.

83. DEC's existing and proposed tariffs do not properly allocate the costs and address the risks associated with the significant new infrastructure necessary to serve data center customers, nor do the existing and currently proposed tariffs appropriately determine when those costs should be directly assigned to data center customers.

84. In order to manage these significant risks reasonably and appropriately and to enhance regulatory clarity and stakeholder confidence, it is appropriate and in the public interest to adopt a rate schedule and supplemental tariff provisions in this proceeding that will apply specifically to data center customers in order to ensure that the costs and risks associated with serving data center customers are assigned to, and recovered from, the data center customers.

85. The DC Rate Schedule and Supplemental Tariff Provisions (DC Schedule), in the form attached to this Order as Appendix A (subject to rate modifications in accordance with this Order) is reasonable and appropriate for both protecting DEC's other retail electric ratepayers and providing electric service to data center customers and is approved.

86. Defining a "DC Customer" as "a customer with an Applicable Demand of at least 50 MW that functions, or is expected to function, as a Data Center" and "Data Center" as "a facility, campus of facilities, or array of interconnected facilities used by a person or an entity or other business enterprise for which either (a) the primary or exclusive demand of the facility(ies) is Computational Load; or (b) the Computational Load is, or is expected to be, at least 50 MW" and defining "Computational Load" as "the demand for, or usage of, electricity associated with storing, retrieving, managing, processing, and/or disseminating electronic data and information, including, but not limited to, activities and information technology infrastructure, such as servers, processors, storage, and networking gear, used for, or involved in, building, running, and delivering applications and services that support, or otherwise involve, artificial intelligence, cloud computing, cryptocurrencies, and/or any other digital services" captures the customer group that imposes the primary risks to DEC's planning, operations, and finances, is reasonable and appropriate, and is approved.

87. Subjecting each DC Customer to the Availability, Definitions, Type of Service, Rate, Riders, Determination of Billing Demand, Power Factor Correction, Payment, Conflict, Waiver, and Reliability and Curtailment provisions (collectively, Rate Provisions) of the DC Schedule is reasonable and appropriate and is approved.

88. Subjecting each New DC Customer (as defined in the DC Schedule) to the Contract Period, Minimum Billing Demand, Required Facilities Costs, Notice of Contract Reduction or Early Termination, Liquidated Damages, Stranded Generation Charge, Security Requirements, and Ride-Through Requirements provisions of the XL Schedule (collectively, Risk Mitigation Provisions) is reasonable and appropriate for both protecting other retail ratepayers and serving such DC Customers and is approved.

89. Subjecting the Qualifying Incremental Demand (as defined in the XL Schedule) of each Existing Customer (as defined in the DC Schedule) and the Subsequent Incremental Demand of each DC Customer and New DC Customer to the Risk Mitigation Provisions on and after the date of the issuance of this Order is reasonable and appropriate for both protecting other retail ratepayers and serving the Incremental Demand of such DC Customers and is approved.

90. It is reasonable and appropriate for the Commission to approve a pro forma ESA to facilitate increased transparency in the DC Customer contracting process, ensure that ESA provisions are applied in a manner that is not unreasonably or unjustly discriminatory to any DC Customer, and protect DEC's other retail ratepayers, and the interim standard ESA attached to this Order as Appendix B is approved.

91. The date of ESA execution will not be used to determine whether the XL Schedule or any portion thereof will apply to an DC Customer. Parties may not contract around the Commission's regulatory jurisdiction over utility rates and services.

92. If a customer initiates Post-Order Service (as defined in the DC Schedule) in a manner that is not specifically contemplated in, and authorized by, the customer's existing ESA, then the customer shall execute a then-current standard ESA or

amendment to the existing ESA that incorporates all pertinent provisions of the then-current standard ESA for the Post-Order Service prior to initiation of the service.

93. Requiring each DC Schedule customer receiving Post-Order Service to pay the applicable contribution in aid of construction (CIAC) amounts for Dedicated Facilities and Transmission Network Upgrades (TNUs) assigned to the customer for the Post-Order Service is reasonable and appropriate for both protecting other retail ratepayers and serving such XL Schedule customers and is approved.

94. Requiring DEC to develop and file an estimated CIAC and supporting workpapers for the direct assignment of TNUs for each DC Schedule customer's requested or planned Post-Order Service, which estimated CIAC will be subject to Commission review and approval, is reasonable and appropriate.

95. Imposing a Stranded Generation Charge (as defined in the DC Schedule) for all Post-Order Service to protect other retail ratepayers from the financial risk of DC Customers terminating their electric service prior to the end of the useful life of the utility assets constructed for the DC Customer-driven unprecedented load growth is reasonable and appropriate for both protecting other retail ratepayers and serving such DC Customers and is approved.

96. Utilizing a proxy combined cycle (CC) unit and the estimated length of the useful life of a new CC unit of 35 years to identify an estimated Stranded Generation Charge based on a per MW-Year charge of $67,357 is reasonable and appropriate.

97. Using a stakeholder group process to develop a standard ESA, a standard methodology for directly assigning CIAC for TNUs, and a standard methodology for determining a Stranded Generation Charge using system modeling, and to identify viable alternatives to the existing DC Schedule Reliability (Curtailment) requirements, all for review and approval by the Commission pursuant to a process to be determined following the outcome of the stakeholder group process, is reasonable and appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-8

Stipulations

The evidence supporting these findings of fact is contained in DEC's verified PBR Application and Form E-1; the stipulations between DEC and the other parties; the testimony and exhibits of DEC witnesses Bowman, Jiggetts, Abernathy, Hager, Heath, Coyne, Bateman, Byrd, Beveridge, and Colley; the testimony and exhibits of Public Staff witnesses Metz, Zhang, Thomas, Fahey, Fernandez, Hill, and T. Williamson; the testimony and exhibits of CIGFUR III witness Collins; the testimony and exhibits of EDF witnesses Lenell and Pol; the testimony and exhibits of NCHBA witnesses Millis, Lange and Olive; the testimony and exhibits of Walmart witness Chriss; and the entire record in this proceeding.

Summary of Evidence

Cost of Service Study Stipulation

On October 24, 2025, the COSS Stipulating Parties filed the COSS Stipulation with the Commission in the instant proceeding and in the DEP Rate Case. Tr. vol. 11, 559-60. 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 only applies in the rate cases in Docket Nos. E-7, Sub 1329 and E-2, Sub 1380, and the COSS Stipulating Parties are free to advocate for different methodologies in future rate cases. COSS Stip. at 3; tr. vol. 19, 229. 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. Tr. vol. 11, 560. The Commission approved an agreement and stipulation of partial settlement among DEC, DEP, the Public Staff, CIGFUR II, and CIGFUR III employing the same methodology for allocating the Companies' production and transmission demand-related costs in DEP and DEC's most recent rate cases in Docket Nos. E-2, Sub 1300 and E-7, Sub 1276, respectively (2022 COSS Stipulation). Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Public Notice, *Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation*, No. E-2, Sub 1300 at 35-36 (N.C.U.C. Aug. 18, 2023) (Sub 1300 Order); Sub 1276 Order at 36-37.

Partial Stipulation

On July 2, 2026, DEC and the Public Staff filed the Partial Stipulation, resolving a narrow set of issues that were only in dispute between DEC and the Public Staff. For clarity of the record, the Partial Stipulation was executed prior to but then ultimately incorporated into the Comprehensive Settlement. Specifically, the Partial Stipulation resolved, among other items: DEC's ongoing bad debt expense amount; certain vegetation management expenses; the removal of identified land purchases from rate base; discrete MYRP project and plant-related items; accounting adjustments related to coal ash, aviation expense, Board of Directors expense, executive compensation, adjustment to the regulatory fee, solar O&M, and the MYRP1 pro forma (NC3060); Transmission Cost Allocation adjustment; additional MYRP2 project level resolutions; carrying costs; and riders. Partial Stip. §§ III.1-III.31.

Public Staff witnesses Metz, Zhang, and Thomas filed joint testimony in support of the Partial Stipulation. The Public Staff testified that the Partial Stipulation is in the public interest and should be approved. Tr. vol. 13, 57. The Public Staff further testified that the Partial Stipulation benefits customers by providing an aggregate reduction to DEC's proposed revenue requirement and avoiding protracted litigation between the Public Staff and DEC. *Id.* at 56.

Storm Cost Stipulation

On July 6, 2026, DEC and the Public Staff filed the Storm Cost Stipulation resolving the storm cost recovery issues between DEC and the Public Staff. For clarity of the record, the Storm Cost Stipulation was executed prior to but then ultimately incorporated into the Comprehensive Settlement. In particular, the Storm Cost Stipulation resolved issues on the following storm-related topics: Winter Storm Fern incremental storm costs, carrying costs, the Hurricane Helene over-securitization amount, DEC's requested storm reserve, and the methodology for calculating incremental storm O&M through the next general rate case.

DEC witness Jiggetts testified in support of the Storm Cost Stipulation and Partial Stipulation. Tr. vol. 21, 487. Witness Jiggetts testified that the adjustments included therein balance the financial impact of the rate increase on customers with DEC's need to recover its revenue requirement to enable DEC to fulfill its obligation to provide safe and reliable electric service to customers. *Id.* at 489. Witness Jiggetts noted that the Storm Cost Stipulation, alongside the Partial Stipulation, resolved many of the issues in this case without the necessity of contentious litigation. *Id.* at 495-96.

Likewise, Public Staff witnesses Metz, Zhang, and Thomas testified that the Storm Cost Stipulation provides ratepayer benefits; strikes an appropriate balance for ratepayers between the tradeoffs of spreading storm costs over a longer period of time and imposing the costs of current storms on future ratepayers; and is in the public interest. Tr. vol. 13, 62-63.

Distribution Line Extension Plan Stipulation

On July 6, 2026, NCHBA filed the DLEP Stipulation between DEC, NCHBA, and Public Staff regarding DEC's DLEP and CIAC policy. The DLEP governs how DEC extends distribution facilities to serve new customers, including cost allocation for line extensions. Tr. vol. 21, 587. Under the DLEP, a revenue credit that is based on projected customer revenue over a defined period is compared to the cost of installing new facilities. *Id.* at 1150-1156. If projected revenues over the defined period equal or exceed the construction cost, no upfront CIAC payment is required. *Id*. If projected revenues over the defined time period do not equal or exceed the construction cost, the shortfall is recovered as an upfront CIAC charge from the customer. *Id*. DEC, NCHBA, and the Public Staff agreed that under DEC's existing DLEP and policy, grid improvements upstream from a new residential real estate development, including grid modernization projects and other off-site facilities upgrades (e.g., substation upgrades), may be treated as "Construction Costs" for purposes of the CIAC calculation under DEC's DLEP only to the extent that (i) they are not included within the scope of DEC's system improvement/capacity plan; and (ii) such costs, which shall include the installed cost of new facilities, the removal cost of existing facilities minus the salvage value of removed facilities, plus any necessary rearrangement costs, are reasonable, proportionate, and solely attributable to the specific real estate development. DLEP Stip. § 2.B; tr. vol. 21, 588-589. DEC further agreed to consider additional feedback from NCHBA and the Public Staff on its letter template that would be provided upon request to residential home builder customers with explanatory details for CIAC charges. DLEP Stip. § 2.D The DLEP Stipulation also makes three modifications to DEC's DLEP.

First, the DLEP Stipulation provides that DEC's DLEP should be amended to extend the revenue credit period from three years to five years for the initial extension of distribution facilities for both residential and nonresidential service and facilities within a residential real estate development. DLEP Stip. § 2.A. What this means on a practical level is that, so long as projected revenues of the customer over a five-year period exceed the cost of providing standard design, the customer is not responsible for paying any costs up front. Second, the DLEP Stipulation provides that DEC's DLEP should be amended to adopt a definition of "residential real estate development" in the Revenue Credit section, meaning "a Real Estate Development which consists primarily of structures subject to the North Carolina Residential Building Code and developed pursuant to a common, unified, or master development plan that is intended to be constructed in phases or as a coordinated whole and which may include appurtenant single-phase or three-phase infrastructure." DLEP Stip. § 2.A; tr. vol. 21, 588.

Third, the DLEP Stipulation addresses how the CIAC calculation is performed for residential developments that include both single-phase facilities (service to individual homes) and three-phase facilities serving appurtenant community infrastructure (e.g., clubhouses). DLEP Stip. § 2.C; tr. ex. vol. 21, 1150-1156. Currently, CIAC for single-phase and three-phase facilities is calculated separately, meaning surplus revenue from residential service cannot offset the costs of three-phase community facilities. Tr. vol. 21, 589. Under the DLEP Stipulation, the Public Staff and NCHBA agree that the CIAC calculation should instead be performed on a cumulative, development-wide basis, thereby aggregating revenue credits and construction costs for both facility types within the same development (the Aggregation Proposal), as set forth in NCHBA witness Millis' Exhibit CWM 1 and DEC Rate Design Panel's Byrd-Beveridge Rebuttal Exhibit 3. *Id*. DEC does not object to the Aggregation Proposal. No other party opposed the DLEP Stipulation.

Direct Current Fast Charging Stipulation

On July 9, 2026, DEC, the Public Staff, and Walmart entered into the DCFC Stipulation, which reached an agreement on an EV pilot program. The DCFC Stipulation establishes a DCFC pilot rate schedule to be available to commercial customers operating public-facing DCFC facilities beginning on January 1, 2027. DCFC Stip. §§ II.1-II.2.

DEC witnesses Byrd and Beveridge testified in support of the DCFC Stipulation. Tr. vol. 21, 594. Witnesses Byrd and Beveridge stated that the DCFC Stipulation advances the deployment of EV charging infrastructure in North Carolina and appropriately balances the promotion of EV infrastructure against the risk of cross-subsidization to other customer classes. *Id.* at 596.

Walmart witness Chriss also testified in support of the DCFC Stipulation and commended DEC and the Public Staff for working with Walmart to develop the DCFC Pilot. Tr. vol. 14, 43-45.

Comprehensive Settlement

On July 17, 2026, the Public Staff, DEC, CIGFUR III, CUCA, NCSEA, and Walmart filed the Comprehensive Settlement, which resolved all outstanding issues between the

Stipulating Parties, and incorporates by reference the terms of the Partial Stipulation and Storm Cost Stipulation described above. On July 20, 2026, the Comprehensive Settlement was amended to include Microsoft, Andale, and EDF, as Stipulating Parties, and further amended on July 23, 2026, to include Harris Teeter as a Stipulating Party.

DEC witness Bowman testified that the Comprehensive Settlement, as amended, was the product of extensive negotiations between the Stipulating Parties and reflects give-and-take by all involved. Witness Bowman noted that the Comprehensive Settlement builds upon DEC's commitment to balance customer affordability with investments needed to ensure continued reliability, resilience, and economic growth. Tr. vol. 21, 66. Witness Bowman also explained how the Comprehensive Settlement resolves all contested revenue requirement issues between DEC and the Public Staff and supports a parallel large load proceeding that would allow for further engagement and comments on the appropriate balance of customer protections and reasonable terms and policies for serving new large load customers. *Id.* at 67.

Witness Bowman further noted that the Comprehensive Settlement, among other things, sets DEC's authorized return on equity at 9.8%, with a capital structure of 53.0% equity and 47.0% debt, resolved customer growth and large load issues, and includes a MYRP Refund Mechanism Rider, under which DEC will provide refunds to customers if approved MYRP2 projects are delayed or not completed. *Id.* at 68.

Public Staff witnesses Metz, Zhang, Thomas, and Fahey filed joint testimony in support of the Comprehensive Settlement, testifying that the Comprehensive Settlement provides important benefits, including a substantial aggregate reduction in DEC's proposed revenue increase in this proceeding and that the Comprehensive Settlement is in the public interest and should be approved. Tr. vol. 21, 150-51. EDF witnesses Lenell and Pol also filed settlement testimony in support of the Comprehensive Settlement. Tr. vol. 22, 18-19. Witnesses Lenell and Pol supported approval of the Comprehensive Settlement, noting that, while EDF's participation in this proceeding focused primarily on large load and transportation issues, the Comprehensive Settlement offers a reasonable framework for addressing the outstanding LL Tariff issues while respecting the various compromises achieved by the Stipulating Parties. *Id.* at 19.

Performance Incentive Mechanisms Settlement

On July 24, 2026, DEC and the Public Staff filed the PIMs Settlement. The Public Staff also filed the Joint Settlement Testimony on Performance Incentive Mechanisms of Erik G. Fernandez, Caleb A. Hill, and Tommy Williamson, Jr.; and DEC witnesses Laura Bateman, Renee Farmer and Brent Guyton testified in support of the PIMs Settlement.

The PIMs Settlement consists of the following four PIMs: Time Differentiated and Dynamic Rate Enrollment PIM, Reliability PIM, Facilities Study PIM, and Vegetation Management PIM. PIMs Settl. §§ II.A-II.D. The Settled PIMs provide for maximum upside rewards to DEC of $8.75 million per rate year and maximum downside penalties of $10 million per rate year. The PIMs Settlement also provides for the following tracking metrics: customer service with the addition of major digital channel customer interactions and beneficial electrification from incremental load of residential EVs, as well as additional

non-tracking metric reporting obligations, and a requirement for DEC to host a PIMs Workshop prior to filing its next PBR rate case. PIMs Settlement § II.

Public Staff witnesses Fernandez, Hill and T. Williamson testified that the Settled PIMs benefit ratepayers by creating incentives for DEC to take actions that are expected to yield net customer savings, more quickly interconnect generation resources, and target its expenditures on reliability improvements most likely to yield customer benefits. Tr. vol. 23, 22-23.

DEC witness Bateman testified that the PIMs Settlement will benefit customers through improved operational efficiencies, cost savings, and reliability of electric service over the course of the MYRP and will advance important policy goals to maintain or improve utility performance. Tr. vol. 22, 463-66.

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. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc.*, 348 N.C. 452, 500 S.E.2d 693 (1998) (*CUCA I*), and *State ex rel. Utilities. Commission v. Carolina Utilities Customers Association, Inc.*, 351 N.C. 223, 524 S.E.2d 10 (2000) (*CUCA II*), 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 17.

The Commission concludes that the COSS Stipulation, the Partial Stipulation, the Storm Cost Stipulation, the DLEP Stipulation, the DCFC Stipulation, the Comprehensive Settlement, and the PIMs Settlement result from give-and-take negotiations between the stipulating parties and represent compromises that are just and reasonable to each party and in the public interest. The Commission has fully evaluated the provisions of these stipulations, the testimony proffered by parties in support of these stipulations cited above, and the absence of persuasive 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. 9-14

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

The evidence supporting these findings of fact is contained in DEC's verified PBR Application and Form E-1; the testimony and exhibits of the public witnesses; the testimony and exhibits of DEC witnesses Bowman, Coyne, Heath, and Jiggetts; the testimony and exhibits of Public Staff witnesses Walters and Fahey; the testimony and exhibits of CUCA witness LaConte; the testimony and exhibits of NCJC, et al. witness Kihm; the testimony and exhibits of AGO witnesses Cassara and Burgess; the testimony and exhibits of Walmart witness Chriss; the testimony and exhibits of NCSEA witness Lin; the testimony and exhibits of CIGFUR III witness Collins; and the entire record in this proceeding.

DEC's embedded cost of long-term debt, capital structure, and cost of common equity capital are used to calculate for rate setting purposes the utility's overall cost of capital. As is typical in utility rate proceedings, the testimony on cost of capital is voluminous. The Commission has carefully considered all the evidence and the record as a whole. Given the volume of prefiled testimony and length of testimony received at hearings, the Commission has not recounted every statement of every witness and has instead summarized the testimony received to the extent necessary to provide a basis for its decision.

Summary of Evidence

Long-Term Debt

The embedded cost of DEC's long-term debt is undisputed in this proceeding. In her second supplemental testimony, DEC witness Jiggetts presented DEC's embedded cost of debt as of March 31, 2026, at 4.57%. Tr. vol. 12, 290.

Capital Structure

In DEC witness Heath's direct testimony, he proposed using a capital structure of 53.0% equity and 47.0% long-term debt. Tr. vol. 8, 213. Witness Heath 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.* As of December 31, 2024, DEC's capital structure was 52.0% common equity and 48.0% long-term debt. *Id.* at 214.

Witness Heath 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 206, 209-12. Witness Heath noted that DEC faces substantial capital needs over the next several years to maintain and upgrade aging infrastructure; construct needed generation resources; strengthen its energy grid; and satisfy its debt maturities. *Id.* at 217. Therefore, to continue to provide safe, reliable, and cost-effective electric service to its customers, DEC must be able to recover prudently incurred costs, attract sufficient capital, and preserve its financial standing with investors and credit rating agencies. *Id.* at 205. Witness Heath explained that investors have a variety of investment options 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 204-05. Witness Heath 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 Heath testified it is critical that DEC maintain strong, investment-grade ratings to assure its financial strength and flexibility and ensure access to capital on reasonable terms. *Id.* at 205.

Discussing DEC's financial objectives, witness Heath addressed specific objectives that support DEC's financial strength and flexibility, including: (1) attaining at least a 53.0% common equity for DEC on a financial capitalization basis; (2) ensuring timely recovery of prudently incurred costs; (3) maintaining sufficient cash flows to meet obligations; and (4) maintaining a sufficient return on equity to fairly compensate shareholders for their invested capital. *Id.* at 205. Witness Heath 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 meet its overall financial objectives. *Id.* at 205-06.

In his direct testimony, DEC witness Coyne testified that based upon his analysis DEC's requested 53% equity 47% long-term debt capital structure was appropriate. Witness Coyne compared DEC's request to the financial capital structures of the operating utilities of the utility holding companies within his proxy group, which consists of companies with risk commensurate to DEC. He concluded that DEC's requested capital structure was reasonable and consistent with industry standards. *Id*. at 194-95.

Of the intervenor witnesses, only Public Staff witness Walters and CUCA witness LaConte addressed capital structure. Based upon their analyses, they recommended a capital structure with a lower equity portion – 51% equity in the case of witness Walters, and 51.5% equity in the case of witness LaConte. Tr. vol. 14, 51; tr. vol. 16, 47. Witness

Walters also testified that DEC's proposed equity ratio exceeds the typical equity ratios being authorized around the country for electric utilities and is significantly higher than the proxy group's equity ratio of 42.3% (excluding short-term debt). Tr. vol. 16, 138-40. Witness Walters evaluated DEC's financial strength and concluded the Public Staff's recommended weighted average cost of capital (WACC) would support an investment grade bond rating for DEC. *Id.* at 141.

Similarly, CUCA witness LaConte testified that DEC's average equity ratio since its last base rate case increase was approved in December 2023 has been significantly below the authorized 53%, yet DEC maintained its credit ratings. Tr. vol. 14, 87. Witness LaConte testified that a reasonable capital structure for DEC is 51.5% equity and 48.5% debt, which she testified she determined by reviewing DEC's historical capital structure since 2022 and the authorized common equity ratios for the companies in her proxy group. *Id.* at 89. Witness LaConte further stated her opinion that DEC could maintain its strong credit ratings and implement its capital expenditure program with her recommended capital structure. *Id.*

On rebuttal, DEC witness Heath took issue with the intervenor witnesses' capital structure recommendations. Witness Heath noted that witness Walters' reliance on capital ratios of his proxy group companies was misplaced because the proxy companies are all publicly traded holding companies not utility operating companies. Tr. vol. 21, 191. In response to witnesses Walters and LaConte, Witness Heath testified that a utility's capital structure should not be viewed in isolation; it is part of an overall framework that considers capital structure, allowed ROE, and the various mechanisms used to recover costs. Witness Heath further testified that the framework adopted by a utility and its regulators determines the level of risk borne by investors, which directly impacts the cost of financing (both debt and equity) borne by customers. *Id.* at 193.

Witness Heath also responded to witness LaConte's recommendation, which is based on the capital structures of her proxy group as well as DEC's actual quarterly capital structures. Witness Heath testified that, like witness Walters, witness LaConte's proxy group contains publicly traded utility holding companies (not operating subsidiaries like DEC). *Id.* at 194. Witness Heath explained how DEC manages its capital structure to the authorized structure, which prior to January 2024, was 52% equity and 48% debt. *Id.* at 195-96. Witness Heath reiterated that it is expected for the debt/equity ratio to 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 and maturities, seasonality of earnings, and dividend payments to the parent company. *Id.* at 196. Witness Heath noted in particular that DEC often makes a large debt issuance early in the calendar year, which is consistent with witness LaConte's Table 5. *Id*.

DEC witness Coyne testified that DEC's proposed capital structure is well within the range of the actual capital structures of the operating companies held by the proxy group companies. *Id.* at 252. Witness Coyne explained, in response to witness Walters recommendation, that the appropriate equity ratio should reflect the relative business and operating risks of the utility for which the authorized return is being set, which makes witness Walters' comparison to equity ratios at the holding company level inappropriate. *Id.* at 367. Witness Coyne explained that the obligation to serve rests with the operating utility, not the holding company, and it is the obligation to serve that drives utility financing

practices and the requirement to access capital in all market environments. *Id.* at 368. Witness Coyne also critiqued witnesses Walters and LaConte's reliance on historical capital structures. Witness Coyne testified that regulated ratemaking is inherently forward-looking and capital structure management is dynamic and complex because it must satisfy multiple objectives subject to multiple constraints. *Id.* at 368-69.

Return on Equity

DEC's rate of return expert, witness James Coyne, recommended a ROE of 10.95% 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	9.45%[2]
AGO Witness Cassara	7.4%[3]
CUCA Witness LaConte	9.54%[4]
NCJC, et al. Witness Kihm	9.1%

Walmart witness Chriss, CIGFUR witness Collins, and NCSEA witness Lin did not perform an independent expert ROE analysis. Rather, they confined their rate of return testimony to commenting on average rates of return awarded to electric utilities over various time periods.

DEC Direct Testimony

DEC witness Coyne explained that the foundations of public utility regulation require that utilities receive a fair rate of return sufficient to attract capital needed to maintain infrastructure at reasonable rates. Tr. vol. 8, 127. He testified that regulated utilities rely primarily on common stock and long-term debt to finance long-lived property, plant, and equipment. *Id.* at 129-30. He further explained that the allowed rate of return for a regulated utility is based on its WACC, where the costs of the individual sources of capital (i.e., debt and equity) are weighted by their respective book values. Witness Coyne noted that the return on equity represents the cost of raising and retaining equity capital and is estimated by using one or more analytical techniques that use market data to quantify investor requirements for equity returns. He emphasized, however, that the ROE cannot be derived through quantitative metrics and models alone; to properly estimate the ROE, the financial, regulatory, and economic context must also be considered. *Id.* at 130. Witness Coyne concluded that the Commission's decision in this case should provide DEC with the opportunity to earn a return on equity that is commensurate with returns on investments in enterprises having comparable risks; adequate to attract capital

[2] Public Staff witness Fahey recommends a downward adjustment in the rate of return on equity if DEC's proposed MYRP is approved. Public Staff witness Walters provided additional testimony on this point and recommended an ROE in the lower half of his range.

[3] AGO witness Brant recommends a downward adjustment in the rate of return on equity if DEC's proposed MYRP is approved.

[4] CUCA witness LaConte recommends a downward adjustment in the rate of return on equity if DEC's proposed MYRP is approved.

on reasonable terms; and sufficient to ensure the financial soundness of DEC's electric utility operations. *Id.*

In estimating a fair ROE for DEC, witness Coyne utilized four cost of capital modeling methodologies: the Discounted Cash Flow (DCF) model, the Capital Asset Pricing Model (CAPM), the Bond Yield Plus Risk Premium (Risk Premium) model, and the Expected Earnings model. Witness Coyne explained that his ultimate return on equity recommendation is based on a range of results produced from the four modeling methodologies. He specifically noted:

> Analysts and academics understand that ROE models are tools to be used in the ROE estimation process, and that strict adherence to any single approach, or the specific results of any single approach, can lead to flawed conclusions. No single model can exactly pinpoint the correct cost of equity, but each is designed to provide a unique estimate of the return required to attract equity investment.

Id. at 124-25.

In witness Coyne's direct testimony, he recommended a return on equity of 10.95%, which he stated was a conservative estimate of the required return on common equity. The four models produced a range of results, from 10.57% to 11.76% with a four-model average of 11.25%, inclusive of 9 basis points for flotation costs. *Id.* at 123.

Witness Coyne also testified that he considered DEC's business and regulatory risks in relation to a set of proxy companies to assist in the determination of the appropriate ROE and capital structure from within the range of analytical results. *Id.* at 125.

Intervenor Direct Testimony (Rate of Return Expert Analysis)

The intervenor ROE expert witnesses generally criticized DEC witness Coyne's analysis that resulted in his recommended 10.95% ROE. In addition, they performed their own analyses as outlined below.

Public Staff Direct Testimony

Public Staff witness Walters performed DCF, Risk Premium, and CAPM analyses for his proxy groups of electric utilities. Tr. vol. 16, 84-85. Public Staff witness Walters recommended a ROE of 9.45% based on a capital structure of 51% common equity and 49% long-term debt. *Id.* at 47-48. Witness Walters testified that DEC's credit ratings are indicative of a significantly different risk profile relative to the proxy group used to assess the cost of equity, and based on that, he would propose a return on common equity in the lower half of his recommended range of 9.0% to 9.9%. *Id.* at 48.

In Public Staff 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 April 17, 2026. *Id.* at 92. For his constant growth DCF 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

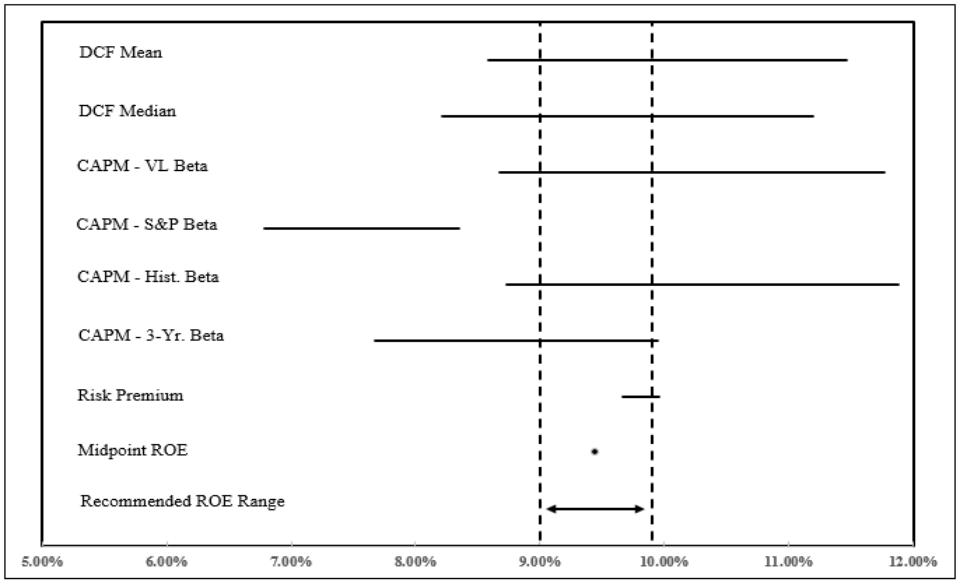
investors' dividend growth rate expectations. *Id.* at 93-94. Witness Walters testified that he used the average of analysts' growth rate estimates from three sources: Zacks, S&P Capital IQ Market Intelligence (MI), and Institutional Brokers' Estimate System from LSEG Workspace. *Id.* at 94. For his sustainable growth DCF model, he estimated the long-term growth rate based on DEC's current market-to-book (M/B) ratio and on Value Line's three- to five-year projections of earnings, dividends, earned returns on book equity, and stock issuances. *Id.* at 97. 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 (i.e., years six through ten); and (3) a long-term growth period starting in year 11 and extending into perpetuity. *Id.* at 99.

For the short-term growth period, witness Walters testified that he relied on the consensus of analysts' growth projections described above in relationship to his constant growth DCF model. *Id.* For the transition period, he 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.* Witness Walters testified that primary weight should be given to the sustainable growth and multi-stage models with minimal weight to the constant growth model. *Id.* at 104.

Witness Walters' Risk Premium model is based on two estimates of an equity risk premium: the annual difference between regulatory commission-authorized ROEs for utility companies and the yield on U.S. Treasury bonds since 1986; and the annual difference between authorized returns on equity and Moody's "A"-rated utility bond yields over the same period. *Id.* at 105. In addition, he evaluated the yield spread between utility bonds and Treasury bonds. *Id.* at 106. Witness Walters added his recommended equity risk premium of 5.33% over Treasury bonds to the projected 30-year Treasury yield of 4.80% to produce a return on common equity of 10.13% and his recommended equity risk premium of 4.14% over "A"-rated utility bond yields to the recent three-month average "A"-rated utility bond yield of 5.70% to produce a 9.84% return on common equity. *Id.* at 107.

Witness Walters' CAPM analysis used Blue Chip Financial Forecasts' projected 30-year Treasury bond yield of 4.80% for the risk-free interest rate. *Id.* at 118. Witness Walters used the current published betas from Value Line, a long-term average of Value Line betas, three-year betas adjusted using Value Line's methodology, and Vasicek-adjusted betas from MI's Beta Generator Model. *Id.* at 119. To derive estimates of the Market Risk Premium (MRP), witness Walters used two general approaches: a Risk Premium approach and a DCF approach. He also considered the normalized MRP of 5.00% with the normalized risk-free rate of 4.81% as recommended by Kroll. *Id.* at 121. For his risk premium approach, witness Walters added the historical arithmetic average real market return of 8.61% to the current consensus for projected inflation of 2.40% before subtracting the 4.80% projected risk-free rate to arrive at 6.40%. *Id.* at 122. Witness Walters used two versions of the constant growth DCF model to develop his DCF-based estimate of the MRP. *Id.* Witness Walters used the 9.15% average of his estimated MRPs of 9.0% and 9.3%. *Id.* at 123-24. Witness Walters testified that as his average expected market return of 11.66% exceeds the long-term market expectations of several financial institutions, his MRPs are reasonable, if not high-end estimates. *Id.* at 125.

Witness Walters concluded that the appropriate equity cost rate for DEC based on companies in his proxy group is in the 9.00% to 9.90% range, recommending the midpoint of 9.45%. *Id.* at 129-30. Witness Walters summarized his findings in the following chart:



Id. at 129.

Witness Walters testified that DEC's PBR Application would shift risk from shareholders to ratepayers by reducing regulatory lag. *Id.* at 131. As such, he recommended a ROE in the lower half of his range. *Id.* at 133-34. He also pointed to potential quantifications (and valuations of those quantifications) of the impact on ROE of an MYRP. *Id.* at 130-133.

Public Staff witness Fahey testified in detail about the relatively lower risk DEC faces compared to comparable utilities, considering the ratemaking tools available under North Carolina law. Witness Fahey testified that North Carolina's MYRP framework and additional alternative ratemaking mechanisms shift financial risk from the utility to its customers. *Id.* at 194. He noted that according to a study published by the Maine Public Utilities Commission, North Carolina is one of only 13 jurisdictions to have implemented PBR. *Id*. at 187. Further, he noted that according to Regulatory Research Associates (RRA), a division of S&P Global, of the 135 major energy rate case filings in 2025, only 16 were MYRPs. *Id*. at 193. Witness Fahey reviewed other North Carolina laws that are favorable to public electric utilities, including Senate Bill 266 (S.B. 266) which authorizes, among other things, inclusion of construction work in progress (CWIP) for certain baseload generation plants into rate base through a rider, shifting financial risks from those projects onto ratepayers. *Id*. at 195. He noted that RRA ranks North Carolina in the "above average" category for investor risk, which places it among the top 9 of the 53 jurisdictions RRA reviews. *Id*. at 209-10.

Witness Fahey noted that North Carolina statutory law requires the Commission to assess whether granting PBR affects consumer and investor risk. *Id*. at 181 (citing N.C.G.S. § 62-133.16(c)(1)(a). Based on his analysis, he recommended that if the

Commission approves DEC's MYRP, the Commission should make a specific, downward adjustment to the return on common equity that places DEC's return on equity below recent nationwide averages. *Id.* at 229-30.

AGO Direct Testimony

AGO witness Cassara recommended that the Commission reject the framework DEC used to develop its return on common equity proposal of 10.95%. Tr. vol. 19, 623. Witness Cassara criticized conflation of the return on equity with the cost of equity, arguing that such confusion has led to inaccurate analysis and an unreasonably high return on equity recommendation. *Id.* at 624. Witness Cassara testified that the return on equity and the cost of equity are different concepts, where the return on equity is a financial performance metric while the cost of equity equates to the expected market return from the perspective of shareholders. *Id.* at 643.

Witness Cassara recommended a ROE of 7.4%. *Id.* at 625. Witness Cassara testified that his recommendation is based on the results of his CAPM and DCF modeling analyses, traditional legal standards applicable to establishing a utility's authorized return on equity, the average electric bill in North Carolina, and the MYRP framework. *Id.* at 625-26. Witness Cassara noted that he adopted DEC witness Coyne's proxy group for his analyses. *Id.* at 687. In his CAPM analysis, witness Cassara testified that he used ten-year US Treasury yields as a measure of the risk-free rate. *Id.* at 689. He further testified that he did not incorporate forecasted interest rates and used beta coefficients reported by Yahoo! Finance and Zacks. *Id.* at 689-90. The low, high, and average estimates of witness Cassara's CAPM analysis were 6.62 percent, 7.30 percent, and 7.01 percent, respectively. *Id.* at 691-92. Witness Cassara's constant growth DCF analysis resulted in an average return on equity of 6.89% while his Multi-Stage DCF analysis yielded an average result of 7.79%, with a mean of the two of 7.34%. *Id.* at 701.

CUCA Direct Testimony

CUCA witness LaConte testified that a fair and reasonable ROE should be based on accepted methodologies. The inputs and assumptions used should consider current financial and economic realities such as the principles used to determine a fair return on equity, DEC's financial strength and credit rating, rates of return on common equity authorized by state regulatory commissions, and DEC's business and regulatory risk. Tr. vol. 14, 52. Witness LaConte referenced principles established by the U.S. Supreme Court for determining a fair return on capital for regulated monopolies. *Id.* at 52-53. Witness LaConte also highlighted DEC's current credit ratings and current economic conditions. *Id.* at 53-55.

Witness LaConte calculated a range of return on equity DEC using a combination of methodologies: three DCF analyses and two CAPMs. The results of these analyses produced an average return on equity of 9.54%. *Id.* at 64. First, her DCF analysis involved the use of a proxy group of 11 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 69. 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: 9.05% (low estimate), 10.51% (mean estimate), and 11.87% (high estimate). *Id.* Witness LaConte's two-stage DCF produced a return on equity of 9.89%, and her multi-stage DCF produced a range of results from 7.76% to 8.37%. *Id.* at 69-71. Witness LaConte utilized two CAPM models, using the average of the betas for each company in the proxy group and two estimates of the MRPs: a historical MRP of 7.37% and a projected MRP of 7.49%. *Id.* at 72-73. Her CAPM analyses resulted in an estimated return on equity of 10.32% using the historical MRP and 10.01% using the projected MRP. *Id.* at 75.

NCJC, et al. Direct Testimony

NCJC, et al. witness Kihm recommended a ROE of 9.1%. Witness Kihm testified that the key factors in setting a reasonable return on equity are (1) setting a return that is not so low as to be confiscatory to current investors (which can be easily determined by an ROE that maintains a M/B ratio of 1.0 or above) or that would inhibit future capital investment; and (2) setting a return that is fair to consumers and not so high as to make their rates unaffordable. Tr. vol. 19, 505. AGO witness Cassara and NCJC, et al. witness Kihm also testified on the difference between rate of return on equity and cost of equity for a utility. *Id.* at 507-12, 643-44. Witness Kihm explained that there is a feasible range for the return on common equity of 7.7% to 9.3%, and the average of the two returns is 8.5%, which would be a reasonable rate of return on equity for DEC. *Id.* at 568. However, witness Kihm testified that return on equity ignores DEC's most recently authorized ROE of 10.1%. *Id.* Instead, witness Kihm testified that as a first step it is reasonable to move the authorized rate of return on equity inside the range to 9.1%, but at this point to keep it near the upper end. *Id.* Witness Kihm further testified that the determination of the rate of return on equity is a judgment call for the Commission and recommended the Commission recognize the principles and structures underlying return on equity recommendations. *Id.* at 569.

Intervenor Direct Testimony (Experts Without Specific Analysis)

As noted above, Walmart witness Chriss, CIGFUR III witness Collins, and NCSEA witness Lin provided ROE -related testimony but did not perform any ROE analysis.

Walmart Witness Chriss

While Walmart witness Chriss did not provide a ROE analysis in his testimony, he testified that DEC's proposed ROE was significantly higher than rates of return approved by the Commission since 2019. Tr. vol. 14, 21. Likewise, witness Chriss testified that DEC's proposed ROE is significantly higher than most reported ROE decisions by utilities commissions from 2023 to the present. *Id.* at 22. Witness Chriss testified that according to S&P Global MI the average of 145 reported utility rate case ROEs authorized by commissions to investor-owned utilities since 2023 is 9.7%, with results ranging from 8.63% to 11.45% and a median authorized rate of return on equity at 9.74%. *Id*. Removing distribution-only utilities and distribution service rates from the analysis, witness Chriss testified that the average ROE for vertically integrated utilities authorized from 2023 through the time of his direct testimony filing was 9.78%. *Id.*

CIGFUR III Witness Collins

CIGFUR III witness Collins recommended that the Commission reject DEC's proposed return on equity of 10.95%. Tr. vol. 19, 285. Witness Collins testified that RRA published average return on equity for 2025 indicates that electric authorized ROEs have trended slightly downward from the 2024 level to 9.77%, and the full data set of average authorized ROEs over the past decade therefore sits between approximately 9.4% and 9.8%. *Id.* at 281. Witness Collins testified that DEC's requested return on common equity was materially above recent industry averages for vertically integrated electric utilities, and he further stated that DEC maintained strong investment-grade credit ratings and continuous access to capital markets at returns well below 10.95%. *Id.* at 283.

NCSEA Witness Lin

NCSEA witness Lin testified that the proposed return on common equity of 10.95% was unreasonably high and overstated the risks to the utility's shareholders and investors. *Id.* at 782. Witness Lin further testified that DEC's analysis of balancing the interests between shareholders and customers is incomplete, and the proposed return on common equity appears inflated and disproportionately beneficial to shareholders. *Id.* at 782-83.

DEC Rebuttal Testimony

DEC witness Bowman testified in rebuttal that DEC heard customers' concerns about affordability and made adjustments to its initial application designed to mitigate the rate impact on customers without jeopardizing DEC's ability to make reliability investments and serve North Carolina's growth. Tr. vol. 21, 35. Witness Bowman testified that the primary rate mitigant DEC proposed was reducing the requested return on equity from 10.95% to 10.48%. Witness Bowman noted that the figure is at the very bottom of Witness Coyne's range, and DEC recognized that the reduction would meaningfully reduce the revenue requirement and keep DEC within witness Coyne's range of reasonableness. *Id.* at 35-36.

Witness Coyne, in his rebuttal testimony, testified that his return on equity recommendation of 10.95% continued to be supported by his updated analysis based on April 30, 2026, data. *Id.* at 249. He provided a chart comparing the results of his direct testimony analysis with his analysis on rebuttal:

	Sep 30 '25 Data	Apr 30 '26 Data
DCF	10.92%	10.76%
CAPM	11.67%	11.08%
Risk Premium	10.48%	10.56%
Expected Earnings	11.57%	11.40%
Mean of All Methods	**11.16%**	**10.95%**
Flotation Costs	0.09%	0.09%
ROE – Model Results	**11.25%**	**11.04%**
Range Including Flotation Costs	**10.57%-11.76%**	**10.65%-11.49%**
Recommended ROE	**10.95%**	**10.95%**

Id. at 277.

Witness Coyne noted that DEC's updated return on equity request of 10.48% is at the very low end of his model results (excluding flotation costs). *Id.* at 249. Witness Coyne responded to criticism by intervenor 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, such as the removal of Portland General Electric from the proxy group, he noted that the intervenor recommendations are below the level appropriate to reflect investors' return requirements for DEC given DEC's investment risk profile and the current higher interest rate environment. *Id.* at 276, 249.

Witness Coyne additionally addressed the findings of the intervenors individually. Witness Coyne noted that witness Cassara's ROE recommendation and model results, witness Kihm's model results, certain of witness Walters's CAPM results, and the multi-stage DCF model results presented by both witness Walters and witness LaConte are below all vertically integrated electric utility authorized ROEs in at least the past 46 years and fail the *Hope* and *Bluefield* comparable return standard. *Id.* at 250.

Witness Coyne testified that Public Staff witness Walters' testimony did not, in his view, fully account for the impact of heightened interest rates and policy uncertainty. *Id.* at 279. Witness Coyne disagreed with witness Walters' claims that a narrowing spread between 30-year treasury and utility bonds suggests that investors perceive a lower relative risk in utility bonds and explained that a narrower spread in bond yield is impactful to debt investors, not equity investors. *Id.* at 282. Witness Coyne criticized witness Walters' use of sustainable growth rates in the DCF model as well as his application of the multi-stage DCF model. *Id.* at 298-300. Witness Coyne noted that limiting growth in the DCF to long-term GDP was, in his view, an unfounded constraint, and addressed the Commission's treatment of that constraint in the 2023 Rate Case. *Id.* at 301-03.

As it pertained to witness Walters' CAPM model, DEC witness Coyne noted two main concerns with witness Walters' beta estimates. First, witness Coyne testified that a

shorter-duration three-year Beta estimate is not appropriate as shorter-duration Beta coefficients may not fully capture a broad base of market conditions, leading to a cost of equity capital estimate that is unduly based on recent market conditions that may not reflect future market conditions. *Id.* at 309-10. Second, he testified that Vasicek-adjusted Beta coefficients assume that Beta coefficients for the proxy group companies revert to the industry mean rather than the average for the broad market of 1.0, which is inconsistent with the findings of Dr. Blume, and it overlooks the periods when utility companies have traded in line with the broad market such as during the COVID-19 pandemic and the financial crisis of 2007-2009. *Id.* at 310.

In response to CUCA witness LaConte's analysis, witness Coyne noted his disagreement with her proxy group rationale. Witness Coyne testified that witness LaConte's removal of Edison International (EIX) for wildfire risk excludes a proxy company that has heightened severe weather risk similar to DEC. *Id.* at 286. Witness Coyne noted that the removal of EIX actually biases the proxy group towards excluding the risks associated with severe weather. *Id.* Witness Coyne also explained that witness LaConte compared the high DCF result that contains the proxy companies she removes to the mean DCF result from Coyne Direct Exhibit 4. *Id.* at 287. Witness Coyne reiterated that witness LaConte's multi-stage DCF model results are below all vertically integrated electric utility authorized ROEs in at least the past 46 years and inappropriate given the reliance on GDP growth. *Id.* at 250, 300.

Witness Coyne criticized the testimony of AGO witness Cassara. Witness Coyne stated that witness Cassara's extreme recommendation "would jeopardize the financial integrity of DEC and almost certainly lead to a credit rating downgrade for DEC, as well as be detrimental to existing shareholders of DEC's parent company." *Id.* at 249. Witness Coyne explained that witness Cassara's discussion of the market to book (M/B) ratios and extrapolations regarding value creation for investors inherent in the utilities' stock prices are irrelevant in the determination of a just and reasonable return on equity and represent a radical departure from generally accepted principles for establishing a return on equity. *Id.* at 259. Witness Coyne testified that using the M/B ratios to guide return on equity decisions would improperly shift the regulatory focus from setting just and reasonable rates to managing shareholder value. *Id.* at 261. Witness Coyne further explained that publicly traded utility holding companies are the traded entities with a publicly available market value, whereas the regulated utility operating companies to which the authorized returns on equity apply are not publicly traded and therefore do not have an observable market value. *Id.* at 262. Witness Coyne also addressed witness Cassara's use of the historical growth rate in the DCF model, explaining that it gives undue weight to historical estimates. *Id.* at 295-96.

In response to witness Cassara's CAPM model, DEC witness Coyne explained that it is appropriate to use yields on long-term Treasury bonds as the risk-free rate component of the CAPM and selecting the more appropriate April 2026 30-year Treasury yield of 4.91% increases witness Cassara's CAPM results by approximately 60 basis points. *Id.* at 307-08. Witness Coyne also testified that witness Cassara's beta coefficients, which rely on both Zacks and Yahoo! Finance, are calculated based on monthly return data over a five-year period as opposed to weekly return data over five years as Value Line does. Witness Coyne explained that this is significant because Beta coefficients calculated using

monthly returns do not capture intra-month return volatility and could lead one to conclude utility stock returns are more stable than they actually are. *Id.* at 311.

In response to NCJC, et al. witness Kihm, DEC witness Coyne emphasized that there are real world consequences of setting the authorized return lower than what is fair and reasonable. *Id.* at 258. He reiterated his testimony pertaining to the use of M/B ratios and the use of Zacks and Yahoo! Finance beta coefficients as well as the multi-stage DCF model. *Id.* at 300, 311.

Witness Coyne also responded to intervenor witness criticism regarding the inclusion of flotation costs, explaining that flotation costs are a legitimate cost of issuing common stock. *Id.* at 346. Witness Coyne noted that Duke Energy, the parent company of DEC, issues common equity and incurs costs associated with those issuances that apply to its subsidiaries, including DEC. *Id.*

Witness Coyne further disputed the contentions of witnesses Walters, Fahey, LaConte, Cassara, and Burgess that PBR and other regulatory mechanisms in North Carolina, including MYRPs, reduce DEC's business risk and regulatory lag, thereby justifying a downward adjustment to the return on equity. *Id.* at 348. Witness Coyne noted that none of the intervenor witnesses provided any quantitative evidence to support their claims that investors reduce their return requirements due to the presence of discrete regulatory mechanisms. Witness Coyne explained that investors consider the constructiveness of a utility's regulatory environment holistically, including the consistency and predictability of the regulatory framework and the ability to recover prudently incurred costs (including the cost of capital) in a timely manner. *Id.* Witness Coyne further explained that regulatory mechanisms that mitigate regulatory lag are nearly universal among the proxy companies and the utility industry nationwide. *Id.* at 349. Witness Coyne testified that all but 13 jurisdictions in the United States (approximately 75%) have two or more regulatory mechanisms that mitigate regulatory lag. Witness Coyne explained that these mechanisms are reported publicly in investor-facing materials and are widely known to the investment community such that any effect on investors' return requirements is likely embedded in the market data in the ROE models. *Id.* at 351-52. Witness Coyne further noted that his analysis and recommendation incorporated the effect of regulatory risk. *Id.* at 354-55. Witness Coyne also noted that the Commission addressed these same arguments in the 2023 DEC Order and stated that the Public Staff offered no new evidence to support a quantitative downward adjustment. *Id.* at 354.

DEC witness Bateman also addressed intervenor recommendations that the availability of PBR in North Carolina warrants a downward adjustment to DEC's otherwise authorized ROE. Echoing witness Coyne's analysis as well as the Commission's rejection of downward adjustment in the Sub 1276 Order, she noted that the conclusion to be drawn "is that that alternative ratemaking regulation is the *norm* and North Carolina's ratemaking practices are aligned with the rest of the country." Tr. vol. 22, 405. She also rebutted intervenor witnesses' contentions that North Carolina's alternative ratemaking mechanisms are more favorable to the utility than other states' mechanisms, noting, for example, that other states' formula rates and capital riders typically allow for true-ups not available in North Carolina, permit fully forecasted test years not available in North

Carolina, that North Carolina's MYRP construct places significant execution risk upon the utility, and that North Carolina's asymmetric ESM places significant risk upon the utility, more risk than in other jurisdictions. *Id.* at 404-10. Similarly, DEC witness Coyne noted that Public Staff witness Fahey's focus on limiting his comparison to MYRP frameworks designed precisely like DEC's was overly narrow in scope because "[I]nvestors are foremost concerned that the regulatory framework provides the utility with a reasonable opportunity to recover its prudently incurred costs, including a fair return …[and that the] specific mechanics of how that occurs (whether through base rates, cost recovery riders, forecasted test years, multiyear rate plans, etc.) is secondary." Tr. vol. 21, 355-56.

In DEC witness Heath's rebuttal testimony, witness Heath criticized intervenor return on equity recommendations, explaining that a reduction in authorized return on equity to 7.4% (Cassara), 9.10% (Kihm), 9.45% (Walters), or 9.54% (LaConte), especially when combined with a reduction in the equity component of the capital structure from DEC's proposed 53% to 51% (Walters) or 51.5% (LaConte), would weaken the qualitative (i.e., less constructive regulatory environment) and quantitative (i.e., weaker credit metrics) aspects of DEC's credit quality and diminish its overall financial health, likely increasing future costs to customers. *Id.* at 189. Witness Heath explained that access to capital is not simply binary (i.e., ability to execute versus inability to execute), but diminished access to capital is most often manifested as reduced investor demand, more restrictive terms and covenants, wider credit spreads, shorter maturities, and, ultimately, greater reliance on parent support. *Id.* at 201.

Witness Heath provided an overview of market dynamics since DEC's last rate case, noting, persistently high inflation, geopolitical issues like the conflict in Iran and ongoing war in Ukraine, and uncertainty of ongoing economic conditions including tariff impacts that are continuing to drive heightened market volatility. *Id.* at 206-07. Witness Heath stressed the value during these times of maintaining 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.* 188-89, 207.

DEC Settlement Testimony

DEC witness Coyne testified in support of the Comprehensive Settlement. *Id.* at 377. Witness Coyne noted that the proposed return on equity of 9.8% is within the range of results presented by Public Staff witness Walters. *Id.* at 378. Witness Coyne emphasized that the Comprehensive Settlement represents negotiations among the Stipulating Parties regarding numerous otherwise-contested issues and is the product of good-faith, give-and-take negotiations to reach a settlement in this case that resolves the issues between the Stipulating Parties. Witness Coyne stated that, on balance, it is his opinion that the proposed 9.80% return on equity coupled with a 53.00% common equity ratio is supported by the evidence in the record and would provide DEC a fair and reasonable allowed return on equity in the context of the broader settlement. *Id.* at 378-79.

Witness Heath also testified in support of the Comprehensive Settlement, stating that the terms of the Comprehensive Settlement, including the proposed capital structure and return on equity, will provide DEC the opportunity to maintain its financial health and credit ratings to the benefit of DEC and its customers. *Id.* at 235. Witness Heath also

noted that DEC's ability to resolve issues in this proceeding with the Stipulating Parties through settlement, rather than through continued contested litigation, itself demonstrates to the rating agencies DEC's ability to effectively manage regulatory risk within a constructive regulatory environment. *Id.* Witness Heath explained that strong credit ratings allow DEC to finance capital projects under more favorable terms, which helps reduce borrowing costs and keep prices affordable for customers. *Id.* at 237. Witness Heath also testified to the benefit of the MYRP, which he indicated has played a critical role in DEC's financial health. *Id.* at 238.

Discussion and Conclusions

A regulated utility's overall cost of capital, otherwise known as the overall rate of return, is a function of the utility's authorized cost of common equity capital (also known as the return on common equity or ROE), authorized cost of embedded long-term debt capital, and authorized capital structure. Mathematically, the rate of return is calculated as follows:

(Cost of common equity capital x percentage of common equity in the capital structure)

plus

(Cost of embedded long-term debt capital x percentage of long-term debt in the capital structure)

In this case, DEC's embedded cost of long-term debt (4.57%) is undisputed, and the Comprehensive Settlement establishes the following additional inputs to the formula:

- Capital structure: 53% common equity / 47% long-term debt; and
- Cost of common equity: 9.80%.

The resulting rate of return based upon these inputs is 7.34%. The Commission, exercising its independent and subjective judgment as set forth below, approves the Comprehensive Settlement's stipulated ROE of 9.80% and capital structure composed of 53% common equity and 47% long-term debt. These inputs and the resulting rate of return meet the legal requirements for determining the cost of capital (both debt and equity), are reasonable and appropriate for use in this case, and result in rates that are just and reasonable.

Embedded Cost of Long-Term Debt

DEC's embedded cost of long-term debt was testified to by DEC witness Jiggetts and is 4.57%. Tr. vol. 12, 289-90. The Public Staff testified DEC's proposed long-term debt rate was reasonable and well supported. Tr. vol. 16, 174. The long-term debt cost rate is undisputed, and the Commission accepts it as reasonable and appropriate for use in this case.

Capital Structure

DEC's previously authorized capital structure was 53% common equity and 47% long-term debt. In its PBR Application, DEC requested that same capital structure be approved for use in this case, and its request was supported by the testimony of DEC witness Heath. Tr. vol. 8, 207. The only intervenor witnesses who testified concerning capital structure recommended lower equity ratios – 51% by Public Staff witness Walters, and 51.5% by CUCA witness LaConte. Tr. vol. 14, 51; tr. vol. 16, 47. Both Public Staff and CUCA are Stipulating Parties that have agreed to the Comprehensive Settlement. The parties who presented cost of capital testimony in this case but did not sign on to the Comprehensive Settlement – AGO and NCJC, et al. – did not present any evidence or make any recommendations regarding DEC's capital structure. The Commission takes into account that neither the AGO nor NCJC, et al. offered evidence or recommendations contrary to DEC's proposed capital structure. Further, the Comprehensive Settlement is itself significant evidence supporting the 53/47 capital structure. The Commission is entitled to fully consider the Comprehensive Settlement and provide it weight. *CUCA I*, 348 N.C. at 466, 500 S.E.2d at 703. The Commission has the authority to set a reasonable capital structure and chooses to give the Comprehensive Settlement substantial weight, and determines in the exercise of its independent and subjective judgment that the 53/47 capital structure agreed to by the Stipulating Parties appropriately balances customers' interests with DEC's need to attract capital so as to maintain the safety, adequacy, and reliability of its service.

DEC's future capital needs are substantial. Witness Heath estimated DEC's capital need over the 2026-2028 period at $20.1 billion, including $18.5 billion in projected capital expenditures and $1.6 billion in debt retirements. Tr. vol. 8, 217. The capital investments are needed to ensure continued reliability of DEC's electric grid and will fund replacing and upgrading aging infrastructure, developing new generation resources, and grid modernization. Tr. vol. 6, 55. Numerous witnesses at the evidentiary hearing in this case emphasized the unprecedented load growth being experienced by DEC. *See*, *e.g.*, DEC witness Bateman, tr. vol. 7, 193-94 ("If I look at the CPIRP, the projected capital was over a hundred billion dollars over the 15-year period. That's a significant amount of capital that the Company needs to raise, finance, and then construct all of the plant…"); DEC witness Heath, tr. vol. 8, 330 ("unprecedented capital build over the next several years"); DEC witness Guyton, tr. vol. 10, 40 (extraordinary load growth occurring now, with over 120,000 new customers having been added in the last three years); DEC witness Hager, tr. vol. 12, 30 (North Carolina is experiencing unprecedented load growth); Public Staff Policy Panel, tr. vol. 18, 53-54 ("The Public Staff is cognizant that North Carolina is facing substantial load growth … We recognize that substantial grid improvements are necessary to accommodate new generation and maintain or improve reliability for existing and new customers."); Public Staff witness Thomas, tr. vol. 18, 195-96 ("we are seeing … load growth accelerating from large load customers," continuing, "a lot of distribution investments are related to new residential customers," noting that, "North Carolina, particularly areas within DEC's service territory, have been growing quite rapidly for some time now.").

The Commission gives substantial weight to the Comprehensive Settlement, noting witness Coyne stated that the proposed 9.80% return on equity coupled with a

53.00% common equity ratio would provide DEC a fair and reasonable allowed return on equity in the context of the broader settlement. Tr. vol. 21, 379. With rapid load growth and its associated capital projects comes risk. Moody's, one of the two credit rating agencies that rates DEC's debt, notes that one of DEC's principal credit challenges is "Potential pressure on credit metrics due to rising debt to fund high capital expenditures." DEC Heath and Coyne Direct Exs. 1-2. As DEC witness Heath put it, as DEC must raise the funds to make investments into plant and put the plant into service to provide service to customers, there is more risk associated with that activity. Tr. vol. 9, 26-27.

Ratings agencies pay attention to capital structure, tr. vol. 8, 287, and risk increases as DEC's capital structure "gets out of line with rating agency expectations." Tr. vol. 9, 27. Lowering the equity portion of the ratio "introduces more leverage where there is already significant incremental debt that will have to be raised even at the 53/47 proposed cap structure." *Id*. DEC is operating "barely at [Moody's] downgrade threshold," which puts pressure on its credit metrics. Tr. vol. 8, 301. Such pressure creates concerns for the rating agencies about whether DEC can actually raise the amount of capital it needs and keep the integrity of its balance sheet in place for the long term. Tr. vol. 9, 27. In the Commission's considered judgment, to lower the equity portion of the capital structure below the Comprehensive Settlement's 53/47 structure is not supported by the record. The Commission therefore accepts the 53% common equity/47% long-term debt capital structure provided for in the Comprehensive Settlement.

Cost of Common Equity (Return on Equity)

In its direct case, DEC proposed a Return on Equity (ROE) of 10.95%. Tr. vol. 8, 214. Intervenors' ROE recommendations (for those intervenor witnesses who performed detailed ROE analysis) ranged from a low of 7.4% to a high of 9.54%. Tr. vol. 14, 50; tr. vol. 19, 625. Public Staff witness Walters' recommendation was no more than 9.45%, the mid-point of his ROE range of 9.0% to 9.90%. Tr. vol. 16, 47. In its rebuttal case, DEC reduced its ROE request to 10.48%, the lowest point of its ROE witness Coyne's ROE range (not including flotation costs), citing the need to mitigate DEC's proposed rate increase due to customer affordability concerns. Tr. vol. 21, 35. In the Comprehensive Settlement, the Stipulating Parties agreed to an allowed ROE of 9.80%. Comp. Settl. § II.1.

The Commission chooses to give the Comprehensive Settlement substantial weight, and determines in the exercise of its independent and subjective judgment that the 9.80% ROE agreed to by the Stipulating Parties appropriately balances customers' interests with DEC's need to attract capital so as to maintain the safety, adequacy, and reliability of its service. The Commission details its reasoning below but first turns to a brief discussion of the law governing its ROE determination so as to provide appropriate legal context for its decision.

Law Governing the Commission's Decision on Rate of ROE

The baseline for establishing an appropriate ROE is the constitutional foundation established by the United States Supreme Court's decisions in *Bluefield Water Works & Improvement Co. v. Public Service Commission*, 262 U.S. 679 (1923) (*Bluefield*), and *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591 (1944) (*Hope*).

As summarized by the Commission in its Order in DEC's last rate case, these seminal decisions hold that

> 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.

Sub 1276 Order at 195; *see also State ex rel. Utils. Comm'n v. Gen. Tel. Co.,* 281 N.C. 318, 370, 189 S.E.2d 705, 738 (1972) (*General Telephone*). 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.*

In *Hope*, the Court emphasized that it was the "end result," rather than the application of any specific analytic methodology, that was the ultimate test of a selected ROE's appropriateness. *Hope*, 320 U.S. at 603. The North Carolina Supreme Court has long emphasized that "[s]uch rate-setting determinations always 'require[ ] the exercise of subjective judgment.'" *State ex rel. N.C. Utils. Comm'n v. Carolina Indus. Grp. for Fair Util. Rates II*, 389 N.C. 455, 510, 930 S.E.2d 151, 191 (2026) (*CIGFUR II*) (citing *State ex rel. Utils Comm'n v. Public Staff-N.C. Util's. Comm'n*, 323 N.C. 481, 490, 374 S.E.2d 361, 369 (1988)). As the Court noted in *CIGFUR II*, an ROE determination is a necessary result of subjective judgment because in reaching it, the Commission must consider a "mountain of evidence … much of it highly technical [including] an array of mathematical models produced by expert witnesses using various methodologies." *CIGFUR II*, 389 N.C. at 510, 930 S.E.2d at 191. That "mountain" certainly exists in this case.

The North Carolina Supreme Court has interpreted the language of N.C.G.S. § 62-133(b)(4) as requiring the Commission to make findings regarding the impact of changing economic conditions on customers when determining the proper ROE for a public utility. *State ex rel. N.C. Utils. Comm'n v. Cooper*, 366 N.C. 366 N.C. 484, 495, 739 S.E.2d 541, 548 (2011) (*Cooper I*). The Commission must exercise its subjective judgment to balance two competing ROE-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. Sub 1276 Order at 198. The Commission's determination in setting rates pursuant to N.C.G.S. § 62-133, which includes the fixing of the ROE, always takes into account affordability of public utility service to the using and consuming public. The impact of changing economic conditions on customers was considered and evaluated in the analyses conducted by the expert witnesses on ROE, as the various economic models widely used and accepted in utility regulatory rate-setting proceedings take into account such economic conditions. Sub 1276 Order at 198, *aff'd CIGFUR II*, 389 N.C. at 513-14, 930 S.E.2d at 193-94.

Thus, in summary and in accordance with the applicable law, the Commission's duty under N.C.G.S. § 62-133 and the PBR Statute 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.

ROE Determination

As noted, in the Comprehensive Settlement the Stipulating Parties agreed to an ROE of 9.80%. There is ample evidence supporting the stipulated ROE, and in the exercise of the Commission's judgment, the Commission independently finds an ROE of 9.80% is appropriate.

The Commission agrees that the correct way to determine a utility's cost of equity capital is through application of rigorous analysis using financial models and market data from reliable sources. The North Carolina Supreme Court's decision in *CIGFUR* supports this conclusion, as the Court premised its decision upholding the Commission's exercise of subjective judgment in determining ROE in part upon the Commission's expert consideration of "mathematical models produced by expert witnesses using various methodologies." *CIGFUR II*, 389 N.C. at 510, 930 S.E.2d at 191.[5] The Commission's evaluation of evidence from ROE expert witnesses who performed analysis using financial models reinforces its view that the stipulated 9.80% ROE is the appropriate ROE for DEC in this case.

Evaluation of Testimony from ROE Expert Witnesses for Stipulating Parties

When determining the authorized ROE for a utility, the Commission must set the ROE high enough to allow the utility to attract capital while also ensuring the authorized ROE yields the lowest possible rates for customers. Here, DEC has stipulated to a 9.8% ROE which is lower than the ROE DEC initially requested. No other party has supported a higher ROE for DEC. The Commission concludes the stipulated 9.8% ROE is sufficient to allow DEC to recover its cost of equity and attract new capital while resulting in the lowest possible rates for ratepayers. Further, the Commission finds that an authorized ROE of 9.8% is supported by the greater weight of the evidence and should be approved.

To determine the authorized ROE, the Commission first examines the evidence from ROE expert witnesses submitting testimony for parties that have accepted and signed on to the Comprehensive Settlement – Public Staff, DEC, and CUCA.

Public Staff witness Walters testified that, based upon his analyses and the various methodologies employed by him in those analyses, he estimated DEC's current market ROE to be in the range of 9.00% to 9.90%. Tr. vol. 16, 129. The stipulated ROE is within this range, albeit at the higher end. But, in evaluating the entirety of the cost of capital

[5] The Commission acknowledges, but gives little weight to, the ROE testimony and evidence submitted by parties that did not perform financial model analysis. For example, both Walmart witness Chriss and CIGFUR III witness Collins refer in their testimony to industry average ROEs, tr. vol. 9, 22-24; tr. vol. 19, 281, but neither presents the detailed financial analysis traditionally performed by ROE expert witnesses to assist the Commission in selecting the appropriate ROE for a utility. While this evidence may allow the Commission to assess the reasonableness of ROE recommendations made by other parties that used financial models or help validate the ultimate ROE awarded by the Commission, such evidence does not provide an independent basis upon which the ROE could be determined.

evidentiary record, the Commission determines that authorizing the stipulated 9.80% ROE is reasonable and appropriate. The Commission notes as well that witness Walters' analyses produced ranges of results that significantly exceeded his recommended range, including his DCF, and CAPM using current Value Line beta values. *Id.*

The Commission gives substantial weight to the testimony of Public Staff witness Walters whose recommended ROE ranged from 9.0% to 9.9%, as well as CUCA witness LaConte, whose recommended ROE (based on mean results) ranged from 8.11% to 10.51%. The Commission is persuaded by this evaluation and analysis related to a recommended range and finds an ROE within this zone to be well-supported by the evidence. Although the 9.8% ROE is at the upper end of Public Staff witness Walters' testimony, the Commission judges this appropriate. In doing so, the Commission places great weight on two factors: (1) after witness Walters' testimony was filed, DEC made several concessions in the Stipulation that provide substantial benefits to customers, particularly the MYRP refund rider, ESM calculation methodology, and other agreed-upon settlement terms; and (2) the Commission finds persuasive and gives great weight to the settlement testimony of DEC witness Coyne, which determined a 9.8% ROE to be reasonable. The Commission finds and concludes that the MYRP refund rider in particular appropriately shifts the risk of timely project execution from ratepayers to DEC.

In its evaluation of an appropriate ROE, the Commission considered and weighed the whole record, especially the competing testimony. Without limiting that evaluation, the Commission highlights the following additional factors in support of its determination.

First, the Commission notes witness Coyne and witness Walter used the same proxy group and used the DCF, CAPM, and Risk Premium methodologies to derive their range of reasonable ROEs. Tr. vol. 21, 285. These methodologies are precisely the type of rigorous analyses favored by the Commission and the Court. They are sophisticated financial models that analyze market data. The Commission notes the United States Supreme Court has observed that "[t]he economic judgments required in rate proceedings are often hopelessly complex and do not admit of a single correct result." *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 314 (1989). Further, the Commission notes that utilizing these methodologies, witness Walters' evaluations yielded an ROE within just a few basis points of the stipulated 9.80%[6], a fact to which the Commission assigns great weight. The Commission has evaluated Walter's testimony, and in the exercise of its independent and subjective judgment, is persuaded by the analysis conducted by witness Walters that a 9.80% ROE is reasonable. The Commission, in the exercise of its independent and subjective judgment, finds an ROE of 9.8% to be warranted for the reasons set forth throughout this Order. Further, the Commission finds the fact that both witnesses Coyne and Walters used the same proxy group and similar analyses: (1) bolsters Coyne's settlement testimony (finding the 9.80% ROE to be reasonable), especially as both witnesses were committed to using sophisticated financial data and methodologies to arrive at an appropriate ROE; and (2) lends credence to finding the appropriate ROE to

[6] The mean of his constant growth DCF model (sustainable growth analysis) was 9.89%; in his Risk Premium analysis, using "A"-rated utility bonds, witness Walters derived a 9.84% ROE for 3-month average yields and 9.79% for 6-month average yields; and using current Value Line betas, his CAPM result under the Risk Premium method was 9.77%.

be in the upper half of Walters' ROE range. Additionally, the Commission notes witnesses Coyne and Walters used the same proxy group and similar analyses to evidence the reasonableness of these proxy groups. These similarities support the determination of a 9.8% ROE. There is much competing evidence around an appropriate ROE and the Commission finds that using an ROE in the upper end of Walters' range is appropriate.

Second, the Commission notes that although witness Coyne did not change his ROE recommendation between his direct and rebuttal testimonies, the mathematical results of his models did decline in his rebuttal testimony, largely as a result of declines in his DCF and CAPM results. Tr. vol. 21, 277. This decline persuades the Commission that authorizing an ROE in the upper end of Walters' range is appropriate. This is particularly the case since while the stipulated 9.80% ROE is below the range of estimates testified to by witness Coyne, he nevertheless filed testimony expressly supporting — and finding reasonable — the Comprehensive Settlement, including its stipulated ROE. Witness Coyne noted in his testimony that the stipulated ROE is within Public Staff witness Walters' range. *Id.* at 378. He testified further that he understood and respected the give-and-take inherent in any settlement, particularly one that comprehensively resolves numerous complex issues, and supported the stipulated ROE on that basis. *Id*. Witness Coyne's settlement supporting testimony echoed his earlier testimony from the stand, when addressing questions concerning the settled ROE in DEC's most recent South Carolina rate case. He stated there that while he could and routinely does provide analysis regarding the market cost of equity, the "utility and the parties are in the best position to decide what the tradeoffs are amongst [the] various components of the settlement." Tr. vol. 8, 321. The Commission agrees.

Third, the Commission notes also that 9.80% is within the range of mathematical results from the analyses performed by CUCA witness LaConte. Tr. vol. 14, 64. The average of witness LaConte's analytic results is 9.54%.

Fourth, the Commission reiterates its conclusion that the Comprehensive Settlement is itself significant evidence, upon which it places substantial weight, respecting the appropriateness of the stipulated 9.80% ROE.

Fifth, the Commission notes that that the industry average evidence supports the 9.80% ROE the Commission authorizes in this case. The Commission does not blindly rely on the national averages of other utilities in undertaking its obligation to rigorously evaluate the cost of capital for this proceeding. However, the Commission observes that in their testimony concerning industry averages, both Walmart witness Chriss and CIGFUR witness Collins rely principally upon the quarterly major rate case decision recap compiled by RRA. As of the evidentiary hearing in this case, the most recent RRA major rate case publication (through the first quarter of 2026) noted that the average authorized ROE for vertically integrated electric utilities over the twelve-month period ending March 31, 2026, was 9.84%. Public Staff Cross Heath and Coyne Direct Ex. 4 at 3. While, as noted above, the Commission exercises caution in utilizing industry average evidence, the fact that the industry average aligns with the stipulated 9.80% ROE is an additional piece of evidence, upon which the Commission places some weight, supporting its ROE determination.

Evaluation of Testimony from ROE Expert Witnesses for Non-Stipulating Parties

The Commission next examines the evidence from ROE expert witnesses submitting testimony for parties that did not accept and sign on to the Comprehensive Settlement – AGO, and NCJC, et al. AGO witness Cassara calculated DEC's cost of equity as 7.40%. Tr. vol. 19, 625. NCJC, et al. witness Kihm calculated DEC's cost of equity as 7.70%, but, notwithstanding that calculation, recommended an ROE of 9.10%. *Id*. at 503. The Commission rejects their ROE recommendations. In the Commission's judgment, witness Cassara's exceedingly low 7.40% recommendation is given little weight because it falls below every authorized return on equity for vertically integrated utilities in the record and, based on the record in this proceeding, would not satisfy the *Bluefield/Hope* test. Further, in the Commission's judgment, witness Kihm's "cost of equity" calculation of 7.70% is likewise given little weight, and his 9.10% ROE recommendation is completely arbitrary in light of the results of his mathematical modeling. His modeling produces a cost of equity of 7.70%, but witness Kihm opines that DEC's ROE is 140 basis points higher. Witness Kihm did not adequately explain the basis for selecting 9.10% rather than another point within or above his stated range. The Commission accordingly gives his baseless 9.10% recommendation no weight.

Witness Kihm himself describes his testimony as "light on models and long on qualitative analysis." Tr. vol. 19, 518. The Commission, however, has already determined, that the preferred way to determine a utility's cost of equity capital is through application of rigorous analysis using financial models and market data from reliable sources. Tr. vol. 21, 248. The Commission gives weight to witness Kihm's own characterization of his testimony in according his recommendation less weight than the witnesses who presented model-based analyses in the record.

There are numerous reasons to discount the evidence presented by witnesses Cassara and Kihm. In the Commission's view, the most telling reason is foreshadowed by witness Kihm's differentiation between the "cost of equity" for DEC — which he pegs at 7.70% — and the "return on equity" for DEC, which he pegs at 9.10%. That is, contrary to the testimony of each of the other ROE expert witnesses and contrary to the Commission's own understanding, witnesses Cassara and Kihm insist that there is a distinction between a utility's "cost of equity" and its ROE and this purported distinction is fundamental to their respective opinions. *See*, *e.g.*, tr. vol. 19, 507-12, 624, 643-44. The Commission disagrees. In its view, and in its understanding of the governing law, cost of equity and ROE are synonymous, and it is the task of the Commission to ascertain the cost of equity/ROE because that is a utility "cost," which the utility is entitled to recover, just as the utility is entitled to recover the cost of poles, wires, generating plant, and people employed in the service of its customers. 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. Public Service Commission of Missouri*, 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 603.

In the Commission's judgment, these witnesses' insistence on the distinction between cost of equity and required return on equity leads them astray. For example, witness Cassara asserts that "conflation" of ROE and cost of equity "leads to inaccurate analysis and an unreasonably high ROE recommendation," but in the Commission's view the forced distinction between cost of equity and ROE that witnesses Cassara and Kihm seek to make leads to their unreasonably *low* ROE recommendations.

Witnesses Cassara and Kihm assert that historic overvaluation of utility ROEs results from commissions not paying sufficient attention to what is in their opinion a critical financial ratio — the M/B ratio, also known as the price to book (P/B) ratio — which compares a company's stock price to the net book value of its assets. Tr. vol. 19, 653. In their view, if a regulated utility has an M/B ratio of greater than 1.0 that signals that its ROE is set too high. The Commission is not persuaded. Rather, as DEC witness Coyne, quoting from one of the seminal works on utility cost of capital, testified,

> It is quite plausible and likely that M/B ratios will exceed one if inflation increases the replacement cost of a firm's assets at a faster pace than historical cost (book equity). Perhaps this explains in part why utility M/B ratios have remained well above 1.0 over the past two decades. Are we to conclude that regulators have been systematically misguided all across the United States for all these years by awarding overgenerous returns, or are we to conclude that M/B ratios are largely immaterial in the context of ratemaking? The latter is more likely.

Tr. vol. 21, 261 (quoting Roger A. Morin, *New Regulatory Finance*, at 378 (2006)).[7]

In essence, witnesses Cassara and Kihm assert that nearly all state utilities commissions in the nation, along with the Federal Energy Regulatory Commission (FERC),

[7] Dr. Morin makes the same observation in his most recent text. *See* Roger A. Morin, *Modern Regulatory Finance*, at 419 (2021).

have gotten ROE wrong for the past few decades. The Commission is not persuaded by this line of analysis, and, accordingly, declines to adopt their ROE recommendations.

Conclusion as to ROE Determination Prior to Application of Cooper I Factors

The Commission is mindful that its ROE determination of 9.80% for DEC will impact DEC's ability to compete for capital upon reasonable terms with other business enterprises, including other regulated utilities. *See*, *e.g.*, tr. vol 21, 203. DEC witness Heath filed settlement-supporting testimony. In it, witness Heath stated that the capital structure and ROE components of the Comprehensive Settlement are reasonable when viewed within the context of the settlement as a whole and will provide DEC the opportunity to maintain its financial health and credit ratings. *Id*. at 235. He testified further:

> I believe that approval of the Comprehensive Settlement would be viewed by the rating agencies as constructive and equitable. In addition to the resolution of the ROE and capital structure issues, I believe the rating agencies would view continued use of the PBR multiyear rate plan ("MYRP") mechanism as contributing to DEC's financial strength, and further evidence of a constructive regulatory environment. Just as importantly, the fact that [DEC], the Public Staff, and other Stipulating Parties were able to resolve these issues through settlement, rather than through continued contested litigation, is itself a signal to the rating agencies of a constructive regulatory environment, because the agencies view a utility and intervenors willingness and ability to reach negotiated, balanced outcomes as a qualitative credit factor. Approval of the Comprehensive Settlement will support [DEC]'s ability to achieve its financial objectives.

Id. at 236.

This testimony, which the Commission credits and relies upon, reinforces the considerable weight that the Commission places on the Comprehensive Settlement. Not only does the testimony reiterate the value of viewing the interlocking pieces of the settlement as a comprehensive whole, but there is supporting testimony that it will support a reasonable credit strength for DEC. While maximizing DEC's credit strength is not a goal to the exclusion of other considerations, the Commission agrees that as a general principle, maintaining reasonable creditworthiness — neither too strong nor too weak — is beneficial to customers and the utility by keeping capital costs as low as possible.

In the final analysis, the Commission's task is to balance, on the one hand, the customer interest in maintaining rates as low as possible consistent with constitutional constraints, and, on the other hand, DEC's ability to attract needed capital on reasonable terms in order to provide safe and reliable electric service and recover its cost of providing service. In articulating this balance, the Commission recognizes that ROE itself does not provide the funding for DEC's capital projects. Rather, ROE is the cost DEC must bear in order to attract capital from equity investors needed to make investments in its system.

In the Commission's independent judgment, an ROE of 9.8% appropriately strikes that balance.

Cooper I Factors and Ultimate Conclusion Regarding Cost of Equity Capital

Cooper I requires the Commission to consider the impact of changing economic conditions on customers in connection with its selection of a rate of return on equity. The Commission will next address this topic.

In this case, all parties had the opportunity to present the Commission with evidence concerning changing economic conditions as they affect customers. DEC witness Coyne addressed changing economic conditions at some length. Witness Coyne provided detailed data concerning changing economic conditions in North Carolina, as well as nationally, and concluded that the North Carolina-specific conditions are sufficiently correlated with conditions in the broader national economy such that economic conditions affecting North Carolina are reflected in the models he used to estimate DEC's cost of equity. Tr. vol. 8, 133-34.

Public Staff witness Walters also reviewed regional and national economic data and testified that as a general matter he did not take issue with any of the economic factors considered or conclusions reached by witness Coyne. Tr. vol. 16, 146-47. The Commission credits and gives weight to the testimony of both witnesses and therefore concludes that the econometric data relied upon by ROE expert witnesses captures the effects and impacts of changing economic conditions upon DEC's customers.

AGO witness Cassara also evaluated the correlation between economic conditions in North Carolina and nationwide and came to the same conclusion, noting that "[o]ver the past five years, economic conditions in North Carolina and the US have been similar." Tr. vol. 19, 678. Witness Cassara also examined affordability factors affecting North Carolina electric customers, and in that connection, raised affordability concerns with respect to customers' ability to pay increased electric bills. *Id*. at 682-87.

CUCA witness LaConte also provided an overview of changing economic conditions and discussed how recent national and international events provided further support for her recommendations. Tr. vol. 14, 62-63.

The Commission takes seriously the affordability concerns raised directly by customers at the public hearings in this case, by expert witnesses at the evidentiary hearings, and in Consumer Statements filed in the docket. The Partial Stipulation and Comprehensive Settlement take meaningful steps toward addressing these concerns. The 68 basis point reduction in ROE from DEC's rebuttal position (10.48%) to the stipulated 9.80% alone significantly reduces DEC's revenue requirement. Further, the fact that the stipulated ROE is below the lower bound of DEC's rebuttal testimony demonstrates how affordability concerns and changing economic conditions are key considerations and components shaping the Commission's 9.80% ROE determination. Over the span of the MYRP, the reduction in ROE alone will reduce by hundreds of millions of dollars DEC's requested revenue requirement as compared to both DEC's direct and rebuttal testimonies. Standing alone, this will result in lower customer bills. The stipulated ROE also reflects a 30 basis point reduction from DEC's currently authorized ROE of 10.10%, which is a significant change that addresses affordability concerns and will mitigate the rate increase approved herein. In addition, the Comprehensive

Settlement obligates DEC to make a $10 million shareholder-funded contribution to assist low-income customers in paying electric bills and to weatherize homes, thereby facilitating reductions in electricity usage. The Commission recognizes that absent a settlement, it could not order such a contribution by shareholders. Further, beyond the $10 million shareholder contribution, the Commission recognizes that DEC maintains a comprehensive suite of affordability programs for low-income customers as discussed extensively by DEC witness Colley. Tr. vol. 6, 75-78; tr. vol. 21, 89-90.

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, even small changes in the ROE 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 ROE.

The Commission understands that ROE does not provide funding for rate base projects but instead provides a just return on the equity investment portion of rate base. Nevertheless, the Commission also recognizes that DEC faces considerable capital needs due to the need to replace aging infrastructure, maintain and enhance grid reliability and resiliency, and meet the challenge of load growth resulting from economic development and population growth in our State. The need to invest significant sums to serve its customers requires DEC to maintain its creditworthiness to compete for large sums of capital on reasonable terms. And, 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. *See*, *e.g.*, tr. vol. 9, 33-34. 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. 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 ROE to those rates, but the Commission must balance the burden against DEC's being in a position to access capital on reasonable terms in order to provide reliable service.

The Commission concludes in the exercise of its discretion and independent judgment, informed further by its subjective judgment, that a 9.80% ROE is supported by the evidence and should be adopted. This approved ROE appropriately balances the benefits received by DEC's customers — DEC's provision of safe, adequate, and reliable electric service and access to capital on reasonable terms to 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) — with the difficulties that some of DEC's customers will experience in paying DEC's adjusted rates. The Commission further concludes that a 9.80% ROE will allow DEC to compete in the market for equity capital, providing the opportunity for a fair return on investment to its investors. Accordingly, the Commission concludes, taking into account changing economic conditions and their

impact on customers, that the approved ROE will result in rates that are as low as reasonably possible without impairing DEC's ability to attract the capital needed at reasonable rates to provide safe and reliable electric service.

In the final analysis, the Commission notes that the United States Supreme Court has observed that "[t]he economic judgments required in rate proceedings are often hopelessly complex and do not admit of a single correct result." *Duquesne Light Co. v. Barasch*, 488 U.S. at 314. Long-standing decisions of the North Carolina Supreme Court have recognized that the Commission's subjective judgment is an inherently necessary part of determining the authorized ROE. *State ex rel. Utils. Comm'n. v. N.C. Natural Gas Corp.*, 323 N.C. 481, 498, 374 S.E.2d 361, 370 (1988). The Commission has described that "of all the components of a utility's cost of service that must be determined in the ratemaking process the appropriate ROE is the one requiring the greatest degree of subjective judgment by the Commission." 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 (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).

The Commission has independently exercised its subjective judgment and expertise and has weighed the evidence and testimony of witnesses who have addressed ROE. The stipulated ROE is within the range calculated by Public Staff witness Walters and found reasonable by DEC witness Coyne's settlement testimony. As detailed in its discussion above (especially the benefits received by customers in the settlement that was filed after witness Walters' testimony), the Commission finds an appropriate ROE should fall at the upper end of witness Walters' range. The Commission further finds in its independently exercised subjective judgment that 9.80% strikes the appropriate balance when considering the impact of changing economic conditions on customers in connection with its selection of a rate of return on equity. Having considered the entire record and weighed the competing evidence, in light of the impact of changing economic conditions on customers, the Commission independently exercises its subjective judgment and determines that a 9.8% ROE is warranted and represents a reasonable figure that balances the competing priorities, evidence, applicable jurisprudence, and considerations impacting ROE.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15-18

Depreciation

The evidence supporting these findings of fact is contained in DEC's verified PBR Application and Form E-1; the testimony and exhibits of DEC witnesses Jiggetts, Speros, Spanos, Bowman, and Kopp; the testimony and exhibits of the Public Staff's Accounting Panel and witnesses Lucas, McCullar, and Thomas; and the entire record in this proceeding.

DEC witness Spanos sponsored the 2024 DEC Depreciation Study. Tr. vol. 11, 330; Spanos Direct Ex. 1. Witness Spanos testified that the purpose of the 2024 Depreciation Study was to estimate the most current annual depreciation accruals

related to electric plant in service for ratemaking purposes and to determine the appropriate average service lives and net salvage percentages for each plant account. Tr. vol. 11, 330. Witness Spanos testified that certain life span estimates had changed since the Commission last approved DEC's depreciation rates. *Id.* at 336.

Section II, ¶ 6 of the Comprehensive Settlement provides that the Stipulating Parties agree to implement DEC's 2024 Depreciation Study as originally proposed by DEC, updated to reflect the Public Staff's proposed adjustments, including recommended adjustments to DEC's 2024 Decommissioning Study, except that the Stipulating Parties agree to apply a 10% contingency factor in lieu of the contingency percentages proposed by either DEC or the Public Staff. Comp. Settl. § II.6. The Stipulating Parties further agree that DEC will use good faith estimates reflecting a 10% contingency factor for purposes of the settlement schedules, and in a compliance filing, DEC's depreciation consultant will apply the agreed-upon assumptions in their model to develop the final depreciation rates to be implemented by DEC. *Id.* § II.6.a. The Stipulating Parties agree to exclude asbestos decommissioning costs related to the Bad Creek and Bridgewater hydroelectric plants from the depreciation study in this case, as reflected in the proposed depreciation rates of Public Staff witness McCullar. *Id.* § II.6.b. Finally, the Stipulating Parties agree that this agreement is made solely for the purposes of reaching settlement in this proceeding and shall not be construed as an admission by, or agreement of, DEC that the Public Staff's proposed adjustments are appropriate or should be adopted in future proceedings. *Id.* § II.6.c.

In its rebuttal case, DEC withdrew its request to adjust annualized depreciation expense to reflect the 2024 Depreciation Study as a rate mitigation measure, electing instead to hold depreciation rates at currently approved levels. Tr. vol. 21, 36. Witness Jiggetts testified that the withdrawal reduced DEC's requested revenue requirement by $137.8 million, with depreciation expense calculated using the rates approved by the Commission in Docket No. E-7, Sub 1276. *Id*. at 452-53. Witnesses Spanos and Kopp did not oppose the withdrawal, while standing by their respective studies and rebutting the Public Staff's proposed adjustments. Tr. vol. 11, 353-54, 414, 423. The Comprehensive Settlement reverses that position. Tr. vol. 21, 502. DEC's settlement schedules update depreciation rates to those proposed by the Public Staff and apply a 10% contingency factor, which increases the traditional base rate revenue requirement by approximately $61.1 million relative to DEC's rebuttal position. Jiggetts Comp. Settl. Ex. 2 at 20, l. 10, Ex. 3 at 167. At the evidentiary hearing, DEC witness Abernathy explained that the 10% contingency applies only to the decommissioning estimates embedded in the depreciation rates, not to the contingency amounts in the MYRP project estimates; the decommissioning estimates will be recalculated with a 10% contingency and flowed through the depreciation consultant's model to produce final depreciation rates. Tr. vol. 21, 510-11. She agreed that the 10% factor reflects the parties meeting halfway between DEC's 20% and the Public Staff's zero percent. *Id*.

Summary of Evidence

Coal Plant Retirement Dates

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. 11, 336. Witness Spanos testified that he used these factors to evaluate DEC's recommended retirement dates and agreed that they were reasonable. *Id.* at 336-37. The 2024 Depreciation Study identified the following retirement dates for DEC's coal plants:

Unit	Probable Retirement Date
Belews Creek 1	December 31, 2035
Belews Creek 2	December 31, 2035
Cliffside 5	December 31, 2030
Cliffside 6	December 31, 2048
Marshall 1	December 31, 2028
Marshall 2	December 31, 2028
Marshall 3	December 31, 2031
Marshall 4	December 31, 2031

Spanos Direct Ex. 1 at 41.

Witness Spanos testified that since the last approved depreciation rates in DEC's previous rate case, the Allen Units were retired, the life spans for Marshall Units 3 and 4 were shortened from 2032 to 2031, the life span for Bad Creek was extended to 2077, the Clemson Combined Heat and Power Plant was adjusted to 2054, and Lincoln Unit 17 was added to the fleet. Tr. vol. 11, 336. Witness Spanos testified that the new life spans for the units are reasonable and consistent with both DEC's plans as well as industry expectations. *Id.* at 336-37.

Public Staff witnesses Thomas and McCullar addressed coal plant retirements and life spans in their testimony. In his direct testimony, witness Thomas recommended that the 2024 Depreciation Study probable retirement dates be aligned with the 2025 Carbon Plan and Integrated Resource Plan (2025 CPIRP). Tr. vol. 13, 113. Witness Thomas noted the probable retirement dates in the 2024 Depreciation Study match those in the Commission-approved 2023 CPIRP and the Public Staff did not recommend any revisions to the 2025 CPIRP retirement schedule in its CPIRP testimony. *Id*. at 112-13. To adjust the dates to align with the 2025 CPIRP, the probable retirement date for Belews Creek would be extended from 2035 to 2039; Cliffside Unit 5 would be extended from 2030 to 2032; and Marshall Units 3 and 4 would be extended from 2031 to 2033. *Id.* Witness Thomas testified that depreciation rates for these units are set to reduce the remaining book value for DEC's coal units to zero by the units' probable retirement date; if the probable retirement date is earlier than the most up-to-date retirement date used in system planning, this results in a higher depreciation cost for customers. *Id.* at 112-13. Witness Thomas provided these proposed retirement dates to witness McCullar, and in her direct testimony, witness McCullar proposed depreciation rates that include the

adjusted coal-fired steam production plant retirement dates. McCullar Corrected Ex. 1; tr. vol. 13, 113; tr. vol. 17, 116.

In rebuttal, DEC witness Spanos testified that the 2025 CPIRP was filed after conducting and completing the 2024 Depreciation Study and that the 2025 CPIRP is still pending before the Commission. Tr. vol. 11, 354-55. Witness Spanos testified that the methodology used during this case and previous cases for DEC is the same, and all pertinent information and resources were factored into the determination of the probable retirement dates of each unit. *Id.* at 355. However, witness Spanos testified that some of the key factors have changed since 2021, which is why the probable retirement dates needed to be updated to the dates recommended in the 2024 Depreciation Study. *Id.* Witness Spanos testified that many other DEC coal-fired power plants as well as other coal-fired plants in the industry either have been or are planned to be retired with life spans of around 40-50 years, with a recent average around 46 years, and that the proposed life spans of DEC's plants are consistent with those of other utilities. *Id.* Witness Spanos testified that the retirement dates for the coal-fired plants in the 2024 Depreciation Study are consistent with informed judgment based on each unit and the expectation within the industry. *Id.* at 356.

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. 11, 338, 356. 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 357-58. 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 357-60. Witness Spanos testified that the net salvage percentages estimated in DEC's 2024 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.* at 339.

Regarding net salvage, the parties presented three main topics of disagreement: (1) asbestos decommissioning costs; (2) contingency; and (3) estimated future net salvage rates for mass property accounts, specifically Accounts 362, 366, and 367.

Asbestos

Public Staff witness Lucas recommended that the Commission disallow $981,000 and $220,000 in asbestos removal costs for the Bad Creek and Bridgewater hydroelectric plants, respectively. Tr. vol. 17, 166. Witness Lucas testified that the Bad Creek plant was built in the 1980s and early 1990s, while the new Bridgewater plant was built from 2009 through 2011 with the old plant demolished sometime later. *Id.* at 167. Witness Lucas then cited the 1976 National Institute for Occupational Safety and Health's Revised Recommended Asbestos Standard (NIOSH Standard), which stated, "evaluation of all available human data provides no evidence for a threshold or for a 'safe' level of asbestos exposure." *Id.* Witness Lucas additionally noted that in 1982, following years of lawsuit

and claims, Johns-Manville, one of the earliest companies to use asbestos in roofing, insulation, and other building products, became the largest company to file for bankruptcy. *Id*. Accordingly, he testified that it would not have been prudent for DEC to have used asbestos-containing materials at these plants because the dangers of asbestos were well known before either plant was built. *Id.* at 169.

In rebuttal, DEC witness Kopp noted that exploration and construction at Bad Creek occurred throughout the late 1970s and into the 1980s, with some structures constructed in the early 1980s. Tr. vol. 11, 415. Asbestos-containing materials were still used in construction during this time, and therefore, equipment or parts manufactured before the broad 1989 ban could contain asbestos. *Id.* at 415-16. Additionally, 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. *Id.* at 362. Witness Spanos testified that for Bridgewater, although the facility was rebuilt around 2011-2012, many of the assets were maintained from the original plant, which was built many years prior to 1989. *Id.* Specifically, witness Kopp testified that for Bridgewater, the original powerhouse, penstock and dam structures were constructed in 1919, and that part of those original structures still remain at the site and are likely to contain asbestos. *Id.* at 416. Witness Spanos testified that these older assets need to be considered when establishing a decommissioning study. *Id.* at 362. Witness Kopp testified that the proper removal and disposal of that asbestos will be legally required during decommissioning, so those costs should be included. *Id.* at 416-17.

At the evidentiary hearing, witness Lucas testified that he was recommending removal of asbestos costs only for the Bad Creek and Bridgewater plants, and that he did not fault DEC for including asbestos removal costs for its older plants that were built before asbestos was a known danger. Tr. vol. 17, 182, 198-99. He further testified that DEC had not tested for asbestos at Bad Creek or Bridgewater since he raised the issue in DEC's prior rate case, and that for the current Decommissioning Study, Burns & McDonnell visited only one plant site, Lincoln County Combustion turbine (CT) 17. *Id*. at 182, 191-92.

Contingency

DEC's 2024 Decommissioning Study included a 20% adder for contingency. Speros Direct Ex. 4; tr. vol. 17, 166. Similar to Public Staff witness Thomas, witness Lucas recommended that DEC recover no contingency on the projects in the Decommissioning Study, arguing that ratepayers should be protected from paying costs in advance that may never occur. Tr. vol. 17, 170. Witness Lucas testified that DEC could recover the actual reasonable and prudent costs, even if they exceed DEC's Decommissioning Study estimates, in the same manner as other costs are recovered in a rate case after decommissioning is complete. *Id.* at 171. Witness Lucas noted that this was a departure from his testimony in previous cases, where he had recommended a 10% contingency. *Id.* at 171. He testified that he changed his recommendation in this case based on further examination of DEC's discovery response to PS DR 99-7 and the current environment of increasing customer rates. Lucas Direct Ex. 4; tr. vol. 17, 171.

In rebuttal, witness Spanos testified that contingency costs are a standard component of decommissioning studies. Tr. vol. 11, 363. He noted that standard decommissioning

studies support a 20% contingency factor. *Id.* He also noted that a 10% 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% in many instances in recent years, witness Spanos testified that 20% is more appropriate. *Id.* at 363-64.

Witness Kopp testified that a reasonable magnitude of contingency is directly related to the level of project definition, and that because decommissioning projects inherently have more defined project scope limitations during this planning phase, a 20% contingency is typically applied to cover a greater level of logistical and structural complexity. *Id.* at 417-18. Witness Kopp testified the standard contingency range for estimates like decommissioning studies is 15% to 30%, so the 20% contingency in DEC's Decommissioning Study is on the lower-middle end of this range. *Id.* at 418. Witness Kopp also testified witness Lucas did not present an independent cost-engineering study or alternative analysis demonstrating the appropriate contingency level and that a zero percent contingency lacked any basis in cost-estimating standards. *Id.* at 419. Witness Kopp testified that regulatory precedent in other states supported the inclusion of contingency. *Id.* at 421. He addressed witness Lucas's argument that DEC could recover contingency costs in a rate case after decommissioning is complete, testifying that the goal of the study is to establish an accurate, realistic forecast of total costs so that such costs can be recovered equitably over the asset's remaining useful life. *Id.* at 422. Witness Kopp testified that doing otherwise, as witness Lucas suggests, would create intergenerational equity issues by shifting recovery of dismantlement costs away from the current customers who benefit from the asset and placing those costs on future customers who receive no operational benefit. *Id*. Witness Kopp testified that excluding the contingency factor from the Decommissioning Study does not eliminate the physical cost events covered by the contingency factor; it simply removes the quantified provision for them while leaving the risk of those expenditures intact. *Id.* at 423.

At the evidentiary hearing, witness Lucas testified that the Public Staff and DEC settled on a 10% decommissioning contingency in DEC's prior rate case, which the Commission approved, and that customers' current rates reflect that 10% contingency plus a 5% adder for project indirect costs. Tr. vol. 17, 181, 193, 199. Witness Lucas also testified he did not disagree with the Decommissioning Study's cost estimates, other than the asbestos costs at Bad Creek and Bridgewater, or with its 11% adder for project indirect costs, but maintained that customers should not pay up front for a 20% contingency on costs that may never materialize. *Id*. at 185-86, 193. He testified that if actual costs exceed the estimates, DEC can recover the prudently incurred excess in a future rate case. *Id*. at 195.

At the evidentiary hearing, witness Kopp testified that planning-level decommissioning estimates do not become materially more accurate until a facility is close to demolition, when binding contractor bids and destructive testing become possible. Tr. vol. 11, 434-35. He testified that the Decommissioning Study includes line items only for environmental remediation that is known or highly likely, with contingency intended to cover other environmental issues, conditions not shown on drawings, weather delays, and similar non-ideal conditions. *Id*. at 451-53. Witnesses Kopp and Spanos identified other jurisdictions in which decommissioning estimates with contingencies of 15% to 20% have

been accepted. *Id*. at 440-43. Witness Kopp acknowledged that DEC's prior rate case settled on a 10% contingency, while stating that Burns & McDonnell has always estimated decommissioning costs using a 20% contingency. *Id*. at 450-51. At the Commission's request, witness Kopp also filed responses explaining that the increases in decommissioning costs at the Allen, Belews Creek, Cliffside, and Marshall plants since the 2022 study are driven mainly by higher labor and equipment costs, lower net scrap pricing, changes in inventory values, and an increase in project indirect costs from 10% to 11%. DEC Late-Filed Ex. 4, Ex. 5; tr. vol. 11, 433-34.

Net Salvage for Mass Property Accounts

Public Staff witness McCullar proposes different net salvage estimates for three distribution accounts: Account 362 – Station Equipment, Account 366 – Underground Conduit, and Account 367 – Underground Conductors and Devices. Tr. vol. 17, 131. Witness McCullar's proposed net salvage estimates for these accounts, along with DEC's proposed net salvage estimates and the currently approved net salvage percentage, are included in Table 5 of witness McCullar's testimony and shown below:

Table 5: Comparison of Proposed Estimated Future Net Salvage Percentage Recommendations

Account	Description	Current Approved	DEC Proposal	Public Staff Proposal
362.00	Station Equipment	-15%	-20%	-15%
366.00	Underground Conduit	-20%	-25%	-20%
367.00	Underground Conductors and Devices	-20%	-25%	-20%

Id.

Witness McCullar testified that these estimates are more reasonable than DEC's proposed figures because Public Staff's estimated future net salvage percentages will allow DEC an appropriate recovery of its actual costs, will contribute to building the book reserve for future retirement costs, and are more reasonable for customers. *Id.*

Witness McCullar testified that her analyses and witness Spanos's followed similar steps in their analyses by reviewing the historic net salvage data and other information provided by DEC, their previous experience, and the use of informed judgment. Witness McCullar pointed out that the difference in their proposals is most likely related to the use of informed judgment. *Id.* at 126. Additionally, witness McCullar testified her proposed future net salvage estimates are an appropriate balance of the interests of both current and future ratepayers. *Id*.

In rebuttal, witness Spanos disagreed with witness McCullar's approach. Tr. vol. 11, 376. He noted that a trend towards increased retirement activity, both in North Carolina and nationwide, will result in higher levels of net salvage. *Id*. Witness

Spanos further testified that net salvage accruals are the amount of depreciation expense that is recovered annually while net salvage costs are the actual costs of removal and gross salvage incurred each year. *Id*. Witness Spanos noted that the amount of cost for removal has considerably increased for all three accounts since the last proceeding yet witness McCullar does not change the current estimate. *Id*. Witness Spanos also noted that the texts cited by witness McCullar, as well as FERC and the USOA, support the methodology he uses for DEC's 2024 Depreciation Study. *Id.* at 393-98. He further testified that the Public Staff's proposed estimates for these accounts are not representative of DEC data. *Id.* at 378.

At the evidentiary hearing, witness McCullar responded that witness Spanos's rebuttal mischaracterized witness McCullar's salvage proposal as setting accruals equal to recent average net salvage expense, and that Table 6 of her testimony shows her proposal both covers the expected near-term costs and builds a reserve for future cost increases. Tr. vol. 17, 178-79, 183-84. She also noted that her proposed percentages for Accounts 362, 366, and 367 are the currently approved percentages. *Id*. at 131.

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. 11, 365. Service lives of these accounts are estimated using survivor curves, which provide an estimate of both an average service life and a dispersion of lives or retirements around the average. *Id.*

Public Staff witness McCullar proposed changes to the proposed service lives for two distribution mass property accounts: Account 368 – Line Transformers, and Account 369 – Services. *Id.* at 366; *see also* tr. vol. 17, 117. For Account 368, witness McCullar recommended a 50-year estimated average service life with an R1 Iowa survivor curve, whereas DEC proposed a 45-year estimated average service life with an R1.5 Iowa survivor curve. Tr. vol. 17, 117. For Account 369, witness McCullar recommended a 65-year estimated average service life with an R1 Iowa survivor curve, whereas DEC proposed a 55-year estimated average service life with an R1.5 Iowa survivor curve. *Id.* Witness McCullar testified that her proposals for Account 368 and Account 369 are both a better mathematical and visual fit to historic observed life data. *Id.* at 119-20, 122.

In rebuttal, witness Spanos explained that the primary difference between his estimates and witness McCullar's estimates is in their interpretations of the data. Tr. vol. 11, 366. These differences are outlined below.

Account 368 – Line Transformers

For Account 368, witness Spanos testified that witness McCullar did not consider some key elements of life estimation such as planned work for distribution lines and the transition to more underground lines, which will result in high levels of retirements for pole-mounted line transformers for the foreseeable future. *Id.* at 371. Witness Spanos also testified that witness McCullar's estimates (which include a small percentage of line transformers lasting almost 100 years) reflect an expectation that more line transformers will remain in service than is realistic. *Id.* He pointed out that the level of retirements has

increased considerably over the last few years, but witness McCullar did not take issue with this account's 45-R1.5 survivor curve in the previous proceeding. *Id*. Witness McCullar noted during the evidentiary hearing that the Depreciation Study shows that a small percentage of assets actually has lived to almost a hundred years. Tr. vol. 17,179.

Account 369 – Services

For Account 369, witness Spanos testified that witness McCullar's statistical analysis is inconclusive, as 70% of the account has lasted 60 years and there are no historical indications of retirements beyond that time period; this pattern of low retirements cannot be expected to continue into the future. Tr. vol. 11, 373. Witness McCullar responded to this point during the evidentiary hearing, testifying that she considered this to be a good data point to consider. Tr. vol. 17, 179. Witness Spanos also 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. Tr. vol. 11, 373. Witness Spanos also testified that witness McCullar's proposed 65-R1 survivor curve unrealistically has a maximum life of 125 years. *Id*. Because the currently approved life estimate is a 55-R1.5 curve, witness McCullar expects a 10-year average life extension for the assets in this account, which is not realistic. *Id*. He again noted that witness McCullar did not take issue in the last case with the 55-R1.5 survivor curve that witness Spanos recommends for this account. *Id*. Witness Spanos testified that Public Staff's proposed estimates appear to be based on a limited consideration of the assets in each account, and he noted that due to the nature of the assets in this account, higher replacement is expected due to both failure and planned replacement. *Id.* at 373.

Deferral of Impact of Accelerated Depreciation for Subcritical Coal Plants

In Docket No. E-7, Sub 1276, DEC requested authorization to establish a regulatory asset and defer to that regulatory asset 50% of the incremental depreciation expense for North Carolina retail customers resulting from the accelerated retirement dates for Allen Units 1 and 5, Cliffside Unit 5, and Marshall Units 1 and 2 in the 2021 Depreciation Study. Tr. vol. 12, 267. House Bill 951 (S.L. 2021-165) allowed DEC to securitize 50% of the remaining net book value of these facilities upon retirement. *Id.*

In the Amended Agreement and Stipulation of Partial Settlement reached with the Public Staff and approved in the Sub 1276 Order, DEC agreed to defer 75% of the impact of accelerated depreciation for the impacted coal plants, with 50% of the net book value being recovered through securitization and the remaining 25% to be recovered with a return over an amortization period to be determined by the Commission in a future rate case. Tr. vol. 12, 267-68.

In this proceeding, DEC is proposing to increase the accelerated depreciation deferral to 100% of the impact of the 2021 Depreciation Study based on the passage of S.L. 2025-78, which amended N.C.G.S. § 62-172 to allow DEC to securitize 100% of the remaining net book value of subcritical coal facilities upon retirement. Tr. vol. 12, 268; tr. vol. 17, 307. The annual depreciation deferral is $13.956 million on a North Carolina retail basis. Jiggetts Comp. Settl. Ex. 3 at 138.

The Public Staff did not recommend any adjustment to DEC's request to defer the accelerated depreciation expense of its subcritical coal units for later securitization and no other party presented evidence on this issue. Tr. vol. 17, 316.

Discussion and Conclusions

Based on the Comprehensive Settlement and the entire record in this proceeding, the Commission concludes that it is appropriate to adopt and implement the depreciation rates set forth by DEC in the 2024 Depreciation Study sponsored by witness Spanos, updated to reflect the Public Staff's proposed adjustments, including those Public Staff adjustments made to DEC's 2024 Decommissioning Study, except that a 10% contingency factor shall be applied in lieu of the contingency percentages proposed by either DEC or the Public Staff.

Additionally, based on the Comprehensive Settlement and the entire record in this proceeding, the Commission concludes that it is reasonable for witness Spanos to apply the agreed-upon settlement assumptions in his model to develop the final depreciation rates to be implemented by DEC, which will then be included in DEC's compliance filing to this Commission.

Based on the evidence presented, the Commission concludes the resolution of these issues through the Comprehensive Settlement is just and reasonable.

In reaching this conclusion, the Commission notes the Comprehensive Settlement resolves each of the contested depreciation and decommissioning issues summarized above. By adopting the Public Staff's proposed adjustments, which are reflected in witness McCullar's proposed depreciation rates, the Comprehensive Settlement aligns the probable retirement dates of DEC's coal units with the 2025 CPIRP as recommended by Public Staff witnesses Thomas and McCullar; adopts witness McCullar's proposed net salvage estimates for Accounts 362, 366, and 367 and her proposed survivor curves for Accounts 368 and 369; and excludes the Bad Creek and Bridgewater asbestos decommissioning costs as recommended by Public Staff witness Lucas. *See* tr. vol. 13, 112-13; tr. vol. 17, 116-18, 316. The 10% contingency factor falls between DEC's originally proposed 20% and the Public Staff proposed 0%, and is the same contingency factor agreed upon in DEC's prior rate case and reflected in current rates. *See* tr. vol. 17, 193, 199. Having independently considered all of the evidence, including the competing testimony of witnesses Spanos, Kopp, Thomas, Lucas, and McCullar, the Commission concludes that these provisions of the Comprehensive Settlement are just and reasonable to all parties considering all the evidence presented.

In addition, based on the entire record in this proceeding, the Commission concludes that it is appropriate to grant DEC's request to defer to a regulatory asset 100% of the impact of accelerating the depreciation of DEC's subcritical coal plants based on the 2021 Depreciation Study for an annual deferral of $13.956 million on a North Carolina retail basis. This preserves the ability of DEC to recover the remaining net book value of the subcritical coal plants through securitization, as allowed under S.L. 2025-78, and was not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

Base Period Plant-Related Items

The evidence supporting this finding of fact is contained in DEC's verified PBR Application and Form E-1; the testimony and exhibits of DEC witnesses Jiggetts, Fogg, Guyton, Haaf, Speros, Teckenbrock, Tompson, and Walsh; the testimony and exhibits of Public Staff witnesses Lawrence, Metz, Thomas; the joint testimony and exhibits of the Public Staff Distribution Panel; the joint testimony and exhibits of the Public Staff's Renewables Panel, the joint testimony and exhibits of the Public Staff Accounting Panel; the Partial Stipulation and Comprehensive Settlement; and the entire record in this proceeding.

Summary of Evidence

Generation Capital Investments

DEC witness Walsh described DEC's traditional (fossil) and renewable fleet and the operational performance of those assets during the test year. Tr. vol. 11, 73-75, 83-85. Witness Walsh also testified regarding the major capital projects undertaken by DEC for maintenance of the fossil and renewable fleets since DEC's last general rate case in Docket No. E-7, Sub 1276, which was a three-year MYRP. (2023 Rate Case). *Id*. at 79-82. Witness Walsh expanded on the continuing importance of the fossil fleet to North Carolina customers, noting that the coal fleet remains a key contributor to resource adequacy and ensuring the availability of needed generation during seasonal peak load periods and extreme weather events. He further testified DEC will continue to rely on its fossil fleet, including natural gas, as part of the diverse and dispatchable resource mix needed to ensure reliable service now and in the future, and DEC will continue to incur costs for these assets as appropriate and prudent to ensure the same reliable, cost-effective electricity customers have depended on for decades. *Id*. at 78-79. Witness Walsh addressed how DEC ensures generating assets remain operationally reliable during extreme weather and "peak load" demand events and how DEC's processes and weather preparedness helped it prepare for Hurricane Helene. *Id*. at 75-79. Witness Walsh described how DEC controls and mitigates O&M expense increases. *Id*. at 82-83. He testified that, in his opinion, DEC prudently incurred capital and O&M costs to operate the traditional/renewable fleets and that DEC prudently operated the traditional/renewables fleet during the test period. *Id*. at 81-83, 85.

DEC witness Haaf described DEC's nuclear generation assets and capital additions made to the fleet since the 2023 Rate Case to enhance safety, reliability, and efficiency, preserve performance and reliability of the plants throughout their extended life operations, and address regulatory requirements. Tr. vol. 11, 24-25, 27-33. Witness Haaf provided an update on Duke Energy's plans related to subsequent license renewal for the existing nuclear fleet. *Id*. at 26-27. He testified to the exceptional performance of DEC's nuclear fleet during the test period, how DEC ensures that the fleet remains operationally reliable during extreme weather and "peak load" demand events, and initiatives DEC has undertaken to increase nuclear operational efficiency. *Id*. at 56-58.

Witness Haaf discussed the significant cost drivers impacting O&M expense for the fleet and how DEC manages O&M costs for the nuclear units. *Id.* at 51-54, 58-59.

Public Staff witnesses Metz, Thomas, and the Renewables Panel reviewed DEC's capital investments in its generation fleet. Public Staff witness Metz reviewed DEC's nuclear plant in service during the historic period. Tr. vol. 17, 207-11. Witness Metz's recommendations are addressed below. Witness Thomas reviewed DEC's steam and natural gas plant in service during the historical period and did not recommend any adjustments to these investment costs. Tr. vol. 13, 97-98, 114-15. The Renewables Panel reviewed historic period solar, battery, and hydro capital plant in service. Tr. vol. 17, 270-83. The Renewables Panel's recommendations are addressed in more detail below.

Gaston Drone Project

The Public Staff Renewables Panel (Renewables Panel) recommended a reduction of $248,145 related to the Gaston Solar facility's Drone in a Box project, explaining the project was a corporate initiative. DEC did not explain why Gaston Solar was chosen for the project or justify the need at that specific site. The Renewables Panel asserted the investment was therefore imprudent and should not be paid for exclusively by DEC ratepayers. Instead, the Renewables Panel recommended the cost be borne by shareholders or shared among Duke Energy's six state jurisdictions. *Id.* at 275-76.

In rebuttal testimony, witness Walsh explained the recommendation does not account for the many benefits the drone provides to the Gaston Solar site, which DEC had described as outlined in Renewables Panel Exhibit 3. Witness Walsh clarified that while the drone was acquired as part of a broader enterprise initiative to deploy and test drone technology where appropriate, this unit was purchased for use at the Gaston site and has already completed dozens of flights that have delivered operational value. Witness Walsh cited the drone's use during recent winter storms to assess panel conditions as an example of its benefit, avoiding the need to send personnel to the site in hazardous weather. He further noted the drone is trailer mounted and capable of responding to needs at multiple solar locations and, based on the justified Gaston use case, represents a prudent and reasonable investment whether at Gaston or elsewhere in the fleet. Tr. vol. 22, 312-13.

In the Partial Stipulation, DEC agreed to the Public Staff's recommended reduction. Partial Stip. § III.7.

Buck Pipeline Lease

In its second supplemental filing, DEC included accelerated depreciation associated with the existing Buck natural gas pipeline lease. *See* tr. vol. 12, 297. DEC witness Jiggetts explained the existing lease will end in 2029, which is 22 years earlier than the original 2051 end date, resulting in a higher annual deprecation rate for the remainder of the lease term. Tr. vol. 21, 454.

The Public Staff recommended removal of DEC's $3.8 million accelerated depreciation request, arguing that the CPIRP proceeding does not support selection of DEC's proposed Buck CTs until after 2029. *Id.*

In her rebuttal testimony, witness Jiggetts clarified that when the existing pipeline lease will end and when Buck CTs will be selected in the CPIRP are two separate issues. *Id*. She testified that the accelerated depreciation at issue relates to the existing lease, which contractually ends in 2029 regardless of what the CPIRP ultimately determines about the Buck CTs. She stated that the existing lease's 2029 end date is a known and measurable change that is independent of the outcome of the CPIRP proceeding. *Id*. In the alternative, DEC requested an accounting order to defer accelerated amortization expense required by Generally Accepted Accounting Principles (GAAP) and only record the amount of amortization expense that the Commission deems is appropriate to include in customer rates. *Id*.

In the Partial Stipulation, DEC agreed to the Public Staff's adjustment for the Buck Pipeline Lease, and the Public Staff agreed to support DEC's alternative request for an accounting order permitting DEC to defer and amortize expense in order to match the net amortization expense to the amount currently in customer rates and to continue that amortization through the original expected life. DEC and the Public Staff further agreed that the resulting regulatory asset will not accrue a return, and ratemaking treatment will otherwise remain as it is today with amortization over the remaining life of the plant. Partial Stip. § III.9.

Anderson Combined Cycle Construction Work in Progress

DEC witness Jiggetts explained that pro forma NC3050 adjusts rate base to include CWIP related to baseload generation projects as allowed per N.C.G.S. § 62-133(b)(1). The only CWIP included in this adjustment is that associated with the construction of the Anderson CC. Tr. vol. 12, 253. As of March 31, 2026, the CWIP balance for Anderson CC was approximately $14.1 million on a North Carolina retail basis, which results in an increase to the annual revenue requirement of nearly $1.4 million. Jiggetts Comp. Settl. Ex. 2 at 12, Ex. 3 at 176-77.

Public Staff witness Lawrence explained that DEC has filed with this Commission an Application for Determination of Need for an Out-of-State Electric Generating Facility pursuant to N.C.G.S. § 62-110.6 and Commission Rule R8-61(f). Tr. vol. 16, 539. Additionally, DEC has filed a joint application for a certificate of environmental compatibility and public convenience and necessity (CECPCN) with the Public Service Commission of South Carolina (SCPSC). *Id*. at 539-40. On March 26, 2026, the SCPSC issued a notice of approval with a full order to be issued at a later date. *Id*. at 540. The Commission's order on the determination of need for the Anderson facility must be issued within 180 days of the March 18, 2026 filing, which is before the final order in this proceeding is expected. *Id*. As such, the Public Staff did not make an adjustment to remove the CWIP costs requested by DEC. However, if the Commission disapproves DEC's application for the Anderson CC, the Public Staff indicated that these CWIP costs should be removed from recovery in the rate case. Tr. vol. 17, 369-70.

The Partial Stipulation provides that if DEC's application for a CPCN for the Anderson CC is denied by the Commission prior to the compliance filing in this rate case, the Stipulating Parties agree to remove the Anderson CC CWIP from this proceeding. Otherwise, the Anderson CC CWIP as of March 31, 2026, will be included in rate base, and AFUDC will stop on the amount in rate base starting with the effective date of new rates in this case. Partial Stip. § III.29.

McGuire Nuclear Spare Exciter

Public Staff witness Metz recommended a reduction of approximately $7.3 million related to the purchase of a spare main generator exciter for McGuire Nuclear Station on the basis that DEC transferred spare parts to another utility and customers should not be responsible for the cost of a replacement spare part since such customers pay for reasonable inventory of spare parts through base rates. Tr. vol. 17, 207-08.

In his rebuttal testimony, witness Haaf explained that the Public Staff's characterization of this issue did not reflect the full circumstances. Witness Haaf continued that the McGuire spare exciter was traded to another utility for a similar item that supported bringing DEP's Robinson plant back online as quickly as possible to continue providing service to customers. He continued that while DEC does maintain spare parts to support continued plant operations, a spare main generator exciter is not a traditional spare part that can be readily replaced within a few hours or days, but rather is specific to the plant and has a lead time of 12-24 months to procure, fabricate, and deliver. He concluded that purchasing a replacement spare exciter for McGuire was reasonable and allowed DEC to mitigate the risk of an extended unplanned outage of a baseload power generating source. Tr. vol. 22, 162-64.

The Partial Stipulation provides that DEC will forego recovery of the McGuire Nuclear Spare Exciter in this proceeding and that upon the effective date of the DEC/DEP business combination, DEC may seek recovery of the remaining undepreciated amount in the next general rate case. Partial Stip. § III.27.

Additional Nuclear Historical Period Capital Items

Public Staff witness Metz recommended removal of certain costs related to DEC's purchase and installation of condenser circulating water (CCW) crossover valves at Oconee Nuclear Station, asserting that the costs associated with metrology for the project (i.e., modeling and measurements of the layout of the area where the valves were installed) should not be recovered because re-work related to this project was necessitated by personnel changes and did not provide additional benefit to customers. Tr. vol. 17, 209. Witness Metz also recommended removal of approximately $156,000 related to the purchase of rifles for use in maintaining physical security at McGuire Nuclear Station. He asserted that since the rifles are issued to security officers over time as their training and evaluation cycles are completed, those not yet physically in an officer's hands are not "used and useful." *Id.* at 210-22.

In rebuttal, witness Haaf disagreed with Public Staff witness Metz's recommendations, noting that personnel changes (i.e., disbandment of a metrology team

in 2023) did not impact the timeline for executing the Oconee CCW crossover valve project and added no additional metrology costs. Tr. vol. 22, 165. Witness Haaf emphasized that no metrology data associated with the project was lost following the team's disbandment, and that the costs incurred supported valve replacement by providing a detailed map and measurements of the plant layout. He concluded that these costs were indeed reasonably incurred to support the replacement of equipment that had reached the end of its service life. *Id.* at 164-66.

Regarding the rifle purchases for McGuire Nuclear Station, witness Haaf testified that all DEC nuclear stations employ security personnel to provide physical security in accordance with Nuclear Regulatory Commission (NRC) regulations. *Id.* at 166. The rifles are purchased by station nuclear protective services personnel and are replaced as they near their end of life. Once received by the station, the rifles are placed in the station's armory ready for issuance to security personnel. Witness Haaf explained that McGuire distributes rifles as officer's training cycles and evaluations are performed periodically. He noted that once the rifles are placed in the site armory they directly support site security as they are ready and available for use when equipment failures or malfunctions occur with other issued rifles. He provided his operational perspective and understanding that the "used and useful" standard does not require that every unit of equipment be actively deployed at every moment; but rather than the equipment be available to serve its intended purpose. He concluded that the rifles meet that standard. *Id.* at 166-69.

The Partial Stipulation provides that DEC agrees to the Public Staff's adjustment to remove $0.8 million in nuclear costs as identified in the direct testimony of Public Staff witness Metz. Partial Stip. § III.6.

Nuclear M&S Inventory

Public Staff witness Lawrence recommended removal of the nuclear materials and supplies (M&S) inventory categorized as Quality Hold that has been on hold for four or more years. Tr. vol. 16, 542. He explained that M&S inventory is included in rate base but not depreciated. *Id*. Witness Lawrence testified that the parts are unusable in their current condition and have been for a significant amount of time. *Id*.

In his rebuttal, witness Haaf disagreed with the Public Staff's recommendation. Witness Haaf explained that this inventory is held to support plant operations and is therefore of benefit to customers, regardless of the duration of the hold. He noted that removing this inventory based solely on the length of the hold period does not reflect why the hold status exists and how nuclear inventory management works. Witness Haaf continued that including items in Quality Hold that are four or more years old in nuclear M&S inventory is prudent and appropriate because the inventory ultimately benefits the customer by ensuring adequate spare parts and material are available to support the stations' safe and efficient operation. While similar components or parts can be procured, they require engineering analysis and validation before being installed and placed in service. Rather than a sign of waste, this approach reflects the rigorous engineering standards that govern nuclear plant operations. Witness Haaf noted that the Public Staff cited no policy, standard, or precedent to support its recommendation. Tr. vol. 22, 159-61.

The Partial Stipulation provides that DEC will accept the Public Staff's adjustment, reducing nuclear M&S inventory by approximately $0.9 million. Partial Stip. § III.10.

BESS Performance Monitoring Tool

The Public Staff Renewables Panel recommended disallowance of the BESS Monitoring Tool project (a software project for aggregating, managing, and processing BESS data at a pilot site), resulting in a recommended downward adjustment of $299,307. The Renewables Panel asserted that the project was not demonstrably used and useful because it had been placed in service on March 31, 2026, and users were still in training. The Renewables Panel opined that DEC should not invest in projects to reduce O&M without demonstrating and passing onto customers associated O&M savings. Tr. vol. 17, 279-81.

In his rebuttal testimony, witness Walsh explained this project implements a third-party software application to monitor site performance with improved speed and depth of information to facilitate decision making on O&M activities. Witness Walsh disagreed that the project was not used and useful and clarified the project was placed in service on December 31, 2025. He noted DEC explained in discovery that production data is flowing to the application and the production interface is available to DEC personnel for use in monitoring and modeling site performance. Tr. vol. 22, 314-15.

The Partial Stipulation provides no adjustments will be made for the BESS Performance Monitoring Tool. Partial Stip. § III.8.

Transmission and Distribution Base Period Investments

In their direct testimonies, DEC witnesses Guyton and Fogg discussed DEC's distribution and transmission investments since its last general rate case. DEC witness Guyton testified that DEC has invested approximately $2.6 billion in distribution system additions since PBR1, which included investments made as part of DEC's MYRP1. Tr. vol. 9, 190. Witness Guyton testified MYRP1 projects comprised approximately 40% of DEC's distribution investments, and the remaining 60% of distribution investments were for serving new customers, lighting installations, and reactive maintenance and service restoration. *Id*. at 192. Witness Guyton explained that the MYRP1 distribution investments included projects in the following categories: (1) Substation and Line, which includes ten sub-programs; (2) Retail and System Capacity; (3) Hazard Tree Removal; (4) Integrated Volt Var Control / Voltage Regulation & Management; and (5) Other non-distribution MYRP1 Projects. *Id*. at 206.

In his direct testimony, witness Fogg testified that since DEC's PBR1, DEC has made targeted investments in its transmission system totaling approximately $684 million to provide capacity to serve system growth, ensure adequate system voltage and compliance with North American Electric Reliability Corporation (NERC) transmission planning standards, support transmission-related infrastructure for new generation and the decommissioning of generation, and improve system reliability. *Id.* at 147. He explained that the majority of the investments were for reliability & integrity work (46%) and capacity improvements (25%). *Id*. In terms of transmission MYRP1

investments, he explained that the transmission projects included grid investments critical to maintaining and improving the transmission system and that the projects included investments in system intelligence, hardening and resiliency, transformer and breaker upgrades, and capacity and customer planning. *Id*. at 153.

In Public Staff witnesses Lawrence, the Distribution Panel and the Renewables Panel's direct testimonies, they took issue with some of the T&D capital investments made by DEC since its last rate case, as discussed in more detail below. Specifically, the Public Staff Distribution Panel took issue with certain Substation Optimization investments, costs related to the Ashe Street Substation Outage, the inclusion of a portion of the NextGen GIS project in rate base, and the inclusion of substations ready for use but not yet servicing customers. The Renewables Panel took issue with the inclusion in rate base of the Washington Solar and Hornet Solar interconnection facilities.

Substation Optimization

In witness Guyton's Direct Testimony, he explained that Substation and Line MYRP Projects, also known as "Substation Optimization" or SO work, are geographically based projects that include a combination of ongoing work necessary for safe and reliable service and work needed to deliver essential grid capabilities. Tr. vol. 9, 206. More specifically, he explained that the work consists of the following ten sub-programs which are summarized in Guyton Direct Exhibit 5 and were discussed in detail in his direct testimony filed in Docket No. E-7, Sub 1276:

- Self-Optimizing Grid (SOG)
- Distribution Automation
- Capacity
- Hardening and Resiliency: Laterals
- Hardening and Resiliency: Storm
- Hardening and Resiliency: Public Interference
- Long Duration Interruptions
- Targeted Underground
- Infrastructure Integrity, and
- Hazard Tree Removal.

Id. at 206-07.

Witness Guyton testified that the Substation and Line projects were selected on a data-driven basis utilizing the Integrated Systems Operations Planning (ISOP) tools, and that each distribution substation and its associated circuits were evaluated for current and historical operating performance as well as any gaps to the critical grid capabilities (reliability, capacity, automation and communication, and voltage regulation). *Id*. at 207. Specific programmatic solutions were then identified and scoped to close any performance

or grid capability gaps for each substation. He explained that each substation, based on its specific needs, will receive selected improvement programs (not one-size fits all). Next, he testified that these scopes for geographic clusters were then aggregated into an MYRP project for execution and that this geographical approach enables efficient resource utilization and delivery of customer benefits across a large area. *Id*.

In the Distribution Panel's direct testimony, Public Staff witness T. Williamson voiced concerns about the level of investment in the distribution system and DEC's reliability performance given these investments. Tr. vol. 16, 427. He testified that the Public Staff understands that distribution system upgrades do not occur in a vacuum, and other circumstances can lead to changes in system reliability year over year and that as the distribution system ages, equipment failures can become more common, and it is appropriate for DEC to deploy targeted grid upgrade solutions to address the need for new capacity related to customer growth, to replace equipment that is close to failure or has failed, and to address reliability that is worse than system averages on specific substations and circuits. *Id*. at 428-29. However, he testified that the Public Staff is concerned that upgrading the distribution system has become somewhat of a "blank check" for DEC. *Id*. at 429. He testified that substations and circuits are targeted for massive infrastructure upgrades, often without clear goals for service quality improvements at individual substations and circuits, and that there is also little accountability for whether these upgrades achieve the estimated reliability benefits and are beneficial in the long run. *Id*. Finally, he testified that the Public Staff is concerned that many of the substations and circuits targeted for investment are already performing better than the system average in terms of service quality. *Id*. Thus, witness T. Williamson recommended that the Commission disallow as imprudent cost recovery of the $12.8 million spent during the Historic Period on Substation Optimization projects for 44 substations it identified with better-than-average non-MED SAIDI performance. *Id*. at 384.

On rebuttal, DEC witness Guyton disagreed with the Distribution Panel's recommendation to disallow $12.8 million of Substation Optimization work testifying that average is not the target and customers are not best served if DEC only invests in circuits and substations after they fall below a "historical average," reliability metrics alone do not capture risk and condition, and Public Staff's position ignores resiliency benefits of the work performed. Tr. vol. 22, 45-46. He testified that DEC's strategy is to maintain and improve reliability across the system, including at substations that currently perform relatively well, particularly where the assets are aging, critical, or exposed to emerging risks, and a system managed only to avoid below average performance is a system permanently trending towards decline. *Id*. at 45. He explained that rather than just historical reliability data, investment decisions are based on multiple factors such as equipment age and condition, criticality, customer mix, load growth, configuration, and operational flexibility. *Id*. at 46. For example, he explained that a substation with favorable historical indices may still contain aging, obsolete, or high-risk equipment that needs proactive replacement to avoid future degradation and outages from equipment failures and that this is especially true in a period of significant load growth and accelerated electrification, where substations and circuits must be equipped to handle these conditions as they materialize. *Id*. Finally, he testified that a substation can show acceptable System Average Interruption Duration Index (SAIDI)/System Average Interruption Frequency Index (SAIFI) under normal conditions while remaining highly

vulnerable to storm damage, equipment failures, or load fluctuations. *Id*. Witness Guyton further testified that completed MYRP1 Substation Optimization work was already producing measurable reliability benefits. *Id.* at 56-57. Specifically, for the 112 MYRP1 Rate Year 1 Substation Optimization substations placed in service by the end of 2024, witness Guyton testified that SAIDI improved by approximately 24% and SAIFI improved by approximately 20%, compared to a 3.7% SAIDI improvement and a 0.5% SAIFI worsening for substations without Substation Optimization improvements. *Id.*

Section III, ¶ 4a of the Partial Stipulation specified that with respect to distribution capital, no adjustments shall be made to DEC's Substation Optimization projects in the base period. Partial Stip. § III.4.a.

Ashe Street Substation

In the Distribution Panel's direct testimony, Public Staff witness T. Williamson recommended that the Commission disallow as imprudent costs related to the Ashe Street substation repair. Tr. vol. 16, 385. Witness T. Williamson explained that on January 17, 2024, a DEC line crew was performing scheduled work to install two poles inside the Ashe Street substation when the crew damaged underground control cables while performing the work which led to an outage of nearly 30 hours during cold weather and an accumulation of 16 million customer-minutes interrupted (CMI), resulting in repairs at a cost of $2,435,086. *Id*. at 435. Witness T. Williamson testified that the outage occurred as a result of DEC's documented errors and that the outage would have been avoidable if DEC had acted prudently. He therefore recommended disallowance of the $2,435,086 sought for recovery in this proceeding. *Id*. at 436.

In his rebuttal testimony, DEC witness Fogg explained that the outage occurred when a crew struck underground control cables while installing temporary poles within an older substation. Tr. vol. 22, 143. Witness Fogg testified that once the damage occurred, DEC appropriately focused on safe, rapid restoration and was able to restore service without any additional safety incidents during the response effort. *Id*. at 142. He explained that DEC's planning and response were within the range of reasonable utility practice, and that DEC's post-event actions reflect a commitment to continuous improvement rather than imprudence. *Id*. at 143.

Section III, ¶ 4b of the Partial Stipulation specified that with respect to distribution capital, the costs related to the Ashe Street Substation repair shall be removed from the base period. Partial Stip. § III.4.b.

Substations Ready for Use

In the Public Staff Distribution Panel's direct testimony, Public Staff witness T. Williamson recommended an adjustment for DEC's Substation Group Project W20036201 (Chastain Ave. Ret – New Substation) and Project W25025201 (EMERGENT (E0) Monroe Rd Ret Repla). Tr. vol. 16, 434. He explained that in response to discovery, DEC identified a set of substations that were ready for use but not yet serving customers, and as a result, recommended the Commission disallow the $14.3 million sought for recovery in this proceeding*. Id.* at 436.

In his rebuttal testimony, DEC witness Guyton, testified that the Distribution Panel's analysis appears to focus on assets that are energized, or substantially complete, but where load is still ramping up or where the specific contingency conditions under which the assets will operate have not yet occurred. Tr. vol. 22, 79. Witness Guyton explained that the assets are part of DEC's integrated distribution system and are performing a utility function today, even if their loading and utilization will increase over time, and as such, they are properly included in rate base. *Id*. With respect to the $11.9 million investment in the Chastain New Substation witness Guyton explained that the existing Woodlawn 12.5 kV circuits are highly loaded and new development (under construction) just to the north of the substation will overload the two circuits serving this area that this substation will relieve. *Id*. He further explained that the substation construction is complete, the substation is energized and duct bank scope outside the fence was underway and scheduled for completion in June 2026. *Id*. He also explained that the $2.4 million investment in the Monroe Rd Retail Substation Replacement project was necessary to replace a failed transformer bank and that the substation is energized and customers are drawing power as of May 2026, meaning this substation is currently used and useful. *Id*.

Section III, ¶ 4c of the Partial Stipulation specified that with respect to distribution capital, for the substations that are ready for use but not yet serving customers, 50% shall be removed from rate base for purposes of this proceeding, and DEC may seek recovery of the net depreciated value of those substations in the next general rate case. Partial Stip. § III.4.c.

Washington Solar Interconnection Facilities

In the Public Staff Renewables Panel's direct testimony, the Public Staff recommended disallowance of the project's interconnection costs, for a total downward adjustment of $220,483. The Public Staff stated that the Washington Solar Interconnection facilities serve a 5 MW, PURPA PPA solar facility that has reimbursed DEC for the cost of its interconnection facilities through a CIAC. The Public Staff further added that inclusion of these project costs was due to the time when DEC pulled the information, before all of the CIAC funds had been included in the project account. DEC stated in response to discovery that this project has been fully reimbursed by the developer. Tr. vol. 17, 274.

In her rebuttal testimony, DEC witness Jiggetts testified that DEC agreed with the adjustment for the Washington Solar interconnection to address the timing issue raised by the Public Staff and that the CIAC received will be credited to the project balance. Tr. vol. 21, 445.

Section III, ¶ 7 of the Partial Stipulation specified that the Stipulating Parties agree to the Public Staff's adjustments to the Washington Solar Interconnection Facilities as agreed to by DEC in witness Jiggetts' rebuttal testimony. Partial Stip. ¶ lll.7.

Hornet Solar Interconnection Facilities

In the Public Staff Renewables Panel's direct testimony, the Public Staff explained that DEC closed two projects to plant related to Hornet Solar's interconnection facilities: Tap Line and Boger City. Tr. vol. 17, 274. The Renewables Panel explained that the

Hornet Solar facility was not expected to be in service until the end of May 2026, and because the solar facility is not online, the costs are not used and useful and should be disallowed for a downward adjustment of $813,887. *Id*. at 274-75. The Renewables Panel also noted that DEC will recover the costs of these projects through CIAC and EFCs. *Id.* at 275. Should the Commission disagree and allow the projects to be included in rate base, the Public Staff recommends an amended adjustment to otherwise account for the revenue DEC has received and will continue to receive to cover these costs. *Id*.

In his rebuttal testimony, DEC witness Fogg testified that the Hornet Solar interconnection facilities are used and useful because they are completed, energized components of the 100 kV network that are needed to fulfill a firm, long-term commitment to interconnect a 75 MW resource. Tr. vol. 22, 148. He testified further that the Hornet Solar tap line and Boger City facilities are not speculative or stand-alone assets; rather, they are designed and built to integrate a specific resource into the transmission system and are part of the physical network over which power is flowing, which began in January 2026. *Id*. He argued that once a new transmission tap and associated switching equipment are installed and energized, they become part of the integrated transmission grid and that power flows are determined by network conditions, not by whether the interconnecting generator has begun commercial operation on a particular day. *Id*. As such, the tap line and the new Boger City switching configuration are now functioning transmission assets that support the safe and reliable operation of the 100 kV system. *Id*.

Section III, ¶ 7 of the Partial Stipulation specified the Stipulating Parties agree to the Public Staff's adjustments to the Hornet Solar Interconnection Facilities. Partial Stip. § III.7.

NextGen GIS

In his direct testimony, DEC witness Guyton testified that the DEC NextGen Geospatial Information System (GIS) Replacement project was originally estimated to be placed in service in the last month of DEC's MYRP1 (December 2026), but due to refinements in the implementation strategy, the in-service date was extended to mid-2027, thus falling within MYRP2. Tr. vol. 9, 231. Witness Guyton explained that Duke Energy's current core GIS system has reached obsolescence and poses risks to key asset data access across multiple lines of business (i.e., distribution, transmission, gas). *Id*. He further explained that the current version was upgraded ten years ago and now is on limited vendor support and cannot take application patches or infrastructure upgrades and therefore, a full replacement of the current GIS system is needed to ensure the continuation of a resilient and reliable electric grid. *Id*. In her second supplemental testimony, DEC witness Abernathy testified that DEC made an adjustment to reflect that Phase 1 of the NextGen GIS project went into service in March 2026 and therefore should not be included in the estimate for MYRP2 for this project. Tr. vol. 12, 214. Witness Abernathy explained that the remaining portion of the project has a projected in-service date of June 2027 and is still included in the MYRP2 project list. *Id.*

The Public Staff Distribution Panel (Distribution Panel) recommended the removal of approximately $33 million in costs related to DEC's NextGen GIS program for the portion placed in service in March 2026. Tr. vol. 16, 465. The Distribution Panel agreed with DEC's supporting documentation that moving away from its current GIS software,

GE Smallworld, is necessary due to the lack of support, new features, and inability to integrate with newer technology; but based on the history of delays, cost increases, and missed milestones for the NextGen GIS project, the Public Staff claimed that it is entirely foreseeable that a significant issue or internal resource constraint could become apparent before this project is completed, which could push back the cutover date due to DEC's acknowledged lack of schedule contingency or any contingency plan related to user acceptance testing and cutover. The Public Staff disagreed with Duke's position that the project was partially placed in service and that it is used and useful. *Id*. at 462, 465-66.

In his rebuttal testimony, DEC witness Teckenbrock addresses the Distribution Panel's contention that the $33 million portion placed in service on March 31, 2026, is not used and useful because the project is not yet fully in service for DEC's customer or employees and will not be fully operational until June 2027. Tr. vol. 17, 387. Witness Teckenbrock testified that the Distribution Panel's position does not reflect how a large, enterprise-wide system like NextGen GIS is built and brought into operation. *Id*. He explained that for a complex program like NextGen GIS, which replaces a core GIS platform and interfaces with numerous operational and planning systems, implementation is necessarily staged. *Id*. at 387-88. He testified that foundational elements of the technical solution are complete and are actively used for configuration, testing, data validation, and other essential steps to deliver the final system. *Id.* at 388.

In his rebuttal testimony, DEC witness Speros addressed the Distribution Panel's recommendation from an accounting and ratemaking perspective. Tr. vol. 11, 481. He testified that under Duke Energy's capitalization policy and consistent with the FERC USOA which expressly permits discrete, complete portions of a larger project to be placed in service once they are ready for use, even while other phases remain underway, the $33 million of NextGen GIS that was placed in service prior to the capital cut-off was appropriate and should remain in rate base. *Id*. at 481, 487. Witness Speros explained that the NextGen GIS project is being implemented using the Agile methodology project management approach, which means the project is being developed, tested, and deployed in discrete increments that deliver usable functionality at different points in time, rather than only through a single event at the end of the entire program. *Id*. at 488. He explained that this implementation approach is consistent with the accounting principle recognized in 18 C.F.R. Part 101 that only part of a plant or project may be placed in operation or be ready for service before the overall construction effort is complete, and the completed portion is then treated as plant-in-service while the incomplete portion remains in construction. *Id*. Witness Speros testified that same principle applies to the NextGen GIS project where portions of the functionality were deployed and available for use in supporting Duke Energy's operations as of March 31, 2026, and it was therefore appropriate under Duke Energy's Capitalization Policy to close those portions to plant even though additional phases, integrations, or enhancements remained underway. *Id*. In her rebuttal testimony, DEC witness Jiggetts testified that if the Commission believes recovery should be deferred until the entire project is placed in service in 2027, DEC respectfully requests an accounting order that allows it to establish a regulatory asset to defer the depreciation expense it will incur on the $33 million in projects costs and property taxes, as applicable, and a return on this investment, for full recovery in a future rate proceeding. Tr. vol. 21, 451.

Section II, ¶ 10 of the Comprehensive Settlement specified the Stipulating Parties agree to remove the NextGen GIS project from the base case and the MYRP in this proceeding. Comp. Settl. § II.10. The Stipulating Parties further agree that DEC may seek recovery of the undepreciated amount in a future rate case, subject to Public Staff's review for reasonableness and prudence and that there will be no regulatory asset/liability treatment for NextGen GIS project costs incurred before rates become effective in the next rate case. *Id.* § II.10.a.-b.

Longtown Microgrid and Nebo Microgrid

DEC witness Tompson addressed the Longtown and Nebo Microgrid projects approved as part of the MYRP1 Battery Energy Storage project portfolio. Tr. vol. 11, 184-85. The Nebo and Longtown 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 187-88, 233-35. Witness Tompson explained that costs for both Longtown and Nebo were higher than expected due to unanticipated tariff cost premiums and increases in engineering, procurement, and construction contract costs. *Id.* at 185. Tompson Direct Exhibit 1 presented the expected in-service dates as March 2026 for Longtown and May 2026 for Nebo.

The Renewables Panel recommended removal of the Nebo and Longtown microgrid projects from the base case. The Renewables Panel explained that microgrids differ from standalone BESS in that they can isolate, or "island," from the rest of the grid in the event of an outage or emergency but can also be dispatched as a generating resource in grid-parallel mode. Tr. vol. 17, 249 n.4, 280 n.39. Both Longtown and Nebo have significantly limited discharge capabilities while in grid-parallel mode; additionally, islanding capability is not yet available for either project. *Id.* at 280-81. The Renewables Panel asserted that, because the production value of both resources is limited and neither has islanding capability, Longtown and Nebo are not in service and "will not truly be used and useful until islanding capability is available." *Id.* The Renewables Panel argued further that Nebo is imprudent because its costs exceed quantifiable project benefits, as demonstrated by the benefit cost ratio metric. *Id.* at 281-82.

In his rebuttal, witness Tompson testified that the Longtown and Nebo projects are in-service, connected to the grid, and providing grid support during peaks while islanding commissioning is completed. Tr. vol. 22, 202-04. DEC placed the two projects in service by the March 31, 2026, capital cutoff period. Tompson testified that "neither the Sub 1276 Order, nor the settlement agreement that preceded it, imposed any specific cost-benefit analysis value requirements or cost restrictions on DEC's microgrid projects." *Id.* at 206. During the evidentiary hearing, witness Tompson confirmed that "both the Longtown and Nebo projects were dispatching to meet system peaks throughout the last few days" — the hot weather period in early July 2026 — and stated this was "evidence that we are deriving benefit from the distribution-connected batteries." Tr. vol. 11, 232-35.

In the Partial Stipulation, the Stipulating Parties agree that DEC shall recover 100% of the Longtown Microgrid project cost and 50% of the Nebo Microgrid project cost. Partial Stip. § III.5.

Land Purchases

Public Staff witness Lawrence testified that out of the 34 projects he reviewed related to land acquisitions, 17 were booked incorrectly, by being placed in accounts for land acquired for immediate development (FERC Account 101) or land acquisitions where construction has begun (FERC Account 106), rather than FERC Account 105 as Plant Held for Future Use. Account 105 does not receive a rate of return and is not included in rate base. Tr. vol. 16, 503-04. As a result, he recommended that certain projects be reclassified to FERC Account 105 and thus removed from rate base. In addition, witness Lawrence testified that within the 17 projects that were booked incorrectly, he identified purchases where DEC did not appropriately remove from rate base the portion of land not necessary for providing electric service, for example land purchased for the potential right-of-way needed for an expansion of the Bad Creek Pumped Storage facility. *Id*. at 507. Witness Lawrence concluded that he did not have confidence that ratepayers are currently paying only for the land necessary for electric service. *Id*. at 508. Accordingly, he recommended that DEC complete an audit of the remaining land it has included as capital plant in service in rate base and return inappropriately collected amounts to ratepayers in the next rate case. *Id.* at 508-09.

In his rebuttal testimony, DEC witness Speros indicated that he disagreed with witness Lawrence's proposed reclassification of various parcels from FERC Account 101 (Electric Plant-in-Service) to FERC Account 105 (Electric Plant Held for Future Use). He stated that, under Duke Energy's capitalization policy, land and rights-of-way are recorded as plant-in-service when acquired for immediate development with active engineering, site planning, or construction commenced or expected within 12 months. Witness Speros contended that each challenged property is tied to an identified transmission, distribution, or hydro project with construction completed, underway, or scheduled in the near-term, and the project-specific facts provided by witnesses Fogg and Walsh support their current classifications. Witness Speros also disagreed that there is a systematic issue warranting an audit or potential refunds. Tr. vol. 11, 490-93.

In his rebuttal testimony, DEC witness Walsh explained that DEC identified an opportunity to acquire property near Bad Creek Station to not only provide land for a potential second transmission line to support future expansion of the Station but also to support existing infrastructure. Witness Walsh specified that the land purchase was an essential piece of the stakeholder settlement reached by Duke and other parties supporting the relicense application pending at FERC, for Bad Creek as an entire project. Witness Walsh also explained that the land purchase at Thorpe Hydro Station was made to protect the safety and integrity of established station assets. Tr. vol. 22, 316-17.

In the Partial Stipulation, DEC agreed to accept the Public Staff's corrected adjustment removing the identified land purchases from rate base, and the Public Staff agreed to forgo its request for an external audit of land in rate base. Partial Stip. § III.3.

Miscellaneous Capital Charges

Public Staff witness Metz testified that in his review of capital project samples, the Public Staff identified multiple line-item charges as part of a sample of overall projects

that are unnecessary for the provision of electric service. Tr. vol. 17, 214. Witness Metz listed as examples over $50,000 in items including apparel and miscellaneous gifts, booked as service awards or recognition awards. *Id.* He contended that ratepayers should not bear the costs of these awards, and while acknowledging that it is not practical to review the entire capital spend placed in service in the case, he proposed an adjustment to remove $2 million on a system basis to represent a fair and reasonable estimate of an amount by which to reduce capital spend to account for these expenditures. He recommended that the amount be divided between plant type. *Id.* at 215. He also recommended that DEC management review training and internal practices to ensure these charges are approved and booked correctly. *Id.* He concluded that while booking such charges to capital comports with Duke's capitalization guidelines and may meet GAAP criteria, that does not make it appropriate to recover such charges from ratepayers in every instance. *Id.* at 214-217.

In their rebuttal testimonies, DEC witnesses Walsh and Haaf addressed the Public Staff's recommendation from a generation perspective. Witnesses Walsh and Haaf responded that witness Metz's characterization of these awards does not fully reflect the nature and purpose of these expenditures. They testified that capital project teams consist of a large number of people working in concert (often around the clock during outages) executing complex, technically demanding work that is critical to maintaining safe and reliable operation of DEC's generation fleet. They noted that the awards and recognition are a way to thank employees for the important and complex work performed, represent a small portion of the overall capital projects, and are provided consistent with DEC's policies and procedures; they also noted that witness Metz did not identify any errors in DEC's treatment of these costs or raise a concern with any specific charge. Tr. vol. 22, 169-70, 318-19.

From a T&D perspective, DEC witnesses Fogg and Guyton testified that they did not agree with Public Staff witness Metz's recommendation to remove items such as service awards and recognition costs because they are appropriate costs necessary to attract and retain employees to provide reliable, safe, electric service and are appropriately included in rates. Tr. vol. 22, 86, 150. Witnesses Fogg and Guyton explained that capital charges incurred for DEC's distribution and transmission system include all costs associated with executing the project that depending on the project, include materials and equipment purchases, DEC and contract labor, and project expenses. *Id.* at 87, 150. They explained that some examples of project expenses related to travel, lodging and meals related to visits to an equipment manufacturer's facility to provide oversight and witness factory acceptance testing, and purchase of awards and recognition items provided to project team members in recognition of project achievements (i.e., large multiyear enterprise system projects or completion of project implementation work ahead of schedule). *Id.* They explained that these awards are a modest way of thanking employees for the important and complex work performed that is critical to maintaining safe and reliable operation of DEC's distribution system, represent a small portion of the overall capital project costs, and are provided in accordance with DEC's policies and procedures. *Id.* at 88, 151.

In the Partial Stipulation, DEC agreed to the Public Staff's adjustment to remove $2.0 million on a system basis for miscellaneous capital charges as identified in the direct testimony of Public Staff witness Metz. Partial Stip. § III.6.

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 T&D investments made during the test period, as adjusted by the Partial Stipulation and Comprehensive Settlement, should be recovered. The Commission also concludes that DEC's Longtown Microgrid should appropriately be included in the base period as set forth in the Partial Stipulation. The Commission further concludes that the adjustments for land purchases, miscellaneous capital charges, and the Nebo Microgrid project, as the Public Staff and DEC agreed in the Partial Stipulation, are reasonable. Finally, the Commission concludes that accepting the Public Staff's adjustment related to the Buck Pipeline Lease and granting DEC's alternative request for an accounting order as set forth in the Partial Stipulation is a reasonable resolution of this issue. The Commission further concludes that the Partial Stipulation's and Comprehensive Settlement's resolutions of the Gaston Drone Project, the Anderson CC CWIP (subject to the condition in Partial Stipulation § III.29), the McGuire Nuclear Spare Exciter, the additional nuclear historical period capital items, the nuclear M&S inventory, the BESS Performance Monitoring Tool, Substation Optimization, the Ashe Street Substation, substations ready for use, the Washington Solar and Hornet Solar interconnection facilities, and NextGen GIS are reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

Base Period Accounting Adjustments

The evidence supporting this finding of fact is contained in DEC's verified PBR Application and Form E-1; the testimony and exhibits of DEC witnesses Abernathy, Bateman, Guyton, Jiggetts, Haaf, Caldwell, Wathen, Speros, and Walsh; the testimony and exhibits of Public Staff witnesses Metz and Thomas; the joint testimony and exhibits of the Public Staff Accounting Panel, the Public Staff Distribution Panel, the Public Staff Renewables Panel, and the Public Staff's Policy Panel; the testimony and exhibits of AGO witness Burgess; the settlement testimony and exhibits of DEC witnesses Bateman and Jiggetts and the joint settlement testimony of the Public Staff; the Partial Stipulation and Comprehensive Settlement; and the entire record in this proceeding.

Summary of Evidence

Payroll and Benefits Operations and Maintenance

The Public Staff's Accounting Panel (Accounting Panel) proposed an adjustment to DEC, DEP, and DEBS payroll costs of 1.90%, 1.17%, and 2.06%, respectively, and testified that it was based on experience from past decisions where DEC reduced staffing following a rate case proceeding. Tr. vol. 17, 324. The Accounting Panel testified that, in its view, significant workforce reductions immediately following a rate case

proceeding overstates actual payroll and benefits expenses when the reduced staffing expenses are not reflected in the rate case. *Id.*

DEC witness Caldwell rebutted the Accounting Panel's contention and testified that DEC continuously reviews its operations for improvement opportunities to address evolving business needs to better serve its customers, which result in workforce adjustments. Tr. vol. 22, 260. Witness Caldwell also noted that the Accounting Panel's workforce reduction figure was inaccurate as it included employees who were severed during February through April 2024 and did not account for new hires during this same time frame. *Id.* at 261.

In the Partial Stipulation, DEC and the Public Staff agreed no adjustments will be made to Payroll and Benefits O&M, and DEC confirmed that it has no plan, at this time, for a workforce reduction subsequent to this rate case. Partial Stip. § III.14.

Incentive Compensation

In DEC witness Caldwell's direct testimony, she testified that DEC included in its cost of service incentive compensation at target levels that are assigned or allocated to DEC. Tr. vol. 11, 315. The Public Staff Accounting Panel testified that incentive compensation in DEC's Short-Term Incentive Plan (STIP) and the Long-Term Incentive Plan (LTIP) related to Earnings Per Share (EPS) and Total Shareholder Return (TSR) metrics should be excluded because they benefit shareholders and not customers. Tr. vol. 17, 329-31. In rebuttal, DEC witness Caldwell disagreed with this assertion, explaining that metrics such as EPS and TSR are appropriate for recovery as they benefit customers and are a prudently incurred cost of providing electric service. Tr. vol. 22, 250-52. DEC witness Caldwell also argued that whether compensation is delivered entirely through base pay or through a combination of base pay and incentives, the total cost to customers is the same. The incentive-based approach (including metrics tied to financial performance) motivates employees to perform efficiently and effectively and helps attract and retain a skilled workforce, all while maintaining overall compensation levels at prudent, market-competitive levels. *Id.* at 253.

In the Comprehensive Settlement, DEC agreed to exclude from test year expenses 100% of the compensation pay associated with the EPS and TSR metrics included in the STIP and the LTIP for employees that participate in the LTIP. Comp. Settl. § II.8.

Executive Compensation

In DEC's PBR Application, it removed 50% of the compensation of the top five Duke Energy executives with the highest levels of compensation allocated to DEC in the test year. DEC witness Caldwell explained in her direct testimony 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. 11, 315.

The Public Staff Accounting Panel recommended an adjustment to remove an additional 25% based on its review of the Guidelines. Tr. vol. 17, 325-26. The Accounting Panel asserted that based on the Guidelines, management's "charge" is primarily to benefit shareholders. *Id.* at 327.

In witness Caldwell's rebuttal testimony, she explained that DEC has an obligation to both its shareholders and customers to make fiscally responsible decisions, and that the financial performance of DEC is essential to customers receiving reliable and safe electric service efficiently and at a reasonable price. Tr. vol. 22, 256. Witness Caldwell testified that the Guidelines are not a management philosophy document, and they along with the 2026 Duke Energy Proxy Statement make clear that Duke Energy's leadership takes not just shareholders but also customers' interests into account. *Id.* at 256-57.

In the Partial Stipulation, DEC agreed to remove an additional 25% (for a total of 75%) of the executive compensation expenses allocated to DEC for the top five executives as proposed by the Public Staff. Partial Stip. § III.12.c.

Board of Directors Expenses

With respect to Board of Directors expenses, the Public Staff Accounting Panel recommended an adjustment to remove 50% of the expenses associated with the Board of Directors of Duke Energy that had been allocated to DEC. Tr. vol. 17, 329. In her rebuttal testimony, DEC witness Caldwell noted that DEC is required by law to have a Board of Directors and the costs of being an investor-owned utility, including those related to having a Board of Directors, are in fact costs of service. Tr. vol. 22, 262.

In the Partial Stipulation, DEC agreed to remove 50% of Board of Director expenses allocated to DEC as proposed by the Public Staff. Partial Stip. § III.12.b.

Ongoing Bad Debt Expense

DEC witness Jiggetts explained that DEC is reversing the bad debt expense that was deferred during the test year to account for the cessation of the bad debt expense deferral and to set the ongoing expense level. Tr. vol. 12, 258-59; *see also* tr. vol. 11, 496. To set an ongoing uncollectible expense in this case, DEC used the adjusted bad debt expense of the Test Year of 0.7292%. Tr. vol. 17, 348.

The Public Staff Accounting Panel testified that DEC should use the 2025 actual bad debt percentage of 0.4154% to set its ongoing level of uncollectible expense because it is more representative of the current North Carolina level of bad debt expense. *Id*. at 348-49. Applying this 2025 uncollectible rate would result in an estimated $20 million reduction to the revenue requirement as compared to using the 2024 uncollectible rate. *Id*. at 349.

In his rebuttal testimony, witness Speros explained that now that the bad debt deferral is coming to an end, DEC will recover an ongoing amount in rates based on the actual bad debt experienced during the test year, which in this case is 2024. He also testified that DEC's use of actual test year bad debt expense is consistent with how bad debt is appropriately recovered in the absence of a deferral. Tr. vol. 11, 496. He argued that the Public Staff has not demonstrated any imprudence or anomaly in 2024 figures that would justify departing from using the test year. *Id*. Witness Speros stated that while DEC believes the test year bad debt expense is representative of ongoing expense levels, if the Commission were to update it, the 2025 amount should be adjusted to exclude

reserve adjustment credits. *Id*. The normalized 2025 bad debt expense, excluding these non-recurring reserve adjustments would be $39 million North Carolina retail. *Id*.

In the Partial Stipulation, DEC and the Public Staff agreed to an ongoing bad debt expense amount of approximately $36.7 million (North Carolina retail) and an uncollectibles rate of 0.585%. Partial Stip. § III.1.

Multiyear- Rate Plan 1 Pro Forma

In her direct testimony, DEC witness Abernathy explained DEC's MYRP1 Pro Forma (NC3060 – MYRP Annualization) is an adjustment included in the traditional revenue requirement related to MYRP1 projects that were not yet in service by the March 31, 2026, capital cut-off but will be placed in service prior to the end of MYRP1. Tr. vol. 12, 184. This adjustment calculates the annual revenue requirement on those projects based on the projected net book value as of December 31, 2026. *Id*. Witness Abernathy noted that these projects were all approved as part of MYRP1, and a portion of their costs are included in MYRP1 Rate Year 3 rates; however, now that those projects will be in service, an annual revenue requirement must be included in the base rates effective January 1, 2027. *Id*. at 184-85.

With respect to the MYRP1 Pro Forma, the Public Staff Accounting Panel acknowledged that the net plant amount for these MYRP 1 Rate Year 3 projects should be calculated through December 31, 2026, and that annual depreciation expense should reflect this net plant amount. Tr. vol. 17, 319. However, they recommended two adjustments to this pro forma: (1) an adjustment to remove $0.319 million in net incremental O&M; and (2) an adjustment to reduce $65.476 million in plant and $1.134 million in accumulated depreciation related to projects that have been substituted with other projects, directly assigned to South Carolina, or included in the base case plant in service. *Id*. at 319-20.

AGO witness Burgess testified that the Commission should not allow the MYRP1 Pro Forma adjustment to be included in the base case revenue requirement and instead should require the projects included in NC3060 to be included in the MYRP2 Rate Year 1 increase in order to ensure that MYRPs enforce cost containment. Tr. vol. 19, 77.

In her rebuttal testimony, DEC witness Bateman addressed witness Burgess's objection to the MYRP1 Pro Forma and testified that he misses the alignment between revenue and costs. DEC included the annualized impact of the Rate Year 3 MYRP1 rates in the revenue annualization pro forma (NC1010). Witness Bateman testified that it is therefore appropriate to include both the costs of the MYRP1 Rate Year 3 projects in the same part of the case as the revenues designed to recover those costs. Otherwise, there would be a mismatch of costs and revenues in the base case. Tr. vol. 22, 426-28.

In her rebuttal testimony, witness Abernathy testified that DEC agreed to make the Public Staff's adjustment to O&M to address affordability concerns as set forth in the rebuttal testimony of DEC witness Bowman. Tr. vol. 21, 416-17. She noted that DEC agreed to make the second adjustment to plant because it is a correction that DEC previously identified and would be appropriate in any event. *Id*.

The Partial Stipulation memorializes DEC's agreement to the MYRP1 Pro Forma (NC3060) adjustments reflected in DEC's rebuttal, removing approximately $0.319 million (North Carolina retail) of net incremental O&M and reducing plant by approximately $65.476 million (North Carolina retail) and accumulated depreciation by approximately $1.067 million (North Carolina retail) for substituted, separately assigned, and base case projects. Partial Stip. § III.17.

Aside from the AGO, no other party opposed the MYRP1 Pro Forma in the base case revenue requirement; the Public Staff's concerns were resolved through the two adjustments reflected in the Partial Stipulation. The Commission agrees that the MYRP1 Pro Forma, as modified by the Partial Stipulation, is appropriate in this proceeding to reflect the annual revenue requirement relating to projects that were approved by the Commission as part of MYRP1 but go into service during the period between March 31, 2026, and December 31, 2026. The Commission finds witness Bateman's testimony persuasive regarding the importance of matching the annualized impact of rates for Rate Year 3 of MYRP1 included in the revenue annualization pro forma (NC1010) with the annualized impact of the Rate Year 3 MYRP1 projects included in the MYRP1 Pro Forma (NC3060). As such, the Commission declines to disallow this pro forma as recommended by AGO witness Burgess.

Aviation Expense

In its initial filing, DEC removed 50% of corporate-related aviation expenses allocated to DEC in the test period that were not related to aerial patrol. Tr. vol. 12, 249. DEC witness Jiggetts testified that DEC believes these costs were reasonable, prudent, and appropriate to recover from customers, but DEC elected to remove them in this case as it has in its last three rate cases. *Id*. at 249-50; tr. vol. 21, 460.

The Public Staff recommended removal of an additional 25% of corporate aviation expenses, on the basis that DEC purchased, rather than leased, new aircraft, and discretionary corporate travel has increased compared to the levels in DEC's last base rate case. Tr. vol. 17, 331-33.

In her rebuttal testimony, DEC witness Jiggetts noted that while depreciation expense increased as a result of the new aircraft purchases, that increase was partially offset by a reduction in lease expense. Tr. vol. 21, 460. Witness Jiggetts also explained that travel in 2021 (the test year in the last base rate case) was impacted by COVID-related travel restrictions. Therefore, she concluded that the increase between cases is more indicative of a return to normal travel and meeting patterns after the pandemic, not an increase in discretionary corporate travel. *Id*. at 460-61.

In the Partial Stipulation, the Public Staff agreed with removal of 50% of the aviation expenses as included in DEC's initial application in conjunction with DEC's agreement to: (1) remove an additional 25% (for a total of 75%) of the executive compensation expenses allocated to DEC for the top five executives; and (2) remove 50% of Board of Director expenses allocated to DEC as proposed by the Public Staff. Partial Stip. § III.12.a. Under the Partial Stipulation, these three terms are binding only if all three are accepted in their entirety. *Id.* § III.12. No intervenor opposed this provision of

the Partial Stipulation nor provided evidence on the issue of aviation expense. The Commission concludes that the Partial Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Regulatory Fee

In her direct testimony, DEC witness Jiggetts explained that rates currently charged to customers based on the Sub 1276 Order reflect the regulatory fee in effect during that proceeding of 0.1475%. Effective July 1, 2024, the regulatory fee changed to 0.17%. Tr. vol. 12, 258. At that time, DEC began recording a deferral associated with the incremental regulatory fees not in customer rates. *Id*. The deferral includes actuals plus projections through March 31, 2026. *Id*. at 258-59. The projected amounts were updated to actuals in DEC's second supplemental filing. *Id*. at 298. DEC's pro forma adjustment NC5030 amortizes the deferral balance, net of the over-amortization of regulatory fees related to Docket No. E-7, Sub 1146, over two years. *Id*. at 259; tr. vol. 17, 350. No party contested pro forma NC5030 or DEC's proposed recovery of the net deferred regulatory fees over a two-year period. The Commission concludes that pro forma NC5030 and the two-year amortization of the net deferred regulatory fees are just and reasonable and should be approved.

In the Partial Stipulation, DEC and the Public Staff agreed to adjust the regulatory fee in rates to 0.15%, consistent with the Commission's June 23, 2026, Order Decreasing Regulatory Fee Effective July 1, 2026, in Docket No. M-100, Sub 142. Partial Stip. § III.13.

Tax Rate Change

In her direct testimony, DEC witness Jiggetts explained that DEC has adjusted income tax expense to reflect the change in the North Carolina income tax rate from 2.5% to 2.0% that will be effective January 1, 2027. Tr. vol. 12, 261. In her second supplemental testimony, witness Jiggetts updated this adjustment to flow back to customers excess deferred income taxes associated with reductions in the North Carolina corporate tax rate from 2.5% to 2.25% in 2025 and from 2.25% to 2.0% in 2026. *Id*. at 299. DEC proposed to flow back to customers excess deferred income taxes of approximately $52.6 million over a two-year period, starting on January 1, 2027, concurrent with new rates effective in this case. *Id*. at 299-300. No party contested this adjustment or DEC's proposed flow back of North Carolina excess deferred income taxes over a two-year period.

Vegetation Management and Power Grid Operations Expenses

In its initial filing, DEC proposed an adjustment to O&M expenses in the Test Year to reflect an increase in the number of planned annual right-of-way miles trimmed. Tr. vol. 9, 202. DEC witness Guyton explained that historically, DEC targeted approximately 6,050 miles or approximately 11% of its total distribution miles on an annual basis, and DEC is proposing in this case to increase that target to approximately 15% of total distribution miles, aligning with its approach in DEP's service territory. *Id.* DEC also requested additional O&M funding related to wildfire mitigation activities, underground utility line locator services, and the operation of DEC's T&D vehicle fleet. *Id.* at 203.

No party challenged the request related to the distribution vehicle fleet, but the Public Staff proposed adjustments to DEC's request related to wildfire O&M and underground utility line locator services. Tr. vol. 16, 437. Specifically, the Public Staff Distribution Panel challenged the wildfire O&M request because it contends it is not known and measurable because DEC only began tracking its wildfire costs in 2025 and as such, no such costs are included in the 2024 Test Year. *Id.* at 438. In addition, the Public Staff Distribution Panel testified that data was still being gathered to further develop DEC's wildfire risk plan. *Id.* Therefore, the Public Staff recommended that the Commission disallow the requested distribution and transmission incremental O&M and first allow DEC to complete the current data collection effort, complete analysis of the data, and report on the actual risks and mitigations of those risks. *Id.* at 438-39. In regard to the underground locate service pro forma request, the Public Staff Distribution Panel testified that while DEC's vendor was the low bid winner in 2023, the vendor requested a modification to the contract in 2024, that DEC allowed an increase in the locate ticket rate, and DEC should not have allowed the underground-line-locate-services vendor to alter the contract after it was executed. *Id.* at 439. Therefore, the Public Staff Distribution Panel recommended a reduction to DEC's requested pro forma based on the five-year average compound annual growth rate for locate ticket costs. *Id.* Finally, regarding DEC's request to increase its vegetation management pro forma, the Public Staff Distribution Panel agreed with the proposed increase in the production budget when paired with the Public Staff's proposed Distribution Vegetation Management (DVM) PIM. *Id.* at 479.

In his rebuttal testimony, with respect to the wildfire O&M adjustment, DEC witness Guyton testified that he was concerned the Public Staff may be conflating the intent of the wildfire risk assessment with the wildfire mitigation activities that comprise the O&M adjustment. Tr. vol. 22, 80. He explained that the pro forma amounts are based on work orders for needed repairs identified from the operational testing of breakers in high and elevated wildfire risk zones and that the further details supporting the adjustment, including more than 5,000 identified orders and cost estimates associated with the types of work identified, were provided in discovery. *Id.* at 81. Concerning the locate services O&M adjustment, witness Guyton testified that DEC had no practical alternative to renegotiating the terms of the agreement because the vendor, USIC, was the only single provider large enough to handle the volume of locate services across DEC's service territory and a replacement vendor that could scale up that volume or coordination with multiple vendors could not be accomplished in 90 days. *Id.* at 83-84. Further, even after the contract renegotiation, witness Guyton testified that the agreed upon rates remained competitive with the current market. *Id.* at 84. Finally, with respect to the vegetation management O&M adjustment, witness Guyton noted that the Distribution Panel does not contest the adjustment so long as it is paired with the Public Staff's proposed DVM PIM, but testified that the DVM PIM is not appropriate, as further discussed by DEC witness Farmer in her rebuttal testimony. *Id.* at 85-86.

In the Partial Stipulation, DEC and the Public Staff agreed to remove approximately $7.2 million (North Carolina retail) of incremental wildfire spend and to allow DEC's remaining requested spend, subject to a regulatory liability for any underspend over the cumulative two-year MYRP period. Partial Stip. § III.2.

Solar Operations and Maintenance

The Public Staff Renewables Panel reviewed the solar O&M costs incurred in the test year as well as historic O&M spend. Spend in the test year was noticeably higher. Tr. vol. 17, 276. The Renewables Panel further elaborated that DEC had stated that the increase was a result of an increased number of solar sites, but the Public Staff was unaware of any utility-owned solar facilities that went into service in 2022-2024 in DEC territory. *Id.* The Public Staff recommended a $2,257,240 reduction in test year O&M costs to reflect a typical spend. *Id.* at 277.

In his rebuttal testimony, DEC witness Walsh disagreed with the Public Staff's recommendation, noting the proposed reduction relies on a backward-looking average that does not adequately reflect the operational circumstances, cost drivers, and accounting impacts present during the test year. Witness Walsh stated that test year spending should be evaluated based on whether the costs were reasonable, necessary, and appropriately incurred to support safe and reliable operations, and not reduced solely because they exceed historical averages. Tr. vol. 22, 314.

DEC witness Jiggetts added in her rebuttal testimony that in cost of service ratemaking, the objective is to set rates that reasonably reflect the utility's expected cost to provide service, not to adjust every minor variance in historical expense levels. Witness Jiggetts continued that ratemaking appropriately relies on historical actuals and known, measurable changes that are significant enough to influence the test year revenue requirement. Tr. vol. 21, 463-64.

In the Partial Stipulation, DEC agreed to accept the Public Staff's filed position to reduce solar O&M by approximately $1.5 million (North Carolina retail). Partial Stip. § III.16.

Hydro Operations and Maintenance

The Public Staff Renewables Panel recommended a reduction to test year O&M by $1.39 million to account for "extra" and emergent work, such as testing during outages, additional contract services and emergent maintenance, that led to "one off" increased O&M expenses at certain hydro facilities during the Test Year that are not expected to be ongoing. Tr. vol. 17, 283.

In his rebuttal testimony, DEC witness Walsh disagreed with the recommendation. Witness Walsh emphasized that DEC's conventional hydro fleet (as opposed to the 8 pumped storage units) includes 57 individual units with an average age of 93 years, including 35 units that are over 100 years old. He explained that the types of work identified by the Public Staff commonly arise with units that have been operating for such a long time. He noted that these units continue to provide cost-effective benefits for customers and considering the spread across 65 total hydro units, the $1.39 million adjustment amounts to approximately $21,000 per unit, which reflects reasonable and necessary maintenance spending to support the continued reliable operation of these valuable resources. He noted further that the prudent and well-executed work performed on these units is reflected in the hydro fleet's strong operating performance. Regarding the specific work identified by the Public Staff, witness Walsh responded that this was not extra or one-off work but rather

represented periodic maintenance, including emergent work, that is part of the normal course of day-to-day operations of the hydro fleet. Tr. vol. 22, 310-11.

DEC witness Jiggetts added in her rebuttal testimony that in cost of service ratemaking, the objective is to set rates that reasonably reflect the utility's expected cost to provide service, not to adjust every minor variance in historical expense levels. Witness Jiggetts continued that ratemaking appropriately relies on historical actuals and known, measurable changes that are significant enough to influence the test year revenue requirement. If an adjustment is made for a "non-recurring expense," consistency requires corresponding adjustments for any credits or expense offsets during the test year. Tr. vol. 21, 463-64.

In the Partial Stipulation, the Public Staff agreed to accept DEC's filed position to resolve the hydro O&M adjustment. Partial Stip. § III.16.

Coal Reliability Assurance Operations and Maintenance Adjustment

In his direct testimony, DEC witness Walsh supported DEC's requested adjustment to test year O&M expense of approximately $25.6 million, representing an average expected expense level for 2027-2028 compared to 2024 test year expense, to reflect the continued work needed to maintain reliability of DEC's aging coal units. Tr. vol. 11, 102. Witness Walsh elaborated that the proposed adjustment reflects maintenance needed to continue and expand the Coal Reliability Assurance (CRA) work addressed in PBR1. He explained that one of the primary challenges related to DEC's coal plants is determining the most prudent way to make plant investment decisions to maintain continued reliability and respond to growing demand while navigating uncertain plant retirement timelines. He added that the changing competitiveness of coal in DEC's resource stack impacts the commitment and dispatch of coal units that were designed and built to run as baseload resources but which are now required to be far more operationally flexible. He noted that the operating conditions for these aging plants increase the operational wear and tear on the units as they cycle on and off more frequently, which also increases their maintenance costs. *Id.* at 103. Witness Walsh noted that in the 2024 test year, DEC invested more than the $4.50 million (North Carolina retail) approved for CRA work in PBR1 to address coal reliability assurance needs at these units. He explained that this maintenance addressed the reliability assurance needs identified at that time and have contributed to these units' ability to continue reliable operations. Specifically, he cited DEC's ability to place equipment at Marshall Units 3 and 4 back in service to improve unit efficiency and continue to operate until their scheduled replacement in 2026. He added in another example that winterization work, including repairs to heat tracing on piping and to boiler and turbine room doors and windows to prevent air leakage, will ensure reliability during cold weather months. *Id.* at 104.

With respect to the adjustment requested in this case, witness Walsh stated that DEC uses historical performance data to analyze factors that most affect coal plant reliability and this analysis, in combination with original equipment manufacturer recommendations, accepted industry standards, and internal engineering assessments, is used to identify and prioritize projects with the greatest opportunity to maintain or improve operational reliability. Witness Walsh stated that based on this evaluation

DEC identified targeted maintenance needed for each unit. He continued that the majority of the identified CRA work involves reliability maintenance of major equipment including pumps, motors, large breakers, coal handling and boiler support systems, and emissions control equipment. He continued that the CRA work will also include continued winter readiness work such as heat tracing system updates, and the adjustment reflects costs associated with ensuring adequate operations staff remain available to continue to safely operate the plants. *Id.* at 105-06.

Public Staff witness Thomas discussed DEC's execution of CRA work approved in the 2023 Rate Case and coal unit performance since that case. Witness Thomas testified that DEC's request for increased CRA O&M is justified, with the caveat that the Public Staff is concerned about DEC's ability to execute the work to be covered by the increased CRA amount within the 2027-2028 time frame. He noted that it is reasonable to invest in capital projects and targeted increases to CRA O&M expenses to keep the coal units reliable and ensure they are able to provide capacity when called upon. Tr. vol. 13, 108-09. While witness Thomas concluded that O&M expenses in the Test Year appeared to be in line with historic levels, he recommended a reduction in each of Rate Year 1 and Rate Year 2 in the CRA O&M related to general managed accounts to reflect emergent work. Witness Thomas testified that DEC's existing internal process to handle emergent work should be sufficient to cover this work, and DEC did not justify the additional amount per year. He also argued that the adjustment did not reflect specific costs and was therefore not appropriate for a pro forma adjustment as it was not known and measurable. He also argued that DEC could use dollars associated with Allen Station O&M for this purpose. He recommended that DEC continue the annual CRA reporting agreed upon in the 2023 Rate Case stipulation. *Id.* at 110-11.

In his rebuttal testimony, witness Walsh emphasized that the Public Staff did not raise any concern with the CRA work DEC has previously executed or plans to complete in the future, or that the planned CRA work is not needed, prudent, or reasonable. Witness Walsh addressed the general managed account, explaining that based on DEC's recent experience with the remaining coal units and considering their age and cycling history, it is prudent and good practice to use the general managed account to address emergent work. He added that DEC had evolved its planning for this work and identified specific projects that the general emergent dollars would fund if triggered. He identified examples of such projects including service water tank maintenance at Marshall and purge pump maintenance at Cliffside. He stated that these types of projects represent the type of work that the CRA funding is intended to address. He explained that the stations monitor needed O&M work, which may not require the repair of a full unit of property and may not be scheduled for an outage, but is fit in when the opportunity arises. He noted that this approach exemplifies DEC's prudent and experienced day-to-day operation of these units. Regarding Allen O&M, witness Walsh stated that dollars DEC received during 2025 and 2026 are not available to use for CRA needs starting in 2027. Finally, he stated that DEC does not object to continued CRA reporting. Tr. vol. 22, 337-39.

In the Comprehensive Settlement, the Stipulating Parties agreed to increase DEC's O&M (net of the retired Allen O&M that was removed in DEC's second supplemental testimony) by $22.7 million (North Carolina retail) to support coal reliability work, and the Stipulating Parties also agreed that DEC will create a regulatory liability for

any under-spend over the cumulative two-year MYRP period. The Stipulating Parties agreed that DEC will not seek a similar coal reliability pro forma in the next general rate case, though no party is prevented from proposing or challenging an update to test year expense to a more current 12-month period of actuals, if available. Comp. Settl. § II.9. The Stipulating Parties agreed further to meet to discuss the design of the required CRA O&M reporting to determine whether it can be produced more efficiently. *Id.* § III.1.

Level 2 Charger Deferral

On November 24, 2020, in Docket Nos. E-7, Sub 1195 and E-2, Sub 1197, the Commission approved multiple electric transportation pilot programs (Phase 1 ET Pilots), including DEC and DEP's Public L2 Charging Pilot. Throughout the implementation of the Phase 1 ET Pilots, DEC and DEP successfully deployed L2 charging infrastructure at multiple locations across their North Carolina service territories, providing publicly accessible charging services to support the growing EV market and fulfill the pilot programs' objectives of facilitating EV adoption and gathering valuable operational data. The Phase 1 ET Pilots were scheduled to conclude November 24, 2025. On December 19, 2025, in Docket Nos. E-7, Sub 1195 and E-2, Sub 1197, DEC and DEP filed a motion requesting that the Commission authorize DEC to establish a regulatory asset for the remaining net book value of the L2 public charging infrastructure deployed under the Phase 1 ET Pilots, less any proceeds received from the sale of such assets, and to amortize such regulatory asset using the depreciation expense currently included in customer rates until the regulatory asset balance reaches zero. On March 12, 2026, DEC filed a motion to establish a new docket (E-7, Sub 1355) for its request for an accounting order and to consolidate that request with this rate case.

The Public Staff agrees with DEC's request to establish a regulatory asset to recover the remaining net book value of the L2 charging infrastructure. However, the Public Staff recommended that DEC remove test period O&M net of test period revenues associated with the charging infrastructure to reflect that DEC no longer has to maintain those assets. Tr. vol. 17, 371. In her rebuttal testimony, DEC witness Jiggetts indicated that DEC agrees with this recommendation and removed the test period O&M net of test period revenues associated with the charging infrastructure. Tr. vol. 21, 483-84. The Partial Stipulation memorializes DEC's agreement to accept the Public Staff's filed position, including removal of the test period O&M net of test period revenues associated with the L2 charging infrastructure. Partial Stip. § III.28.

The Commission finds good cause to grant DEC's motion to consolidate its request for an accounting order with this proceeding and hereby approves DEC's request to establish a regulatory asset to recover the remaining net book value of the L2 charging infrastructure. The Commission also concludes that the related removal of the test period O&M associated with those assets as set forth in the Partial Stipulation is just and reasonable. Further, the Commission finds good cause to close Docket No. E-7, Sub 1355.

Transmission Cost Allocation Adjustment

DEC witness Bateman testified that in the prior rate case proceedings, DEC and DEP entered into a Transmission Cost Allocation Agreement and Stipulation of Settlement

(TCA Stipulation). Tr. vol. 7, 34. In the TCA Stipulation, the Public Staff, DEC, and DEP agreed to a pro forma adjustment to increase the revenue requirement for DEC by approximately $20 million and to decrease the revenue requirement by the same amount for DEP (First TCA Adjustment). *Id.* The First TCA Adjustment was based on a pro forma amount of transmission expense for DEC and transmission revenue for DEP, calculated by multiplying the net transfers from DEP to DEC under the Joint Dispatch Agreement (JDA) by the DEP non-firm transmission rate in the FERC-approved Joint Open Access Transmission Tariff (OATT) of DEP, DEC, and Duke Energy Florida, LLC. *Id.* at 34-35. The First TCA Adjustment was designed to address the growing level of net transfers under the JDA from DEP to DEC and the resulting impact on the rate differences between the two utilities. *Id.* In PBR1, the Commission approved the TCA Stipulation and the corresponding First TCA Adjustment, which remains on appeal before the North Carolina Supreme Court. *Id.* at 35. Witness Bateman testified that DEC proposed to extend the TCA Stipulation to continue to address the rate differences between DEC and DEP. *Id.* DEC proposes to use the same methodology in the TCA Stipulation to calculate a pro forma adjustment based on net transfers from DEP to DEC under the JDA using an average of calendar years 2022 through 2024, and DEP is proposing a corresponding adjustment in Docket No. E-2, Sub 1380. *Id.* at 36. Witness Bateman testified that the updated pro forma adjustment amount is approximately $26 million and is included in the revenue requirement calculation in pro forma adjustment NC2080. *Id.*

Public Staff witness Metz testified that the Public Staff agreed the TCA Stipulation should be extended and agreed with DEC's application of a three-year average of net power flows. Tr. vol. 17, 213. However, witness Metz proposed an adjustment to add to the pro forma amount the incremental investments made in the transmission system for which DEP is currently seeking recovery in Docket No. E-2, Sub 1380, excluding MYRP2 Rate Year 1 and Rate Year 2 projects, which would result in an updated pro forma adjustment of $47.1 million on a system basis (Second TCA Adjustment). *Id.*

On rebuttal, DEC witness Bateman testified that DEC verified the figures in Witness Metz's testimony and agreed with Public Staff witness Metz's recommendation to increase DEC's pro forma adjustment to the TCA Adjustment to $47.1 million (system), a $7.1 million (system) increase over DEC's proposed $40 million, or $4,701,553 (North Carolina retail). DEC will work with Public Staff to memorialize an extension of the TCA Stipulation. Tr. vol. 22, 430-31.

In the Partial Stipulation, DEC and the Public Staff agreed to the Second TCA Adjustment, resulting in a pro forma adjustment that increases the revenue requirement for DEC in this proceeding and decreases the revenue requirement for DEP in the ongoing DEP rate case proceeding in Docket No. E-2, Sub 1380 by approximately $31.2 million on a North Carolina retail basis. Partial Stip. § III.18. The Stipulating Parties further agreed that the Second TCA Adjustment is for North Carolina retail ratemaking purposes only in Docket Nos. E-2, Sub 1380 and E-7, Sub 1329; shall not trigger any accounting entries or changes to the JDA, dispatch or dispatch costs, or the method for calculating OATT rates; shall not interfere with FERC rules and ratemaking or impact the jurisdiction of the Public Service Commission of South Carolina; shall become effective January 1, 2027, for both DEC and DEP; shall be added to the earnings test calculation

under the ESM for both DEC and DEP; and shall terminate at the effective date of rates in DEP's or DEC's next general rate case. *Id.* § III.19.

Rate Case Expense

DEC witness Jiggetts testified that DEC's pro forma adjustment NC5020 amortizes over a two-year period the incremental rate case costs incurred and projected to be incurred for this proceeding, as well as costs incurred associated with the ongoing appeals for the last rate case. Tr. vol. 12, 258. Over-amortizations associated with rate case expenses for Docket Nos. E-7, Sub 1214 and E-7, Sub 1276 were used to offset the amount requested in the instant case. *Id.*

The Public Staff Policy Panel recommended that the rate case expenses incurred by DEC in the instant proceeding be shared between shareholders and ratepayers on a 50/50 basis, applied after removing the specific rate case expenses recommended for disallowance by the Public Staff Accounting Panel. Tr. vol. 18, 67. The Public Staff Policy Panel also recommended that such 50% sharing should apply to the fees for consultants retained by the Public Staff. *Id.* The Public Staff Policy Panel testified that the primary rationale for the proposed adjustment is that rate case expense benefits shareholders as well as ratepayers, and cost sharing would directionally align rate case expense with the benefits gained by those who pay for it. *Id.* at 68. The Public Staff Policy Panel further testified that rate case spending is largely within DEC's control, and because the vast majority of rate case expense is paid by ratepayers, there is little incentive for DEC to control overspending or the inefficient use of outside counsel and consultants. *Id.* at 71.

The Public Staff Accounting Panel recommended removing the cost associated with Deloitte's audit fee for preparing workpapers for the Public Staff, testifying that the preparation of workpapers should be part of Deloitte's annual audit service and not invoiced separately and treated as a rate case expense. Tr. vol. 17, 342. The Public Staff Accounting Panel also recommended removing the appeal costs related to DEC's prior rate case, testifying that such costs are related to the prior rate case and should not be recovered in the current rate case proceeding. *Id.*

On rebuttal, DEC witness Bateman testified that North Carolina rate cases are intensively litigated regulatory proceedings, and the burden of proof on every issue rests with DEC. Tr. vol. 22, 415. Witness Bateman also testified that DEC controls when it files rate cases but does not control the required filing schedules, how many parties intervene, how many consultants parties retain, how many issues are raised, how much discovery is served, or how quickly responses are required. *Id.* at 421. As to the Public Staff Accounting Panel's recommendations to remove specific rate case expense costs, witness Bateman testified that costs associated with the prior rate case appeal were not discretionary and could not have been recovered earlier. *Id.* at 423-24.

In the Comprehensive Settlement, DEC agreed to remove rate case appeal costs for E-7, Sub 1276, as proposed by the Public Staff; remove rate case expenses associated with Deloitte's audit workpaper review fees; and make an additional one-time reduction of $2.0 million of its deferred balance related to outside legal fees. Comp. Settl. § II.14.a.-c. DEC also agreed that the deferred rate case expense balance will be

excluded from rate base with no return and no carrying costs, and rate case expense will be amortized over a three-year period. *Id*. § II.14.d.-e. Lastly, DEC agreed to update its projected balance with actuals through the filing of proposed orders in this docket, subject to Public Staff's review. *Id*. § II.14.f.

Discussion and Conclusions

In their respective settlement testimonies, DEC witnesses Bateman and Jiggetts explained that the Comprehensive Settlement, taken as a whole with the Partial Stipulation and Storm Cost Stipulation, reflects a fair, just, and reasonable resolution of the issues in this proceeding. Tr. vol. 22, 478; tr. vol. 21, 507. In the Public Staff's joint settlement testimony on the Partial Stipulation, witnesses Metz, Zhang, and Thomas testified that the Partial Stipulation provides an aggregate reduction in DEC's proposed revenue increase in this proceeding, and the Partial Stipulation is in the public interest and should be approved. Tr. vol. 13, 56-57. Likewise, in the Public Staff's joint comprehensive settlement testimony, Public Staff witnesses Metz, Zhang, Thomas, and Fahey testified that the Comprehensive Settlement provides important benefits, including a substantial aggregate reduction in DEC's proposed revenue increase in this proceeding, and the Comprehensive Settlement is in the public interest and should be approved. Tr. vol. 21, 150-51.

The Commission concludes that the accounting adjustments in the Partial Stipulation and the Comprehensive Settlement are supported by the evidence, are just and reasonable to all parties, and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 21-23

Federal Funding

The evidence supporting these findings of fact is contained in DEC's verified PBR Application and Form E-1; the testimony and exhibits of DEC witnesses Abernathy and Jiggetts; the testimony and exhibits of Public Staff witness Thomas; the Comprehensive Settlement; and the entire record in this proceeding.

Summary of Evidence

In her second supplemental direct testimony, witness Abernathy explained the accounting treatment for IIJA grants that was approved in DEC's last North Carolina rate case (Docket No. E-7, Sub 1276). At that time, DEC had applied for several grants under the IIJA but did not yet know the outcome of those grant applications. However, as part of the settlement with the Public Staff in that case, DEC agreed to incorporate assumed receipt of such IIJA grants net of costs incurred for purposes of establishing the base period and MYRP revenue requirement for such projects with deferral of any variance to the revenue requirement once actual IIJA funding amounts were known, including the impact should DEC not receive the funding. The Commission approved 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. Tr. vol. 12, 216; Sub 1276 Order at 248, 274 (Ordering ¶ 50).

Ultimately, DEC did not receive funding for any of the grants that were part of the settlement. As such, part of DEC's request in this case is recovery of the deferred revenue requirement impacts of the assumed grants, net of costs to pursue the grants. Tr. vol. 12, 217. The deferred balance is included in pro forma NC5060 and amortized over two years. *Id.* at 259.

No party contested this pro forma adjustment or DEC's proposed two-year amortization period. *See* Public Staff Accounting Panel Ex. 1, sched. 1. The Commission concludes that DEC's requested recovery of the deferred revenue requirements over a two-year period is just and reasonable and consistent with the Sub 1276 Order.

DEC witness Abernathy testified that, other than the deferral approved in the Sub 1276 Order, DEC has not included any assumed amounts related to future grant funds as an offset to the costs included for recovery in this case because future grant funding is not known and measurable. Tr. vol. 12, 217. She testified that certain MYRP2 projects are part of pending DOE grant applications and that an application related to capital projects at Belews Creek had been selected to move forward with grant negotiations, although the amount DEC would ultimately receive was not yet known. *Id.* With respect to grant funding going forward, DEC requests approval to continue to defer all incremental costs related to pursuing grant funding. *Id*. at 217-18. If DEC is successful in obtaining a grant, then the grant amount received, net of the associated incremental costs to achieve the grant, will be recorded as an offset to the capital project receiving the grant, which will ultimately reduce the rate base impacts of that project. *Id*. at 218. If the capital project receiving the grant was in service as of March 31, 2026, or is a MYRP2 project approved in this case, DEC will defer the depreciation and return amounts related to the net grant amount to a regulatory liability to return to customers in a future rate case. *Id*. Any incremental costs related to grants that are not ultimately received will remain in a regulatory asset account to be recovered in a future rate case. *Id*.

Public Staff witness Thomas testified that in February 2026 the DOE awarded DEC $34 million under its "Restoring Reliability: Coal Recommissioning and Modernization" grant program for DEC's Belews Creek Coal Reliability Assurance Initiative. Tr. vol. 13, 101. Applying a pro rata share of the grant to each project included in the grant application, witness Thomas calculated that approximately $25.8 million of the grant is associated with MYRP2 projects and recommended reducing those MYRP2 project costs by that amount. *Id.* at 101-02. Witness Thomas disagreed with DEC's proposal to defer the depreciation and return on the net grant amount to a regulatory liability, recommending instead that the assumed receipt of the grant be incorporated in the MYRP2 revenue requirement, similar to the treatment of certain IIJA grants in the Sub 1276 case, with DEC able to seek any shortfall in its next general rate case. *Id.* at 102-03.

In the Comprehensive Settlement, the Stipulating Parties agreed to remove from MYRP2 the costs for the portion of the Belews Creek projects expected to receive DOE funding, per witness Thomas's testimony, and agreed that if such funding is not received or is less than estimated, there will be no deferral, but DEC may seek recovery of the actual undepreciated value of the projects in future rate cases. Comp. Settl. § II.20.

Discussion and Conclusions

Other than the Belews Creek DOE grant, which the Comprehensive Settlement addresses, no party contested DEC's proposed accounting treatment for grants going forward. The Commission concludes that DEC's proposal to continue to defer incremental costs related to pursuing grant funding for recovery in a future rate case is just and reasonable. If DEC obtains a grant, DEC should record the grant amount received, net of the associated incremental costs to achieve the grant, as an offset to the capital project receiving the grant, and, if that project was in service as of March 31, 2026, or is a MYRP2 project approved in this case, DEC should also defer the depreciation and return amounts related to the net grant amount to a regulatory liability to return to customers in a future rate case. Any incremental costs related to grants that are not ultimately received will remain in a regulatory asset account to be recovered in a future rate case. This accounting ensures that customers receive the full benefit of any grants received and DEC can recover incremental costs incurred to actively pursue grant funding for the benefit of customers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 24

Coal Ash

The evidence supporting this finding of fact is contained in the Coal Combustion Residuals Settlement Agreement (CCR Settlement) approved by the Commission in DEC's 2019 Rate Case;[8] DEC's verified PBR Application and Form E-1; the testimony and exhibits of DEC witnesses Jiggetts and Hill; the testimony and exhibits of Public Staff witness Lucas; the Partial Stipulation; and the entire record in this proceeding.

Summary of Evidence

In its initial application, DEC requested to recover $566 million in actual and forecast system spend of CCR expenditures from July 1, 2023, through March 31, 2026. Tr. vol. 9, 102. 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. *Id.* at 102-03. Witness Hill testified that the actual and forecasted activities as well as costs incurred were reasonable and prudent. *Id.* at 103. Moreover, he 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 (DEQ), and in South Carolina, the Department of Environmental Services. *Id.* He testified that the CCR Settlement Agreement addresses the prudency of the DEQ-approved closure plan, and that closure activities have been performed in accordance with that approved plan. *Id.* at 110.

DEC witness Jiggetts presented DEC's request to amortize deferred costs associated with the CCRs and to continue deferring costs related to compliance with coal ash regulations. Tr. vol. 12, 255. Witness Jiggetts testified as to the key components of the CCR Settlement and the associated adjustments made in this case to comply with the

[8] Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice, *Application by Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina,* No. E-7, Sub 1214 (N.C.U.C. Mar. 31, 2021) (CCR Settlement).

CCR Settlement. *Id.* at 255-56. In her direct testimony, she explained that the CCR costs sought for recovery are based upon actual costs incurred from July 1, 2023, through June 30, 2025, and projected costs from July 1, 2025 through March 31, 2026. *Id.* at 256-57. Witness Jiggetts updated the projected amounts to actual amounts through December 31, 2025, in the supplemental filing made on February 12, 2026, and through March 31, 2026, in the second supplemental filing made on April 22, 2026. *Id.* at 282, 298. She testified that the cost, less the adjustments and as updated with actual amounts through March 31, 2026, totals approximately $566 million on a system basis and $377 million on a North Carolina retail basis. *Id.* at 257. Witness Jiggetts also testified that DEC proposes to offset the ending deferral balance by the over-amortization of tranche 2 of deferred environmental costs established in Docket No. E-7, Sub 1214 of $19.8 million. *Id.* She testified that DEC's initially proposed adjustment amortizes the net deferred balance over a five-year period, which results in an annual amortization of $83.4 million. *Id*. at 257. In the Partial Stipulation, DEC and the Public Staff agreed to extend the amortization period for the deferred CCR costs from five years to eight years. Partial Stip. § III.11; *see also* tr. vol. 12, 313.

Public Staff witness Lucas investigated and discussed DEC's management of CCRs and the operation of DEC's CCR beneficiation projects. Tr. vol. 17, 158-65. Witness Lucas concluded that DEC's CCR management and disposal practices, including beneficiation, since the last rate case, are reasonable and prudent. *Id.* at 165. No intervenor challenged the reasonableness and prudence of DEC's management of CCRs or the operation of DEC's CCR beneficiation projects.

Discussion and Conclusions

Based on the entire record in this proceeding, 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 in this case to reflect that settlement. The Commission approves DEC's proposal to offset the ending deferral balance by the over-amortization of tranche 2 of deferred environmental costs established in Docket No. E-7, Sub 1214, and the Commission approves the recovery of the net deferred balance over an eight-year period as well as the continued deferral of costs related to compliance with CCR regulations beyond March 31, 2026. Consistent with ¶ 22 of the Partial Stipulation and the Commission's conclusions regarding carrying costs set forth below, the return accrued during the deferral period shall be compounded annually.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 25-33

Storm Costs

The evidence supporting these findings of fact is contained in DEC's verified PBR Application and Form E-1; the testimony and exhibits of DEC witnesses Jiggetts and Culbreth; the joint testimony and exhibits of the Public Staff Accounting Panel and the joint settlement testimony of Public Staff witnesses Metz, Zhang, Thomas, and Fahey; the Storm Cost Stipulation; and the entire record in this proceeding.

Summary of Evidence

Storm Normal Expenses

In prior DEC rate cases, including Docket Nos. E-7, Sub 1026, E-7, Sub 1146, E-7, Sub 1214 and E-7, Sub 1276, the Commission approved a calculation of storm normal expenses for inclusion in rates, which is based upon a 10-year average of storm costs, after removing costs associated with major storms and adjusting for inflation. DEC witness Jiggetts explained the methodology for the calculation of storm normal in this case. Tr. vol. 12, 261. The resulting amount to include in rates per DEC's calculation is approximately $34.194 million. Jiggetts Direct Ex. 3 at 264; Jiggetts Partial Settl. Ex. 3 at 262. No party disputes DEC's methodology for calculating storm normal expenses to include in rates. Public Staff Accounting Panel Ex. 1, sched. 1 at l. 21; tr. vol. 17, 362. The Commission concludes that the appropriate North Carolina retail normalized annual level of storm costs to include in DEC's rates in this case is $34.194 million.

Two-Year Amortization of Regulatory Asset for Up-Front Financing Costs and Regulatory Liability for Servicing and Administration Fees

In DEC's 2020 Storm Securitization, DEC agreed to establish regulatory asset or regulatory liability accounts to track up-front financing costs and servicing and administration fees related to the first storm securitization proceeding. In DEC's 2024 Storm Securitization, DEC agreed to establish regulatory asset or regulatory liability accounts to track up-front financing costs and servicing and administration fees related to the second storm securitization proceeding. Amended Agreement and Stip. of Settl. §§ II.1-II.2, II.8, Docket Nos. E-7, Sub 1325 and E-2, Sub 1370 (Apr. 17, 2025); Financing Order, Docket No. E-7, Sub 1325, at 8 (Findings of Fact Nos. 14, 17) (N.C.U.C. Jun. 18, 2025). In this proceeding, DEC proposed to amortize over two years the resulting regulatory liability of approximately $152,000 for storm securitization overcollections of servicing and administration fees for the first securitization proceeding and the resulting regulatory asset of approximately $118,000 for under-recovered upfront financing costs associated with the second securitization proceeding, in each case net of the over-amortization of the prior tranche. Jiggetts Partial Settl. Ex. 3 at 270; tr. vol. 12, 262-63, 300-01. No party opposed this treatment or amortization period. The Commission concludes that the two-year amortization period is supported by the evidence, is just and reasonable, and should be approved.

Hurricane Helene, Winter Storm Fern, and Methodology for Calculating Incremental Operations and Maintenance Costs

In its initial filing, DEC projected a regulatory liability balance of $112.1 million to true-up Hurricane Helene storm costs, inclusive of returns on the overcollection from the securitization bond issuance date through the proposed rates effective date and proposed to amortize that balance over five years. Tr. vol. 12, 262-63. DEC witness Culbreth subsequently updated the Hurricane Helene true-up figures in her supplemental direct testimony to reflect finalized actual costs in the amount of $351.3 million and addressed Winter Storm Fern, which resulted in estimated storm costs of approximately $133.8 million. Tr. vol. 11, 266, 269. In her second supplemental direct testimony, witness

Jiggetts testified that DEC's incremental O&M storm costs for Winter Storm Fern were approximately $99.9 million on a North Carolina retail basis and requested an accounting order to defer those costs, and any additional 2026 incremental storm costs exceeding the annual storm deductible, with returns, for recovery over five years. Tr. vol. 12, 301-02. DEC's settlement exhibits reflect Winter Storm Fern costs of $99.910 million with no returns. Jiggetts Partial Settl. Ex. 3 at 275.

DEC witness Culbreth testified that DEC's approach for calculating incremental O&M and capital costs for Hurricane Helene and future storms adopts the "Florida Rule," which compares O&M costs in the month of a storm to the average O&M costs for the same month in three prior years, with any excess deemed incremental to the storm. Tr. vol. 11, 261-62.

The Public Staff Accounting Panel testified that it did not support the use of the Florida Rule in this proceeding and argued that DEC had not fully demonstrated that the Florida Rule is more accurate than the existing method, recommending that the methodology issue be left open until DEC's next general rate case. Tr. vol. 17, 363-64.

In addition, the Public Staff Accounting Panel testified that the amortization of the overcollection of Hurricane Helene costs should be spread over the remaining 225 months (18.75 years) of the recovery period for the storm securitization bonds *Id.* at 336-37. The Public Staff Accounting Panel also did not support recovery of estimated Winter Storm Fern costs at this time and recommended that DEC seek a deferral of the actual cost of Winter Storm Fern to be considered in or before DEC's next general rate case. *Id*. at 338. If estimated costs were approved for recovery, the Public Staff Accounting Panel stated that recovery or amortization should start the month after the storm over a ten-year period. *Id*. at 339. The Public Staff also opposed DEC's request to defer any additional 2026 storm costs, contending that deferral accounting should be reserved for actual extraordinary events. *Id*.

In rebuttal, witness Culbreth testified that the prior methodology omits a category of incremental costs, and the Florida Rule had already been subject to audit and investigation by the Public Staff in the Prudency Review Proceeding. Tr. vol. 11, 283. Witness Jiggetts likewise testified that the Florida Rule, rather than the Public Staff's traditional method, should be used for the Hurricane Helene true-up. Tr. vol. 21, 471. In her rebuttal testimony, witness Jiggetts disagreed with the proposed 18.75-year amortization period proposed by the Public Staff Accounting Panel and explained how the amortization period for the overcollection of Hurricane Helene costs was reduced from five years to two years in the interest of customer affordability. *Id*. at 471-72. Witness Jiggetts also testified that, while DEC disagreed with the Public Staff's position on Winter Storm Fern cost recovery, DEC would pursue securitization of Winter Storm Fern costs in the interest of customer affordability as well, removing those costs from this proceeding and reducing the revenue requirement by $27.8 million. *Id*. at 474.

DEC and the Public Staff also disagreed on the appropriate carrying cost methodology for the Hurricane Helene true-up. DEC proposed a monthly undiscounted after-tax WACC, while the Public Staff recommended a monthly discounted after-tax WACC. Tr. vol. 17, 336-37. When the Public Staff applied its recommended methodology

together with the traditional cost calculation method, extended amortization period for the over-recovery of Helene costs, and removed Winter Storm Fern costs, the Public Staff calculated an annual Hurricane Helene refund of $8.641 million over the remaining 18.75 years of the securitization bond. By contrast DEC's proposed annual refund was $30.8 million based on the Florida Rule, an undiscounted after-tax WACC, and a five-year amortization period. Tr. vol. 21, 470-71. On rebuttal, DEC changed its recommended amortization period from five years to two years to mitigate customer rate impacts as discussed in the testimony of DEC witness Bowman. *Id.* at 472. The carrying cost dispute was subsequently resolved in the Partial Stipulation, in which DEC and the Public Staff agreed to annual compounding of returns during the deferral period for the Hurricane Helene post-securitization deferral, which may be achieved either by applying monthly compounding at a discounted rate or by applying annual compounding at the annual rate. Partial Stip. § III.22; tr. vol. 12, 314.

In the Storm Cost Stipulation, the Stipulating Parties agreed that the Hurricane Helene over-securitization amount would be the amount reflected in DEC's filing in this case ($141.557 million overcollection plus $12.639 million return on the overcollection, calculated using DEC's proposed incremental O&M calculation), for purposes of this case only. Storm Cost Stip. § II.4. DEC also agreed to include estimated Winter Storm Fern incremental storm costs of $99.910 million in the revenue requirement, subject to audit by the Public Staff and a final true-up based on actual reasonable and prudent costs determined under the traditional method in DEC's next general rate case and without any carrying costs. *Id.* §§ II.2-II.3. The Stipulating Parties further agreed to net the Hurricane Helene over-securitization amount against the Winter Storm Fern incremental storm costs, resulting in a $54.287 million credit to customers (differences due to rounding), to be amortized over 18.75 years with the unamortized balance included in rate base. Storm Cost Stip. §§ II.1, II.5; *see also* tr. vol. 13, 61-62.

The Stipulating Parties also agreed that DEC will use the traditional method for calculating incremental storm operations and maintenance costs on a going-forward basis for 2026 through DEC's next general rate case. Storm Cost Stip. § III.1.

Storm Reserve

In DEC and DEP's most recent storm securitization proceedings, Docket Nos. E-7, Sub 1321 and 1325 and E-2, Sub 1362 and 1370, DEC agreed to evaluate the potential for establishing storm reserves to serve as an alternative or complementary recovery tool. In its initial application, DEC proposed to establish and fund a storm reserve that, as described by DEC witness Jiggetts, would function like a savings account whereby a portion of the revenues collected from customers would be set aside each year to build a dedicated fund that could be used when a qualifying storm occurs. Tr. vol. 12, 268. DEC proposed to collect $20 million per year to be recorded to a regulatory liability for the benefit of customers. *Id*. at 269. As DEC incurs future incremental storm costs, they would be recorded as an offset to the accumulated reserve once storm costs exceed the normal range of fluctuation. *Id*. at 269-70.

The Public Staff testified that it did not support creation of a storm reserve in this proceeding because customers are already struggling to pay their electric bills, and this

is not an ideal time to ask them to pay more in advance of potential future storms. Tr. vol. 17, 362. In her rebuttal testimony, witness Jiggetts acknowledged the Public Staff's concern about current customer bill pressures but indicated that a modest reserve can help avoid more significant volatility and higher customer impacts later if major storm costs are incurred. Tr. vol. 21, 476.

In the Storm Cost Stipulation, DEC agreed to withdraw its request to establish a storm reserve in this proceeding. Storm Cost Stip. § II.6.

Discussion and Conclusion

No party opposed the Storm Cost Stipulation and under Section II, ¶ 30 of the Comprehensive Settlement, the Stipulating Parties to the Comprehensive Settlement that were not parties to the Storm Cost Stipulation agreed to its terms. Tr. vol. 21, 149-50. Based on the entire record, the Commission concludes that the Storm Cost Stipulation's resolution of storm cost recovery is just and reasonable and should be approved. The Commission notes that the Storm Cost Stipulation resolves DEC's request to defer Winter Storm Fern costs by including the estimated $99.910 million in the revenue requirement, without carrying costs and subject to audit and true-up in DEC's next general rate case, and nets that amount against the Hurricane Helene over-securitization amount.

Neither the Storm Cost Stipulation nor the Comprehensive Settlement addresses DEC's request for authority to defer incremental costs of storms occurring in 2026 after Winter Storm Fern. *See* tr. vol. 12, 301-02; tr. vol. 21, 475-76. Consistent with the Public Staff's recommendation, the Commission declines to grant deferral authority for storms that have not yet occurred, without prejudice to DEC's ability to request deferral accounting treatment for a specific storm after it occurs. *See* tr. vol. 17, 339-40.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 34

Multiyear Rate Plan 2 Capital Investments

The evidence supporting this finding of fact is contained in DEC's verified PBR Application and Form E-1; the testimony and exhibits of DEC witnesses Abernathy, Bateman, Jiggetts, Fogg, Guyton, Haaf, Holeman, LaRoche, Tompson, Teckenbrock, Walsh; the testimony and exhibits of Public Staff witnesses Lawrence and Thomas; the joint testimony of Public Staff's Distribution Panel; the joint testimony and exhibits of the Public Staff's Renewables Panel, the Partial Stipulation and Comprehensive Settlement; and the entire record in this proceeding.

Summary of Evidence

In its PBR Application, DEC identified and provided detailed project documentation regarding capital spending projects projected to be placed in service during the MYRP period. These projects consist of T&D projects and investments, GP&I, solar and battery storage, and fossil, hydro, and nuclear investments.

Transmission

DEC witness Fogg testified in support of the MYRP2 transmission projects. He explained that the proposed MYRP2 transmission portfolio consists of discrete and identifiable projects designed to maintain and enhance reliability, address aging infrastructure, support customer load growth, prepare the system for interconnecting additional distributed energy resources (DERs), and improve system resiliency from severe weather events. Tr. vol. 9, 157, 160. He testified that the transmission projects included as part of MYRP2 and presented at the Technical Conference on March 9, 2026, were selected to address these needs. *Id.* Witness Fogg explained that targeted reliability improvements are logically selected and grouped within the MYRP2 transmission projects based on the areas that provide the greatest value to customers. *Id*. at 162. During the hearing, in response to questions from Commissioner McKissick, witness Fogg explained that to identify MYRP2 projects, there are sponsors in two categories that identify need for the projects. Tr. vol. 10, 72. He explained that transmission planning sponsors look at the needs of the system, NERC requirements, and necessary investments for growth to serve customers, while asset management sponsors look at need based on the condition of the assets. *Id.* at 72-73. For example, he explained that breakers and transformers are degrading and DEC needs to invest in those replacements. *Id.* at 73. He explained that as transmission goes through the project development process, DEC determines the scope, schedule and cost of identified projects, and if those projects are discrete and identifiable and fit within the rate year timeframe, then they are candidates for MYRP inclusion and CBAs are conducted to assist with project prioritization. *Id*.

Specifically, witness Fogg testified that the transmission MYRP2 portfolio includes investments in the following seven projects:

1. The System Intelligence project consists of the installation of Remote Line Switches, Protective Relays (Breaker, Bus, Transformer & Line Relays), Digital Fault Recorders, Remote Terminal Units, supervisory control and data acquisition equipment, and Communication Devices and Condition Based Monitoring Devices for transformers. These investments are designed to improve grid awareness by modernizing transmission system communication capabilities to increase operator and engineer visibility of system conditions. Tr. vol. 9, 157.

2. The Substation Hardening & Resiliency (H&R) project aims to create a stronger and more resilient transmission grid capable of withstanding or quickly recovering from extreme external events such as storms and from internal events such as a mis-operation caused by aging equipment. The Substation H&R project scope includes animal mitigation, substation reliability upgrades and air-break switch replacements. *Id.* at 157-58.

3. The Transmission Line H&R project aims to create a stronger and more resilient transmission grid capable of withstanding or quickly recovering from extreme external events. The Transmission Line H&R scope includes Cathodic Protection to protect and harden transmission towers from corrosion and degradation. This project scope also includes rebuilding aged

and end of life transmission lines segments as well as replacing targeted wood transmission poles with stronger steel poles. *Id.* at 158.

4. The Breaker Replacement project aims to strategically replace degraded and outdated oil circuit breakers with circuit breakers that utilize modern gas and vacuum technologies. It aims to increase system resiliency through rapid outage recovery and reduce the environmental footprint. *Id.*

5. The Transformer Replacement project anticipates future transformer failures and replaces those transformers in a proactive manner, aiming to reduce customer outages and environmental risks associated with unexpected failures. *Id.*

6. The Transmission Capacity and Customer Planning project includes upgrading equipment such as line conductors, transformers, breakers, and switches to a higher capacity. Capacitors are added in locations of declining voltage. Protective relay systems are upgraded to add redundancy to help reduce the likelihood and severity of critical equipment outages. These investments are targeted at meeting customer compliance obligations as demand grows and DERs are added to the system. *Id.* at 158-59.

7. The Transmission Integrated Vegetation Management (IVM) Danger Tree project focuses on ensuring the reliable operation of the transmission system by minimizing vegetation-related interruptions and maintaining adequate conductor-to-vegetation clearances while maintaining compliance with regulatory, environmental, and safety requirements and standards. The specific component of the IVM in MYRP2 is danger tree removal. Trees along the right-of-way are targeted based on threat assessment and removed prior to causing an impact on the transmission system. *Id.* at 159.

Witness Fogg's testimony and exhibits included a list of the projects; the projected costs per project per rate year; timing of each project including projected in-service month and year; projected impacts to operating expenses for each of the MYRP2 transmission projects, locations for the projects, additional details about the projects and cost benefit analyses. *Id.* at 160-61. He also testified that in addition to the information presented in his direct testimony and exhibits, DEC also provided detailed project information along with supporting workpapers as required by Commission Rule R1-17B, including subsection (d)(2)(j). *Id.* at 161.

Witness Fogg testified that to calculate the benefits of MYRP2 transmission projects, DEC used a Cost Benefit Analysis (CBA) methodology at the project location level for the majority of its proposed transmission MYRP2 projects. *Id.* at 163. He explained that the Net Present Value (NPV) of the monetized financial benefits over an established period of time is divided by the NPV of the cumulative costs over that same period which results in a Benefit-to-Cost Ratio (BCR). *Id.* He testified that the expected financial benefits are based primarily on customer savings from reliability risk reduction estimated using historic outage information, data from the Interruption Cost Estimate (ICE) Calculator, and a decision analytics software tool used for modeling critical

infrastructure investments. *Id.* In terms of the use of the ICE calculator, witness Fogg testified that it is a useful tool for valuing reliability improvements, and the underlying data supporting the ICE Calculator model is derived from extensive, statistically representative utility customer surveys and has undergone multiple rounds of validation and refinement through ongoing updates led by Lawrence Berkeley National Laboratory and Resource Innovations. *Id.* at 164. He explained that since DEC's last rate case, a major update, referred to as ICE Calculator 2.0, was released in April 2025, and this version was developed through a national initiative involving standardized customer interruption cost surveys conducted between 2022 and 2024 across 24 electric utility service territories including Duke Energy service territories. *Id.* He testified that importantly, while all economic benefit estimates are inherently approximations, the ICE Calculator provides statistically valid outputs based on rigorously modeled customer damage functions. *Id.* ICE 2.0 is recognized as the leading and only publicly available tool for estimating the economic impacts of electric power interruptions, and its use is endorsed by the DOE and widely adopted across the industry for reliability planning, investment justification, and regulatory filings. *Id.* at 164-65. He testified that DEC used the same approach for calculating CBAs for MYRP2 transmission projects as it did for MYRP1. *Id.* at 165. For projects where a CBA was not performed, witness Fogg explained that the work underlying the project is required as part of DEC's obligation to serve and/or comply with NERC reliability standards. *Id.* at 163-64.

Finally, in his direct testimony, witness Fogg explained that due to DEC's experience with transmission project execution in MYRP1, DEC advanced many individual projects further along in the project development lifecycle before it included them in MYRP2, resulting in more accurate cost and in-service estimates. *Id.* at 156. During the hearing, witness Fogg elaborated that the transmission project planning life cycle is an iterative process where DEC consistently fine-tunes estimates regarding schedule, scope, and cost over the course of the project. Tr. vol. 10, 13. Witness Fogg explained that in the MYRP2 process, DEC selected projects further in the stage gating process so that estimates could be as close as possible to what actuals would be. *Id.* at 13-14.

In witness Fogg's supplemental testimony, witness Fogg provided updates for the certain MYRP2 transmission project locations consistent with the parameters set forth in Commission Rules R1-17B(f), removed 19 transmission project task/locations, updated 18 project task/locations to reflect material changes in scope or schedule, updated 35 project task locations with initial or updated capital costs equal to or greater than $10 million, and provided corrections for certain projects task/locations. Tr. vol. 9, 169-71. Collectively, the updates to the transmission project task/locations in the MYRP2 resulted in a decrease of $59.3 million to the system amount of capital expected to be placed in service for the MYRP2 projects. *Id.* at 171.

DEC witness Fogg's Supplemental Direct Exhibit 1 provides the total updated projected in-service costs for the proposed MYRP2 Transmission Project as follows:

1. Breakers - $240,049,072;
2. Capacity and Customer Planning - $265,873,319;
3. Transmission Line Hardening & Resilience - $150,784,130
4. Substation Hardening & Resilience - $57,149,723;
5. System Intelligence - $90,403,282;
6. Transformers - $158,529,420;
7. Vegetation Management - $ 44,894,372.

Fogg Supp. Direct Ex. 1.

The modifications to the proposed MYRP transmission projects described in witness Fogg's supplemental direct testimony and accompanying exhibits resulted in an updated estimated capital cost to DEC's proposed MYRP Transmission projects of approximately $1.008 billion. *Id.*

Public Staff witness Lawrence testified that he reviewed the transmission plant capital projects that DEC proposed for inclusion in MYRP2 which total approximately $1 billion. Tr. vol. 16, 498-99. His review of the MYRP2 transmission projects resulted in recommendations related to CBAs, the Transmission Breaker Replacement Program, and the calculation of operating benefits customers will receive for the Breaker Replacement Program. *Id.* at 500-01.

With respect to CBAs, witness Lawrence testified that he does not believe the CBAs accurately represent the benefits of the projects to all customers because DEC used only state-level data to evaluate the financial benefits of outage risk reduction. *Id.* at 513-15. He also testified that the North Carolina ICE Calculator shows that the transmission projects evaluated benefit nonresidential customers to a far greater extent than residential customers. *Id.* at 516. However, witness Lawrence also recognized there are inherent challenges to more granular data because the transmission system is intended to facilitate the transfer of energy over large areas and to a large number of customers. *Id*. at 517. He criticized DEC's delineation between using North Carolina and South Carolina information as creating an artificial difference in benefits between customers being served by the same system and argued that a DEP customer in Wilmington, North Carolina is assigned the same benefit for an upgrade as a DEC customer in Cherokee, North Carolina, but two neighboring DEC customers would be assigned different benefits simply based on which state they are located in. *Id.* He recommended that the benefits assigned to each customer group should take more granular information into consideration where reasonable and possible. *Id.* He further explained that the purpose of his testimony was to provide context in light of the affordability concerns ratepayers have voiced; he testified that the CBA can be a useful tool when comparing projects to alternatives or making project selections, but a project simply having a CBA greater than one does not establish its need or the true cost to customers, especially when considering non-energy benefits. *Id*. at 517-18. He recommended that in future MYRP proceedings, if DEC uses a CBA as justification

for a proposed project, it should clearly indicate any savings that will directly impact energy bills in addition to any other benefits. *Id.* at 518.

Witness Lawrence testified that DEC did not justify the pace of the Breaker Replacement Program, given only six breaker failures had occurred for the period 2023-2025.[9] *Id.* at 500, 521-22. He testified that DEC's System Reliability Plan (SRP) for breaker replacements indicate an average life of 38 years for this equipment, but the equipment has the ability to last far longer than 38 years, noting that the three failed Distribution oil breakers had an average age and service life of 63 years, and the three failed Transmission oil breakers had an average age and service life at failure of 57 years. *Id.* While he testified that he does not necessarily recommend that breakers should only be replaced after failure, he explained that breaker failure is difficult to predict and there are no strong quantitative measurements to predict breaker failure. *Id.* Witness Lawrence concluded that DEC had not demonstrated that the proactive replacement of the oil-filled breakers at the pace proposed is appropriate. *Id*. at 523. He asked that in its rebuttal testimony, DEC address how it determined the appropriate pace of proactive replacements along with specific indices and observable evidence used in the determination. *Id.*

Finally, with respect to O&M Benefits, witness Lawrence testified that DEC did not offset any of the costs of its proposed transmission MYRP2 programs with operating benefits. *Id.* at 524. He explained that when a utility seeks an MYRP, which includes "costs associated with a known and measurable set of capital investments," the revenue requirement must be "net of operating benefits" under N.C.G.S. § 62-133.16(c)(1)(a). *Id*. Witness Lawrence observed that despite projecting billions in savings through the CBAs, DEC has not identified any operating benefits resulting from the work it proposes to complete on the transmission projects. *Id.* Despite DEC's system reliability program (SRP) and project business justifications noting that many of the projects will reduce O&M maintenance costs, witness Lawrence testified that he was not able to identify any O&M savings for MYRP2 projects due to a lack of data from DEC because DEC tracks O&M costs at the program level rather than physical locations. *Id.* at 525-27. Witness Lawrence recommended that to ensure costs and benefits are commensurate — and ensure the intent of N.C.G.S. § 62-133.16(c)(1)(a). is met — that DEC include in its rebuttal testimony a comprehensive quantification of the operational benefits customers will receive for the Breaker Replacement Program, and should DEC be unable to quantify these operational benefits, he recommended disallowance of approximately $240 million for the Breaker Replacement Program for purposes of MYRP2. *Id.* at 530-31.

In his rebuttal testimony, DEC witness Fogg responded to Public Staff witness Lawrence's recommendations concerning DEC's CBAs, the Breaker Replacement Program, and O&M benefits. Tr. vol. 22, 94-97. With respect to DEC's cost benefit analyses, he testified that DEC's CBAs and use of the ICE calculator are reasonable, industry accepted tools for evaluating transmission investments with system-wide reliability and outage-reduction benefits. *Id.* at 97. He explained that the fact that the ICE calculator

[9] Witness Lawrence testified that he had sought information going back to 2015, as was provided in DEP's pending general rate case, Docket No. E-2 Sub 1380; however, DEC stated it was too voluminous and burdensome. Tr. vol. 16, 520.

estimates higher direct economic losses from outages for commercial and industrial customers than for residential customers does not mean that DEC's transmission investments disproportionately benefit nonresidential customers. *Id.* He testified that residential customers benefit directly from fewer and shorter outages, improved system resilience, and a transmission system that supports the reliable delivery of power to all customer classes. *Id.* He further testified that witness Lawrence's characterization of DEC's CBAs as insufficiently granular misunderstands how DEC's transmission value models work, because the models do not simply apply a broad statewide benefit assumption to every project; rather, the models begin with customer specific ICE outputs derived from state level inputs and then apply detailed project-specific engineering, operational, and risk information to estimate the value of individual transmission investments. *Id.* Further, he testified that DEC agrees with witness Lawrence that a CBA greater than one is not, by itself, the sole basis for establishing transmission project need. *Id.* at 97-98. Finally, he concluded that witness Lawrence's criticisms do not demonstrate that DEC's CBAs produce inaccurate or unreliable results, and they provide no basis to reject or discount DEC's MYRP2 transmission investments. *Id.* at 98.

With respect to the Breaker Replacement Program, witness Fogg responded that the relative scarcity of recent failures is evidence that the program is working as intended. *Id.* at 95-96. He stated that the program prevents failures that would otherwise occur in a fleet of approximately 2,500 oil-filled breakers that have been in service for an average of 57 years, well beyond their recognized industry service life of approximately 40 years. *Id.* at 96. He explained that DEC does not pace its Breaker Replacement Program based on observed failures alone but employs a structured condition-based asset management process that considers inspection findings, mechanism condition, contact wear, maintenance history, system criticality, spare-part availability, and obsolescence risk, all evaluated through DEC's SRP. *Id*. Additionally, the parts for many of these legacy oil-filled breakers are no longer manufactured by approved Duke Energy suppliers and their functional obsolescence represents an independent justification for proactive replacement regardless of recent failure history. *Id.* With respect to witness Lawrence's contention that DEC's MYRP2 transmission proposal fails to comply with the requirement under N.C.G.S. § 62-133.16(c)(1)(a). that MYRP costs be presented "net of operating benefits," witness Fogg disagreed. *Id*. He testified that transmission operating benefits often arise as avoided failures, avoided emergency work, reduced corrective maintenance, improved reliability, and reduced environmental risk, rather than as immediate asset-specific O&M reductions. *Id.* He explained that these benefits are real and material to customers, even if they do not translate into a discrete, asset-by-asset reduction in test-year O&M. *Id.*

During the hearing, in response to questions from Commissioner McKissick, witness Fogg provided further detail and an overview of DEC's strategy around breaker replacement and when the technologies became obsolete. Tr. vol. 10, 79. He explained that the SRP was established around 2017, when DEC began to see a trend of degradation to the breakers as well as unavailability of support and parts from manufacturers. *Id.* DEC witness Guyton added that DEC is replacing both distribution and transmission oil breakers and explained that as distribution oil breakers age, they may mis-operate and if they fail to reclose properly, it can result in outages to several thousand distribution customers until a substation crew can respond; thus, mis-operations can also be very impactful to customers.

Id. at 80-81. Witness Fogg explained that many of these breakers were installed in the 1960s to 1980s and DEC has extended the useful life of those breakers for as long as it can; however, witness Fogg warned that if DEC does not address this wave of aged breakers, it could begin to impact reliability. *Id.* at 81-82. He explained that DEC has put forth a systematic and methodical condition-based proactive replacement program to avoid jumping into a reactive mode that can be more costly. *Id.* at 82.

Section III, ¶ 21 of the Partial Stipulation provides that DEC agrees to provide additional support for its cost-benefit analysis processes, including the formulas and more technical explanations of the value models used, in the next general rate case. Partial Stip. § III.21. No intervenor took issue with this provision of the Partial Stipulation.

Section II, ¶ 19 of the Comprehensive Settlement provides that the Stipulating Parties agree to reduce DEC's Breaker Replacement Program's costs sought for recovery in MYRP2 by 50%. Comp. Settl. § II.19. No intervenor took issue with this provision of the Comprehensive Settlement.

After having carefully reviewed all the evidence in the record on DEC's transmission MYRP2 proposal in this docket, and based on that evidence, the Commission finds that DEC's transmission MYRP2 projects, as adjusted by the Partial Stipulation and Comprehensive Settlement, are needed to maintain and improve the safe and reliable delivery of electric service to DEC's customers. The Commission further finds that these projects are discrete and identifiable capital projects with known and measurable costs based on anticipated in-service dates within the MYRP2 rate years, and they will be used and useful in providing service to customers in the rate year in which each project is placed in service.

The Commission accepts DEC's commitment in the Partial Stipulation to provide additional support for its cost-benefit analysis processes, including the formulas and more technical explanations of the value models used, in its next general rate case. In furtherance of this commitment, the Commission directs DEC to file a report (the Cost-Benefit Report) within 180 days of the issuance of this rate case order providing a detailed explanation on:

(a) The historical use of the ICE calculator for T&D investments;

(b) The key inputs and assumptions assembled for the ICE calculator;

(c) Other similar examples of where Duke's CBA analyses include direct customer dollar impacts under the "benefit" side of the calculation as done with the ICE calculator rather than focusing on goals like a target SAIDI or SAIFI goal;

(d) A detailed case study of example CBA analyses of transmission/distribution projects, including one that failed to meet the 1.0 CBA threshold, and did not get included as a MYRP project;

(e) The optimal goals for SAIDI, SAIFI, CAIDI, and various CEMI metrics, and any other applicable metrics and their relation to balancing reliability and cost-effectiveness for Duke's customers;

(f) Alternative methods of evaluating CBA for T&D investments; and

(g) Any additional information that would help the Commission better understand the underlying mechanisms of DEC's calculations of T&D costs and benefits, including DEC's use of the ICE calculator.

The Commission further finds that the Comprehensive Settlement's 50% reduction to the Breaker Replacement Program costs sought in MYRP2, reasonably resolves the issues raised with respect to these projects. Accordingly, the Commission concludes that DEC's transmission MYRP2 projects, as adjusted by the Partial Stipulation and the Comprehensive Settlement, satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a), and the evidence supports approval of the Partial Stipulation and Comprehensive Settlement's provisions regarding these transmission MYRP projects as just, reasonable, and in the public interest.

Grid Planning & Integration

DEC witness Holeman testified in support of the inclusion of GP&I investments in MYRP2 as part of DEC's PBR Application. Tr. vol. 9, 250. Witness Holeman specifically supported the need, benefits, and costs for the following grid investments included in DEC's MYRP2: (1) Red Zone Expansion Plan (RZEP) Projects; (2) Network Upgrade Projects; and (3) Enterprise Technology Projects. *Id.* at 249. He testified that each GP&I Project meets the statutory and regulatory requirements for MYRP2 inclusion, will be used and useful during the MYRP2 period, and is either supported by a cost-benefit analysis or justified by legal or operational necessity. *Id.* at 250. Witness Holeman explained that the GP&I projects enable DEC to execute the 2023-2024 CPIRP on the Commission-approved schedule. *Id.* at 253. To comply with the Commission's December 30, 2022 Order, DEC has taken significant actions to successfully implement the CPIRP, including the advancement of the GP&I Projects. *Id.*

Witness Holeman addressed the RZEP Projects, which consist of transmission upgrades needed to reduce congestion in the "red zone" and facilitate the interconnection of additional generation to DEC's transmission system at the pace and volume required by the CPIRP. *Id.* at 252. He explained that current transmission constraints are primarily caused by the large volume of incremental generation resources attempting to interconnect in the red zone, and he testified that enabling the interconnection of these incremental resources requires significant transmission network upgrades. *Id.* at 258. Witness Holeman noted that DEC included three RZEP Projects in MYRP1, and DEC included a second phase of RZEP Projects in MYRP2, including two rebuilds, one upgrade, and one reconductoring project. Holeman Direct Ex. 2; tr. vol. 9, 259-60. Witness Holeman testified that the RZEP Projects in MYRP2 provide reliability and resiliency by, for example, replacing aging equipment and enabling reliable power flow from multiple resource types. Tr. vol. 9, 263. Witness Holeman testified that DEC used a cost benefit analysis methodology at the project location level for RZEP Projects in

MYRP2. *Id.* at 264. This methodology involves dividing the NPV of the monetized financial benefits over an established period by the NPV of the cumulative costs over the same period. *Id.* This ratio is the BCR, and a BCR greater than 1.0 indicates the project or program should deliver tangible business value. *Id.* The RZEP BCR is 9.9, and the cumulative net benefits are $4,974,229,943. Holeman Direct Ex. 3 at 6. At the hearing, witness Holeman responded to questions from Commissioner McKissick concerning the interconnection studies that show nearly 3,000 megawatts (MW) of generation depend on red zone projects that are being included in MYRP2. Tr. vol. 10, 51. Witness Holeman explained that in addition to generation interconnection, the red zone projects also address compliance studies that reveal congestion and constraints through the transmission planning studies that result in compliance work that must be completed and those findings have also been validated through the Carolinas Transmission Planning Collaborative. *Id.* at 51-53.

Witness Holeman also addressed the Network Upgrade Projects, which consist of improvements to transmission lines, substations, and other facilities to support new DEC-owned and -operated generation. Tr. vol. 9, 252. Witness Holeman explained that the Network Upgrade Projects are needed to mitigate congestion identified by interconnection studies, and the related generation resources are needed to ensure reliability and security for DEC's customers. *Id.* at 267. Further, DEC must construct the Network Upgrade Projects pursuant to DEC's Joint OATT on file at FERC, and failure to construct any required Network Upgrades results in liability. *Id.* Witness Holeman testified that DEC identified the Network Upgrade Projects using DEC's state- and FERC-approved interconnection procedures. *Id.* at 268. Based on these procedures and interconnection studies, the Network Upgrade Projects were selected to maintain grid reliability and to ensure that the new interconnections do not negatively impact other users of the grid. *Id.* Witness Holeman explained that the Network Upgrade Project costs are calculated based on the principle of cost causation. *Id.* at 269. He testified that the Network Upgrade Project costs are allocated to the interconnection customers whose generation resources necessitate the Network Upgrade Projects, and he explained that this method is consistent with DEC's state- and FERC-approved interconnection procedures. *Id.*

Finally, witness Holeman described the Enterprise Technology Projects, which consist of two enterprise-level technology projects, the Integrated Grid Planning (IGP) Project and the Energy Orchestration Project, designed to enhance DEC's existing distribution planning platform to leverage certain grid edge assets to support reliability. *Id.* at 252. Witness Holeman explained that the IGP Project allows distribution capacity planners to assess an expanded array of non-traditional solutions for capacity needs, such as EVs, customer-sited solar, and other grid edge distributed energy resources. *Id.* at 270. He testified that the Energy Orchestration Project implements a control platform in the form of a software package that allows DEC, with customer permission, to control and dispatch certain grid edge distributed energy resources and customer-sited assets. *Id.* at 271. Witness Holeman explained that the Enterprise Technology Projects will optimize how DEC models, forecasts, and plans to use certain grid edge distributed energy resources and customer-sited assets. *Id.* Further, the Enterprise Technology Projects optimize the value of grid edge resources for customers and aid in reducing congestion and outages on the system. *Id.* at 272. Witness Holeman also addressed other customer benefits, including customer savings based on DEC deferring or avoiding

traditional T&D investments. *Id.* at 273. Witness Holeman testified that DEC estimated the Enterprise Technology Projects' costs based on the comprehensive scope required to implement these Projects across DEC and its public utility affiliates. *Id.* at 274. To determine the estimated portion of DEC's costs, DEC used a representation of customer count in proportion to total customers across all affiliates as a guideline. *Id.* Witness Holeman testified that this approach ensures that the costs are fairly and accurately distributed between DEC and its affiliates. *Id.* During the hearing, witness Holeman responded to questions from Commissioner McKissick about what new capabilities the enterprise technology provides beyond DEC's current systems. Tr. vol. 10, 56. Witness Holeman testified that based on his 41 years in the industry, this is the most active time of change for the industry over the next 15 years or so, and DEC must stay ahead of the technologies that are emerging. *Id.* at 57. Witness Holeman explained that the enterprise technology projects allow DEC on the distribution side to plan for behind-the-meter capabilities and inverter-based resources that are smaller and there are more of to manage as compared to planning for a large, central generator, and the technology identifies the best locations for those capabilities going forward where they are most effective. *Id.* at 58-59.

In his supplemental direct testimony, witness Holeman updated certain GP&I project locations included in MYRP2 in accordance with the parameters set forth in amended North Carolina Utilities Commission Rule R1-17B(f). Tr. vol. 9, 276. Witness Holeman testified that DEC is removing three Energy Orchestration project locations from MYRP2 because DEC completed the work prior to March 31, 2026, and DEC is removing one Network Upgrade project location because the project's in-service date moved outside of the MYRP2 window due to schedule optimization. *Id.* at 278. Additionally, DEC is updating six Network Upgrade project locations and two RZEP project locations because the in-service dates for these project locations have shifted by more than three months. *Id.* at 279. Finally, DEC has updated cost estimates and schedules for one Network Upgrade project location and three RZEP project locations where DEC's initial or updated capital cost is equal to or greater than ten million dollars. *Id.* In summary, the overall net result of the updates to the GP&I MYRP2 projects is a decrease in costs of $32.9 million to the system amount of capital expected to be placed in service for the MYRP2 projects. *Id.*

DEC witness Holeman's Supplemental Direct Exhibit 1 provides the total updated projected in-service costs for the proposed MYRP GP&I Programs as follows:

1. Energy Orchestration - $0

2. IGP - $13,093,823;

3. Network Upgrades - $39,462,213;

4. Red Zone Expansion Plan - $85,872,753.

Holeman Supp. Direct Ex. 1.

The modifications to the proposed MYRP GP&I projects described in witness Holeman's supplemental direct testimony and accompanying exhibits resulted in an

updated estimated capital cost to DEC's proposed MYRP GP&I projects of approximately $138 million. *Id.*

Public Staff witness Lawrence testified that he reviewed the GP&I MYRP2 projects and they are different from the transmission projects sponsored by DEC witness Fogg because the GP&I projects are largely for the interconnection of generation resources identified through planning processes such as DEC's FERC-approved generator interconnection study process, the CPIRP process, and the CTPC. Tr. vol. 16, 533. He explained that with the exception of the IGP program, these projects have gone through more robust study processes and review as compared to the transmission projects sponsored by witness Fogg, with need, costs, and benefits more thoroughly reviewed. *Id.* With respect to the IGP program, he testified that DEC has developed thorough documentation for this project, which provides information in much greater detail than other MYRP2 project documentation than he had reviewed and that documentation, along with the expected efficiencies that will be gained from the program, lead him to believe that the benefits customers receive will beneficially impact customer rates. *Id.* at 533-34. Witness Lawrence concluded that the proposed GP&I programs will provide benefits to customers through a more efficient system, opening headroom for expeditious interconnection of needed generation resources and greater abilities to efficiently manage the system, and therefore, he does not recommend any adjustments related to those projects. *Id.* at 534. However, similar to the transmission projects, the GP&I Integration projects use the ICE Calculator to determine the benefits to customers; thus, for the reasons discussed previously, while he does believe the Integration programs are needed and provide benefits to customers, he also contends the CBA does not provide a comprehensive view of the benefits customers will receive. *Id.*

Based on the entire record in this proceeding, the Commission finds that DEC's projected GP&I MYRP capital investments, as adjusted by the Comprehensive Settlement, are needed to maintain and improve the safe and reliable delivery of electric service to DEC's customers. The Commission further finds that these projects are discrete and identifiable capital projects with known and measurable costs based on anticipated in-service dates within the MYRP2 rate years, and they will be used and useful in providing service to customers in the rate year in which each project is placed in service. The Commission further finds that no party recommended any adjustment to the GP&I MYRP2 projects, and the Public Staff's review supports the conclusion that these projects will benefit customers through a more efficient system and the timely interconnection of needed generation resources. Accordingly, the Commission concludes that DEC's GP&I MYRP2 projects, as adjusted by the Comprehensive Settlement, satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a), and the evidence supports approval of the Comprehensive Settlement's provisions regarding those projects as just, reasonable, and in the public interest.

Distribution

DEC witness Guyton testified in support of DEC's proposed MYRP2 distribution capital investments. Tr. vol. 9, 219-32. Witness Guyton explained that the proposed MYRP2 distribution portfolio consists of discrete and identifiable capital spending projects designed to support continued safe and reliable service, improve resiliency, address

customer demand and load growth, modernize grid operations, and replace or upgrade aging infrastructure. *Id.* at 188-89, 219-22. Witness Guyton testified that the distribution projects included as part of MYRP2 and presented at the Technical Conference on March 9, 2026 were selected to address these needs. *Id.* at 219. At the hearing, witness Guyton further explained that, under the discrete and identifiable standard, DEC's distribution projects are appropriate for inclusion in MYRP2 because they constitute planned, known work that DEC can identify, scope, and develop in advance. Tr. vol. 10, 29-31. Witness Guyton testified that DEC's proposed MYRP2 distribution and other non-T&D projects total $1.712 billion, consisting of approximately $1.557 billion in distribution projects and approximately $0.155 billion in other non-T&D projects supporting distribution operations. Guyton Direct Ex. 2 at 4; tr. vol. 9, 219.

Witness Guyton testified that the MYRP2 distribution investments include projects in the same categories as those included as part of MYRP1: (1) Substation and Line. This category includes ten sub-programs totaling $1.162 billion and consists of geographically-based projects which complete the ongoing work necessary to deliver essential grid capabilities; (2) Retail and System Capacity. This category totals $362 million and consists of retail substation upgrades and system distribution-line capacity upgrades. These projects are designed to serve new and existing load, address capacity constraints, support distributed energy resources, and accommodate increasing demand associated with transportation electrification and other customer needs; (3) Hazard Tree Removal. This category totals $30 million and consists of work to identify and remove dead, dying, diseased, leaning, structurally unsound, or otherwise defective trees outside the maintained right-of-way that could strike distribution lines or equipment; (4) Integrated Volt Var Control (IVVC), which totals $2.5 million and consists of remaining IVVC work at five substation locations; and (5) other non-distribution MYRP2 Projects. These total $155 million and consist of enterprise communications, enterprise systems, facilities, and wildfire mitigation projects that support distribution operations and enable continued safe, reliable, and resilient grid operations. Guyton Direct Ex. 4 at 1, Ex. 5 at 3-25, Ex. 6 at 3-17; tr. vol. 9, 219-22, 229-32.

Witness Guyton's testimony and exhibits included a list of the MYRP2 distribution projects; the projected costs per project per rate year; timing of each project including the projected in-service month and year; projected impacts to operating expenses for each of the MYRP2 distribution projects; locations for the projects; and CBAs. Tr. vol. 9, 222-23. He also testified that, in addition to the information presented in his direct testimony and exhibits, DEC also provided detailed project information and supporting workpapers as required by Commission Rule R1-17B, including subsection (d)(2)(j). *Id.* at 223.

Witness Guyton explained that the Substation and Line portfolio consists of projects intended to deliver multiple distribution grid capabilities that are necessary for safe and reliable service. *Id*. at 219-20. DEC's Substation and Line projects consist of the following ten sub-programs:

1. Self-Optimizing Grid (SOG), which consists of projects that redesign portions of the distribution system into a dynamic, automated, self-healing network by installing sensors, switches, communications, and controls that can detect faults, isolate affected areas, and reroute power to reduce the number and

duration of customer outages. Guyton Direct Ex. 5 at 3-6. The total capital cost for this program is approximately $280.6 million.

2. Capacity, which consists of distribution system upgrades needed to address forecasted load growth from traditional loads, enhance reliability for new and existing customers, and support transportation electrification and integration of distributed energy resources. Guyton Direct Exs. 2-3. The total capital cost for this program is approximately $523 million. Guyton Direct Ex. 5.

3. Voltage Regulation and Management, which consists of investments in voltage regulation equipment and related grid modernization devices to improve voltage management and power quality for all customers. Guyton Direct Ex. 5. at 10-13. The total capital cost for this program is approximately $0.9 million. *Id.* at 1.

4. Hardening and Resiliency: Laterals, which consists of targeted work to harden distribution lateral lines, reduce outage exposure, and improve service to customers served from lateral facilities. *Id.* at 14-16. The total capital cost for this program is approximately $275.2 million. Guyton Direct Ex. 4 at 1.

5. Hardening and Resiliency: Storm, which consists of work to strengthen distribution facilities in areas vulnerable to severe weather and high-impact outage events, improve storm resiliency, and reduce customer outage impacts during and after storms. Guyton Direct Ex. 5 at 14-16. The total capital cost for this program is approximately $75.9 million. Guyton Direct Ex. 4 at 1.

6. Hardening and Resiliency: Public Interference, which consists of investments to address outage risks from public interference, including locations where distribution facilities are vulnerable to vehicle strikes or other third-party damage. Guyton Direct Ex. 5 at 14-16. The total capital cost for this program is approximately $23 million. Guyton Direct Ex. 4 at 1.

7. Hardening and Resiliency: LDIs, which consists of targeted investments to address locations with historical long duration outages, including locations where line access or other system characteristics can extend restoration times. Guyton Direct Ex. 5 at 14-16. The total capital cost for this program is approximately $18.2 million. Guyton Direct Ex. 4 at 1.

8. Equipment Retrofit, which consists of work to modernize legacy overhead equipment and reduce outages associated with wildlife interference, lightning strikes, and legacy spacing or insulation at certain pole equipment installations, including transformers, line arresters, riser poles, fusing, wildlife guards, insulated leads, and polymer arresters. Guyton Direct Ex. 5 at 17-20. The total capital cost for this program is approximately $42.8 million. *Id.*

9. Infrastructure Integrity, which consists of field assessments and proactive replacement or upgrade of end-of-service, obsolete, damaged, or otherwise

at-risk distribution equipment, including poles, capacitors, regulators, reclosers, and other line equipment. *Id.* at 21-22. The purpose of the program is to convert potential emergency outage responses into planned replacements and maintain safe and reliable service. *Id.* The total capital cost for this program is approximately $273.4 million. *Id.*

10. Hazard Tree Removal, which consists of identifying and removing dead, structurally unsound, dying, diseased, leaning, or otherwise defective trees outside the maintained right-of-way that could strike distribution lines or equipment where that work can be aligned with Substation and Line projects. *Id.* at 23-25. The total capital cost for this program is approximately $37.5 million, which includes Hazard Tree Removal work performed outside of the Substation and Line program.

Id.

With respect to the non-T&D projects, witness Guyton explained that these include DEC's allocated cost share for enterprise communications (Land Mobile Radio (LMR), Towers Shelters & Power Supplies, and Mission Critical Transport), the NextGen GIS Replacement project, facilities projects, and a Wildfire Mitigation program. Tr. vol. 9, 229-32. Specifically, the non-T&D projects include:

- The LMR project, which installs equipment on DEC-owned and leased towers to provide radio frequency coverage for the LMR solution in DEC's Nantahala area and deploys mission-critical voice assets at DEC's Control Center and operations centers. Guyton Direct Ex. 6 at 5-7. The total capital cost for this project is approximately $31.6 million. *Id.* at 6.

- The Towers, Shelters & Power Supplies projects, which address aging infrastructure and construct new communications towers to provide greater physical capacity, reliability, and support for future growth in microwave, LMR, and other strategic high-capacity wireless technologies. Guyton Direct Ex. 5. at 8-10. The total capital cost for these projects is approximately $23.7 million. *Id.* at 9.

- The Mission Critical Transport projects, which build segments of overhead and underground private fiber to connect multiple sites and create redundancy for the current Transmission Overhead Protective Ground Wire fiber ring supporting high-speed, reliable, and interoperable communications for grid devices and personnel. *Id.* at 11-12. The total capital cost for these projects is approximately $37.8 million. *Id.* at 11.

- The NextGen GIS project, which replaces DEC's current obsolete core GIS with a new cloud-based platform, GIS toolset, and interfaces to critical systems providing more reliable, accessible, and timely GIS data while leveraging technology to improve the effectiveness, efficiency, and quality of operations. *Id.* at 3-4. The total capital cost for this project is approximately $49.6 million. *Id.* at 3.

- The Toddville Training Building Renovation & New Building project, which co-locates Transmission & Distribution training into one location on the Toddville campus and improves deteriorating conditions of existing training facilities. *Id.* at 13-14. The total capital cost for this project is approximately $8.2 million. *Id.* at 13.

- The Wildfire Mitigation program, which includes a software solution and ten meteorological monitoring tower locations to predict, assess, and mitigate wildfire risks, as well as line sensors designed to detect momentary arcing line loss and falling conductors to prevent potential wildfire events. *Id.* at 15-17. The total capital cost for this project is approximately $4.0 million.

Id. at 16.

Witness Guyton testified that DEC selected MYRP2 distribution projects on a data-driven basis, using ISOP tools to evaluate substations and circuits for reliability, capacity, automation and communications, and voltage-regulation needs. Tr. vol. 9, 220-22. Witness Guyton also testified at the hearing that DEC's distribution project identification process is agnostic to geography or customer count, instead selecting projects based on the needs and performance of individual circuits. Tr. vol. 10, 50-51. He explained that DEC's grid plan evaluates circuits across both DEC and DEP and North Carolina and South Carolina using the same process. He further explained that DEC identifies whether work is appropriate based on circuit needs and the opportunity to improve reliability, resiliency, and system performance. *Id.* at 50-51. Ultimately, witness Guyton testified that DEC's MYRP2 distribution projects were identified through DEC's data-driven grid planning process and consist of known, planned work that can be identified, scoped, and placed in service during the applicable MYRP2 rate years. Tr. vol. 9, 220-23; tr. vol. 10, 30, 50-51.

Witness Guyton also testified that DEC calculated the benefits of certain MYRP2 distribution projects using CBAs developed at the program level. Tr. vol. 9, 226-27. As discussed above in the Transmission MYRP2 section, DEC's CBA methodology compares the NPV of monetized financial benefits and costs over an established period, resulting in a BCR. *Id*. Consistent with that methodology, witness Guyton testified that, for the MYRP2 distribution CBAs, a BCR greater than 1.0 indicates that the project or program is expected to deliver tangible business value. *Id.* Witness Guyton further testified that DEC used the same general approach for calculating CBAs for MYRP2 distribution projects as it used for MYRP1. *Id.* at 228.

Witness Guyton explained that the expected financial benefits for the MYRP2 distribution CBAs are based primarily on operational benefits from cost avoidance and customer benefits from reliability improvements. *Id.* at 226-27. These reliability benefits were estimated using historical outage information, data from the ICE Calculator, and defined reliability improvement estimates associated with deploying specific solutions within specific programs. *Id.* With respect to the ICE Calculator, witness Guyton testified that it is a useful tool for valuing reliability improvements, and the underlying data supporting the ICE Calculator model is derived from extensive, statistically representative utility customer surveys and has undergone multiple rounds of validation and refinement

via ongoing updates led by Lawrence Berkeley National Laboratory and Resource Innovations. *Id.* at 228-29. He explained that since DEC's last rate case, a major update referred to as ICE Calculator 2.0 was released in April 2025, and this version was developed through a national initiative involving standardized customer-interruption cost surveys conducted between 2022 and 2024 across 24 electric utility service territories, including Duke Energy service territories. *Id*.

Witness Guyton further testified that, while all economic benefit estimates are inherently approximations, the ICE Calculator provides statistically valid outputs based on rigorously modeled customer damage functions. *Id*. He testified that ICE Calculator 2.0 is recognized as the leading and only publicly available tool for estimating the economic impacts of electric power interruptions, and its use is endorsed by the DOE and widely adopted across the industry for reliability planning, investment justification, and regulatory filings. *Id.* Witness Guyton also explained that customer reliability risk-reduction benefits represent inherent savings realized by customers through avoiding outage events or reducing potential outage severity. *Id.* at 227. Because these benefits take the form of fewer and/or shorter outages, DEC cannot pass these savings directly to customers as a bill credit or other direct payment; rather, customers realize the benefits through improved reliability. *Id.*

For programs where a CBA was not performed, witness Guyton explained that the work is required as part of DEC's obligation to serve through prudent and safe utility practices. *Id.* at 228. Specifically, DEC did not prepare CBAs for the Capacity, Voltage Regulation, Infrastructure Integrity, and Hazard Tree programs because the work performed under these programs is essential to ensuring safe, reliable, and affordable service to customers; however, the costs for this work are incorporated into the CBA Portfolio Summary, demonstrating the overall net positive value of the portfolio even when including costs from projects with no quantified benefits. *Id.*

Finally, witness Guyton explained that DEC's experience with MYRP1 directly informed the development, selection, planning, and prioritization of MYRP2 distribution projects. *Id.* at 214-15. He testified that in most cases the distribution projects included in MYRP2 are more developed than those in MYRP1 and, as a result, are more accurate. *Id.* at 214. Witness Guyton further testified that when initially identifying the Substation and Line projects for inclusion in MYRP2, the cost estimates benefited from prior work scope completed for similar assets at similar locations. *Id.* at 215.

In witness Guyton's supplemental direct testimony, he updated certain MYRP2 distribution project locations in accordance with the parameters set forth in Commission Rule R1-17B(f). *Id.* at 234. Pursuant to Rule R1-17B(f), witness Guyton testified that DEC: (1) updated ten project tasks/locations to reflect material changes in scope or schedule; (2) updated capital cost estimates for 25 project tasks/locations with capital costs equal to or greater than $10 million, and; (3) corrected certain project information. *Id.* at 235-37. Witness Guyton testified that DEC neither added nor removed any MYRP2 distribution projects or project locations. *Id.* at 235-36. Collectively, the updates resulted in a net increase of $56 million to the system amount of capital expected to be placed in service for the MYRP2 projects. *Id.* at 239.

Witness Guyton's Supplemental Direct Exhibit 2 provides the updated MYRP2 distribution project costs and related non-T&D project costs that support distribution operations. Guyton Supp. Direct Ex. 2. The total projected in-service costs for the MYRP2 distribution projects and related non-T&D projects sponsored by witness Guyton are approximately $1.768 billion, revised from $1.712 billion, consisting of:

1. Approximately $1.194 billion for Substation and Line projects;

2. Approximately $364.7 million for Retail and System Capacity projects;

3. Approximately $29.9 million for Hazard Tree Removal projects;

4. Approximately $2.5 million for Integrated Volt Var Control projects; and

5. Approximately $177.3 million for other non-T&D projects.

Guyton Supp. Direct Ex. 2 at 1-7.

The Public Staff Distribution Panel reviewed DEC's MYRP2 distribution capital portfolio and raised concerns regarding the pace, prioritization, and cost justification of certain distribution investments. Tr. vol. 16, 430-31, 456-57, 485, 492, 554, 558; tr. vol. 17, 69-70. In particular, the Public Staff Distribution Panel expressed concern that DEC's distribution capital spending had increased substantially since 2015 while certain reliability metrics, including SAIDI, SAIFI, and Customers Experiencing Multiple Interruptions (CEMI), had not shown corresponding improvement. Tr. vol. 16, 379-81, 407-10, 419-21, 427-28; tr. vol. 17, 14-15. As such, the Public Staff Distribution Panel made several recommendations regarding DEC's Substation Optimization program in addition to reducing DEC's proposed distribution MYRP2 capital by approximately $317 million, or approximately 18%. Tr. vol. 16, 467.

With respect to Substation Optimization, referred to in DEC witness Guyton's testimony as the MYRP Substation and Line projects, the Public Staff Distribution Panel provided recommendations for both base[10] and MYRP2 Substation Optimization projects. The Distribution Panel testified that it is concerned that many of the substations and circuits targeted for Substation Optimization investment are already performing better than the system average in terms of service quality. *Id.* at 429. Witness Thomas noted that DEC is seeking cost recovery of $12.8 million in this proceeding for a subset of 44 DEC retail substations whose annual non-MED SAIDI is below the system average in each year for 2015 through 2025. He recommended this amount be disallowed from the Historic Period, as discussed above, and stated that DEC gave no indications in the prior rate case that these better-than-average substations needed to be prioritized. *Id.* at 430-31. In addition, the Distribution Panel identified a list of 15 substations that had non-MED SAIDI levels that were worse than system non-MED SAIDI in every year from 2015 through 2025. He criticized DEC for making no investment, or investment of a de minimis nature, in those substations. *Id.* at 431.

[10] The Public Staff's recommendations with respect to base plant Substation Optimization projects is addressed herein in the Evidence and Conclusions for Finding of Fact No. 19.

Because of its concerns regarding DEC's execution of Substation Optimization projects, the Public Staff Distribution Panel recommended going forward that the Commission require DEC to complete two reliability reports for each Substation Optimization project with an estimated cost of $200,000 or greater: (1) one for the distribution circuit of the proposed project; and; (2) one for the upstream substation serving the distribution circuit. *Id*. at 483. The Distribution Panel further testified that it was not proposing that the reliability report be filed, but rather that it would be required to be kept by DEC and provided to the Public Staff upon request when the utility seeks cost recovery for the project. *Id*. The Distribution Panel recommended that the reliability report should include the following information for the: (1) system; (2) substation; and (3) distribution circuit:

(a) Annual, year-end values for major event day (MED) and non-MED SAIDI, SAIFI, CEMI-2, CEMI-4, CEMI-6, and CEMI-8 for the five most recent years;

(b) Annual, year-end values for MED and non-MED distribution vegetation management (VM) number of outages, customers interrupted (CI), and CMI for the five most recent years;

(c) Annual, year-end values for MED and non-MED distribution equipment failure number of outages, CI, and CMI for the five most recent years;

(d) The most recent three- and five-year averages for each reliability metric in items a-c above; and

(e) A statement of how the capital project will address reliability concerns identified in items a-d above.

Id. at 483-84.

In addition, the Public Staff recommended that the Commission direct DEC to suspend all ongoing Substation Optimization projects that have not yet proceeded to in-field construction where service quality at the substation is better than the system average and there are no safety concerns in order to evaluate the ongoing cost-effectiveness of the project in light of declining overall service quality and changing system dynamics. *Id*. at 484. The Public Staff also recommended that the Commission direct DEC to file a report within 120 days of the final order in this proceeding, with the following information:

(a) A list of the suspended projects with the projected construction start date and completion date that existed prior to its suspension;

(b) A determination as to whether each suspended Substation Optimization project is prudent based on project cost and improved reliability and in the public interest; and

(c) DEC's position on whether each suspended project should be continued.

Id. at 484-85.

Finally, the Distribution Panel recommended that the Commission require DEC to prioritize Substation Optimization projects for substations and circuits that have three-year average non-MED SAIDI and SAIFI that are worse than the system averages of those metrics, with additional priority given to circuits that experience persistently high non-MED CEMI-6 and non-MED CEMI-8. *Id*. at 485.

The Public Staff Distribution Panel also recommended reducing DEC's proposed Substation and Line program by approximately $249.4 million (21%). The reductions include approximately $86 million from Capacity, $68.9 million from SOG, and $51.7 million from Hardening and Resiliency, along with elimination of the Equipment Retrofit package totaling approximately $42.9 million. *Id.* at 456. To arrive at its adjustment to the Substation and Line Program, the Distribution Panel analyzed circuit-level data from 2015 to 2025 for each of the 125 substations and 554 attached circuits included in DEC's MYRP2 request. *Id.* at 457. The Distribution Panel proposed exclusion of packages from MYRP2 Substation and Line project locations (i.e., substations) where the following conditions were true: (1) SAIDI and SAIFI had both been declining or had increased by no more than 3% annually at the substation level between 2020 and 2025; (2) the three-year average (2023 through 2025) SAIDI and SAIFI were both at least 10% below the system-average SAIDI and SAIFI; and (3) at least 50% of the customers served by that substation were on circuits where the three-year average SAIDI and SAIFI were each 10% below the system average SAIDI and SAIFI. *Id.* at 457. Regarding the Capacity package that is part of the Substation and Line program, the Distribution Panel testified that it removed capacity package spend from substations that have seen their annual growth rate of customers decline over the past five years. *Id.* at 459. The Distribution Panel also removed the Capacity package from any circuits where they also recommended removing the SOG package. *Id.* at 460. For Equipment Retrofit removal, the Distribution Panel testified that the equipment to be replaced under this program is not at end of life and is being targeted for replacement only because DEC has upgraded its own internal construction standards. The Distribution Panel further testified that no evidence was presented demonstrating meaningful improvements to operations or system reliability following the completion of MYRP1 transformer equipment replacements. Finally, the Distribution Panel noted that DEC clarified no replacements were proposed due to safety concerns. *Id.* at 458.

The Distribution Panel also recommended removing the entire NextGen GIS program from MYRP2[11] due to cost increases, schedule changes, and uncertainty of completion. *Id.* at 460-67. The Distribution Panel testified that it agrees that moving away from its current GIS software, GE Smallworld, is necessary due to the lack of support and new features and inability to integrate with newer technology. *Id.* at 462. However, given the historic performance and based on discovery responses from DEC, the Distribution Panel testified that it does not have confidence that the NextGen GIS project will be completed on schedule to include in DEC's proposed MYRP2 timeline. *Id.* at 462-64. The Distribution Panel also testified that it had IT resource concerns regarding the proposed business combination between DEC and DEP and the work required to merge billing and

[11] The Public Staff's recommendations with respect to the base period NextGen GIS investment is addressed herein in the Evidence and Conclusions for Finding of Fact No. 19.

other complex IT systems before "Legal Day 1" of the merger which takes effect on January 1, 2027, six months before NextGen GIS is due to go in service. *Id.* at 464.

The Distribution Panel also raised concerns regarding DEC's CBAs for certain MYRP2 distribution investments. *Id*. at 450-55. In particular, the Public Staff Distribution Panel asserted that only approximately 2% of the customer reliability benefits from avoided or shortened outages reflected in DEC's CBAs accrue to residential customers, while approximately 98% accrue to nonresidential customers. *Id.* at 452-53. The Public Staff Distribution Panel further noted that residential customers are anticipated to pay approximately 63% of North Carolina distribution costs under DEC's proposed COSS. Witness Thomas asserted that this creates a significant mismatch between who pays for the projects and who benefits. *Id.* at 452. Though the Public Staff Distribution Panel acknowledged that quantifying and monetizing potential reliability benefits is appropriate for evaluating programs and locations to find the most beneficial projects, it testified that a reliability program having a BCR above one does not necessarily mean it is the appropriate investment for customers. *Id.* at 453.

The Public Staff Distribution Panel did not recommend reductions to DEC's Hazard Tree Removal program. *Id.* at 456. During the hearing, in response to questioning by CUCA probing whether the removal of trees not yet identified represents a discrete and identifiable capital project, witness Thomas explained that the Hazard Tree Removal program is not discrete in that it identifies specific individual trees for inclusion in MYRP2, but that it is discrete and identifiable in the sense that it is a program DEC is executing with a defined budget and outlook for the scope of work within each rate year. *Id.* at 561-63. Witness Thomas further explained Hazard Tree Removal program costs are split into twelve monthly projects, with a certain amount coming into service each month as a capital project, such that the MYRP2 rates reflect the incremental, "discrete" in-service pacing rather than treating the entire annual amount as a single capital item. *Id.* at 562-63.

In rebuttal, witness Guyton responded to the Distribution Panel's testimony and recommended reductions to DEC's MYRP2 distribution capital investments. Tr. vol. 22, 23-90. Witness Guyton testified that the Distribution Panel's recommendations were based on an overly narrow view of distribution planning and placed undue emphasis on short-term historical reliability metrics, such as SAIDI and SAIFI, while giving insufficient weight to other relevant planning considerations, including asset condition, equipment age, criticality, capacity needs, load growth, resiliency, operational flexibility, and the benefits of coordinated project execution. *Id.* at 24-30, 44-57, 89-90.

With respect to the Distribution Panel's criticisms of DEC's Substation Optimization investments, in his rebuttal testimony, DEC witness Guyton testified that he did not agree with the Distribution Panel's assertion that DEC has under-invested in the 15 substations the Public Staff characterized as below average performing substations. *Id.* at 47. He testified Guyton Rebuttal Exhibit 1 demonstrates all 15 substations have Substation Optimization projects either completed prior to MYRP1, recently completed or underway in MYRP1, or planned for MYRP2, totaling nearly $142 million. *Id*. Witness Guyton provided further information on how DEC selects and prioritizes its Substation and Line MYRP projects using the Grid Plan and how, contrary to the Distribution Panel's claims,

the data-driven Grid Plan approach does prioritize selection of circuits with historically poorer SAIDI and SAIFI metrics. *Id*. at 48. He explained further that a prudent portfolio must balance targeted remediation at poorer performing substations/circuits with proactive asset management and risk reduction at other critical locations. *Id*. When addressing witness Thomas's recommended reduction to the 44 "better-than-average" substations, witness Guyton testified that simply deferring investment until equipment incurs problems would lead to a cycle of reactive spending that fails to account for the natural degradation of assets across the broader system and without continued investment in circuits that currently perform at or above average, those assets will deteriorate over time, offsetting any gains achieved on the worst performing circuits. *Id*. at 48-49. Witness Guyton explained that Substation Optimization projects were prioritized in the Grid Plan tool based on the objective of reliability and considered the physical condition of the assets, whether they were approaching end-of-life, failure risk, and other important considerations such as thermal capacity. *Id*. at 50. He explained that DEC provided the Public Staff with the Grid Plan methodology, a list of potential projects, their current stages and exclusion basis through the discovery process. *Id*.

Regarding the Public Staff's recommendation to immediately suspend all Substation Optimization work, witness Guyton testified that project suspension carries real risk. For many of the projects targeted by the Public Staff, detailed design, engineering and procurement are already underway, or the work is sequenced, aligned and dependent on other system work. *Id*. at 53. He explained that suspending or re-prioritizing them midstream, as the Distribution Panel suggests, can increase total cost from multiple deployments to the same site, disrupt outage planning, and extend risk exposure which is not in customers' best interests. *Id*. With respect to the Public Staff's recommendation to provide the Commission a report within 120 days following the suspension of Substation Optimization work, witness Guyton testified that he disagrees that this is appropriate or necessary because, in his view, the Public Staff's conclusions regarding DEC's reliability performance do not account for the full range of planning considerations reflected in the Grid Plan. *Id*. at 54. Second, he testified that the Public Staff's recommendation would have DEC focus solely on reliability metrics and ignore several other important factors that are appropriately considered as part of DEC's project planning and prioritization, which DEC has carefully and thoughtfully reviewed and prioritized as part of the Grid Plan. *Id*. Further, he testified this information was provided to with the prioritization methodology in the Grid Plan analysis that led to the selection of the MYRP1 and MYRP2 Substation and Line projects. *Id*.

In response to the Public Staff Distribution Panel's approximately $249.4 million in recommended disallowances to the SOG, H&R, Capacity, and Equipment Retrofit portfolios, witness Guyton testified that the Public Staff Distribution Panel's recommendations are based on flawed analyses that rely solely on historical reliability metrics and fail to account for how the removal of these investments would impact restoration times during contingencies, system resiliency to extreme events, and long-term maintenance or operational costs. *Id.* at 67-76. With respect to Capacity investments, witness Guyton testified that the Public Staff Distribution Panel conflated two different types of capacity work: native load capacity upgrades needed to address thermal overloads identified through DEC's planning tools, and SOG-related capacity upgrades that enable automatic load transfers for reliability and resiliency purposes. *Id.* at 71-75. He explained that the Public

Staff Distribution Panel's recommendation would remove "obligation to serve" capacity upgrades needed to address native load thermal violations. *Id.* at 72-73. Regarding Equipment Retrofit, witness Guyton testified that the MYRP2 program is materially different in scope from MYRP1, as it has been expanded beyond transformer retrofits to include arrestor stations and riser poles, presenting quantified opportunities for reliability improvement that the Public Staff Distribution Panel does not address. *Id.* at 75-76.

In his rebuttal testimony, DEC witness Guyton also responded to the Public Staff Distribution Panel's criticism of DEC's CBAs. *Id.* at 77-78. Witness Guyton testified that the Public Staff Distribution Panel's conclusion that the monetized reliability benefits accrue disproportionately to nonresidential customers was flawed because it conflated the actual reliability benefits customers receive — avoided customer interruptions and avoided customer minutes of interruption — with the monetized value assigned to those benefits by the ICE Calculator. *Id.* at 77. During the hearing, witness Guyton further explained this distinction. Tr. vol. 10, 35-36. He testified that the reliability benefits of avoiding an outage are the avoided customer interruptions and avoided customer minutes of interruption, while the dollar values produced by the ICE Calculator are an attempt to monetize those avoided outage impacts. *Id.* at 35. By way of example, witness Guyton testified that if a circuit serving one industrial customer, one commercial customer, and one residential customer experiences a one-hour outage, each customer experiences one outage and 60 minutes of interruption. *Id.* at 35-36. If that outage is avoided, each customer avoids one outage and one hour of outage time. *Id.* at 36. Witness Guyton explained that the ICE Calculator may assign different dollar values to those outage impacts because commercial and industrial customers can identify lost revenue or lost production, whereas residential customers are generally surveyed regarding willingness to pay to avoid an outage. *Id.* He testified, however, that the underlying reliability benefit — avoiding the outage and the outage duration — is identical for each customer affected by the outage. *Id.* at 35-36.

In his rebuttal testimony, DEC witness Teckenbrock responded to the Public Staff Distribution Panel's recommendation to remove the NextGen GIS project from MYRP2. Tr. vol. 17, 385-98. Witness Teckenbrock testified that the increase in the DEC system-level allocation for the NextGen GIS project reflects normal and expected progressive elaboration for a large, multi-year enterprise implementation, not a failure of cost discipline. *Id.* at 389. He further testified that the forecasted in-service date remains squarely within the MYRP2 period, and the six-month schedule adjustment from the in-service date forecasted when the project was proposed as part of MYRP1 reflects refinements informed by the completed implementation for Duke Energy's Midwest gas operations. *Id.* at 392. With respect to schedule contingency, witness Teckenbrock testified that the absence of a separately labeled contingency line item does not mean that schedule risk is unmanaged. He explained that the revised project schedule includes extended testing windows that provide flexibility to absorb schedule movement, and DEC employs a robust schedule management process under which the project schedule is regularly updated and critical path analyses are used to identify tasks that could affect the Go-Live date. *Id.* at 395-96.

The Partial Stipulation resolved certain discrete MYRP2 project-specific issues between DEC and the Public Staff, while expressly leaving the overall MYRP2 capital

dispute and MYRP2 Substation Optimization suspension and reporting unresolved. Partial Stip. §§ II.16, III.20, III.21. As relevant here, DEC and the Public Staff agreed to reduce the Substation and Line program by $42.9 million (system) to reflect removal of the Equipment Retrofit program. *Id.* § III.20.d. The Partial Stipulation also addressed the Public Staff's concerns regarding CBAs by providing that, in DEC's next general rate case, DEC will include additional support for its CBA process, including formulas and technical explanations of value models. *Id*. § III.21. The Comprehensive Settlement, in turn, includes additional modifications to DEC's MYRP2 distribution projects. Specifically, as relevant here, the Comprehensive Settlement provides that the NextGen GIS project is removed from MYRP2 and there will be no additional reductions to DEC's MYRP2 distribution projects in this proceeding. Comp. Settl. §§ II.10, II.21; Partial Stip. § III.6.

The Commission gives significant weight to the compromise agreements reflected in the Partial Stipulation and the Comprehensive Settlement. The Partial Stipulation and the Comprehensive Settlement's MYRP2 distribution adjustments are the product of good-faith, give-and-take negotiations among the Stipulating Parties and represent a reasonable resolution of the disputed issues regarding the appropriate level of MYRP2 distribution capital investment. Taken together, these provisions reflect a balanced resolution that permits DEC to proceed with needed MYRP2 distribution investments while providing meaningful safeguards for customers.

Based on the entire record in this proceeding, the Commission finds that DEC's proposed MYRP2 distribution projects, as adjusted by the Partial Stipulation and the Comprehensive Settlement, are needed to maintain and improve the safe and reliable delivery of electric service to DEC's customers. The Commission further finds that these projects are discrete and identifiable capital projects with known and measurable costs based on anticipated in-service dates within the MYRP2 rate years, and they will be used and useful in providing service to customers in the rate year in which each project is placed in service. The Commission further finds that the Partial Stipulation's removal of the Equipment Retrofit program and the Comprehensive Settlement's removal of the NextGen GIS project reasonably resolve the issues raised with respect to these projects. Accordingly, the Commission finds that DEC's distribution MYRP2 projects, as adjusted by the Partial Stipulation and Comprehensive Settlement, are needed to provide reliable service to customers and, further, satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a), and the evidence supports approval of the Partial Stipulation's and Comprehensive Settlement's provisions regarding those projects.

Fossil/Hydro

DEC witness Walsh testified in support of the 107 traditional and hydro projects included in the proposed MYRP2, the process used to select the projects, and the method by which DEC calculated projected costs for the projects. The estimated spend for these projects is $885 million. Tr. vol. 11, 99. Witness Walsh testified that DEC followed its established capital project prioritization framework to identify traditional and hydro projects for MYRP2, by which it uses a project prioritization or stack/rank process to assign an initial score to capital projects. Projects are assigned a category, such as compliance mandate, safety, and routine reliability, and the scoring process factors in safety and environmental risks, economic evaluation, and unit operating priority

depending on the project category. *Id.* at 94-95. After scoring, DEC evaluates projects for MYRP eligibility based on their contribution to reliability and resiliency benefits, projected timing, and execution confidence. Witness Walsh noted that final selection was informed by lessons learned from MYRP1, which resulted in DEC applying additional scrutiny to projects considered for MYRP2, including additional regional management oversight and a focus on projects that are required to maintain reliable operations. *Id.* at 95. He added that DEC's project management guidelines regarding project scope development and cost estimating were applied to determine the projected costs for the traditional and hydro projects. He also stated that cost estimates can be based on a combination of vendor quotes or budgetary estimates for labor and materials, and previous similar experience on similar projects. *Id.* at 96. He noted that since MYRP projects represent future work, as they progress through the normal stages of development their costs are expected to change as design and scope are finalized and estimates are refined. He stated that all MYRP2 traditional and hydro projects offer operating benefits including extending asset life, avoiding unplanned outages, meeting compliance requirements, and improving overall system reliability. Witness Walsh provided an overview of the traditional and hydro MYRP2 projects in his Exhibit 2, which provided further details on those projects. Tr. vol. 11, 99-102; Walsh Direct Ex. 2.

Witness Walsh also provided an update on the status of DEC's execution of the 220 traditional and hydro projects included in MYRP1. Witness Walsh described how DEC managed and controlled the costs and schedule of these projects. He explained why certain projects were cancelled or their in-service dates shifted. For example, he noted that a Dan River cooling tower variable frequency drive project was cancelled due to the need being addressed by new anti-counter rotation gearboxes installed under another project, and that certain hydro projects' in-service dates moved from Rate Year 1 to Rate year 2 due to material lead time and manufacturer delays. Witness Walsh's Exhibit 1 provided DEC's MYRP project quarterly report for the quarter ended June 30, 2025. Tr. vol. 11, 85-94; Walsh Direct Ex. 1.

In his supplemental testimony, witness Walsh updated certain traditional and hydro MYRP2 projects in accordance with Commission Rule R1-17B(f). Witness Walsh testified that DEC did not propose to include any additional traditional or hydro projects in the MYRP2. He identified the projects that DEC determined were no longer necessary or moved beyond the MYRP2 period and the reasons for those changes, which brought the updated total of proposed projects to 103. Two of the updated projects were completed early. Tr. vol. 11, 109-10. He also identified 17 projects with adjusted in-service dates due to updated outage schedules, site sequencing, material lead times, and refined project scope. *Id.* at 109-12. Witness Walsh supported updated cost estimates for two traditional/hydro MYRP2 projects that were originally estimated to cost more than $10 million. He explained that the cost estimates for these projects changed due to normal refinement as each project progressed through its development life cycle, including updated information on materials, labor, and contract costs. Witness Walsh's Supplemental Direct Exhibit 1 provided updated details for the MYRP2 projects and identified the reason for the changes to certain projects. Tr. vol. 11, 113-14; Walsh Supp. Direct Ex. 1.

Public Staff witness Thomas testified to his review of DEC's proposed coal and natural gas MYRP projects. Witness Thomas recommended a reduction to the projected

cost of certain Belews Creek coal and gas projects by $25.8 million to reflect the DOE grant award announced in February 2026. Tr. vol. 13, 101. Witness Thomas acknowledged that the award had not yet been fully negotiated or received but asserted that the DOE will likely make the award during the MYRP2 period. He argued that it is appropriate to give customers the credit for the award now, similar to the treatment of IIJA awards in the 2023 Rate Case, and DEC can recover any difference from actual costs in its next rate case. *Id.* at 101-03.

Regarding hydro projects, the Public Staff Renewables Panel asserted that, based on a three-year delay in the Lookout Shoals seismic project, the nine months of weather delay contingency built into the Mountain Island dam project was insufficient. The Renewables Panel noted the project's projected December 2028 in-service date, the last month of MYRP2, and contended that the project was not likely to go in service on time and should be removed from the MYRP. Tr. vol. 17, 266-68. The Renewables Panel also recommended that the FERC Fishing Creek Access Area and Tail Race Access Area projects be moved from Rate Year 1 to Rate Year 2 of MYRP2. *Id*. at 268. The Renewables Panel recommended further that if the Commission does not adopt Public Staff witness Thomas's blanket MYRP2 reduction, then certain traditional/hydro MYRP2 projects (those with identifiers RRE-53, RRE-60, and RRE-65) should be shifted from Rate Year 1 to Rate Year 2; the Renewables Panel contended that each of these projects has an estimated in-service date of December 2027, but DEC did not provide detailed schedules to support this date. *Id*. at 268-69. Finally, the Renewables Panel recommended that the Allen Renewables Center be removed from the MYRP, asserting that the scope is speculative and the siting is uncertain. Should the Commission decide to include the project in the MYRP, the Renewables Panel recommended that the cost estimate be reduced to match the current project scope and be allocated between legacy DEC and DEP proportional to each legacy utility's use of the facility. *Id*. at 260-66.

Public Staff witness Thomas and the Renewables Panel recommended reductions to O&M costs for several MYRP2 projects based on asserted projected savings noted in the supporting documentation for those projects. These recommendations included $300,000 of O&M at Belews Creek for the Unit 2 boiler reheater replacement project, $5 million of O&M for the Buck and Dan River heat rate projects, and $50,000 of O&M for the Thorpe turbine and generator assembly replacement project. Tr. vol. 13, 100-01, 118; tr. vol. 17, 269-70.

In rebuttal testimony, witness Walsh emphasized that no party found DEC's MYRP1 or MYRP2 traditional or hydro projects to be unreasonable, imprudent, or not beneficial to customers. Tr. vol. 22, 323.

Witness Walsh testified in opposition to the Public Staff's recommended $25.8 million downward adjustment to the Belews Creek coal and gas projects based on anticipated DOE funding. He stated that negotiations between Duke Energy and the DOE regarding award specifics are still ongoing, so neither the amount DEC will receive nor the projects that will be funded is yet known. Witness Walsh argued that the appropriate and prudent course is to proceed on the information known today and adjust rates at a future time, as needed. *Id.* at 333-34.

Witness Walsh also addressed the Renewables Panel's recommendation to remove the Mountain Island dam seismic project from MYRP2. He explained that the project is required for compliance with the station's FERC license and is the last of a series of seismic dam reinforcement projects conducted throughout the fleet at the Catawba and Linville dams. Witness Walsh testified that the timeline of a project at a different hydro station completed years ago is not a sound basis for removing the Mountain Island project from MYRP2. He noted that the Public Staff's comparison of this project to Lookout Shoals misses several key distinctions that support DEC's projected in-service date for Mountain Island. Most important of these was that a significant portion of the delay for Lookout Shoals was due to challenges encountered during installation of the wells to draw down the water level to permit the dam work to be conducted and the resulting need to obtain FERC approval of changes to the project design. In contrast, the Mountain Island project has progressed beyond the stage at which Lookout Shoals encountered these delays. He confirmed that DEC expects this project to go in service on or before December 2028. *Id.* at 330-32.

Witness Walsh agreed with the Renewables Panel's recommendation regarding the Fishing Creek projects. He explained that the originally provided in-service dates for these projects were inadvertently not updated prior to the original filing and currently have projected in-service dates within Rate Year 2. *Id.* at 332.

With regard to the Renewables Panel's recommendation to shift additional projects to Rate Year 2 based on an alleged lack of documentation, witness Walsh responded that each of these projects entails a level of complexity and is at a stage of execution for which only a high-level schedule is required pursuant to the documentation requirements DEC and the Public Staff agreed upon subsequent to the 2023 Rate Case. He continued that DEC provided the high-level schedule required for these projects with the initial MYRP2 documentation. *Id.* at 333.

With respect to the Allen Renewables Center, witness Walsh noted that the proposed construction of this project is analogous to the work DEC would execute for a new CC; it is prudent to have space to manage maintenance and inventory, seat employees when they are not in the field, etc. He also noted precedent for having similar operations centers for distributed assets within the Power Grid Operations organization, centralized by region. He concluded that with the growing fleet of solar and battery sites, DEC needs a central administrative location to house the functions associated with these new facilities commensurate with how DEC would treat other generation facilities' needs throughout the fleet. *Id.* at 336-37.

The Partial Stipulation provides that the Mountain Island Dam project will be included in MYRP2. Partial Stip. § III.20.b. The Partial Stipulation provides further that the Fishing Creek projects would move to Rate Year 2. *Id.* § III.20.f. The Partial Stipulation provides that the Allen Renewables Center is removed from MYRP2. *Id.* § III.20.a.

The Comprehensive Settlement provides that costs associated with the portion of the Belews Creek projects that are expected to receive funding from the DOE will be removed from MYRP2. The parties agreed that if such funding is not received or is less than estimated, there will be no deferral, but DEC may seek recovery of the actual

undepreciated value of the projects in future rate cases. Comp. Settl. §§ II.20-II.20.a. The Comprehensive Settlement provides further that there will be no additional reductions beyond those specified in the Stipulations to the MYRP2 projects in this proceeding. *Id*. § III.21.

Based on the entire record in this proceeding, the Commission finds that DEC's proposed fossil and hydro MYRP2 projects, as adjusted by the Partial Stipulation and the Comprehensive Settlement, are needed to maintain and improve the safe and reliable delivery of electric service to DEC's customers and are needed to maintain the fossil and hydro fleets for reliability, safety, and regulatory compliance. The Commission further finds that these projects are discrete and identifiable capital projects with known and measurable costs based on anticipated in-service dates within the MYRP2 rate years, and they will be used and useful in providing service to customers in the rate year in which each project is placed in service. The Commission further finds that the Partial Stipulation's treatment of the Mountain Island Dam, Fishing Creek, and Allen Renewables Center (as discussed further below) projects, and the Comprehensive Settlement's removal of the portion of the Belews Creek project costs expected to receive DOE funding, reasonably resolve the issues raised with respect to these projects. Accordingly, the Commission finds that DEC's fossil and hydro MYRP2 projects as adjusted by the Partial Stipulation and Comprehensive Settlement are needed to provide reliable service to customers and, further, satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a), and the evidence supports approval of the Partial Stipulation's and Comprehensive Settlement's provisions.

Nuclear

DEC witness Haaf testified in support of: (1) the 27 nuclear projects DEC included in the proposed MYRP2; (2) the process DEC used to select the projects; and (3) the method by which DEC calculated projected costs. He testified that DEC selected these projects based on four primary criteria: safety, reliability, equipment condition, and confidence in cost and schedule estimates. Tr. vol. 11, 43. Witness Haaf added that DEC applied lessons learned from MYRP1 projects to the selection of MYRP2 projects. One such lesson was that routine preventive maintenance activities were some of the most predictable MYRP1 projects, because they are tied to scheduled refueling outages and the stations have a history of executing similar work. Based on this experience, DEC included 15 routine preventive activities in MYRP2. *Id.* at 44. Another key lesson was the value of selecting projects that are in-flight, which are more predictable than projects that are not yet underway. He added that all 12 non-routine projects selected for MYRP2 are underway and have progressed through internal management review, thereby increasing predictability and confidence of their costs and schedules. *Id.* Witness Haaf explained that the projected costs for the MYRP2 nuclear projects were obtained from DEC's long-range nuclear planning tool, which is updated regularly to reflect the most accurate total project costs, including AFUDC and contingency, cash flows, and schedule. He explained that all MYRP2 nuclear projects support ongoing operational efficiencies, with a detailed breakdown of projects and their benefits provided in Haaf Direct Exhibit 2. Haaf Direct Ex. 2; tr. vol. 11, 43-45.

Witness Haaf also provided an update on the status of DEC's execution of the 35 nuclear projects included in MYRP1. He noted that 33 of the 36 approved MYRP1 projects will be placed in-service by the end of the MYRP1 period and explained the reasons for the delayed in-service date and cost shifts for certain projects. Tr. vol. 11, 38. For example, he noted that a McGuire Unit 2 lower containment air handling unit coils replacement project was delayed from the spring 2026 to fall 2027 refueling outage based on experience replacing other lower containment air handling units. Previous experience had indicated that a shift would prevent extension of the planned refueling outage beyond its allocated duration. Witness Haaf's Exhibit 1 contained DEC's MYRP project quarterly report for the quarter ended June 30, 2025. Haaf Direct Ex. 1; tr. vol. 11, 38-42.

In his supplemental testimony, witness Haaf provided project cost updates for two MYRP2 nuclear projects in accordance with Commission Rule R1-17B(f). Tr. vol. 11, 64. He testified that this update did not include any additional nuclear projects for MYRP2, did not alter the inclusion or exclusion of any nuclear projects from MYRP2, and did not require updates to in-service dates. *Id.* at 63. Witness Haaf supported updated cost estimates for two nuclear MYRP2 projects that were originally estimated to cost more than $10 million. The two revised estimates were the McGuire Nuclear Station Power Range Nuclear Instrumentation Replacements 1 and 2. He explained that cost estimate refinements such as the ones provided were common as projects advance through their life cycles. Specifically, he noted that the primary equipment manufacturer had notified DEC that it would be unable to meet certain project deliverables by the original in-service date; DEC therefore modified the projects' scope and cost estimates while maintaining the original in-service dates. Witness Haaf's Supplemental Direct Exhibit 1 provided updated details for the MYRP2 projects and identified the reason for the changes to certain projects. Haaf Supp. Direct Ex. 1; tr. vol. 11, 64-65.

Neither the Public Staff nor any other party recommended reductions or other adjustments to nuclear projects proposed for inclusion in the MYRP2.

In his rebuttal testimony, witness Haaf noted that the Public Staff did not identify any nuclear MYRP2 projects as unnecessary, imprudent, or unreasonable. Tr. vol. 22, 174.

Based on the entire record in this proceeding, the Commission finds that DEC's proposed nuclear MYRP2 projects are needed to maintain and improve the safe and reliable delivery of electric service to DEC's customers and to maintain the nuclear fleet for reliability, safety, and regulatory compliance. The Commission further finds that these projects are discrete and identifiable capital projects with known and measurable costs based on anticipated in-service dates within the MYRP2 rate years, and they will be used and useful in providing service to customers in the rate year in which each project is placed in service. The Commission further finds that no party recommended any reduction or other adjustment to any nuclear projects proposed for inclusion in MYRP2. Accordingly, the Commission finds that DEC's nuclear MYRP2 projects satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a). The evidence supports approval of those projects as just, reasonable, and in the public interest.

Solar

DEC witness Laroche supported DEC's utility-owned solar and solar paired with storage (SPWS) investments, including the investments approved in DEC's MYRP1 and proposed in MYRP2. Tr. vol. 11, 152-72. He began by providing an update on DEC's two MYRP1 projects, Baxter Creek Solar and Beaverdam Solar, which as of the time of filing, were on track to be placed in service during Rate Year 3. *Id.* at 157-64. He then explained the processes DEC has adopted to manage and control the costs and schedules for these two projects. *Id.* He further described the three solar projects DEC has proposed for MYRP2: Hudson Place Solar, Bush River Solar, and the Clark Creek SPWS. *Id.* at 164-72. He explained how DEC used its MYRP1 experience to inform the development and construction timelines for these MYRP2 projects and the benefits that customers will receive from them. *Id.* In his supplemental testimony, witness LaRoche provided updates on the three solar and SPWS MYRP2 projects, including updating projected in-service costs for the projects. He also provided the update that the Commission granted DEC a Certificate of Public Convenience and Necessity for Clark Creek SPWS on November 14, 2025. *Id.* at 175-77.

The Public Staff did not challenge the overall reasonableness or prudence of DEC's MYRP1 solar projects. The Public Staff Renewables Panel did, however, recommend that DEC offset Beaverdam Solar's project costs by a $2,009,724.78 credit security, noting that DEC had previously communicated its intention to credit this amount. Tr. vol. 17, 272-73. Regarding DEC's proposed MYRP2 solar projects, the Public Staff Renewables Panel testified that the three solar projects were procured through Commission-approved competitive bidding processes, ensuring that the expected costs were the lowest available to meet the capacity need, and thus reasonable. *Id.* at 258. However, the Renewables Panel found that the bid price for the Clark Creek BESS equipment estimate had come in lower than the original estimate and recommended a downward adjustment to that MYRP2 solar projects' costs. *Id.* at 258-59.

On rebuttal, DEC witness LaRoche responded to the Public Staff Renewables Panel regarding DEC's MYRP1 and MYRP2 solar projects. He explained that DEC agrees with the Renewables Panel's recommendation to offset Beaverdam Solar's project costs by the credit security amount and testified that DEC always intended to credit those costs to customers. Tr. vol. 22, 186. Witness LaRoche then rebutted the Renewables Panel's proposed adjustment to the Clark Creek Energy Complex cost estimate, explaining that the adjustment is premature and relies on outdated cost estimate information because the project is in the pre-contract execution phase and costs are still subject to change. He stated that the most recent estimate is evidence of this, as tariffs and material/production costs have led the Company to procure domestic content materials for tax credit purposes. The revised estimate is now closer to that originally provided by the Company. *Id.* at 188-90.

Section III, ¶ 20.e. of the Partial Stipulation provides that the Clark Creek SPWS estimate is reduced by approximately $6 million (system) as proposed by the Public Staff.

The Commission gives significant weight to the compromise agreements reflected in the Partial Stipulation. The Partial Stipulation's solar adjustment is the

product of good-faith, give-and-take negotiations among the Public Staff and DEC, and represents a reasonable resolution of the disputed issue of the appropriate level of MYRP2 solar investment.

Based on the entire record in this proceeding, the Commission finds that DEC's proposed solar MYRP2 projects as adjusted by the Partial Stipulation are needed to maintain and improve the safe and reliable delivery of electric service to DEC's customers. The Commission further finds that these projects are discrete and identifiable capital projects with known and measurable costs based on anticipated in-service dates within the MYRP2 rate years, and they will be used and useful in providing service to customers in the rate year in which each project is placed in service. The Commission further finds that the Partial Stipulation's approximately $6 million reduction to the Clark Creek SPWS cost estimate, and DEC's agreement to credit the Beaverdam Solar credit security to customers reasonably resolve the issues raised with respect to these projects. Accordingly, the Commission finds that DEC's solar MYRP2 projects as adjusted by the Partial Stipulation and Comprehensive Settlement are needed to provide reliable service to customers and satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a). The evidence supports approval of the Partial Stipulation's provisions regarding those projects as just, reasonable, and in the public interest.

Battery Storage

DEC witness Tompson testified in support of DEC's MYRP1 and MYRP2 BESS investments and outlined DEC's foundational MYRP1 BESS portfolio execution, describing how lessons learned from that experience supported the planning and development of the proposed MYRP2 BESS portfolio. Tr. vol. 11, 184-90. He further detailed the costs, schedule outcomes, and benefits delivered by the six MYRP1 BESS projects. Building on that foundation, witness Tompson presented the MYRP2 BESS portfolio that includes six BESS projects and the Allen Renewables Center: Allen Energy Storage 2 (Allen 2), Allen Energy Storage 3 (Allen 3), Harrisburg Energy Storage, Maiden Creek Energy Storage, Riverbend Energy Storage, and Wilkes Energy Storage, and the Allen Renewables Center. *Id.* at 190-91.

Tompson Direct Exhibit 2 provides detailed information on each proposed investment, including the reason, scope, estimated cost, and projected in-service month and year. *Id.* at 190. Witness Tompson explained that the MYRP2 portfolio includes approximately $1.6 billion in system costs for nearly 850 MW of new battery storage capacity across six projects. *Id.* at 210. His testimony highlighted that the proposed MYRP2 projects align with near-term system needs contemplated in the 2024 CPIRP Order, which established a near-term action plan delivering 2,700 MW of battery energy storage, including 1,475 MW of standalone storage, by January 1, 2031. *Id.* at 192. Witness Tompson further testified that the proposed MYRP2 portfolio reflects lessons learned from MYRP1 including: (1) a shift toward larger-scale projects to capture economies of scale; (2) improved cost and schedule forecasting based on execution experience; and (3) process improvements from constructing batteries in varied settings. *Id.* at 189-90. For the Allen 2 and Maiden Creek projects, DEC evaluated vendor bids and project-specific risks to develop cost estimates. For the remaining proposed MYRP2

projects, DEC developed estimates based on industry benchmarking consistent with the approach used in the IRP process. *Id.* at 194-95.

In his supplemental direct testimony, witness Tompson provided an update on four of DEC's proposed MYRP2 BESS projects, including updated cost estimates, in-service dates, and ITC assumptions. *Id.* at 200-02; Tompson Supp. Direct Ex. 2. These updates reflect a collective decrease of approximately $32 million to the system amount of capital expected to be placed in service for the proposed MYRP2 projects. Tr. vol. 11, 201.

The Renewables Panel testimony presented its findings and recommendations regarding BESS MYRP1 execution and the proposed BESS MYRP2 projects. The Renewables Panel recommended removal of the following from MYRP2: (1) the Allen Renewables Center; (2) the Allen 3 and Harrisburg tariff costs; and (3) Maiden Creek project land purchase costs. Tr. vol. 17, 259-66. As previously discussed, the Renewables Panel found issues with the scope, cost, and need for the Allen Renewables Center project and therefore recommended that it be removed from MYRP2. *Id.* at 257. Regarding the Harrisburg and Allen 3 cost estimates, the Renewables Panel testified that tariff-related costs should be excluded due to the dynamic and evolving policy changes surrounding those tariffs. *Id.* at 259. The Renewables Panel further testified that, should tariff costs materialize, DEC can seek recovery once the projects are in-service. The Renewables Panel also recommended removing $1.8 million in land purchase costs from the Maiden Creek MYRP2 cost estimate. This was recommended to ensure double recovery of said costs does not occur, as the land purchase had also been included in historic plant. *Id.* at 260.

CIGFUR III witness Collins raised concerns about MYRP2 BESS project cost and delivery risks which can challenge forecasted schedules and costs. Tr. vol. 19, 246-47. Because of these risks, he recommended the Commission adopt guardrails for MYRP2 BESS projects: (1) a project-level cost cap above which incremental costs are subject to disallowance or 50/50 sharing between shareholders and ratepayers; (2) a claw-back mechanism that would be triggered by project cancellation, a delayed in-service date, material changes in configuration, or lower actual in-service costs less than approved for recovery; and (3) a return of project-level underspend to customers. *Id.* at 247-48.

Witness Tompson's rebuttal testimony responded to the various Public Staff and intervenor recommendations regarding DEC's BESS investments. Witness Tompson highlighted that no party disputed the need for the proposed BESS projects and reiterated that each investment is reasonable, prudent, and in the best interest of customers. Tr. vol. 22, 200-01. Witness Tompson explained that DEC developed and submitted cost estimates based on the best information and operational data available as part of the MYRP1 proceeding. *Id.* at 211. Subsequent estimates reasonably incorporated learnings and on-the-ground experience gained from executing the foundational BESS portfolio. *Id.* Witness Tompson also highlighted that MYRP2 BESS estimates are competitive with MYRP1 project costs and reasonable relative to 2024 industry prices, as also stated by the Public Staff Renewables Panel. *Id.* at 209. Witness Tompson disagreed with the Public Staff's recommended removal of the Allen Renewables Center as it is a necessary operational hub for DEC's deployment and operation of BESS resources. He stated

further support for this position was provided by witness Walsh, as discussed previously. *Id.* at 217-18. Regarding the recommendation that DEP be allocated a portion of costs for the Allen Renewables Center, witness Tompson stated that foreseeable growth in the western portion of the Carolinas is happening within DEC rather than DEP, meaning DEP facilities will require an increasingly diminishing fraction of total support. *Id.* at 218. Witness Tompson also disagreed with removal of tariff costs from MYRP2 BESS cost estimates, citing volatility of tariff implementation. While the Supreme Court struck down the Liberation Day tariffs in February 2026, new tariffs were announced the following day. *Id*. Regarding the Maiden Creek land purchase, witness Tompson agreed that this recommendation was reasonable, stating DEC would update its MYRP2 cost request accordingly. *Id.* at 217-19. When rebutting witness Collins' testimony, witness Tompson explained that his recommended proposals contradict the MYRP statutory framework under the PBR Statute which provide for prospective capital investment with Commission prudence review, and existing ESM protections provide an adequate customer safeguard against over-earning. *Id.* at 220-21.

Section III, ¶ 20.a. of the Partial Stipulation provides that the Allen Renewables Center is removed from the MYRP2. Section III, ¶ 20.c. of the Partial Stipulation provides that the tariff adjustment as proposed by the Public Staff be reduced by 50%. Section III, ¶ 20.g. of the Partial Stipulation provides that the Maiden Creek project be reduced by approximately $1.8 million (system) to account for the land purchase as reflected in DEC's rebuttal testimony. Section II, ¶ 21 of the Comprehensive Settlement provides that there will be no additional reductions to MYRP2 projects. CIGFUR III witness Collins agreed that the MYRP Refund Mechanism, discussed below and as presented in the Comprehensive Settlement, provides the same or similar customer protections as intended by CIGFUR III's proposed BESS claw-back mechanism. Tr. vol. 21, 179.

Based on the entire record in this proceeding, the Commission finds that DEC's proposed BESS MYRP2 projects as adjusted by the Partial Stipulation and the Comprehensive Settlement are needed to maintain and improve the safe and reliable delivery of electric service to DEC's customers. The Commission further finds that these projects are: (1) discrete and identifiable capital projects with known and measurable costs based on anticipated in-service dates within the MYRP2 rate years; (2) consistent with the near-term battery storage needs identified through the Commission-approved resource planning process, and; (3) will be used and useful in providing service to customers in the rate year in which each project is placed in service. The Commission further finds that the Partial Stipulation's removal of the Allen Renewables Center from MYRP2, and the Stipulating Parties' resolution of the remaining BESS issues through the Comprehensive Settlement, reasonably resolve the issues raised with respect to these projects. Accordingly, the Commission finds that DEC's BESS MYRP2 projects as adjusted by the Partial Stipulation and Comprehensive Settlement are needed to provide reliable service to customers and satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a). The evidence supports approval of the Partial Stipulation and Comprehensive Settlement's provisions regarding those projects as just, reasonable, and in the public interest.

Multiyear Rate Plan Project Contingency

In Public Staff witness Thomas's testimony, he recommended the Commission remove 100% of DEC's MYRP2 project contingency costs, which represents a reduction to MYRP2 capital costs of approximately $604 million. Tr. vol. 13, 96. He stated that, for the purposes of an MYRP that sets retail rates, contingency is a budgeting tool and should not be included in rates prospectively. *Id*. at 78. Witness Thomas testified that DEC included contingency for most of the proposed MYRP projects, with individual estimates varying across project function. *Id.* at 93-94. While he acknowledged that contingency is an important component of budgeting, he argued that including it in MYRP project costs for rate recovery was inappropriate because it places upward pressure on rates and reduces the incentive to complete projects under budget. *Id.* at 93-95. Customers pay for contingency until the next general rate case. Witness Thomas stated that this is inherently unjust and unreasonable because ratepayers receive no credit for the overpayment, while the utility may file its next rate case and request an increase to cover any cost overruns. *Id.* at 94-96.

DEC witnesses Fogg, Guyton, Walsh, Haaf, LaRoche, and Tompson addressed witness Thomas's contingency recommendation in their rebuttal testimony, explaining its impact on each of their respective MYRP subjects. Witness Fogg testified that DEC's MYRP2 transmission projects carry contingency of approximately 13.3% of total estimated in-service costs. He argued this is a reasonable allowance consistent with industry expectations which accounts for cost-estimate uncertainty and known and unforeseen project risks. Tr. vol. 22, 99. Similarly, with respect to distribution projects, witness Guyton testified that contingency is a standard construction industry risk management tool, not a DEC-invented mechanism. He further testified that the contingency included in DEC's distribution projects is approximately 11% of total in-service costs and is a reasonable amount given known and unknown project uncertainties. *Id.* at 29.

DEC witness Haaf testified that the proposed removal of 100% of contingency from MYRP2 project cost estimates would artificially lower these costs and ignores why contingency is included. He explained that contingency represents a critical aspect of project planning and execution that allows DEC to accurately estimate a project's in-service costs. Witness Haaf stated that contingency amounts represent approximately 9.9% of the total in-service costs of DEC's nuclear projects. *Id.* at 180. With respect to solar projects, DEC witness LaRoche testified that incorporating some amount of contingency to cover cost uncertainty and/or project risks is prudent and beneficial. He further testified that the amounts included for MYRP2 solar projects are a reasonably low amount. *Id.* at 196-97.

Regarding battery storage projects, DEC witness Tompson testified on rebuttal that DEC identified specific uncertainties and risks for energy storage projects when determining contingency for storage projects with Class 3 or 4 estimates. Storage projects with Class 5 estimates used contingency rates based on experience developing contingency estimates for prior Class 4 projects. *Id*. at 213-14. He added that contingency is needed to develop risk-informed cost estimates, as it quantifies risk and estimate uncertainties that could impact total project costs. *Id.* at 214. He opposed the removal of contingency for many of the same reasons outlined by DEC's other operational witnesses and further added that it

would be unreasonable to remove contingency for MYRP2 energy storage projects given ITCs are calculated on DEC's estimated contingency. *Id.* at 215.

Finally, DEC witness Walsh testified that the proposed contingency amounts for the traditional/hydro MYRP2 projects were reasonable at the time of filing based on the facts known. He further testified that traditional/hydro MYRP2 project contingency represents approximately 7.1% of the total in-service costs of DEC's traditional/hydro MYRP2 projects. Tr. vol. 22, 329. Witness Walsh added that DEC does not establish contingency amounts arbitrarily; rather, contingency amounts are set based on DEC's internal engineering guidelines for project risk assessment and align with industry project management best practices. *Id.*

Section II, ¶ 16 of the Comprehensive Settlement provides that the Stipulating Parties agree that the contingency amounts for MYRP2 projects shall be 25% of the amounts included in DEC's second supplemental filing (subject to the project removals discussed further in the Comprehensive Settlement). Comp. Settl. § II.16. No intervenor took issue with this provision of the Comprehensive Settlement. The Commission concludes that the Comprehensive Settlement provides a reasonable resolution of this issue for purposes of this proceeding.

Discussion and Conclusions

In testimony and during the evidentiary hearing, DEC, the Public Staff, and some intervenors provided extensive testimony regarding the appropriate level of MYRP2 capital investment and contingency. Positions ranged from support for DEC's original estimates to staunch opposition, recommending the Commission reduce both estimated project costs and the level of contingency included in project estimates. The MYRP2 adjustments reflected in the Comprehensive Settlement, including the reduction of contingency to 25% of the amounts included in DEC's second supplemental testimony and the project-level adjustments described above, are the product of good faith negotiations among the Stipulating Parties to resolve these disputed issues. The Comprehensive Settlement further aims to do this while preserving the funding needed for DEC to complete its approved MYRP2 projects and provide reliable service to its customers. Therefore, in sum, the Commission approves DEC's proposed MYRP2 projects as modified by the Comprehensive Settlement and finds that such projects are needed to provide reliable service to customers and, further, satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a).

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 35-36

Cost Allocation

The evidence supporting these findings of fact is contained in DEC's verified PBR Application and Form E-1; the COSS Stipulation; the testimony and exhibits of DEC witness Hager; the joint the testimony and exhibits of Public Staff's Rates Panel; the testimony and exhibits of CIGFUR III witness Collins; the testimony and exhibits of CUCA witness McGlothlin; the testimony and exhibits of Walmart witness Chriss; the testimony

and exhibits of AGO witness Burgess; the testimony and exhibits of NCJC, et al. witness Wilson; and the entire record in this proceeding.

Summary of Evidence

DEC Direct Testimony

COSS Overview

In her direct testimony, DEC witness Hager described the purpose of a COSS and how costs are assigned pursuant to such study. Tr. vol. 11, 561. 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. *Id.* 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 561-62. Costs are first grouped according to their function. *Id.* at 563. 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, using cost causation principles. *Id.* at 563-64. Once all costs and revenues are assigned, the COSS identifies the return on investment that DEC has earned for each customer class during the test period, and these returns can then guide rate design. *Id.* at 562.

The COSS Stipulation

On October 24, 2025, the COSS Stipulating Parties filed the COSS Stipulation with the Commission in the instant proceeding and in DEP's pending rate case in Docket No. E-2, Sub 1380. *Id.* at 559-60. 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.* at 560. 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 states that it applies only in the current DEC rate case in Docket No. E-7, Sub 1329, and in the DEP rate case in Docket No. E-2, Sub 1380. The COSS Stipulating Parties are free to advocate for different methodologies in future rate cases. COSS Stip. § II.E. DEC witness Hager testified that the COSS Stipulation is reasonable and 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. Tr. vol. 11, 560. The Commission approved the 2022 COSS Stipulation among DEC, DEP, the Public Staff, CIGFUR II, and CIGFUR III employing the same methodology for allocating DEP and DEC's production and transmission demand-related costs in Docket Nos. E-2, Sub 1300 and E-7, Sub 1276. E-2, Sub 1300 Order at 35-36; E-7, Sub 1276 Order at 36-37. The COSS Stipulating Parties urge the

adoption of the COSS Stipulation in this case as a fair and reasonable methodology for the allocation of costs. COSS Stip. § III.B.

The 12 CP Method

Under the COSS Stipulation, the 12 CP method was used to allocate costs to the North Carolina retail, South Carolina retail, and wholesale jurisdictions. Tr. vol. 11, 568. Witness Hager testified that DEC believes employing the 12 CP method is appropriate because it is consistent with DEC's integrated resource planning; by averaging the twelve monthly peaks, the 12 CP method is less volatile than a single coincident peak, particularly in regard to weather; the 12 CP method is regularly used by utilities in allocating costs to customers and has been approved by other Southeastern state utilities commissions and FERC. *Id.* at 569.

The Modified A&E Method

The COSS Stipulation also provides for a Modified A&E Method to allocate production demand costs across North Carolina retail customer classes. *Id.* at 572. 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. *Id.* 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 572-73. 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 non-coincident peak (NCP) is the maximum demand regardless of the time of the system peak. *Id.* at 573. Witness Hager explained that each rate class's non-coincident demand likely occurs at different times, and the sum of the non-coincident class peaks is different from the systemwide peak demand. *Id.* Witness Hager noted that the A&E method is an accepted method of allocating demand-related production costs in Texas, Arkansas, and Missouri, and is a reasonable method for allocating demand-related production costs to the North Carolina retail classes in this case. *Id.* at 575. DEC slightly modified the A&E method to conform the A&E allocators to the 12 CP method used at the North Carolina retail jurisdictional level. *Id.* at 574-75.

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 575. 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.* at 575-76.

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.* at 576. 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 such as substation and below, primary and below, and secondary. *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 these 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 577. Witness Hager testified that these costs are allocated using DEC's kWh of generation and deliveries during the test period. *Id.* Witness Hager explained that kWh sales information is collected and adjusted for the level of losses attributable to each class and jurisdiction to determine the level of kWh at the generator attributable to that class or jurisdiction. *Id.*

Customer Allocators

DEC included operating expenses in FERC accounts 901-17 for allocation as customer-related costs that include meter reading, billing and collection, and customer information and services. *Id.* DEC also included in this category a portion of distribution costs that it identified as customer-related, such as meters and service drops (FERC accounts 369 and 370) and a portion of transformers (FERC account 368). *Id.* Some 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. *Id.*

Witness Hager testified that the NARUC Cost Allocation Manual (NARUC CAM) states a portion of distribution costs related to FERC accounts 364-368, including costs of poles, towers, fixtures, overhead and underground conductors, and transformers, are customer-related. *Id.* at 578. Witness Hager further testified that the Minimum System method recognizes that some portion of the distribution system is necessary to serve customers regardless of whether the customers take any energy from the system and therefore 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.*

Witness Hager testified that DEC's Minimum System study allowed DEC to classify the distribution system into customer-related and demand-related portions. *Id.* 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.* 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, for example, one light bulb. *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.* at 578-79. 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.* at 579. Witness Hager testified that the use of the Minimum System method is required by the PBR Statute, N.C.G.S. § 62-133.16(b). *Id.*

Public Staff Direct Testimony

The Public Staff's Rates Panel recommended that the Commission approve the COSS Stipulation. Tr. vol. 13, 189. The Rates Panel explained that the general principle underlying a COSS is that each jurisdiction, customer class, or, in some cases, an individual customer should be responsible for an appropriate share of the costs that the utility plans for and incurs to provide service. *Id.* at 192. They further explained that some costs can and should be directly assigned, while those that cannot be directly assigned should be allocated using the methodology that most accurately and equitably follows cost causation. *Id.* For production plant, specifically, the Rates Panel testified that the COSS allocation should account for the customers' use of generation that best matches the way the utility plans and incurs costs. *Id.*

The Rates Panel explained that under the COSS Stipulation, costs will first be allocated among North Carolina retail, South Carolina retail, and wholesale jurisdictions using the 12 CP method, and then costs at the North Carolina retail level will be allocated using the Modified A&E Method. *Id.* at 193. They testified that this approach is consistent with the 2022 COSS Stipulation accepted by the Commission in DEC's last general rate case proceeding in Docket No. E-7, Sub 1276. The Rates Panel stated they support incorporating an average demand component in the COSS as it more appropriately reflects the way that a utility actually plans, builds, and operates its system and allows for all annual hours of utility operation to be considered when assigning cost responsibility to all classes. *Id.* at 193-94.

The Rates Panel elaborated on the 12 CP and Modified A&E methodologies used in this rate case. *Id.* at 194. Specifically, they testified that the 12 CP method moderates the impacts of weather extremes from one month or one season. The Rates Panel noted that cost of service methodologies that *only* use coincident peaks to assign costs, including the 12 CP methodology used in this case, do not incorporate any consideration of the average demand component in the determination of production-related factors, though the 12-CP methodology has been historically utilized to allocate jurisdictional costs by FERC and the Public Service Commission of South Carolina. *Id.* While employing the same allocation methodologies across all jurisdictions is not required, the Rates Panel explained that it ensures all costs of the utility have been accounted for, eliminating the risk of under- or over-allocation of rate base due to the choice of allocation methodology. *Id.* at 194-95. The Rates Panel noted that, with respect to North Carolina retail customer

classes, the use of the Modified A&E Method incorporates a customer class's average demand and non-coincident demands to allocate production related costs. The Rates Panel also testified that the Modified A&E Method more appropriately allocates costs to users of the system that do not traditionally have high demand during the peak hours of the year, such as certain lighting classes, but require the utility to supply baseload resources that meet year-round customer needs. *Id.* at 195-96.

The Rates Panel also testified that the Modified A&E Method allows DEC to account for certain customers' ability to curtail during peak hours. *Id.* at 196. However, the Public Staff noted that DEC does not have any curtailable or interruptible loads; therefore, the Modified A&E methodology is not adjusted by DEC to account for any reduction of load for certain customers. The Rates Panel testified that if DEC had specific riders or tariffs that incorporated or allowed for curtailable events at peak periods, then a pre-determined amount of load that could be curtailed would be removed from the "excess" portion of that class's Modified A&E calculation. As a result, depending on the amount of curtailable load, a class could theoretically eliminate the entirety of its "excess" portion of the Modified A&E calculation. *Id.*

In sum, the Rates Panel recommended that the Commission approve the COSS Stipulation filed in this proceeding on October 24, 2025, which proposes the use of the 12 CP methodology for jurisdictional allocation purposes and the use of the Modified A&E Method for North Carolina retail allocation purposes. *Id.* at 197.

CIGFUR III Direct Testimony

CIGFUR III witness Collins testified that CIGFUR III is a party to the COSS Stipulation and recommended that the Commission accept the COSS Stipulation in its entirety and apply its methodology to set rates in this case. Tr. vol. 19, 223. Witness Collins noted that in DEC's most recent general rate case, the Commission credited witness testimony that the 12 CP method "is less volatile than a single coincident peak" because it averages the test year's twelve monthly peaks, rather than relying on a single seasonal peak, and that the 12 CP and Modified A&E methodologies are together "theoretically sound, [and] reflect principles of cost causation as required by N.C.G.S. § 62-133.16(a)(1) and (b)." *Id.* (quoting E-7 Sub 1276 Order, at 125, 129). Witness Collins explained how the Modified A&E method allocates average and excess costs and testified that the Modified A&E method is more reflective of cost causation than methods that allocate capacity costs on the basis of energy alone because energy-only allocation would assign capacity costs without regard to which classes drive peak demand. *Id.* at 228.

Witness Collins further clarified that CIGFUR III's support of the COSS Stipulation does not constitute an endorsement of the Modified A&E Method as the optimal allocation methodology for all future rate cases, but rather that the Modified A&E Method is a reasonable cost allocation and constitutes a negotiated compromise. *Id.* Witness Collins noted that because DEC's generation and transmission system is planned and built principally to serve peak demand, the relative weight that a cost-of-service allocation methodology places on class peak demand directly affects how capacity cost responsibility is distributed among the customer classes. *Id.* at 228-29. He argued that the average-demand component of the Modified A&E method moves some capacity cost

responsibility from low-load-factor classes onto high-load-factor classes, including industrial classes. *Id.* at 229. He stated that this impact to industrial classes is reflected in the give-and-take of the 2025 COSS Stipulation. *Id.* Witness Collins stated that CIGFUR III supports the COSS Stipulation because it preserves the methodology approved in DEC's most recent rate case and avoids any further erosion of peak-demand weighting while expressly reserving each COSS Stipulating Party's right to propose any cost allocation method it chooses in future rate cases. *Id.*

CUCA Direct Testimony

CUCA is a COSS Stipulating Party. Although CUCA witness McGlothlin stated that he disagreed with the use of the Modified A&E Method for allocating production plant and related expenses and the 12 CP method for allocating transmission plant and related expenses, witness McGlothlin testified that he accepts the results of DEC's COSS consistent with the COSS Stipulation for the purpose of this proceeding. Tr. vol. 8, 96.

While witness McGlothlin does not take issue with the class COSS methodologies identified in the COSS Stipulation, he also testified to the importance of aligning rates with cost. *Id.* He stated that cost-based rates reflect the actual cost to serve each class, incentivize customers to minimize their costs, enhance revenue stability, and encourage conservation by sending proper price signals to customers. *Id.* at 96-97.

In his analysis, witness McGlothlin argued that DEC is not reducing interclass subsidization to the greatest extent practicable. He found that the OPT-V and Lighting classes are moving further away from cost, meaning that DEC is proposing that OPT-V customers subsidize other classes more, while Lighting customers received greater subsidization. In order to reduce subsidization for all classes and move all classes closer to cost, witness McGlothlin recommended that interclass subsidies be reduced by 50% overall, with a cap on the increase to any class at 1.5 times the system average increase with any excess revenues spread back to all classes on rate base. *Id.* at 99.

Walmart Direct Testimony

While Walmart is not a COSS Stipulating Party, Walmart witness Chriss testified that Walmart does not oppose the COSS Stipulation or DEC's proposed production capacity cost allocation methodology. Tr. vol. 14, 17-18, 28. He stated that generally, Walmart advocates that rates be set based on the utility's cost of service for each rate class to produce equitable rates that reflect cost causation, send proper price signals, and minimize price distortions. *Id. a*t 26. Witness Chriss explained that the A&E method is, in his experience, an objective, transparent, and reasonable production plant cost allocator. *Id.* at 29.

AGO Direct Testimony

AGO witness Burgess testified that the Modified A&E Method agreed to in the COSS Stipulation does not accurately reflect relative production cost causation between DEC's customer classes. Witness Burgess testified that the argument that production demand costs are driven by peak demand was accurate when NARUC published its Cost Allocation Manual in 1993, but the electricity system has evolved considerably since that

time and cost allocation methods must evolve as well. He stated that as the power system adds more renewable energy sources, power system planning will shift away from "building to the peak" and toward optimizing a diverse array of renewable energy resources, including demand side resources. Tr. vol. 19, 88-89. In a "modernized" electric system, witness Burgess explained that a customer's impact on peak demand may not be the predominant factor driving cost. *Id.* at 89. Instead, factors such as a customer's consumption of fuel-intensive resources or impact on net peaks may be more indicative of a customer's cost causation. *Id.* at 89-90.

Therefore, witness Burgess recommended the Commission require DEC to use the Probability of Dispatch (POD) methodology to allocate demand-related production costs. *Id.* at 25-26, 91. Witness Burgess explained that POD cost allocation matches historical hourly dispatch data for each of a utility's generation sources with the hourly load of each customer class for each hour of the year to calculate the actual proportion of each generation source's annual output that was required to meet each class's annual load. He argued that the POD method has the advantage of matching customer class load with the relative cost of generation during the hours they are actually contributing to demand *Id.* at 91. Witness Burgess performed his own POD allocation analysis for DEC's production costs and testified that his results allocate less demand-classified production costs to residential customers, with a matching increase in the allocation for nonresidential, optional time-of-use (OPT) customers. *Id.* at 92. Witness Burgess testified that, by contrast, DEC's Modified A&E allocation places undue burden on residential space-heating customers who are more affected by the weather (which is not within those customers' control) than large industrial customers. *Id.* at 93-94. As a result of these findings, witness Burgess recommends the Commission reject DEC's proposed use of Modified A&E allocation methodology for production costs and instead adopt the AGO's POD-based COSS, or alternatively direct DEC to conduct its own POD analysis and prepare a new COSS using the results. *Id.* at 95.

Witness Burgess also took issue with DEC's method of allocating distribution plant asset costs in its COSS. He testified that the Minimum System model does not allocate distribution plant costs using customer-related allocations. *Id.* at 96-97. Specifically, witness Burgess testified that DEC utilized NCP-Customer, the sum of the average maximum demand of customers, but witness Burgess recommended NCP-Class, the aggregated peak load for a particular class. *Id.* at 97. Witness Burgess testified that NCP-Customer harms more diverse classes, whereas NCP-Class is more common because it acknowledges the load diversity of customers within a class — particularly for residential customers — where customers use electricity at different times. *Id.* Therefore, witness Burgess recommended that the Commission require DEC to modify its NCP methodology for distribution system assets to use the NCP-Class or diversified method. *Id.* at 26, 99.

NCJC, et al. Direct Testimony

NCJC, et al. witness Wilson opposed both DEC's jurisdictional method for allocating production and transmission costs and class allocation methods for allocating production costs. *Id.* at 366. Witness Wilson testified that DEC's jurisdictional and class allocation methods take different views of generation and transmission capital costs. For jurisdictional purposes, he stated that costs are fixed and allocated using 12 CP. For class purposes, he

testified that DEC acknowledges an energy component. As a result, witness Wilson argued that DEC applies two different understandings of cost causation. *Id.*

As to jurisdictional allocation of production costs, witness Wilson testified that the 12 CP method for jurisdictional allocation creates unstable cost allocation outcomes because DEC does not classify or allocate at the jurisdictional level any generation or transmission capital costs as energy-related, even though DEC has invested in its generation and transmission systems to not only meet peak monthly demand, but to also reliably generate and deliver electricity during all periods of the day. *Id.* at 379-80. Witness Wilson further alleged that 12 CP is biased toward wholesale customers and against retail customers. *Id.* at 382. For support, witness Wilson pointed to DEC's and DEP's Combination proceeding, testifying that North Carolina retail customers will experience a persistent increase in costs of $5-7 million per year due to the use of the 12 CP jurisdictional cost allocation method. *Id.* Witness Wilson determined the use of the 12 CP method for allocation of class transmission demand was not the best choice for the same reasons he determined the method is problematic for allocation of jurisdictional costs. *Id.* at 386.

Witness Wilson further testified that the Commission should reject the Modified A&E method for allocating class costs because it allocates generation costs on the basis of NCP demand, which witness Wilson stated is inconsistent with DEC's planning process that considers system reliability metrics such as peak load and does not consider the sum of class NCPs in determining peak generation needs. *Id.* at 389.

Witness Wilson also testified that the Modified A&E Method produces inequitable results when large new production capacity investments are required. He stated that the magnitude of project load from high-load factor customers like data centers will reduce the share of total system load from the residential customer class and other low-load factor customer classes. However, because the Modified A&E Method uses non-coincident peaks, he testified that the addition of high-load factor large loads will cause the relative share the costs allocated to low-load factor customer classes to diminish less than their share of the system coincident peak. Therefore, witness Wilson argued that the share of production costs, including those near-term investments, is likely to be allocated to low-load factor customers as a result of system growth. Witness Wilson argued that near-term investments are driven more by new loads rather than older loads, so it would be more equitable to adopt a production cost allocation method with a stronger cost-causation relationship rather than the Modified A&E Method. *Id.* at 390-91.

Witness Wilson recommended DEC utilize the Hourly Cost Model (HCM) method for jurisdictional and class production cost allocation. *Id.* at 369. Witness Wilson testified that the HCM method estimates production costs on an hourly basis and can be readily calculated based on historical test year data and with few subjective assumptions about the operation of production resources. *Id.* Witness Wilson stated that he recommends the HCM method because it provides a clear link between expenses and capital costs and the users of the electricity produced as a result of those costs, and it readily adapts to changing circumstances in both load and generation. *Id.* Witness Wilson further testified that the increased temporal granularity of costs provides a more equitable basis for design of time-varying rates. In contrast, he argued that the use of low-granularity cost-of-service

data, such as that generated using the Modified A&E Method, dilutes the potential for resulting time-varying rates to encourage demand shifts that reduce system costs between classes. Witness Wilson testified that the HCM method, he argued, is well-suited to support the adoption of cost-based load flexibility programs for large loads. *Id.* at 369-70.

While recognizing that the PBR Statute requires the Minimum System method, witness Wilson took issue with DEC's implementation of the Minimum System method for allocation of distribution costs. *Id.* at 458. Witness Wilson testified that DEC's Minimum System method relies on unsupported assumptions about the length of secondary distribution lines and potentially primary distribution lines, causing an inequitable assignment of secondary distribution costs to customers. *Id.* Witness Wilson also testified that DEC's Minimum System method unnecessarily and inequitably assigns the costs of the primary distribution system to secondary distribution customers, causing a cost shift from customers who interconnect to the primary distribution system to those who interconnect to the secondary distribution system. *Id.* at 458-59. Witness Wilson identified four alternatives the Commission could adopt to address these issues: (1) classify primary distribution costs as 100% demand-related; (2) split the Minimum System method study into primary and secondary components; (3) temporarily exclude most secondary system costs until data are adequately supported; and (4) adjust secondary class cost allocation to reflect peak load carrying capability. *Id.* at 374-75.

DEC Rebuttal Testimony

On rebuttal, witness Hager testified that DEC's method for allocating demand-related production costs is reasonable. Tr. vol. 11, 585. In response to witness Wilson's contention that DEC's jurisdictional cost allocation created an "unstable jurisdictional outcome" by not classifying or allocating any generation or transmission capital costs at the jurisdictional level, witness Hager testified that it is not clear to her how witness Wilson's proposal to allocate more generating and transmission capital costs as energy-related, which she stated are by definition variable, is more stable than DEC's methodology. *Id.* at 587. Witness Hager further explained that reallocation of costs is a natural consequence of combining DEC and DEP unrelated to a specific cost allocation method and argued that the extent to which wholesale customers are allocated lower costs under the 12 CP method does not demonstrate inequity, bias, or "arbitrary cost shifts" but rather analytical outcomes because wholesale customers have the ability to shift load from the monthly peaks. *Id.* at 588-89. In response to witness Wilson's concerns of DEC's use of inconsistent methodology between jurisdictional allocation and class allocation methods, witness Hager testified that the COSS Stipulation represents the result of the give-and-take inherent in reaching settlement with parties with diverse views on appropriate methodologies, and she argued the resulting method is a reasonable way to allocate costs in this case. *Id.* at 589-90. Witness Hager also explained how DEC allocates battery storage and CPRE-related costs and argued that their different treatments demonstrate sound cost of service practices. *Id.* at 590-92.

In response to the alternative cost allocation methods proposed by witness Burgess and witness Wilson, witness Hager testified that the HCM method is only used by one utility and is not included in the 1992 NARUC CAM or in the 2020 Regulatory Assistance Project Cost of Service Manual (RAP Manual). *Id.* at 593-94. Witness Hager

also testified that while the POD method is included in the NARUC CAM and RAP Manual, it has not seen industry acceptance despite having been around for over 30 years, with only Xcel Colorado employing a modified version of the methodology. *Id.* at 594. In addition to not being commonly used, witness Hager argued that the POD and HCM methods violate cost causation principles as they are based on how units were used in the test year, not what caused the investments to incur over many years. Referencing James C. Bonbright et al.'s 1988 work *Principles of Public Utility Rates*, witness Hager stated that customers should be responsible for the costs they cause, not those who are the beneficiaries of system investments. *Id.* at 594-95. Therefore, witness Hager testified she continues to believe the 12 CP and Modified A&E methodologies are reasonable for allocating demand-related production costs. *Id.* at 595. Witness Hager also testified that the majority of utilities allocate transmission costs using a coincident peak demand allocator, with 12 CP being the most common. *Id.* at 597.

In response to witness Wilson's concerns with DEC's explanation of its minimum system methodology, witness Hager testified the method requires developing a cost estimate for a theoretical construct that necessarily involved a large number of assumptions, and that there can be different views on those assumptions. Witness Hager further testified that witness Wilson's criticisms of the minimum system line length were based on a spreadsheet that she acknowledged is "somewhat cryptic," but argued that witness Wilson that he could have sought additional information about the basis for DEC's assumptions. *Id.* at 598-99. Witness Hager also clarified that the Minimum System methodology does not address transmission assets, but if it did, there would also be some portion of transmission assets necessary to serve customers. *Id.* at 600. Witness Hager further explained that customers receiving service off the secondary system receive service through the primary system that is then stepped down to the primary level. *Id.*

Regarding DEC's use of the NCP methodology for allocating demand-related distribution costs, witness Hager testified that while there is no perfectly correct answer for addressing how distribution assets are "caused," she argued that DEC's methodology is reasonable. *Id.* at 585, 602.

During the evidentiary hearing, witness Hager further testified that the HCM method is not consistent with cost causation because it considers only the previous year's usage of an asset, rather than what caused that asset to exist. Tr. vol. 12, 116. Witness Hager explained that the assets DEC is allocating were selected through a planning process that for many years was chiefly focused on demand as opposed to energy. *Id.* Witness Hager further testified that she takes issue with attempting to allocate costs based on which customers benefit from assets because such efforts are forward-looking or focused on the present, rather than the historical circumstances requiring costs to be incurred and because benefits are subjective and variable. *Id.* at 117-18.

Discussion and Conclusions

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 which includes the 12 CP method to allocate costs to the North Carolina retail jurisdiction and the Modified A&E Method to allocate production demand costs to North

Carolina retail customer classes. The Commission notes that the methodologies agreed to in the COSS Stipulation were determined following a give-and-take negotiation process between various stakeholders with diverse views, and the Commission gives significant weight to this agreement. Specifically, the Commission gives significant weight to the testimony of the Stipulating Parties in support of the Stipulation, as well as the testimony of witness Chriss that Walmart does not oppose the COSS Stipulation. The Commission also notes that the COSS Stipulation maintains consistency in the jurisdictional allocation methodology between North Carolina and South Carolina retail, helping to ensure that DEC does not under- or over-collect costs due to a mismatch in allocation methodologies. The Commission has weighed the evidence in this proceeding and concludes that the 12 CP and Modified A&E methodologies are together theoretically sound and reflect principles of cost causation as required by N.C.G.S. § 62-133.16(a)(1) and (b).

Although the COSS Stipulation is non-unanimous, the Commission finds that the COSS Stipulation appropriately balances the various interests of the parties to this proceeding and is just and reasonable based on the full evidence of the record. The Commission finds persuasive witness Hager's testimony that the alternative methods presented by NCJC, et al. witness Wilson and AGO witness Burgess are not consistent with cost causation and therefore declines to adopt the HCM or POD methodologies in this proceeding. Therefore, the Commission concludes that the COSS Stipulation should be approved.

The Commission further finds and concludes that DEC's Minimum System methodology is reasonable, supported by the record, and should be adopted. The Commission acknowledges that the Minimum System methodology is required by the PBR Statute. The Commission is not persuaded by witness Wilson's testimony that DEC's study rests on unsupported secondary-line assumptions and improperly includes primary distribution costs. Rather, the Commission gives greater weight to witness Hager's rebuttal testimony, which explained that the DEC's Minimum System methodology reflects a detailed, well-considered construct that necessarily reflects certain assumptions. Witness Hager additionally explained that secondary system customers are served through the primary system; therefore, primary distribution assets are appropriately included in the Minimum System. The Commission finds this explanation by witness Hager to be reasonable for the purposes of this proceeding.

Lastly, the Commission finds and concludes that DEC's use of NCP-Customer to allocate distribution plant asset costs is reasonable, supported by the record, and should be adopted. Witness Burgess argued that NCP-Customer harms more diverse classes, but the Commission gives greater weight to witness Hager's explanation that NCP-Customer better reflects distribution cost causation. The Commission acknowledges that no allocator perfectly captures distribution cost causation, but finds that DEC's NCP-Customer methodology is reasonable for purposes of this proceeding.

Accordingly, the Commission accepts the cost allocation methodologies used by DEC in its COSS for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 37-38

Distribution Line Extension Plan

The evidence supporting these findings of fact is contained in the rebuttal testimony and exhibits of DEC witnesses Byrd and Beveridge; direct testimony and exhibits of NCHBA witnesses Millis, Lange, and Olive; the DLEP Stipulation; and the entire record in this proceeding.

Summary of Evidence

DEC witness Byrd testified in his direct testimony that DEC was proposing changes to the DLEP to align with DEP by clarifying that it is the responsibility of the customer requesting conversion from overhead to underground service to provide necessary rights of way and clearing, and by incorporating language addressing updated development design expectations along with construction services and costs. Tr. vol. 11, 542-44. Public Staff witnesses Thomas and Williamson testified that they had no objections to the changes in the DLEP proposed by DEC. Tr. vol. 16, 481-82.

NCHBA witness Millis testified that the DLEP, and specifically any resulting CIAC costs, impact home builders and home prices. Tr. vol. 19, 762. NCHBA witness Millis recommended targeted modifications to DEC's DLEP, as shown in Exhibit CWM-1 to his testimony. *Id.* at 766-68. NCHBA witness Lange testified regarding the impact that CIAC can have on an individual residential real estate development. Tr. vol. 8, 18-19. NCHBA witness Olive testified that the modifications to DEC's DLEP proposed in Exhibit CWM-1 would accurately reflect cost causation and would have no long-term impacts on rates and a de minimis short-term impact. *Id.* at 41-45.

DEC witnesses Byrd and Beveridge testified in their rebuttal testimony that DEC has improved billing transparency since its engagement with NCHBA, supported the addition of a definition of "residential real estate development" to the DLEP, and supported provision of a 5-year revenue credit for the initial extension of distribution facilities for both residential and nonresidential service and facilities within a residential real estate development. Tr. vol. 21, 587-88. Witnesses Byrd and Beveridge further testified that DEC agreed that grid modernization projects and other off-site facilities upgrades may be treated as "Construction Costs" for purposes of CIAC calculation only to the extent that (1) they are not included within the scope of DEC's system improvement/capacity plan, and (2) such costs, which shall include the installed cost of new facilities, the removal cost of existing facilities minus the salvage value of removed facilities, plus any necessary rearrangement costs, are reasonable, proportionate, and solely attributable to the specific residential real estate development. *Id.* at 588-89. DEC witnesses Byrd and Beveridge indicated that DEC does not oppose NCHBA's proposal to aggregate the CIAC calculation on a cumulative, development-wide basis for residential real estate developments. *Id.* at 589.

On July 6, 2026, NCHBA filed the DLEP Stipulation between DEC, NCHBA, and Public Staff regarding DEC's DLEP and CIAC policy. The DLEP governs how DEC extends distribution facilities to serve new customers including cost allocation for line

extensions. *Id.* at 587. Under the DLEP, a revenue credit that is based on projected customer revenue over a defined period of three years is compared to the cost of installing new facilities. Tr. vol. 8, 56. If projected revenues over the defined period equal or exceed the construction cost, no upfront CIAC payment is required. *Id.* If projected revenues over the defined time period do not equal or exceed the construction cost, the shortfall is recovered as an upfront CIAC charge that is paid by the customer. *Id.* at 44. DEC, NCHBA, and the Public Staff agreed that under DEC's existing DLEP and policy, grid improvements upstream from a new residential real estate development, including grid modernization projects and other off-site facilities upgrades (e.g., substation upgrades), may be treated as "Construction Costs" for purposes of the CIAC calculation under DEC's DLEP only to the extent that (1) they are not included within the scope of DEC's system improvement/capacity plan; and (2) such costs, which shall include the installed cost of new facilities, the removal cost of existing facilities minus the salvage value of removed facilities, plus any necessary rearrangement costs, are reasonable, proportionate, and solely attributable to the specific real estate development. DLEP Stip. at 2.B. DEC further agreed to consider additional feedback from NCHBA and the Public Staff on its letter template that would be provided upon request to residential home builder customers with explanatory details for CIAC charges. *Id.* § 2.D.

The DLEP Stipulation also makes three modifications to DEC's DLEP. First, the DLEP Stipulation provides that DEC's DLEP should be amended to extend the revenue credit period from three years to five years for the initial extension of distribution facilities for both residential and nonresidential service and facilities within a residential real estate development. On a practical level, this change means that if projected revenues of the customer over a five year period exceeds the cost of providing standard design, the customer is not responsible for paying any cost up front via CIAC. Second, the DLEP Stipulation provides that DEC's DLEP should be amended to adopt a definition of "residential real estate development" in the Revenue Credit section, meaning "a Real Estate Development which consists primarily of structures subject to the North Carolina Residential Building Code and developed pursuant to a common, unified, or master development plan that is intended to be constructed in phases or as a coordinated whole and which may include appurtenant single-phase or three-phase infrastructure." Tr. vol. 21, 588.

Third, the DLEP Stipulation addresses how the CIAC calculation is performed for residential developments that include both single-phase facilities (service to individual homes) and three-phase facilities serving appurtenant community infrastructure (e.g., clubhouses). Currently, CIAC for single-phase and three-phase facilities is calculated separately, meaning surplus revenue from residential service cannot offset the costs of three-phase community facilities. Under the DLEP Stipulation, the Public Staff and NCHBA agree that the CIAC calculation should instead be performed on a cumulative, development-wide basis, thereby aggregating revenue credits and construction costs for both facility types within the same development (Aggregation Proposal), as set forth in NCHBA witness Millis' Exhibit CWM 1 and DEC Rate Design Panel's Byrd-Beveridge Rebuttal Exhibit 3. DEC did not object to the Aggregation Proposal. No other party opposed the DLEP Stipulation.

Discussion and Conclusions

Although the DLEP Stipulation is not unanimous, no party to this proceeding has opposed it.

Based upon the evidence presented in this case, including the evidence offered in testimony as discussed above, the Commission approves the DLEP Stipulation in its entirety. NCHBA witnesses Millis and Lange offered uncontroverted testimony that the modifications to the DLEP would support both housing supply and housing affordability in North Carolina, and NCHBA witness Olive offered uncontroverted testimony that the modifications would have only a de minimis short-term impact on rates. Therefore, the Commission directs DEC to incorporate the modifications to the DLEP as set forth in the DLEP Stipulation in its compliance filing and to implement all of the policies included in the DLEP Stipulation, including the Aggregation Proposal.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 39-46

Rate Design

The evidence supporting these findings of fact is contained in DEC's verified PBR Application and Form E-1; the direct testimony and exhibits of DEC witness Byrd; the rebuttal testimony and exhibits of DEC witnesses Byrd and Beveridge; the settlement testimony and exhibits of DEC witnesses Byrd and Beveridge; the supplemental settlement testimony and exhibits of DEC witnesses Byrd and Beveridge; the direct testimony and exhibits of the Public Staff Rates Panel; the direct testimony and exhibits of CIGFUR III witness Collins; the direct testimony and exhibits of CUCA witness McGlothlin; the direct testimony and exhibits of Walmart witness Chriss; the direct testimony and exhibit of Harris Teeter witness Bieber; the direct testimony and exhibits of EDF witnesses Lenell and Pol; the Comprehensive Settlement; the DCFC Stipulation; and the entire record in this proceeding.

Summary of Evidence

DEC's Performance-Based Rate Application and Direct Testimony

In his direct testimony, DEC witness Byrd explained that DEC proposes modest changes to DEC's residential and nonresidential rate design. The only change proposed for residential customers is the closure of Schedule ES, and for nonresidential customers, DEC proposes to modify the Minimum Billing Demand calculation for Small General Service (SGS) Schedule SGS, increase fixed cost recovery from demand charges for Schedules Large General Service (LGS), Industrial (I), and Optional Power Service, Time of Use (OPT-V), and provide improvements to Schedule Hourly Pricing (HP). Tr. vol. 11, 523. Similarly, DEC only proposes modest changes to its Outdoor Lighting and Street and Public Lighting schedules, which seek to provide a clear description of standard wood poles for flood light and non-flood light luminaires. *Id.* at 516. Witness Byrd also explains that DEC proposes to improve several areas of its service regulations to provide clarification and transparency of actual practices, reduce complexity and administrative burden, and align best practices between DEC and DEP. *Id.*

DEC witness Byrd also presented DEC's proposed revenue apportionment methodology, which applied a 25% reduction in each customer class's variance from the North Carolina retail average rate of return to reduce interclass subsidies, subject to a 3% cap ensuring no class experiences disproportionate increases. *Id.* at 532. The Public Staff Rates Panel described DEC's five-stage methodology: DEC first determines the test year financial perspective. Tr. vol. 13, 203. Next, DEC determines the amount of revenue surplus or deficiency that each customer class is experiencing under current rates compared to the overall NC-retail level. *Id.* at 204. Then, DEC applies an adjustment that equates to a 25% adjustment of the calculated revenue surplus or deficiency. *Id.* For classes that are in a deficiency position, this adjustment will result in a revenue requirement increase apart from any overall increase resulting from proposed plant additions in the general rate case; for classes that are in an excess position, the adjustment will result in a revenue requirement decrease that will be netted against the proposed plant additions in this general rate case. *Id.* After this adjustment, DEC determines the individual class responsibility for the new, incremental amount of revenue required above current revenues to recover the increased rate base for this proceeding. *Id.* at 205. Finally, as a new component to the proposed revenue apportionment methodology, DEC applies a 3% cap to ensure that no class experiences an increase that is more than 3% above the NC-retail determined increase. *Id.* The surplus/deficiency 25% variance adjustment is not impacted by this cap. *Id.*; Byrd Direct Ex. 4, 4_1, 4_2.

DEC proposed increasing the Basic Customer Charge (BCC) for all residential, general service, and industrial schedules. Tr. vol. 11, 521, 538. For residential service, DEC proposed to raise the Residential BCC for Rate Schedules RS, RSTC, RE, RETC, RT, RT-EV, and ES from $14.00 to $15.50 per month in Rate Year 1 and to $16.00 in Rate Year 2. *Id.* at 521. For the general and industrial schedules, DEC proposes monthly BCC rates of $23.00 for Rate Schedule SGS, $28.00 for Rate Schedule LGS, $80.00 for Rate Schedule PG, $23.00 for Rate Schedule I, and $37.00 for Rate Schedules OPT and MP. *Id.* at 538.

DEC proposed to close Schedule ES, the residential rate schedule that provides an approximate 5% discount on energy charges for customers whose dwellings meet Energy Star standards, to new residential customers effective January 1, 2027, and terminate Schedule ES effective March 31, 2029. *Id.* at 521-22. DEC proposed this delayed closure date to ensure that customers who make the effort to apply during 2026 can benefit for at least two years before termination, motivated by DEC's aim to avoid negative customer experiences and allow for gradualism. *Id.* at 522. DEC witness Byrd testified that modernized TOU rates provide refined price signals that better reflect system costs and effectively supersede Schedule ES's volumetric discount approach; he also testified that any revenue differences from termination of Schedule ES would be included in the decoupling rider. *Id.* at 521-22. DEC currently serves approximately 15,000 residential customers under Schedule ES. Under DEC's proposal, remaining Schedule ES customers would transition to either Schedule RS or Schedule RE based on their Schedule ES classification. *Id*. at 522-23.

For Rate Schedule HP, DEC does not propose changes to the structure or design features in this proceeding, given the modernization efforts that occurred in the last rate case proceeding. *Id.* at 539. Witness Byrd testifies that DEC is simply increasing the

Incremental Demand Charges as well as providing new customers the ability to request a Customer Baseline update after 12 months instead of waiting 48 months. *Id*.

Witness Byrd testified that demand charges are important pricing mechanisms for aligning prices paid with cost causation because they enable price variation amongst customers based on efficient or inefficient use of grid assets. *Id.* at 524. As witness Byrd explains, demand charges are necessary to address cost-causation alignment across customers with different load factors, which is especially true for non-residential customers. *Id*. Thus, DEC proposes to increase demand charges for General Service and Industrial Rate Schedules, modify the minimum billing demand provision for Schedule SGS, and eliminate the Customer Size Classification language on Schedule OPT-V. *Id.* at 525-26.

For Outdoor Lighting, DEC proposes increasing all Existing Pole rates by a consistent percentage to achieve the proposed revenue increase by rate schedule. *Id.* at 540. The rates for New Pole and New Pole Served Underground are increased by the same dollars per month as their corresponding Existing Pole rates before applying the applicable adder fees. *Id*. DEC also proposes updated language to reflect policy that requires all non-floodlight luminaires to be installed on standard 30-foot wood poles and all floodlight luminaires to be installed on standard 40-foot wood poles, where available. *Id.* at 540-41.

Public Staff Direct Testimony

Overall Rate Design and Revenue Apportionment

The Public Staff Rates Panel recommended the Commission accept DEC's revenue apportionment approach, stating that "with respect to gradualism, the application of a 25% variance adjustment is reasonable compared to impacts associated with fully moving each class to full COSS or applying no movement at all." Tr. vol. 13, 212. The Rates Panel also found that the class-level rates of return resulting from DEC's proposal are reasonable. *Id.* at 210. The Public Staff further noted that DEC's PBR Application of the 25% variance adjustment, including its proposed 3% cap to individual classes compared to the system average increase, "strikes a balance of minimizing interclass subsidization to the greatest extent practicable by the conclusion of the MYRP period while also reducing the potential for rate shock." *Id*. at 211-12.

Basic Customer Charge

The Public Staff acknowledged that historically, a portion of customer-related fixed costs determined by the COSS have been recovered in rates through energy and/or demand charges. *Id.* at 217. The Public Staff testified that DEC has continued this practice in this proceeding, although the proposed BCCs have been designed to recover more of the actual fixed costs identified in the COSS. *Id*. The Rates Panel stated that DEC proposed increasing BCCs to move the BCCs closer to the level supported by the COSS while applying the principle of gradualism to mitigate potential bill impacts. *Id.* at 218. The Rates Panel stated that while the COSS determined that the theoretical BCC is higher than what is being proposed, the requested BCC will recover a slightly greater portion of fixed customer-related costs than the previous BCC. *Id*. Further, as a result of an

evaluation that the Public Staff conducted on the impact of the proposed BCC increases, the Public Staff found that as the BCC increases, total bill volatility that exists as part of a volumetric rate is reduced across the year. *Id.* at 219. The Public Staff recommends approval of the BCC increases for Rate Year 1 and Rate Year 2, acknowledging that the "increases present a reasonable change in the BCC with respect to the full customer-related fixed cost recovery as indicated in the COSS." *Id.* at 221.

Net Metering Bridge and Solar Choice Rider Modifications

The Public Staff proposed wording changes to the NMB and RSC riders to allow batteries paired with net-metered solar or small generation to support reliability and participate in DEC-sponsored DSM programs. *Id.* at 229-30. Specifically, the Public Staff proposed to modify the NMB and RSC Rider as follows:

> Each Customer receiving service under this Rider must be an owner, operator, or lessee of an electric generation system that generates or discharges electricity from a renewable energy resource, ~~including~~ which may include an energy storage device ~~configured to receive electrical charge solely from onsite renewable energy generation.~~

Id. at 229.

Similarly, the Public Staff proposed the following edits to the specific language of the Nonresidential Solar Choice Rider (NSC)

> A Customer-Generator is an owner, operator, or lessee of an electric generation unit that generates or discharges electricity from a renewable energy resource, ~~including~~ which may include an energy storage device ~~configured to receive electrical charge solely from onsite renewable energy generation~~.

Id.

The Public Staff explained that current rider language restricts the manner in which customers may use BESS and the proposed edits are necessary to allow BESS operation for reliability and participation in DEC-sponsored demand-side management programs. *Id.* at 230.

Schedule ES

The Public Staff did not object to closing Schedule ES; however, they argued that maintaining the full 5% discount until the March 31, 2029, termination date would result in a significant bill increase for participating customers. *Id.* at 223. Accordingly, while supporting DEC's proposal to close Schedule ES, the Public Staff recommended reducing the Schedule ES discount from 5% to 2.5% beginning January 1, 2028, to avoid potential rate shock to customers transitioning to Schedule RS or Schedule RE. *Id.* at 223-24.

Future Tariff Modifications

The Public Staff recommended that the Commission direct DEC address the following in its next general rate case: (1) creating a Medium General Service (MGS) tariff for DEC; (2) raising the demand requirements for qualification for Schedules LGS and OPT-V to a minimum threshold of either 500 kW or 1 MW; and (3) combining Schedules RE and RS into a single residential rate tariff. *Id.* at 230.

Specifically, the Public Staff requested the Commission to direct DEC in its next general rate case to investigate and report on the potential creation of a general service rate structure reflective of DEP's current general service structure, where SGS, MGS, and LGS rates exist, and include a review of the impacts associated with the transition of the minimum eligibility thresholds for current SGS, LGS, and OPT-V customers. *Id*. at 233. Further, the Public Staff recommended that prior to the filing of DEC's next general rate case, the Commission direct DEC to investigate this topic and report on, as part of its initial testimony, the potential combination of Schedules RS and RE and whether these tariffs should be combined in that proceeding. *Id.* at 236.

Other Intervenor Direct Testimony

Overall Rate Design and Revenue Apportionment

CIGFUR III witness Collins argued that DEC should increase its rate of return variance reduction percentage from 25% to at least 50%, because a 50% reduction is "practicable" within the meaning of N.C.G.S. § 62-133.16(b). Tr. vol. 19, 230. Witness Collins acknowledged that some subsidy between customer classes may remain at the end of the MYRP period, but he argued that employing a 50% variance reduction would not cause unreasonable harm to any customer class. *Id.* at 230-31.

Witness Collins also argued that the 50% variance reduction would be consistent with the principle of gradualism as compared to the 10% variance reduction percentage approved in DEC's last rate case, as his proposal moves each class only halfway towards its cost of service. *Id.* at 231-32. He stated that DEC's proposed 3% gradualism cap constrains the Commission's ability to move to a 50% variance reduction and instead recommended that no cap be used. *Id.* at 237.

CUCA witness McGlothlin also proposed at least a 50% reduction in the rate of return variance. Tr. vol. 8, 99.

BCC

CUCA opposed DEC's proposed BCC increases, and found that DEC's proposed BCC would not sufficiently move these charges towards cost. Instead, CUCA proposed a 50% increase to the BCCs for Schedules LGS, Industrial, and OPT-V. *Id.* at 102-03.

Adjustment of Demand Charges for Schedules LGS, I, and OPT-V

With respect to demand and energy charges, Harris Teeter proposed modifications to OPT-V pricing that would materially increase demand-charge recovery relative to

energy charges. Harris Teeter's proposed rate design would increase the proportion of revenues recovered through demand charges from 38.2% to 43.4% in Rate Year 1 and to 45.4% in Rate Year 2, and witness Bieber's Exhibits JB-1 and JB-2 reflect the resulting OPT-V Secondary revenues under that alternative. CUCA proposed increasing the Schedule OPT-V Transmission demand charge to match the percentage increase in demand charges for OPT-V Primary customers with a corresponding decrease in energy charges. Tr. vol. 8, 105.

DCFC EV Charging Pilot Rate

Walmart proposed a DCFC EV charging pilot rate. As witness Chriss explains, Walmart and DEC have had ongoing discussions regarding the development of rate design options for public-facing DCFC EV charging facilities. Tr. vol. 14, 33-34. Witness Chriss explained that because DEC's PBR Application was filed before the Merger Stipulation, where DEC agreed to support a DCFC EV charging rate, DEC could not propose a DCFC EV charging rate in its direct case in this docket. *Id.* at 34. Witness Chriss testified that Walmart continues to support a DCFC EV charging pilot rate, specifically those that are designed for high-speed charging deployments, including public EV charging. *Id*. Witness Chriss testified that more EV chargers, including public-facing DCFCs, are needed in DEC's service territory, and EV-specific rate options for public DCFCs are an important component to third-party investment in public EV chargers. *Id.* at 34-35.

Witness Chriss argued that a tariff structure that includes a demand charge can disincentivize investment in EV charging and infrastructure. *Id.* at 37. He stated that nonresidential rate structures typically include a customer charge, energy charge, and demand charge, and this rate structure is only economical only at certain level of usage. *Id.* Witness Chriss testified that a newly installed EV charger typically does not have consistent usage, yet even a single usage can trigger substantial demand charges. *Id.* Witness Chriss argued that, in the absence of an alternative tariff mechanism to address the negative impact of high demand charges on lower utilization EV chargers, customers may not elect to invest in EV charging infrastructure. *Id.*

Walmart and DEC developed a pilot rate applicable to public-facing DCFC EV charging as an alternative to Schedule LGS to create pricing certainty for charging operators. *Id.* at 37, 39. Walmart recommends approval of the DCFC EV Charging Pilot Rate presented in witness Chriss's direct testimony. *Id.* at 37, 40. The proposed DCFC EV Charging Pilot contains the following conditions:

1. The rate would be available on and after January 1, 2027, with an initial cap of 100 individual EV charging locations, which may include multiple stalls at each location. Customers have until December 31, 2028, to elect the pilot, and it would sunset on December 31, 2031, spending modification or extension by the Commission. Customers would be able to participate in the pilot rate for a maximum of three years beginning on the date of election.

2. The pilot rate excludes a demand charge, and instead the participating customer would be charged the LGS customer charge then in effect and a

$/kWh energy charge that is higher than a typical LGS energy charge, which designed to recover the costs of an LGS customer at 10% monthly load factor.

3. Participants will be notified by DEC if the customer exceeds a 10% load factor for three consecutive months, and participants will be automatically transferred back to the standard LGS rate if they exceed the 10% load factor for six consecutive months.

Id. at 38.

Schedule RT-EV

EDF recommended expanding upon the TOU-EV pilot to align price signals with existing time-of-use rate offerings. Tr. vol. 20, 84. EDF also recommended providing additional rates for parties willing to engage in managed charging or participate in vehicle-to-grid offerings. *Id.* EDF urged DEC to conduct a study to understand how to effectively incorporate EV load not only related to residential EV but also commercial private-fleet and public fast charging load profiles. *Id*.

DEC Rebuttal Testimony

Overall Rate Design and Revenue Apportionment

Witness Byrd testified that under DEC's proposed rate design, Residential and Lighting classes, which have below-average rates of return, receive above-average percentage increases, while General Service, Industrial, and OPT classes, which have above-average rates of return, receive lower percentage increases. Tr. vol. 21, 585. This approach reflects cost causation, avoids rate shock, and complies with N.C.G.S. § 62-133.16(b), which directs the Commission to reduce inter-class subsidies to the "greatest extent practicable by the conclusion of the MYRP period." *Id.* at 584-85. At the hearing, witness Beveridge explained that subsidy determinations depend on the cost-of-service methodology used, which reinforces the appropriateness of applying the stipulated Class COS results through a measured revenue-apportionment methodology in this case. *Id.* at 639-40.

On rebuttal, DEC also responded to CIGFUR III witness Collins' and CUCA witness McGlothlin's recommendations of least a 50% reduction in the rate of return variance. Tr. vol. 8, 81; tr. vol. 19, 230. In their rebuttal testimony, DEC witnesses Byrd and Beveridge opposed the 50% reduction, citing the Supreme Court of North Carolina's confirmation that "practicable" requires judgment and allows incremental reductions, and noting that a 50% reduction would go well beyond the 10% reduction approved in DEC's last rate case and recently upheld on appeal. Tr. vol. 21, 584. During the hearing, witness Beveridge further confirmed that any asserted interclass subsidy depends on the cost-of-service methodology used, and a different cost-of-service methodology can yield a different result as to the direction or amount of interclass subsidization. *Id.* at 639-40.

BCC

On rebuttal, witnesses Byrd and Beveridge opposed CUCA's recommended 50% increase to the BCCs for Schedule LGS, Industrial, and OPT-V, explaining that DEC's proposed BCC increase already improves alignment with cost-causation while preserving gradualism and avoiding adverse rate impacts. *Id.* at 582.

Schedule ES

On rebuttal, DEC agreed with the Public Staff's modification and believed it consistent with gradualism, as it gives Schedule ES customers a smoother transition before the schedule sunsets. *Id.* at 575.

Schedules NMB and RSC

DEC agreed with Public Staff's proposed wording changes and recommended approval of the proposed modifications. *Id.* at 580.

Future Tariff Modifications

While DEC witnesses Byrd and Beveridge agreed that Public Staff's proposed future tariff recommendations may merit discussion in DEC's next rate case for the combined utility; however, they testified that this proceeding is not the right forum to decide the proposed recommendations. *Id.* at 580-81. Witnesses Byrd and Beveridge explained that the Commission's 1U Order directs future stakeholder meetings on rate classes, schedules, customer programs, and new tariff offerings, and that the Commission should use these stakeholder meetings and the next combined rate case to address the future tariff modifications together. *Id.* at 581.

Adjustment of Demand Charges for Schedules LGS, I, and OPT-V

DEC opposed Harris Teeter and CUCA's proposed modifications to schedule OPT-V. *Id.* As witnesses Byrd and Beveridge explained, DEC's proposal already moves OPT-V toward recovering more fixed costs through demand charges and is the more measured approach; in contrast, they argued that witness Bieber's proposed 5% shift would increase demand charges by 23% while changing energy charges by less than 1%. *Id*. With respect to CUCA's proposal, witnesses Byrd and Beveridge testified that CUCA's proposal would not send proper price signals, explaining that raising the Transmission demand charge further would require lowering energy charges during the discount period, thus moving those charges closer to or below historical marginal energy costs. *Id.* at 582-83.

DCFC EV Charging Pilot Rate

DEC supported Walmart's proposed modifications and recommended approval of the DCFC EV pilot. *Id.* at 576. Witnesses Byrd and Beveridge explained that the pilot is the result of constructive discussions between DEC and interested stakeholders held after the Commission issued its order in Docket No. E-7 Sub 1332. *Id.*

Schedule RT-EV

DEC disagreed with EDF's time-of-use recommendations. Witnesses Byrd and Beveridge testified that DEC intentionally designed Schedule RT-EV to encourage charging from 11:00 p.m. to 5:00 a.m., to diversify charging behavior across EV tariffs, and to preserve stronger price signals in Schedules RSTC and RETC, as those rates provide broader on-peak and critical-peak price signals to encourage customer savings and grid benefits. *Id.* at 577-78. Witnesses Byrd and Beveridge also testified that the existing energy efficiency/demand side management and Electric Transportation working groups are a more appropriate venue to evaluate EDF's recommendations related to managed charging, vehicle-to-grid technologies, and EV fleets. *Id.* at 578. Similarly, witness Guyton asserted that EDF's recommended electrification of transportation study is better suited for consideration as part of the Electric Transportation working group, as a rate case is generally not appropriate for evaluating customer programs outside of core rates and tariffs and existing stakeholder working groups are already established to consider such programs. Tr. vol. 22, 87.

Stipulations and Settlement Testimony

Overall Rate Design and Revenue Apportionment

Witnesses Byrd and Beveridge testified that the Comprehensive Settlement resolves the remaining revenue requirement issues between DEC and the Public Staff, resulting in revised revenue requirements for Rate Year 0, Rate Year 1, and Rate Year 2. Tr. vol. 21, 602. Witnesses Byrd and Beveridge explained that the proposed 25% reduction in variance from present rates of return by class are reflected in Byrd-Beveridge Settlement Exhibits 4, 4_1, and 4_2, and that Byrd-Beveridge Comprehensive Settlement Exhibits 2, 2_1, and 2_2 present the updated rate design revenues at the tariff level agreed upon in the Partial Stipulation as well as the 3% cap on any class increase relative to the retail average. *Id*. at 601-02. DEC testified that the Comprehensive Settlement did not impact its proposed rate design methodology and that DEC's revenue apportionment methodology and rate design approach remain unchanged from what was proposed in direct and rebuttal testimony. *Id.* at 602-03. Witnesses Byrd and Beveridge recommended that the Commission approve the Comprehensive Settlement in its entirety and testified that it is the result of give-and-take negotiations that resolve the issues in the case between the Stipulating Parties. *Id.* at 603. At the hearing, witness Byrd confirmed that he reviewed the Third Amended Comprehensive Revenue Requirement Agreement and Stipulation of Settlement, that he believed it to be in the public interest, and that believed it should be adopted in its entirety. *Id.* at 549-50.[12]

Public Staff witnesses Metz, Zhang, Thomas, and Fahey testified that based on ratepayer benefits enumerated in the Comprehensive Settlement as well as provisions of

[12] After witness Byrd testified, the Stipulating Parties filed a Fourth Amended Comprehensive Settlement on July 23, 2026, which reflects Harris Teeter joining the Comprehensive Settlement as a stipulating party.

the Partial Stipulation and the Storm Cost Stipulation, they believe the Comprehensive Settlement is in the public interest and should be approved. *Id.* at 150-52.

CIGFUR III witness Collins testified that CIGFUR believes that the Comprehensive Settlement results in a fair and reasonable outcome for DEC and its customers and is in the public interest. *Id.* at 177. CIGFUR III acknowledged the 25% variance reduction proposed by DEC is an increase from the 10% variance reduction approved in DEC's last rate case and recommended the Commission approve the Comprehensive Settlement in its entirety. *Id.* at 177-78.

DCFC EV Charging Pilot Rate

DEC, Public Staff, and Walmart entered into the DCFC Stipulation, under which DEC agreed to create a DCFC Pilot structured as a standalone tariff that would open on January 1, 2027, for initial participation of up to 100 customers. DCFC Stip. § II.2. The DCFC Pilot will only be available to commercial customers operating public-facing DCFC Facilities. *Id*. § II.3.

In their Settlement Testimony, DEC witnesses Byrd and Beveridge testified that the DCFC Pilot: (1) provides a standalone tariff designed specifically for nonresidential, public-facing DCFC facilities, which removes a significant barrier to entry for EV charging station operators whose utilization may be low during the early stages of market development; (2) appropriately balances the promotion of EV infrastructure against the risk of cross-subsidization to other customer classes; (3) provides an opportunity to investigate actual DCFC Pilot utilization and any required system upgrades before seeking extension or expansion, ensuring that any future decisions will be informed by real-world data; and (4) represents the product of good-faith negotiations among DEC, the Public Staff, and Walmart, and constitutes a reasonable compromise of positions advanced by each party. Tr. vol. 21, 596-97. The DCFC Pilot shall terminate on December 31, 2031, unless the Commission grants authorization to extend or modify the pilot. *Id.* at 595.

DEC witnesses Byrd and Beveridge and Walmart witness Chriss testified that each entity supported the DCFC Stipulation, which represented some give-and-take among the parties and recommended the Commission approve the DCFC Stipulation in its entirety. Tr. vol. 14, 43-44; tr. vol. 21, 597-98.

Discussion and Conclusions

Overall Rate Design and Revenue Apportionment

The Commission has reviewed the rate design methodology proposed by DEC and the testimony of all parties regarding rate design, as well as the Comprehensive Settlement. Based upon the record in this proceeding, the Commission accepts the Stipulating Parties' agreement regarding rate design as fair, just, reasonable, and in the public interest. The proposed revenue apportionment methodology, which applies a 25% reduction in each class's variance from the average rate of return subject to a 3% cap, is just and reasonable and consistent with N.C.G.S. § 62-133.16(b). The Commission notes that both DEC and the Public Staff support this approach. The Public Staff found the methodology "reasonable" and stated that it "strikes a balance of minimizing interclass subsidization to

the greatest extent practicable by the conclusion of the MYRP period while also reducing the potential for rate shock." The Commission agrees with this assessment.

Finally, the Commission finds that DEC's rate design, as reflected in the Byrd-Beveridge Settlement Exhibits and the supplemental settlement exhibits, appropriately implements the approved revenue apportionment methodology and is consistent with the Comprehensive Settlement. The agreement reflects negotiated compromise among the Stipulating Parties. As a result, the Commission adopts the Comprehensive Settlement as in the public interest. The Commission directs DEC to follow the pricing relationships provided in the Byrd-Beveridge Settlement Exhibits when it files its compliance rates in accordance with this Order.

Other Rate Design Issues

The Commission approves DEC's proposal to close Schedule ES to new residential customers effective January 1, 2027, and terminate Schedule ES effective March 31, 2029, as modified by the Public Staff's recommendation to reduce the Schedule ES discount from 5% to 2.5% beginning January 1, 2028. The Commission finds this modification is just, reasonable, and consistent with gradualism and provides Schedule ES customers a smooth transition to either Schedule RS or Schedule RE. The record further supports this conclusion because modernized TOU rates provide more refined price signals better reflective of system costs, any revenue differences from termination of Schedule ES will be included in the decoupling rider, and the Public Staff's staged reduction mitigates the approximately 5% bill increase that would otherwise occur upon abrupt termination.

The Commission approves the Public Staff's proposed wording changes to the NMB and RSC riders to allow batteries paired with net-metered solar or small generation to support reliability and participate in DEC-sponsored DSM programs. The Commission finds these revisions operationally just and reasonable as the existing tariff language restricts how customers may use BESS resources, while the revised language allows use of those resources for reliability and DEC-sponsored demand-side management purposes.

The Commission finds it appropriate to defer the Public Staff's proposed future tariff modifications — including the creation of a Medium General Service tariff, raising demand requirements for Schedules LGS and OPT-V, and combining Schedules RE and RS — to DEC's next general rate case and the stakeholder process directed by the Commission's 1U Order.

The Commission further notes that EDF's proposals regarding managed charging rates, vehicle-to-grid programs, an EV distribution system study, and modifications to Schedule RT-EV beyond those addressed herein are not adopted in this proceeding. These proposals may be addressed in the stakeholder process directed by the Commission's 1U Order, which includes discussion of rate classes, schedules, customer programs, and new tariff offerings, with DEC's first stakeholder meeting scheduled for August 25, 2026, as part of the Electric Transportation working group.

DCFC Pilot

Based upon the evidence presented in this case, including the evidence offered in support of the DCFC Stipulation as discussed herein, the Commission approves the DCFC Stipulation. The Commission finds that the Pilot will provide valuable information on actual DCFC utilization that will aid DEC and the Commission on potential future decisions to extend or expand the Pilot.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 47-49

Customer Growth and Large Load Interconnection Facilities

The evidence supporting these findings of fact is contained in DEC's verified PBR Application and Form E-1; the testimony and exhibits of DEC witnesses Jiggetts, Bateman, Duff, Byrd, and Beveridge; the testimony and exhibits of Public Staff witnesses Fahey and the Large Load Panel; the testimony and exhibits of AGO witness Burgess; the testimony and exhibits of CUCA witness McGlothlin; the Comprehensive Settlement; and the entire record in this proceeding.

Summary of Evidence

The Public Staff Large Load Panel stated that six large load customers have been identified by DEC as having project specific investments for serving new or expanded sites with contract demands of 20 MW or greater. Tr. vol. 14, 150. Project investments allocated to these large load customers are primarily composed of FERC Transmission Plant and Distribution Plant from a functional standpoint. *Id*. Costs related to facilities the Public Staff alleges were constructed solely to serve these six large load customers, which the Large Load Panel terms "Dedicated Facilities," are approximately $198 million. *Id*. at 151.

DEC relies on its Service Regulations to determine whether CIAC from a particular customer is required. *Id*. at 152. The relevant portion reads: "The Company will require a contribution in aid of construction when the investment required to provide the requested facilities does not produce sufficient revenue to support the investment." *Id*.

The Public Staff Large Load Panel testified that in this case, DEC is requesting to increase its rates in part to account for the $198.1 million in Dedicated Facilities, which they argued should have been recovered from the six large load customers via CIAC. *Id*. at 156, 159. In addition, they stated that these customers have not, in most cases, begun taking service or have not reached their maximum contract demand. *Id*. Therefore, the Public Staff Large Load Panel concluded that the total contracted megawatt-hour sales from these customers are not included in setting rates, meaning that the higher revenue requirement from the Dedicated Facilities is not reduced by additional sales without some recognition within the customer growth and usage adjustment, an adjustment that DEC did not propose in its PBR Application. *Id*.

The Large Load Panel testified that, based upon its understanding of these projects and the methodology by which the CIAC was waived, they are recommending removal of $198.1 million of costs related specifically to Dedicated Facilities that solely serve these six large load customers. *Id*. at 159. In addition, some of the $198.1 million

is classified as Excess Facilities and is recovered through an EFC collected from the customer. In DEC's supplemental testimony, it included approximately $9 million of EFC revenue in pro forma NC1030B. *Id*. Because it would not be appropriate to remove the $198.1 million in plant while keeping the partially offsetting EFC revenue, the Large Load Panel also recommends reducing this $9 million of EFC revenue to zero. *Id*.

The Large Load Panel also recommended that the Commission require DEC to revise, standardize, and formalize its CIAC waiver calculations to ensure that CIAC contributions for Dedicated Facilities are waived only in instances where other ratepayers are found not to be harmed by standard cost allocation methodologies, taking into account the shortcomings with DEC's current methodology identified by the Public Staff. *Id*. at 163.

Public Staff witness Fahey and AGO witness Burgess both recommended that DEC include revenues from projected customer growth for Rate Years 1 and 2, the impact being to adjust the Rate Year 1 and 2 rates downward, to reflect the impacts of projected load growth. Similarly, CUCA witness McGlothin noted that DEC proposes to set rates through 2028 based on adjusted test-year 2024 billing determinants even though DEC is also projecting significant sales growth. Witness McGlothin proposes that DEC be required to update its billing determinants prior to setting rates for Rate Year 2 in a compliance filing.

Witness Fahey explained that customer growth and usage adjustments are modifications to a utility's historic test year sales that account for expected changes in both the number of customers and their energy consumption. Tr. vol. 16, 252. In traditional ratemaking, these adjustments are made on a point-in-time basis and are weather normalized to better align historical data with longer-term load forecasting assumptions. *Id*. at 253-54. Because rates are designed to recover a fixed revenue requirement, the accuracy of customer count and usage estimates is critical – underestimates can cause the utility to over-earn relative to its approved return on equity, while overestimates can cause under-earning. *Id*. DEC has historically based these adjustments on actual customer counts through the end of the update period, using annualized account openings and closings or regression analysis depending on the customer class. *Id*.

Public Staff witness Fahey raised concerns about DEC's methodology in the context of PBR2, arguing that DEC's approach — which does not incorporate signed ESA contracts with large customers — is no longer appropriate given the unprecedented scale of anticipated load growth. *Id*. at 256-57. Specifically, he noted that DEC has signed long-term contracts with customers that are expected to start consuming large volumes of power during the PBR2 rate years, much of which is known and measurable. *Id*. at 253. He explained that failing to credit those contracted sales against the class revenue requirement allows DEC to collect revenues above what is needed to earn its approved ROE, effectively shifting risk onto other ratepayers. *Id*. at 256-57. Witness Fahey argued that the structure of the MYRP — which already incorporates capital additions tied to serving these large customers — makes it unreasonable to exclude the corresponding revenue-generating sales from the rate-setting calculation. *Id*. He noted that Commission Rule R1-17B(2) requires an application for PBR to include, with respect to nonresidential customers, a forecast for sales, load, and the number of expected customers in each class. *Id*. at 259-60. Accordingly, witness Fahey recommended that the Commission require DEC to include expected sales to future large customers that have signed ESAs

and are coming online or ramping up during future MYRP years covered by this proceeding in its customer growth adjustment. *Id*. at 261-66.

AGO witness Burgess recommended that DEC be required to adjust the billing determinants used to calculate MYRP2 rates to account for expected load growth during MYRP Rate Year 1 and MYRP2 Rate Year 2. He testified that this adjustment would ensure that rates are not set too high due to kWh sales assumptions that are unrealistically low and would ensure that DEC does not obtain windfall profits by locking in high rates before significant sales growth is expected to materialize. Tr. vol. 19, 84.

CUCA witness McGlothlin testified that because DEC projects significant growth in retail sales during the timeframe of MYRP2, DEC should be required to update its billing determinants prior to implementing Rate Year 2 base rates. Otherwise, to the extent DEC experiences customer additions and load growth above its test-year adjusted 2024 amounts, its base revenues will also increase beyond the target base revenues established in this proceeding. Tr. vol. 8, 86-89.

In her rebuttal testimony, witness Bateman testified that DEC disagrees with these recommendations because they deviate from the revenue requirement calculation under North Carolina's PBR framework. Tr. vol. 22, 412. She explained the North Carolina PBR Statute is prescriptive regarding what elements can be used to set rates, but it does not allow fully forecasted test years. *Id*. While DEC will most likely experience positive load growth over the MYRP2 period, it is also likely that it will experience cost increases associated with O&M, general taxes, and depreciation on non-MYRP capital. *Id*. All of these costs are excluded from a MYRP under North Carolina law, and the burden is on the utility to balance these factors. *Id*. She testified that it is inappropriate to isolate one item — load growth — and add it into the MYRP calculation but then ignore all other countervailing increasing costs. *Id*. at 412-13.

Witness Bateman acknowledged that Commission Rule R1-17B implementing the PBR Statute (PBR Rule) requires utilities to include forecasted billing determinants in their PBR Application but testified that this requirement does not mean that forecasted billing determinants should be used in establishing MYRP rates and such an approach is not authorized by the PBR Statute. *Id*. at 413. She noted that the PBR Rule also requires that DEC include in its PBR Application fully forecasted test years for each year of the MYRP, yet no party contends that rates may be set on a fully forecasted test year. *Id*. Requiring that information be filed is not the same as authorizing its use to adjust MYRP rates. *Id*. Witness Bateman also disagreed that excluding projected load growth will result in a windfall for DEC because North Carolina's PBR framework already prevents any form of windfall through the ESM. *Id*. at 413-14.

In their rebuttal testimony, DEC witnesses Byrd and Beveridge addressed the Public Staff's recommended disallowance of certain large load interconnection costs from DEC's rate base, specifically costs tied to "Dedicated Facilities" that solely serve large load customers as well as their argument that DEC needs a more rigorous CIAC analysis and should not waive CIAC requirements. Tr. vol 21, 567-72. Witnesses Byrd and Beveridge testified that DEC strongly disagrees, asserting that its CIAC methodology is a well-established, decades-old practice applied consistently and non-discriminatorily to

all transmission-connected customers. They explained that the basic premise of the methodology is that a new customer's projected revenues — assessed over one year at full load — will, over time, cover the costs of providing standard service, making an upfront CIAC charge unnecessary when those projected revenues are sufficient. DEC notes that the same revenue-credit logic underlies its distribution-connected customer policy (DLEP), and that there is no basis for applying revenue credits to one class of customers but not the other. *Id.* at 568-69.

Witnesses Byrd and Beveridge also oppose the Public Staff's recommendation on the grounds that it would retroactively disallow costs incurred under a methodology the Public Staff never previously challenged and without citing any Commission order, statute, or rule requiring a different approach. With respect to the Public Staff's concern that larger projects may require more significant infrastructure investment — such as large substations or transmission upgrades — witnesses Byrd and Beveridge respond that larger projects also generate substantially higher revenues, and there is no evidence that DEC's revenue-credit approach fails to appropriately scale to account for both higher costs and higher revenues. *Id.* at 570-71.

Witnesses Byrd and Beveridge added that DEC's COSS also allocates the costs of existing transmission and generation resources to the tariffs under which large load customers take service, and load growth from these customers increases the revenue allocated to those customer classes. DEC's Large Load Impact Analysis submitted in the CPIRP shows that large load customers cover their costs, including generation and transmission costs, and still contribute net revenue benefiting other customers. Similarly, DEC disputes the Public Staff's claim that 100% of large load customers' revenue is assumed to offset only the cost of required facilities; in reality, large load customer revenues are projected to far exceed the revenue requirement for non-network capital investments, leaving substantial additional revenues to support broader system costs, including existing infrastructure and future generation needs. *Id.* at 571-72.

Nevertheless, in her rebuttal testimony, DEC witness Jiggetts indicated that to address affordability concerns raised by customers, as addressed by DEC witness Bowman, DEC removed approximately $173.2 million of plant associated with certain large load customers identified by the Public Staff. Tr. vol. 21, 446. Accordingly, DEC must also remove the extra facilities revenues associated with these large load customers to match. *Id*. The net effect of removing both the plant and the associated extra facilities revenues is a reduction to the revenue requirement of $12.1 million. *Id*. at 446-47.

The Comprehensive Settlement provides that revenues in the customer growth pro forma and the corresponding interconnection facilities for three specified large load customers shall be included in the rate case and allocated to all customer classes. Comp. Settl. § II.3. The revenues included are $21.884 million and the revenue requirement associated with the interconnection facilities is $2.353 million, resulting in a net benefit of $19.531 million to be allocated to all customer classes. *Id*. The Stipulating Parties agreed that no additional adjustments shall be made to the customer growth pro forma or billing determinants. *Id*.

Aside from the three specific customers the Stipulating Parties agreed to include in the case as agreed to in ¶ 3, DEC agreed to remove from this case the three remaining interconnection facilities identified by the Public Staff in its direct testimony as agreed to by DEC in the rebuttal testimony of witness Jiggetts, resulting in a reduction in rate base of $173.2 million on a system basis. *Id*. § II.4. The Comprehensive Settlement provides that DEC may seek recovery of the North Carolina retail portion of the associated undepreciated plant balance in future rate cases subject to the Public Staff's review of these costs and determination of its position as to the appropriateness of the recovery of these costs. *Id*. In addition, the Stipulating Parties agree there will be no regulatory asset/liability treatment for project costs incurred before rates become effective in DEC's next rate case. *Id*.

Finally, the Comprehensive Settlement requires DEC to establish a process to update the capital additions for interconnection facilities and the associated revenue for such customers through the same period subject to any changes directed by the Commission in a future proceeding. *Id*. § II.5.

Discussion and Conclusions

The Commission finds that the provisions of the Comprehensive Settlement addressing contested issues relating to the propriety of adjusting customer growth/billing determinants during MYRP2 to reflect revenues from large load customers as well as the inclusion of interconnection facilities associated with large load customers in DEC's rate base are the result of give-and-take inherent in settlement and are a reasonable resolution of these contested issues. The Commission also recognizes the potential benefit of establishing, for future rate cases, a process to update the capital additions for interconnection facilities and the associated revenue for relevant customers.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 50-54

COVID Bad Debt Deferral Recovery

The evidence supporting these findings of fact is contained in DEC's verified PBR Application and Form E-1; the testimony and exhibits of DEC witnesses Jiggetts, Speros, and Colley; the joint testimony and exhibits of the Public Staff Accounting Panel; the Comprehensive Settlement; and the entire record in this proceeding.

Summary of Evidence

In DEC's last rate case in Docket No. E-7, Sub 1276, the Commission granted DEC authority to continue to defer incremental bad debt expense from July 1, 2023, for future recovery. DEC intends to end the deferral as of the rates effective date in this proceeding. Tr. vol. 17, 344. DEC witness Jiggetts testified that the forecasted deferral balance is based on deferral through March 31, 2026, with returns calculated up to the rates effective date of January 1, 2027. Tr. vol. 12, 260. She added that DEC will seek recovery of incremental bad debt expense from April 1, 2026, through December 31, 2026, in a future rate case proceeding. *Id*.

The Public Staff agrees that DEC should cease the bad debt deferral but testified that the deferral should cease as of August 31, 2024, instead of DEC's proposed date of December 31, 2026. Tr. vol. 17, 344. The Public Staff Accounting Panel explained that the State of Emergency related to the COVID pandemic, which included a moratorium on utility disconnections, ended in August 2022, and DEC may have experienced high bad debt expense for some reasonable time thereafter, especially for customers on installment plans who enroll, default, then re-enroll on installment plans. *Id*. at 345. The Public Staff stated that during various discussions between DEC and the Public Staff, DEC indicated that policies on customer installment plans have evolved and from March 2022 onwards, the plans have been limited to 12 months or less and in some cases require down payments from customers to be in place. The Public Staff claimed that given the maximum extent allowed for a customer on a payment plan to enroll and to re-enroll in another payment plan before the disconnection process starts the latest month for any bad debt deferral to be COVID-related should have ended by August 2024. *Id*.

The Public Staff agreed with the five-year amortization period as proposed by DEC but does not believe DEC should be authorized to include the unamortized bad debt deferral balance in rate base. *Id*. The Public Staff also recommended that DEC not be permitted to earn a return on the deferred bad debt balance from July 2023 onwards. *Id*.

In her rebuttal testimony, DEC witness Jiggetts disagreed with the Public Staff's recommendation to end the bad debt deferral as of August 2024, which she testified was inconsistent with the Commission's order in the previous rate case (Docket No. E-7, Sub 1276). Tr. vol. 21, 455-57. She testified that the Commission directed the deferral to continue through the next general rate case, which is the current proceeding. *Id*. at 455-56. In addition, witness Jiggetts stated that in the absence of the continuation of the deferral, DEC's ongoing level of bad debt expense included in customer rates would have been $61 million higher to reflect DEC's test year level of bad debt expense in that case. *Id*. at 456. Instead, the Commission decided to allow DEC to continue the deferral, which witness Jiggetts testified resulted in a deferral balance of approximately $65 million compared to the $183 million that would have been collected from customers over three years if the actual 2022 amount had been included in base rates for 2024 through 2026. *Id.* at 456-57.

Witness Jiggetts also opposed the Public Staff's recommendation to deny a return during the deferral period and the amortization period. *Id*. at 457-58. She testified that to the extent bad debt expense has exceeded the amount in rates from July 2023 forward, that excess has been funded by DEC's investors, and they are entitled to a return on that capital until the balance is recovered. *Id*.

DEC witness Speros testified that DEC continued to experience elevated levels of bad debt compared to pre-pandemic levels throughout the deferral period which supported DEC's request to recover the deferred incremental bad debt balance for the full period authorized by the Commission. Tr. vol. 11, 493-94. From an accounting perspective, the Commission authorized DEC to defer incremental bad debt above the amount embedded in base rates until new base rates from this proceeding become effective. *Id*. at 495. Once that regulatory authorization was granted, DEC appropriately recorded the incremental bad debt amounts as a regulatory asset rather than

current-period expense based on the expectation of recovery established by the Commission's order. *Id*. An August 2024 cut-off would impose a new accounting end date that is not the one provided in the Commission's authorization and would arbitrarily split a single, continuous deferral period into two different treatments without any corresponding change in the underlying regulatory authorization. *Id*.

In his rebuttal testimony, DEC witness Colley described how DEC's credit policies evolved gradually from 2020 through 2025 in direct response to sustained elevated arrears. Tr. vol. 21, 79-86. During and after the pandemic, DEC offered a range of options to help customers manage their outstanding balances, including extended installment plans that allowed customers to pay down arrears over time, hardship assistance programs for customers facing severe financial difficulty, and outreach to help customers access available federal and state resources, and DEC's Share the Light Fund to help qualifying customers pay their energy bills. *Id*. at 83. He testified that while DEC believes these measures were appropriate and necessary to support customers during an unprecedented time period, the added flexibility in credit and payment arrangements contributed to a rise in customer arrearages over time. *Id*. at 84. Customers were eligible for multiple opportunities to defer or restructure balances and past-due levels increased. *Id*.

As DEC observed sustained increases in arrears following the pandemic, it took proactive steps to refine credit policies. Witness Colley explained that these adjustments were implemented incrementally over time and each step was focused on encouraging more timely customer payments with incremental adjustments made as payment behavior changed and arrears remained above pre-pandemic levels. It was not a one-time shift, but a steady progression over time. That evolution shows that the impact of the pandemic on customer payment behavior did not end on any fixed date. It persisted and required a measured, ongoing response. *Id.* at 79-80.

In the Comprehensive Settlement, the Stipulating Parties agree that DEC's bad debt deferral balance in this case shall include actual deferral amounts through June 2026, plus an estimated deferral amount of $12 million for the period from July through December 2026, less a one-time impairment of $17 million removed in June 2026. Comp. Settl. § II.7. The deferral shall cease on December 31, 2026. The deferral will include a debt-only return compounded annually during the deferral period with no rate base treatment (no return) during the amortization period. *Id*. This results in a total deferral of $60.4 million ($58 million plus $2.4 million from the prior tranche) which will be amortized over five years. Jiggetts Comp. Settl. Ex. 3 at 233; tr. vol. 17, 344.

Under the Comprehensive Settlement, the Stipulating Parties agree that DEC will be permitted to continue to defer the difference between actual bad debt expense and the amount in customer rates for the period from July 2026 through December 2026, subject to a $12 million cap. Tr. vol. 21, 503. If the actual deferral for such period is less than $12 million, DEC will defer the difference to be returned to customers in the next rate case. *Id*. If the actual deferral equals or exceeds $12 million, DEC will not collect additional amounts from customers in the next rate case. *Id*.

Discussion and Conclusions

The Commission accepts the Stipulating Parties' agreement regarding DEC's bad debt deferral as fair, just and reasonable, and in the public interest. The record reflects a dispute between DEC and the Public Staff regarding the appropriate end date for the deferral authorized in Docket No. E-7, Sub 1276, with the Public Staff recommending an August 31, 2024, cutoff, and DEC maintaining the deferral should continue through December 31, 2026. The Comprehensive Settlement resolves this dispute on reasonable terms, providing that the deferral balance shall include actual amounts through June 2026, plus an estimated $12 million for July through December 2026, less a one-time $17 million impairment, with the deferral ceasing on December 31, 2026. The Commission further finds that the $12 million cap on the July through December 2026 deferral period, combined with the mechanism requiring any shortfall to be returned to customers in the next rate case, appropriately ensures that customers only pay for actual incremental bad debt expense. The settlement's inclusion of a debt-only return during the deferral period with no rate base treatment during amortization, represents a reasonable compromise of the parties' competing positions regarding whether the deferred costs should accrue a return. Consistent with DEC and the Public Staff's agreement (as contained in ¶ 22 of the Partial Stipulation) concerning the methodology for determining carrying costs, the return accrued during the deferral period shall be compounded annually. Accordingly, the Commission approves the bad debt deferral terms set forth in ¶ 7 of the Comprehensive Settlement.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 55

Lead Lag Study

The evidence supporting this finding of fact is contained in DEC's verified PBR Application and Form E-1; the testimony and exhibits of DEC witnesses Jiggetts and Speros; the joint testimony and exhibits of the Public Staff Accounting Panel; the Sub 1276 Order; the Partial Stipulation and Comprehensive Settlement; and the entire record in this proceeding.

Summary of Evidence

In DEC's last rate case, DEC agreed in settlement to perform a lead-lag study prior to its next general rate case proceeding and to incorporate the results of this study in DEC's next rate case application. In accordance with this settlement, which was approved by the Commission, DEC engaged Atrium Economics to perform a detailed lead-lag study, which was completed on August 15, 2025, and included as Speros Direct Exhibit 2 and in Item 14 of DEC's Form E-1. Tr. vol. 11, 467; Sub 1276 Order at 25, 270.

Witness Speros explained that the purpose of a lead-lag study is to measure the amount of investor-supplied funds used to sustain utility operations from the time expenditures are made until the time payment is received. Tr. vol. 11, 466. Generally, a utility provides service before receiving payment from customers and often pays vendors for goods and services acquired by the utility after the expense is incurred, creating a timing gap. *Id*. Therefore, a lead-lag study is used to analyze transactions throughout the

year to determine the number of days between when services are rendered and when 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). *Id*. In some instances, revenue may be received prior to payment for the related expense (i.e., a net lead or alternatively a negative net lag). The revenue lag is compared to the expense lead and the net result is applied to each category of cost of service to determine DEC's cash working capital requirements. *Id*. at 466-67.

Speros Direct Exhibit 3 presents the calculation of DEC's North Carolina retail amount for investor funds invested in operations, which reflects the amount of investor-supplied funds needed to bridge the timing gap between when DEC pays expenses and when it receives revenues. *Id*. at 467. The exhibit applies the revenue lags and expense leads from the updated lead-lag study to the applicable components of the Test Year per books cost of service as allocated to DEC's North Carolina retail operations. *Id*. Based on this analysis, DEC's cash working capital requirement for investor funds for North Carolina retail operations is $466.1 million. *Id*. at 467-68. This amount is included in the cash working capital component of rate base. *Id*. at 468.

Witness Jiggetts explained how DEC adjusts cash working capital to incorporate the impact of the other pro forma adjustments using the updated lead-lag study provided by witness Speros. DEC also calculates the additional cash working capital required due to the proposed increase in rates. Witness Jiggetts testified that this adjustment is in accordance with the Commission's March 21, 2016, Order Clarifying Order on Lead-Lag Study Procedure in Docket No. M-100, Sub 137. Tr. vol. 12, 260-61; Jiggetts Direct Ex. 3 at 245-54. Witness Jiggetts updated this adjustment in her supplemental, second supplemental, and settlement testimony to reflect changes to other adjustments, including those agreed to in the Partial Stipulation. Tr. vol. 12, 283, 299, 316.

The Public Staff noted that in the current proceeding, DEC submitted a lead-lag study based on 12 months of historical data ending December 31, 2023. Tr. vol. 17, 321. DEC computed cash working capital using the lead-lag method and then adjusted it to fully reflect all of DEC's proposed adjustments before the amount of the proposed rate increases. *Id*. The Public Staff Panel testified that they likewise adjusted cash working capital under present rates to reflect all of the Public Staff's adjustments in accordance with the same Commission ruling on lead-lag study procedure. *Id*.; *see also* Public Staff Accounting Panel Ex. 1, sched. 2-1(d). The Public Staff likewise calculated the cash working capital effect of its recommended revenue change. Tr. vol. 17, 356.

In the Partial Stipulation, the Public Staff and DEC agreed to update cash working capital based on other agreed-to adjustments and agreed on the method for doing so, although the resulting amounts would vary based on the Commission's determination of the issues that remained unresolved. Partial Stip. § III.31. Those remaining issues were subsequently resolved in the Comprehensive Settlement, and the Stipulating Parties to the Comprehensive Settlement that were not parties to the Partial Stipulation agreed to its terms. Comp. Settl. § II.30.

Discussion and Conclusions

The Commission finds and concludes that DEC complied with the directive in the Sub 1276 Order to prepare an updated lead-lag study and incorporated the results of that study into its filing in this case. The Partial Stipulation provides that DEC and the Public Staff agreed to update cash working capital to reflect their agreed-upon adjustments and they also agree on the method for doing so. No party challenged DEC's lead-lag study or its method for calculating cash working capital. The Commission finds and concludes that the lead-lag study filed as Speros Direct Testimony Exhibit 2 should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 56-57

Reporting Requirements

The evidence supporting these findings of fact is contained in DEC's verified PBR Application and Form E-1; the Comprehensive Settlement; the Partial Stipulation; the testimony and exhibits of DEC witness Guyton; the joint testimony and exhibits of the Public Staff Distribution Panel; and the entire record in this proceeding.

Summary of Evidence

Quarterly Reliability Reporting

In the Public Staff Distribution Panel's testimony, the Public Staff recommended that the Commission require DEC to include SAIDI, SAIFI, CEMI-2, CEMI-4, CEMI-6, and CEMI-8 with MED and non-MED data, as well as the number of MEDs, annually for the most recent five years and quarterly for the most recent four quarters in its Quarterly Reliability Reports in Docket No. E-100, Sub 138A. Tr. vol. 16, 382. Finally, the Public Staff Distribution Panel recommended DEC track outages caused by equipment damage not related to weather outages and list it as Equipment Damage. *Id.*

In DEC witness Guyton's rebuttal testimony, witness Guyton explained that DEC supports reasonable enhancements to its reliability reporting that provide the Commission and interested stakeholders with clearer understanding of trends and the impact of grid investments. Tr. vol. 22, 41. Witness Guyton clarified that for outage cause coding, DEC follows Commission-approved and industry-standard methodologies for MED classifications. *Id.*

At the evidentiary hearing and in response to questions from counsel for CIGFUR III, DEC witness Guyton testified that DEC would be happy to report on reliability metrics as directed by the Commission, specifically Momentary Average Interruption Frequency Index event (MAIFIe). Tr. vol. 9, 284.

In Section IV, ¶ 1 of the Partial Stipulation, DEC agreed to report system reliability metrics quarterly, including CEMI-2, CEMI-4, CEMI-6, CEMI-8, and the number of MEDs. In Section III, ¶ 3 of the Comprehensive Settlement, DEC also agreed to include MAIFIe in its quarterly reliability reporting.

Multiyear Rate Plan Quarterly Reporting

In Section II, ¶ 18 of the Comprehensive Settlement, DEC agreed to file its quarterly MYRP project reports with the Commission showing the percentage of MYRP projects placed in service for each quarter and their respective costs during each Rate Year.

Discussion and Conclusions

The Comprehensive Settlement and Partial Stipulation establish certain reporting obligations. Specifically, Section IV, ¶ 1 of the Partial Stipulation and Section III, ¶ 3 of the Comprehensive Settlement obligate DEC to include additional reliability metrics as part of its Quarterly Reliability Reports filed in Docket No. E-100, Sub 138A. Section II, ¶ 18 of the Comprehensive Settlement obligates DEC to include percentages of MYRP projects placed in service for each quarter and their respective costs for each Rate Year.

No other party offered any evidence addressing the reporting obligations outlined in the Comprehensive Settlement and Partial Stipulation or otherwise addressed above. Based upon the record evidence and consistent with the Comprehensive Settlement and Partial Stipulation, the Commission finds and concludes that the reporting obligations outlined in § II and § III of the Comprehensive Settlement and § IV of the Partial Stipulation are approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 58

Affordability

The evidence supporting this finding of fact is contained in the testimony and exhibits of DEC witnesses Bowman and Colley; the joint testimony and exhibits of the Public Staff Policy Panel; the Comprehensive Settlement; and the entire record in this proceeding.

Summary of Evidence

DEC witness Colley presented testimony describing DEC's Affordability Ecosystem. Witness Colley explained that the ecosystem encompasses four principal components: (1) energy efficiency and demand-side management programs, (2) bill management options, (3) agency partnerships and financial assistance, and (4) customer assistance programs. Tr. vol. 6, 75-76.

Regarding the Customer Assistance Program (CAP) pilot, witness Colley testified that the program was approved by the Commission in Docket No. E-7, Sub 1276 as a three year pilot beginning January 2024 that provides a $42 monthly bill credit to LIHEAP-eligible customers. *Id.* at 80. Approximately 43,000 customers were enrolled as of September 2025, with enrollment expected to increase to approximately 56,000 by 2026. *Id.* Through the end of 2025, the program's cost was approximately $33 million with net benefits to all customers of approximately $600,000. *Id.* at 144, 153. Witness Colley confirmed that DEC is not proposing to continue the CAP pilot beyond its December 31, 2026, expiration date and is not proposing any new affordability programs. *Id.* at 80, 144.

Witness Colley testified regarding agency partnerships, noting that since January 2024, DEC customers have received approximately $53 million in agency pledges, including over $600,000 from the Share the Light Fund. *Id.* at 78-79. DEC's Payment Navigator program received approximately 24,000 calls between June 2024 and June 2025, connecting customers with available financial assistance. *Id.* at 79-80.

DEC witness Bowman testified regarding the bill impact of the proposed rate adjustments, explaining that a typical residential customer using 1,000 kWh per month would experience an increase of approximately $10 per month in Rate Year 1 from current bill levels of approximately $156. *Id.* at 147. Witness Bowman further addressed the combined impact for CAP participants following the expiration of the pilot, noting that such customers would experience an effective monthly change of approximately $52 (comprising the $42 credit loss plus the $10 rate increase). *Id.* at 147-48.

In their testimony, the Public Staff Policy Panel testified that DEC's customers have expressed concerns about affordability "in staggering amounts" and summarized the public witness testimony received in this proceeding as well as the Consumer Statements of Position filed in the docket. Tr. vol. 18, 76-77. Witnesses at public witness hearings testified on the difficult choices ratepayers are currently facing between paying an electric bill, putting food on the table, or accessing healthcare. *Id.* They highlighted that nearly a third of North Carolinians are living at or below 200% of the federal poverty level, and many families and individuals in North Carolina are at risk of spending a disproportionate amount of their income on electricity and other essentials. *Id.* The Policy Panel further testified that in addition to bill increases resulting from a general rate case, ratepayers also experience rate increases several times each year as a result of riders or other alternative ratemaking mechanisms. *Id.* at 78-79.

Section II, ¶ 28 of the Comprehensive Settlement provides for shareholder financial contributions totaling $10 million to support bill assistance through the Share the Light Fund and health and safety repairs through the Helping Home Fund, which facilitates weatherization for income-qualified customers. Comp. Settl. § II.28. It also provides that DEC will file an annual report by April 1, starting in 2028, that will include evidence that shareholder funds were disbursed to agencies and provide the total number of customers assisted through Share the Light and from health and safety funds in the prior calendar year.

Discussion and Conclusions

The Commission has carefully considered the evidence regarding affordability presented in this proceeding, including the testimony of DEC witnesses Colley and Bowman, the testimony of the Public Staff Policy Panel, and the provisions of the Comprehensive Settlement. The Commission recognizes that affordability is an important consideration under the PBR Statute, which identifies reducing the energy burden for low-income customers among the purposes a PBR application may serve. The Commission further recognizes and underscores the significant impact on ratepayers of the rate increase initially requested in this proceeding and has heard concerns from many such ratepayers at the public witness hearings held throughout DEC's service territory and in consumer statements of position filed in this proceeding.

The Commission finds that the provisions of the Partial Stipulation and Comprehensive Settlement, which include a substantial aggregate reduction in DEC's revenue requirements, the MYRP Refund Rider, and $10 million in shareholder contributions, in conjunction with DEC's existing Affordability Ecosystem, provide a reasonable framework for addressing customer affordability during the rate plan period.

The Commission must balance affordability concerns against the critical need for infrastructure investment to maintain and improve system reliability. The investments approved in this proceeding as set forth in the Partial Stipulation and Comprehensive Settlement are necessary to serve customers reliably. The rate increases resulting from these investments are moderated by the reductions to DEC's requested revenue requirement reflected in the Partial Stipulation and Comprehensive Settlement.

The Commission encourages DEC to continue to explore all avenues to reduce costs for customers, to continue its efforts to connect customers with available assistance resources, and to explore additional opportunities to reduce low-income energy burdens consistent with the objectives of the PBR Statute. The Commission will continue to monitor affordability metrics in future proceedings.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 59-65

Riders

The evidence supporting these findings of fact is contained in DEC's verified PBR Application and Form E-1; the testimony and exhibits of DEC witnesses Jiggetts, Sykes, Byrd, and Speros; the testimony and exhibits of Public Staff witness Metz; the joint testimony and exhibits of the Public Staff Accounting Panel; the testimony and exhibits of CUCA witness McGlothlin; the Partial Stipulation and Comprehensive Settlement; and the entire record in this proceeding.

Summary of Evidence

DEC witness Sykes testified in support of expanding the existing Nuclear PTC Rider to include PTCs associated with non-nuclear facilities, such as solar and hydroelectric, and renaming it the PTC Rider so that customers receive the benefits of any PTCs generated and monetized under the IRA. Tr. vol. 12, 160-62. Public Staff witness Metz testified in support of the expansion, stating that it would facilitate timelier flowback of PTC benefits to ratepayers and that it is administratively efficient to use one rider mechanism for all PTCs. Tr. vol. 17, 218-19. Witness Metz testified that it is reasonable to continue the existing rider's four-year amortization of such credits and that DEC provide information in its annual rider update regarding the disposition of PTCs being flowed back, the method and timing of monetization, and the amount returned to customers. *Id.* at 219-20. CUCA witness McGlothlin generally supported the expansion but recommended that costs already included in base rates or charged against earnings be excluded from the PTC Rider, that DEC provide sufficient documentation of incremental costs in its PTC Rider updates, and that the Commission consider a cap disallowing incremental costs exceeding 10% of the PTC value unless DEC demonstrates that they were reasonable and necessary. Tr. vol. 8, 107-09. In rebuttal, DEC witness

Sykes testified that recovery of incremental costs is reasonable, that DEC's accounting controls and quarterly reporting to the Public Staff ensure only proper costs are included, and that a 10% cost cap could lead to reasonable and prudent costs being unrecovered. Tr. vol. 22, 235-37. Witness Sykes also testified that the Sub 1276 stipulation establishing the Nuclear PTC Rider already provided for netting of costs, and that incremental costs include execution costs to monetize the credits, such as broker, legal, and tax advisory fees, and costs to comply with the IRA's prevailing wage requirements. *Id*. at 233-35.

In the Partial Stipulation, the Stipulating Parties agreed to expand the PTC Rider as proposed by DEC, provided that DEC will add back non-outage incremental O&M for prevailing wages to the test year and discontinue all prevailing wage deferrals effective January 1, 2027. Other incremental costs not in customer rates to achieve the tax credit benefits may still be netted in the PTC Rider. Partial Stip. § III.25; tr. vol. 12, 312, 314.

DEC witnesses Sykes and Jiggetts testified in support of terminating the EDPR and incorporating amounts that would otherwise be recovered through the EDPR into base rates. Tr. vol. 12, 159-60, 272-73. Witness Sykes explained that the EDPR is unique to DEC, is relatively small and will continue to decline because it includes only costs of DSM programs that predate 2007 and has resulted in an over-collection of $1.2 million or less in each of the past five years, and thus, eliminating it promotes regulatory efficiency and aligns DEC's riders with DEP's. *Id*. at 159-60. The Public Staff Accounting Panel did not object to the elimination of the EDPR and inclusion of the amount normally recovered through the rider in base rates, noting that the rider is relatively small and has been over-recovered in recent years. Tr. vol. 17, 369. In the Partial Stipulation, the Stipulating Parties agreed to eliminate the EDPR Rider and recover the associated costs in base rates. Partial Stip. § III.26.

DEC witness Jiggetts testified that pursuant to Ordering ¶ 48 of the Sub 1276 Order, DEC continued to record revenues received for deferred costs beyond the approved amortization period and proposes to return the resulting net over-amortization balance to customers over a two-year period through the RAL Rider. Tr. vol. 12, 239, 272. Witness Byrd testified that RAL-2 is a new tranche of DEC's Regulatory Asset and Liability Rider and would be set at a uniform rate of $(0.000030) per kWh for all rate schedules. Tr. vol. 11, 541-42. No party opposed DEC's proposal to establish the RAL Rider. In the Partial Stipulation, the Stipulating Parties agreed that DEC shall establish a RAL Rider to refund to customers the net over-amortization of expired regulatory assets and liabilities as described in the direct testimony of witness Jiggetts. Partial Stip. § III.24.

DEC witnesses Jiggetts and Speros testified in support of establishing a pension rider to collect the difference between pension expense included in base rates and actual pension expense, which is subject to significant volatility due to financial market conditions outside DEC's control. Tr. vol. 11, 475-77; tr. vol. 12, 271. The Public Staff Accounting Panel recommended that the Commission not approve the proposed pension rider, reasoning that the Accounting Standards Codification Topic 715 (ASC 715) already smooths actuarial losses over five years, that strong market performance since 2022 mitigates the 2022 losses, and a pension rider would create single-issue ratemaking outside of a full rate case. Tr. vol. 17, 366-68. In his rebuttal, witness Speros testified that the fundamental purpose of the rider is to provide timely and appropriate recovery of pension cost volatility, and the

deferral of asset gains and losses under ASC 715 supports rather than undermines the argument for a rider. Tr. vol. 11, 497-98. He also testified that a rider established in a general rate case, in which all elements of the revenue requirement are examined, does not constitute single-issue ratemaking. *Id*. at 498-99. In the Partial Stipulation, DEC agreed to withdraw its proposed pension rider. Partial Stip. § III.23.

Discussion and Conclusion

No party opposed the rider-related provisions of the Partial Stipulation, and under Section II, ¶ 30 of the Comprehensive Settlement, the Stipulating Parties that were not parties to the Partial Stipulation, including CUCA, agreed to its terms. The Commission concludes that the expansion of the PTC Rider, the elimination of the EDPR Rider, the establishment of the RAL Rider, and DEC's withdrawal of its proposed pension rider as set forth in the Partial Stipulation are just and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 66-67

Carrying Costs

The evidence supporting these findings of fact is contained in DEC's verified PBR Application and Form E-1; the testimony and exhibits of DEC witness Jiggetts; the joint testimony and exhibits of the Public Staff Accounting Panel; the Partial Stipulation; the Storm Cost Stipulation and Comprehensive Settlement; and the entire record in this proceeding.

Summary of Evidence

DEC divides the after-tax annual WACC by 12 to calculate a monthly WACC percentage rate that is used in the calculation of carrying costs on the cumulative deferred balance accumulated through the preceding month. Tr. vol. 17, 352. DEC calculates carrying costs in this manner on, among other items, the Hurricane Helene securitization true-up, the storm securitization servicing and administration fee and upfront bond issuance cost true-ups, Winter Storm Fern costs, the CCR deferral, and the bad debt expense deferral. *Id.*

The Public Staff has raised concerns in several dockets regarding how DEC applies the WACC approved by the Commission to situations where it calculates interest for an interval of less than one year, and the Commission has directed the Public Staff to address this issue in a general rate case proceeding. *Id* at 351-52.

The Public Staff argued that DEC's carrying cost methodology overstates the appropriate return because DEC applies the full annual WACC on a monthly basis and compounds that return each month. *Id*. at 353. In the Public Staff's view, because WACC is an annual rate, any calculation for periods of less than one year should either apply a simple pro rata rate to principal or use a discounted monthly rate that, when compounded, equals the approved annual WACC. *Id*. Using an illustrative $100,000 deferral balance and DEC's Commission-approved after-tax WACC of 6.9958%, the Public Staff showed that DEC's method produces an effective annual return of 7.2245%, compared with 6.9958% under the Public Staff's discounted method. *Id.* at 354-55. The Public Staff made

adjustments to carrying costs on the Hurricane Helene costs true-up, the CCR deferral, and the COVID bad debt deferral in this case. *Id*. at 355.

In her rebuttal testimony, DEC witness Jiggetts disagreed with the Public Staff, testifying that DEC's methodology applies the Commission-approved after-tax WACC to deferred balances on a monthly basis because DEC finances those balances continuously, and that the Public Staff's discounting method would deny DEC full recovery of its authorized return. Tr. vol. 21, 478-79. She further testified that it is appropriate to add the prior month's interest to the deferral balance because the amounts are not being received from customers on a monthly basis. *Id*. at 479. She indicated that this process of adding the prior month's interest to the outstanding balance, or compounding of interest, is a standard practice for loans or borrowing arrangements and for deferrals, which are, in essence, borrowing arrangements between DEC's investors and its customers. *Id*.

In the Partial Stipulation, the Stipulating Parties agreed that the return accrued during the deferral period shall be compounded annually for the COVID bad debt, CCR, and Hurricane Helene (post-securitization bond issuance) deferrals. Partial Stip. § III.22. Additionally, the Stipulating Parties agreed to use annual compounding when accruing a return, if applicable, for deferrals (both regulatory assets and liabilities) and riders through the next two general rate cases. *Id*. Per the Partial Stipulation, the effect of annual compounding may be achieved by either (a) applying monthly compounding at a discounted rate to achieve the effect of annual compounding, or (b) applying annual compounding at the annual rate. *Id*.

Discussion and Conclusion

The Commission adopts the Stipulating Parties' agreed-upon approach to carrying cost methodology as part of the give and take of the Partial Stipulation. The Commission notes that the appropriate methodology for calculating carrying costs has been a disputed issue between DEC and the Public Staff in a number of recent dockets and appreciates the Stipulating Parties reaching a resolution that applies not only to the true-up and deferrals identified in the Partial Stipulation but also to future deferrals and riders through the next two general rate cases. The Commission concludes that this resolution reasonable and in the public interest and accordingly accepts the carrying cost methodology set forth in the Partial Stipulation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 68

Quality of Service

The evidence supporting this finding of fact is contained in DEC's verified PBR Application and Form E-1; the testimony and exhibits of DEC witnesses Guyton, Fogg, Colley, and Bowman; the joint testimony and exhibits of the Public Staff's Distribution Panel; and the entire record in this proceeding.

Summary of Evidence

DEC witnesses Guyton and Fogg testified to the performance of DEC's T&D system during the base period. Witness Fogg testified that DEC's transmission system performed

well, and current reliability metrics show that the transmission system is performing strongly, and DEC is seeking to continue transmission investments to expand capacity, meet energy demand, and strengthen the grid. Witnesses Fogg and Guyton noted that DEC utilizes industry-standard SAIDI and SAIFI metrics to measure outage durations and that the transmission system also utilizes the Outages per Hundred Miles per Year — Sustained Automatic (OHMY-SA) metric. Tr. vol. 9, 149-50, 193. Witness Fogg testified that the primary drivers for the OHMY-SA performance are vegetation from outside the right-of-way, wildlife contact, lightning, public interference, and relay and control systems. *Id.* at 150. Witness Guyton testified that DEC's operational investments since PBR1 have allowed DEC to meet its operational performance and customer satisfaction goals, and it is providing safe and reliable service. Witness Guyton cited notable improvements in DEC's SAIDI and SAIFI metrics for 2024, which he attributed to DEC's grid improvement efforts, adjustments to the hotline tag protection settings, and continued implementation of Self-Optimizing Grid technology. *Id.* at 192-95.

In the Public Staff Distribution Panel's direct testimony, Public Staff testified that while DEC's overall provision of service is adequate, it was troubled by the fact that the major service quality metrics are heading in a worse direction for customers. Tr. vol. 16, 403. The Distribution Panel recommended DEC implement additional reliability metric reporting in its quarterly reliability report in Docket No. E-100, Sub 138A to include SAIDI, SAIFI, CEMI-2, CEMI-4, CEMI-6, and CEMI-8, with MED and non-MED data, and the number of MEDs annually for the most recent five years and quarterly for the most recent four quarters. Tr. vol. 16, 382.

In his direct testimony, DEC witness Colley testified that in addition to providing safe and reliable electric service, DEC continues to invest in people, processes, and technology to meet its evolving customer expectations. Tr. vol. 6, 69. Witness Colley explained that DEC's customer service teams support diverse customer needs through personalized assistance, multi-channel communications, and expanded digital self-service tools, which are all informed by direct customer feedback and industry benchmarking. *Id.* at 69-70. Witness Colley described the enhancements DEC made to its mobile app in response to customer feedback, which includes the ability to view and pay bills, report an outage, enroll in billing and payment programs, view billing history, monitor usage, receive personalized offers, and receive outage restoration updates. *Id.* at 73-74.

Witness Colley further described the customer care teams, which are specialized to provide support to residential and business customers. Witness Colley testified that DEC's contact center team includes a blend of remote, on-site, and vendor customer care specialists that are available to process and support inbound and outbound calls, live web chat, emails, mailed letters, faxes, and social media inquiries from DEC's nonresidential and residential customers. *Id.* at 72. Witness Colley noted that the customer care specialists receive ongoing training to remain current on rates, programs, and services, enabling them to handle a broad range of customer inquiries. *Id.*

Witness Colley also testified about the programs DEC offers to support customers with the affordability of electric service. Witness Colley described the combination of energy efficiency and demand-side management offerings, bill management options, agency partnerships, and customer assistance programs. *Id.* at 75-81. Witness Colley

also described the ways in which DEC provided customer relief during the aftermath of Hurricane Helene by temporarily suspending billing for customers unable to receive service, suspending disconnections for non-payment in affected areas, waiving late payment charges, offering customized storm arrangement installment plans, and waiting connection fees and security deposits for customers relocating due to impacts of Hurricane Helene. *Id.* at 83-86.

Through the Partial Stipulation and Comprehensive Settlement, DEC agreed to report system reliability metrics quarterly, including CEMI-2, CEMI-4, CEMI-6, CEMI-8, MAIFIe and the number of major event days. Partial Stip. § IV.1; Comp. Settl. § III.3.

In DEC witness Bowman's settlement testimony, she testified that the Comprehensive Settlement is a fair and balanced outcome for both DEC and its customers, and the compromises achieved therein will allow DEC to keep rates competitive, maintain the reliability DEC's customers expect, support North Carolina's continued growth while ensuring the State remains an affordable place for all of our customers, and continue to be an attractive and competitive climate for business and industry. Tr. vol. 21, 66-67.

Discussion and Conclusion

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 2023 Rate Case Order, the Commission concludes, based on the record in this proceeding, that the quality of service provided by DEC is adequate. No party other than the Public Staff presented evidence on DEC's service quality.

Additionally, no party other than the Public Staff 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. 69-71

Base Fuel and Fuel-Related Factors

The evidence supporting these findings of fact is contained in DEC's verified PBR Application and Form E-1; the testimony and exhibits of DEC witness Sykes; the joint testimony and exhibits of the Public Staff Accounting Panel, the testimony and exhibits of Public Staff witness Lawrence; the testimony of AGO witness Burgess; the testimony of CIGFUR III witness Collins; the Comprehensive Settlement; and the entire record in this proceeding.

Summary of Evidence

In his direct testimony, DEC witness Sykes supported DEC's fuel component of proposed base rates for all customer classes and the fuel pro forma adjustments to the test year operating expenses shown on Jiggetts Direct Exhibit 2. Tr. vol. 12, 155-57. Witness Sykes proposed to use the total prospective fuel and fuel-related cost factors approved in

Docket No. E-7, Sub 1313 and implemented September 1, 2025. *Id.* Witness Sykes explained that these factors represented the fuel-related amounts that DEC is collecting from its North Carolina retail customers through its approved rates as of the filing date of the PBR Application and related testimony, and DEC's intent in using the fuel-related factors in effect at the time of the PBR Application was to make clear that DEC is requesting a rate increase that relates to non-fuel revenues only, i.e., a request that includes neither an increase nor a decrease related to the recovery of fuel costs. *Id.* at 155, 157.

Public Staff witness Lawrence testified that pro forma adjustment NC2010 did not include the full purchase power expense and other miscellaneous expenses, which are now recoverable within the fuel rider. Tr. vol. 16, 502. He recommended that NC2010 be modified to include the additional costs now allowable within the fuel rider. *Id.* However, he noted that the Public Staff and DEC will work together to determine the appropriate adjustment to be made. *Id.* The Public Staff Accounting Panel referenced Public Staff witness Lawrence's testimony regarding pro forma adjustment NC2010, noted that the Public Staff did not make an accounting adjustment related to witness Lawrence's pro forma NC2010 testimony, and reiterated that the Public Staff will work with DEC to determine the appropriate adjustment to be made. Tr. vol. 17, 335.

AGO witness Burgess opposed DEC's pro forma NC2010, recommending that DEC set the pro forma fuel costs in this proceeding equal to the per-book fuel expense to provide greater assurance of separate fuel rider treatment, arguing that any over- or under-collection would accrue to the deferred fuel balance and be addressed through the fuel rider. Tr. vol. 19, 70-71. Witness Burgess contended this would not pose an undue burden or regulatory lag on DEC because the fuel rider is now subject to quarterly updates following the enactment of S.B. 266. *Id.* at 71. Finally, he argued that the impact of his recommendation would reduce the baseline revenue requirement by approximately $300 million. *Id.*

CIGFUR III witness Collins recommended that the Commission eliminate DEC's accrual of interest on fuel under-recoveries that fall within the operational scope of the quarterly fuel true-up mechanism. *Id.* at 280. He argued that elimination of interest is consistent with the quarterly true-up mechanism created by S.B. 266, which he argued "materially compressed" the regulatory lag between DEC's fuel cost incurrence and recovery that the interest was meant to cover, avoids requiring ratepayers to fund a carrying charge that compensates DEC for a delay the new mechanism substantially removes, and that elimination is "consistent with the principle that ratepayers should pay only for the costs they cause." *Id.* at 279-80.

On rebuttal, DEC witness Sykes began his testimony by explaining the changes resulting from S.B. 266 to fuel cost recovery in North Carolina as it relates to concerns raised by the intervening parties. Tr. vol. 22, 226-27. He further testified that DEC agreed with the Public Staff's recommended adjustment to DEC's pro forma NC2010 and that DEC will make the appropriate fuel cost adjustment in its compliance filing once it has the requisite orders from the Commission in this proceeding and its current fuel proceeding. *Id.* at 228. He further testified that DEC remains committed to working with the Public Staff to ensure that the fuel cost treatment in this proceeding is appropriate and that customers are not overcharged or undercharged for fuel-related expenses. *Id.*

In response to AGO witness Burgess, DEC witness Sykes explained that DEC uses Commission-approved fuel factors when setting base fuel rates in a general rate case proceeding, and that N.C.G.S. 62-133.2(d) describes: (1) how base fuel factors are established in a general rate case; (2) the increment or decrement fuel factors in an annual fuel proceeding; and (3) how these factors work together to recover DEC's fuel expense. *Id.* at 229. He further explained that DEC does not have the discretion to propose fuel factors in a general rate case proceeding that have not been approved by the Commission as witness Burgess recommends, and that when filing its PBR Application, DEC was therefore limited to using the most recently approved fuel factors from Docket No. E-7, Sub 1313. *Id.* at 230. Witness Sykes reiterated that DEC will work with the Public Staff to ensure customers are not over- or under-charged for fuel-related expenses in the compliance filing after the requisite orders are issued by the Commission. *Id.* He also noted that, by updating the fuel base fuel factors in its compliance filings, DEC will comply with N.C.G.S. § 62-133.2(a)(4), which requires DEC to make appropriate adjustments to its fuel and fuel-related costs already being recovered in base rates to avoid double recovery of such fuel costs. *Id.*

In response to CIGFUR III witness Collins, DEC witness Sykes stated that it is reasonable for DEC to continue to accrue interest on fuel under-recoveries. *Id.* at 231. He explained that S.B. 266 requires DEC to recognize interest on fuel under-recoveries, and that there is a real and unavoidable financing cost associated with carrying deferred fuel balances (i.e., short-term debt). *Id.* He noted that these costs have always been incurred by DEC and stated that S.B. 266 acknowledges this reality by requiring that interest be applied to an under-recovered fuel balance. *Id.* Finally, witness Sykes explained that while quarterly fuel filings may reduce regulatory lag associated with over- and under-recovery balances, it is not a guarantee that quarterly fuel filings will adjust fuel factors already being billed to customers and noted that they also do not eliminate the financing costs incurred during the deferral period on fuel. *Id.* at 232.

In the Comprehensive Settlement, the Stipulating Parties agreed to work together on a proposal to finalize DEC's fuel treatment in its compliance filing, the intent of which will be to update the base fuel factors to reflect the Commission's forthcoming order in Docket No. E-7, Sub 1334. Comp. Settl. § II.11. In addition, the Stipulating Parties agreed that DEC would not seek to true-up any additional fuel and fuel related costs incurred prior to January 1, 2025, that are not already included in either the current DEC fuel rider or the pending DEC fuel rider, Docket No. E-7, Sub 1334, for rates effective September 1, 2026. *Id*. § II.12. Finally, the Stipulating Parties agreed to meet and discuss the appropriate calculation of interest under N.C.G.S. 62-133.2. *Id*. § II.13.

Discussion and Conclusions

The Commission gives significant weight to ¶¶ 11-13 of the Comprehensive Settlement regarding DEC's fuel updates, the testimony of DEC witness Sykes, and the testimony of Public Staff witness Lawrence and the Public Staff Accounting Panel. In doing so, the Commission declines to accept AGO witness Burgess' recommendations regarding DEC's base fuel costs in this proceeding and instead determines that the provisions of the Comprehensive Settlement related to DEC's fuel updates are reasonable and appropriate. Accordingly, the Commission finds and concludes that the

Stipulating Parties shall work together on a proposal to finalize DEC's fuel treatment in DEC's compliance filing, the intent of which will be to update the base fuel factors so that they reflect the Commission's order in Docket No. E-7, Sub 1334. The Commission further finds and concludes that DEC shall not seek to true-up any additional fuel and fuel related costs incurred prior to January 1, 2025, that are not already included in the current DEC fuel rider or in the pending DEC fuel rider for rates effective September 1, 2026, in Docket No. E-7, Sub 1334. Finally, the Commission directs the Stipulating Parties to meet and discuss the appropriate calculation of interest under N.C.G.S. § 62-133.2, in accordance with the Comprehensive Settlement.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 72-73

Residential Decoupling Mechanism and Earnings Sharing Mechanism

The evidence supporting these findings of fact is contained in DEC's verified PBR Application and Form E-1; the testimony and exhibits of DEC witnesses Abernathy, Byrd, and Beveridge; the testimony and exhibits of Public Staff witnesses D. Williamson, Fernandez, and Fahey; the Comprehensive Settlement; and the entire record in this proceeding.

Summary of Evidence

Residential Decoupling Mechanism

DEC witness Abernathy provided direct testimony on DEC's RDM, which is a rate-making 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. Tr. vol. 12, 186. The following Rate Schedules are affected by the RDM: RS, RE, ES, RT, RSTC, RETC, and RT-EV, along with any new residential rate schedules approved by the Commission during the plan period. *Id*. Witness Abernathy explained how the annual and monthly target revenues per customer are calculated for Rate Years 1 and 2, as well as how DEC estimates the number of residential customers for each month for each rate year. *Id*. at 186-88. Witness Abernathy's testimony also discussed how the difference between target residential revenues and actual residential revenues is deferred and includes a carrying charge and that deferral amount would be adjusted to account for incremental EV revenues. *Id*. at 188-91.

Witness Abernathy explained that DEC no longer includes an adjustment to the decoupling calculation to account for Demand-Side Management/Energy Efficiency (DSM/EE) net lost revenues in accordance with the Commission's May 22, 2024, Order Approving Revisions to Demand Side Management and Energy Efficiency Cost Recovery and Utility Incentive Mechanism issued in Docket No. E-7, Sub 1032. *Id*. at 191-92. Witness Abernathy also explained that the residential decoupling mechanism rider and the ESM rider are now subject to true-up as approved by the Commission in its August 13, 2025, Order Amending Commission Rule R1-17B issued in Docket No. E-100, Sub 178. *Id.* at 192-93.

Public Staff witnesses D. Williamson and Fernandez testified that the PBR Statute authorizes the Commission to approve a residential decoupling mechanism designed to break the link between revenues and the consumption of electricity. Tr. vol. 13, 236-37. Witnesses D. Williamson and Fernandez also testified that the statute provides the utility with an opportunity to exclude rate schedules or riders associated with EV charging from sales calculations for purposes of the mechanism. *Id*. at 237. Witnesses D. Williamson and Fernandez recommended that instead of using North Carolina Department of Transportation data to estimate the number of EVs in DEC's service territory, DEC should use only EVs registered to customers enrolled in DEC's recently approved Schedule RT-EV to determine the number of EVs on its system for purposes of calculating the residential decoupling mechanism. *Id*. at 242-43.

In their rebuttal testimony, DEC witnesses Byrd and Beveridge testified that limiting the number of EVs for purposes of the decoupling calculation to those registered to customers enrolled in Schedule RT-EV would deny DEC the full EV revenue exclusion allowed by the PBR Statute. Tr. vol. 21, 579.

In the Comprehensive Settlement, the Stipulating Parties agreed to accept the Public Staff's position that only sales under DEC's EV tariff should be included in the calculations to exclude EV sales margin from the residential decoupling mechanism and ESM. Comp. Settl. § II.22.

Earnings Sharing Mechanism

DEC witness Abernathy testified in support of the ESM, which is a component of the MYRP. Tr. vol. 12, 193-96. Witness Abernathy explained that if DEC's adjusted earnings exceed the authorized ROE established by the Commission in this rate case plus 50 basis points, those excess earnings, including a return calculated at the WACC, will be distributed to customers over a 12-month period via the annual ESM Rider. *Id*. at 193.

Witness Abernathy testified that for purposes of the ESM calculation, in accordance with the PBR Statute, DEC adjusts earnings for weather, DSM/EE incentives, and PIMs. *Id*. at 194-95. DEC also adjusts earnings for EV sales, the Second TCA Adjustment, and amounts related to the ESM rider, if applicable. *Id*.

Witness Abernathy noted that DEC is not proposing any changes to the ESM methodology approved in MYRP1 and therefore proposes to calculate adjusted earnings using end of period rate base and the actual regulatory capital structure as of the end of the Rate Year. *Id*. at 194. Witness Abernathy also stated that if the proposed business combination for DEC and DEP is approved, then DEC and DEP will no longer retain separate accounting books and records. Under the combined utilities, witness Abernathy explained, the ESM cannot be separately calculated. *Id.* at 195

Public Staff witness Fahey testified that he disagreed with DEC's practice of using a single point in time (end of the Rate Year) for rate base, equity, cost of debt and capital structure in calculating the ESM and recommended that the Commission require the ESM for future MYRPs to be calculated on a 13-month average basis using the capital structure approved by the Commission and calculated on an individual utility basis. Tr. vol. 16, 184,

236-39. When calculated in that manner, he noted that the ESM would have returned almost $30 million to ratepayers in rate year one of DEP's MYRP. *Id*. at 237. Witness Fahey explained that one-time events such as debt-issuances or changes in the size of rate base can influence a single-point-in-time earnings and ROE analysis. *Id*. at 238-39. He indicated that when rate base is growing, using an end of period analysis results in an underestimation of the earned return. *Id*. at 240. Witness Fahey explained that the impact of one-time events is mitigated by using an average across the period rather than a single point in time and by using DEC's approved capital structure. *Id*. at 239, 245. He noted that the Commission had taken a similar approach with respect to the ESM available to water and sewer utilities. *Id*. at 241-44.

Witness Fahey also recommended that the Commission reject DEC's proposal to exclude EV sales from the ESM calculation, as it is not required by the statute and allows DEC to retain a greater total of earnings as sales from EVs increase. *Id*. at 247-48.

Finally, witness Fahey opposed DEC's proposal to combine the DEC and DEP ESMs beginning January 1, 2027. *Id*. at 184. He noted that the ESM is the only element of rates that DEC and DEP are proposing to merge in the pending general rate cases while their other rates will remain separate and indicated that the ESM rider should be applied on a combined basis at a point when rate schedules have been generally aligned between the two legacy entities. *Id*. at 248-29. He explained that if the ESM were calculated on a combined basis, the payback would be the average of the two utilities' earnings, thus resulting in under-payment to one utility's customers and an overpayment to the other, resulting in a cross-subsidy. *Id*. at 250-51.

In her rebuttal testimony, DEC witness Abernathy disagreed with the changes to the ESM calculation recommended by the Public Staff. She noted that end of period rate base is used to set rates in base rate cases and is also used in DEC's deferral requests. She concluded that DEC's methodology is consistent with standard ratemaking and is a reasonable way to evaluate earnings. Tr. vol. 21, 420. Witness Abernathy also noted that the PBR Statute allows the exclusion of revenues associated with EV charging from the decoupling mechanism to "preserve the electric utility's incentive to encourage electric vehicle adoption" and provides that the Commission may consider whether a PBR application "encourages beneficial electrification, including electric vehicles." *Id*. at 422. She testified that DEC is proposing to exclude revenues associated with EV charging from the earnings calculation for the same policy reasons, reasoning that if EV revenues are included in the ESM calculation, DEC would have a disincentive to offer programs to encourage EV adoption. *Id*. Witness Abernathy also described the challenges of maintaining separate ESMs for DEC and DEP following the Combination, indicating that while revenues will be tracked separately following Legal Day 1, costs will not be tracked separately. *Id*. at 424.

In the Comprehensive Settlement, the Stipulating Parties agreed that EV sales, calculated using DEC's EV tariff, should be excluded from the ESM calculation. Comp. Settl. § II.22. In addition, the Stipulating Parties agreed to use a 13-month average rate base and DEC's approved capital structure for purposes of calculating the ESM. *Id*. §§ II.23-ll.24.

The Comprehensive Settlement also provides that DEC and DEP shall maintain separate ESMs for PBR2 with the understanding that expenses and rate base will have to be allocated to the separate utilities based on revenue, and a blended capital structure and debt rate will be used to derive individual utility results. *Id*. § II.25.

Discussion and Conclusion

The Commission concludes that the residential decoupling mechanism and the ESM proposed by DEC as modified by the Comprehensive Settlement 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 Comprehensive Settlement is reasonable and should be approved. The Commission notes that the Partial Stipulation, which is incorporated by reference in the Comprehensive Settlement, provides that the $31.2 million adjustment in the revenue requirement agreed upon therein will be included in the ESM for DEC, which is reasonable and consistent with the treatment of the First TCA Adjustment included in PBR1.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 74

Performance Incentive Mechanisms

The evidence supporting this finding of fact is contained in DEC's verified PBR Application; the testimony and exhibits of DEC witnesses Bateman, Farmer, and Guyton; the joint testimony and exhibits of Public Staff PIMs Panel; the testimony and exhibits of CIGFUR III witness Collins; the testimony and exhibits of NCSEA witness Lin; the testimony and exhibits of CUCA witness McGlothlin; the PIMs Settlement; and the entire record in this proceeding.

Summary of Evidence

DEC initially proposed the following PIMs in its PBR Application: (1) Time Differentiated and Dynamic Rate Enrollment; (2) Reliability; (3) Renewables Integration; and (4) Customer Service. Tr. vol. 7, 47-49. Witness Farmer testified that DEC's proposed PIMs reflect the experience and learnings from PBR1 and, where possible, feedback from its stakeholder engagement meeting. *Id*. at 44-47. DEC proposed a PIMs portfolio with $8.1 million in maximum upside rewards and $8.1 million in maximum downside penalties. *Id.* at 49. This maximum financial incentive structure has a lower cap than that approved for PBR1. *Id.* at 88.

According to DEC, as filed, the Time Differentiated and Dynamic Rate Enrollment PIM is identical to the existing PIM approved in PBR1 other than changes to the financial incentives. The Time Differentiated and Dynamic Rate Enrollment 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*. at 47.

DEC testified that the Reliability PIM is essentially identical to the existing PIM approved as part of PBR1. The Reliability PIM holds DEC accountable to maintain service reliability as measured by SAIDI (excluding MEDs). This PIM is downside-only to DEC and features graduated penalties to be distributed to customers if DEC fails to maintain

SAIDI below tiered threshold levels that are to be based upon historic averages adjusted for statistical probability levels and increased outages due to additional grid work that is expected during the MYRP, and for expected improvements due to certain MYRP grid projects. DEC's only proposed changes to this PIM from what was approved in PBR1 is to add additional exclusions for Force Majeure events, which are events caused by circumstances beyond DEC's control and adjusting the tiers to reflect updated historical SAIDI experience. *Id.* at 47-48.

DEC testified that the Renewables Integration PIM involves three metrics to incentivize and reward DEC. The DERs Integration Metric A provides graduated rewards to DEC for exceeding targets for the number of net-metered DER customers interconnected to the DEC system. The only proposed change from the existing Metric A is to base the incentive on a flat $300 per incremental DER interconnection rather than basing the tiered incentive on a comparison to three-year historical interconnection averages. Metric B: Maximize Clean Energy Environmental Attributes (CEEAs) Customer Benefits provides an incentive for DEC to maximize sales of CEEAs generated by customer programs and provides a shared reward structure with a 50/50 sharing of proceeds from the sales of CEEAs. This PIM replaces the existing Metric B Large Customer Renewable Program Encouragement approved in PBR1, which was based upon large customer subscriptions to renewable programs. Metric C: Utility Scale Interconnections incentivizes solar and solar + storage interconnections. This proposed PIM is similar to the existing Metric C PIM except that DEC is proposing to base the PIM metrics on target in-service interconnections based upon signed Interconnection Agreements instead of estimated annual interconnection limits from the CPIRP. Provisions are made to adjust the target incentive levels if reductions in interconnection levels result from actual changes outside of DEC's control. *Id.* at 48-49.

Finally, DEC proposed a new Customer Service PIM based upon the existing customer service tracking metric and provides incentives to timely answer customer calls at its service centers. *Id*. at 49.

In addition to the PIMs, DEC also proposed to continue the three existing tracking metrics in the areas of beneficial electrification from estimated incremental load from EVs, the Circuit Performance Report, and the customer service call center answer rate and speed of answer tracking metric. *Id*. at 63-64.

The Public Staff PIMs Panel expressed concerns with DEC's approach to PIMs and testified that DEC's proposed PIMs would reward actions that DEC should perform without the need for incentives, and that the rewards and penalties proposed by DEC are at levels not likely to provide any meaningful performance change by DEC. Tr. vol. 13, 293. The Public Staff testified that in the first two rate years under PBR1, DEC earned very little of the available PIMs rewards and paid no penalties, while DEC was proposing lower PIMs incentives in connection with its PBR Application in this case. *Id.* at 299.

Regarding the Time Differentiated and Dynamic Rate Enrollment PIM, the Public Staff testified that well-designed TOU rates are a valuable tool for reducing peak load and many customers testified in public witness hearings that they were actively managing and monitoring their electric usage to lower their bills. *Id.* at 309. The Public Staff supported

continuing the PIM with several modifications: (1) enrollment should be based upon unique customer accounts rather than meters; (2) a $10 incentive for each new customer enrollment in an eligible TOU rate during the applicable rate year as proposed by DEC but with a reduced $5 incentive for customers who remain continuously enrolled in eligible TOU rates from the prior rate year; and (3) eliminating DEC's proposed cap of 75,000 eligible annual enrollments and instead applying a maximum annual reward cap of $2.25 million. *Id.* at 310-12.

Regarding the Renewables Integration PIM, the Public Staff testified that it should be eliminated in its entirety. *Id.* at 315. As to Metric A, the Public Staff testified that DER adoption is largely customer driven and DEC already has an obligation to connect these customers. As to Metric B, the Public Staff was concerned that it did not reward actions that were within DEC's control, and DEC had previously represented that the revenues from the sale of CEEAs would benefit all ratepayers. Regarding Metric C, although the Public Staff originally proposed this PIM in PBR1, the Public Staff testified that DEC's proposal in this case fundamentally changes the reward basis from connecting generating resources to building interconnection facilities, does not incent behavior, and simply rewards DEC for work it is already doing. *Id.* at 315-17.

Regarding the Reliability PIM, the Public Staff supported the PIM with several modifications. *Id.* at 318. Instead of basing SAIDI performance on a system-wide design, the Public Staff testified to a new proposed design based upon reliability performance for each of DEC's five distribution zones. *Id.* at 320-24.

Regarding the Customer Service PIM, the Public Staff opposed this PIM on the basis that: (1) DEC's proposed performance target does not represent an incremental improvement over historical performance; (2) the PIM relies on a single metric, call answer speed, which may not fully reflect overall customer service performance; (3) the PIM is upside-only; (4) DEC did not provide quantitative support that the proposed $2.25 million incentive is reasonably related to the cost of achieving improved performance or to measurable customer benefits; and (5) a substantial number of customers interact with DEC via digital channels. *Id.* at 324-28.

The Public Staff proposed three PIMs in its testimony: (1) RFP Utility Ownership PIM – a symmetrical PIM to encourage the development of utility owned solar and solar paired with storage bids at or below the capital cost of the facility provided in the bid; (2) Facilities Study Timing PIM - an upside-only PIM designed to encourage efficient and accelerated facilities studies related to interconnecting new generation; and (3) Distribution Vegetation Management (DVM) PIM — a downside-only PIM designed to track improvement of the DVM program based on two metrics: the annual number of DVM non-MED outages and the total annual DVM non-MED SAIDI — both tracked within each of DEC's five distribution zones. *Id.* at 329. The Public Staff's total proposed PIMs portfolio reward and penalty structure was to be finally determined after the revenue requirement was ultimately approved in this case up to the 1% statutory maximum. *Id.* at 342-43.

NCSEA witness Lin and CIGFUR III witness Collins both testified in support of fuel PIMs. Tr. vol. 19, 276, 777-78. NCSEA witness Lin testified to a Fuel Cost Efficiency PIM, in which DEC and its customers would share the gain or loss in fuel cost efficiency each

year as measured by a ratio for each current major category of fuel and then compared to the prior year. *Id.* at 791. NCSEA witness Lin argued that his proposed Fuel Cost Efficiency PIM is consistent with the requirements of the PBR Statute. *Id.* at 779-81, 795-802. NCSEA witness Lin also acknowledged that he had previously testified to similar, but distinct, fuel cost sharing mechanisms pursuant to a different statute, which had been denied by this Commission in recent annual fuel proceedings in Docket Nos. E-7, Sub 1313 and E-2, Sub 1358. *Id.* at 779. CIGFUR III witness Collins testified in support of a symmetrical fuel-hedging PIM to protect customers from fuel price volatility but did not provide details or suggested metrics of such a PIM. *Id.* at 277.

CUCA witness McGlothlin testified in support of a Rate Competitiveness PIM which would either reward or penalize DEC for changes in the competitive ranking of its rates relative to other IOUs in the Southeast region. Tr. vol. 8, 80, 90. Under CUCA's proposed PIM, a rate-competitiveness index would be derived from the typical monthly bills of residential, commercial and industrial customers as published by the Edison Electric Institute and averaged to establish a three-year rolling average. *Id.* at 90-93. CUCA witness McGlothlin testified that DEC's average rates for all customer classes are currently below the baseline average of IOUs in the surrounding states. CUCA's PIM would establish a reward or penalty of $5 million per year for every percentage point change below or above a 5% change. *Id.* at 93.

In its rebuttal testimony, DEC's PBR Policy Panel explained that DEC's proposed PIMs reflect a meaningful and thoughtful approach to advance policy goals as DEC, interested stakeholders and the Commission continue to gain experience from PBR1 PIMs. Tr. vol. 22, 431. Regarding the Time Differentiated and Dynamic Rate Enrollment PIM, the DEC PBR Policy Panel agreed with the Public Staff's proposed modification to base enrollment upon unique customer accounts but disagreed with the Public Staff's proposal to reduce the PIMs incentive to $5 per customer for subsequent rate years. *Id*. at 435. They testified that the annual system benefit for each customer enrollment is $39.95, which more than justifies the $10 proposed incentive. *Id*. As to the Reliability PIM, DEC objected to the Public Staff's proposed zone-based approach and proposed tiers. *Id*. at 436-37. As to the Renewables Integration PIM, the PBR Policy Panel reiterated its support for this PIM. *Id*. at 437. Likewise, the PBR Policy Panel affirmed the basis for the Customer Service PIM as proposed. *Id*. at 442. As to the RFP Utility Ownership PIM, the DEC PBR Policy Panel expressed concern with the structure of the PIM to compare total capital cost at the time of the RFP selection to capital cost after construction for several reasons and explained that the proposed PIM provided no relief for cost impacts that were caused by items outside of DEC's control. *Id*. at 443-44. As to the Facilities Study Timing PIM, the DEC PBR Policy Panel testified that DEC is not opposed to such a PIM concept and was open to further dialogue with the Public Staff. *Id*. at 444-45. As to the DVM PIM, the PBR Policy Panel testified to concerns with the proposal, including the potential for a double penalty with the Reliability PIM, that the PIM would penalize DEC for items outside of its control, and the zone-based structure. *Id*. at 445-46. Finally, DEC opposed the Public Staff's incentive structure as heavily weighted to penalties and reiterated its support for a symmetrical, balanced, and measured approach to PIMs as approved by the Commission in PBR1. *Id*. at 447.

In rebuttal testimony, DEC's PBR Policy Panel also testified that the fuel PIMs proposed by NCSEA and CIGFUR III are not appropriate for several reasons. The PBR Policy Panel explained that DEC has both the incentive and tools to manage fuel costs for the benefit of its customers, including but not limited to its natural gas fuel hedging program, the JDA system fuel savings, its "One Face to the Market" fuel procurement strategy, its energy trading operation and its participation in the Southeast Energy Exchange Market. The PBR Policy Panel explained that because fuel prices are not within DEC's control, the proposed fuel PIMs are inconsistent with N.C.G.S. § 62-133.16(c)(3). Finally, the PBR Policy Panel testified that the Commission's oversight during the annual fuel clause proceedings effectively serve as a penalty if DEC's actions are found to be imprudent. *Id.* at 448-54. At the hearing, witness Bateman further explained DEC's objections to the proposed NCSEA fuel PIM. Tr. vol. 23, 52-53.

In rebuttal testimony, DEC witness Bateman proposed a new MYRP Timely Completion PIM structured with similar performance requirements that the Commission has approved for water and sewer utilities in response to criticism by the Public Staff regarding DEC's MYRP 1 performance. The MYRP Timely Completion PIM is downside only and holds DEC accountable for completing MYRP projects on a timely basis by establishing tiered penalties in the form of basis point reductions for DEC's ROE used to set the top of the ESM band. Tr. vol. 22, 455-58.

As detailed below, the PIMs Settlement contains four PIMs, each of which are described with specificity, including thresholds, tiers, penalty and reward amounts, and projections of costs as set forth in PIMs Settlement Conforming Exhibits 1, 2, 3, and 4. The Settled PIMs provide for maximum upside rewards to DEC of $8.75 million per rate year and maximum downside penalties of $10 million per rate year. *Id.* at 463. The PIMs Settlement also provides a requirement for DEC to host a PIMs Workshop prior to filing its next PBR rate case and for the following tracking metrics (as well as additional non-tracking metric reporting obligations): customer service with the addition of major digital channel customer interactions and beneficial electrification from incremental load of EVs. Public Staff witnesses Fernandez, Hill and T. Williamson testified that the Settled PIMs are in the public interest and benefit ratepayers, tr. vol. 23, 22-23, and DEC witness Bateman testified that the PIMs Settlement will benefit ratepayers through improved operational efficiencies, cost savings, and reliability of electric service over the course of the MYRP and will advance important policy goals to maintain or improve utility performance. Tr. vol. 22, 463-66.

Elements of the Performance Incentive Mechanisms Settlement

Time Differentiated and Dynamic Rate Enrollment PIM

As discussed in the PBR Policy Panel and Public Staff PIMs Panel testimony, this PIM is a continuation of the existing PIM with modifications in the PIMs Settlement to base enrollment upon unique customer accounts and an increased upside maximum reward of $2.25 million per rate year. Tr. vol. 23, 21. Witness Farmer 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. Tr. vol. 7, 50. In the PIMs Settlement, DEC agreed to update the evaluation, measurement, and

verification used to calculate the estimated per customer system benefit from this PIM (currently $39.95) no later than 60 days prior to the completion of the PIMs Workshop agreed to in the PIMs Settlement.

Reliability PIM

As discussed in the PBR Policy Panel and Public Staff PIMs Panel testimony, this PIM is a continuation of the existing PIM with modifications in the PIMs Settlement to make the PIM symmetrical with maximum $2 million in rewards per rate year and maximum $10 million in penalties per rate year. Per the PIMs Settlement, the incentive structure is based on a negotiated SAIDI midpoint of 174 minutes and a deadband and sliding scale of rewards/penalties. The Reliability PIM holds DEC accountable to maintain or improve SAIDI for the benefit of all customers. Tr. vol. 23, 22.

Facilities Study PIM

This is a new PIM as proposed by Public Staff with modification in the PIMs Settlement to include all projects for which an interconnection study is required (i.e., FERC projects in addition to state interconnection standards projects). This PIM provides an upside reward for each interconnection Facility Study completed on a sliding scale based on the duration of the study with a maximum reward of $2.5 million per rate year. As discussed in the testimony of the Public Staff PIMs Panel and the hearing testimony of the PBR Policy Panel, this PIM encourages DEC to complete required facilities studies faster, which could lead to bringing needed new generation sources online more quickly. *Id.* at 21.

Vegetation Management PIM

This is a new PIM that rewards DEC for reductions in actual (inflation-adjusted) DVM cost per mile as compared to a 5-year historical average (2021-2025). This PIM provides for rewards to DEC of $200,000 for each 1% reduction to the 5-year average (2021-2025) DVM cost per mile with maximum rewards of $2 million per rate year. This PIM targets and advances operational efficiency and cost savings through a shared savings incentive structure. *Id.* at 26-28.

PIMs Workshop

The PIMs Settlement provides that DEC will host a PIMs workshop to be completed prior to the filing of its next PBR rate case. PIMs Settlement § II. Topics will include learnings from PIMs performance to date and potential PIM proposals from interested participants, including but not limited to potential PIMs that align with the N.C.G.S. § 62-133.16(d)(2) public policy goals that the Commission may consider in evaluating a PBR application. DEC will file a report with the Commission following completion of the PIMs workshop and may engage a third-party facilitator. Pursuant to the PIMs Settlement, DEC may charge the costs of the PIMs workshop not to exceed $100,000 as incremental rate costs in its next rate case with the Public Staff reserving its right to review such costs for reasonableness and prudence in the next rate case.

Tracking Metrics

DEC witness Farmer 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. Tr. vol. 7, 63.

In the PIMs Settlement, DEC and the Public Staff agreed to maintain the existing beneficial electrification from EV load tracking metric as modified in the Comprehensive Settlement and agreed to remove the Circuit Performance Report as a tracking metric but replace it with a quarterly report provided to the Public Staff and an annual report filed with the Commission. PIMs Settl. § II.E.1. In addition, DEC will maintain its existing Call Center answer rate tracking metric and add the number of web portal and/or mobile applications logins to track customer interactions through major digital channels. Finally, in lieu of a tracking metric, DEC will make an annual report as proposed by the Public Staff for the Duke Program Utilization Tracker. In addition, DEC will provide a report showing the number of unique customers enrolled in multiple programs or participating at any point during the calendar year. PIMs Settl. § II.E.

Discussion and Conclusions

Upon review of the testimony of DEC and the Public Staff regarding the PIMs Settlement, the Commission concludes that the PIMs Settlement is the product of give-and-take negotiations between DEC and the Public Staff to achieve PIMs and tracking metrics that are consistent with the PBR Statute, and it strikes an appropriate balance among competing positions. In its discretion, the Commission declines to consider or adopt any other proposed PIM or tracking metric not agreed to in the PIMs Settlement.

The PIMs and the tracking metrics set forth in the PIMs Settlement reflect lessons learned from PBR1 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. In particular, the Commission notes the more stringent thresholds set for the reliability PIM relative to the original thresholds proposed by DEC. Therefore, the Commission concludes that the PIMs Settlement is entitled to substantial weight and that the PIMs and tracking metrics set forth in the PIMs Settlement should be approved. The Commission also concludes that it is reasonable for DEC to conduct a PIMs workshop prior to the next PBR rate case for further discussion and potential enhancement of the PIMs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 75-76

Multiyear Rate Plan Refund Rider

The evidence supporting these findings of fact is contained in DEC's verified PBR Application and Form E-1; the testimony and exhibits of DEC witnesses Abernathy, Bateman, and Bowman; the joint testimony and exhibits of Public Staff Policy Panel, the testimony and exhibits of Public Staff witness Thomas, and the joint settlement testimony and exhibits of Public Staff witnesses Metz, Zhang, Thomas, and Fahey; the testimony

and exhibits of CIGFUR III witness Collins; the Comprehensive Settlement; and the entire record in this proceeding.

Summary of Evidence

As discussed in its PBR Application, DEC identified capital spending projects projected to be placed in service during the MYRP2 period. The Public Staff Policy Panel testified that it recognizes substantial load growth in North Carolina is driving electric utilities to make capital investments to support growth, maintain reliability and improve the grid. The Public Staff Policy Panel did not fundamentally disagree that DEC needs to make significant capital expenditures. Tr. vol. 18, 53-54. However, the Public Staff Policy Panel expressed concerns regarding DEC's execution of MYRP1 projects in terms of in-service delays. *Id.* at 46. Given that the MYRP1 rates were calculated based upon projected in-service dates, but the depreciation expense and a return do not begin accumulating on DEC's books until the assets are placed in service, the Public Staff Policy Panel argued that not only are operational and customer benefits delayed from what was anticipated when MYRP1 was approved, but without a true-up mechanism for excessive depreciation and return expense for MYRP projects not in service, customers inappropriately bear the risk of project execution. *Id.* at 47-51. Witness Thomas argued this effect with a simple example: "an MYRP RY1 project with a 10-year depreciable life that is placed in service two years later than expected will result in ratepayers paying 12 years of depreciation and return expense." *Id.* at 47-48. The statutory ESM provides that if weather-normalized earnings exceed the authorized rate on equity by 50 basis points after adjustments, the excess earnings must be refunded to customers. In the Public Staff's opinion, the ESM provides some guardrails against excess overearning by the utility, but it is not sufficient to address the Public Staff's concerns. *Id.* at 51-53.

Public Staff witness Thomas analyzed the actual project completion and cost for MYRP1 Rate Year 1 and Rate Year 2 projects compared to the estimated in-service dates and project costs. Tr. vol. 13, 81-90. Witness Thomas evaluated DEC's completion of MYRP1 projects considering both number of projects and project costs. *Id.* at 85. Based on project count, witness Thomas concluded that 62% of Rate Year 1 projects were placed in service in Rate Year 1, with another 20% placed in service in Rate Year 2. For Rate Year 2 projects, he concluded that 49% were placed in service in Rate Year 2. *Id.* at 85-86. On a dollar basis, he concluded that 70% of Rate Year 1 projects by cost were completed in Rate Year 1 and another 20% in Rate Year 2, while 59% of Rate Year 2 projects by cost were completed by the end of Rate Year 2. *Id.* at 86-87. Witness Thomas estimated that these incomplete projects represented $1.1 billion in capital costs included in rates that had not been completed by the end of Rate Year 2. *Id.* at 90. The Public Staff Policy Panel anticipates similar challenges with the execution of the MYRP2 projects. Tr. vol 18, 46-47. The Public Staff Policy Panel estimated, on a simplified basis, that the $1.1 billion in incomplete MYRP1 capital projects caused NC ratepayers to pay approximately $83 million annually in depreciation expense and return on capital for incomplete MYRP1 projects for each Rate Year. *Id.* at 49-50.

Based upon his analysis of DEC's performance in MYRP1 Rate Year 1 and Rate Year 2, Public Staff witness Thomas recommended an across-the-board reduction in the MYRP2 capital costs of approximately $1.06 billion, assuming a similar rate of delay in the

in-service dates for the MYRP2 projects. Tr. vol. 13, 90-92. Witness Thomas's recommendation is based upon a 10% reduction to the proposed MYRP2 Rate Year 1 project costs and 35% reduction to Rate Year 2 projects with exceptions for projects in later stages of development. *Id.* at 91-92. Public Staff witness Thomas testified that this adjustment is not based upon the need for specific MYRP2 projects or the reasonableness of the cost estimates. *Id.* at 92. On cross examination, the Public Staff Policy Panel testified that as an alternative to their proposed across-the-board adjustment, a refund rider (as opposed to an across-the-board reduction) would likewise rebalance risk appropriately and provide relief to ratepayers. Tr. vol. 18, 101-04, 123-26, 181-82.

CIGFUR III witness Collins raised concerns about MYRP2 BESS projects, stating there are industry-wide cost and delivery risks unique to BESS which can challenge forecasting project schedules and costs. Tr. vol. 19, 246-47. Witness Collins identified updates to MYRP1 BESS projects including underspend, overspend, cancellation, and in-service delays. *Id.* Because of these risks, he recommended the Commission adopt guardrails for MYRP2 BESS projects, including: (1) a project-level cost cap above which incremental costs are subject to disallowance or 50/50 sharing between shareholders and ratepayers; (2) a claw-back mechanism that would be triggered by project cancellation, a delayed in-service date, material changes in configuration, or lower actual in-service costs less than approved for recovery; and (3) a return of project-level underspend to customers, together with carrying costs, return on rate base, depreciation, AFUDC, and income tax gross-up components of revenue requirement attributable to that differential. *Id.* at 247-48.

On rebuttal, DEC witnesses Bowman, Abernathy, and Bateman challenged the Public Staff's analysis of DEC's MYRP1 project execution as relying on an unreasonably strict and impractical perspective — measuring whether a project was completed in the exact month originally forecasted. Tr. vol. 21, 53-56, 413-15; tr. vol. 22, 397-98. This standard, witness Bowman stated, does not reflect how complex utility capital programs are reasonably managed and executed, and fails to account for the fact that the completion date can be subject to influences that are outside of the utility's control such as the once in a century Hurricane Helene. Tr. vol. 21, 53-54. Witness Bowman pointed to DEC's obligation to continually assess MYRP projects and ensure customer benefits are maximized throughout the execution phase. *Id.* at 53-56. Witness Bateman and witness Bowman in rebuttal both urged the Commission not to adopt a rigid standard of perfection that is both unrealistic and not in the customers' best interest, arguing that such a standard is inconsistent with Commission Rule R1-17B and the Commission's expectations of water utilities. Tr. vol. 22, 397-401.

In rebuttal, witness Abernathy performed an alternative analysis calculating the MYRP1 projects completed within three months of the projected in-service dates. Tr. vol. 21, 409-12. Witness Abernathy determined that $3.9 billion of MYRP1 capital spend was in service through March 2026, constituting an 89% completion rate. By the end of Rate Year 3, DEC is on track for a 99% completion rate. *Id.* at 412.

As an alternative to the Public Staff's across-the-board MYRP2 reduction recommendation, DEC proposed a Timely MYRP Completion PIM modeled on a PIM approved by the Commission for water utilities. Tr. vol. 22, 455-58. The proposed PIM would track actual project completion compared to estimates used to set rates and impose

a basis point reduction to the ROE used in the ESM calculation on a tiered basis. *Id.* Witness Bateman estimated the maximum penalty translates to a range of approximately $35 million to $40 million. *Id.* at 458. During the evidentiary hearing, the Public Staff Policy Panel explained that their concern with DEC's PIM proposal is that the PBR Statute caps the cumulative amount of penalties and incentives at 1% of the utility's total annual revenue requirement used to set rates during the first year of the MYRP. Tr. vol. 18, 127-30.

In lieu of the MYRP Timely Completion PIM, the Comprehensive Settlement and Exhibit 1 thereto include a MYRP Refund Mechanism, which is designed to address the concerns expressed by the Public Staff regarding MYRP execution and provide a refund for customers for MYRP2 projects that are delayed or canceled. Comp. Settl. § II.17. It incorporates the number of projects completed and the actual project costs as compared to the numbers and estimated costs incorporated into the Rate Year revenue requirement, calculating both a project completion ratio and a revenue requirement ratio. *Id.* These ratios are combined to produce a composite factor that is multiplied against the cost delta to produce the refund amount to be returned to customers through the MYRP Refund Rider. Comp. Settl. § II.17*;* DEC Late Filed Ex. 14. (providing an example of the MYRP Refund Mechanism calculation). The Comprehensive Settlement sets forth the mechanics associated with implementing the MYRP Refund Rider on an annual basis. Comp. Settl. § II.17.

DEC witness Bowman testified that the MYRP Refund Mechanism strikes an appropriate balance between retaining necessary flexibility for DEC's customers facing temporary hardship and supporting efforts to manage customer arrears and bad debt expenses. Tr. vol. 21, 68. DEC witness Bateman likewise testified that DEC was able to make critical investments that are difficult to execute at scale under traditional ratemaking on a timely basis for customers. Tr. vol. 22, 472-74. While DEC contends its MYRP1 execution was strong, given the concerns raised about MYRP1 projects that were delayed or cancelled even if for reasons outside the utility's control, witness Bateman believes the MYRP Refund Rider is a fair and reasonable mechanism to address these concerns. *Id.* at 472. Witness Bateman further explained how DEC proposes to track, compare and report project in-service dates and costs; and how refund amounts will be calculated, allocated among the customer classes, and paid to customers. *Id.* at 472-74. Witness Bateman specifically noted that the MYRP Refund Mechanism does not allow for substitute projects to be included in the calculation and that it is asymmetrical in that it will not allow for additional recovery if the actual Rate Year revenue requirement is more than the approved amount in rates. *Id.*

Public Staff's Settlement Panel of Metz, Zhang, Thomas and Fahey stated that the MYRP Refund Mechanism is one of the most important benefits provided by the Comprehensive Settlement. Tr. vol. 21, 150-51. On cross examination, witness Thomas noted that the MYRP Refund Mechanism accounts for projects placed in service late as well as those placed in service early. *Id.* at 160. Witness Thomas described the approach as novel and was developed through "a lot of back and forth" between DEC and the Public Staff. *Id.* at 167. He highlighted that the composite factor is a "compromise between the two individual metrics." *Id.* at 169. Witness Metz added that the Public Staff believes it is not reasonable to expect the utility to achieve 100% completion given the complexity of

executing a multiyear plan and that the composite factor is a reasonable means to address that. *Id.* at 169-70.

CIGFUR III witness Collins agreed that the MYRP Refund Rider is consistent with the Public Staff's initial across-the-board MYRP2 reduction recommendation and provides the same or similar customer protections as intended by CIGFUR III's proposed BESS claw-back mechanism. *Id.* at 179.

Discussion and Conclusions

The MYRP component of PBR allows an electric utility to adjust its base rates annually over a multi-year period without the need to file a new general rate case by estimating costs associated with a known and measurable set of capital investments (net of operating benefits) associated with discrete and identifiable capital projects based on the projects' anticipated in-service dates. N.C.G.S. § 62-133.16(c)(1). In the context of both electric utility and water utility MYRPs, the Commission has recognized the need for flexibility in the execution of an MYRP. In adopting the PBR Rule, the Commission found that:

> it is unreasonable to assume that across a three-year period, there will not be circumstances in which it would be prudent and reasonable for the utility to modify or delay certain investment decisions, nor would it be in the public interest for the Commission to approve a PBR Rule structure that limits the ability of or disincentivizes the utility to bring its technical expertise to bear in real time on its system.

Order Adopting Commission Rule R1-17B, *Rulemaking Proceeding to Implement Performance-Based Regulation of Electric Utilities*, No. E-100, Sub 178, at 42 (N.C.U.C. Feb. 10, 2022).

Likewise, under N.C.G.S. § 62-133.1B, which permits a multiyear Water and Sewer Investment Plan for water utilities, the Commission has acknowledged "that over the course of the MYRP, the relative priority of projects is likely to change, and some projects will inevitably be delayed [and] [a]t the same time, others may need to be accelerated relative to the plan as approved." Thus, the Commission has found that a "reasonable accommodation to the inherent uncertainty of creating capital plans" is appropriate in determining penalties under an MYRP. 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 Rate 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 117-18 (N.C.U.C. June 5, 2023).

That flexibility is not without limits. The Commission must determine that the PBR Application, including the MYRP component, results in just and reasonable rates that are fair both to the electric utility and to customers. N.C.G.S. § 62-133.16(d). In evaluating this standard, the Public Staff and other intervenors raise reasonable concerns regarding setting rates for an MYRP based on estimated in-service dates. The Commission

concludes that the proposed MYRP Refund Mechanism and MYRP Refund Rider provide a fair and reasonable approach to address these concerns.

The MYRP Refund Mechanism and MYRP Refund Rider agreed to under the Comprehensive Settlement balance the magnitude and complexity of executing a multi-year capital spending plan with the impact on customers' rates. It maintains the financial benefits of minimizing regulatory lag that PBR is intended to provide and continues to keep project execution risk with the utility. The use of a composite factor accounts for flexibility and events beyond DEC's control. The lack of substitution and the asymmetrical operation of the MYRP Refund Rider, such that it only operates to reduce rates and does not collect under-collected costs, further provides a negotiated compromise.

For all of these reasons, the MYRP Refund Mechanism (including the MYRP Refund Rider) is reasonable and is hereby approved as a mechanism implemented through the Comprehensive Settlement. Finally, the Commission appreciates the Stipulating Parties collaborating to develop a novel approach to address concerns with MYRP project execution.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 77

Performance-Based Regulation

The evidence supporting this finding of fact is contained in DEC's verified PBR Application and Form E-1; the joint testimony and exhibits of the DEC PBR Policy Panel; the joint testimony and exhibits of the Public Staff Policy Panel; the Comprehensive Settlement; the PIMs Settlement; and the entire record in this proceeding.

Summary of Evidence

DEC's PBR Application seeks approval of PBR including the proposed two-year MYRP beginning on January 1, 2027, and ending December 31, 2028. Tr. vol. 7, 25, 39-40. DEC witness Bateman testified that in addition to the two-year MYRP, which includes an ESM, DEC's PBR Application includes an RDM, PIMs, and tracking metrics. *Id.* at 25. Witness Bateman testified that DEC's PBR Application is in the public interest because the PBR framework best supports DEC's significant investments that are required to ensure a safe, reliable, and resilient electric grid for the benefit of customers; reinforces cost containment; and better aligns performance and revenue with customers and state policy goals than traditional ratemaking. *Id.* at 27. Witness Bateman further explained that modernized regulatory mechanisms, such as PBR, have become the norm and are important to support the utility investments necessary to ensure the continuation of safe and reliable electric service. *Id.* at 28.

Prior to execution of the Comprehensive Settlement, the Public Staff Policy Panel testified that DEC's PBR Application does not appear to be in the public interest. Tr. vol. 18, 40. While the Public Staff Policy Panel did not fundamentally disagree that DEC must make significant capital expenditures to accommodate new generation and maintain and improve reliability for existing and new customers, the Public Staff Policy Panel expressed concerns regarding MYRP1 execution and DEC's capital spending outside of the MYRP framework. *Id.* at 53-58. The Public Staff Policy Panel testified that

capital spending outside of and alongside the MYRP undermines one of the purported benefits of an MYRP: the implementation of a series of small rate increases spread over a multi-year period, thus eliminating periodically large rate increases. *Id.* at 54. The Public Staff Policy Panel used the term "shadow MYRP" not in a nefarious manner but rather to refer to capital projects that are not proposed in an MYRP but are placed in service during the MYRP period and would most likely be included in the base case in the utility's next general rate case, referred to as "non-MYRP projects" by DEC witnesses. *Id*. at 54, 158-59. The Public Staff Policy Panel testified that "shadow MYRP" spending is ultimately added to rate base in the base year of the next MYRP resulting in an immediate increase to base rates before the next multiyear rate increases are included. *Id.* at 54.

On rebuttal, DEC witness Bateman affirmed that DEC's PBR Application is in the public interest and testified that the Public Staff identified no specific deficiency in the PBR Application but rather appears to disagree with the ratemaking structure authorized by the PBR Statute. Tr. vol. 22, 392. Specifically, witness Bateman testified that the Public Staff's contrary assertion rests on two premises with which DEC disagrees: (1) an overly rigid assessment of DEC's MYRP1 execution, and (2) the misconception that capital invested outside of the MYRP reflects a flaw in the PBR framework, rather than the framework operating as designed under the PBR Statute. *Id.* at 382. As discussed above, as to MYRP1 execution, witness Bateman testified DEC's execution was far better than characterized by Public Staff, and the Public Staff Policy Panel's assessment does not account for the operational realities involved in executing billions of dollars of necessary capital investment over thousands of projects and would effectively require a standard of execution that no utility could meet. *Id.* at 397. Moreover, witness Bateman testified to examples of circumstances that occurred that impacted MYRP1 execution that could not have been known at the time a project was selected for inclusion in MYRP1. *Id.* at 399-400. As to the Public Staff Policy Panel's "shadow MYRP" argument, witness Bateman explained that the reason certain capital is not included in the MYRP is due to the structure of the PBR Statute. *Id.* at 394. The PBR Statute does not allow for a fully forecasted test year in which DEC can include all projected capital investments in establishing rates; instead, the PBR Statute only permits capital projects that are "discrete and identifiable" for the first rate year or "Commission-authorized" for the second and third rate years for inclusion in an MYRP. *Id.* Witness Bateman also testified that there will always be needed capital projects that are not included in an approved MYRP but must be executed during the course of any MYRP period. *Id.* at 395.

As described in greater detail elsewhere in this Order, the Comprehensive Settlement and PIMs Settlement modify DEC's PBR Application to address several items raised in the proceeding. As part of the Comprehensive Settlement, DEC agreed to implement an MYRP Refund Mechanism under which refunds owed to customers for MYRP2 projects that are delayed or cancelled will be made through a MYRP Refund Rider. The MYRP Refund Rider shall be filed annually in conjunction with annual PBR riders and will account for actual MYRP project completions in MYRP2 Rate Year 1 and Rate Year 2. As discussed herein, the MYRP Refund Mechanism directly addresses the most substantial concern expressed by the Public Staff with respect to MYRP1.

As it relates to other elements of PBR, the Stipulating Parties agreed that sales under the EV tariff should be included in the calculation to exclude EV sales margin from

the RDM and ESM, to use a 13-month average rate base for purposes of calculating the ESM, to set the capital structure in the ESM as the Commission-approved target percentages as proposed by the Public Staff, and to maintain separate ESMs for DEC and DEP. Comp. Settl. §§ II.22-II.25. Lastly, DEC agreed to withdraw the Timely Completion PIM it proposed in rebuttal testimony due to the MYRP Refund Mechanism agreed to as part of settlement. *Id*. § II.26.

In her settlement testimony, DEC witness Bateman testified that DEC believes the Comprehensive Settlement balances the financial impact of the rate increase on DEC customers with DEC's need to recover the costs required to continue fulfilling its obligation to provide safe and reliable electric utility service to customers. Tr. vol. 22, 471. She explained that the Comprehensive Settlement modifies DEC's PBR Application to address several items raised in this proceeding with the most material modification being the new MYRP Refund Mechanism and corresponding MYRP Refund Rider. *Id.* Witness Bateman testified that, like every part of the Comprehensive Settlement, the MYRP Refund Rider is a product of give and take. *Id.* at 472. She testified that DEC is proud of its execution under MYRP1 and has learned valuable lessons that will strengthen its execution results under MYRP2, but DEC also heard parties in this proceeding and their concerns about MYRP1 projects that were delayed or canceled, even if for reasons outside of DEC's control. *Id.* Therefore, DEC agreed to the MYRP Refund Rider, and witness Bateman testified that DEC is confident in its planned execution of MYRP2 projects and believes the MYRP Refund Rider is a fair and reasonable mechanism to address concerns raised by the parties. *Id.*

In the Public Staff's settlement testimony, Public Staff witnesses Metz, Zhang, Thomas, and Fahey testified that the Comprehensive Settlement provides important ratepayer benefits and is in the public interest. Tr. vol. 21, 151. EDF also filed settlement testimony in support of the Comprehensive Settlement, noting its specific interest in enabling a LL Tariff stakeholder process and a subsequent comment period. Tr. vol. 22, 16-19.

Discussion and Conclusions

The PBR Statute requires a PBR application to include three elements: (1) an MYRP, which must include an ESM; (2) an RDM; and (3) one or more PIMs. N.C.G.S. § 62-133.16(c). An MYRP 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 rates to be set based on projected capital projects (and associated operating costs and benefits). The MYRP is paired with an ESM that requires the utility to refund to customers all weather-normalized earnings in excess of the authorized rate of return plus 50 basis points during the MYRP. *Id.* § 133.16(c)(1). The RDM is a "rate-making 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 by its residential customers." Under the RDM, 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). Finally, a PIM 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).

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 the MYRP projects and costs, 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 to put the utility in a position to maintain its system and level of service, to have an opportunity to earn a fair return, in view of current economic conditions, and to compete in the marketplace for capital on reasonable terms for the benefit of customers. 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 in a balanced and fair manner. 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.

The Commission finds that the MYRP Refund Mechanism and MYRP Refund Rider resolves the Public Staff's concerns regarding MYRP1 project completion. The MYRP Refund Rider will provide refunds to customers for MYRP2 projects that are delayed or canceled, thus addressing the Public Staff's concerns about a lack of "true up" mechanism for approved project costs. The MYRP Refund Rider is not a tool expressly authorized by the PBR Statute but has been agreed to by DEC as part of the Comprehensive Settlement. All Stipulating Parties agree that the Comprehensive Settlement (including the modifications to DEC's proposed PBR), taken in its entirety, is in the public interest. The Commission finds that DEC's PBR Application, as modified by the Comprehensive Settlement and PIMs Settlement, results in rates that are fair to both DEC and to customers.

The Commission also finds that the Settled PIMs encourage peak load reduction or efficient use of the system, encourage carbon reductions, promote resilience and security of the grid, maintain adequate levels of reliability, power quality, and customer

service, and promote rate designs that yield peak load reduction or beneficial load shaping, which the Commission may consider in approving a PBR application pursuant to 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 DEC's rebuttal testimony, the Partial Stipulation, the Comprehensive Settlement, and the PIMs Settlement, would result in just and reasonable rates, is in the public interest, and is consistent with the criteria established in the PBR Statute.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 78

Revenue Requirement

The evidence supporting this finding of fact is contained in DEC's verified PBR Application and Form E-1; the Comprehensive Revenue Requirement Agreement and Stipulations of Settlement; Agreement and Stipulation of Partial Settlements; the Storm Cost Stipulation; the testimony and exhibits of DEC witnesses Jiggetts and Abernathy; the testimony and exhibits of the Public Staff Accounting Panel; and the entire record in this proceeding.

Summary of Evidence

The Comprehensive Settlements, Agreements and Stipulation of Partial Settlements, and the Storm Cost Stipulation provide for certain accounting adjustments that parties have agreed upon and the Commission has approved in this Order. The settlement issues that impact the revenue requirement in the Partial Stipulation as well as the Comprehensive Settlements are detailed in Jiggetts Comprehensive Settlement Exhibits 1-2, which provides sufficient support for the annual revenue required on the issues agreed to in the Partial Stipulation and the Comprehensive Settlements. Jiggetts Comp. Settl. Exs. 1-2.

Discussion and Conclusions

After giving effect to the approved stipulations, 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 and 2 in the same format as Jiggetts Comprehensive Settlement Exhibits 1-2 in Excel format with detailed footnotes and supporting documentation. The Commission directs DEC to work with the Public Staff to verify the accuracy of the calculations, and the filing should reflect any corrections identified by DEC and agreed upon by the Public Staff.

The Commission concludes the annual revenue requirement for DEC for Rate Years 1 and 2 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. 79-97

Large Loads, Data Centers, and the DC Schedule

The evidence supporting these findings of fact is contained in DEC's verified PBR Application and Form E-1; the testimony and exhibits of DEC witnesses Byrd, Beveridge, Hager, and Duff; the testimony and exhibits of the Public Staff's Large Load Panel; the testimony and exhibits of AGO witness Brant; the testimony and exhibits of CIGFUR III witness Collins; the testimony and exhibits of EDF witnesses Lenell and Pol; the testimony and exhibits of Google witness Dr. Berry; the testimony and exhibits of Microsoft witness Gabel-Frank; the testimony and exhibits of NCJC, et al. witness Wilson; the Comprehensive Settlement; and the entire record in this proceeding.

In addition, policy discussions providing guidance for the identification of the issues and solutions set forth in these findings of fact are contained in the initial and reply comments of DEC and DEP, the Public Staff, AGO, Amazon, Andale, CCEBA, CEBA, CIGFUR II, CIGFUR III, CUCA, Digital Realty, EDF, Google, Microsoft, NCJC, et al., NCSEA, Nucor, and Walmart. Given the extensive overlap of both issues and records in this proceeding and a companion general rate case involving Duke Energy Progress, LLC, and the fact that many parties were making joint filings in both proceedings, the Commission is hereby utilizing its authority under N.C.G.S. § 62-65(b) to take judicial notice of the companion case Order Accepting Stipulations in Part, Granting Partial Rate Increase, Granting Accounting Order and Requiring Public Notice issued in Docket Nos. E-2, Sub 1380 and E-2, Sub 1405 on November 16, 2026.

Summary of Evidence

DEC Direct Testimony

In his direct testimony, DEC witness Byrd testified that DEC's current Schedules OPT-V and HLF provide appropriate tariff options for large load and high load factor customers that already align prices with cost of service. Tr. vol. 11, 520. Witness Byrd explained that Schedule HLF, which serves high load factor customers that otherwise would be served on Schedule OPT-V, provides for significant fixed cost recovery through demand charges, reflecting the unit cost from DEC's COSS. *Id*. As a result, witness Byrd argued, "new tariffs designed for "large loads" would most likely be designed similar to either Schedule OPT-V or Schedule HLF, rendering such new tariffs duplicative and unnecessary." *Id*. Witness Byrd explained DEC presently addresses unique large load challenges and planning concerns through performance and credit provisions enabled within its Service Regulations. *Id*. Witness Byrd also testified if a subset of DEC's Schedule HLF customers begin to exhibit similar load profiles that are materially different from other customers on existing schedules, DEC may then determine whether it needs to separate such customers onto a new tariff within a separate rate class. *Id*.

DEC witness Hager testified in her direct testimony that in a cost allocation process, system costs are first grouped according to their function, such as generation, transmission, distribution, and customer service. Next, functionalized costs are classified based on the utility service provided, including demand-, energy-, and customer-related

costs. Finally, costs are allocated or directly assigned to the appropriate jurisdiction and customer class based on the manner in which the costs are incurred. *Id*. at 563-64.

Public Staff Direct Testimony

The Public Staff Large Load Panel testified regarding DEC's management of large load customers, the limitations of existing mechanisms for addressing large loads, and the Public Staff's proposed large load tariff (Schedule LL). Tr. vol. 14, 106-63.

The Large Load Panel defined a large load as "a substantial, concentrated electrical demand with a high load factor originating from a single user or facility at a specific point on the grid or multiple points in close proximity," and noted that although no universally accepted definition or threshold exists within the utility industry, individual loads or demands of 25 MW or greater are commonly considered large in other states. *Id*. at 108-09. The Large Load Panel recognized the substantial economic benefits that developments requiring large load electric service can bring to North Carolina, and acknowledged that under certain circumstances, large load development can lower average system costs by creating more megawatt hours over which fixed costs can be spread, thereby producing system-wide benefits. *Id*. at 109. The Large Load Panel further testified that DEC and DEP are experiencing unprecedented growth in large load demand and have approximately 7.9 GW of potential large load customers in the advanced development stage, including signed ESAs totaling approximately 6.7 GW of load from March 2024 through April 2026 in North Carolina and South Carolina, of which 92% are for data centers. *Id*. at 110, 126-29, 229; tr. vol. 15, 145-46.

The Large Load Panel expressed concern about highly fluctuating loads, for example from artificial intelligence training data centers, that Duke must have assets and grid management in place to deal with. *Id.* at 237-38. The Large Load Panel also highlighted that large load customers could increase capacity and fuel costs for all other customers during periods of peak demand and increase loss of load risk for other customers if they suddenly disconnect or reconnect. *Id.* at 112. To illustrate this, the Large Load Panel provided an example of a large load reliability incident in Dominion Energy Virginia which caused 1.5 GW of data center load to trip off instantly; PJM narrowly avoided a resulting voltage spike. *Id.* at 112-13. The Large Load Panel also noted that Duke's earnings call transcripts indicate Duke has a specialized team in place whose priority is to sign and service large load customers more quickly. *Id*. at 115-16.

The Large Load Panel testified that accommodating these new large loads will require DEC to invest billions of dollars in new generation, transmission, and distribution facilities. *Id*. at 110. The Large Load Panel noted that the present value revenue requirement (PVRR) associated with the "high load" scenario in Duke's 2025 CPIRP Docket is more than $180 billion in 2050 and $23.5 billion greater than the Base Portfolio PVRR. *Id.* at 126. At the time of the Public Staff filing its testimony, Duke's five-year capital spending plan was $103 billion. *Id.* at 127. The Large Load Panel further testified that stranded asset risk associated with the assets built to serve these customers is substantial because many prospective large load customers may not materialize, may ramp slower than expected, or may leave the system prematurely, causing costs associated with these new generation facilities and infrastructure to be redistributed

among all remaining customers. *Id*. at 110-12. The Large Load Panel highlighted there is a mismatch between the lifecycle and cost of generation assets when compared to the contract terms for large load customers – for example, if the addition of a large load customer requires construction of a natural gas asset, that asset would be in rate base for 35 years (and some assets, such as nuclear assets, may have a lifetime of 60 years or more), while the large load's customer obligation may only extend 10 or 15 years. Public Staff Large Load Panel Conf. Ex. 1; *see also* Public Staff Tech. Conference Presentation, *Large Electric Load Additions,* No. E-100, Sub 208 (Oct. 10, 2025). If this customer were to not renew at the end of its contract term and if no equivalent large load customer with a high load factor occupies the site, remaining customers may then be paying for an asset that they may not otherwise have needed. *Id.*

The Large Load Panel testified that Amazon, Google, Meta, and Microsoft, among others, are signatories to the White House Ratepayer Protection Pledge published on March 4, 2026. Tr. vol. 14, 122. The signatories agreed to: (1) build, bring, or buy the new generation resources necessary to serve their load; (2) pay for the new power delivery infrastructure required for their service; (3) pay for demand and infrastructure requested whether they use the electricity or not; (4) invest in local job creation and workforce development; and (5) contribute to electric and community resilience by making their backup generation resources available at times of scarcity. *Id*. at 122-23.

The Large Load Panel testified DEC currently relies on five separate mechanisms to manage large loads: existing rate tariffs (Schedules I, LGS, OPT-V, HLF, and HP); Letter Agreements; ESA Applications; Service Regulations; and the Line Extension Plan. *Id*. at 117-18. However, the Large Load Panel found none of the 18 ESAs reviewed for DEC's North Carolina territory elected the HLF rate tariff. *Id*. at 119. Instead, 17 of 18 customers plan to take service under DEC's OPT-V tariff. *Id*. at 129. The Large Load Panel testified many of these mechanisms can be applied inconsistently, varying from customer to customer at DEC's discretion without Commission oversight. *Id.* at 120. The Large Load Panel also testified DEC is not properly allocating the costs associated with the new generation, transmission, and distribution plant necessary to serve large load customers, and that improper cost allocation could result in both inter- and intra-class cross-subsidization. *Id*. at 120-21. The Large Load Panel concluded these existing mechanisms are not sufficient to protect all customers and ensure just and reasonable rates. *Id*. at 163.

The Large Load Panel recommended adoption of a new large load tariff, Schedule LL, to mitigate the risks from large load customers that it previously identified and to establish consistent service and contract provisions and thresholds. *Id*. at 130. The Public Staff recommended that Schedule LL should be applicable to new large loads of 50 MW or greater, or incremental (additions of 50 MW or greater) expansions of load, with a load factor of 80% or more. *Id.* at 130-33. Key provisions of the Public Staff's proposed Schedule LL include minimum contract lengths of 10-15 years; minimum billing demand of 75% of contract demand; load ramp period of up to five years; curtailment requirements of 95% for 50 hours or 50% for 100 hours annually; exit fee and notice requirements for load reduction or termination; sudden disconnection/reconnection protection; load aggregation rules; and replacement load provisions. *Id*. at 133-38.

The Public Staff testified that these provisions mitigate stranded cost risk, ensure transparency, and support system reliability. *Id*.

The Large Load Panel testified that conceivably a large load customer could seek to avoid applicability of the proposed large load tariff by misrepresenting its requested load or expected load factor to avoid required costs and charges. *Id*. at 142. To protect against this possibility, the Large Load Panel recommended that the Commission require DEC to monitor the load characteristics of new customers whose load and load factor meet the criteria for a large load tariff and to require those customers to begin using the applicable large load tariff. *Id.*

The Large Load Panel testified DEC's existing pro forma ESA Application and Service Regulations should be revised to ensure that costs are recovered from cost causers and should be approved by the Commission. *Id*. at 143-48. The Large Load Panel recommended that the pro forma ESA Application be amended to add a Local Reliability Requirements section that requires DEC to evaluate the cost of interconnecting a large load customer as compared to the revenue expected under the applicable rate schedule. Any revenue not applied to other costs to serve the large load customer that does not fully recover Required Facilities costs should be recovered via a Required Facility charge as CIAC. *Id*. at 145-46. The Large Load Panel further explained that the existing Service Regulations do not provide a methodology for calculating customer-specific required facilities or CIAC for transmission connected large loads, resulting in inconsistent or insufficient contributions from large load customers. *Id*. at 145-48. The Public Staff's recommended revisions to the Service Regulations would refine how CIAC charges are determined and what portions of revenue from the customer should apply to CIAC. *Id*. at 148. The Large Load Panel further recommended that the Commission approve the Public Staff's proposed pro forma ESA Application and require DEC to use it as the standard contract with large load customers, and that DEC seek Commission approval before deviating from the standard terms. *Id*. at 144-45.

The Large Load Panel testified that for DEC to serve large load customers, it will also need to make transmission and distribution capital investments. The Public Staff categorizes these types of capital investments into two categories: (1) projects caused by a large load customer that benefit multiple customers or the bulk system; and (2) projects needed solely to serve the large load customer that do not benefit other customers, known as dedicated facilities. *Id*. at 139-40. The Public Staff defined the term "Required Facilities" to describe both categories, the dedicated facilities and the facilities that benefit both the large load customer and other customers. *Id*. at 141. The Large Load Panel recommended going forward, the costs of Required Facilities be recovered from the specific customer who caused those costs to be incurred and that DEC update its method for determining CIAC to ensure that revenue received from the customer is sufficient to cover the total cost of the Required Facilities and the typical costs to serve that customer. *Id*. at 141-42. The Large Load Panel stated that their recommendation ensures that specific customer-related costs are not recovered from other customers and indicated that this change is a break from historic practice, which socialized these costs across classes. *Id*.

In its review of DEC's existing CIAC determination method for six large load customers, the Large Load Panel further testified

> the simplistic analysis that DEC has relied upon to waive CIAC from these customers is not reasonable. It does not consider the scale of the investments, treating 50+ MW loads that trigger system-wide transmission upgrades the same as a small residential housing development. This analysis does not consider that the [large load customer] should pay its share of the entire system, not just the costs associated with interconnecting it. The analysis also does not consider the proportion of interconnection costs that are assigned to other jurisdictions or rate classes. Finally, it ignores the timing mismatch, allowing higher rates for other customers in the short term with no analysis or guarantee that the additional energy sales will eventually result in either neutral or reduced rates for other ratepayers over the long term.

Id. at 156-57.

The Public Staff gave an illustrative example for a large load customer with a 720 MW contract demand, 95% load factor, and 15-year ESA term under the OPT-V Transmission Service rate tariff. The Large Load Panel calculated that the customer would pay approximately $402.2 million annually but would only contribute approximately $2.48 million over the 15-year ESA towards the $140.4 million in transmission and distribution costs incurred to serve the customer. The remaining $137.9 million in upgrades the customer caused would be allocated to and recovered from all other customers. *Id*. at 157-58.

The Large Load Panel recommended that DEC be required to file all executed ESAs for loads of 25 MW or greater with the Commission within 10 days of execution in Docket No. E-100, Sub 208A. This would allow the Commission and the Public Staff to monitor ESAs and evaluate any potential issues in a timely manner. *Id*. at 148-49. The Large Load Panel also recommended that DEC should seek Commission approval of any modifications or deviations that are necessary to the pro forma ESA Application to serve a potential customer. The Large Load Panel asserted that this would allow DEC the flexibility it needs to serve potential customers while also ensuring Commission oversight of every large load customer ESA. *Id*. In addition, the Public Staff would continue to review specific projects that come into service within the context of future rate cases. Tr. vol. 15, 124-25.

During the evidentiary hearing, several intervenors asked the Large Load Panel questions about how the Required Facilities charges would be determined and allocated. The Large Load Panel testified that Required Facilities include both dedicated facilities (serving only the large load customer) and facilities that benefit both the large load customer and other customers, such as substation transformers and transmission lines. Tr. vol. 14, 252-53. The Large Load Panel confirmed that the large load customers would only pay the portion of the cost that they cause but provided no specific guidance on how DEC should determine which costs should be allocated to a large load customer, but rather such determination would be handled on a "case-by-case basis" by DEC. *Id*. at 253-54. Public Staff witness Lucas maintained that the guidance presented by the Public Staff in its proposed large load tariff, service regulations, and ESA Application is sufficient for DEC to analyze a large load customer, and noted that the large load customers are varied, with loads of 50 MW to over 1 GW, so "Duke is going to have to evaluate what kind of CIAC would be appropriate" for each customer. *Id.* at 261-62. Based

on her review of large load tariffs in other states, Public Staff witness Dr. Weaver noted that a tiered structure in a large load tariff is valuable considering the broad range of customers. Tr. vol. 15, 136-37. In a late-filed exhibit, the Public Staff pointed to South Carolina, Pennsylvania, Virginia, and Delaware as examples of other states in the Mid-Atlantic region that have implemented enforceable frameworks to ensure that large-load customers are responsible for the T&D costs that their demand imposes on the electric system. Public Staff Late-Filed Ex. 2 at 2.

On the stand, Public Staff witness Lucas provided an example of considerations to be factored into the analysis of the CIAC in the Public Staff's proposal:

> [I]n a rural area if Duke installs facilities that happen to be above and beyond what a particular customer needs, that cost should not be socialized. Like if a customer's load has increased the need for a 100 MVA transformer, but won't use quite the entire capacity, but it's in a rural area and that capacity is not going to be used, other customers should not have to pay for it. That facility was put in just to serve that large load. And if it has some incidental extra capacity that might not get used, other customers shouldn't have to pay for it.

Tr. vol. 14, 284.

Referencing figure 4 on page 48 of the Public Staff's testimony, Public Staff witness Dr. Ssengonzi noted that DEC was able to designate, delineate, and provide information on the transmission, generation, and distribution assets meant to solely serve six large load customers, as well as other transmission, distribution, and a minor amount of generation assets, that were incurred for these large load customers but had larger system benefits. The Public Staff found a great percentage of the costs requested to be put into service were designed or built specifically for a single large load customer. Public Staff witness Dr. Weaver added that the Public Staff found that the existing calculation methodology employed by Duke did not seem to sufficiently result in the single large load customer contributing to the cost of the project. The Large Load Panel testified that their proposed tariff includes required facilities charges and dedicated facilities charges that require the large load customers to pay for these grid assets without being socialized to all other customers. Tr. vol. 15, 138-40.

The Large Load Panel also acknowledged situations could arise requiring cost allocation between two or more competing large load customers, not just between a large load customer and general ratepayers, and cited generator interconnection procedures as similar instances in which similar decisions have been made. Tr. vol. 14, 288. With respect to facilities that benefit both a large load customer and other customers, the Large Load Panel testified at several points during the hearing about the "murkiness" of making that determination and indicated that the issue may require further investigation. *See, e.g., id*. at 253, 281-82.

On cross-examination, the Large Load Panel was asked about liquidated damages a customer would be subject to if it terminated its agreement or did not take service at the level or timeline set forth in the agreement. The Large Load Panel responded some ESAs do contain liquidated damages the customer would be expected to pay if it reduced load,

but Duke has communicated the damages amount is not intended to cover all of the incremental infrastructure costs that would be required to serve customers, contributing to potential stranded asset risk. *Id.* at 173-74. Public Staff witness Dr. Ssengonzi added that the transmission and distribution assets put online are not always able to be incrementally increased or decreased as the load or load ramp changes. Witness Dr. Ssengonzi added, "[t]here are challenges because some of these assets do have long lead times in terms of months or years. So, a change in load at the end of an ESA can have impact on what Duke might want to do. Duke might have a plan that's pretty solid, but if there are changes on the end user, it can really impact whether or not that asset is being used economically or not." *Id.* at 177-79. The Large Load Panel added in their tariff, if another customer can use the assets previously used by a departing customer, then the existing customer would have a reduction in their calculated exit fee. Tr. vol 15, 161.

On cross-examination, the Large Load Panel also addressed a series of questions as to what the Public Staff's intent would be in the event that a provision of Schedule LL conflicts with a provision of an existing ESA — i.e., whether the ESA would control or whether the tariff would control. Tr. vol. 14, 199-202; tr. vol. 15, 31-36, 98-99. The Large Load Panel clarified that if a customer has already signed an ESA application, the Public Staff's ESA terms would not apply. The Large Load Panel further stated that the tariff terms under Schedule LL would apply to a customer who had a signed ESA but had not yet taken service as of January 1, 2027. The Public Staff's proposed ESA is for customers that sign ESAs on or after January 1, 2027. A load ramp agreed to in an ESA would not be forced to change according to a tariff. Tr. vol. 14, 199-202. In addition, they testified that existing customers whose load grows to meet the 50 MW and 80% load factor criteria would be required to conform to Schedule LL, triggered by the customer's growing load characteristics. *Id.* at 206-07. The Large Load Panel confirmed that existing language within DEC's form ESA includes statements that the agreement is "subject to changes or substitutions, either in whole or in part made from time to time by a legally effective filing of the Company with or by order of the regulatory authority having jurisdiction." Tr. vol. 15, 99.

During the evidentiary hearing, the Large Load Panel also indicated that under certain circumstances large load customers could provide benefits to other customers, but they are concerned that those circumstances may not come to fruition. Tr. vol. 14, 219-20. They noted large load customers are going to be providing revenue, but timing is very important and DEC's large load impact analysis is sensitive to certain assumptions. *Id*. at 224. Public Staff witness Dr. Weaver described a variety of concerns the Public Staff had with Duke's large load impact analysis. First, witness Dr. Weaver noted that Duke's analysis uses nominal numbers and does not account for the time value of money. Second, the analysis uses the preliminary base portfolio instead of the NTAP that Duke put forward, which is $2 billion more expensive than the base portfolio. The Public Staff found that moving the timing of the gas resources based on the NTAP results in a net benefit decrease of half a billion dollars. Third, the analysis looks specifically at gas generation assets, which are cheaper than other generation units and not reflective of the cost of the whole system to serve the load. Fourth, the additional infrastructure costs to provide fuel for the gas generation units are not fully captured. Lastly, the Public Staff determined that the assumption of customers operating at 95% of contracted demand for 15 years was not realistic and conducted a minimum bound sensitivity that assumed 75% billing demand which resulted in a net cost of $1.8 billion. *Id*. at 221-24.

When asked about the creation of a new rate class, the Large Load Panel agreed that there could be some advantage to making the large load customers their own rate class, and creating a separate rate class would better enable tracking costs and revenues. Tr. vol 15, 51-52, 162-63. Public Staff witness Dr. Weaver testified the Public Staff did not propose a rate class because a lot of these customers are not yet taking service and therefore there is insufficient data to appropriately allocate costs. *Id.* at 52. Public Staff witness Lucas added that if the Commission put these large load customers in their own class then the customers would know in the future that they would not have intraclass support or subsidy. *Id.* at 53. The Public Staff noted that they were limited in their options for a large load tariff, in that they were unable to create a complete tariff with rates and had to develop a tariff that would work in conjunction with existing rate structures. *Id.* at 165.

The Commission asked the Large Load Panel about the Public Staff's recommendation for customers to provide a NERC compliant written plan, approved by Duke, for managing sudden disconnection and reconnection of load to avoid grid disturbances. The Large Load Panel stated that the goal of the provision is to ensure communication between the customer and the utility, to proactively mitigate reliability issues experienced in other jurisdictions. Public Staff witness Lucas stated a customer could disconnect and reconnect in a matter of seconds, and Duke has some very sensitive equipment and cannot manage very large load changes over a matter of seconds or milliseconds. Witness Lucas added that the plan provides awareness to the customer and Duke Energy, to allow Duke to assess what it will have to do and how much it will have to spend to manage the customer's expectations and put in control equipment to prevent damage to the grid. *Id.* at 131-33. Public Staff witness Dr. Weaver noted that of the 29 current ESAs reviewed by the Public Staff, 57% are data centers, and data centers represent 92% of the load requested in ESAs. *Id.* at 145-46.

Other Intervenor Direct Testimony

AGO witness Burgess testified Duke is adding significant investments to serve large loads, but the revenues from those large loads are not being reflected in the calculation of rates. Tr. vol. 19, 109-10. AGO witness Brant testified that DEC's existing approach and tariffs (Schedules OPT-V and HLF) shift significant costs and risks onto other ratepayers, give DEC significant discretion to negotiate terms without Commission review, and were not designed with the scale, risk profile, or infrastructure requirements of data centers and similar facilities in mind and are therefore inadequate. *Id.* at 128, 146-47. Witness Brant stated large load customers represent new loads of unprecedented size and risk, require unprecedented system upgrades to serve them, and the cost allocation paradigm in use for the past 100 years was not designed to accommodate such large and unprecedented load growth. *Id.* at 131. Witness Brant noted that if the marginal cost to serve a new customer is higher than the average embedded system cost allocated to the new customer, the gap between the costs caused by the new customers and the costs allocated to the new customers must be paid by existing customers. *Id.* at 134. Witness Brant testified that DEC should have conducted a dedicated cost-of-service analysis for a hypothetical very large load customer class to support its assertion that existing schedules align prices with cost-of-service, which it did not provide in discovery. *Id.* at 147-48. DEC's Distribution Line Extension Plan governs

distribution-level CIAC calculations, and witness Brant testified that it does not apply to customers served at transmission voltage and recommended the Commission direct DEC to develop and submit a formal cost recovery framework for transmission-level line extensions serving large load customers. *Id.* at 154.

Witness Brant added that commissions in other jurisdictions are moving to directly allocate all or a portion of incremental generation and transmission costs to serve new large loads and presented different cost allocation approaches in Arizona, Florida, Georgia, Oregon, Minnesota, and Wisconsin. *Id.* at 138-44. Witness Brant recommended five large load recommendations: (1) establish a dedicated large load tariff and new rate class for customers over 100 MW; (2) require DEC to adopt a tiered ESA for customers over 20 MW, incorporating minimum 15-year contract terms, minimum demand charges, exit fees, collateral requirements, curtailment provisions, and options for customers to bring their own resources and financially contribute to DSM programs; (3) include the ESA requirements in the large load tariff; (4) require DEC to update its large load interconnection process to minimize speculative projects; and (5) require DEC to update customer programs to increase large load flexibility participation. *Id.* at 120-22. Witness Brant also proposed an incremental generation charge for large load customers, providing examples of different frameworks used in Arizona and Florida. *Id.* at 141-42. Witness Brant stated these jurisdictions recognize demand growth from large customers is unprecedented and can expose other customers to increased costs in the short-term and stranded assets and cost-shifting over the medium-to-long term. As a result, many jurisdictions are altering their ratemaking practices to address incremental costs with different forms of cost allocation, including direct allocation of costs. *Id.* at 143-44. Witness Brant testified relying on individual ESAs without a governing tariff is insufficient because it lacks consistency, transparency, and Commission oversight. *Id*. at 149-51. Witness Brant testified "ratepayer protection should not depend on how DEC negotiates a particular agreement or on the relative bargaining power of the parties at the time of contracting." *Id.* at 150. Witness Brant recommended a new rate class for large loads, as it would "require DEC to conduct a complete, auditable cost-of-service analysis tracing all revenues and costs attributable to very large load customers and establish liquidated damages based on these costs." *Id.* at 155. At the evidentiary hearing, witness Brant reiterated his recommendation to establish a new rate class, noting this allows more opportunities to address questions about cost allocation and "who pays for what costs and when," and it is easier to ensure customers are paying the incremental costs to serve them. *Id.* at 213.

CIGFUR III witness Collins testified that introduction of a large load tariff in this proceeding is premature, because the record is built around the existing tariff structure and customer classes, and a new large load tariff could materially affect cost allocation among classes. *Id.* at 243. Witness Collins nonetheless recommended, should the Commission determine a tariff is warranted, the matter be addressed in a separate proceeding to allow adequate evidentiary development with broad participation. *Id.* at 346-48. On cross-examination, witness Collins acknowledged that CIGFUR III had changed its position from opposing a tariff in this proceeding to supporting a separate proceeding because the tariff proposals were not presented until the Public Staff's direct testimony and DEC's rebuttal, and intervenors had not had adequate time to evaluate them. *Id*. Witness Collins noted that existing traditional manufacturing customers pose a

different operational risk profile than the new large load customers seeking to take service under the previously discussed ESAs. *Id.* at 302, 351-52.

EDF witnesses Lenell and Pol testified DEC should develop a holistic rate and tariff design framework for data centers over 50 MWs, due to their unique operational characteristics, that includes optional demand response and ring-fencing clean energy portfolios. Tr. vol. 20, 20-21. Witnesses Lenell and Pol noted that DEC is projecting growth from large loads to constitute over 83% of the cumulative load growth to the year 2035 and data centers over 50 MW will comprise 9.2% of DEC's winter peak and 14.5% of total sales by 2030. *Id.* at 26, 33. If large data center loads materialize as forecasted, witnesses Lenell and Pol note that existing Commercial classes would be allocated a greater portion of system costs relative to status quo and non-large-load Commercial customers may experience increased costs. *Id.* at 32.

EDF witnesses Lenell and Pol testified that large load customers, in particular data centers, use the system differently than other customers. *Id.* at 93-94. Data centers have "high load factors, high reliability standards, developmental uncertainty, and unique technological development trajectories" that require significant changes to system planning and operations, impacting allocation factors and rates. *Id*. at 34. Data centers in DEC have an average estimated load factor of approximately 90%, while manufacturing customers in DEC have an estimated load factor closer to 74%. *Id.* at 35. Utilities serving data centers need to provide greater levels of investments to meet reliability expectations, compared to manufacturing customers. *Id.* at 36. Witnesses Lenell and Pol noted that only customers with a consistently high load factor would benefit from being on rate schedule HLF given its billing demand definition. *Id.* at 47. Witnesses Lenell and Pol noted that large data center loads could theoretically put a downward pressure on rates, assuming the load materializes as planned, but also present risks of demand failing to materialize. *Id.* at 44. Reflecting the unique nature of the large data center customers, witnesses Lenell and Pol also recommended DEC evaluate and introduce a new rate class, noting that other states have done so as well. *Id.* at 45, 57.

EDF witnesses Lenell and Pol testified ESAs are not sufficient methods for managing large load customer growth because they lack the transparency and uniformity of Commission-approved tariffs. *Id.* at 49-51. They recommended the Commission develop tailored rate structures for large loads, noting DEC's existing provisions addressing large load risks are spread across ESAs, tariffs, and service regulations, with many key protections residing only in the ESA. *Id*. Witnesses Lenell and Pol presented and discussed large load tariff design elements common between and unique to several utilities. *Id.* at 52-59. Witnesses Lenell and Pol recommended the Commission require DEC to support its claims that the existing framework is adequate and recommended requiring a tiered tariff framework. *Id.* at 61-62. Witnesses Lenell and Pol emphasized that large load growth is reshaping system planning and capital requirements, with costs and commitments to serve large loads occurring now, and concluded that this rate case is the appropriate forum to guarantee that existing ratepayers are appropriately protected. *Id.* at 62-63.

At the evidentiary hearing, witnesses Lenell and Pol argued that a rate class can be designed without a full year of actual data, based on an understanding of the class's usage characteristics, with the impact to other classes determined by how the class is

defined. *Id.* at 91-93. Witnesses Lenell and Pol advised the Commission on particular tariff provisions to closely consider, such as eligibility thresholds, contract length, load ramps, and assignment of incremental costs, and reiterated that a 50 MW load threshold is appropriate. *Id*. at 96-98. Regarding a large load tariff that lacks a dedicated rate schedule, witnesses Lenell and Pol stated this was uncommon and while it provides optionality for the customer, they recommend a specific rate schedule to send efficient price signals and to reflect the cost to serve that rate class. *Id.* at 99-102. Speaking to the large load tariff proposed by the Public Staff, witness Lenell stated while it is a good first step, he would like to see a dedicated rate schedule, demand response flexibility, and more information on the process and methodology for direct assignment of costs. *Id.* at 102-03. Witnesses Lenell and Pol also advised that given the large amount of load to be contracted and put on the system, it is critical for ratepayer protections to be established as early as possible. *Id.* at 105-06.

EDF witnesses Lenell and Pol also recommended a ring-fenced option for data centers, such as clean transition tariffs, to help ensure the cost to serve is borne by the data center loads and other ratepayers are not negatively impacted. *Id.* at 107-09. In response to a question from Commissioner Tucker about large loads paying upfront for some system costs and then repaid over time, witnesses Lenell and Pol stated that type of design is becoming more common, citing Pennsylvania's "but-for" test as an example, but would require further discussion and determination. *Id.* at 110-15.

Google witness Dr. Berry testified that large load customers, particularly those with high load factors, offer both operational and economic advantages to the electric system, including supporting more efficient grid operation and planning, and enabling utility system planners to better optimize existing generation and transmission infrastructure. Tr. vol. 19, 596-97. Witness Dr. Berry testified that large load customers contribute to new and existing costs, thereby reducing the amounts other customers pay. *Id*. at 597-98. Witness Dr. Berry agreed that a new rate schedule for large load customers is not immediately necessary given that existing rate structures are based on cost of service but testified large load customers are quickly evolving and present unique challenges and risks requiring the adoption of policy measures to protect ratepayers, and that a large load tariff is an appropriate mechanism for ensuring transparency and consistency. *Id*. at 595-96. She recommended approval of DEC's proposed enhancements to credit and performance provisions, deferral of a new large load tariff from this proceeding, and if the Commission determines a tariff is required, opening a separate proceeding for that purpose. *Id*. at 592-93. Witness Dr. Berry noted three disadvantages with DEC's current contract-based approach to mitigate risks with large loads: (1) existing policies are not presented comprehensively for clarity, (2) DEC could implement different terms for different customers which presents a transparency and equity issue, and (3) determination of many details within the contracts are uncertain. *Id.* at 600-01. On cross-examination, witness Dr. Berry testified that a large load tariff assures the public there is a minimum set of terms and conditions applicable to all large load customers, providing public scrutiny individual ESAs lack. *Id*. at 615-16.

Microsoft witness Gabel-Frank testified DEC's proposed traditional base rate increase primarily reflects the embedded cost of the existing system rather than new capital investment tied to future load growth, and that the MYRP2 investments reflect a

forward-looking portfolio of system-wide investments driven by multiple factors including reliability needs and prior Commission-directed resource decisions. *Id.* at 130-36. Witness Gabel-Frank further testified the impact of large or growing load on system costs is not uniform and additional load may increase or reduce average system costs. *Id*. at 129. He recommended the Commission direct DEC to open an expedited stakeholder process to evaluate customer driven mechanisms to support load growth while managing cost impacts, and separately recommended that the Commission initiate a separate proceeding with an expedited stakeholder process to fully evaluate the implementation of a large load tariff and develop a comprehensive record. *Id*. at 140, 147-48. Witness Gabel-Frank emphasized that large load tariffs are complex and inherently dependent on system-specific conditions, and that there is no single, widely adopted approach across jurisdictions. *Id*. at 142-43.

At the evidentiary hearing, witness Gabel-Frank provided his thoughts on the Public Staff's large load tariff, stating it was a thoughtful approach but needed more discussion on the interaction between the different concepts. *Id.* at 160-61. Witness Gabel-Frank also noted good aspects of DEC's proposed tariff but added the tariffs needed more discussion on the details of implementation and unintended consequences, emphasizing the need for an expedited stakeholder process. *Id.* at 161-62. Witness Gabel-Frank stated large load customers want to pay their fair share and have certainty in the regulatory environment. *Id.* at 163-64. Speaking to the idea of a separate rate class, witness Gabel-Frank stated that customers with similar load profiles and system use should be treated similarly. *Id*. at 166-67.

NCJC, et al. witness Wilson testified DEC's existing tariffs and practices are insufficient to protect the broader customer base and should be amended to address the unprecedented large load growth forecast of 7,946 MW over ten years. *Id.* at 414-15, 428-29. Witness Wilson identified several key factors that should be included in a large load tariff, including financial security prior to energization, minimum billing terms, minimum contract length, early termination provisions, power quality requirements, and the establishment of a separate large load customer class. *Id.* at 449-51. Witness Wilson recommended proactively establishing a new large load class to effectively and transparently implement cost allocation, even given the lack of customers and data. *Id.* at 372, 451. Witness Wilson further stated he is unaware of an analysis by Duke Energy that provides clear evidence large load customers will bear their full costs under the new cost allocation formula. *Id.* at 416. Witness Wilson recommended a 20-year contract term, noting that DEC's current 15-year minimum is insufficient because generation resources are procured for terms of 20 to 35 years. *Id*. at 371-72, 433. Witness Wilson stated because large load customers present such a singular risk of stranded costs, it is reasonable to require those customers to assume financial obligations pursuant to DEC's rates and service regulations and pointed out that Solar Choice Tariffs have a minimum charge to ensure solar customers contribute sufficient revenue to cover the cost to serve them; witness Wilson asserted that this logic also applies to customers whose impact on the system is orders of magnitude greater. *Id.* at 437. Witness Wilson further recommended increasing the minimum billing demand from 75% to 85% of contract demand and limiting contract demand reductions to 20% (up to 100 MW maximum) with 36-month notice. *Id.* at 444-45. Witness Wilson also noted various operational and economic factors that differentiate a data center customer from a traditional manufacturing customer.

Id. at 416-19. Additionally, witness Wilson proposed that the large load tariff include a Clean Transition Tariff option allowing customers to designate specific clean resources and assume direct financial responsibility for incremental costs. *Id.* at 452-54.

At the evidentiary hearing, witness Wilson discussed his review of the Public Staff's proposed large load tariff proposal and reiterated his support to establish a new rate class. Tr. vol. 19, 482-86. Witness Wilson recommended the Public Staff's proposed contract terms to be added on to a customer's load ramp, maintained his recommended thresholds and minimum billing demand, noted there are cumulative impacts of the Public Staff's exit fee language that need to be considered, and expressed his support for the Public Staff's required facilities approach. *Id.* Witness Wilson warned that choosing not to establish a new rate class now may delay such a decision past the next rate case. While agreeing with the concerns about the impact on rates and COSS if a new rate class is established, witness Wilson recommended the Commission establish a new class in this case to be treated for reporting purposes and for inclusion in future cases. *Id.*

DEC Rebuttal Testimony

DEC witness Duff testified regarding the unprecedented large load growth driven by data centers and advanced manufacturing in DEC's service territory. Witness Duff testified that DEC projects 7,946 MW of large load at full build over a ten-year horizon, with 43 Advanced Development Projects and 16 executed ESAs totaling approximately 4,332 MW of contracted demand. Tr. vol. 21, 525-26. Witness Duff explained that large load customers generally operate at 90% or greater load factors, spread fixed costs across all hours of operation, and benefit all customers by contributing to the recovery of system costs. He described DEC's analysis from the CPIRP, which projects large loads to provide approximately $3.6 billion in net benefit over 15 years and residential bills to be $4 to $6 per month lower through 2040 under the High Load scenario. *Id*. at 525, 533-34.

Witness Duff further testified that DEC is obligated under North Carolina law to serve all customers within its service territory and cannot refuse service based on load size, stating the appropriate mechanism for managing the risks and obligations associated with serving large load customers is through Commission-approved tariffs and service regulations, not through refusal of service. *Id.* at 536-37. In January 2024, the Commission approved new credit and performance requirements for customers with loads over 100 MW, to protect non-participating customers and the Companies for infrastructure buildout required to serve new large load customers. *Id*. at 529. On cross-examination, witness Duff reaffirmed that DEC cannot lawfully refuse to serve a customer merely because the customer is large, and he opposed a moratorium on additional large-load ESAs because it could significantly stifle an economic development opportunity that could be in North Carolina's best interest. *Id*. at 640-41.

Witness Duff emphasized that for customers that have already signed ESAs, DEC does not propose to change the terms or requirements contained in their legally binding agreements, including the cost assignment methodology for interconnection facilities and network upgrades, notice requirements, liquidated damages, or credit security terms previously negotiated in existing ESAs. *Id*. at 541. Witness Duff noted that customers with ESAs have made substantial capital investment decisions based on expectations

regarding the binding terms and conditions of service reflected under the ESA, and in some cases, certain retroactive changes to large load customers with ESAs might be appropriate and equitable while in other cases application of certain retroactive changes to large load customers with ESAs would be inequitable. *Id*. At the evidentiary hearing, witness Duff explained that a study process is conducted for individual large load customers to identify needed network upgrades and other costs, and this process is guided by internal documentation. *Id*. at 635-37.

DEC witnesses Byrd and Beveridge presented DEC's proposed Large Load Tariff (LLT), which would apply to customers with loads of 50 MW or greater and expected load factors of 80% or greater, for contracts executed on or after January 1, 2027. Tr. vol. 21, 558-74; Byrd-Beveridge Reb. Ex. 1. The LLT formalizes existing ESA protections into a tariff that reflects constructive recommendations from the Public Staff and other parties. Tr. vol. 21, 559. On cross-examination, DEC witness Byrd clarified that LLT is not a standalone tariff with distinct demand and energy charges but rather works in concert with underlying tariffs such as OPT-V or HLF. *Id*. at 611. Those tariffs include demand and energy charges designed to recover the full cost of service for larger customers. *Id*. at 559. DEC's LLT adds incremental performance and credit protections to reflect the unique risks applicable to serving large load customers. *Id*. at 560.

DEC's proposed LLT includes the following core provisions: (a) minimum 10-year contract terms as specified in the proposed LLT, with a 15-year minimum contract term for customers at or above 100MW; (b)minimum billing demand equal to 75% of contract demand based on the ESA load ramp; (c)termination damages equal to 25% of remaining Minimum Bills if the customer terminates during the initial term or during an automatic extension period without the required notice; (d)security requirements to support recovery of Minimum Bills and Termination Damages; (e)refundable advances for interconnection infrastructure, with refunds tied to actual billing demand and load factor performance milestones; (f)curtailment provisions (95% of contract load for up to 50 hours per year or 50% for up to 100 hours per year for the first five years); (g)study fees including a $100,000 non-refundable fee for loads over 100 MW; and (h)a structured queue process of approximately 300 days from initial request to ESA execution. *Id*. at 560-66. While DEC recommends the Commission approve the LLT in this proceeding, DEC proposes the LLT serve as a model framework if the Commission were to order a separate docket. *Id*. at 565-66.

DEC witnesses Byrd and Beveridge testified that DEC would not apply the proposed LLT to customers with existing ESAs. *Id*. at 565. Similarly, witness Duff explained that DEC does not propose modifying existing legally binding ESAs, as a separate docket can determine whether and how tariff protections apply to existing ESA customers while respecting bilateral contracts. *Id*. at 541. During the hearing, witness Beveridge confirmed that a customer without a signed ESA as of January 1, 2027, would be subject to the tariff under DEC's proposal. *Id*. at 616-17.

Witnesses Byrd and Beveridge also explained why the Commission should reject certain large load proposals to directly assign incremental generation costs to large load customers, imposing additional termination damages, or lengthen the contract terms. *Id*. at 563-64. They testified that DEC disagrees with the AGO's proposal to directly assign incremental generation costs to certain large load customers because "the cost of service

process already assigns costs to the tariffs serving large loads under Commission oversight." *Id*. at 563. In addition, DEC's large load impact analysis in the 2025 CPIRP proceeding estimates that large loads provide revenues above their incremental cost to serve which benefits other customers. *Id*. However, at the evidentiary hearing witnesses Byrd and Beveridge agreed that estimated interclass subsidies depends on the cost allocation method used, and a different result may occur if the cost allocation methodology changes. *Id.* at 639. Witnesses Byrd and Beveridge argued that directly assigning costs for specific generation resources also raises a range of policy and equitable treatment questions and could have unintended negative consequences in the future when such customers are not required to absorb fixed costs of other incremental generation or investments. *Id*. Witnesses Byrd and Beveridge also opposed termination penalties exceeding those in DEC's LLT because central generation and network transmission assets retain value after one customer terminates, and the LLT's notice periods, Minimum Billing Demand, and Termination Damages provide used and useful asset cost recovery while giving DEC time to adjust its resource plan. *Id*. at 564. At the evidentiary hearing, witnesses Byrd and Beveridge stated that DEC's termination penalties were not intended to recover 100 percent of all incremental resources, as DEC assumed that the resources would be redeployed to other customers or adjusted in the resource planning process. *Id.* at 618-20. Further, witness Byrd stated that where other utilities have included termination penalties that are greater than those in DEC's proposed tariff, those utilities also included mitigation provisions that attempt to capture the use of those assets by other customers, reducing the termination value by the expectation that the assets will be redeployed. *Id.* at 619. Witness Beveridge added that any direct assignment or CIAC of transmission and distribution facilities reduces exposure to stranded costs, and the calculation of termination damages or contract reduction penalties should reflect that change. *Id.* at 623. Witnesses Byrd and Beveridge objected to NCJC, et al.'s proposed 20-year contract term in its testimony and noted that the LLT would already produce terms of that length for customers with long load ramps. *Id*. Finally, witnesses Byrd and Beveridge noted that in its next rate case, DEC can evaluate rates that reflect the unique attributes of large load customers once enough of those customers are taking service to support meaningful cost of service results. *Id*. at 565.

In her rebuttal testimony, DEC witness Hager testified that creating a separate rate class for large load customers would have limited impact, as the only change in cost allocations would be to the class that the large load customers were separated from; all other customer classes would be unchanged. Tr. vol. 11, 605. In addition, as acknowledged by NCJC, et al. witness Wilson, "DEC does not have much or any historical test year data for large load customers on which to design rates." See *id*.; tr. vol. 19, 450. Witness Hager testified that the present COSS approach allocates costs to the various customer classes across the DEC system in a reasonable manner, consistent with methodologies and principles of cost causation which are vetted and reassessed in each rate case. Tr. vol. 11, 605. Therefore, witness Hager concluded that the current approach is appropriate and leads to a just and reasonable outcome. *Id*.

At the expert witness hearing, DEC witness Hager agreed that if large load customers added to the system were to drive down costs on average, that still might not benefit other customers if the large load customers were not paying their fair share of costs. *Id*. at 613-14. Witness Hager further agreed that it is a requirement of the PBR

statute that each jurisdiction and each rate class must pay its fair share of Duke's revenue requirement based on cost causation. *Id.* at 614-15.

Stipulations and Settlement Testimony

The Comprehensive Settlement at ¶ 15, provides that the Stipulating Parties, including DEC; the Public Staff; CIGFUR III; Walmart; NCSEA; CUCA; Microsoft; Andale; EDF; and Harris Teeter, acknowledge that a motion related to establishing a separate docket for the consideration of a large load tariff remains pending before the Commission and do not oppose the pending motion, provided issues involving a large load tariff can be resolved prior to implementation of new rates ordered in this proceeding. The Stipulating Parties proposed a DEC-led stakeholder process, wherein DEC was to submit a summary of stakeholder feedback; all parties file comments, including comments on Public Staff and DEC's proposed tariffs and, if desired, alternative large load tariff proposals; and all parties file reply comments. During the hearing, the Public Staff settlement panel corrected its prefiled testimony to characterize ¶ 15 as an agreement that the parties will not object to a parallel proceeding in which the parties can engage on a large load tariff, so long as issues can be resolved prior to January 1, 2027. Tr. vol. 21, 132-33.

Summary of Policy Statements

Order Requesting Comments

On August 12, 2026, the Commission issued an Order Requesting Comments, asking the parties to this proceeding to file comments and reply comments in this docket regarding the model rate schedule attached to the Order Requesting Comments as Appendix A, the issues set forth in Appendix B thereto, and the proposed large load tariff provisions that each of the Public Staff (Schedule LL) and DEC (LLT) submitted in this docket and, if desired by any party filing comments, one or more alternative data center or large load tariff proposals. While the Commission noted its appreciation for the parties' willingness to participate in the proposed stakeholder process offered by DEC and the other stipulating parties per the Comprehensive Settlement and encouraged them to do so on a voluntary basis, the Commission indicated that it did not believe it was necessary to order the parties to undertake a stakeholder process at that time.

Public Staff's Proposed Tariff

The Public Staff continued to support its proposed large load tariff. Public Staff Initial Comments at 6. EDF stated that the Public Staff's proposed large load tariff included many of the key elements of a well-designed large load tariff but was insufficient in isolation, identifying several deficiencies with proposed corrections. EDF Initial Comments at 9, 21. EDF supported the 50 MW threshold with no paired load factor requirement, arguing that utilities plan their system build-outs primarily for peak demand, not load factor. *Id.* at 9-10. EDF disagreed with the Public Staff's definition of aggregated facilities as a single site, multiple sites within one mile of each other, or sites from a common service point, recommending the definition proposed in the Commission's large load tariff instead. *Id.* at 10-11. EDF supported the Public Staff's proposed contract term lengths and the proposed minimum billing demand of 75%. *Id.* at 11-13. EDF argued that

it was unclear whether the termination fees proposed by the Public Staff sufficiently mitigated against the financial risk of early termination and recommended collection of 100% of minimum bills for the remainder of the contract term instead, with no more than a 25% discount for customers whose generation is redeployed to a different customer. *Id.* at 14-15. EDF detailed that the Public Staff's proposal for the reassignment of load in the event of a customer's early termination may not be sufficiently durable and recommended that a framework for replacement load be considered in a future proceeding. *Id.* at 15-16. EDF noted that Duke and the Public Staff proposed materially different approaches to security requirements and that Duke's appears to be more stringent but did not provide a recommendation on the appropriate amount of security, instead stating that any security requirements should adjust over time as exposure changes. *Id.* at 17-18. EDF cautioned against allowing large load customers to choose among existing rate schedules and instead recommended a dedicated data center rate schedule with options to participate in alternative rate structures such as bring-your-own-capacity or clean transition tariff structure. *Id.* at 20-21. NCJC, et al. argued that the Public Staff's proposed large load tariff was a strong start but omitted essential protections by failing to create a customer class. NCJC, et al. Initial Comments at 67.

Duke acknowledged that while Duke's LLT is aligned with substantial portions of the Public Staff's LLT, they have concerns with other aspects of it. Duke Initial Comments at 23. Specifically, they argued that the Public Staff provided no methodology for cost allocation of system assets and provided no analysis that the standard cost causation principles are insufficient to ensure large load customer pay their fair share of system costs. *Id.* They argued that requiring large load customers to pay transmission and distribution investment costs attributable to their service while also continuing to pay their allocated share of all other transmission and distribution costs under standard embedded rates would create fairness concerns as well as inequitable cross subsidization and rate discrimination relative to other customer classes. *Id.* Duke found the Public Staff's termination penalties to be punitive and failed to recognize the continuing value and contribution to system capacity and reliability if the customer terminates early. *Id.* at 24. Finally, while Duke acknowledged that the Public Staff's curtailment provisions now more closely match Duke's proposed provisions, they remain concerned that the Public Staff's LLT does not recognize the need for Commission-approved alternatives to the two existing curtailment options where curtailment could adversely affect public health or safety functions associated with the customer's load. *Id*. at 24-25.

The AGO argued that the Public Staff's proposed large load tariff was directionally consistent with the AGO's recommendations but did not go far enough to protect customers. AGO Initial Comments at 2-3. The AGO expressed concern that the Public Staff's customer-specific revenue calculation required to implement Public Staff's proposed large load tariff, Schedule LL, could be challenging to implement and easily gamed by Duke and large load customers. *Id.* at 3.

Amazon supported aspects of the Commission's, Duke's, and the Public Staff's proposals, with modifications. Amazon Initial Comments at 11. Amazon supported Duke's initial contract extension of one year per year for load ramp years rather than the Public Staff's five-year load ramp cap. *Id.* at 12. Amazon supported the proposed minimum billing demand of 75% but argued that the large load customer should not be

responsible for this payment for months in which full energization is not possible due to the utility's delays in interconnecting the customer. *Id.* at 13-14. Amazon argued that a 24 month notification period for customers with a contract demand over 250 MW is sufficient. *Id.* at 14. Amazon argued that any termination fees collected should offset Duke's annual revenue requirement and that Duke should be required to mitigate termination fees if a new customer can locate at the same or nearby location that was built for the terminating customer. *Id.* at 15. Amazon supported the Public Staff's proposal to allow a one-time reduction of up to 20% of contract demand without penalty. *Id.* Finally, Amazon supported the Public Staff's proposal to allow large load customers to provide up to 100% of contract demand with behind-the-meter generation but requested further clarification on the definition of "customer-owned generation." *Id.* at 16.

Andale supported the Public Staff's one-time, penalty-free contract demand reduction of 20%; Andale suggested that for any reduction greater than 20%, that the notification period be tied to the magnitude of the reduction. Andale Initial Comments at 7. Andale stated that it did not oppose the upfront payment of Dedicated Facilities but strongly opposed mechanisms that do not refund payment if those costs are not incurred. *Id.* Andale stated that it believed that non-Dedicated Facilities costs and generation costs should be recovered via cost-of-service ratemaking. *Id.* Finally, Andale supported the Public Staff's proposed option for large load customers to provide behind-the-meter generation equal to 100% of the contract demand. *Id.* at 8.

CUCA took issue with the Public Staff's proposed framework for assigning costs for Required Facilities, arguing that the Public Staff provided a concept with no allocation methodology, provided no mechanism to credit large load customers or charge other beneficiaries, and did not provide support for its position through a study, model, or benchmark. CUCA Initial Comments at 15-16.

Google argued that the Public Staff's size threshold may exclude some customers that should be included in the large load tariff, such as a 200 MW large load customer with a load factor of 75%. Google Initial Comments at 8. Google also expressed concern that the Public Staff's proposed large load tariff would be applicable to large loads with incremental service increases that meet the Public Staff's size threshold, arguing that the approach was vague, not easily implemented, and not tied to how large load customers are currently proceeding through Duke's large load interconnection queue. *Id.* at 8-9. Google argued that changes to cost allocation should only be made prospectively and apply to potential large load customers that have evaluated these changes prior to making capital investments in the state. *Id.* at 9. Google neither supported the Public Staff's proposed load ramp cap of 5 years nor its proposed termination fees of 75% to 100% of minimum bills, stating that the latter was excessive. *Id.* Google disagreed with the Public Staff's proposal for cost allocation of Required Facilities to large load customers, stating that the Public Staff did not provide sufficient guidance on the methodology of assigning these costs. *Id.* at 10.

Microsoft found the Public Staff's proposal on exit fees and liquidated damages to be punitive, unreasonable and far in excess of what is required to mitigate the risk of stranded assets if a large load customer terminates or reduces its load. Microsoft Initial Comments at 9. Microsoft supported the Public Staff's proposal for termination or contract demand reduction notification periods and its proposal for large load customers to provide

100% behind-the-meter generation, recommending that the Commission explore the development of additional alternatives for non-customer-sited generation. Microsoft Initial Comments at Ex. A.

Walmart provided a recommended list of provisions for inclusion in any large load tariff that included credit and deposit requirements, minimum demand and contract terms, exit fees, notice periods, CIAC for dedicated facilities, direct assignment of allocated marginal costs for generation and back bone transmission projects based on a growth-for-growth model, and plans to address potential reliability and power quality issues. Walmart Initial Comments at 8-9.

Duke's Proposed Tariff

In response to Commission questions in the Order Requesting Comments, Duke stated that embedded cost of service methodology should remain the primary basis for allocating revenue requirements to customer classes and that this should be paired with large load tariff provisions, contractual safeguards in service agreements, and other rate design tools to mitigate cost-shift and stranded cost risks. Duke Initial Comments at 20. Duke repeated the core customer protections housed within its proposed large load tariff, which include a minimum 10-year contract term for customers below 100 MW and a minimum 15-year contract term for customers at or above 100 MW; a minimum billing demand of 75% of contract demand based on the load ramp; termination charges which recover 15% of remaining minimum bills (25% for DEC) and 100% of Extra Facilities Charges if the customer terminates during the initial term or automatic extension period without required notice; security requirements which require security such as cash collateral or letter(s) of credit and parent guaranty from a creditworthy entity to support the customer's minimum billing demand obligation and termination liquidated damages liability; security deposits for non-network facilities tied to a specific large load customer; mandatory curtailment during the first five years of service; contract termination notices of 24, 36, or 48 months before termination depending on contract demand; annual contract extensions unless properly noticed; and one-time, penalty-free contract demand reduction of up to 20% after seven years of service and with 12 months notice. *Id.* at 20-21.

Duke continued to support its proposed tariff in its Initial Reply Comments, stating that it was consistent with the Ratepayer Protection Pledge and resulted in a measured set of customer protections without adopting more aggressive measures that would violate North Carolina law, discourage economic development, or result in undue discrimination. *Id*. at 25. Andale supported Duke's termination fees and financial security provisions, with modifications, and supported Duke's curtailment proposal that ties curtailment to the load ramp and ends five years after energization. Andale Initial Comments at 8. Andale further supported Duke's proposal to allow large load customers to choose their own rate schedule. *Id.* at 6-7. CUCA supported Duke's proposed applicability date of applying its tariff overlay only to agreements signed on or after January 1, 2027. CUCA Initial Comments at 11. Digital Realty argued that if standardized protections are necessary for future large-load commitments, Duke's proposed large load tariff provides a straightforward means of implementing those protections without disturbing existing contractual arrangements. Digital Realty Initial Comments at 8.

Google supported Duke's proposed large load tariff with minor modifications, including reductions to the notification period and liquidated damages based on those notification period reductions as well as provisions that provide for changes to liquidated damages in the event that a load terminates early and is able to find a replacement customer to utilize that demand. Google Initial Comments at 12-14. Microsoft supported Duke's proposed large load tariff with modifications, including reductions to the termination notice period of 48 to 36 months for reductions of loads 250 MW or greater, modifications to Duke's provision to allow a one-time, 20% reduction in contract demand without penalty, modifications to the calculation of liquidated damages, and additional abilities for Duke to waive or adjust the security amounts based on the customer's credit rating. Microsoft Initial Comments at 9-10.

The Public Staff conceded that while Duke's proposed tariff had many similarities to the Public Staff's proposed Schedule LL, it differed from the Public Staff's proposal by allowing a large load customer to begin its contract term after its load ramp period, proposing a 12-month delay in implementing minimum billing demand charges, adding an additional tier of requirements for contract demand reduction or early termination for loads of 500 MW or more, and applying different liquidated damage requirements. Public Staff Initial Comments at 7. Consequently, the Public Staff continued to support its proposed Schedule LL over Duke's proposal. *Id.* at 6.

The AGO argued that Duke's proposal did not go far enough to protect customers or ensure that large load customers pay the incremental costs to serve them. AGO Initial Comments at 3. The AGO took further issue that Duke's proposal would only apply to customers who signed a Letter Agreement or ESA on or after January 1, 2027, which excludes all facilities currently in Duke's large load customer queue. *Id.* EDF stated that they did not recommend adoption of Duke's proposed large load tariff, arguing that the risks to non-data center customers are not adequately addressed by Duke's proposals. EDF Initial Comments at 22. NCJC, et al. argued that while Duke's proposed large load tariff provisions were similar to the Public Staff's, they were generally less protective of existing ratepayers and thus insufficient. NCJC, et al. Initial Comments at 67. NCSEA did not recommend Duke's large load tariff but did recommend that the Commission reincorporate one of Duke's reliability provisions – namely, the provision that allows for alternative, Commission-approved options that accelerate capacity resources on the utility system during the integration of the customer's full contract demand. NCSEA Initial Comments at 3.

Commission's Proposed Tariff (Appendix A Tariff)

In its initial comments, Duke noted that the Commission's proposal assessed some costs of system assets to serve a large load customer and argued that system assets served all customers. Duke Initial Comments at 5. Duke added that the Commission's proposal appeared to give no credit to account for revenues expected to be contributed by the large load customer over time. *Id.* at 14. Duke argued that the "core cost causation question (i.e., who benefits from new system assets) is not actually answered" by the Commission's proposed tariff. *Id.* at 16. Duke also argued that the independent assessor under the Commission's proposed tariff is tasked with the same Commission roles of making resource plan and rate case determinations, and there was no guidance, no clear

avenues for recourse, and no clear process for such implementation. *Id.* at 17. Duke had significant concerns regarding the feasibility of the curtailment alternative identified as Option B in the Commission's proposal. *Id.* at 34-35.

Duke provided additional concerns with the Commission's proposed tariff in the DEC-DEP Reply Comments. Duke summarized Microsoft's concerns, noting that the Appendix A ESA Deposit could potentially require hundreds of millions of dollars for system assets before capital expenditures are incurred, the refund of which is limited and could create an unlawful interclass subsidy as the customer would have paid for both system assets and embedded rates. Duke noted CUCA's caution about the lack of evidence to implement this methodology and stated that AGO's and NCJC, et al.'s proposals are similarly flawed. Duke Reply Comments at 12. Duke stated that the curtailment alternatives provided in Exhibit D of the Appendix A Tariff have not been vetted to understand feasibility and ensured reliability and would be premature to include at this time. *Id.* at 23. Duke added that the lack of methodology to establish a customer's responsibility for network upgrade costs invites litigation over every new ESA and could lead to increased disputes in future rate cases. *Id.* at 28. Duke further noted that the Appendix A ESAs lack key commercial terms and contain implementation challenges, departures from typical industry practices, and material ambiguities that introduce contract uncertainty. *Id.* at 30. Duke also states Appendix A LLT and a few intervenors seek to directly allocate system assets outside of a rate case and without cost-of-service analysis, noting that this introduces changes in cost allocation and rate design and does not consider compliance with ratemaking statutes, avoidance of double payments or cross-subsidization, or other unintended consequences. *Id*. at 31. Duke observed in its reply comments that except for NCJC, et al., no party fully endorsed the independent assessor proposal within the Appendix A tariff. *Id.* at 33.

Duke also stated that the Appendix A Tariff lacked defined aggregation standards and minimum and maximum contract terms. Duke Reply Comments Attach. 1 at 1. Duke also pointed out that the Commission's proposal did not specify whether the new tariff applied prospectively or retroactively. *Id*. Regarding the upfront cost requirements and cost recovery mechanism, Duke stated that the timing of the ESA Deposit creates significant sequencing issues and financing concerns and is a barrier to economic development and also stated that the bill-credit amortization refund mechanism is unnecessarily complex and creates uncertainty as to whether the customer will ever recover its full deposit within the initial contract term. *Id.* at 2. The reliance on the ESA Deposit as credit protection, Duke states, does not adequately address Duke's ongoing credit exposure over the life of the contract; standard credit support provisions such as a defined schedule of remaining exposure, credit support (such as letters of credit, parent guaranties, and cash), and creditworthiness thresholds protect the utility from default risk over the life of the contract. Duke stated that the actual risk exposure is measured by termination liquidated damages, not estimated project costs, and thus financial security provisions should be tied to applicable termination liquidated damages. *Id.* at 3-4. Duke also noted the Appendix A Tariff did not include a mechanism to address contract demand reduction, which Duke deemed as a significant gap. *Id*. at 3. Finally, Duke expressed several concerns with the curtailment provisions in the Appendix A Tariff. *Id.* at 4.

The Public Staff suggested revisions to the Appendix A tariff in terms of the upfront payment of certain costs, recommended against including generation costs, and proposed adjustments for clarity and to address concerns. Public Staff Initial Comments at 12-16, 24-26. The Public Staff did not oppose the use of an independent firm, but advised that the firm selected have access to and ability to analyze the utility's data, as well as acting in a review capacity instead of an initial determination. The Public Staff warned an independent assessor could end up deciding critical issues and stated that an independent firm should report to the Commission, but the Commission should implement procedures to ensure it can decide any disputes associated with the firm's decisions. *Id.* at 16-19. The Public Staff stated the inclusion of "but-for" generation costs in a tariff is not practicable, as unless the customer requests to be served by a specific generation asset such as through a Clean Customer Tariff (CTT), customer islanding, or other ring-fencing mechanism, the customer will be served by and benefit from the whole system with all generation-related costs allocated through a COSS. *Id.* at 25. As the customer could pay twice for generation "but-for" assets through the ESA Deposit and through rates, the Public Staff recommended creating a billing structure that isolates each demand cost component to create more certainty to show that contributions to certain costs were taken into account. *Id.* at 26-27. The Public Staff's revisions included dedicated facilities, extra facilities, and network improvements within the "but-for" upfront costs. *Id.* at 26.

The Public Staff also recommended changing when "but-for" costs are paid to require payment be on or before execution of the ESA, as the requisite studies would not be complete at the letter agreement stage and Duke's investments prior to ESA execution would be extremely limited. *Id.* at 27. The refund provision within Appendix A was also removed in the Public Staff's edits, as the "but-for" costs as redefined by the Public Staff are required to serve the customer and should be paid for in their entirety by the customer. As this removes the incentive to not reduce load or not terminate the contract, the Public Staff recommended adding exit fees, liquidated damages, and advance notice requirements. *Id.* at 28. Duke pays for investments upfront, the Public Staff noted, taking on risk that is added to the customer's bills, but this monthly payment allows more flexibility for customer bills that lowers the barrier of entry to doing business in North Carolina, compared to an upfront payment from the customer. *Id.* at 29 The Public Staff added that an alternative to upfront payments would be to allow the ESA deposit to be paid over the contract's lifetime and reduce revenue requirement as they are paid, but this would not align the time costs are incurred with when they are paid, thus unfairly impacting other ratepayers. *Id.* The Public Staff also recommended increasing the minimum billing demand to 80% from 75%. *Id*. at 30. Noting the large sizes of these customers and the impact of even small fluctuations, the Public Staff recommended reducing the amount of demand that can be met with behind the meter (BTM) generation and required curtailment, as well as prohibiting large load customers with BTM generation from exporting energy to the system. *Id.* at 30-31. Finally, the Public Staff recommended adding advance notice requirements, minimum contract lengths, and requirements concerning reductions to contract demand. *Id.* at 32.

The AGO recommended several modifications to the Commission's proposal. The AGO recommended Schedule DC-HLF apply to all new and existing data centers. The AGO recommended that data centers pay all network improvements not needed "but for" the data center, and for this to be included in the upfront CIAC payment from data

centers. Regarding ESA Deposits, the AGO recommended these monies not refunded during the initial term be treated as CIAC. The AGO noted the Commission's Form ESA did not specify the contract term, and reiterated its recommendation of at least 15 years, not including a load ramp period of up to five years. Finally, the AGO recommended removing the language regarding opting out of DSM programs and requiring data centers to contribute to utility-run DSM programs. AGO Initial Comments at 12-13.

Amazon commented that the Commission's proposal to require upfront payment without changing other aspects of a customer's bill results in a customer paying for both embedded and incremental costs and causes a cross-subsidy in favor of existing customers. Amazon Initial Comments at 23. Amazon added this upfront payment risks misallocating costs, does not capture cost causation principles, and the 50% cap would be insufficient to fully refund the customer over the contract term. *Id.* at 23-24. The ESA Deposit required at the signing of the Letter Agreement is, in Amazon's view, too early in the contracting process. *Id.* at 24. Andale also flagged that the ESA Deposit payment was too early in the process. Andale Initial Comments at 15. Amazon was also against a Commission-appointed Independent Assessor to determine the costs of dedicated facilities and ESA Deposit amount. Amazon Initial Comments at 25-26.

CIGFUR III stated that the Commission's proposed tariff would "substantially undermine the pro-business environment in North Carolina", recommended higher thresholds and grandfathering for existing customers, and a waiver process for some or all provisions. CIGFUR III Initial Comments at 2-3. CIGFUR III was also concerned about process delays from injecting an independent firm into the process. *Id.* at 7.

CUCA stated that large load customers should be substantially or essentially all of the incremental infrastructure and stranded cost risk they create. CUCA Initial Comments at 3-4. However, CUCA did not believe generation costs should be subject to incremental recovery mechanisms. CUCA Post-Hearing Brief at 16. Regarding an independent firm, CUCA was open to the concept but skeptical of the resulting efficiency. CUCA Initial Comments at 3.

Digital Realty, in its amicus curiae comments, stated the tariff proposed by the Commission substantially departs from existing rate and contractual frameworks, and before making that change, the Commission should develop an evidentiary record that shows existing rates fail to recover those costs and what cost allocation method addresses the deficiency. Digital Realty Initial Comments at 6.

EDF stated the Commission's proposal protects customers in a meaningful way while maintaining lawful ratemaking practices. EDF Initial Comments at 22. EDF preferred the Commission's approach to aggregation and totalization for consideration of facilities integrated operationally or contractually under common ownership or contract. *Id.* at 10. EDF did not take a position on whether an independent firm should be used, expressing concern about a transparent process that reflects cost causation and noted there are limited example of independent assessors auditing cost allocation or cost-of-service studies conducted by utilities. *Id.* at 35. EDF noted that the upfront ESA Deposit is unduly burdensome, and preferred other constructs such as termination fees, incremental cost assignment, and minimum demand charges. *Id.* at 44. EDF provided additional

suggestions on terminology and provisions within the tariff but did not provide specific recommendations on all. *Id.* at 40-45. In its reply comments, EDF reiterated its support of the Commission's proposed tariff as the best starting point. EDF Reply Comments at 19. EDF also supported the use of the DC-HLF rate schedule as a starting point and revised in subsequent rate cases. *Id.* at 31-33.

Noting that the Commission's proposed tariff applied to all data centers and did not specify if it would apply prospectively, Google recommended broadening the applicability based on utility system impact and to apply to letter agreements and ESAs signed on or after January 1, 2027. Google Initial Comments at 21-22. Google opposed the assignment of individual generation or transmission assets to a customer, noting that there is not clear guidance in the Appendix A tariff to determine what costs specifically are being allocated. *Id.*

Microsoft opposed the applicability of the Commission's proposed tariff to focus on data center customers, arguing that a facility-type designation may capture customers with wildly varying load characteristics and that this approach lacks a sound ratemaking basis. Microsoft Initial Comments at 6. Microsoft stated that the ESA Deposit requirement is unworkable for three reasons: (1) the full payment is required before detailed engineering studies have been conducted to determine costs of interconnection; (2) requiring the full ESA Deposit before capital expenditures are incurred constitutes an interest-free loan to the utility with the carrying costs flowing into Duke's revenues at the customer's expense; and (3) the anticipated magnitude of the ESA Deposit would likely be unreasonably large and creates a prohibitive barrier to entry. *Id.* at 6. Microsoft stated large load tariffs should require deposits phased in accordance to construction milestones, reflecting estimates from completed engineering studies, and not required in advance of executed agreements. *Id.*

Microsoft also opposed the allocation of incremental facility costs to individual data center customers, as customers under the proposed framework would be responsible for cost overruns and the lack of a prudency review removes a check on utility spending. *Id.* at 6-7. The ESA Deposit, under the Appendix A tariff, is credited back monthly against the demand charge up to 50% of the billed demand amount, which Microsoft found to create a risk of unrecovered deposits and the unrecovered portion would subsidize the utility's other customers or its shareholders. *Id.* at 8. Microsoft added the dedicated facilities term should exclude generation, and the incremental cost definition and network improvements definitions are not founded on a clear benefits-based methodology grounded in North Carolina's ratemaking statutes. *Id*. at 8-9. Microsoft also opposed the tariff's provision for mandatory service under a specific rate schedule as customer with comparable demand profiles and interconnection characteristics that are not data centers would be able to select their rate schedule, which Microsoft argued constitutes unlawful discrimination. *Id.* The role of the independent assessor, Microsoft argued, should be advisory and not determinative. *Id.* at 9. Microsoft also stated that the initial term provision should specify a defined minimum, rather than leaving the duration to the utility's discretion. *Id.* at 10.

NCJC, et al. used the Appendix A tariff as a basis for proposing Schedule Very Large Load (Schedule VLL). NCJC, et al. Initial Comments at 16. Schedule VLL delineates certain provisions, such as direct assignment of costs for new incremental facilities, between

existing and new customers meeting the criteria. *Id.* at 19-20. NCJC, et al. expressed concern that the "majority of benefits" test within the Commission's model excludes existing facilities that the large load customer may be the majority beneficiary and the cost of incremental facilities where the large load customer is a major, but not majority, beneficiary. *Id.* at 44. Schedule VLL includes a requirement of the customer to pay the ESA Deposit upfront, to be refunded with interest calculated using the FERC Interest Rate, as a bill credit equal up to a capped pro rate amortization amount over the initial contract term, with the balance refunded in total at the duration of the initial contract term after Commission approval. *Id.* at 46-47. NCJC, et al. supported the use of an independent assessor and recommended additional duties to address updates. *Id.* at 47-49.

Conditioned on slight modifications, NCSEA saw the Commission's proposed tariff as the most comprehensive and reasonable solution. NCSEA Initial Comments at 3. While NCSEA supported provisions that broadly reduce risk to customers, NCSEA recommended that the "but-for" provision would benefit from further deliberation in a separate proceeding where the parties could better define the role of the independent assessor or to develop a methodology that can be applied without a third-party contractor. *Id.* at 13-14. NCSEA recommended a separate stakeholder process following the proceeding of any initial large load tariff. *Id.* at 15. In reply comments, NCSEA reaffirmed its recommendation to move forward with adopting the Commission's proposed tariff, noting that parties generally urged the Commission to establish an immediate framework and refine this framework over time. NCSEA Reply Comments at 3-4.

In its initial comments, Nucor took no position on specific provisions or language in the Commission's proposed tariff but recommended that any large load tariff protect existing customers and does not apply to existing industrial or manufacturing customers. Nucor Initial Comments at 1.

Walmart provided a recommended list of provisions for inclusion in any large load tariff ESA, or other mechanism to protect other ratepayers. Walmart Initial Comments at 8. Walmart noted it could support the selection of an independent third-party to identify the "but for" incremental costs caused by large load customers as long as costs are not prohibitive. *Id.* at 9. Walmart added that the Public Staff and Duke may have the capabilities to estimate the resource portfolio costs with and without large load additions, so that an independent firm is not needed. *Id.* at 10.

Dedicated Rate Schedule or Tariff Overlay

Duke advocated for a tariff overlay structure but stated that substantive terms and conditions matter most and these can be implemented via a dedicated rate schedule or overlay structure. Duke Initial Comments at 22. If the Commission implements a dedicated rate schedule, Duke argued that it should incorporate pricing options under both HLF and OPT-V. Duke stated that it is not possible to conduct a new COSS due to the time required and that there are insufficient amounts of large load customers with adequate load history to support a study and represent a standalone class; however, Duke stated it is not opposed to a dedicated customer class and will assess whether there are sufficient customers in the test period for the next rate case. *Id.* at 22-23. Given that Duke is not able to derive unique pricing for large load customers currently, Duke "would

start tracking the costs, loads, and revenues associated with the new rate class, and update rates accordingly in the subsequent rate case filing." *Id*. at 27. In its initial comments, Duke confirmed that there are two manufacturing customers currently served on DEC Schedule HLF. *Id.* at 32.

The Public Staff proposed a tariff overlay in the DEC and DEP proceedings because both companies have rate schedules with demand charges designed for high load factor customers that are aligned with demand-related costs identified in their respective Cost of Service Studies (COSS). Public Staff Initial Comments at 4. The Public Staff noted that DEC's OPT-V, DEP's LGS and LGS-TOU rate schedule rely on sales to become revenue neutral compared to the HLF rate schedules with higher demand rates. *Id.* The Public Staff stated "implementing a structure that recovers specific costs from cost-causers, incorporates appropriate customer protections, and supports economic development can be achieved through either a standalone tariff or a tariff overlay." *Id.* The Public Staff added a standalone tariff applicable to a specified customer group prevents intermingling when allocating costs and enables creating a dedicated rate class. *Id.* The Public Staff added cost allocation is determined at the tariff level, and allows for separation of billing determinants for a rate class and associated rate design practices. *Id.* at 4-5. Speaking to the benefits of a rate class, the Public Staff commented

> the benefit to a separate rate class is clear separation of cost allocation with respect to rate of return. Moreover, having a separate rate class would eliminate the potential ability for any intra-class cross-subsidization that could occur if target loads were in the same rate class with smaller loads that are not similar to the target load. A separate rate class could prevent smaller loads from having their rates increased beyond what is necessary to satisfy a combined rate class's total revenue requirement.

Id. at 9.

Andale, Amazon, CIGFUR III, CUCA, Digital Realty, Google, and Microsoft all supported a tariff overlay. Andale and Amazon noted Duke has already designed a rate schedule for high load factor customers. Andale Initial Comments at 9; Amazon Initial Comments at 10. Andale and Amazon opposed a data-center specific rate schedule and rate class, alleging current rates are based on load characteristics and not type of business, and large load customers with similar load characteristics, electric service requirements, and electric infrastructure requirements should not be treated differently. *Id*. Amazon stated a tariff overlay provides qualifying customers with greater flexibility to select a rate structure that best aligns with their operational needs. Amazon Initial Comments at 9. CUCA argued there is insufficient evidence to establish a "data center only" or "large load customer only" rate class in this proceeding. CUCA Initial Comments at 13-14. CIGFUR agreed there is insufficient evidence to support the creation of a new rate class, reiterating that DEP and DEC have existing tariffs for large load customers, and the tariff overlay allows a customer to select the most appropriate rate schedule for its needs. CIGFUR III Initial Comments at 4-5. Digital Realty stated that Duke's existing large load rate and contractual framework adequately compensates Duke for the costs to serve the large load customers and protects other customers. Digital Realty Initial Comments at 3. Digital Realty suggested a separate proceeding is necessary to

determine cost allocation questions and to retain existing rate schedules. *Id*. at 7-8. Google also supported the tariff overlay structure, noting DEC's witness testified DEC's current rate schedules reflect the costs of service for large load customers, and stated no party presented evidence based on cost of service to support a specific rate class. Google Initial Comments at 7. Microsoft argued rate classes should be defined by a class's usage of the system and cost to serve, rather than the type of facility and supported a tariff overlay, but not a new rate class due to lack of large load customers on the system during the test year. Microsoft Initial Comments at 12-14.

The AGO opposed allowing "data centers" to choose their rate schedule and advocated for a dedicated rate class and rate schedule. AGO Initial Comments at 2. EDF supported a dedicated rate schedule for qualifying data centers given the unique risks and characteristics of data centers, interdependence of tariff provisions and rates, ability to transparently and clearly allocate costs, and allow clear direct cost assignment. EDF Initial Comments at 3-8. Additionally, EDF contented tying termination damages to rate schedules allows customers to select rate schedules and creates a strong incentive for customers to select rate schedules with lower demand charges and lower minimum bills for termination damages. *Id.* at 4-5. EDF also recommended qualifying data center customers be established as a new and separate class. *Id.* at 27. EDF also recommended a dedicated data center rate schedule to separately identify functional components of the demand charge (generation, transmission, and distribution) to provide a transparent structure to evaluate termination fees, curtailment credits, and provide the ability to reflect alternative rate structures. *Id.* at 21. EDF also recommended the Commission require several cost-of-service alternative approaches to be evaluated in the next rate case. *Id.* at 28. NCJC, et al. also supported a dedicated rate schedule and customer class rather than a tariff overlay and argued that a new large load customer class is needed to transparently track costs, allocate costs, and design rates. NCJC, et al. Initial Comments at 11-16, 66.

Nucor took no position on whether the Commission should adopt a large load tariff. Nucor Initial Comments at 3. Nucor stated if the Commission was inclined to implement a large load tariff, it exempt existing manufacturing and industrial customers. *Id.*

In reply comments, EDF reiterated its support for a dedicated data center rate class and argued such a class is not discriminatory and is supported by the record and by North Carolina law. EDF Reply Comments at 17-19, 28-31. EDF also disagreed with the parties that opposed a dedicated rate schedule, arguing that existing rate schedule were not designed for data center customers and the DC-HLF and DEP equivalent would be an appropriate starting point. *Id.* at 31-33. NCJC, et al. also identified transparency, cost allocation, and rate design as three key reasons to establish a new class, noting that the Public Staff stated that a class "allows for separation of billing determinants for a rate class and associated rate design practices." NCJC, et al. Reply Comments at 5. To remain a welcoming business environment, NCJC, et al. state, it is important to prevent intra-class cross-subsidization, as noted by the Public Staff and Walmart, as well as inter-class cross-subsidization. *Id.*

NCSEA also pointed out that the Ratepayer Protection Pledge, signed by Amazon, Google, Meta, Microsoft, and other companies, included a pledge to negotiate separate rate structures with utilities and commit to pay those rates whether they use the electricity

or not. NCSEA Initial Comments at 14. NCSEA also supported a dedicated rate class and center for data centers, stating

> A dedicated rate class and schedule for data centers provides greater transparency, predictability, and enforceability. Data center customers present unique load-growth, infrastructure-planning, and cost-recovery challenges that differ substantially from traditional commercial and industrial customers. Creating a standalone schedule ensures that the rights and obligations associated with this new class of customer are clearly defined and uniformly applied. Most importantly, a dedicated schedule better protects existing ratepayers from the risks associated with large-scale, rapidly developing loads while allowing North Carolina to remain an attractive destination for economic development.

Id. at 5.

In its reply comments, NCSEA reiterated its support for a dedicated rate class and noted that other parties recognized the benefits of a separate rate class, and most of the opposition for a data center specific rate class was from companies that develop data centers. NCSEA Reply Comments at 9-11.

Walmart, in its initial comments, agreed that data centers are unique in their operational characteristics, infrastructure needs, and drive different costs, and therefore should be placed into their own rate class with a dedicated rate schedule, with DC-HLF or DC-HLF DEP as appropriate. Walmart Initial Comments at 4-5. Walmart added that if a large load customer can select its rate schedule, it will likely select that which results in the lowest bill, and costs that would otherwise have been recovered under the higher cost schedule are being recovered from other ratepayers who are thus subsidizing costs incurred by these large customers. *Id.* Walmart stated "a separate rate class will ensure that these costs are easily allocated to – and recovered from – the class of customers causing such costs." *Id.* at 6.

Walmart continued to support a separate rate class and tariff, noting the Public Staff identified several benefits and the optionality of a tariff overlay conflicts with Tenet III of the Ratepayer Protection Pledge. Walmart Reply Comments at 4-5. Recognizing the practical inability to establish dedicated rates for a class in this proceeding, Walmart supported a tariff for data center customers with an existing rate structure, such as Schedules HLF or LGS-HLF, and directing Duke to conduct a COSS in the next rate case that treats applicable customers as a separate class. *Id.* at 5.

Assignment of System Costs

Duke argued that no customer is ever served by a single asset and that the physical and electrical reality is large load customers, like all other customers, will be served in all hours of the day by the entire system. Duke Initial Comments. at 5. Duke argued direct assignment of system assets, or those assets that provide service to all customers, is not consistent with how the electricity system operates. *Id.* at 12. They further highlighted that it is inconsistent to directly assign costs deemed to be serving a

particular customer while also requiring that customer to pay for a full or partial share of the rest of the system that serves other customers. *Id.* at 13. Duke opined that if direct assignment is combined with allocation of embedded system costs without a proper revenue credit to account for tariff cost recovery, then the resulting ratemaking is likely to be discriminatory and result in excessive cross subsidization. *Id.* at 31. DEC explained under the distribution line extension policy, interconnecting customers are given credit for their future revenue when determining the appropriate amount of CIAC payments, and argued that no party has articulated why transmission-interconnecting customers should not receive the same treatment or what policy or cost-based reasons drive the differential treatment of transmission interconnection costs. *Id.* at 14. Duke noted Duke contends direct assignment of system costs will have unintended consequences. *Id.* at 15. Duke also asserts there is no definitive evidence large load customers are not already covering all their costs under existing rates and requirements. *Id.* at 16.

The Public Staff argued that large loads subject to the tariff should be required to be financially responsible for transmission, distribution, and interconnection costs that Duke would not have incurred but for the large load. Public Staff Initial Comments at 13. The Public Staff groups these direct assignment costs into three categories: Required Facilities, Dedicated Facilities, and Extra Facilities. *Id.* Required Facilities are those facilities, excluding system-level generation assets, that are required to serve the large load but may provide incremental benefits to customers besides the large loads. *Id.* Dedicated Facilities are a subset of Required Facilities and are those facilities constructed solely to serve the large load customers. *Id.* Extra Facilities are a subset of Dedicated Facilities and are those facilities built in excess of the standard interconnection service. *Id.* The Public Staff proposed the cost of Dedicated Facilities, as well as the allocable share of the cost of Required Facilities, could be recovered through an additional charge analogous to the existing Extra Facilities Charge that Duke uses presently or via an upfront payment by the large load. *Id.* at 14-15. The Public Staff ultimately recommended that large load customers pay upfront for "but for" costs, arguing that it eliminates the necessity of financing costs and results in a lower overall cost for the customer and reduces Duke's risk, as Duke would not have to initially fund the facilities and apply its weighted average cost of capital. *Id.* at 28. A monthly charge provides large load customers with greater flexibility but would pay for that flexibility with a greater overall price, compensating Duke for the risk taken. *Id.* at 29. The Public Staff stated that the Commission could allow Duke or the customer to apply for a waiver to the upfront payment schedule, so long as the full investment amount is eventually recovered and other ratepayers are held harmless. *Id.* One alternative to upfront payment would be to allow the payment of "but for" costs, or some portion of them, over the lifetime of the large load's contract, similar to how Extra Facilities Charges are currently recovered. *Id.* The Public Staff contended this provides flexibility for the large load customers but would not align the incurrence of costs with their repayment; one way to address this would be to direct-assign costs to the large load customer and remove them from the revenue requirement for all customers, allowing the value of the outstanding "but for" costs to be added to the large load customers' bill payments. *Id.* The Public Staff pointed out if this option is adopted, Duke would need to examine its commercial terms and conditions in more detail to reduce the longer-term financial risk. *Id.*

Ultimately, the Public Staff opposed the direct assignment of generation "but for" costs. *Id.* at 15. The Public Staff explained that unless a large load customer requests to be served by a specific generation asset, the customer will be served by the whole system and will have those generation-related costs allocated to them through a COSS like all other customers. *Id.* at 25. Even if a large load customer is large enough to trigger construction of a new generation asset, existing customers will generally receive some level of benefit from increased efficiencies, resource diversity, and other benefits that new generation provides. *Id.* The Public Staff stated new generation resources may displace older, less efficient generation resources; if large loads are assigned the costs of those new generation assets, they should similarly be assigned the benefits, leaving other customers with a less efficiently dispatched and operated system. *Id.* at 15. Application of this framework would introduce significant complexity into ratemaking and may set a precedent of incremental ratemaking that would separate large load customers from all others for total system costs while not addressing the potential lower energy costs for the entire system. *Id.* at 15-16, 25-26.

AGO argued large loads should be financially responsible for "but for" costs and these costs should be recovered through a non-refundable CIAC, with those costs excluded from rate base in the future. AGO Initial Comments at 8, 12. The AGO's recommendation differs from the Commission's provisions in its proposed Appendix A data center tariff by allocating the entirety of "network improvements" (defined by the Commission as all incremental transmission, distribution, and interconnection facilities needed to provide electric service to the large load customer if the large load customer receives the majority of the benefits of these facilities) directly to the large load customer. *Id.* at 12. The AGO also argued large loads should be required to pay embedded transmission and distribution charges in addition to the direct assignment of dedicated facilities and network improvements, as the large loads will benefit from the broader transmission and distribution system. *Id.* The AGO also supported the requirement that large loads subject to the tariff pay upfront for incremental generation and be refunded over time as the load materializes. *Id.* The AGO clarified that any monies not refunded during the initial contract period of the large load be treated as non-refundable CIAC payment. *Id.* Alternatively, the AGO offered that incremental generation costs could also be allocated by determining the incremental generation costs attributable to large load customers and allocating those costs directly to a large load rate class, as discussed in AGO witness Brant's testimony. *Id.* at 12-13. In its reply comments, the AGO reiterated its stance that the customer should pay for all distribution and transmission upgrades and incremental generation costs it causes upfront, with incremental generation refunded over time. The AGO added customers should pay embedded transmission and distribution charges and expressed confidence in the Public Staff's ability to prevent double recovery. AGO Reply Comments at 3-4.

Amazon and Andale supported upfront payment of dedicated facilities that solely benefit the large load customer, but did not support direct allocation and upfront payment of transmission network upgrades or incremental generation to serve large loads. Amazon Initial Comments at 24; Andale Initial Comments at 14. Amazon argued that direct allocation and upfront payment of network upgrades and incremental generation is inconsistent with cost causation principles as defined in the PBR Statute, which establishes a link between customer classes and how those classes use the electric system; further, they argued that

directly assigning network upgrade costs and incremental generation costs to a particular customer when other customer classes benefit from the new infrastructure would constitute cross-subsidization. Amazon Initial Comments at 21-22. Amazon and Andale pointed out that network upgrades are recovered by both retail and wholesale customers and it is unclear whether Duke can directly assign the costs of a network upgrade to a Duke retail customer that would otherwise be allocated to Duke wholesale customers without violating FERC's jurisdiction. Amazon Initial Comments at 23; Andale Initial Comments at 13. Amazon and Andale argued direct assignment would be a major shift in ratemaking policy, that requiring upfront payments of direct assignment costs without developing a cost allocation methodology risks improperly assigning costs to customers, and that direct assignment of network upgrade and generation costs would necessitate a change in how rates are designed. Amazon Initial Comments at 22-23; Andale Initial Comments at 12-13. Amazon argued requiring upfront payment but not changing any other aspects of the charged customer's bill, such as lowering the demand charge, could result in a cross-subsidy in favor of existing customers. Amazon Initial Comments at 23. Finally, Amazon and Andale stated that if upfront payments are required, large load customers should be subject to a reduced termination charge, notification period, and financial security requirements. Amazon Initial Comments at 23; Andale Initial Comments at 13.

CCEBA, CEBA, and Nucor Steel did not provide comments on direct assignment of "but for" costs.

CIGFUR III did not support direct assignment of "but for" costs. They argued that the concept of "but for" costs could run afoul of the statutory requirement of cost-of-service ratemaking and argued that applying this concept could have unintended consequences. CIGFUR III Initial Comments at 7.

CUCA did not support the direct assignment of "but for" costs for incremental generation costs, stating that no intervenor proposed a specific method by which direct assignment might be made and that generation costs have always been treated as system costs since generation is made available to all customers. CUCA Post Hearing Brief at 16. Furthermore, CUCA did not support the Public Staff's proposed framework for assigning non-generation related "but for" costs, arguing that it was not sufficiently developed to properly assign the costs of facilities that benefit more than one customer. *Id.* at 15-17. In response to questions on assignment of "but for" costs in the Commission's Order Requesting Comments, CUCA stated that they believed large load customers should bear essentially all, or substantially all, of the incremental infrastructure and stranded-cost risk they create, with mechanisms (long contract terms, minimum bills, collateral, exit fees) designed specifically so that a project failure or scale-back does not fall on other ratepayers." CUCA Initial Comments Attach.1.

Digital Realty did not support the direct assignment of "but for" costs, arguing that significant changes to cost responsibility should not be adopted without first establishing that existing rates fails to recover the costs caused by affected customers and that the proposed allocation methodology remedies this. Digital Realty Initial Comments at 6-7. Further, Digital Realty argued that if any new cost-allocation requirements were applied, they should be applied prospectively. *Id.* at 7. Digital Realty stated that if the adequacy of existing large-load rates warrants further examination, the appropriate next step is a

separate proceeding designed to develop the evidentiary record necessary to resolve those issues. *Id.*

EDF supported a framework for determining, quantifying, and assigning incremental costs of assets that are required "but-for" the new qualifying load. EDF Initial Comments at 31-34. In reply comments, EDF reiterated its support for "but-for" and incremental cost testing, noting the proposed framework in its initial comments is intended to ensure large load data centers pay for their impact to the system, not for 100% of new infrastructure. EDF Reply Comments at 34-37.

Google stated that "residential utility customers, small businesses, and other ratepayers should never carry the financial burden of the electricity and grid infrastructure to power its operations" and reiterated its commitment to the Commission from the Technical Conference of Large Electric Load Additions (held October 11, 2025) that it is committed to pay the costs to serve its facilities. Google Initial Comments at 2-3. Google supported cost allocation approaches that reflect the cost to serve and the direct assignment of dedicated facilities and facilities that benefit large load customers, whether in the form proposed by Public Staff or by Duke, but did not support the direct assignment of costs associated with generation or transmission assets that are system assets. *Id.* at 14, 18. Google agreed with the premise of the Public Staff's proposal to allocate costs of Required Facilities, but argued that the Public Staff did not provide sufficient guidance on how the methodology to allocate Required Facilities costs would be determined to properly evaluate the impact of the methodology. *Id.* at 10.

Microsoft stated that it is reasonable for large load customers to be financially responsible for the costs of Dedicated Facilities. Microsoft Initial Comments at 13. Microsoft also stated that it is appropriate for large load customers to pay an allocated portion of non-dedicated Network Upgrades; however, there is no generally accepted or industry standard approach to do this. *Id.* Microsoft clarified that any acceptable methodology should be fair and transparent, should not result in charging customers for unused assets, and should not result in customers being double-charged for both embedded and incremental costs. *Id.* Microsoft argued that any capital costs for infrastructure allocated directly to large load customers should not include a rate of return for Duke. *Id.* They explained that it may be appropriate to allocate costs of certain generating resources to large load customers on a voluntary basis, where a large load customer makes a financial commitment to bringing new generation onto the system and can enjoy some of the direct benefits of that commitment. *Id.* at 14. Microsoft recommended in part that the Commission (1) approve a large load tariff that provides for direct assignment of costs for Dedicated Facilities and (2) direct parties to confer and file within 120 days proposals relating to the allocation of non-Dedicated Required Facilities costs. *Id.*

NCJC, et al. supported the direct assignment of "but for" costs and incorporated its assignment of these costs into a proposed Schedule VLL. NCJC, et al. proposed that Dedicated Facilities, defined in Schedule VLL as all generation, transmission, distribution, and interconnection facilities solely used by the large load customer, should be recovered as an upfront CIAC payment, payable at the time of signing a contract for service. NCJC, et al. Initial Comments at 42. For Required Facilities, defined as projects driven by large load customers which benefit multiple customers and/or the bulk electric system,

NCJC, et al. proposed that those projects should be payable via a refundable ESA Deposit, also paid at the time of signing a contract for service. *Id.* at 42-43, 46-47. NCJC, et al.'s definition of Required Facilities included facilities placed in service after June 1, 2024, to recognize that Duke may have built facilities with headroom available to accommodate growth, and would allow the reasonable reallocation of the cost of recent investments to large load customers. *Id.* at 47-48. NCJC, et al. proposed that any generation that benefits only the large load customers would be included in the Dedicated Facilities charge. *Id.* at 45. For generation that benefits the large load customer as well as the system as a whole, NCJC, et al. proposed that apportionment of those costs would be based on the CPIRP portfolio costs and the large load customer's contract demand, multiplied by one plus Duke's planning reserve margin, divided by Duke's 15-year firm capacity requirement. *Id.* at 45-46. Allocated costs would be payable via the ESA Deposit. *Id.* at 46. NCJC, et al. argued that this approach, while not determining actual costs attributable to the large load customer, is a more reasonable and straightforward method to allocate the cost-of-growth of generation capacity to large load customers. *Id*. NCJC, et al. also proposed assignment of additional responsibilities to the Independent Assessor, including allowing the Assessor to make a determination on whether to either increase cost responsibilities included in the Dedicated Facilities charge or the ESA Deposit, or allow refunds to large load customers based on changing usage of the Required Facilities. *Id.* at 47-48.

NCSEA supported the intent of the framework to assign "but for" costs, but believes it should be a central topic subject to further deliberation in a subsequent docketed proceeding to determine the feasibility of this approach or to identify a different framework that achieves the same result. NCSEA Initial Comments at 13-15. Ultimately, NCSEA argued that assignment of "but for" costs should not be viewed as a barrier to economic development, as it simply enforces the commitments that certain large load customers have agreed to in the Ratepayer Protection Pledge. *Id.* at 14.

Walmart supported allocating the costs of direct connect facilities to the cost-causing customer, ideally through a CIAC payment, and the assignment of higher marginal generation and backbone transmission project costs to the customer classes driving the need for those resources based on a grow-for-growth model. Walmart Initial Comments at 9. Walmart added that other jurisdictions conduct IRP-type modeling both with and without the large load additions to identify the difference in selected resources, noting that the Public Staff and Duke could conduct such modeling. *Id.* at 9-10.

In its reply comments, Duke noted that "there was a broad agreement among all parties that large load customers should pay for all of their costs and not shift their costs onto other customers." Duke Reply Comments at 2. Duke added that if a LLT directs upfront payment of particular network upgrades that is used to inform transmission cost assignment, this would arguable constitute unbundling of transmission rates and would thus be subject to FERC jurisdiction. *Id.* at 12-13. Duke observed that only three parties fully supported direct assignment of generation costs. *Id.* at 31.

NCJC, et al. supported direct assignment of incremental costs, noting direct assignment charged upfront reduces stranded asset risks, reduces regulatory lag, and can be a form of long-term cost allocation. NCJC, et al. Reply Comments at 6-7. NCJC, et al.

argued that reasons opposing direct assignment are not compelling; NCJC, et al. disagreed with Duke's argument that a customer who triggers a need for a new grid investment is not the only customer who benefits from it, as under N.C.G.S § 62-133.16(a)(1), cost causation requires a causal link between the cost-causer and costs incurred, not necessarily an equal division among all beneficiaries. *Id.* at 7. NCJC, et al. added that arguments against direct assignment do not outweigh the reasons for it, and the concerns raised by the parties can be addressed by a fair and accurate method for directly assigning costs. *Id.* at 9. Additionally, while new generation may be more efficient than the least efficient resources in the system, the load growth from large load customers has resulted in delayed retirement of inefficient coal plants, so direct assignment would not target other customers with the costs of inefficient generation. *Id.* at 11. The bases for direct assignment, NCJC, et al. argued, are cost causation and protection from stranded asset risk, neither of which requires allocation of system benefits. *Id.* NCJC, et al. stated its proposal avoids double recovery concerns. *Id.* at 12-13.

NCSEA recommended the Commission establish a subsequent proceeding to analyze "but-for" contributions and determine alternative frameworks for mandatory capital contributions from customers. NCSEA Reply Comments at 18. NCSEA questioned whether all the upgrades to the system would be required absent the proliferation of data center development. *Id.* at 19. NCSEA noted that direct assignment of novel upgrades is not a novel concept, citing interconnection processes for generation procured from independent power producers, mandatory CIAC payments in Pennsylvania, and the method proposed by Xcel Energy in Colorado. *Id.* at 19-20.

In its reply comments, Walmart noted that there is near-uniform agreement that data center or large load customers should be responsible for the costs they cause, but there is disagreement as to where that line falls. Walmart Reply Comments at 6. There seems to be no dispute concerning customers paying for Dedicated Facilities, but there are concerns about direct assignment of broader network upgrades. *Id.* Walmart continued to support an incremental cost process, such as the approach in Colorado for PSCO or Virginia for Dominion, where an IRP process is conducted with an without large loads to identify the additional resources selected. *Id.* at 7-8.

Applicability

Duke stated that any large load tariff or form ESA should apply prospectively to new ESAs executed after the effective date of the new requirements, arguing that customers have made substantial capital investment decisions under the existing ESA terms and it would be inequitable to alter that framework under which these customers have made such investments and potentially impose unplanned and significant capital payment requirements. Duke Initial Comments at 8-9. Duke acknowledged that the ESAs contain language "that make clear the Commission's authority to change rates and tariff provisions." *Id.* at 8. Duke further argued that any retroactive modification of executed ESAs could raise legal concerns regarding vested contractual rights and retroactive ratemaking. *Id.* at 11. Duke stated that it believes a potential rate schedule or tariff should be based on system load impact rather than end-use, stating that operational characteristics and how those operational characteristics impact the system matter more. *Id.* at 26. Duke's proposed LLT applies to customers with 50 MW or more of contract

demand and an expected load factor of 80% or more or 100 MW of contract demand regardless of load factor served at a single site, at multiple sites within one mile of each other, or from a common service point. *Id.*

The Public Staff recommended that a new tariff be applicable to all new or incremental loads that begin taking service on or after January 1, 2027, that will have a contract demand of 50MW or greater and an expected annual load factor of 80% or greater. Public Staff Initial Comments at 8. The Public Staff maintained that customers already taking service before a stated effective date should be allowed to stay on their current rate schedule, but those who take service afterwards or add incremental service should be subject to the new rate schedule even if a signed agreement with the utility exists. This approach, the Public Staff stated, "balances the need to protect ratepayers from the risks of large loads while treating established customers fairly." *Id.* at 20.

The AGO advocated for a rate schedule a rate class specific to data centers consistent with the Commission's proposal, but stated that if a non-industry specific large load tariff is developed, it should be applicable to customers with a contract demand of 100MW or more and a load factor of 80%. AGO Initial Comments at 4. The AGO noted that any data center-specific tariff must be artfully designed so as not to be considered discriminatory. *Id.* The AGO advised that in order to avoid gamesmanship, ensure ratepayers are adequately protected and the rights of existing and future customers are preserved, the applicability of the tariff could be based on the day on which the customer begins taking service, consistent with the Public Staff's language in its proposal, and creating a safe harbor provision for customers who entered into LAs or ESAs before May 29, 2026. *Id.* at 8-9.

Amazon and Andale recommended that new tariffs or rate schedules should apply to large load customers executing ESAs after January 1, 2027, so that customers who made considerable financial and operational commitments are not subject to rewritten rules. Amazon Initial Comments at 26; Andale Initial Comments at 10. Amazon did not support a data center-specific tariff, stating that "creating separate tariffs for data center large load customers and manufacturing large load customers with similar load characteristics, electric service requirements, and electric infrastructure requirements lacks justification and may be considered discriminatory." *Id.* at 9. Amazon supported the tiered eligibility structure proposed by the Public Staff and Duke, and stated that a 50 MW and 80% load factor is an appropriate entry point for the tariff. *Id.* at 12. Amazon stated parties have spent considerable time and financial commitments to arrive at an executed ESA, and a change to ESA terms could cause a customer to violate or default on those commitments. *Id.* at 27. Andale stated it executed its ESA more than 15 years ago and opposed being subject to a new tariff due to factors not under its control. Andale Initial Comments at 11.

CIGFUR III recommended setting eligibility thresholds for all loads over 150 MW and load factors over 80%, so that extremely large load customers would be appropriately captured. CIGFUR III Initial Comments at 6. CIGFUR III also stressed that the LLT should not apply retroactively, in effect grandfathering existing customers and allowing them to stay on current rate tariffs. *Id.* Existing or potential customers with executed ESAs were recommended to be grandfathered into existing regulatory paradigms. *Id.* at 8. CIGFUR III

added that bright-line guidance should be added clarifying that incremental load expansions would not trigger an existing customer to be required to take service under the LLT. *Id.* A waiver process to exempt customers from some or all provisions was also recommended by CIGFUR III as not all requirements of the tariff may be appropriate for all new large load customers. *Id.* However, CIGFUR III added that waivers of certain provisions could violate the prohibition on discrimination and risk violating the filed rate doctrine, and recommended the Commission adopt less onerous policies so a waiver process is unnecessary. *Id.* at 9.

CUCA recommended that the tariff should not capture traditional manufacturing customers, either by adopting a data center/computational load specific tariff or an eligibility threshold that exceeds typical industrial/manufacturing demands, such as 100MW and 80% load factor. CUCA Initial Comments at 3. CUCA also recommended tariffs should apply prospectively and not impose new requirements on customers with existing contracts with Duke. *Id.*

Filing comments under amicus curiae status, Digital Realty stated it supports "reasonable measures designed to ensure that large-load customers appropriately bear the costs and risks associated with service to their facilities and do not shift those costs to other customers." Digital Realty Initial Comments at 2. Digital Realty stated the existing ESAs achieve those objectives and argued against applying new tariffs to existing ESAs. *Id.* Digital Realty adds the tariffs were reviewed and changed by the Commission in its Order Accepting Tariff Revisions in Docket Nos. E-7, Sub 1300 & E-2, Sub 1333 on January 17, 2024. *Id.* Digital Realty stated that applying newly adopted provisions would require determining how the new requirement interacts with existing terms, potentially reopening and renegotiating executed contracts on a project-by-project basis. *Id.* at 4. The recommendation from Digital Realty is for a new tariff to apply to ESAs executed after the tariff becomes effective. *Id*. at 5.

EDF, in its initial comments, recommended that a new tariff apply to large data center customers over 50 MW, citing the direct testimony of EDF witnesses that data centers have materially different characteristics from traditional manufacturing and other large loads that has implications for system planning, rate design, and cost causation. EDF Initial Comments at 25. Data centers are driving roughly 80% of the economic development load in the long run. *Id.* EDF's 50 MW threshold recommendation does not have any load factor requirements to reflect utilities planning for peak demand. *Id.* at 9-10. While EDF does not oppose a tariff to apply to non-data center large loads, EDF states that the record does not establish whether these other large loads exhibit the "same characteristics or planning and financial risks." *Id.* Additionally, EDF notes that legacy rates and tariffs were not designed to address the risks and characteristics of large load data centers. *Id.* at 3. EDF noted that ESAs are contractual agreements subject to statutory and regulatory changes, but tariffs/rate schedules are not necessarily subject to contractual agreements between a utility and a customer. *Id.* at 36. EDF supported grandfathering customers with ESA executed as of May 29, 2026, in alignment with the Public Staff's tariff proposal in the DEC rate case. *Id.*

Google supported large load tariffs that applied to customers "based on expected impact to the grid, rather than the end-use of the customer." Google Initial Comments

at 15. In terms of grandfathering, Google agreed with Duke's proposal to only apply a tariff to letter agreements and ESAs executed on or after January 1, 2027. *Id.* at 20.

Microsoft stated that new tariffs should be consistent with the terms of recently negotiated ESAs, and any new tariff and form ESA should apply prospectively to customers who sign Letter Agreements or ESAs after a future date certain. Microsoft Initial Comments at 4. Microsoft stated that a tariff or rate schedule should "be defined by objective features of the customer's interaction with the electric system, rather than by the end use of electricity", adding that data center operations have widely varying load profiles and the North Carolina Supreme Court has held that "rate differences must bear a reasonable proportion to differences in conditions, including quantity of use, time of use, manner of service, and the costs of rendering service." *Id.* at 13.

Microsoft acknowledged that the Commission has authority to alter utility rates prospectively and that such changes may alter the terms of existing utility contracts. *Id.* at 17. Microsoft warned of the impact to the value of Microsoft's investments if the terms of its ESA changed to increase the financial obligations or exposed Microsoft to significantly increased risks. *Id.* at 18. Microsoft argued that there are legal limitations to the Commission's power to retroactively rewrite customer contracts, citing the bar on retroactive ratemaking, filed-rate doctrine, Contracts Clause, and principles of Federal constitutional law that disfavor retroactive rules absent express authorization and caution against disrupting settled expectations. *Id.* at 18-20. Microsoft added that the Commission has previously rejected provisions that introduce uncertainty to contracts and unanticipated retroactive effected dates within the 1983 PURPA Order and Order Ruling on Exceptions in Docket No. P-100, Sub 133d. *Id.* Microsoft stated that the Commission may implement a new large load tariff on a prospective basis and emphasized that not party in these proceedings has claimed that any term of any existing ESA is not in the public interest, though different ESAs have different contract terms. *Id.* at 20. Finally, Microsoft stated there would be due process concerns if the Commission were to retroactively rewrite the ESAs of non-parties through the ratemaking process, especially if the new tariff has significant financial consequences of potential contract modifications. *Id.* at 21.

In NCJC, et al.'s proposed Schedule VLL, all customers that meet the definition of the class are subject to Schedule VLL as some existing customers with similar load profiles would cause similar costs for cost allocation purposes. NCJC, et al. Initial Comments at 18. NCJC, et al. recommended using NERC's definition of computational load if the Commission wanted a tariff for data centers, but added that data centers are not the only driver of Duke's load growth and customer classes should be based on customers with similar system costs, and recommended tariff thresholds that present similar substantial risks. *Id.* at 21-22. Schedule VLL has a threshold of at least 25 MW and an annual load factor of 85% or more, and for all customers of at least 100 MW, and include provisions incorporating actual annual load factor departures from estimates. *Id.* at 22-24.

NCSEA stated that it is justified to create a data center specific customer class and tariff, given the rapid load growth experienced in the state and the unique operational characteristics of data centers. NCSEA Initial Comments at 7-10. NCSEA added that the "result is a more focused, administratively workable, and ratepayer-protective framework that can be refined over time." *Id.* at 10.

Nucor stated that if a tariff was adopted that is applicable generally to large load customers and not only data center customers, existing manufacturing and industrial customers should be exempt from the requirements. Nucor Initial Comments at 3. However, Nucor acknowledged that incremental loads of existing customers that meets the threshold requirements of a tariff may not be exempt from the provisions. *Id.*

Walmart supported a tariff with a 50 MW threshold that applied only to data centers to ensure the tariff did not impact traditional commercial and industrial customers. Walmart Initial Comments at 3-4. If the Commission preferred a generic large load tariff, then Walmart proposed a tariff with a 50 MW threshold for data centers, 75 MW for all other customers, with an 80% or greater annual load factor. *Id.* at 4. Walmart noted that it might be unfair for a party with an executed ESA to be forced to sign a new ESA, unless they sought to interconnect new load, requiring a customer to take service under a new tariff does not raise similar concerns, adding that Duke's ESA already puts parties on notice that a change could occur. *Id.* at 6. Walmart further states that there "is not unfairness or due process violation in requiring these customers, whether existing customers taking service, customers in the midst of a load ramp, or customers who have only signed an ESA, to take service under a new tariff adopted as part of these proceedings." *Id.* at 6-7.

In Duke's reply comments, Duke expressed significant concerns with any recommendation that unilaterally changed the terms of executed ESAs. Duke noted that many parties agreed that "retroactive application of a new LLT to already executed ESAs" could raise potential legal challenges. Duke noted the capital investments, tax revenue, job growth, and community support mentioned in the comments of parties such as Amazon, Google, and Microsoft. Duke Reply Comments at 7. Duke reiterated its support for the Stipulated LLT's applicability terms. *Id.* at 8. Duke also stated at a majority of parties "took the position that to protect against undue discrimination the applicability should be based upon customers' load characteristics rather than their end use or business classification," but parties also realized that some customers may warrant exemption from some or all LLT provisions and be waived upon Commission approval. *Id.* at 23-24.

The AGO argued that the effective date should be January 1, 2027, and should "apply to new and existing data center customers, as defined by the Commission, regardless of the date on which the customer began taking service or signed their Letter Agreement or Electric Service Agreement." AGO Reply Comments at 2.

In its reply comments, Digital Realty disagreed with Walmart's and EDF's assertion that language in ESAs indicate that provisions beyond rates are subject to regulatory changes. Digital Realty Reply Comments at 2-3. Digital Realty cites Appendix 1 Form ESA ¶ 8:

> This Agreement and the applicable Schedule, Riders, and Service Regulations hereto attached are subject to changes or substitutions, either in whole or in part, made from time to time by a legally effective filing of the Company with, or by order of, the North Carolina Utilities Commission[.]

Id. at 3.

Digital Realty stated that this language does not signal to parties that the negotiated terms of the agreement are subject to change, and agrees with Duke that parties expect changes to be prospective and not materially change initial payment and security obligations. *Id.* Digital Realty echoed Microsoft's observation of the Commission's 1983 PURPA Order regarding the Commission's rejection of provisions allowing unlimited future changes to essential contract terms that would reduce long-term contracts to day-to-day arrangements and impede financing. *Id.* Additionally, Digital Realty echoes Duke's statement regarding lack of precedent for the Commission to abrogate substantive terms of executed ESAs retroactively, and points to other jurisdictions implementing large load tariff revisions that were prospective and not intended to disrupt existing commercial arrangements. *Id.* at 4. In their reply comments, Digital Realty also stated that a customer has little or no control over when an ESA becomes available for execution and argued that the AGO's proposed Safe Harbor proceeding was impractical, unnecessary, and would burden the Commission and parties to preserve bargained-for agreements. *Id.* at 5-6. Finally, Digital Realty claims that existing ESAs already protect ratepayers and reiterates Duke's statement that ESAs have been progressively updated and strengthened over the past two years. *Id.* at 6.

EDF noted in its reply comments that most parties found 50 MW to be the lowest applicable demand threshold for large load tariff provisions, and EDF continued to support that threshold without additional load factor requirements. EDF Reply Comments at 21. EDF also expressed reservations about load factor thresholds based on expected load factors, stating customers may either inappropriately avoid or be subject to the large load provisions if it actual load factor unexpectedly exceeds or is less than the tariff's threshold. *Id.* at 27. Load factor thresholds could also exclude projects with significant peak demand. *Id.* at 28. Noting that multiple parties were concerned about grandfathering provisions, EDF stated that existing loads and substantially established contracts should not be burdened with requirements designed for new development. EDF recommended the Commission use "an anti-gamesmanship trigger tied to the point at which a project becomes materially committed, while preserving a safe harbor for projects that were already genuinely advanced before that date." *Id.* at 37.

Multiple commenters argued that some form of grandfathering should be adopted, but NCJC, et al. argued that these legal arguments are not compelling. NCJC, et al. Reply Comments at 13. In response to a rate shock argument, NCJC, et al. noted the PBR statute requires the Commission to also consider unreasonable prejudice to a class of customers, which would not apply considering the impacts of these customers. *Id.* at 14. While Duke argued that modifying existing ESAs could constitute retroactive ratemaking, NCJC, et al. countered that retroactive ratemaking occurs when an additional charge is made for past use of utility service and customers with signed ESAs but who have not yet taken service have no past utility usage. *Id.* NCJC, et al. noted Microsoft's Contracts Clause argument strains North Carolina jurisprudence, as acknowledged by Microsoft, though tariffs that did not exclude customers with signed ESAs would likely meet the public purpose and reasonable test. *Id.* at 15. NCJC, et al. acknowledged that multiple parties recognized existing ESA terms anticipate changes to tariffs. *Id.*

NCSEA reasserted in their reply comments that a data-center specific customer class is most appropriate, citing the Ratepayer Protection Pledge as an example

supporting distinct regulatory treatment. NCSEA Reply Comments at 4-5. NCSEA noted that the focus on potential long-term benefits of high load factor users "gives insufficient attention to the near-term costs and risks that existing customers may bear," and thus it is critical to ensure adequate protections exist. *Id.* at 5-6. NCSEA disagreed with Duke's opposition to a data center specific class, stating that data centers are not merely larger versions of traditional commercial or industrial customers but rather present unique planning, reliability, and cost allocation challenges. *Id.* at 6-7. NCSEA remarked that NERC has specifically observed that data centers and other computational loads present unique challenges because their electrical behavior can be distinctive and less predictable than conventional loads. *Id.* at 7. NCSEA stated that the support for a data center specific rate class, from NCSEA and other parties, is not seeking to regulate a customer based on the industry in which they operate. *Id.* at 8.

In its reply comments, Nucor recommended that if the Commission adopts a general large load tariff, the tariff should apply to new or incremental loads of at least 50MW with a load factor of 80% or greater, consistent with recommendations from other intervenors. Nucor Reply Comments at 1-2. Nucor added that a cut-off date should be set, before which a tariff would not be mandatory. *Id.* at 2. Nucor disagreed with proposals that applied to loads less than 100 MW regardless of load factor, as loads with lower load factors do not cause the same investments as customers with higher load factors. *Id.* at 2-3. Nucor also stated that existing customers are not causing the same impact as anticipated large loads, and are already included in embedded rates, and thus the Commission should reject proposals requiring large load tariffs to apply to existing customers, such as NCJC, et al.'s Schedule VLL. *Id.* at 3-4. Nucor also recommended a clarification to the AGO's safe harbor provision. *Id.* at 4.

Walmart noted in its reply comments that many parties supported a data center-only tariff, with other parties preferring generic tariff applicable to all large loads but conceding a data center only tariff as reasonable. Walmart Reply Comments at 2. Walmart also noted that the parties who opposed a data center-only tariff were data centers and Duke, all who signed the Ratepayer Protection Pledge, and CIGFUR III. *Id.* at 3. Walmart continued to support a data center-only tariff or one that avoided unnecessarily impacting traditional manufacturing and industrial customers and would not oppose the hybrid approach recommended in the AGO's initial comments of data center customers 20+ MW or all large loads of 100 MW or more with an 80% load factor. *Id.* at 3-4. Walmart clarified that there is a distinction between a typical tariffed rate and contractual terms of service and noted that it is "not seeking to require existing customers to sign a new ESA or become subject to contractual terms often found in an ESA (i.e., a contract term, exit fees, etc.) that are embedded in the tariff." *Id.* at 9. Walmart added that an existing customer who has already executed an ESA and begun taking service should not be assessed the costs of Dedicated Facilities and "but-for costs" after-the-fact. *Id.*

Curtailment

Duke argued for Commission-approved alternatives to curtailment that may include new demand response programs or funding of accelerated system capacity additions, emphasizing that these must be fully developed and vetted to ensure they appropriately address reliability rather than established at the same time as a large load

tariff. *Id.* Duke expressed significant concerns about the proposed curtailment alternative identified as Option B in Appendix 1 of the Standard Form ESA of the Commission's proposed Appendix A large load tariff, which allows a large load customer to procure curtailment rights from a third-party customer to satisfy the large load customer's curtailment obligations. *Id.* at 34-35.

Amazon stated that it prefers optional curtailment and demand response programs to mandatory programs, that it was willing to engage in discussions to create voluntary programs, that the Public Staff and Duke's proposals properly align the curtailment timeline to the load ramp, and that any curtailment provisions in a large load tariff allow modifications and waivers to the curtailment provision. Amazon Initial Comments at 18, 28-29. Google supported the Public Staff's and Duke's curtailment proposals that limited the curtailment provision to the first five years of service and supported Duke's proposed alternative to the curtailment provision that would allow large load customers to accelerate capacity resources on the utility system. Google Initial Comments at 20-21. Microsoft similarly opposed mandatory curtailment for all large load customers and supported additional curtailment options, such as those proposed by Duke and the broader suite of alternatives proposed in the Commission's Appendix A large load tariff. Microsoft Initial Comments at 18-19, 26. CIGFUR III similarly expressed concern about requiring mandatory curtailment provisions for all new large load customers, arguing that it would run afoul of Duke's obligation to serve all customers reliably. CIGFUR III Initial Comments at 7-8.

The Public Staff supported additional curtailment options in addition to existing provisions, including custom curtailment amounts that bundle small reductions with more hours available for curtailments and surcharges for enhanced system reliability. Public Staff Initial Comments at 22-23. The Public Staff further advised that Duke should evaluate its Emergency Load Reduction Plans and Emergency Procedures and propose modifications to ensure that if a load shed event occurs, large load customers are prioritized over other customers for load reduction. *Id.* at 23.

AGO supported the curtailment options provided in the Commission's Appendix A large load tariff, with additional improvements, including options that allow large load customers to negotiate varying levels of curtailment flexibility that exceed minimum requirements in exchange for faster interconnection or other incentives or and options that allow large load customers to invest in behind-the-meter battery storage or other firm capacity resources at third-party customer sites. AGO Initial Comments at 10-11. AGO further recommended that Duke provide information and data on the timing of high risk hours to inform the development of tailored curtailment offerings and that the Commission direct Duke to develop a flexible connection tariff. *Id.*

EDF supported providing additional alternatives to the curtailment options provided in the Commission's Appendix A large load tariff, so long as those alternatives ensure the alternative actually performs during reliability events, the alternatives include measurement and verification measures, and the alternatives do not rely on emitting generation to satisfy the reliability requirement. EDF Initial Comments at 39. EDF recommended that any substitute provides operational reliability, not merely financial compensation, and that any potential alternatives include workload shifting,

behind-the-meter generation through non-emitting resources, or customer-sponsored resources that Duke can observe and depend on during curtailment periods. *Id.*

NCJC, et al. supported the Commission's Appendix A large load tariff curtailment options with modifications and additionally recommended that the Commission adopt a CTT that would allow participating large load customers to pay for distributed resource programs that could provide an alternative to curtailment. NCJC, et al. Initial Comments at 69. In its proposed tariff, NCJC, et al. included alternative curtailment language that that limits curtailment to the amount Duke's requires to (a) resolve local voltage issues, (b) preserve system integrity; (c) accomplish unplanned or planned system maintenance; or (d) comply with NERC reliability standards. *Id.* at 35. The proposed language provides; an annual curtailment limit of 100 hours while carving out exceptions for when Duke has no other customers that it may curtail or for the time it takes to address conditions a-d. *Id.* at 35-36. NCJC, et al.'s language clarified the order of curtailment, specifying that customers on voluntary interruptible tariffs would be curtailed first, followed by customers signed on to NCJC, et al.'s proposed Schedule VLL large load tariff, followed by other load. *Id.* at 36.

NCSEA requested that the Commission reincorporate Duke's proposed reliability provision that allows for a "Commission-approved option that accelerates capacity resources on the utility system during the integration of the customer's full contract demand." NCSEA Initial Comments at 3.

EDF recommended that curtailment alternatives should provide comparable operational reliability. EDF Initial Comments at 39. Google supported curtailment limited to the first five years of service, as proposed by Duke and the Public Staff, as well as Commission-approved curtailment alternatives. Google Initial Comments at 20-21. Microsoft agreed that additional curtailment options should be offered, as not all customers can curtail load. Microsoft Initial Comments at 21. NCJC, et al.'s proposed Schedule VLL includes alternative curtailment language. NCJC, et al. Initial Comments at 35. NCSEA recommended Duke's proposed reliability provision allowing an alternative option that accelerates capacity resources be incorporated into a large load tariff. NCSEA Initial Comments at 3.

Duke's reply comments noted that a "majority of parties agree that mandatory, non-compensated curtailment should be temporary, tied to generation constraints, and provide flexibility consistent with the customer's operations." Duke Reply Comments at 21. NCSEA came to a similar conclusion, noting broad agreement from stakeholders that customers should have mechanisms other than mandatory curtailment to satisfy reliability obligations. NCSEA Reply Comments at 11-13.

In response to arguments concerning obligations to provide service, NCJC, et al. repeated general statutes, stated a utility's obligation is to furnish adequate, efficient and reasonable service and curtailment may be required. NCJC, et al. Reply Comments at 16-17.

Clean Transition Tariff

In an amicus curiae status, CEBA commented that the Commission should require Duke to file a proposed CTT to complement the proposed large load tariff, to provide a mechanism for the large load customers to build, bring, or buy resource to serve all or a part of their load. CEBA Initial Comments at 1-5. CEBA provided six elements of a CCT and recommended a stakeholder process to develop the proposal. *Id.* at 6-7. Similarly, the CCEBA, in its initial amicus curiae comments, requested that the proposed large load tariff include the possibility for a voluntary CCT and direct the utilities to engage stakeholders to develop such a tariff. CCEBA Initial Comments at 2. CCEBA states that a CTT facilitates large customer investment in new clean resources that the utility may not otherwise procure but provides energy and capacity benefits to the grid and for which the customer receives fair value. *Id.* at 1. CCEBA added that CEBA witnesses Priya Barua and Steven Levitas recommended a CTT and provided six elements of a successful CTT in their testimony in Docket No. E-100, Sub 207. *Id.* at 6.

EDF, in its initial comments, also endorsed the concept of a CTT to encourage economic development, accelerate achievement of decarbonization goals, and protect existing customers from cost impacts. EDF Initial Comments at 20. EDF noted that the Commission could approve the concept and allow the CTT to be developed in a separate proceeding. *Id.* NCJC, et al. reviewed potential forms of CTTs at a high level and recommended a timeline for adoption. NCJC, et al. Initial Comments at 56-66. NCSEA also recommended that Duke file a proposed framework for a CTT within 180 days of any large load tariff taking effect. NCSEA Initial Comments at 15-16.

A similar concept was commented on by Microsoft, citing a voluntary program in Nevada that allocated and ring-fenced the costs of certain generating resources to individual large load customers. Microsoft Initial Comments at 16.

Duke argued in its reply comments that this large load comment process was not the appropriate vehicle to discuss BTM or BYOG arrangements. Duke added that BTM generation "raises a host of complex and far-reaching policy and technical questions that extend well beyond the purpose and scope of a LLT. Such issues include interconnection requirements, reliability obligations, operational control, resource adequacy accreditation, treatment during emergency operations, emissions and environmental compliance, cost allocation, rate design, and the interaction between customer-owned resources and utility planning processes. These matters affect not only large load customers but potentially all customer classes and therefore warrant separate consideration" in a separate proceeding. Duke noted that protecting customers against risk go beyond that of BTM generation and mechanisms to address risk can be effective regardless of a customer's procurement choices. Duke Reply Comments at 35-37. Duke noted that several parties recommend that the Commission incorporate a CTT or BYOC program, and while Duke does not oppose exploring this option, Duke recommends declining this proposal in this proceeding as the Green Source Advantage program already exists and no party has provided extensive detail to allow full assessment within this rate case. Duke points out that proponents acknowledge that further stakeholder development and a separate proceeding may be necessary before a CTT can be implemented. *Id.* at 37-38.

The AGO expressed that it was generally supportive of a CTT and noted that it has broad benefits as well as the potential to serve as a pathway for data center customers to adhere to the Ratepayer Protection Pledge. The AGO recommended that the language in the LLT "leaves the door open for development of a CTT" and that the Commission direct Duke to filed a CTT within a reasonable period of time, and recommended a separate proceeding to develop a CTT. AGO Reply Comments at 5.

EDF noted in its reply comments that NCJC, et al. and NCSEA had similar recommendations regarding developing optional rate schedules allowing customers to pay incremental costs of a 100% clean energy portfolio and other mechanisms to develop clean energy on the system. EDF Reply Comments at 24. EDF supported NCSEA and NCJC, et al.'s recommendation for Duke to file a proposed framework for a CTT. *Id.* In their reply comments, NCJC, et al. noted that many intervenors expressed interest in CTT or "bring your own" options, and while the Public Staff expressed concerns about load fluctuations on the grid with BTM generation, the Public Staff was open to net metering arrangements for large load customers. NCJC, et al. Reply Comments at 4. NCSEA also noted some agreement from stakeholders to develop a voluntary framework for large load customers to directly fund new clean energy, storage, and other reliability-enhancing resources that protects other customers. NCSEA Reply Comments at 14-18.

Large Load Tariff Stipulation

On October 6, 2026, DEC and DEP filed an Agreement and Stipulation of Settlement on Large Load Tariff (LLT Stipulation), signed on by seven other parties – the Public Staff, Amazon, Andale, CIGFUR II and III, Google, and Microsoft.

In the LLT Stipulation, the LLT Stipulating Parties agreed on a proposed Large Load Tariff, attached as Exhibit 1 to the Stipulation, to be applicable to both DEC and DEP. The Large Load Tariff would be applicable for customers with either (a) a contract demand of 50 MW or greater and an expected 12-month rolling average load factor of 80% or greater or (b) a contract demand of 150 MW of greater, regardless of load factor. LLT Stip. § II.B.1; LLT Stip. at Ex. 1. The LLT Stipulating Parties agreed that all large load tariff customers with ESAs executed on or after June 1, 2026, will take service on Schedule HLF or a future large load rate schedule. LLT Stip. § II.B.3.

The Stipulation outlined that the Large Load Tariff would be applicable to all Letter Agreements and ESAs executed on and after June 1, 2026. LLT Stip. at Ex. 1. It would not be applicable to any ESA executed prior to June 1, 2026, that is subsequently renewed, extended, or assigned pursuant to the terms of the ESA, unless that change results in incremental service that meets the demand and load factor applicability requirements of the Large Load Tariff. *Id.* The Large Load Tariff would not be applicable to existing customers who have previously been served without an ESA. *Id.*

The Large Load Tariff bifurcated contract term lengths based on contract demand size. For contract demands below 100 MW, the Large Load Tariff requires a minimum contract term of the greater of 10 years or 5 years plus the load ramp period. *Id.* For contract demands of 100 MW or greater, the Large Load Tariff requires a minimum contract term of the greater of 15 years or 10 years plus the load ramp period. *Id.* The contract will

automatically be extended for one-year terms unless the customer notifies Duke at least 24 months in advance. *Id.* The Large Load Tariff requires notice periods for early termination or demand reduction that escalate based on increasing contract demand. For contract demands below 250 MW, the notice period is 24 months; for contract demands between 250 MW and 499 MW, the notice period is 36 months; and for contract demands 500 MW and above, the notice period is 48 months. *Id.* After the sixth anniversary of the provision of service, a customer may provide notice to reduce demand by up to 20% but no greater than 200 MW, one time, without incurring liquidated damages. *Id.*

The Large Load Tariff in the Stipulation provided curtailment options as either (a) curtailment of 95% of contract load for up to 50 hours per year for the load ramp period plus one year; (b) curtailment of 50% of contract load for up to 100 hours per year for the load ramp period plus one year; or (c) an alternative, Commission-approved option that accelerates capacity resources on the utility system during integration of the customer's contract demand. *Id.* The curtailment would be limited to six hours per day, with no compensation. *Id.* The LLT Stipulation included a provision that customers may petition for a modification or exemption of the curtailment provision based on factors such as national security, public safety, continuous process operations, or grid restoration. *Id.* The Large Load Tariff in the Stipulation also provided for a waiver of some or all of the tariff requirements based upon demonstration of good cause, with one possible basis to grant a waiver being demonstration of a substantial workforce in manufacturing, industrial, or qualifying warehouse and distribution activities other than data storage. *Id.*

The LLT Stipulation provided guidance on cost assignment for Dedicated Facilities and Transmission Network Upgrades. For Dedicated Facilities, the large load customer is required to provide advanced funds equal to the estimated total of the Dedicated Facilities as CIAC within 60 days of execution of a Letter Agreement. *Id.* The funds would be subject to refund, less any costs incurred related to the construction of the Dedicated Facilities, if the customer did not sign an ESA; if the customer terminates prior to energization, the unspent amounts would be retained and applied to the liquidated damage liability owed by the customer. *Id.* For Network Upgrades, the customer is required to provide a letter of credit for the total cost of the transmission network upgrades within 60 days of the execution of their ESA; after the customer achieves at least 75% of their actual monthly billing demand for three months, the letter of credit is reduced annually over the remaining contract term. *Id.* If the customer terminates early, then Duke may call upon the letter of credit to recover the remaining book value of the network upgrades as CIAC. *Id.*

The Large Load Tariff in the Stipulation included liquidated damages and provided an example of potential liquidated damage amounts in Exhibit 2 of the Stipulation. If the customer terminates without notice, liquidated damages will total 100% of the minimum bills during the applicable notice period, plus 100% of the Extra Facilities Charges during the applicable notice period, plus the termination liquidated damages under the original contract (which includes 25% of the remaining minimum bills during the remaining contract period and the net present value of the Extra Facilities Charges during the remaining contract period). LLT Stip. at Exs. 1-2. If the customer terminates with proper notice, the normal termination liquidated damages under the original contract will apply. If the customer requests a demand reduction, they will be required to pay 100% of the minimum billing

demand charges, plus 100% of the Extra Facilities Charges during the applicable notice period, plus the termination liquidated damages under the original contract, minus the termination liquidated damages under the new contract based on the reduce contract demand. *Id.* For all calculations of liquidated damages, the customer's actual payment of demand charges, minimum billing demand charges, and Extra Facilities Charges during the notification period will credit against the liquidated damage liability. LLT Stip. at Ex. 1.

Finally, the LLT Stipulating Parties agreed to file, within 12 months of the Commission's approval of the Large Load Tariff, a report following stakeholder discussions, regarding one or more potential methodologies that could be used for determining whether a portion of a given Network Upgrade should be direct assigned to a particular customer triggering or otherwise utilizing the Network Upgrade. LLT Stip. § II.B.2. The methodology would be applied to any ESA executed after such methodology has been approved. *Id.* § II.B.2.d. The LLT Stipulating Parties also agreed to collaborate on a form ESA and to submit such form ESA to the Commission within 30 days of the final Commission Order approving the Large Load Tariff. *Id.* § II.B.5. Finally, the LLT Stipulating Parties agreed that Duke shall provide a large load class cost of service analysis in the next rate case and evaluate class allocation methodologies for large loads, including with respect to assignment and allocation of generation costs, which analysis will assess the cost of service impacts with and without the use of a separate large load class. *Id.* § II.B.6.

Discussion and Conclusions

Tariff Provisions for Large Load Additions of DC Customers

The evidentiary record on this issue is complex and voluminous and presents important policy issues that are expected to have a significant impact on the development of North Carolina's economy over the next few decades. There is no dispute that DEC's service territory is experiencing unprecedented large load growth driven by data centers and advanced manufacturing. The Commission recognizes the weight of its responsibility in this case to ensure that the integration of DC Customer demand occurs in a manner that protects existing ratepayers, including residential customers, commercial customers, and industrial customers and their associated existing and future economic interests, from unreasonable costs and risks, while at the same time offering a viable path forward to maintain a flourishing and vibrant economy during an anticipated period of profound change and unprecedented resource demands. Properly managed and under certain circumstances, the opportunities presented by rapid DC Customer load growth could benefit all customers. The Commission also recognizes DEC's obligation to serve customers in its franchised service territory at rates and on terms that are reasonable and are not unjustly or unreasonably discriminatory, but this requirement must be appropriately balanced with other requirements to ensure system reliability and protect existing customers from subsidization of system risks and costs imposed by new DC Customers. The Commission also recognizes the validity of the concerns raised in the Public Staff's commentary on the Large Load Impact Analysis (filed by DEC and DEP in the CPIRP) regarding the risk that Duke's estimated net benefits are subject to various assumptions that may not hold true in all situations. Tr. vol 14, 221-224. In addition, the Commission takes note of the significant concerns regarding the addition of DC Customers on the

electric system and associated rate impacts expressed by Duke's existing customers during the public witness hearings, as summarized previously in this Order.

The Commission acknowledges that, in December 2023, DEC and DEP proactively requested approval for revisions to their Service Regulations to establish credit and performance requirements for customers with electric demands in excess of 100 MW to provide protection for other customers from certain financial and planning risks. The Commission approved these revisions, which were made effective in January 2024. The Commission also began to see how the increasing demands of DEC's prospective DC Customers might impose substantial resource planning implications in 2023 and 2024 in integrated resource planning proceedings. In 2025, the Commission opened a separate docket to initiate a comment process and convene a technical conference regarding the integration of large load additions, the outcome of which was the periodic filing by DEC of ESAs under seal and continued semiannual reports on potential large load pipeline activity in order to begin providing the Commission with some visibility into the scope of this issue and the speed of its growth.

In this proceeding, the Commission finds credible, and gives significant weight to the following portions of the evidentiary record that the Commission concludes, collectively, play a material role in establishing the necessity of adopting the DC Schedule:

- The Public Staff's Large Load Panel's testimony that DEC and DEP are experiencing unprecedented growth in large load demand and have approximately 7.9 GW of potential large load customers in the advanced development stage and have signed ESAs totaling approximately 6.7 GW of load from March 2024 through April 2026. Tr. vol. 14, 110, 126-29, 229. Data centers represent 92% of the 6.7GW load covered by ESAs. Tr. vol. 15, 145-46;

- The testimony of EDF witnesses Lenell and Pol that large load growth is reshaping system planning and capital requirements, with costs and commitments to serve large loads accumulating now, and their conclusion that this rate case is the appropriate forum to guarantee that existing ratepayers are appropriately protected. Tr. vol. 20, 62-63;

- The testimony of EDF witnesses Lenell and Pol that data centers replace IT equipment on a much more frequent basis than manufacturing facilities replace operational infrastructure, and data centers are expected to increase their power-usage effectiveness over time. Due to a faster pace in AI development, Amazon reported that the useful life of its server and network infrastructure has been reduced to five years. The load density at a location is materially changed by newer hardware, which creates a need for long-term coordination between the utility and data center customer. *Id.* at 41-42;

- The Public Staff's Large Load Panel's expressed concern about the highly fluctuating loads of artificial intelligence training data centers which require

Duke to procure and maintain assets and grid management resources. Tr. vol. 14, 237-38. The Panel also highlighted that large load customers could increase capacity and fuel costs for all other customers during periods of peak demand and increase loss of load risk for other customers if they suddenly disconnect or reconnect. *Id.* at 112. They further testified that stranded asset risk associated with the assets built to serve these customers is substantial because many prospective large load customers may not materialize, may ramp slower than expected, or may leave the system prematurely, causing costs associated with these new generation facilities and infrastructure to be redistributed among all remaining customers. *Id.* at 110-12;

- The Public Staff's Large Load Panel's testimony highlighting the mismatch between the lifecycle and cost of DEC generation assets when compared to the contract terms for large load customers – for example, if the addition of a large load customer requires construction of a natural gas asset, that asset would be in rate base for 35 years (and some assets, such as nuclear assets, may have a lifetime of 60 years or more), while the large load's customer obligation may only extend 10 or 15 years. Public Staff Large Load Panel Conf. Ex. 1; *see also* Public Staff Tech. Conference Presentation, *Large Electric Load Additions,* No. E-100, Sub 208 (Oct. 10, 2025). If this customer were to fail to renew at the end of its contract term and if no equivalent large load customer with a high load factor occupies the site, remaining customers may then be paying for an asset that they may not otherwise have needed. *Id*.

- The Public Staff's Large Load Panel's testimony that DEC currently relies on five separate mechanisms to manage large loads: existing rate tariffs (Schedules I, LGS, OPT-V, HLF, and HP); Letter Agreements; ESA Applications; Service Regulations; and the Line Extension Plan. Tr. vol. 14, 117-18. The Large Load Panel testified that many of these mechanisms have been applied inconsistently, varying from customer to customer at DEC's discretion without Commission oversight. *Id.* at 118-21. The Large Load Panel also testified that it is concerned that DEC is not properly allocating the costs associated with the new generation, transmission, and distribution plant necessary to serve large load customers or appropriately determining when such costs should be directly assigned to a large load customer, and that improper cost allocation could result in both inter- and intra-class cross-subsidization. *Id.* at 120-21. The Large Load Panel concluded these existing mechanisms are not sufficient to protect all customers and ensure just and reasonable rates. *Id.* at 163;

- If large data center loads materialize as forecasted, EDF witnesses Lenell and Pol noted that existing Commercial classes would be allocated a greater portion of system costs relative to status quo and non-large-load Commercial customers may experience increased costs. Tr. vol. 20, 32. They also testified that ESAs are not sufficient methods for managing large load customer growth because they lack the transparency and uniformity of Commission-approved tariffs. *Id.* at 49-51. They recommended that the

Commission develop tailored rate structures for large loads, noting that DEC's existing provisions addressing large load risks are spread across ESAs, tariffs, and service regulations, with many key protections residing only in the ESA. *Id*. Witnesses Lenell and Pol presented and discussed large load tariff design elements common between and unique to several utilities. *Id.* at 52-59. Witnesses Lenell and Pol recommended the Commission require DEC to support its claims that the existing framework is adequate and recommended requiring a tiered tariff framework. *Id.* at 61-62; and

- NCJC, et al. witness Wilson's testimony that DEC's existing tariffs and practices are insufficient to protect the broader customer base and should be amended to address the unprecedented large load growth forecast of 7,946 MW over ten years. *Id*. at 414-15, 428-29. Witness Wilson identified several key factors that should be included in a large load tariff, including financial security prior to energization, minimum billing terms, minimum contract length, early termination provisions, power quality requirements, and the establishment of a separate large load customer class. *Id*. at 449-51. Witness Wilson recommended proactively establishing a new large load class to effectively and transparently implement cost allocation, even given the lack of customers and data. *Id.* at 372, 451.

The Commission also agrees with, and gives substantial weight to, the testimony of the Public Staff, that this rate case offers the appropriate forum and timing for establishing comprehensive tariff provisions to address the potential costs and benefits of DC Customers and protect other customers while ensuring grid reliability. Tr. vol. 14, 115-16. In contrast, AGO witness Brant, CIGFUR III witness Collins, Google witness Dr. Berry, and Microsoft witness Gabel-Frank recommended a separate proceeding to more fully discuss these issues. However, through the Comprehensive Settlement, the LLT Stipulating Parties suggested a stakeholder and comment process in this docket to address potential tariff provisions for large load additions instead of initiating a separate parallel proceeding, the timing of which could have interfered with the progress in this proceeding. On August 12, 2026, the Commission issued its Order Requesting Comments to receive comments on data center and other large load issues and proposed tariff provisions. The Commission received the initial and reply comments from the various parties and has evaluated the policy considerations raised in these filing as part of the process of developing this Order. The Commission further notes that the comment process provided interested organizations an opportunity to present their views on the proposed large load tariff.

The Commission is persuaded by, and gives substantial weight to, the Public Staff's recommendation for DEC's existing ESA Application to become a public pro forma standardized application for transparency and uniformity, with any deviations subject to Commission approval. Tr. vol. 14, 143-48. The Commission notes that Duke confirmed that no more than two customers are currently taking service under Rate Schedule HLF, which is designed for high load factor customers. The Commission finds persuasive the Public Staff's argument that Duke has not properly allocated costs associated with significant transmission and distribution facilities or appropriately determined when these facilities should be directly assigned to large load customers. The Commission also gives some weight to AGO witness Brant's testimony that the current mechanisms are inconsistent and

lack transparency but is not persuaded that a tariff necessarily provides improvements to resource planning. The Commission agrees that "ratepayer protection should not depend on how DEC negotiates a particular agreement or on the relative bargaining power of the parties at the time of contracting." Tr. vol. 19, 150. The Commission gives substantial weight to the testimony of EDF witnesses Lenell and Pol that ESAs are not sufficient for managing large load growth, given the lack of transparency and uniformity. Tr. vol. 20, 49-50. The Commission also gives substantial weight to the testimony of NCJC, et al. witness Wilson that keeping large load provisions in an ESA under seal, without Commission approval, lacks transparency and creates difficulty evaluating large load cost of service issues. Tr. vol 19, 423-27. In addition, the Commission gives substantial weight to the testimony of witness Wilson that an ESA will still be necessary for customer-specific terms, but terms that should apply to all large load customers should be within a Commission-approved tariff. *Id.* at 451. The Commission also gives some weight to the testimony of Google witness Dr. Berry that there are disadvantages with DEC's current contract approach concerning the lack of a transparent, uniform, and comprehensive approach without clear details, though the Commission notes that to understand provisions applicable to many customer types one must review materials spread across multiple dockets. *Id.* at 600-01. The Commission finds persuasive intervenors' testimony that it is important to establish a new rate class and assign a rate schedule for DC Customers to send efficient price signals and to reflect the cost to serve that rate class. The Commission is further persuaded by NCJC, et al. witness Wilson's recommendation to establish a rate class to accurately track costs attributable to relevant customers for reporting purposes and inclusion in future rate cases.

The Commission also acknowledges that signatories to the President's Ratepayer Protection Pledge made public commitments that included: (1) to build, bring, or buy the new generation resources necessary to serve their load; (2) to pay for the new power delivery infrastructure required for their service; and (3) to pay for demand and infrastructure requested whether they use the electricity or not. Tr. vol. 14, 122-23. These signatories include parties to the current proceeding, such as Amazon, Google, Microsoft, and Duke Energy.

Based on the evidentiary record in the proceeding, the Commission determines that implementing tariff provisions to address credit risks and other financial and operational risks, including, but not limited to, cross-subsidization, stranded generation, and grid reliability, imposed by new or expanding DC Customers, complemented by a Commission-approved standard form ESA, is consistent with fairly and efficiently integrating these large electric loads on DEC's system. The tariff provisions adopted by the Commission, referred to collectively as the DC Schedule, are attached to the Order as Appendix A, along with an interim standard ESA which is attached as Appendix B. The Commission directs DEC to initiate a stakeholder process to, among other things, develop and submit for Commission review and approval, a proposed standard form ESA. The specific tariff provisions applicable to DC Customers are discussed in more detail below.

Applicability

Grandfathering

The Commission gives substantial weight to the testimony of the Public Staff concerning risks associated with bringing new large load additions onto the DEC system. As noted by the Public Staff, the risk of stranded assets has always existed, but the pace and scale of the risk associated with recent contracted load growth from large data centers is unprecedented, with individual customers seeking to connect load in amounts equivalent to CC or small modular nuclear reactor facilities. Tr. vol. 14, 111. The Commission is cognizant of the potential risks should this large load fail to fully materialize or terminate service before the cost of the assets built to serve the load are recovered, including the risk that existing customers will be required to bear significant costs associated with overbuilt or stranded assets, as well as the timing mismatch between the construction of assets and large load additions coming online. *Id.* The Commission also gives significant weight to the testimony of the Public Staff that large customers are put on notice of changes to the contractual terms within their signed ESAs, by a legally effective filing of DEC or by Commission Order, and this notice is written in the standard ESA language. Tr. vol. 15, 98-99. The Commission also gives some weight to the testimony of CIGFUR witness Collins that existing customers have provided rate recovery for assets constructed to meet their requirements, but new large loads require significant investments that introduce a different risk to the utility. Tr. vol. 19, 351-52. The new large load additions discussed during this proceeding have significant contracted demand ramping over the course of several years that requires substantial infrastructure investments.

The LLT Stipulating Parties' proposed tariff provisions and DEC, in its reply comments, ask the Commission to exempt, or grandfather, from the new tariff provisions all relevant customers that had signed a letter agreement or an ESA prior to June 1, 2026. They also requested a forward-looking exemption from the obligation to pay for CIAC associated with the direct assignment of TNUs for all ESAs that will be signed during the LLT Stipulation's contemplated stakeholder process to develop the direct assignment methodology, which would allow new large load customers simply signing an ESA over the next one to two years (when a reasonable time for the Commission review and approval process is taken into consideration) to avoid the CIAC obligation.

However, the Commission does not believe that the use of a contract execution date is a reasonable or appropriate basis for grandfathering customers from tariff provisions under the circumstances that exist in this environment of broad and significant risk. As a general principle, regulated parties may not contract around the Commission's regulatory jurisdiction over utility rates and services. The Commission is not beholden to the agreements made by and between utilities under its jurisdiction and private parties that conflict with the authority granted to the Commission by the North Carolina General Statutes. The Commission has the authority to "regulate public utilities generally, their rates, services and operations." N.C.G.S. § 62-2(b). The Public Utilities Act defines "Rate" as "every compensation, charge, fare, tariff, schedule, toll, rental and classification, or any of them, demanded, observed, charged or collected by any public utility, for any service product or commodity offered by it to the public, *and any rules, regulations, practices or contracts affecting any such compensation, charge, fare, tariff, schedule, toll, rental or*

classification." N.C.G.S. § 62-3(24) (emphasis added). The "rates, services and operations of public utilities", as defined by the Public Utilities Act, "are affected with the public interest", and it is a matter of policy that "adequate, reliable and economic utility service" is provided to "all of the citizens and residents of the state" and just and reasonable rates are provided "without unjust discrimination, undue preferences or advantages, or unfair or destructive competitive practices"; the Commission is vested with authority to regulate utilities in accordance with the policies of the Public Utilities Act. N.C.G.S. § 62-2.

DEC seems to recognize this reality, notwithstanding its testimonial assertions to the contrary. Tr. vol. 21, 541. As evidenced in the record, the form ESA which these large load customers have signed contains language that makes clear the Commission's authority to change rates and tariff provisions and the manner in which changes will apply to the ESA. Specifically, ¶ 7 of the "Application for Supply of Electricity Form" states:

> This Agreement and the applicable Schedule, Riders, and Service Regulations hereto attached are subject to changes or substitutions, either in whole or in part, made from time to time by a legally effective filing of the Company with, or by order of, the regulatory authority having jurisdiction, and each party to this Agreement reserves the right to seek changes or substitutions, in accordance with law, from such regulatory authority. Unless specified otherwise, any such changes or substitutions shall become effective immediately and shall nullify all prior provisions in conflict therewith.

Public Staff Corrected Large Load Panel Ex. 4 at 1, ¶ 7; tr., vol. 15, 98-99, 108.

In addition, the Commission is not persuaded that it is in the public interest to base an exemption from the DC Schedule provisions on the date on which an ESA or letter agreement is signed. Customers with similar cost characteristics and risk profiles should be placed in the same customer class, as they will cause the utility to incur similar costs and the system to bear similar risks. *See, e.g.,* N.C.G.S. § 62-133.16(a)(1), (b). Granting an exemption from tariff provisions based upon the signing date of an ESA or letter agreement presents a situation in which two customers with otherwise similar load profiles and system impacts would be subject to potentially substantially different system requirements, thus giving preference or advantage to one customer over another. This situation could also create complications for future rate class design due to disparities in the rate schedules on which electric service is taken and the treatment of CIAC payments.

Moreover, rates and terms of service are inextricably intertwined. Rates must be designed to reflect the cost of service. *Id.* Curtailment, which is a process to temporarily suspend a customer's access to electric service, reduces the cost of service for a utility. If one customer is subject to mandatory curtailment and a similarly sized customer with similar operating characteristics is exempt from curtailment, the curtailable customer should pay a lower rate because the cost to serve the customer is lower. However, if an ESA execution date-based exemption DEC is seeking is granted, two large data centers could end up paying the same rates (assuming one customer was exempt from the DC Schedule and opted into the HLF schedule while the other customer is required to take service on the DC Schedule) but receiving markedly different terms (and quality) of service because only one would be subject to mandatory curtailment based upon

regulation. In addition, the two customers would also impose the same risks on the DEC system and its other ratepayers but bear very different costs.

The Commission gives significant weight to the Public Staff's original proposal for a Schedule LL in terms of establishing a tariff for all customers taking new or incremental electric service after a proposed certain date (aligned with the anticipated effective date of DEC's new rates after issuance of this Order) that meets the threshold criteria. Tr. vol. 14, 206. The Commission is persuaded that significant new load has substantial impacts on the electric system. However, the Commission is not persuaded that an existing customer, meeting the threshold load and load factor requirements, should be fully exempt from any tariff provisions as these existing customers with similar load profiles will cause the system to incur similar costs for cost allocation purposes. Accordingly, these existing customers should be grouped together under any future class cost of service analysis.

The fact that DC Customers are predominantly customers who will take service in the future, whether such service is entirely or incrementally new, confirms that widespread "rate shock" is not an actual issue for customers who will be taking service on the new DC Schedule. The Commission gives significant weight to the testimony of DEC witness Hager that large load customers did not make up a meaningful portion of Duke's customer base in the historical test year and Public Staff witnesses Lucas and Dr. Weaver's testimony that very little large load is currently connected and taking service. Tr. vol. 11, 605, 624; tr. vol. 15, 52-53.

In addition, the Commission gives significant weight to the recommendation of AGO witness Brant to establish a tariff before large loads interconnect and costs are incurred. Tr. vol. 19, 149. The Commission is persuaded that serving new large load additions requires an unprecedented speed and scale of new generation and transmission infrastructure, and that due to this increased demand, supply limitations, and inflation, recent prices for utility infrastructure have increased significantly in just a few years. *Id.* at 132-33.

For these reasons, the Commission is mandating the implementation of estimated CIAC payments for directly assignable TNUs and Security for estimated Stranded Generation Charges with the issuance of this Order. If the Commission were to wait for the completion of the stakeholder process and then implement CIAC payments for TNU and Stranded Generation Charges, DC Customers who begin taking full service before the completion of the stakeholder process (including Commission review and approval of any proposals, which could in aggregate take up to two years or longer) would presumably contest any new charges and financial obligations that are imposed for existing electric service that was initiated prior to the imposition of such charges and obligations. In an effort to reduce an DC Customer's exposure to the risk of misestimated financial obligations and charges prior to completion of the stakeholder process, the DC Schedule will allow customers three years to deliver payment to DEC for estimated CIAC payments for TNU and to deliver Security for Stranded Generation Charges, during which period the Commission will allow the estimates to be trued up after completion of the stakeholder process if the Commission adopts standard methodologies that result in lower CIAC or Security amounts.

The only “exemption” for which DC Customers are eligible in the environment of broad and significant risk is the exemption necessitated by the prohibition on retroactive ratemaking. Each existing DC Customer that, on the issuance date of this Order, meets the threshold load and (applicable) load factor requirements of the DC Schedule shall be subject to the Rate Provisions of the Schedule for the entirety of its contract demand for the electric service DEC provides following the issuance of this Order, but not the additional Risk Mitigation Provisions unless incremental load is added after the issuance of this Order that meets the threshold criteria of the DC Schedule.

To be clear, the Commission is mindful of the prohibition against retroactive ratemaking. “[R]etroactive rate making occurs when an additional charge is made for past use of utility service, or the utility is required to refund revenues collected, pursuant to then lawfully established rates, for such past use.” *State ex rel. Utils. Comm'n v. Edmisten*, 291 N.C. 451, 468, 232 S.E.2d 184, 194 (1977). Using the initiation of new or incremental demand as the trigger for the application of the Risk Mitigation Provisions of the DC Schedule to such new or incremental demand fully comports with the restriction on retroactive ratemaking. Under the proposed structure of the DC Schedule, the Commission is not seeking to implement additional charges for an DC Customer’s past use of DEC service. The DC Schedule is intended and designed to require new DC Customers, or customers with new incremental demand meeting the thresholds of the DC Schedule, to bear responsibility only for the prospective costs of facilities required to provide this new or incremental service. Notably, DC Customers who have signed ESAs but have not yet taken service have no past use of utility service that can serve as a basis for retroactive ratemaking. The Commission thus determines that a critical factor for determining the applicability of the Risk Mitigation Provisions of the DC Schedule is the impact of that new or incremental load to be added to the system. The Commission finds that a delineation separating existing customers and new load to be added to the system reflects the additional impact to the system and prevents undue discrimination. Therefore, the entire DC Schedule will apply to any new or incremental loads to the system, on and after the date of the issuance of this Order, that meet the applicable demand and Load Factor thresholds. This requirement is applicable to customers currently on their load ramp when the remaining load to be added under the load ramp meets the demand and Load Factor thresholds set forth in this tariff.

Applicability Thresholds

Data Centers

As the witness testimony summarized above establishes, data centers present unique and substantial risks to DEC’s system through three primary factors: (1) the unprecedented scale and speed at which they are seeking to interconnect to the DEC system and consume electricity; (2) the risk of the unprecedented speed and scale at which they might leave the DEC system; and (3) their operating characteristics, including their high load factors and reliability standards. These risks must be borne either by existing ratepayers, who have no responsibility for the imposition of the risks, or the data centers, who are imposing these risks. These risks translate into real and substantial costs, in the form of, among other things, the construction of large, expensive generation assets and transmission network enhancements.

By adopting the DC Schedule, the Commission is consciously allocating these substantial risks (and associated costs) to the data centers responsible for imposing the risks. The Risk Mitigation Provisions in the DC Schedule allow the risks imposed upon DEC's system by data centers to be controlled in a manner that largely prevents other DEC ratepayers from being forced, by default, to bear these risks. Since system risks and system costs are inter-related, the DC Schedule's mitigation of data center-imposed risks also allows the Commission to set electric rates for data centers that are, consistent with cost-causation principles, the same as smaller traditional industrial companies would pay if they were taking service on DEC's HLF rate schedule. According to EDF witnesses Lenell and Pol, DEC's HLF rate schedule, given its single flat demand charge and single non-seasonal and non-time differentiated energy charge, is better suited to customers with consistently high load than other DEC rate schedules. Tr. vol. 20, 47.

In adopting the DC Schedule that is applicable only to data centers rather than a "large load" tariff that would be applicable to a broader group of customers, the Commission gives substantial weight to the testimony of the Public Staff Large Load Panel that Duke's load growth is unprecedented in scale and speed, Duke signed ESAs totaling approximately 6.7 GW of load within a timeframe of a little over two years, and data centers represent 92% of this 6.7 GW of load (for perspective, Duke's entire existing system serving the Carolinas, which was built over decades, is less than 40 GW). Tr. vol. 15, 30, 145-46. The Commission also gives substantial weight to the testimony of EDF witnesses Lenell and Pol that this large load growth is reshaping system planning and capital requirements, with costs and commitments to serve large loads accumulating now, and their conclusion that this rate case is the appropriate forum to guarantee that existing ratepayers are appropriately protected. Tr. vol. 20, 62. They further testified that large data centers, due to their high load factors, high reliability standards, developmental uncertainty, and unique technological development trajectories, utilize the utility system differently than other ratepayers, and these characteristics may require significant changes to transmission and generation planning to facilitate their service, ultimately impacting allocation factors and rates. *Id.* at 34. Witnesses Lenell and Pol concluded on these bases that a data center-only large load tariff is appropriate and reasonable. *Id.* at 84.

The Commission recognizes that other parties also opined that the appropriate entities to be subject to Risk Mitigation Provisions are data centers specifically, and the Commission, in the sound exercise of its discretion and independent judgment and based upon substantial, competent, and material evidence in the record, agrees. For example, NCSEA pointed out that:

> A dedicated rate class and schedule for data centers provides greater transparency, predictability, and enforceability. Data center customers present unique load-growth, infrastructure-planning, and cost-recovery challenges that differ substantially from traditional commercial and industrial customers. Creating a standalone schedule ensures that the rights and obligations associated with this new class of customer are clearly defined and uniformly applied. Most importantly, a dedicated schedule better protects existing ratepayers from the risks associated with large-scale, rapidly developing loads while allowing North Carolina to remain an attractive destination for economic development.

NCSEA Initial Comments at 5.

Walmart noted that the data centers and Duke opposed a data center-only tariff even though they all signed the Ratepayer Protection Pledge. Walmart Reply Comments at 3. “The Ratepayer Protection Pledge was not geared towards all large load customers; it was specifically geared towards data centers and the utilities who provide them power... A solution that is tethered to the problem, namely one focused on the unique risks and challenges of data centers, is the right solution.” *Id.* The Ratepayer Protection Pledge is specifically associated with the energy infrastructure needed to serve data centers and reflects an industry recognition that data centers warrant distinct regulatory treatment and allocation of data center-driven costs to the large data center customers that caused these costs to be incurred.

While customer load size may often have been relevant in determining the applicability of various Duke rate schedules, it need not be, and has not been, the controlling factor in all cases. For example, Duke’s operating companies have adopted, with Commission approval, rate schedules based upon NAICS (as the successor to SIC) codes for manufacturing in DEC’s Schedule I, based upon the type of institution in DEP’s Church Service-Time-of-Use (CH TOUE) Schedule for churches, and in DEP’s Schedule LGS-RTP, which allowed customer participation on what amounted to a first-come, first-served basis. Moreover, any “typical” past practice of using load size to develop rates should not serve as a hindrance to the Commission’s actions here to address a new and unprecedented development, specifically the remarkable speed and massive size at which data centers are now seeking to interconnect to the Duke system, along with the other associated risks addressed herein. The Commission finds important support for this “new problems need new solutions” approach in a recent white paper from the North American Electric Reliability Corporation (NERC), which regulates the reliability of the transmission grid. In NERC’s Large Loads Task Force White Paper, entitled “Characteristics and Risks of Emerging Large Loads”, NERC explained:

> Given the numerous categories and subtypes of large loads, a classification system based solely on a load’s peak demand may be overly simplistic. Due to the differences highlighted above, it cannot be assumed that all loads will behave similarly. Several other factors, such as load ramp rates, real-time behavior and flexibility, protection systems, and backup power schemes, should be considered if a large load definition is developed for regulatory procedures or policies.

Public Staff Large Load Panel Conf. Ex 1; *see also* Public Staff Tech. Conference Presentation, *Large Electric Load Additions,* No. E-100, Sub 208 (Oct. 10, 2025).

According to the testimony of EDF witnesses Lenell and Pol, to which the Commission gives substantial weight, treating data centers as identical to conventional large load customers risks inefficient outcomes and potential for cross-subsidization if these differences are not explicitly addressed through planning and tariff design. Tr. vol. 20, 45. The Commission’s decision in this proceeding to adopt a DC Schedule that is specific to data centers thus reduces the risk of cross-subsidization and other inefficiencies.

In addition, the Commission gives substantial weight to the testimony of AGO witness Brant on this issue. According to him, the size and scale of and significant demand from data centers create new risks and mean that cost allocation frameworks relied on in the past will not necessarily work as well in the future. Tr. vol. 19, 131-34. Witness Brant noted other commissions are moving towards directly allocating a portion of incremental transmission and generation costs that are required to serve new data center load directly to new data center loads. *Id*. at 138. In addition, the Independent Market Monitor for PJM found that data center load growth was directly responsible for the extremely high capacity prices in the PJM Capacity Market. *Id*. at 139. A single data center, Witness Brant observed, may demand hundreds or thousands of megawatts of power, triggering infrastructure investments of a nature and magnitude that existing tariff structures were not designed to govern. Additionally, these customers can come online quickly, are highly speculative in some cases, and have an unknown lifespan, characteristics at odds with the nature of utility generation and transmission investments. *Id*. at 147. The Commission gives significant weight to witness Brant's concerns about the risks created by the unprecedented size and speed of the load growth from large data centers and resulting impact on other ratepayers, and thus gives little weight to recommendations to create a broader large load tariff that applies to all large loads of a certain size instead of a data center-only tariff.

Data centers, in addition to arriving at unprecedented levels of size and speed to seek interconnection to Duke's system, also impose the risk of, and are capable of, leaving a utility system at unprecedented levels of size and speed. The identification of this material risk is based upon the substantial weight that the Commission gives to the testimony of EDF witnesses Lenell and Pol, who explained that data centers replace IT equipment on a much more frequent basis than manufacturing facilities replace operational infrastructure, and data centers are expected to increase their power-usage effectiveness over time. Due to a faster pace in AI development, Amazon reported that the useful life of its server and network infrastructure has been reduced to five years. In addition, the load density at a location is materially changed by newer hardware, which creates a need for long-term coordination between the utility and data center customer. Tr. vol. 20, 41-42. The Commission also gives substantial weight to the testimony of NCJC et al witness Wilson, who explained that data centers are expected to have costly hardware refresh cycles of about five years, thereby resulting in a data center customer reassessing its business case for continuing to operate. Tr. vol. 19, 418.

Even if a data center customer remains on the DEC system for the full initial term of its contract, the Public Staff highlighted the mismatch between the lifecycle and cost of DEC generation assets when compared to the contract terms for these customers -- for example, if the addition of a large load customer requires construction of a natural gas asset, that asset would be in rate base for 35 years (and some assets, such as nuclear assets, may have a lifetime of 60 years or more), while the large load customer obligation may only extend 10 or 15 years. Public Staff Large Load Panel Conf. Ex 1; *see also* Public Staff Tech. Conference Presentation, *Large Electric Load Additions,* No. E-100, Sub 208 (Oct. 10, 2025). If this customer were to fail to renew at the end of its contract term and if no equivalent large load customer with a high load factor occupies the site, DEC's remaining customers may then be paying for an asset that they may not otherwise have needed. *Id*. The Panel further testified that stranded asset risk associated with the assets

built to serve these customers is substantial because many prospective large load customers may not materialize, may ramp slower than expected, or may leave the system prematurely, causing costs associated with these new generation facilities and infrastructure to be redistributed among all remaining customers. Tr. vol. 14, 110-111.

By adopting the DC Schedule for data center customers, the Commission is able to effectively prevent or mitigate the risk associated with the unprecedented size and speed of date center load growth and the risks associated with rapid widespread departures from the system and stranded assets. The Risk Mitigation Provisions of the DC Schedule, specifically those addressing the Contract Period, Minimum Billing Demand, Required Facilities Costs, Notice of Contract Reduction or Early Termination, Liquidated Damages, and Stranded Generation Charges, act collectively to ensure that data centers remain obligated to pay charges that are sufficient to recover the costs that are appropriately allocated to data centers, so that DEC's other ratepayers are not subsidizing the cost and risk associated with unprecedented load changes and planning challenges. Curtailment provisions, which are relevant to pricing, also play a role in helping to manage the risk of integrating large load data centers into DEC's system in an orderly and manageable manner. Each of these Risk Mitigation Provisions is addressed in more detail in the sections below.

Operationally, data centers have estimated load factors of 91%, which is significantly higher than the estimated 74% load factor for large manufacturing loads in Duke's territory. Tr. vol. 20, 35. High load factor customers need to be served by expensive, long-lived base load capacity. In addition, according to EDF witnesses Lenell and Pol, data centers often require higher reliability standards than industrial customers, with the target often cited as "five nines" or 99.999% availability for critical systems. Redundancies are not just a factor of the internal configuration of the IT systems, but part of a holistic plan that includes backup generation and transmission configurations such as dual feeds and other grid level upgrades. Unlike manufacturing, which generally accepts standard transmission service and does not hold itself to a five nines standard, data centers incorporate grid reliability into their internal risk assessments. As a result, utilities serving these large load data centers will need to provide greater levels of investments relative to a manufacturing load. *Id.* at 36.

In addition, the Commission gives substantial weight to the Public Staff's testimony that NERC issued its rarest and highest-level alert, which it typically reserves for critical and time-sensitive circumstances, "warning of immediate and serious reliability risks to the United States bulk power systems from large computational loads, particularly loads for artificial intelligence training, cryptocurrency mining, and traditional data center uses." Tr. vol. 14, 124. NERC noted that data centers and other computational loads have software load control systems that enable these data center loads to rapidly change their electricity consumption, creating previously unseen load behavior that can cause bulk power system planning and operational challenges. Public Staff Large Load Panel Conf. Ex 1; *see also* Public Staff Tech. Conference Presentation, *Large Electric Load Additions,* No. E-100, Sub 208 (Oct. 10, 2025). NERC also states that each "category of large load – computational, industrial, and hydrogen – displays real-time operating characteristics that differ from loads previously connected", but the focus of NERC's July 2025 white paper (Characterization and Risks of Emerging Large Loads) is on data centers due to

their rapid growth and limited operating experience with other emerging large loads. *Id*. The Commission is persuaded that large data center customers have created documented and unique reliability risks to the electric system given both the size of the demand, load fluctuations, and the protective equipment installed by the data center customers that suddenly disconnects the facility from the grid.

Once again, by adopting the DC Schedule for data center customers, the Commission is able to effectively prevent or mitigate the risk associated with these operational issues. The Risk Mitigation Provisions of the DC Schedule ensure that data centers remain obligated to pay charges for base-load generation and grid enhancements. In addition, Ride-Through Requirements help DEC to manage its data center customer relationships with regard to the type of sudden load disconnection and reconnection about which NERC expressed concern with data centers, which in the absence of ride-through obligations have the ability to effectively instantaneously turn power consumption off and then on in a manner that jeopardizes grid stability.

Demand

In forming its conclusion with regard to the applicability threshold for DC Customers, the Commission considered the contract demand and load factor applicability thresholds and tiered structure proposed by the Public Staff and DEC in its initial tariff overlay, as well as the varying tiered approaches proposed by AGO witness Brant, NCJC, et al. witness Wilson, and DEC in its initial tariff overlay.

The Commission gives significant weight to the testimony of EDF witnesses Lenell and Pol that DEC should develop a holistic rate and tariff design framework for data centers over 50 MW, due to their unique operational characteristics. Tr. vol. 20, 20. They noted that 50 MW is a common threshold and it captures the majority of large economic development growth. *Id.* at 98-99. Witnesses Lenell and Pol explained that DEC is projecting growth from large loads to constitute over 66% of the cumulative load growth to the year 2040, and data centers over 50MW will comprise 9.2% of DEC's winter peak and 14.5% of sales by 2030. *Id*. at 27,33. If large data center loads materialize as forecasted, witnesses Lennel and Pol asserted that existing Commercial classes would be allocated a greater portion of system costs relative to status quo and non-large-load Commercial customers may experience increased costs. *Id*. at 33-34.

The Commission gives little weight to the contract demand and load factor applicability thresholds and tiered structure proposed by the Public Staff because they are designed for generic large loads rather than data centers in particular. However, the Commission is persuaded that 50 MW is an appropriate threshold to apply to DC Customers because it exceeds the demand of the majority of traditional commercial and industrial customers and marks the threshold at which DEC needs to make substantial investments. The Commission agrees that balance is needed between mitigating risks and disproportionately burdening smaller customers and hampering economic development.

The Commission gives little weight to the recommendation of AGO witness Brant to establish a tiered approach to a large load tariff. The Commission is persuaded that the current ESA and service regulation approach that applies to loads of 100 MW demand

or above, tr. vol. 21, 523, 559, does not sufficiently capture risks of large loads and protect other customers. However, the Commission is not persuaded that customers with loads as little as 20 MW should be subject to the same requirements as those with significantly higher contract demands.

The Commission gives little weight to the recommendation of NCJC, et al. witness Wilson to establish a tiered threshold of (1) loads above 25 MW with load factors of 85% and (2) all loads above 100 MW, because these tiers are designed for generic large loads rather than data centers in particular. The Commission acknowledges that witness Wilson states that it could be reasonable to establish a minimum threshold of 50 MW but is not persuaded that a load factor of 85% for this demand or a threshold of 100 MW is appropriate. The Commission is persuaded that the characteristics of data center customers with high loads are sufficiently distinct from other large customers and should be evaluated separately. Tr. vol. 19, 449.

The Commission gives little weight to the eligibility thresholds and tiered structure proposed by DEC in its proposed overlay tariff because the tiers are designed for generic large loads rather than data centers in particular. However, the Commission notes that the threshold of 50 MW or greater aligns with the Public Staff's recommendation.

In the sound exercise of its discretion and independent judgment to implement policy in accordance with N.C.G.S. § 62-2, the Commission concludes setting the applicability threshold for DC Customer status and inclusion on the DC Schedule at 50 MW or greater is reasonable and appropriate. Given the testimony regarding anticipated data center load factors, the Commission is not persuaded that a load factor threshold is warranted for the DC Schedule. The rates of DC Schedule are based on Schedule HLF, which is designed for very high load factor customers.

Customers whose incremental billing demand increases in aggregate in an amount sufficient to satisfy the criteria above shall also be subject to the DC Schedule. If a customer's incremental demand will be sufficient to satisfy or exceed the demand, that incremental demand will be subject to the Risk Mitigation Provisions of the DC Schedule, but the customer's entire electric service will be subject to the Rate Provisions of the DC Schedule.

Applicability Provisions and Grandfathering

For avoidance of doubt as to the Commission's intention with the application of the DC Schedule, the Commission clarifies that the DC Schedule shall be applicable to all new and existing customers that meet the threshold requirement (50 MW) of the DC Schedule. Existing DC Customers that, on the issuance date of this Order, meet the threshold load requirement of the DC Schedule shall be subject to the Rate Provisions of the Schedule for the entirety of their respective Applicable Demands but not the Risk Mitigation Provisions. Any existing customers with incremental load additions that, singly or in aggregate, cause the customer to meet the threshold demand requirement will be subject to the DC Schedule; the DC Schedule Rate Provisions shall apply to the total contract demand of the DC Customer's facility, but only the incremental amount of load added that causes the customer to meet or exceed the threshold demand and load requirements shall be subject

to the Risk Mitigation Provisions. Any new customers that meet the threshold load shall be subject to the entirety of the DC Schedule provisions for the total amount of contract demand.

Contract Term and Load Ramp

The Commission gives some weight to the recommendation of the Public Staff to set minimum contract lengths of 10 years for loads of 50 MW to 100 MW and 15 years for loads of at least 100 MW, including a maximum load ramp of five years. Tr. vol. 14, 133-34. The Commission is persuaded that the tiered structure of higher requirements for larger sized loads appropriately reflects risks and allows a reasonable time to recover some costs based on the load size. However, the Commission is concerned that load ramp caps may pose unnecessary or unrealistic construction limits on customers.

The Commission gives little weight to the recommendation of AGO witness Brant to establish a minimum contract term of 15 years plus a load ramp of no more than 5 years for all loads of 20 MW or more. Tr. vol. 19, 162-163. The Commission is not persuaded that this approach appropriately reflects the risks and cost recovery from larger loads.

The Commission gives little weight to the recommendation of NCJC, et al. witness Wilson to set a minimum contract term of 20 years for loads of 25 MW or greater. Tr. vol. 19, 432-33. While the Commission notes this contract term is closer to the useful life of some utility assets built to serve customers, the Commission is persuaded by DEC's response in rebuttal that a large customer with a long load ramp would already produce terms of similar length and that contracts are designed to secure financial commitments and add flexibility to planning. Tr. vol. 21, 564.

The Commission gives substantial weight to the recommendation of DEC witnesses Byrd, Beveridge, and Duff to set contract terms for customers of 50 MW to 100 MW to the greater of 10 years or 5 years plus the load ramp, and the greater of 15 years or 10 years plus the load ramp for customers above 100 MW. Tr. vol 21, 627-29. The Commission is persuaded that this approach reflects the ability of customers to meet the load ramp appropriate for their project while also protecting other rate payers with longer contracts and contract minimums.

Thus, the Commission determines it is reasonable to set the minimum initial contract term for DC Customer ESAs below 100 MW to be the greater of (a) 10 years or (b) 5 years plus the load ramp period; the minimum initial contract term for DC Customer ESAs of 100 MW or more will be the greater of (a) 15 years or (b) 10 years plus the load ramp period.

Dedicated Facilities

The Commission gives substantial weight to the testimony of the Public Staff that large load customers should be fully responsible for the costs of projects that are solely for their benefit, termed Dedicated Facilities, which also includes facilities added at the customer's request. Tr. vol. 14, 140. The Commission is persuaded that it is appropriate and reasonable for each DC Customer to fully pay the costs of Dedicated Facilities.

DEC witness Byrd explained that if service to a customer is beyond the standard level of service, the customer is expected to contribute the capital costs of those facilities. Tr. vol. 12, 38-39. DEC requires up-front funding for nonnetwork upgrade costs, which are refunded to the large load customer after the customer has met certain milestones. Tr. vol. 21, 567. The Commission is not persuaded that a refundable advance for interconnection facilities built to serve a large individual customer is appropriate and gives little weight to this recommended tariff provision.

The Commission concludes that each DC Customer subject to the Required Facilities Costs provision of the DC Schedule shall provide advanced funds equal to the estimated total cost of Dedicated Facilities as CIAC within 60 days of executing a letter agreement with DEC and shall provide all necessary additional funds if actual costs exceed estimates. For customers subject to the Required Facilities Costs provision of the DC Schedule that executed a letter agreement more than 30 days before the date of the issuance of this Order, the customer shall pay the remaining total costs of Dedicated Facilities as CIAC within 60 days of the date of this Order. If an ESA is not executed, any advanced funds shall be refunded to the customer, less any actual costs incurred by DEC. If an ESA is terminated prior to energization, any unspent funds from the advanced funds will be retained by DEC and applied towards the liquidated damage liability owed by the customer.

Minimum Billing Demand

The Commission gives substantial weight to the testimony of the Public Staff's Large Load Panel, AGO witness Brant, and DEC witnesses Byrd, Beveridge, and Duff, who recommended a minimum billing demand of 75%. The Commission is persuaded that the minimum billing demand will help ensure capital cost recovery is not completely shifted to other customers should the load fail to materialize. Tr. vol. 14, 133-34. The Commission also acknowledges that this minimum billing demand is within the 60-100% range reflected in a survey of the 28 tariffs containing minimum billing demand terms per DEC witness Duff. Tr. vol. 21, 540.

Although CIGFUR III witness Collins did not have a proposal for a large load tariff in this proceeding, witness Collins noted that minimum demand provisions, long-term contract commitments, collateral, and security can mitigate some risks of new large loads that require significant investment. Tr. vol. 19, 352. The Commission gives this testimony some weight.

The Commission also gives some weight to the testimony of EDF witnesses Lenell and Pol that there is a national consensus to include financial commitments such as minimum demand provisions within large load tariffs. Tr. vol. 20, 51-52.

NCJC, et al. witness Wilson stated that minimum demand charges should be sufficient to recover a substantial portion of the cost of system upgrades but not so high as to disincentivize energy conservation, and that given the link between minimum demand and termination charges, it is possible that DEC's existing terms could undermine the effectiveness of minimum contract demand in protecting customers from stranded assets. Tr. vol. 19, 436-39. Witness Wilson recommended raising the minimum billing

demand from 75% to 85%, which he argued should provide large load customers with an incentive to conserve energy and protect other customers from bearing the costs associated with investments to serve those large load customers. *Id.* at 444-45. The Commission notes this may be a material bill increase for customers and is not persuaded that the recommendation would achieve meaningful results that could not be achieved by other risk mitigation methods and thus gives this recommendation little weight.

The Commission concludes that a minimum billing demand of 75% is reasonable and appropriate.

Liquidated Damages for Early Termination (plus Security Requirements)

The Public Staff recommended a notice period of at least 24 months in advance of full termination for loads under 250 MW, and a notice period of 36 months in advance of full termination for loads over 250 MW, to allow time for DEC to reflect the change in resource planning or find a similar load to match the loss, if possible. Tr. vol. 14, 135. In the event of a full termination, the Public Staff recommended the early termination fee to be the sum of the minimum annual bill for the remainder of the contract term plus the net present value of any Extra Facilities Charges and Required Facilities Charges not yet recovered. *Id.* The Commission gives this recommendation some weight. Increased notice periods for larger sized loads is appropriate and reasonable, but the Commission is not persuaded that this recommendation goes far enough with the largest sized loads and is not persuaded that the determination of the termination fee is appropriate.

AGO witness Brant recommended significant early termination fees and notice requirements with a minimum of three years for contract termination covered by liquidated damages designed to recover the greater of all remaining undepreciated costs of infrastructure built to serve the customer or all remaining monthly minimum bills. Tr. vol. 19, 158, 164-65. The Commission gives this recommendation little weight because the Commission concludes that a differentiation of liquidated damages for early termination and stranded generation charges at the conclusion of service for the recovery of undepreciated generating asset costs better reflects the separate risks imposed by the two events. In addition, the Commission is not persuaded that a three-year notice is appropriate for all sizes of loads.

EDF witnesses Lenell and Pol recommended that tariff mechanisms should disincentivize early project termination and include financial commitments. The Commission agrees and gives this recommendation some weight.

Although Google witness Dr. Berry did not have a specific proposal for a large load tariff in this proceeding, the Commission gives some weight to Google witness Dr. Berry's testimony that provisions concerning penalties for early contract termination are commonly found in large load tariffs. Tr. vol. 19, 598.

NCJC, et al. witness Wilson supported the Public Staff's approach to advanced notice requirement of early contract termination and recommended that the termination charge requirements ensure the minimum transmission and generation demand charges are collected from customers regardless of contract demand reduction, with charges

excused in the event Duke Energy can bring another large load customer online to utilize the available capacity. *Id.* at 438-45. The Commission gives this recommendation some weight but is not persuaded that customers should be assessed with larger minimum charges after reducing their contracted demand.

The Commission gives significant weight to the early termination provision recommended by DEC in rebuttal, which requires early termination notices of 24 months for demand below 250 MW, 36 months for demand between 250 MW and 499 MW, and 48 months for demand of 500 MW or greater. The Commission also gives substantial weight to DEC's recommendation of the determination of liquidated damages and security requirement for applicable liquidated damages for early termination. The Commission finds these recommendations to be reasonable and appropriate.

The Commission thus concludes that a customer must notify DEC in advance of early termination, and the large load tariff shall require early termination notices of 24 months for demand below 250 MW, 36 months for demand between 250 MW and 499 MW, and 48 months for demand of 500 MW or greater. The Commission also determines that liquidated damages for early termination, as recommended by DEC, are reasonable and appropriate and shall be adopted for the large load tariff.

Contract Demand Reduction (Notification & Liquidated Damages)

The Public Staff recommended a required notice period of at least 12 months in advance of a permanent contract demand reduction of 20% or more and required payment of 75% of the customer's Exit Fee. Tr. vol. 14, 135. Although the Commission agrees that a notification period is required for material contract demand, the Commission gives this recommendation little weight as a 20% reduction has a vastly different impact depending on the contracted demand and additional notice may be reasonable.

AGO witness Brant recommended clear parameters on a customer's ability to reduce contracted load, with a minimum of three years of advanced notice for material reductions in contracted demand. Tr. vol. 19, 164-65. The Commission gives this recommendation little weight as the Commission is not persuaded that a three-year notice is appropriate for all sizes of loads.

NCJC, et al. witness Wilson expressed concern at DEC's terms allowing what he deemed as permissive language in contract reductions, recommending only limited reductions in the contract demand without charge and allowing reductions in contract demand by 20%, up to a 100 MW maximum, with a notice period of 36 months. *Id.* at 438-45. The Commission gives this recommendation some weight, as the Commission is not persuaded that a three-year notice is appropriate for all sizes of loads. The Commission gives significant weight to the concern brought forward by witness Wilson regarding the amount of load to be reduced and is persuaded that the amount being reduced, rather than the percentage reduction, is a more important factor.

DEC also recommended a required notice period of at least 12 months in advance of a permanent contract demand reduction of 20% or more and required liquidated damages for a contract reduction equal to 100% of the minimum bills and Extra Facilities

Charges during the applicable notification period, plus the termination liquidated damages under the original contract, minus the termination liquidated damages under the new contract based on the reduced contract demand. DEC also allows one penalty-free reduction of up to 20% after seven years of service with 12 months' notice. Tr. vol. 21, 559-62. Although the Commission agrees that a notification period is required for material contract demand, the Commission gives this recommendation little weight as a 20% reduction has a vastly different impact depending on the contracted demand and additional notice may be reasonable.

The Commission determines that reductions in contract demand shall have an applicable notice period based on the MW amount of reduced demand from the full contract demand. Contract demand reductions require advanced notice of 24 months for reductions under 250 MW, 36 months for reductions between 250 MW and 499 MW, and 48 months for reductions of 500 MW or greater. Liquidated damages for a contract demand reduction will be equal to 100% of the minimum billing demand charges and Extra Facilities Charges during the applicable notification period, plus the termination liquidated damages under the original contract (measured in the contract year of the reduction), minus the termination liquidated damages under the new contract based on the reduced contract demand (measured in the contract year of the reduction). After the 6th anniversary of initial provision of service, the customer may provide notice to reduce contract demand by up to 20% but no greater than 200 MW, one time, without incurring liquidated damages.

Curtailment Obligations - Reliability Provisions

The Public Staff recommended including required curtailment provisions as a tool for system operators to maintain reliability during certain situations, with an option of 95% curtailment of contracted demand for 50 hours per year or 50% of contracted demand for 100 hours per year, aligning with the temporary provisions in proforma ESAs, limited to five years. Tr. vol. 14, 112, 135-36, 194. The Commission gives significant weight to the Public Staff's recommendation.

AGO witness Brant recommended that the curtailment provisions should be evaluated for sufficiency, scaled to contracted demand level, and treated as a planning resource in future CPIRP analyses. The Public Staff warned that the absence of reasonable curtailment measures for large load customers could increase loss of load risk for other ratepayers. Witness Brant also recommended that DEC develop a tariff option or rider to compensate very large load customers for committing to defined levels of dispatchable load reduction. *Id*. at 182. The Commission determines these recommendations would be more appropriate for consideration in other proceedings and after more large load customers have taken service and therefore gives this recommendation little weight.

NCJC, et al. witness Wilson recommended clarifying or expanding the scope of the advance for customer requested facilities to include costs related to resolve transmission contingency violations related to limited duration curtailment provisions. The Commission gives this some weight and discusses its findings and conclusions concerning transmission network upgrade costs in another section of this Order.

The Commission gives significant weight to the reliability provision and curtailment concerns identified by DEC in rebuttal, noting that curtailment is a valuable system tool but some large load customers may have operational profiles that require an alternative curtailment option than that currently in the form ESA.

The Commission determines that it is reasonable and appropriate for each ESA to include one of the following reliability provisions: (a) curtailment of 95% of contract load for up to 50 hours per year for the load ramp period plus one year of service, (b) curtailment of 50% of contract load for up to 100 hours per year for the load ramp period plus one year of service, or (c) an alternative Commission-approved option that accelerates capacity resources on the utility system during the integration of the customer's full contract demand. Customers will not be compensated for curtailment under this provision, and curtailment shall be limited to a maximum of six hours per day. Additionally, a customer may petition the Commission for a modification or exemption from this requirement, consistent with exceptions contemplated under Section 202(c) of the Federal Power Act.

The Commission further directs Duke, through the 12-month stakeholder process outlined below, to propose parameters for evaluating alternative options under part (c) of the reliability provisions above. These parameters shall address what constitutes a qualifying capacity resource and a meaningful acceleration of its availability. The filing containing these parameters shall identify areas of agreement and disagreement, and any proposed alternative shall remain subject to the Commission's approval.

Rate Schedule

DEC witness Byrd testified that the Company did not propose a specific rate schedule for large load customers because the current rate schedules OPT-V and HLF "provide appropriate tariff options for large load and high load factor customers that already align prices with cost-of-service." Tr. vol. 11, 520. As a result, witness Byrd explained, new tariffs designed specifically for "large loads'" would "most likely be designed similar to either Schedule OPT-V or Schedule HLF, rendering such new tariffs duplicative and unnecessary." *Id*. Witness Byrd also noted that Schedule HLF provides for significant fixed cost recovery through demand charges. *Id.* at 520. The Commission gives significant weight to the testimony of DEC witness Byrd that Schedule HLF is designed for very large high load factor customers. *Id.* at 625.

The Public Staff stated that large load customers may currently take rates under five rate schedules, and the Public Staff's proposed Schedule LL allowed customers under the tariff to elect service under the same five rate schedules. Tr. vol. 14, 114, 139. The Public Staff noted that in their review of the ESAs in DEC's North Carolina territory, none of those customers plan to take service under HLF. *Id.* at 129. The Commission gives some weight to the Public Staff's acknowledgement that if a customer has the option of different rate schedules, the customer will choose the rate schedule under which it pays the least. *Id.* at 49-50.

The Commission gives some weight to the concerns raised by AGO witness Brant regarding DEC's existing OPT-V and HLF tariffs. Tr. vol. 19, 146-48. The Commission agrees that a rate schedule alone is not sufficient to guarantee customer protection, but

notes that the lack of large load customers during the test year creates difficulty accurately designing unique rates for this future group of customers.

The Commission gives significant weight to the concerns brought forward by EDF witnesses Lenell and Pol that if large load tariff provisions are based on the selected rate schedule, customers selecting one rate schedule will have different minimum bills and different termination fees based on those minimum bills than if another rate schedule was selected. Tr. vol. 20, 99-101.

The Commission also gives significant weight to the recommendation of NCJC, et al. witness Wilson to set an initial rate schedule based on Schedule HLF, as he notes this would be relatively simple and avoids the need to re-evaluate DEC's rate designs. *Id*. at 450.

In rebuttal, DEC proposed Schedule LLT, which does not include a separate rate class but requires customers to take service on Schedule OPT-V or Schedule HLF. Tr. vol. 11, 627; tr. vol. 21, 560. DEC also offered in rebuttal that in the next rate case, DEC can evaluate rates that reflect large load customers once enough are taking service to develop meaningful results. Tr. vol. 21, 565.

The Commission finds that Schedule HLF provides more appropriate price signals and reflection of the cost of service for large load customers with very high load factors than Schedule OPT-V. The Commission also notes that Schedule HLF recovers greater fixed costs through demand charges than Schedule OPT-V, which recovers fixed costs through energy charges, and thus minimum bills based on Schedule HLF recover a greater portion of the infrastructure needed to serve DC Customers. Based on the evidentiary record, the Commission concludes that Schedule HLF is a reasonable and appropriate basis for the DC Schedule for electric service DC Customers in this proceeding.

Creation of a New Rate Class

The Commission declines to adopt the AGO witness Brant's suggestion to create a separate rate class for data centers in this rate case because the currently available data is insufficient to support its development. While a separate class establishes a mechanism to ensure that revenues, costs, investments, and risks are tracked and appropriately reflected in rates, beyond broad suggestions to create a separate rate class, the Commission finds the record devoid of evidence that there is sufficient data for the creation of a new rate class in this proceeding. However, the Commission determines that creating a large load rate class in the next rate case is appropriate, provided sufficient data is obtained before that proceeding.

The Commission gives weight to DEC witness Hager's testimony that there is insufficient test-year data to support the establishment of a separate customer class. Tr. vol 11, 605. However, this objection reflects the issue of collecting data for the rates established for this proceeding, but not the principle of a rate class. Witness Hager noted that allocation methods are reassessed for each rate case and the Commission will have the opportunity to evaluate this approach on a recurring basis. *Id.* In rebuttal, DEC proposed Schedule LLT, which does not include a separate rate class but requires customers to take service on Schedule OPT-V or Schedule HLF. *Id.* at 627;

tr. vol. 21, 560. DEC also offered in rebuttal that in the next rate case, DEC can evaluate rates that reflect large load customers once enough are taking service to develop meaningful results. Tr. vol. 21, 565.

The Commission gives significant weight to the testimony of the Public Staff that there was not enough data on these customers to propose a rate class and appropriately allocate costs in this proceeding, and the Public Staff's acknowledgement putting the large load customers in their own class now would give them advance notice that they would have their own rates and have no intraclass support or subsidy. Tr. vol. 15, 52-53.

The Commission also gives some weight to NCJC, et al. witness Wilson's testimony that it may be appropriate to wait to establish a separate class, as there may only be a couple customers qualifying under the conditions, and the data to develop their rates could reveal confidential information. The Commission gives significant weight to the recommendation of witness Wilson to establish a class for reporting purposes. Tr. vol. 19, 485.

In sum, the evidence in this proceeding, particularly the testimony of DEC witness Hager, the Public Staff, and NCJC, et al. witness Wilson, supports deferring the creation of a separate large load rate class and unique rate schedule until the next rate case, provided sufficient data are available at that time to support its development and the appropriate allocation of costs. The Commission directs Duke to define the class for reporting purposes and conduct separate tracking of costs and revenues for DC Customers taking service on the DC Schedule.

Network Upgrades

Based on the evidentiary record, the Commission concludes that there is a need to protect existing ratepayers from the scale of transmission network upgrade costs caused by DC Customers, which have traditionally been socialized across all customer classes. The Commission acknowledges the complexity of the task since transmission network upgrades triggered by DC Customers can often provide benefits to other customers and the entire system overall by increasing capacity and reliability.

To mitigate the risk of early termination, the Commission concludes that it is reasonable and appropriate to require each DC Customer to provide a deposit in the form of a letter of credit equal to the estimated total transmission network upgrade costs necessary to serve the customer's Post-Order Service. To the extent the actual cost of the network upgrades exceeds the original deposit, the DC Customer will provide additional deposit through the letter of credit to cover the full cost of the network upgrade. After the DC Customer meets or exceeds an actual monthly billing demand of 75% of full contract demand for three consecutive billing months, the letter of credit required to cover and secure the costs of the Transmission Network Upgrades will be reduced once per year on a ratable basis over the remaining term of the DC Customer's ESA. In the event of early termination pursuant to the terms of the ESA, DEC will draw on the letter of credit to recover the remaining net book value, as of the date of termination, of Transmission Network Upgrades as CIAC.

The Commission, in the sound exercise of its discretion and independent judgment to implement policy in accordance with N.C.G.S. § 62-2, determines that a stakeholder process to develop potential methodologies for identifying and directly assigning the customer-attributable portion of transmission network upgrade costs will be a reasonable and prudent path forward. Accordingly, the Commission adopts the stakeholder process reflected in the LLT Stipulation to develop a methodology to identify and directly assign the customer portion of the transmission network upgrade costs.

Additional details on the scope of the stakeholder process are outlined below.

Estimated Network Upgrade Charge

The Commission directs DEC to calculate, on a case-by-case basis and using its engineering judgment, an estimated Customer Portion of Network Upgrade costs to be paid as CIAC for each DC Customer's Post-Order Service and file this information with the Commission for review and approval. An approved estimate must be paid to DEC no later than 36 months after the initiation of Post-Order Service unless a lower Commission-approved Customer Portion is developed based upon the standard methodology adopted following the completion of the stakeholder process, in which event the lower Customer Portion must be paid to DEC within 60 days after Commission approval of the Customer Portion.

Stranded Generation

In the sound exercise of its discretion and independent judgment to implement policy in accordance with N.C.G.S. § 62-2, the Commission concludes that the risk of stranded generation posed by DC Customers warrants protection for DEC's other existing retail customers. While the two-year-check-and-adjust CPIRP cycle may provide limited protection from this risk through measures such as potential adjustments to coal retirement schedule and potential deferral of generation units as new information becomes available, the Commission finds these measures to be insufficient to protect DEC's existing retail customers from stranded generation costs. The Commission therefore determines that a stranded generation charge is a reasonable and appropriate cost to be borne by DC Customers for Post-Order Service.

The timing mismatch between large load customer contracts and generation asset lifetimes was confirmed during the evidentiary record in this proceeding. Multiple intervenors highlighted the additional risk of stranded generation, emphasizing the fact that the sudden and significant load growth, largely due to the rapid signing of ESAs by data centers and other DC Customers, necessitates DEC constructing a significant amount of generation within a short period of time. These generation assets have typical useful lives of approximately 35 years, or longer, whereas DC Customer contract terms tend to last 10 to 15 years. While DEC and the Public Staff have proposed large load tariff structures which impose liquidated damages on customers terminating their ESAs before the end of their contract periods, both parties acknowledge that the liquidated damages would not cover the full cost of generation built to serve these customers. Further, none of the parties' proposed tariffs addressed the concern that even if a customer allows its DEC electric service to be terminated at the conclusion of customer's contract term, the

generation assets built to serve the customer will still have approximately 20 years of depreciation that must be funded by DEC's other ratepayers who remain on the system.

The Commission acknowledges that large load customers, typically in the form of industrial customers, have existed on DEC's system for decades and the Commission has not expressed concern about stranded generation assets that may result from these customers allowing their electric service to expire at the conclusion of their ESA terms. However, the Commission recognizes that recent and impending data center customer interconnections are unique for two reasons – both the size and speed with which they interconnect to Duke's system. This was noted by the Public Staff's Large Load Panel in their testimony:

> While some risk of stranded assets has always existed within the system, the scale of the risk presented by the large load customer load growth is unprecedented. Individual large load customers are seeking to interconnect load in the hundreds of megawatts, the equivalent of a combined cycle facility or small modular nuclear reactor, over a relatively short period of time . . . the current size and pace of load growth has significantly increased the likelihood of overbuild and stranded assets in the event load does not materialize or is not sustained as expected. Absent strong protections that ensure that those causing large, expedited investment are ultimately responsible for paying for that investment, there is a significant risk that the remaining customer base will be asked to bear those costs.

Tr. vol. 14, 111.

In response to the Commission's August 12, 2026, Order Requesting Comments, multiple intervenors suggested proposed solutions to address stranded generation risk in their initial and reply comments. The AGO and NCJC, et al. supported direct allocation of generation costs via upfront payments that are refunded as the customer's load materializes. EDF advocated for a framework which isolated generation needed to serve a specific large load customer class via a "but for" analysis and assigned the incremental costs of generation to that class.

The Commission believes the complexities of establishing a standard methodology for identifying and allocating Stranded Generation Charges using utility system modeling are best resolved through a stakeholder process and subsequent Commission proceedings. The Commission therefore concludes it is reasonable and appropriate to direct DEC to implement a stakeholder process described in greater detail in the following section of this Order for the development of Stranded Generation Charges applicable to the Post-Order Service of DC Customers. In the interim, the Commission concludes it reasonable and appropriate to impose an estimated Stranded Generation Charge applicable to Post-Order Service that is initiated before the conclusion of the stakeholder process and Commission review and approval of the methodology developed in the stakeholder process. Security for an estimated Stranded Generation Charge must be delivered to DEC no later than 36 months after the initiation of Post-Order Service unless a lower Commission-approved Stranded Generation Charge is developed based upon the standard methodology adopted following the completion of the stakeholder process,

in which event Security for the lower Stranded Generation Charge must be delivered to DEC within 60 days after delivery of notice to the customer of the new Stranded Generation Charge based upon the Commission's approved standard methodology.

Estimated Stranded Generation Charge

Prior to the conclusion of the stakeholder process, an estimated Stranded Generation Charge based upon a proxy CC unit will be assessed for all DC Customer Post-Order Service. Using a proxy CC unit is appropriate during this interim period because a CC unit provides the base load capacity that DEC needs to serve DC Customers' demand and because Duke's operating companies, including DEC, are actually constructing, or seeking CPCNs to construct, thousands of megawatts of CC capacity, and CC capacity appears to be the only viable baseload capacity Duke can install at this point to serve these new loads. In addition, in this rate proceeding, DEC referenced a Large Load Impact Analysis that was filed in a pending CPIRP proceeding (Docket No. E-100 Sub 207) as support for the contention that large load customers not only cover their costs, including generation and transmission costs, but contribute net revenue benefiting other customers. Tr. vol. 21, 534, 572. Duke itself assumed in the Large Load Impact Analysis that new large loads would be served by CC units.

In order to identify the cost of the proxy CC unit for purposes of developing an estimated Stranded Generation Charge, the Commission hereby utilizes its authority under N.C.G.S. § 62-65(b) to take judicial notice of its Corrected Order Determining Need for Out-of-State Generating Facility, *Application of Duke Energy Carolinas, LLC for a Determination of Need for an Out-of-State 1,365 MW Natural Gas-Fueled Combined Cycle Electric Generating Facility in Anderson County, South Carolina,* No. E-7, Sub 1357 (N.C.U.C. Sep. 28, 2026). According to the Commission's Corrected Order, the Class 4 estimated overnight cost of the Anderson CC unit totals $3.218 billion. Since this CC unit has an assumed capacity of 1,365 MW, the $/MW cost is $2.36 million. *Id.* at 19. Assuming a useful life of 35 years for a new CC unit, *Id.* at 15, the cost of the CC unit is approximately $67,357/MW-Year.

The estimated Stranded Generation Charge will be assessed based upon the net present value of the $67,357/MW-Year multiplied by the customer's Contract Demand assessed for each year during the period between the scheduled expiration of the DC Customer's initial term of service and the conclusion of the CC unit's 35-year useful life. The Security for Post-Order Service that must be delivered to DEC for this estimated Stranded Generation Charge must be delivered by the later of 36 months after the date of the issuance of this Order or 60 days after initiation of the Post-Order Service, unless a lower Commission-approved Stranded Generation Charge is developed based upon the standard methodology adopted following the completion of the stakeholder process, in which event Security for the lower Stranded Generation Charge must be delivered to DEC within 60 days after delivery of notice to the customer of the Commission's approval of the standard methodology applicable to determine the Stranded Generation Charge. If an DC Customer extends its electric service past the initial term of the ESA, the Security held by DEC will be reduced pro rata for each additional year of service beyond the initial term. If electric service continues for 35 years or longer, there will be no assessed Stranded Generation Charge at the conclusion of electric service.

Example of Estimated Stranded Generation Charge for a 500 MW Customer

If an DC Customer with a 500 MW Billing Demand executes an electric service agreement with DEC for an initial 15-year term, the DC Customer will be required to provide Security for an estimated Stranded Generation Charge of the net present value of approximately $673.6 million (500 MW multiplied by the $/MW-year value, multiplied by 20 years). Assuming a discount factor of 7.7%, or the WACC approved in this Order grossed up for tax purposes, this hypothetical 500 MW customer would be required to pay DEC a Stranded Generation Charge of approximately $338.2 million at the end of its 15-year contract, assuming it terminates service with Duke at that time. The customer will thus be required to post the $338.2 million security by the later of 36 months after issuance of this Order or 60 days after initiation of the Post-Order Service.

Ride-Through Requirements

The Commission gives substantial weight to the Public Staff's recommendation to adopt a requirement for a written plan that meets all applicable requirements of the North American Electric Reliability Corporation for managing incidental sudden disconnection and reconnection of load to avoid grid disturbances. Tr. vol. 14 at 137. In addition, in order to facilitate the flow of information between DEP and the customer regarding ride-through issues, the Commission has added disclosure and supplementation requirements with which the customer must comply.

Stakeholder Process

The Commission directs Duke to convene a stakeholder process to develop a methodology to allocate Network Upgrade costs and to develop a methodology to appropriately allocate stranded generation risk and cost.

The Commission shall determine the reasonable and appropriate stranded generation charge upon the conclusion of the stakeholder process in accordance with a procedure to be adopted after completion of the stakeholder process. If the final methodology results in a lower charge for a customer than the estimated amount, that customer's required payment or security, as applicable, shall be reduced accordingly.

Accordingly, within 12 months of the Commission's issuance of this Order, Duke shall file a report in Docket No. E-100, Sub 208 and the docket for this proceeding, detailing:

Network Upgrades

(a) One or more methodologies to be used for determining the portion of a given Network Upgrade to be directly assigned to a particular customer triggering or otherwise utilizing a network upgrade;

(b) Cost allocation between DC Customers that trigger upgrades on the same elements of Duke's system; and

(c) Any other issues relevant to implementing potential allocation methodologies, including, but not limited to, adjustments to demand

charges, minimum demand charges, exit fees, and other tariff provisions to account for customer CIACs.

Stranded Generation

(d) One or more methodologies to be used for (1) determining the conditions under which a stranded generation charge is appropriate, and (2) determining the appropriate amount and payment procedure for paying said stranded generation cost; and

(e) A mechanism to adjust the allocated stranded asset risk as the system changes over time (i.e., an adjustment that increases allocation if stranded asset risk increases due to DC Customers exiting the system or an adjustment that reduces allocation if stranded asset risk driven by DC Customers decreases over time).

Proposed stranded generation asset provisions should ultimately hold other ratepayers harmless for stranded asset costs and reflect reasonable and evidence-backed considerations such as projected load growth and overall system capacity.

If stakeholder participants disagree with the conclusions or recommendations included by Duke in the report, the Commission directs those parties to file comments outlining their areas of agreement with Duke, their areas of disagreement, and their proposed recommendations.

Prior Notice

Some parties have asserted in this proceeding that the first time the parties were given notice that a large load tariff might be considered in this proceeding was when the Public Staff filed their testimony on May 29, 2026. Some of these parties further contend that applying the tariff to ESAs signed before this date would constitute retroactive ratemaking. *See generally*, Microsoft Corporation's Request that the Commission Open a Separate Docket to Address a Large Load Tariff, LLT Stipulation, Duke Reply Comments, and Digital Reality Reply Comments. The Commission disagrees with this flawed premise.

In its Order Initiating Proceeding and Requesting Comments, issued June 6, 2025, of which the Commission takes judicial notice pursuant to N.C.G.S. § 62-65(b), the Commission expressly opened Docket No. E-100 Sub 208 (Sub 208 Proceeding), noting "the rising prevalence of large electric load additions in the region" and sought "information and recommendations as how to fairly and efficiently integrate large electric load additions." Tr. vol. 14, 113. Multiple intervenors, including many of the parties in this proceeding, provided comments and presented at the technical conference in October 2025. During this process a broad range of approaches, including a large load tariff and its consideration in a general rate case, was not only expressly discussed but recommended by several parties.

In the same docket, the Commission issued the Order Establishing Filing Requirements with Respect to Large Electric Loads on March 13, 2026, in Docket E-100, Sub 208, of which the Commission also takes judicial notice pursuant to

N.C.G.S. § 62-65(b). The order referenced the Comments of the North Carolina Utilities Commission before the Federal Energy Regulatory Commission, Docket No. RM26-4-000 (dated November 20, 2025), stating:

> As stated in its recent comments to the Federal Energy Regulatory Commission (FERC), the Commission notes that upcoming Commission proceedings, including the CPIRP proceedings and Duke's multi-year rate plan proceedings, will be appropriate venues for addressing issues related to how new large-load integration costs should be allocated within North Carolina's bundled-rate structure."

Tr. vol. 19, 130.

The Commission also questioned CIGFUR witness Collins regarding statements made by CIGFUR's counsel, Mr. Ledford, during the October 2025 technical conference that matters involving rate design, rate allocation, and cost allocation are traditionally addressed in a general rate case.

> Q. Mr. Collins, during the Commission's large load technical conference in E-100, Sub 208, last year, CIGFUR's counsel, Mr. Ledford, indicated that matters involving rate design, rate allocation, and cost allocation are traditionally addressed in a general rate case. Despite saying on page 26 of your testimony that a new large load tariff could materially affect cost allocation among classes and the assignment of interconnection and network upgrade costs, you now recommend this matter be addressed in a separate proceeding outside of this rate case. Why has CIGFUR now changed its position? They seem to have flipped.
>
> A. Well, a large load tariff was not presented in the Company's, you know, direct case. We agreed to a stipulation on cost of service without the existence of a large load tariff. And, you know, now we sit here today with, you know, a large load tariff presented by staff in their direct testimony, and then we also have one now from the Company in rebuttal. So, you know, we just have not had adequate time. We have a lot of, you know, concerns and questions that remain unanswered and that's the reason for the, you know, request and my testimony to move this to a separate proceeding.
>
> And, again, as I have stated in my testimony of this -- what happens here in this proceeding will likely set precedent for not only DEC customers but also DEP customers, and, as well, possibly Dominion Energy North Carolina customers. So, I think it's important for those customers to have due process and, you know, have their concerns. And on behalf of CIGFUR, you know, we're definitely willing to work with parties in the proceeding and do it on an expedited basis.

Tr. vol. 19, 345-46.

CIGFUR III witness Collins subsequently acknowledged, however, that consideration of the large load tariff in this proceeding was within the Commission's purview, while reiterating preference for it to be addressed in a separate proceeding. *Id.* at 347. The Commission agrees with CIGFUR III witness Collins that it is in the purview of the Commission to consider a large load tariff in this proceeding and finds that the separate expedited comments proceeding within this rate case provided further opportunity for parties (such as CIGFUR) to provide further input to the Commission on this vital policy issue.

The Commission also notes that the Public Staff's testimony addresses the Governor's Energy Policy Task Force interim report on February 15, 2026, which identifies "Develop Options for Large Load Tariffs" as the first of its nine recommendations and indicates that the Task Force would continue to study and refine those recommendations. Tr. vol 14, 122. The Commission further notes that participants in the Task Force included representatives of several intervening parties in this docket, including Duke, Google, Amazon, EDF, NCSEA, and the Public Staff[13].

Based on the foregoing, as well as the spirited national conversation surrounding large load integration over the past several years and the serious concerns expressed by existing Duke customers at public witness hearings in several proceedings, the Commission is somewhat at a loss as to why sophisticated parties that regularly appear before the Commission would not have expected this issue to be considered and decided in this general rate case. The Commission's proactive opening of the large load docket in June 2025, testimony from multiple parties on a proposed large load tariff, multiple days of cross-examination by intervenors, and an expedited comment process within this general rate case collectively provided a forum for thorough consideration of these issues. The parties were also given multiple opportunities to provide their perspective on this issue. This rigorous and painstaking process on this vital policy issue has culminated in the adoption of the DC Schedule by the Commission.

IT IS, THEREFORE, ORDERED as follows:

1. That the Comprehensive Settlement, the Partial Stipulation, the COSS Stipulation, the DLEP Stipulation, the Storm Cost Stipulation, the DCFC Stipulation, and the PIMs Settlement are accepted and approved in their entirety, as detailed in this Order;

2. That the depreciation rates based on the 2024 Depreciation Study as originally proposed, adjusted to reflect the Public Staff's proposed adjustments, including recommended adjustments to the 2024 Decommissioning Study, except that a 10% contingency factor shall be applied in lieu of the contingency percentages proposed by either DEC or Public Staff shall be, and are hereby approved;

3. That, as part of DEC's compliance filing, DEC's depreciation consultant shall apply the agreed-upon assumptions in his model to develop the final depreciation rates to be implemented by DEC, and DEC shall file the final depreciation rates, together with supporting workpapers, for review by the Public Staff;

[13] *See* https://governor.nc.gov/documents/files/nc-energy-policy-task-force-2026-report/open.

4. That the exclusion of asbestos decommissioning costs related to the Bad Creek and Bridgewater hydroelectric plants from the 2024 Depreciation Study, as reflected in the proposed depreciation rates of Public Staff witness McCullar, shall be, and is hereby approved;

5. That DEC's request for an accounting order to defer to a regulatory asset 100% of the impact of accelerating the depreciation of DEC's subcritical coal plants resulting from the 2021 Depreciation Study, for an annual deferral of $13.956 million on a North Carolina retail basis, for future securitization, shall be, and is hereby approved;

6. That DEC's plant-related capital investments in the base period general/intangible, transmission, distribution, fossil/hydro, nuclear, solar, and storage assets, as adjusted in the Partial Stipulation and Comprehensive Settlement, shall be included in rates for the base period;

7. That DEC's requests to amortize costs associated with its CCR obligations incurred through March 31, 2026, over an eight-year period and to continue the deferral of any CCR costs incurred subsequent to March 31, 2026, shall be, and are hereby approved;

8. That the Commission authorizes the continuation of the CCR deferral in accordance with the CCR Settlement;

9. That the agreed-upon accounting adjustments outlined in the Partial Stipulation and Comprehensive Settlement shall be, and are hereby, approved;

10. That DEC's rates during the MYRP Rate Period shall reflect a rate of return on equity of 9.80%, an embedded cost of debt of 4.57%, and a capital structure consisting of 53% common equity and 47% long-term debt, for a rate of return of 7.34%;

11. That DEC shall recover the balance of the bad debt deferral, including actual deferral amounts from July 1, 2023, through June 30, 2026, plus an estimated deferral amount of $12 million for the period from July 1, 2026, through December 31, 2026, less a one-time impairment of $17 million removed in June 2026, over an amortization period of five years;

12. That the bad debt deferral shall include a debt-only return during the deferral period, with no rate base treatment (no return) during the amortization period;

13. That DEC shall continue to defer the difference between actual bad debt expense and the amount in customer rates for the period from July 2026 through December 2026, subject to a $12 million cap, and if the actual deferral for July 2026 through December 2026 is less than $12 million, DEC shall return the difference to customers in the next rate case;

14. That DEC is allowed to collect in rates its North Carolina Retail normalized annual level of storm costs in the amount of approximately $34.194 million;

15. That DEC shall amortize the regulatory liability of approximately $152,000 for storm securitization servicing and administration fees and the regulatory asset of

approximately $118,000 for upfront bond issuance costs related to storm securitization over two years;

16. That the Hurricane Helene over-securitization amount of $141.557 million, plus a return of $12.639 million, shall be netted against the Winter Storm Fern incremental storm costs of $99.910 million (net of the applicable storm deductible), and the resulting $54.287 million credit to customers shall be amortized over 18.75 years, with the unamortized balance included in rate base;

17. That the Winter Storm Fern incremental costs shall not incur any carrying costs;

18. That DEC shall use the traditional method for calculating the incremental storm O&M costs for 2026 through DEC's next general rate case;

19. That DEC's request to establish a storm reserve is deemed withdrawn, and no storm reserve shall be established in this proceeding;

20. That DEC shall use annual compounding of the return accrued during the deferral period for the COVID bad debt, CCR, and Hurricane Helene (post-securitization bond issuance) deferrals;

21. That DEC shall use annual compounding when accruing a return, if applicable, on deferrals (both regulatory assets and liabilities) and riders through DEC's next two general rate cases, which may be achieved either by applying monthly compounding at a discounted rate or by applying annual compounding at the annual rate;

22. That the Commission authorizes DEC to establish a regulatory asset to defer and amortize expenses related to the expiring Buck Pipeline Lease as provided in the Partial Stipulation. The resulting regulatory asset will not accrue a return, and ratemaking treatment will otherwise remain as it is today, with amortization over the remaining life of the plant;

23. That DEC's motion to consolidate its request for an accounting order relating to L2 public charging infrastructure in Docket No. E-7, Sub 1355 with this docket is granted;

24. That the Commission authorizes DEC to establish a regulatory asset for the remaining net book value of the L2 public charging infrastructure deployed under the Phase E1 ET Pilots, less any proceeds received from the sale of such assets, and to amortize such regulatory asset using the depreciation expense currently included in customer rates until the regulatory asset balance reaches zero;

25. That the Commission authorizes DEC to recover over a two-year amortization period the deferred revenue requirement impacts, included benefits and costs, associated with the IRA and the IIJA, including the impacts of IIJA grants that were reflected in the rates approved in the Sub 1276 Order but not ultimately received and the costs incurred to pursue the grants;

26. That the Commission authorizes DEC's request to continue to defer incremental costs related to pursuing grant funding; any incremental costs related to grants that are not ultimately received shall remain in a regulatory asset account to be recovered in a future rate case;

27. That, if DEC obtains a grant, DEC shall record the grant amount received, net of the associated incremental costs to achieve the grant, as an offset to the capital project receiving the grant, and, if that project was in service as of March 31, 2026, or is a MYRP2 project approved in this Order, DEC shall also defer to a regulatory liability the depreciation and return amounts related to the net grant amount to return to customers in a future rate case; provided, however, that DEC's accounting for the DOE grant for the Belews Creek Coal Reliability Assurance Initiative shall be governed by § II.20 of the Comprehensive Settlement;

28. That DEC's Lead-Lag Study filed as Speros Exhibit 2 shall be, and is hereby, approved for purposes of calculating the cash working capital amounts to be included in DEC's rates;

29. That DEC shall establish a process for future rate cases to update capital additions for customer interconnection facilities and the associated revenue for such customers through the same period, for review by the Commission in the next rate case;

30. That the Commission finds DEC's quality of service to be adequate;

31. That the shareholder financial contribution, detailed in the Comprehensive Settlement shall be, and is hereby approved;

32. That the revisions to rate schedules, as proposed by DEC or as modified by the revenue adjustments set forth in the Comprehensive Settlement or otherwise modified herein shall be, and are hereby approved;

33. That the revisions to the service riders, as proposed by DEC or otherwise specifically modified herein, shall be, and are hereby approved;

34. That the Basic Customer Charges, as set forth in the Comprehensive Settlement, shall be, and are hereby approved;

35. That Schedule ES shall be closed to new residential customers effective January 1, 2027;

36. That the Schedule ES discount shall be reduced from 5% to 2.5% beginning January 1, 2028, and Schedule ES will close on March 31, 2029;

37. That the NMB and RSC riders shall be modified as proposed by Public Staff;

38. That DEC shall establish a DCFC Pilot in accordance with the DCFC Stipulation;

39. That DEC's proposed MYRP, reflecting the projected costs associated with the Transmission, Distribution, GP&I, Fossil/Hydro, Nuclear, Solar, and Storage as adjusted by the Partial Stipulation and Comprehensive Settlement, as reflected in Abernathy Comprehensive Settlement Exhibits 1 and 2, is just and reasonable and adopted in its entirety;

40. That within 180 days of the issuance of this Order, DEC shall file the Cost-Benefit Report;

41. That DEC shall file the final annual revenue requirements for Rate Years 1 and 2 consistent with the Commission's findings and rulings herein within ten days of the issuance of this Order in the same format as Jiggetts Comprehensive Settlement Exhibits 1 and 2. DEC shall work with the Public Staff to verify the accuracy of the calculations;

42. That DEC is authorized to adjust its rates and charges in accordance with the Partial Settlements, Partial Stipulation, DEC Agreement and Stipulation of Settlement of Storm Costs with the Public Staff, Comprehensive Revenue Requirement Agreements and Stipulations of Settlement, and findings in this Order effective for service rendered on and after the date following the Commission's issuance of an Order accepting the calculations required by Ordering ¶ 41;

43. That DEC's proposed residential decoupling mechanism as modified by the Comprehensive Settlement is consistent with the PBR Statute and Commission Rule R1-17B and is hereby approved;

44. That DEC's proposed ESM, as modified by the Comprehensive Settlement, is consistent with the PBR Statute and Commission Rule R1-17B and is hereby approved;

45. That DEC's proposed PIMs, as modified by the PIMs Settlement, are consistent with the PBR Statute and Commission Rule R1-17B and achieve a measured balance between encouraging behavior and risk/reward to utility shall be, and are hereby approved;

46. That DEC will not seek to true-up any additional fuel and fuel related costs prior to January 1, 2025, that are not already included in the current DEC fuel rider, or in the pending DEC fuel rider case for rates effective September 1, 2026;

47. That DEC will meet with the Stipulating Parties to discuss the appropriate calculation of interest under N.C.G.S. § 62-133.2;

48. That DEC shall adhere to the reporting obligations outlined in § II and § III of the Comprehensive Settlement and § IV of the Partial Stipulation;

49. That DEC shall implement the MYRP Refund Mechanism and Rider as proposed in the Comprehensive Settlement;

50. That DEC shall continue and expand the Nuclear PTC Rider to include other available PTCs and rename it the PTC Rider, as modified by the Partial Stipulation, under

which DEC shall add back non-outage incremental O&M for prevailing wages to the test year and discontinue all prevailing wage deferrals effective January 1, 2027;

51. That DEC shall establish a new tranche of its RAL Rider, Rider RAL-2, to refund to customers over a two-year period the net over-amortization of expired regulatory assets and liabilities;

52. That DEC shall eliminate the EDPR Rider and recover costs associated with the EDPR program in base rates;

53. 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;

54. That as part of DEC's compliance filing, DEC's base fuel factors shall be updated, in coordination with the Stipulating Parties, to reflect the Commission's forthcoming Order in Docket No. E-7, Sub 1334;

55. That the Chief Clerk is directed to close Docket No. E-7, Sub 1355;

56. That as part of DEC's compliance filing, DEC shall submit the final list of MYRP2 projects approved in this Order;

57. That as part of DEC's compliance filing, DEC shall submit updated RDM and ESM templates reflecting the terms of the Comprehensive Settlement;

58. 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 new rates. DEC shall also make a copy of the notice prominently available on its website and provide an email with an electronic link to the notice for all customers receiving bills electronically;

59. That the DC Schedule is hereby approved and adopted, effective upon the issuance of this Order, except that any Rate modifications otherwise applicable to the proposed Schedule HLF implemented pursuant to this Order, shall also be incorporated into the DC Schedule;

60. That DEC shall file with the Commission in Docket No. E-100, Sub 208 within ten days of execution all ESAs and ESA amendments for Post-Order Service;

61. That DEC shall propose within 90 days of this Order a modification to DEC's economic development riders to allow service on the DC Schedule, maintaining proportionate impacts across rate schedules;

62. That DEC shall initiate a stakeholder process that includes all intervening parties and entities that have been granted amicus curiae status who wish to participate in the process to address and develop a standard ESA and standard methodologies for determining the amount of CIAC to be directly assigned from TNU costs and for

determining Stranded Generation Charges, as well as curtailment alternatives and relevant parameters to evaluate the proposed alternatives;

63. That the interim standard ESA attached to this Order as Appendix B is hereby approved and adopted, effective with the issuance of this Order;

64. That the proposed standard ESA that is created in the stakeholder process shall be submitted to the Commission for review within 30 days after the issuance of this Order;

65. That the proposed standard methodologies for determining Stranded Generation Charges and the amount of CIAC to be directly assigned from TNU costs, as well as curtailment alternatives, shall be submitted to the Commission for review within 12 months after issuance of this Order, and DEC shall in the interim file quarterly status reports with the Commission as to the progress of the stakeholder process in this docket and Docket No. E-100, Sub 208;

66. That DEC shall treat DC Customers as a class for reporting purposes and track the revenues and costs of DC Customers following the issuance of this Order; and

67. That DEC shall provide an DC Customer class cost-of-service analysis in the next rate base rate case and evaluate class allocation methodologies for DC Customers, including with respect to assignment or allocation of generation costs, which analysis will assess the cost-of-service impacts with and without the use of a separate DC Customer class.

ISSUED BY ORDER OF THE COMMISSION.

This the 16th day of November, 2026.

NORTH CAROLINA UTILITIES COMMISSION

Tamika D. Conyers, Deputy Clerk

Commissioner Donald R. van der Vaart did not participate in this proceeding.

Commissioners Floyd B. McKissick, Jr. and John W. Gajda, concurring.

DOCKET NO. E-7, SUB 1329
DOCKET NO. E-7, SUB 1355

Commissioners Floyd B. McKissick, Jr. and John W. Gajda, concurring:

We concur in the Commission's Order Accepting Stipulations in Part, Granting Partial Rate Increase, Granting Accounting Order, And Requiring Public Notice, however we believe that a large load tariff should be applicable to all large load users, not just data centers. We believe that the appropriate resolution of the significant concerns raised in this docket about the unprecedented size and speed of the new demand for power coming from prospective large load customers across our State would be to adopt a large load tariff applicable to all customers that meet specified load size and load factor thresholds, rather than adopting a tariff addressing only loads greater than 50 MW who meet the Commission's definition of a "data center." While we agree with other aspects of the Order, including the rate provisions and risk mitigation provisions adopted in the Order, we believe these provisions should apply to all large loads, not just data centers, and we believe the Commission could, and should, have crafted a large load tariff that strikes a better balance between the interests of protecting retail customers and fostering economic development.

We write separately to question why the majority sees no need to subject other large load customers who may have equal or larger impacts on the system in terms of extraordinary and potentially stranded costs to similar if not equally strong ratepayer protection measures. Further, we are concerned that the distinction drawn between data centers and other large load customers may be discriminatory.

If the concern of the majority is to assure that large scale manufacturing concerns are not adversely impacted by a large load tariff, then that concern could be effectively addressed with a waiver provision that allows for exceptions for projects that have substantial long term economic development impacts upon our State, such as large-scale employers. It is due to these factors that we respectfully reluctantly concur.

/s/ Floyd B. McKissick, Jr.
Commissioner Floyd B. McKissick, Jr.

/s/ John W. Gajda
Commissioner John W. Gajda

APPENDIX A

Duke Energy Carolinas, LLC NC Original Leaf No. __
(North Carolina Only)

DC RATE SCHEDULE AND SUPPLEMENTAL TARIFF PROVISIONS
(DC SCHEDULE)

AVAILABILITY

Available only to customers that qualify as a DC Customer. Each DC Customer is required to take service on this Schedule. Customer facilities under common ownership or control that are operationally or contractually integrated or interconnected, whether located on one or multiple parcels, shall be treated as a single DC Customer for purposes of this Schedule.

The entirety of each DC Customer's and New DC Customer's Billing Demand and energy consumption will be subject to the Rate Provisions of this Schedule. Each customer's Post-Order Service will be subject to the Risk Mitigation Provisions (as defined hereinbelow) of this Schedule.

An Existing Customer (who does not qualify as a DC Customer as of November 16, 2026) will become a DC Customer upon contracting to energize, or energizing (whichever is earlier) Qualifying Incremental Demand.

Power delivered under this schedule shall not be used for resale or exchange or in parallel with other electric power or as a substitute for power contracted for or which may be contracted for, under any other schedule of the Company.

The obligations of the Company in regard to supplying power are dependent upon its securing and retaining all necessary rights-of-way, privileges, franchises and permits, for the delivery of such power. The Company shall not be liable to any customer or applicant for power in the event it is delayed in or is prevented from, furnishing the power by its failure to secure and retain such rights-of-way, rights, privileges, franchises and permits.

Each New DC Customer energizing, or seeking to energize, Post-Order Service shall execute a Commission-approved form ESA. Each Existing Customer or Existing DC Customer initiating Post-Order Service in a manner that is not specifically contemplated in, and authorized by, the customer's existing ESA shall execute either the form ESA or an amendment to the existing ESA that incorporates all pertinent provisions of the form ESA for the Post-Order Service prior to initiation of the service.

DEFINITIONS

"Applicable Demand" means the higher of the customer's Contract Demand (as defined hereinbelow) or Billing Demand (as defined hereinbelow).

"Company" means Duke Energy Carolinas, LLC.

"Commission" means the North Carolina Utilities Commission.

"Common ownership" means at least a 50 percent interest of the businesses are owned or controlled, directly or indirectly, by the same entity (i.e., person, corporation, partnership, joint venture or other entity).

"Computational Load" means the demand for, or usage of, electricity associated with storing, retrieving, managing, processing, and/or disseminating electronic data and information, including, but not limited to, activities and information technology infrastructure, such as servers, processors, storage, and networking

gear, used for, or involved in, building, running, and delivering applications and services that support, or otherwise involve, artificial intelligence, cloud computing, cryptocurrencies, and/or any other digital services.

"Contract Demand" means the maximum kilowatt demand which the Company is required to supply to the customer under the Electric Service Agreement.

"Data Center" means a facility, campus of facilities, or array of interconnected facilities used by a person or an entity or other business enterprise for which either (a) the primary or exclusive demand of the facility(ies) is Computational Load; or (b) the Computational Load is, or is expected to be, at least 50 MW.

"DC Customer" or "Data Center Customer" means a customer with an Applicable Demand of at least 50 MW that functions, or is expected to function, as a Data Center.

"Dedicated Facilities" means all transmission, distribution, and interconnection facilities used for providing Post-Order Service electric service to the DC Customer which solely benefit the DC Customer. Dedicated Facilities include Extra Facilities.

"Discount Factor" means the utility's weighted average cost of capital approved by the Commission.

"ESA" or "Electric Service Agreement" means the contract that a DC Customer must execute with the Company before any Required Facilities Costs may be incurred by the Company, except as otherwise provided in this Schedule.

"Existing Customer" means a retail customer taking electric service from the Company that does not qualify, as of November 16, 2026, as a DC Customer. (As stated above, an Existing Customer will become a DC Customer upon contracting to energize, or energizing (whichever is earlier) Qualifying Incremental Demand.)

"Existing DC Customer" means a retail customer taking service from the Company that qualifies, as of November 16, 2026, as a DC Customer.

"Extra Facilities" means all customer-requested installed by the Company to supply electricity to the DC Customer for Post-Order Service in a special manner requiring facilities over and above those normally provided by the Company, including but not limited to interconnection, distribution, transmission, and substation facilities.

"Incremental Demand" means the amount of the increase in a customer's Applicable Demand during the Contract Period after November 15, 2026, relative to the customer's Applicable Demand prior to November 16, 2026.

"New DC Customer" means a retail customer of the Company that initiates (or reinitiates) electric service after November 15, 2026 that meets the qualifications of a DC Customer.

"Post-Order Service" means each of the following: (i) the Applicable Demand of each New DC Customer; (ii) the Qualifying Incremental Demand of each Existing Customer; and (iii) the Subsequent Incremental Demand of each DC Customer and New DC Customer, as applicable.

"Qualifying Incremental Demand" means the amount of Incremental Demand of a customer, whether implemented in a single instance or in aggregate as a result of more than one increase in Applicable

Demand, sufficient to increase the customer's Applicable Demand to 50 MW or more if the Customer qualifies as a Data Center at any time after November 15, 2026.

"Rate Provisions" mean the following provisions of this schedule: Availability, Definitions, Type of Service, Rate, Riders, Determination of Billing Demand, Power Factor Correction, Payment, Conflict, and Reliability and Curtailment.

"Remainder Years" means the period beginning on the later of (a) the applicable Contract Period for the Post-Order Service or (b) the expiration of the DC Customer's continued service on the DC Schedule, and ending on the last day of the 35th year following the initiation of electric service on the DC Schedule.

"Risk Mitigation Provisions" mean the following provisions of this schedule: Contract Period, Minimum Billing Demand, Required Facilities Costs, Notice of Contract Reduction or Early Termination, Liquidated Damages, Stranded Generation Charge, Security Requirements, and Ride-Through Requirements.

"Security" means collateral in the form of either non-interest bearing cash security or standby letter(s) of credit, each in a form and from an entity (as applicable) reasonably acceptable to the Company in its sole discretion or a parent guaranty from a parent with an S&P Long Term Issue Credit Rating of at least A- (or the equivalent from another recognized credit rating agency) that unconditionally and irrevocably guarantees to the Company the prompt and full payment and performance of the DC Customer obligations and liabilities imposed by this DC Schedule; provided that in order to qualify as Security any standby letter of credit must issued by a U.S. commercial bank with total assets of at least $10 billion having a general long-term senior unsecured debt rating of A- or higher as rated by S&P Global Ratings, Inc. or A3 or higher as rated by Moody's Investors Service, Inc. or other financial institution reasonably acceptable to the Company.

"Subsequent Incremental Demand" means the increase or aggregate increases in Applicable Demand (a) after November 15, 2026 of each Existing DC Customer, or (b) after the establishment (or reestablishment) of initial electric service for each New DC Customer.

"Transmission Network Upgrades" means all incremental transmission facilities, other than Dedicated Facilities and Extra Facilities, needed to provide Post-Order Service electric service to the DC Customer while maintaining reliable service to the remainder of the grid.

TYPE OF SERVICE

Except as otherwise provided herein, the Company will furnish 60 Hertz service through one meter, at one delivery point, at one of the following approximate voltages, where available:

Single-phase, 120/240 volts, 120/208 volts, 240/480 volts or other available single-phase voltages at the Company's option; or
3-phase, 208Y/120 volts, 460Y/265 volts, 480Y/277 volts; or 3-phase, 3-wire, 240, 460, 480, 575, or 2300 volts: or
3-phase, 4160Y/2400, 12470Y/7200, or 24940Y/14400 volts; or
3-phase voltages other than those listed above may be available at the Company's option if the size of the customer's contract warrants a substation solely to serve that customer, and if the customer furnishes suitable outdoor space on the premises to accommodate a ground-type transformer installation, or substation, or a transformer vault built in accordance with the Company's specifications.

If a customer has two or more facilities under common ownership or control that are operationally or contractually integrated, whether located on one or multiple parcels, each such facility may have its own meter, but the meters will be aggregated for purposes of determining whether the customer's Applicable Demand qualifies for DC Customer status, Qualifying Incremental Demand, or Subsequent Incremental Demand.

The type of service supplied will depend upon the voltage available. Prospective customers should determine the available voltage by contacting the nearest office of the Company before purchasing equipment.

Motors of less than 5 H.P. may be single-phase. All motors of more than 5 H.P. must be equipped with starting compensators. The Company reserves the right, when in its opinion the installation would not be detrimental to the service of the Company, to permit other types of motors.

RATE

I. Basic Customer Charge per month	$34.00		
II. Energy Charge per kWh, per month	2.1775¢		
III. Demand Charge per kW of Billing Demand, per month	Secondary	Primary	Transmission
	$28.32	$24.61	$22.28

Demand Charge is based on delivery voltage. Secondary service includes delivery voltage less than or equal to 600 volts. Primary service includes delivery voltage greater than 600 volts but less than 44 kV. Transmission service includes delivery voltage greater than or equal to 44 kV.

RIDERS

The Renewable Energy Portfolio Standard (REPS) Rider charge shown on Leaf No. 68 and the Customer Assistance Recovery (CAR) Rider charge shown on Leaf No. 144 will be added to the monthly bill for each agreement for service under this schedule.

The following Riders are applicable to service supplied under this schedule. The currently approved cents/kWh rider increment or decrement must be added to the cents/kWh rates shown above to determine the monthly bill.

Leaf No. 60	Fuel Cost Adjustment Rider
Leaf No. 62	Energy Efficiency Rider
Leaf No. 64	Existing DSM Program Costs Adjustment Rider
Leaf No. 105	BPM Prospective Rider
Leaf No. 106	BPM True-Up Rider
Leaf No. 127	CPRE Rider
Leaf No. 131	EDIT-4 Rider
Leaf No. 148	ESM Rider
Leaf No. 149	PIM Rider

A Storm Securitization (STS) Rider charge will be added to the monthly bill based on the currently approved cents/kWh incremental rate as shown in Leaf No. 133.

DETERMINATION OF BILLING DEMAND

The Billing Demand each month shall be the largest of the following:

1. The maximum 30-minute demand during the current billing month
2. 90% of the maximum 30-minute demand during the previous 12 billing months including the current billing month
3. 75% of the Contract Demand, until such time as the Billing Demand first equals or exceeds the effective Contract Demand
4. 50,000 kW

POWER FACTOR CORRECTION

When the average monthly power factor of the customer's power requirements is less than 85 percent, the Company may correct the integrated demand in kW for that month by multiplying by 85 percent and dividing by the average power factor in percent for that month.

PAYMENT

Bills under the Schedule are due and payable on the date of the bill at the office of the Company. Bills are past due and delinquent on the 25th day after the date of the bill. If any bill is not so paid, the Company has the right to suspend service. In addition, all bills not paid by the 25th day after the date of the bill shall be subject to a one percent (1%) late payment charge on the unpaid amount. This late payment charge shall be rendered on the following month's bill, and it shall become part of and be due and payable with the bill on which it is rendered.

CONFLICT
In case of a conflict between this rate schedule and the Service Regulations, the provisions of this rate schedule shall prevail.

RELIABILITY AND CURTAILMENT

During any applicable load ramp period plus one year, each customer shall be subject to one of the following requirements:

a) Interruptibility of 95% of contract load for up to 50 hours per year for the load ramp period plus one year of service;
b) Interruptibility of 50% of contract load for up to 100 hours per year for the load ramp period plus one year of service; or
c) Alternative Commission-approved options that accelerate capacity resources on the utility system during the integration of the customer's full contract demand.

Interruption (curtailment) will be limited to a maximum of six (6) hours per day. The customer will not be compensated for curtailment under this provision, and any voluntary load reduction by the customer when a curtailment event has not been ordered by the Company will not count towards curtailment hours.

RISK MITIGATION PROVISIONS:

CONTRACT PERIOD

Each DC Customer with a Post-Order Service Applicable Demand of less than 100 MW shall enter into an ESA (or ESA amendment, as applicable) to purchase electricity from the Company for a minimum original contract term of the greater of (a) 10 years and (b) 5 years plus the load ramp period. The minimum initial contract term to initiate Post-Order Service of 100 MW or more will be the greater of (a) 15 years and (b) 10 years plus the load ramp period. At the expiration of the contract term, ESAs will be automatically extended for one-year terms unless the customer notifies the Company in writing of its intent to terminate the contract at least 24 months in advance of such termination.

MINIMUM BILLING DEMAND

Billing Demand will not be less than 75% of Contract Demand for all demand charges in this DC Schedule. This provision shall apply as soon as Contract Demand is in effect. This provision supplements the billing demand provisions in this DC Schedule.

REQUIRED FACILITIES COSTS

Dedicated Facilities: The customer will provide advanced funds equal to the estimated total cost of Dedicated Facilities as a contribution in aid of construction (CIAC), within 60 days of execution of its Letter Agreement with the Company for Post-Order Service. The customer will further provide all necessary additional funds to cover the actual cost of such Dedicated Facilities, to the extent actual costs exceed the advanced funds. If a customer executed a Letter Agreement more than 30 days before November 16, 2026, then the customer shall pay the remaining total costs of Dedicated Facilities as CIAC within 60 days after November 16, 2026. If the customer does not execute an ESA pursuant to the requirements of the Letter Agreement, such advanced funds, less any actual costs incurred by the Company related to the customer's Dedicated Facilities, will be refunded to the customer. If an ESA is terminated prior to energization, any unspent amounts from the advanced funds in excess of costs the Company has incurred related to the Dedicated Facilities at the time of such early termination will be retained by the Company and applied towards the liquidated damage liability owed by customer arising from the termination.

Transmission Network Upgrades: The customer will deliver to the Company a deposit in the form of a letter of credit that qualifies as Security in an amount equal to the Company's estimated total cost of Transmission Network Upgrades necessary to serve the customer load ("Network Upgrades") within 60 days of execution of the ESA. If a customer executed an ESA more than 30 days before November 16, 2026, then the customer shall deliver the letter of credit within 60 days after November 16, 2026. The customer will provide additional deposits through the letter of credit to cover the actual cost of Transmission Network Upgrades to the extent that the actual cost of Transmission Network Upgrades exceeds the original deposit. After the customer meets or exceeds an actual monthly Billing Demand of 75% of full Contract Demand for three (3) consecutive billing months, the letter of credit required to cover and secure the costs of the Network Updates will be reduced once per year on a ratable basis over the remaining term of the ESA. In the event of early termination pursuant to the terms of the ESA, the Company will draw on the letter of credit to recover the remaining net book value, as of the date of termination, of Transmission Network Upgrades as CIAC. If a portion of Transmission Network Upgrades are direct assigned to the customer based upon a Commission-approved estimate or methodology ("Customer Portion"), the Customer Portion will be paid by the customer as CIAC, and the letter of credit will be reduced by an equal amount. If the CIAC amount is a Commission-approved estimate rather than an amount derived using a Commission approved standard methodology, then the

amount of the approved estimate must be paid to the Company no later than 36 months after the initiation of Post-Order Service, unless a lower Customer Portion is determined based upon a Commission approved methodology adopted during the 36 month period, in which event the lower Customer Portion must be paid to the Company within 60 days after delivery of notice to the customer of the Customer Portion due based upon the Commission's approved standard methodology.
Note all CIAC amounts will be grossed up for tax implications.

NOTICE OF CONTRACT REDUCTION OR EARLY TERMINATION

For a customer request for a contract demand reduction or early termination, and subject to the customer's payment of any applicable liquidated damages, the customer must notify the Company in advance by the applicable period below. All billing requirements including minimum billing demand charges and Extra Facilities Charges will apply during the notification period. Termination or contract demand reduction prior to energization requires such advance notification, but minimum billing demand charges do not apply to the applicable monthly periods within the notification period occurring prior to energization. For a reduction in contract demand, the applicable notification period is based on the requested reduction in full contract demand. For early termination, the applicable period is based on the full contract demand of the ESA.

- Below 250 MW: 24 months
- Between 250 MW and 499 MW: 36 months
- 500 MW or more: 48 months

LIQUIDATED DAMAGES

Liquidated Damages for Early Termination: Liquidated damages for early termination arising from customer notification and/or customer default will be equal to (1) 100% of minimum billing demand charges at the customer's annual contract demand and Extra Facilities Charges during the applicable notification period, plus (2) the net present value of remaining Extra Facilities Charges under the remaining term of the contract after expiration of the notification period, plus (3) 25% of remaining minimum billing demand charges at the customer's annual contract demand under the remaining term of the contract after expiration of the notification period. The customer's actual payments of minimum billing demand charges and Extra Facilities Charges during the notification period will credit against the liquidated damage liability calculated hereunder.

Liquidated Damages for Contract Reduction: Liquidated damages for a contract demand reduction will be equal to 100% of the minimum billing demand charges and Extra Facilities Charges during the applicable notification period, plus the termination liquidated damages under the original contract (measured in the contract year of the reduction), minus the termination liquidated damages under the new contract based on the reduced contract demand (measured in the contract year of the reduction). The customer's actual payments of demand charges or minimum billing demand charges (as applicable) and Extra Facilities Charges during the notification period will credit against the liquidated damage liability calculated hereunder. After the 6th anniversary of initial provision of service under this Schedule, the customer may provide notice to reduce contract demand by up to 20% but no greater than 200 MW, one time, without incurring liquidated damages.

STRANDED GENERATION CHARGE

A Stranded Generation Charge will be imposed upon the termination of a customer's electric service from the Company. The estimated Stranded Generation Charge will be computed prior to the energization of

Post-Order Service and will equal the net present value over the Remainder Years of the product of (a) the Post-Order Service maximum Contract Demand (in MW) over the Contract Period multiplied by (b) $67,357 per MW-Year for each year of the Remainder Years. The net present value shall be computed using the Discount Factor. The Security for the estimated Stranded Generation Charge must be delivered to the Company by the later of November 16, 2029 for Post-Order Service or 60 days after energization of the Post-Order Service, unless a lower Stranded Generation Charge derived from a Commission-approved standard methodology is adopted prior to the delivery of the Security, in which event the approved methodology-based Stranded Generation Charge must be delivered to the Company within 60 days after delivery of notice to the customer of the new Stranded Generation Charge based upon the Commission's approved standard methodology. If a customer extends its electric service past the initial term of its ESA, the Security held by the Company and the Stranded Generation Charge due at the termination of electric service will be reduced pro rata for each additional continued year of electric service beyond the initial term. If electric service continues for 35 years or longer, there will be no assessed Stranded Generation Charge at the conclusion of electric service.

SECURITY REQUIREMENTS

The customer must deliver to the Company Security equal to the applicable liquidated damages for early termination. Security for the applicable liquidated damages for early termination must be delivered to the Company before the energization of Post-Order Service. If a customer executed an ESA prior to November 16, 2026, but will be receiving Post-Order Service, the date by which any applicable Security for liquidated damages must be delivered to the Company associated with the Post-Order Service, if not otherwise specified in the existing ESA, will be the earlier of (a) March 16, 2027, or (b) 12 months before the planned energization date of the Post-Order Service. Except as otherwise provided in this Schedule, Security for the Stranded Generation Charge based upon a Commission-approved standard methodology and Security for Transmission Network Upgrades must be delivered to the Company within 60 days after execution of the ESA for Post-Order Service.

RIDE-THROUGH REQUIREMENTS

Before the initiation of Post-Order Service, each customer must provide to the Company, and receive written approval from the Company of:

1. the written disclosure of the customer's ride-through and reconnection protocols and capabilities; and
2. a written plan that meets all applicable requirements of the North American Electric Reliability Corporation for managing incidental sudden disconnection and reconnection of load to avoid grid disturbances.

Each customer must also provide to the Company: (a) written updates regarding each proposed change to such information at least 10 days prior to implementation of the change; and (b) comprehensive responses, including supporting records, to requests from the Company for additional information regarding relevant protocols, capabilities, and plans.

APPENDIX B

Duke Energy Carolinas, LLC
(North Carolina Only)

NC Original Leaf No. __

INTERIM STANDARD FORM OF ELECTRIC SERVICE AGREEMENT

Application For Supply of Electricity

1. The undersigned, hereinafter called "Customer," hereby applies to Duke Energy Carolinas, LLC, hereinafter called "Company," for the supply of all purchased electricity needed for the operation of Customer's facility (or integrated facilities) located on _____ in accordance with the load ramp provided in Exhibit A; the terms hereof; the Company's DC Schedule, and its Service Regulations, a copy of each being attached hereto and hereby made a part hereof.

2. Electricity supplied hereunder shall be in the form of [phase,_ wires], alternating current of approximately [hertz] frequency and at approximately [kV]. The maintenance by the Company of electricity available to Customer in the above form, and in the quantity applied for, at the point(s) of delivery defined below, shall constitute deliver by the Company of the electricity applied for whether or not Customer makes any use thereof.

3. The point(s) of delivery for service supplied hereunder will be as described in Exhibit B.

4. Upon the acceptance hereof by the Company, evidenced by the signature of its authorized representative appearing below, this Application shall be an Agreement for the supply of the electricity applied for. The date of such Company signature shall be the "Effective Date".

5. The initial Contract Period shall begin on the Energization Date and end on the [_____] anniversary of the Energization Date, and thereafter the term shall be extended from year to year unless either party notifies the other parties in writing of its intent to terminate the contract at least 24 months in advance of such termination. "Energization Date" means the date that Customer first takes electricity from the Company.

6. Bills rendered for the electricity supplied hereunder are payable at the Company's Charlotte NC office at Duke Energy Central Cash Remittance, PO Box 1094, Charlotte, NC 28201-1094. Bills may be separately rendered based on customer points of delivery, subject to mutual written agreement of Company and Customer; provided however, for the avoidance of doubt, all Customer demand and usage shall be aggregated and totalized to calculate applicable demand and energy charges under the DC Schedule and riders.

7. Customer's Contract Demand is [ ], which shall be based upon the anticipated demand and serves as the maximum kilowatt demand which the Company is required to supply to Customer. Customer's computation load, as defined in the DC Schedule is, or is expected to be [ ]. The Company will diligently plan for, install, and maintain all the facilities necessary to meet all of Customer's electricity need under this Agreement in accordance with Exhibit A following the Company's receipt of the ESA Deposit and payment in full for the Dedicated Facilities.

8. The terms and conditions of electric service under this Agreement shall be subject to the DC Schedule (and any successor tariff provisions) and this Agreement shall be interpreted in a manner that is consistent with the DC Schedule. This Agreement and the applicable Schedule, Riders, and Service Regulations hereto attached are subject to changes or substitutions, either in whole or in part, made from time to time by a legally effective filing of the Company with, or by order of, the North Carolina Utilities Commission, and each party to this Agreement reserves the right to seek changes or substitutions, in accordance with law, from such regulatory authority. Unless specified otherwise, any such changes or substitutions shall become effective immediately and shall nullify all prior provisions in conflict therewith.

9. The Company's obligation to deliver electricity as covered in this Agreement on the agreed upon date is contingent upon the Company receiving the rights-of-way and receiving the necessary equipment in sufficient time to install it on or before that date.

10. Customer shall be responsible for installing and maintaining devices adequate to protect against damages caused by irregularities or outages on the Company's system, regardless of the cause or fault, including devices to protect against voltage fluctuations and single phasing.

11. The Company is not liable for any loss, cost, damage, or expense to any customer occasioned by any failure to supply electricity according to the terms of the contract or by any interruption or reversal of the supply of electricity,

if such failure, interruption, or reversal is due to storm, lightning, fire, flood, drought, strike, or any cause beyond the control of the Company or any other cause except willful neglect on the Company's part.

12. Customer further agrees, during any applicable load ramp period plus one year, to:

    a. Curtail up to a total of fifty (50) hours per calendar year for ninety-five percent (95%) of Customer load;
    b. Curtail up to a total of one hundred (100) hours per calendar year for fifty percent (50%) of Customer load; or
    c. Implement or bear the cost of alternative Commission-approved options that accelerate capacity resources on the utility system during the integration of Customer's full contract demand.

    Any curtailment hereunder will be further governed by the terms set forth in Exhibit E. For the avoidance of doubt, any service interruption or curtailment as contemplated hereunder pursuant to subsection (a) will be mandatory, and Customer will not be compensated for any such curtailment availability or any actual curtailment. Customer shall not be required to participate in any Energy Efficiency, Demand Response or Demand-Side Management tariff or program that has been or may subsequently be approved by the Commission. The Parties also agree that Customer's agreement to curtail load pursuant to this Section shall satisfy the requirements of G.S. 62-133.9(f) and Commission Rule R8-69(d)(1), such that Customer shall be exempt from any annual rider established pursuant to Commission Rule R8-69. If, at any time during the Initial Term, Customer voluntarily elects to participate in such applicable EE/DSM Programs, it will be subject to applicable riders and schedules related to such programs.

13. If, at any point after the Effective Date, the Security fails to meet the requirements set forth in the DC Schedule, then Customer shall replace the Security within ten (10) business days with Security that does meet the requirements set forth in the DC Schedule. Customer may not provide a parent guaranty in place of a letter of credit that does not meet the requirements described in the DC Schedule to satisfy the Security obligations. Customer acknowledges and agrees that Security shall be a source of non-reimbursable funds for the Company in the event Customer does not fulfill its obligations to the Company under this Agreement. Customer acknowledges and agrees that Company shall have the right to draw on and retain funds from any letter of credit provided hereunder if fewer than 30 days remain until such letter of credit's expiration and the letter of credit has not been renewed as required by this Agreement. Any Security provided under this Agreement shall remain in full force and effect until Customer has satisfied all obligations under this Agreement, and such Security shall not be deemed a limitation on damages. Company may require Customer to adjust the Security to conform to any amendments to this Agreement. Such Security requirements hereunder shall adjust pursuant to the table set forth in Exhibit C. Customer also agrees to make payments in accordance with Exhibit D. In the event Customer fails to provide or maintain Security in accordance with this agreement and the applicable rate schedule after ten (10) business days, the total amount of Security, as adjusted by Exhibit C, shall be deemed immediately due and payable to the Company.

14. Before energization, Customer shall deliver to the Company Customer's written ride-through and reconnection protocols and capabilities and its plan that meets all applicable NERC requirements for managing incidental sudden disconnection and reconnection of load to avoid grid disturbances, answer the Company's questions and provide relevant records, and obtain the Company's written approval of the plan. Customer shall also provide to the Company written updates regarding each proposed change to such information at least 10 days prior to implementation of the change.

15. This Electric Service Agreement shall be governed by the laws of the State of North Carolina.

16. Capitalized terms used herein but not defined in this ESA shall have the meaning set forth in the DC Schedule or any successor rate schedule or tariff. Exhibits A, B, C, D and E attached hereto constitute a part hereof.

Witness as to Customer:

_____ _____ (Customer)

_____ By _____ Title _____

ACCEPTED: Duke Energy Carolinas, LLC Mail Bill to:

By _____ Name: _____

APPENDIX B

Exhibit A
Customer Load Ramp and Estimated Schedule

INSERT TABLE

Exhibit B
Customer Delivery Points; Customer Requested Facilities

Point of Delivery	Maximum Demand (MW)	Effective Date	Description
POD #1			
POD #2			
POD #3			

Exhibit C
Liquidated Damages

INSERT TABLE

Stranded Generation Charge

INSERT TABLE

Transmission Network Upgrades

INSERT TABLES

Exhibit D
Extra Facilities and Extra Facilities Charge(s)

INSERT TABLES

Additional Dedicated Facilities

INSERT TABLES

CIAC for Directly Assigned Transmission Network Upgrades

INSERT TABLES

Exhibit E
Curtailment Protocols

GENERAL PROVISIONS

This Exhibit will govern the curtailment of Customer load pursuant to the ESA. The terms of this Exhibit will not modify, supersede, or otherwise impact the Company's approved Emergency Load Reduction Plan, and its operation and execution thereof during system emergency events.

DEFINITIONS

Capitalized terms used but not defined in this Exhibit shall have the meaning set forth in the ESA.

Contract Demand: The Contract Demand is the maximum kilowatt demand which the Company is required to supply to Customer under the ESA.

Curtailment Load: Curtailment Load means Energized Load reduced by either (i) a total of fifty (50) hours per calendar year for ninety-five percent (95%) of Customer Contract Demand, or (ii) a total of one hundred (100) hours per calendar year for fifty percent (50%) of Customer Contract Demand, as measured in kilowatts ("kW") exclusive of Force Majeure events.

Curtailment Notification: Curtailment Notification means the notification delivered by the Company to Customer prior to the initiation of a Curtailment Period.

Curtailment Period: A Curtailment Period is that interval of time, initiated and terminated by the Company when the Company has capacity constraints, including generation, transmission or distribution capacity constraints or reactive power concerns on its system, during which Customer may be curtailed.

Customer Site: Customer Site means the Customer location for delivery of electric service, inclusive of all points of delivery set forth in Exhibit B to the ESA.

Energized Load: Energized Load means the total Customer load at the Customer Site, as measured kW being served by the Company at the time of the Curtailment Notification.

Maximum Annual Curtailment Hours: The maximum aggregate duration of all Curtailment Periods that the Company is authorized to require in a given calendar year. The maximum Annual Curtailment Hours shall be 100 hours.

CONTROL NOTICES AND LIMITATIONS

The Company will provide Curtailment Notifications to Customer at least ninety (90) minutes prior to the beginning of the applicable Curtailment Period, and the Company shall notify Customer thirty (30) minutes before the end of a designated Curtailment Period. The Curtailment Notification shall be via communication path designated by Customer, which may be electronic mail, text or phone call, with redundancy provided through at least one (1) additional communication path. The Curtailment Notification will include the anticipated duration of the Curtailment Period.

Upon receipt of the Curtailment Notification, Customer will reduce Energized Load to Curtailment Load, or other specified load above the Curtailment Load as directed by the Company in the Curtailment Notification in its sole discretion, prior to the start of the Curtailment Period. If Customer does not reduce the Energized Load at the Facility to the Curtailment Load at or prior to the start of the Curtailment Period, the Company, in its discretion, may force the curtailment and discontinue service to the Customer Site to the extent specified herein for the duration of the Curtailment Period, subject to any other applicable limitations set forth in this Exhibit D. In the event Customer does not reduce the Energized Load as directed by the Company for a particular Curtailment Period and the Company does not force the curtailment and discontinue service to the Customer Site, those Curtailment Period hours shall not count toward the Maximum Annual Curtailment Hours. For the avoidance of doubt, to the extent Customer does not reduce load as called upon by the Company, and the Company does not force curtailment, Customer shall be subject to the same number of Maximum Annual Curtailment Hours going forward as if the particular Curtailment Period had not been called by the Company.

The Company may invoke Curtailment Periods for not more than the Maximum Annual Curtailment Hours in any calendar year. Further, the Company's right to invoke a Curtailment Period is subject to a maximum Curtailment Period duration of six (6) hours in any calendar day, which may be extended only by mutual agreement of Customer and the Company. In the event of a change in applicable legal requirements, including any law, rule, regulation or order from any governmental authority, that could materially impact either Party's ability to comply with the requirements of this Exhibit D, the Parties shall negotiate in good faith on revisions to this Exhibit D to conform to such changes in law.

To the extent any aspect of the curtailment provisions set forth herein are rejected or modified by the Commission by rule or order, the Parties will exercise commercially reasonable efforts to replace such provisions with mutually agreeable terms that conform to the requirements of the Commission's rule or order. If the Parties are unable to agree on such replacement terms, Customer's curtailment obligations will be equitably adjusted to reflect the removal of any terms that would cause either Party to violate the Commission rule or order. Any terms that are not directly impacted by such Commission rule or order will remain in effect.