STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1380
DOCKET NO. E-2, SUB 1405

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1380	)	
	)	
In the Matter of	)	
Application of Duke Energy Progress, LLC	)	
for Adjustment of Rates and Charges	)	
Applicable to Electric Service in North	)	ORDER ACCEPTING STIPULATIONS
Carolina and Performance-Based	)	IN PART, GRANTING PARTIAL RATE
Regulation	)	INCREASE, GRANTING
	)	ACCOUNTING ORDER, AND
DOCKET NO. E-2, SUB 1405	)	REQUIRING PUBLIC NOTICE
	)	
In the Matter of	)	
Application of Duke Energy Progress, LLC	)	
for Accounting Order Regarding Level 2	)	
Charging Infrastructure	)	

HEARD: Monday, March 30, 2026, at 7:00 p.m., North Carolina Utilities Commission, Commission Hearing Room 2115, 430 North Salisbury Street, Raleigh, North Carolina 27603

Tuesday, March 31, 2026, at 7:00 p.m., Robeson County Courthouse, 500 North Elm Street, Lumberton, North Carolina 28359

Wednesday, April 1, 2026, at 6:30 p.m., via Webex Videoconference

Monday, April 6, 2026, at 7:00 p.m., Greene County Courthouse, 301 North Greene Street, Snow Hill, North Carolina 28580

Monday, April 13, 2026, at 7:00 p.m., Person County Courthouse, 105 South Main Street, Roxboro, North Carolina 27573

Tuesday, April 14, 2026, at 7:00 p.m., Haywood County Courthouse, 285 North Main Street, Waynesville, North Carolina 28786

Tuesday, August 11, 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; Donald van der Vaart; and John W. Gajda.

APPEARANCES:

For Duke Energy Progress, LLC (DEP):

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

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For Andale, LLC (Andale):

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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 II (CIGFUR II):

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

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For Environmental Defense Fund (EDF):

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For Google LLC (Google):

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For Harris Teeter LLC, a Division of The Kroger Company (Harris Teeter):

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

Microsoft Corporation (Microsoft):

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

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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 the United States Department of Defense and all other Federal Executive Agencies (DoD/FEA):

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For Walmart Inc. (Walmart):

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

For the Using and Consuming Public:

Lucy E. Edmondson, Anne M. Keyworth, Nadia L. Luhr, 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: This proceeding was initiated on July 8, 2025, with DEP's filing of a Motion Requesting a Limited Waiver of Commission Rule R1-17B(c). DEP 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 DEP 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 includes a PBR application.

On October 20, 2025, pursuant to Commission Rule R1-17(a) and the R1-17B(c) Order, DEP filed a letter providing 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, DEP filed its Application to Adjust Retail Base Rates, 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, DEP's PBR Application included a residential decoupling 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 DEP and other parties and the procedural orders issued by the Commission.

On October 7, 2025, CIGFUR II filed a petition to intervene in this proceeding, and on October 10, 2025, the Commission entered an order granting CIGFUR II's petition.

On October 24, 2025, pursuant to N.C.G.S. § 62-69, DEP, Duke Energy Carolinas, LLC (DEC), the Public Staff, CIGFUR II, Carolina Industrial Group for Fair Utility Rates III (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-2, Sub 1380 and E-7, Sub 1329.

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

[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.

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; Nicole L. Flippin, Senior Vice President of Nuclear Operations for Duke Energy Corporation (Duke Energy); John Samuel Holeman III, Vice President of Grid Integration Strategy for DEP; 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 DEP; 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.

The AGO filed a petition to intervene on November 25, 2025. The Commission entered an order granting the AGO's petition on December 1, 2025.

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

NCSEA filed a petition to intervene on December 3, 2025. The Commission entered an order granting NCSEA's petition on December 5, 2025.

NCJC, et al. filed a petition to intervene on December 9, 2025. The Commission entered an order granting the petition of NCJC, et al. on December 12, 2025. The Commission entered an Errata Order on July 23, 2026, correcting the attorney of record.

On December 15, 2025, DEP filed a Response in Opposition to CIGFUR II's Motion, arguing that N.C.G.S. § 62-133.16(f), which provides that 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 DEP'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 DEP 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 DEP's T&D Information Filing on or before January 26, 2026.

Google filed a petition to intervene on January 7, 2026. The Commission entered an order granting Google's petition on January 12, 2026.

EDF filed a petition to intervene on January 8, 2026. The Commission entered an order granting EDF's petition on January 9, 2026.

On January 9, 2026, the Commission issued its Order Denying CIGFUR II's Motion to Deem Performance-Based Regulation Application Incomplete, finding that the PBR Statute allows utilities to request a MYRP lasting fewer than 36 months and that DEP's PBR Application, which included a request for a MYRP of "not more than 36 months," could not fail for lack of a proposed third rate year.

Harris Teeter filed a petition to intervene on January 12, 2026. The Commission entered an order granting Harris Teeter's petition on January 20, 2026.

On January 12, 2026, CIGFUR II and III filed a Notice regarding Technical Conference Participation, indicating that they 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, DEP 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 Raleigh, Lumberton, Snow Hill, Roxboro, and Waynesville, North Carolina on March 30, March 31, April 6, April 13, and April 14, 2026, respectively, as well as a remote public witness hearing via Webex on April 1, 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 August 11, 2026. The Commission directed, among other instructions, DEP and the Public Staff to confer and file a proposed Public Notice with the Commission.

Also on January 15, 2026, DoD/FEA filed a petition to intervene. The Commission entered an order granting DoD/FEA's petition on January 28, 2026.

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

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

On January 21, 2026, the Public Staff and DEP 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 DEP's proposed Public Notice. The Commission directed DEP 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 23, 2026, DEP filed a Motion for Limited Waiver of the public notice mailing deadline, requesting approval to mail customers the Public Notice by March 10, 2026, via bill insert to save approximately $300,000 in printing and postage. On January 26, 2026, the Commission issued its Order Granting Motion for Limited Waiver of Public Notice Requirements, allowing DEP to mail its customers a copy of the Notice by March 10, 2026, via bill insert.

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 DEP's T&D Information Filing on or before March 6, 2026.

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

CUCA filed a petition to intervene on February 5, 2026. The Commission entered an order granting CUCA's petition on February 9, 2026.

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

Walmart filed a petition to intervene on February 18, 2026. The Commission entered an order granting Walmart's petition on February 24, 2026.

On February 26, 2026, DEP filed the supplemental direct testimony and exhibits of witnesses Jiggetts, Sykes, Abernathy, Flippin, Fogg, Guyton, Holeman, LaRoche, Tompson, Walsh, and the amended direct testimony of witness Byrd.

NCHBA filed a petition to intervene on March 4, 2026. The Commission entered an order granting NCHBA's petition on March 18, 2026.

On March 5, 2026, DEP 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, DEP and DEC 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 DEP's rate case pending in this docket and DEC's rate case pending in Docket No. E-7, Sub 1329.

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

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

On March 31, 2026, DEP 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, DEP filed a Clarification Regarding Consolidation with Accounting Order Request. DEP clarified 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-2, Sub 1405, is intended to be consolidated with DEP's general rate case proceeding pending in this docket, Docket No. E-2, Sub 1380.

Microsoft filed a petition to intervene on April 29, 2026. The Commission entered an order granting Microsoft's petition on May 5, 2026.

On May 6, 2026, DEP filed the supplemental testimony of Jonathan Byrd and supplemental testimony and exhibits of Melissa Culbreth. Also on May 6, 2026, DEP filed the second supplemental testimony and exhibits of witnesses Melissa B. Abernathy and LaWanda M. Jiggetts. DEP filed the supplemental direct exhibits of Jonathan Byrd on May 18, 2026.

On May 26, 2026, DEP 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 August 6, 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 Electrification Coalition filed Comments on DEP's PBR Application.

Amazon filed a petition to intervene on June 24, 2026. The Commission entered an order granting Amazon's petition on June 26, 2026.

Andale filed a petition to intervene on July 7, 2026. The Commission entered an order granting Andale's petition on July 9, 2026.

On July 9, 2026, the Public Staff's Energy Division filed the following sets of direct testimony 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); two separate sets of individual testimony of Patrick A. Fahey, Public Utilities Regulatory Analyst; Jay B. Lucas, Leah M. M. Weaver, and Dr. Jethro Ssengonzi, Engineer (the Public Staff Large Load Panel); 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 the Brubaker & Associates, Inc.

Also on July 9 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; DoD/FEA filed the direct testimony and exhibits of Maureen L. Reno, founder and principal consultant at Reno Energy Consulting Services, LLC and Brendan Larkin-Connolly, Managing Consultant at Exeter Associates, Inc., and the direct testimony of Larry Blank, principal at TAHOEconomics; 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, James Robert Wiggins, Division President for Mattamy Homes, 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, Partner at Bates White Economic

Consulting; CIGFUR II filed the direct testimony of Brian C. Collins, Managing Principal at Brubaker & Associates, Inc.; Harris Teeter filed the direct testimony and exhibits of Jason Kiengsiri, Consultant 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.

On July 24, 2026, DEP filed the rebuttal testimony and exhibits of DEP's witnesses Bowman; Abernathy; Coyne; Heath; Timothy J. Duff, Managing Director, Large Load Strategy & Enablement for DEBS; Colley; Guyton, Fogg, Justin A. Teckenbrock, General Manager of Enterprise Information Solutions at Duke Energy; Flippin; Walsh; LaRoche; Tompson; Jiggetts; Caldwell; David J. Wathen, Senior Managing Director, Southeast Work & Rewards Region Leader for Willis Towers Watson (WTW); Hager; Speros; Spanos; Jeffrey T. Kopp, Senior Managing Director of the Energy & Utilities Consulting department of Burns & McDonnell Engineering Company, Inc.; Culbreth; Sykes; and 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 August 5, 2026, DEP filed a Comprehensive Revenue Requirement Agreement and Stipulation of Settlement (Comprehensive Settlement) between DEP and the Public Staff, CIGFUR II, CUCA, NCSEA, and Walmart (collectively, Stipulating Parties); an Agreement and Stipulation of Settlement on Performance Incentive Mechanisms and Tracking Metrics (PIMs Settlement) between DEP, the Public Staff, and NCSEA; and an Agreement and Stipulation of Settlement on the Direct Current Fast Charging (DCFC) Pilot Program (DCFC Stipulation) between DEP, the Public Staff, and Walmart.

On August 6, 2026, NCHBA filed a Settlement Agreement and Partial Stipulation between DEP, NCHBA, and Public Staff on the Distribution Line Extension Plan (DLEP Stipulation).

Also on August 6, 2026, the Public Staff filed the joint comprehensive settlement testimony of witnesses Metz, Zhang, Thomas, and Fahey; and the joint settlement testimony of witnesses Fernandez, Hill, and T. Williamson.

Also on August 6, 2026, DEP filed an Amended Comprehensive Settlement adding DoD/FEA as a Stipulating Party.

Also on August 6, 2026, DEP filed the settlement testimony of witnesses Bowman, Colley, Heath, Coyne, Abernathy, Jiggetts, Byrd and Beveridge, and Bateman and Farmer.

Also on August 6, 2026, CIGFUR II filed a Motion to Excuse Witness Brian C. Collins; CUCA filed a Motion to Excuse Witnesses LaConte and McGlothlin; NCSEA filed a Motion to Excuse Witness Albert Lin; Public Staff filed a Motion to Excuse Witness or Panel, seeking to excuse witnesses Fahey, Walters, Metz, Lucas, McCullar, Lawrence

Thomas and the Rates, Renewables, Distribution, PIMs, Accounting, and Policy panels; DEP filed a Motion to Excuse Witnesses, seeking to excuse witnesses Holeman, Fogg, Flippin, Walsh, Hill, LaRoche, Tompson, Speros, Spanos, Sykes, Culbreth, Caldwell, Wathen, Kopp, and Teckenbrock; DoD/FEA filed a Motion to Excuse Witnesses from Hearing, seeking to excuse witnesses Reno, Larkin-Connolly, and Blank. The Commission granted DoD/FEA, Harris Teeter, NCSEA, NCHBA, and CUCA's motions; denied CIGFUR II's motion; granted in part and denied in part the Public Staff's motion, denying the Public Staff's request with respect to the Accounting Panel and witness Metz's standalone direct testimony; and granted in part and denied in part DEP's motion, denying DEP's request with respect to witness Sykes.

On August 7, 2026, the AGO filed a Motion to Excuse Witnesses, seeking to excuse witnesses Brant, Burgess, and Cassara; Harris Teeter filed a Request for Excusal of Witness Jason Kiengsiri and Motion to Admit Testimony; Google filed a Motion to Waive Appearance of Witness at Hearing, seeking to excuse witness Dr. Berry; Microsoft filed a Motion to Excuse Witness Isaac Gabel-Frank; NCJC, et al. filed a Motion to Excuse Witnesses Kihm and Wilson; Walmart filed a Motion to Excuse Witness Steve W. Chriss; and NCHBA filed a Motion to Excuse NCHBA Witnesses Millis, Wiggins, and Olive. The Commission granted Walmart's motion; denied Microsoft and Google's motions; granted in part and denied in part the AGO's motion, denying the AGO's request with respect to witness Brant; and granted in part and denied in part NCJC, et al.'s motion, denying NCJC, et al.'s request with respect to witness Wilson;

Also on August 7, 2026, Walmart filed the settlement testimony of witness Chriss.

Also on August 7, 2026, DEP filed a Second Amended Comprehensive Settlement adding EDF as a Stipulating Party.

Also on August 7, 2026, Google filed a Letter in Support of ¶ 41 (Large Load 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 August 10, 2026, DEP filed a Motion to Excuse DEP Witness Duff and EDF filed a Motion to Excuse Witnesses Lenell and Pol. The Commission granted DEP's motion and denied EDF's motion on August 10, 2026.

Also on August 10, 2026, Amazon filed a Letter in Support of ¶ 41 of the Comprehensive Settlement and noted it does not object to any other terms of the Comprehensive Settlement.

On August 11, 2026, Andale filed a Letter stating its support for ¶ 41 of the Comprehensive Settlement and stating it does not object to any other terms of the Comprehensive Settlement.

On August 12, 2026, the AGO and NCJC, et al. each filed letters responding to the Presiding Commissioner's request for a response from each of the nonparticipating parties setting forth the party's objections, if any, to the Comprehensive Settlement.

Also on August 12, 2026, DEP filed the Third Amended Comprehensive Settlement clarifying ¶ II.2 regarding DEP's reports on the Momentary Average Interruption Frequency Index event (MAIFIe).

Also on August 12, 2026, Microsoft filed a Letter in support of ¶ 41 of the Comprehensive Settlement and noted it does not oppose any other provision of the Comprehensive Settlement.

On August 14, 2026, the Commission issued an Order Requesting Comments on a model rate schedule, the proposed large load tariff provisions that each of the Public Staff and DEP submitted in this docket, and other large load issues as specified therein. 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. 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 and granted CCEBA amicus curiae status on August 21, 2026.

From August 18, 2026, through August 24, 2026, DEP filed three late-filed exhibits.

On August 19, 2026, Public Staff filed three late-filed exhibits.

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 9, 2026, parties filed initial comments in response to the Commission's August 14, 2026 Order Requesting Comments.

Also on September 9, 2026, Digital Realty Trust, L.P. (Digital Realty) filed a Petition to Intervene Out of Time 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 1, 2026, parties filed proposed orders and briefs.

On October 6, 2026, parties filed reply comments or letters in lieu of reply comments in response to the Commission's August 14, 2026 Order Requesting Comments. DEP also submitted an Agreement and Stipulation of Settlement on Large Load Tariff (LLT Stipulation) among DEC, DEP, the Public Staff, Amazon, Andale, CIGFUR, DoD/FEA, and Microsoft that DEP and DEC 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.

Performance-Based Regulation Application

In summary, DEP requested in its PBR Application and initial direct testimony and exhibits, a net base rate revenue increase of approximately $401 million, which represents an overall increase in its retail revenues of approximately 8.3%, including a rate of return on common equity of 10.95% and a capital structure consisting of 47% debt and 53% equity. DEP's PBR Application and initial direct testimony and exhibits also sought approval of PBR, and a series of rate increases based on DEP'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. DEP sought incremental increases to the revenue requirement of $127.4 million in Rate Year 1 and $200.3 million in Rate Year 2.

DEP 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. DEP'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:

Raleigh: Tate Boulware, Anna Flanagan, Karen Bearden, Amelia Covington, John Saffold, Jon Belisario, Linda Chavis, Fran Lynch, Christie Moser, Michael Haley, Jasmine Wilkie, Tonya Wilkie, Francine Echols, Sherri Dillon, Anne Gordon, Michelle Ingram, Jordan Lawrence, Robert Rodriguez, Kara Sanders, Ernestine Ledbetter, Mazzie Hill, Catherine Carver, George Adler, Lucy Roussa, Cathy Buckley, Michal Brzezicki

Lumberton: Gene McLaurin, Irene Crossland, Everest Brickhouse, Nancy Catherine Hunt, Sandra McCallum, Mac Legerton, Sallie McLean, Ladaris Jefferson, Felicia Bethea, Janet Menzak, Christina Davis McCoy, Wanda Crump, Yvette Alford, Willis Brown

Snow Hill: Joan Gallimore, Johnny Jernigan, Sherry Archibald, Melissa Gray, Daryl Howard, Morgan Berard, Cale Grady, Angelica McCreary, Kelli Burlingame, Glenda Thomas

Roxboro: Keith Sexton, Donald Cain, Gordon Phillip Allen, Jr., Julie Maybee, Carol Carter, Tracy Sexton, Glen Willison, Hope Taylor, Skye Golann, Julie Nye, Susan Jacques, Carol Truby, Annie Bethea

Waynesville: Judy Mattox, Maggie Rowe, Jann Rosemerta, Connie Allen, Chelsea White-Hoglen, Max Ringenbach, Nathan Ramsey, David Francis, Vicki Hyatt,

Tamera Trexler, Staff Horgan, Todd Kemmerling, Molly McDowell, Laura Mayes, Bridget Siedler, Trinity Jaynes, Rachel Cohen, Gray Jernigan, Patrick Berger, Joshua Jones, Stephen Kangas, Rob Denton, Kristen Hammett, Susan Hicks, Jesse Ross, Morgan Alderman, Carolina Sawyer, Parker Sloan, Drew Ball

Virtual: Evelyn Johnson, Gloria Mathey, Tameria Johnson, Debra Cook, Althea Taylor Jones, Hannah Williams, Leah Bishop

In summary, the majority of public witnesses stated their opposition to DEP's proposed rate increase, and recommended the Commission deny the requested increase in part or in full. *See generally*, tr. vols. 1-6. Public witnesses testifying on behalf of the Zebulon Chamber of Commerce, Morrisville Chamber of Commerce, Wake County Economic Development and the Greater Raleigh Chamber of Commerce, and the Economic Development Partnership of North Carolina, testified to DEP's positive impact on local communities and commended the role DEP plays in economic development through providing jobs and reliable electric service. Tr. vol. 1, 31-34, 47-50, 51-54; tr. vol. 2, 17-21. Many public witnesses expressed affordability concerns for residential ratepayers. Public witnesses voiced concerns regarding the impact that DEP's proposed rate increase would have on residential ratepayers living on fixed incomes and on those facing financial hardship in the present economic environment. Several public witnesses testified that they themselves or those in their community currently forgo spending on groceries and medical care to pay their power bills, and that DEP's proposed rate increase will exacerbate this financial strain. Public witnesses testified against DEP's investment in natural gas infrastructure and indicated their opposition to DEP's reliance on fossil fuels, stating their concern for environmental impacts. Instead, public witnesses testified that DEP should invest in and rely on renewable energy resources.

Public witnesses also expressed their concerns with data center load growth. Specifically, witnesses testified that data centers should pay for all costs DEP incurs to accommodate their increased electricity demand; public witnesses further reiterated that costs associated with infrastructure built to support these facilities should not be subsidized by residential ratepayers. Public witnesses also voiced concerns with DEP constructing fossil-fuel fired generating infrastructure to supply data centers with power, expressing opposition to the pollution and natural resource strain that would result from this power supply strategy.

JURISDICTION

No party has contested the fact that DEP 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 DEP and subject matter jurisdiction over the matters presented in DEP's PBR Application.

WHEREUPON, the Commission makes the following

FINDINGS OF FACT

Stipulations

1. On October 24, 2025, DEP, DEC, the Public Staff, CIGFUR II, CIGFUR III, and CUCA (COSS Stipulating Parties) filed the COSS Stipulation. The COSS Stipulation provides that DEP 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 August 5, 2026, DEP, the Public Staff, CIGFUR II, Walmart, NCSEA, and CUCA filed the Comprehensive Settlement. The Comprehensive Settlement was subsequently amended on August 6, 2026, to add DoD/FEA as a Stipulating Party, and was further amended on August 7, 2026, to add EDF. The Comprehensive Settlement resolved all outstanding revenue requirement issues in this proceeding as between the Stipulating Parties.

3. On August 5, 2026, DEP filed the PIMs Settlement, among DEP, the Public Staff, and NCSEA, resolving DEP's MYRP2 PIMs and Tracking Metrics between the parties to the PIMS Settlement.

4. On August 5, 2026, DEP filed the DCFC Stipulation, among DEP, 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.

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

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

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

7. In the PBR Application, DEP proposed to set rates using a rate of return on common equity (ROE) of 10.95%, with a capital structure consisting of 53.0% common equity and 47.0% long-term debt. In its rebuttal testimony, DEP 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.

8. After filing the PBR Application, DEP updated its cost rate for long-term debt. As of March 31, 2026, the embedded cost of DEP's long-term debt is 4.23%, which is reasonable and appropriate for use in this proceeding.

9. 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 DEP's debt (4.23%), results in an overall rate of return for the Comprehensive Settlement of 7.18%.

10. The resulting overall rate of return of 7.18% is reasonable and appropriate for use in this proceeding.

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

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

Depreciation

13. DEP's 2024 DEP 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 DEP's 2024 Decommissioning Study (except that a 10% contingency factor shall be applied in lieu of the contingency percentages proposed by either DEP or Public Staff), as stipulated, is reasonable for purposes of this proceeding.

14. It is reasonable for DEP to use good faith estimates reflecting a 10% contingency factor for purposes of the settlement schedules, and for DEP'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 DEP.

15. DEP's proposal to defer 100% of the impact of accelerating the depreciation of DEP's subcritical coal plants resulting from the 2021 Depreciation Study to a regulatory asset for future securitization, for an annual deferral of $63.527 million on a North Carolina retail basis, as permitted by S.L. 2025-78, is reasonable.

Base Period Plant-Related Items

16. DEP'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 Comprehensive Settlement, are the reasonable product of give-and-take negotiations and should be included in the revenue requirement.

Base Period Accounting Adjustments

17. The accounting adjustments set forth in the Comprehensive Settlement, as further described in detail in Jiggetts Comprehensive Settlement Exhibit 2, are the reasonable product of give-and-take negotiations among the parties. DEP'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-2, Sub 1405 to establish a regulatory asset for the remaining net book value of its Level 2 public charging infrastructure are just and reasonable.

Federal Funding

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

19. It is just and reasonable for DEP 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.

20. It is just and reasonable that, if DEP is successful in obtaining a grant, DEP 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, DEP 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 DEP's accounting for the Department of Energy (DOE) grant for the Roxboro Coal Reliability Initiative shall be governed by Section II.47 of the Comprehensive Settlement.

Coal Ash

21. DEP's request to recover costs associated with its coal combustion residual (CCR) obligations incurred from April 1, 2023, through March 31, 2026, net of the over-amortization of tranche 2 of deferred environmental costs established in Docket No. E-2, Sub 1219, over an eight-year period as provided in the Comprehensive Settlement, and to continue the deferral of any CCR costs incurred subsequent to March 31, 2026, is reasonable.

Storm Costs

22. The adjustment to DEP's revenue requirement, calculated using the method approved by the Commission in Docket No. E-2, Subs 1023, 1142, 1219, and 1300, to account for anticipated storm expenses based upon a 10-year average of storm costs after removing costs associated with major storms, is approximately $23.822 million.

23. Per DEP's Agreement and Stipulation of Partial Settlement with the Public Staff in Docket No. E-2, Sub 1262 (2020 Storm Securitization) and the Agreement and Stipulation of Settlement in Docket Nos. E-2, Sub 1362 and E-2, Sub 1370 (2024 Storm Securitization), DEP 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.

24. The regulatory liability for servicing and administration fee overcollections related to the 2020 Storm Securitization totals approximately $1.128 million, and the regulatory asset for under-recovered upfront bond issuance costs related to the 2024 Storm Securitization totals approximately $78,000. After application of the over-amortization of prior tranches, the net balances for amortization are approximately $1.021 million and $151,000, respectively. A two-year amortization of each balance is just and reasonable.

25. Per the Comprehensive Settlement, the Hurricane Helene over-securitization amount is the amount per DEP's filing in this case ($68.456 million overcollection plus $5.802 million return on the overcollection), using DEP's proposed incremental Operation and Maintenance (O&M) calculation for purposes of the Hurricane Helene over-securitization amount in this case only.

26. The Comprehensive Settlement includes Winter Storm Fern incremental storm costs of $62.188 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 DEP's next general rate case.

27. The Comprehensive Settlement includes the Hurricane Helene over-securitization amount, netted against the Winter Storm Fern incremental storm costs, resulting in a $12.070 million credit to customers, to be amortized over 18.75 years with the unamortized balance included in rate base.

28. Per the Comprehensive Settlement, DEP and the Public Staff agree that the Winter Storm Fern incremental costs will not incur any carrying costs.

29. Per the Comprehensive Settlement, DEP agrees to use the traditional method for calculating the incremental storm operations and maintenance costs for 2026 through DEP's next general rate case.

30. In its initial application, DEP proposed to establish a storm reserve. DEP agreed to withdraw its storm reserve proposal as part of the Comprehensive Settlement.

Multiyear Rate Plan 2 Capital Investments

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

Cost Allocation

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

33. The cost allocation methodologies used in DEP'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 N.C.G.S.§ 62-133.16, are reasonable for purposes of this proceeding.

Distribution Line Extension Plan

34. DEP, 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, agreed to amend DEP's DLEP as set forth in the DLEP Stipulation, which, in part, defines residential real estate development and 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.

35. The Public Staff and NCHBA agreed that with respect to CIAC obligations arising within a specific residential real estate development pursuant to DEP'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. DEP does not object to this aggregation proposal.

Rate Design

36. The objective of DEP'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 DEP to incur. DEP's proposed rate design allocates the revenue increase between customer classes by rate base amounts.

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

38. DEP proposed a 25% reduction in variance from present rates of return by class, subject to a 2% cap in Rate Year 1 and 2.5% cap in Rate Year 2. 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 does not change DEP's proposed rate design methodology.

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

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

41. DEP proposed, consistent with principles of gradualism, increasing the Basic Customer Charge (BCC) for residential customers to $15.50 per month in Rate Year 1 and to $16.00 in Rate Year 2. For the general and industrial schedules, DEP proposed monthly BCC rates of $24.50 for Rate Schedule Small General Service (SGS), $33.00 for Rate Schedule Medium General Service (MGS), $42.00 for Rate Schedule Medium General Service – Time-of-Use (MGS-TOU), and $33.00 for Schedule Seasonal and Intermittent Service (SI). The Comprehensive Settlement does not change DEP's proposed increases to the BCCs.

42. DEP proposed to close Rider Residential Service Energy Conservation Discount (RECD) to new residential customers effective January 1, 2027. The Public Staff proposed to reduce the Rider RECD discount from 5% to 2.5% beginning January 1, 2028, to mitigate any rate shock. Rider RECD will close on March 31, 2029, and remaining customers will take service on one of DEP's other available core tariffs.

43. DEP should address the future of Schedule Church Service – Time-of-Use (CH-TOUE) and Rider 9 in the stakeholder process directed by the Commission's 1U Order.

44. The modifications to the Net Metering Bridge Rider (NMB) and Residential Solar Choice Rider (RSC) proposed by the Public Staff are just and reasonable.

45. The Public Staff's proposed recommendations to investigate prior to the next general rate case whether both seasonal and an 800-kilowatt-hour (kWh) threshold for winter months in Schedule Residential Service (RES) should continue and whether there is a need for a rate schedule like DEC's Optional Power Service, Time-of-Use with Voltage Differential (OPT-V) rate tariff option for legacy DEP customers should be addressed in the stakeholder process directed by the Commission's 1U Order.

46. Pursuant to the DCFC Stipulation, DEP 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 DEP's customer growth pro forma and the corresponding interconnection facilities for a certain large load customer shall be included in the case and that the resulting net benefit of $3.602 million shall be allocated to all customer classes.

48. Aside from the facilities for that specific large load customer, 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 DEP in rebuttal, resulting in a reduction in rate base of $0.72 million on a North Carolina retail basis.

49. DEP 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, 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 197 (N.C.U.C. Aug. 18, 2023) (Sub 1300 Order), approved DEP's request to continue to defer incremental bad debt for future recovery.

51. The Comprehensive Settlement allows DEP to recover the deferred bad debt balance in this case to include actual deferral amounts from April 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 DEP 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; if the actual deferral for that period is less than $12 million, DEP should defer the difference as a regulatory liability to be returned to customers in its next general rate case, and if the actual deferral equals or exceeds $12 million, DEP should not collect any additional amount for that period from customers in its next general rate case.

53. It is reasonable and appropriate that the deferral include a debt-only return, compounded annually, during the deferral period ending December 31, 2026, with no rate base treatment (no return) during the amortization period.

54. It is reasonable and appropriate for DEP to recover the North Carolina retail deferred balance, approximately $61.6 million at the rates effective date, over a five-year period.

Lead-Lag Study

55. In accordance with the Sub 1300 Order, DEP 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, ¶ 44 of the Comprehensive Settlement are appropriate.

57. The reporting obligations established in Section III of the Comprehensive Settlement are appropriate.

Affordability

58. Under the Comprehensive Settlement, DEP agreed to make shareholder financial contributions totaling $10 million. The contributions 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. DEP 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. It is reasonable and appropriate for DEP to establish a Production Tax Credit (PTC) Rider as proposed by DEP in its PBR Application, provided that DEP 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 included in customer rates to achieve the tax credit benefits may still be deferred beyond January 1, 2027, and all deferred incremental costs may be netted in the PTC Rider, subject to the Public Staff's review.

60. It is reasonable and appropriate that a fixed amount of PTCs of $120 million per year be flowed back to customers through the PTC Rider for 2027 and 2028 (2027-2028 Agreed Amount). If, despite DEP's reasonable and prudent efforts to maximize the benefit of PTCs for customers, subsequent changes in law, final determinations by the Internal Revenue Service (IRS) or other governmental or judicial bodies, or lack or insufficiency of a monetization market result in DEP's inability to monetize or use PTCs equal to the 2027-2028 Agreed Amount, DEP shall accelerate the flowback of North Carolina State Excess Deferred Income Tax (EDIT) to true up the shortfall so as to achieve the 2027-2028 Agreed Amount in the PTC Rider.

61. Certain regulatory assets and liabilities previously approved by the Commission have been over-amortized, resulting in a net over-recovery, estimated at approximately $25.8 million North Carolina retail as of December 31, 2026, that should be returned to customers.

62. The establishment of a Regulatory Asset and Liability (RAL) Rider, Rider RAL-3, to refund to customers over a two-year period the net over-amortization of expired regulatory assets and liabilities, as agreed to in the Comprehensive Settlement, is just and reasonable.

63. It is reasonable and appropriate for DEP to establish an annual Bulk Power Marketing (BPM) Rider as proposed by DEP in its PBR Application, provided that DEP shows in each rider filing that the BPM Rider is net cost effective for DEP to implement and maintain.

64. Consistent with the Comprehensive Settlement, DEP 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.

65. It is reasonable and appropriate for DEP to incorporate into base rates the prospective amounts that would otherwise be recovered through the Joint Agency Asset Rider (JAAR), including the continued levelization of the applicable acquisition costs, and to terminate the JAAR once any remaining over- or under-recovery balances have been resolved through the rolling recovery factor in the remaining annual JAAR proceedings.

66. DEP's agreement, as part of the Comprehensive Settlement, to withdraw its pending appeal related to the 2025 JAAR rider proceeding, Docket No. E-2, Sub 1354, and to support holding that appeal in abeyance until the Commission issues its decision in this proceeding, is reasonable and appropriate.

Carrying Costs

67. 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 Comprehensive Settlement, is just and reasonable.

68. The use of annual compounding when accruing a return, if applicable, on deferrals (both regulatory assets and liabilities) and riders through DEP'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 Comprehensive Settlement, is just and reasonable.

Quality of Service

69. DEP and the Public Staff presented evidence indicating the adequacy of the electric service provided by DEP.

Base Fuel and Fuel-Related Factors

70. The Stipulating Parties agree to work together on a proposal to finalize DEP's fuel treatment in its compliance filing to update the base fuel factors to reflect the Commission's Order in Docket No. E-2, Sub 1398.

71. The Stipulating Parties agree that DEP 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 DEP fuel rider, or in the pending DEP fuel rider for rates effective December 1, 2026, in Docket No. E-2, Sub 1398.

72. 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

73. DEP's PBR Application includes an RDM, a rate-making mechanism intended to break the link between DEP'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 DEP's EV-specific tariff will be included in the calculation to exclude EV sales margin from the RDM and ESM.

74. DEP's PBR Application includes an ESM, an annual rate-making mechanism that shares surplus earnings between DEP 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, DEP has agreed to calculate the ESM using a 13-month average rate base, use the Commission-approved target capital structure, and maintain separate ESMs for DEP and DEC. 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

75. The PIMs Settlement consists of the following four PIMs: Time Differentiated and Dynamic Rate Enrollment PIM, Reliability PIM, Facilities Study PIM, and the Vegetation Management PIM (collectively, the 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 requires DEP to host a PIMs Workshop prior to filing its next PBR rate case.

Multiyear Rate Plan Refund Rider

76. It is just and reasonable to implement the MYRP Refund Mechanism and MYRP Refund Rider agreed to in the Comprehensive Settlement, under which DEP 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 refund for each rate year is determined by applying a composite factor, based on both the number of projects completed and the revenue requirement of completed projects, to the difference between the MYRP revenue requirement included in rates and the actual revenue requirement for completed MYRP projects. The MYRP Refund Rider will be filed annually in conjunction with DEP's annual PBR riders, and any refund will be paid to customers over a 12-month period with interest at the A2/P2 commercial paper rate at the federally published monthly average.

77. 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

78. DEP's PBR Application, as modified by DEP's rebuttal testimony, 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 and Commission Rule R1-17B.

Revenue Requirement

79. After giving effect to the stipulations approved herein, the annual revenue requirement for DEP for Rate Years 1 and 2 will allow DEP 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.

Large Loads, Data Centers, and the DC Schedule

80. 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 load 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 load covered by ESAs.

81. 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.

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

83. If the potential data center customer load fails to materialize in whole or in part, terminates its contractual obligations early, or leaves DEP's system before the new assets can reasonably be absorbed by existing ratepayers or fully recovered from the existing 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.

84. DEP'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.

85. 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.

86. 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 DEP's other retail electric ratepayers and providing electric service to data center customers and is approved.

87. 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 DEP's planning, operations, and finances, is reasonable and appropriate, and is approved.

88. Subjecting each DC Customer to the Availability, Definitions, Type of Service, Monthly Rate, Riders, Minimum Bill, Determination of Billing Demand, Power Factor Adjustment, Sales Tax, Payments, General, Conflict, and Reliability and Curtailment provisions (collectively, Rate Provisions) of the DC Schedule is reasonable and appropriate and is approved.

89. 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 (collectively, Risk Mitigation Provisions) of the DC Schedule is reasonable and appropriate for both protecting other retail ratepayers and serving such DC Customers and is approved.

90. Subjecting the Qualifying Incremental Demand (as defined in the DC 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.

91. It is reasonable and appropriate for the Commission to approve a pro forma Electric Service Agreement (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 DEP's other retail ratepayers, and the interim standard ESA attached to this Order as Appendix B is approved.

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

93. 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.

94. 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 DC Schedule customers and is approved.

95. Requiring DEP 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.

96. 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.

97. 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.

98. 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. 1-6

Stipulations

The evidence supporting these findings of fact is contained in DEP's verified PBR Application and Form E-1; the stipulations between DEP and the other parties; the testimony and exhibits of DEP 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 II witness Collins; the testimony and exhibits of EDF witnesses Lenell and Pol; the testimony and exhibits of NCHBA witnesses Millis, Wiggins 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 DEC Rate Case. The COSS Stipulation provides that DEP 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. COSS Stip. § II.A. Because transmission demand does not have average or excess energy components, the transmission demand factors at the customer class level are equivalent to the 12 CP calculation. *Id*. The COSS Stipulation also provides that, for purposes of allocating production demand costs on a jurisdictional basis as well as to North Carolina retail rate classes, DEP will make an adjustment to exclude certain curtailable/interruptible loads if they were not curtailed at the twelve system peak hours during the test year. *Id*. § II.B. 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. *Id*. § II.E. DEP 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. 8, 119. 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). Sub 1300 Order at 35-36; 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 36-37 (N.C.U.C. Dec. 15, 2023) (Sub 1276 Order).

Comprehensive Settlement

On August 5, 2026, DEP, the Public Staff, CIGFUR II, CUCA, NCSEA, and Walmart filed the Comprehensive Settlement, which resolved all outstanding revenue requirement issues between the Stipulating Parties. On August 6, 2026, the Comprehensive Settlement was amended to include DoD/FEA and further amended on August 7, 2026, to include EDF as a Stipulating Party. On August 12, 2026, the Comprehensive Settlement was amended to clarify DEP's reporting obligations with respect to MAIFIe.

DEP 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 DEP's commitment to balance customer affordability with investments needed to ensure continued reliability, resilience, and economic growth. Tr. vol. 7, 779. Witness Bowman also explained how the Comprehensive Settlement resolves all

contested revenue requirement issues between DEP and the Public Staff and supports a parallel large load proceeding that would allow parties an opportunity to provide additional information regarding adoption of a large load tariff. *Id*. at 781.

Witness Bowman further noted that the Comprehensive Settlement, among other things, sets DEP'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 DEP will refund customers if approved MYRP2 projects are delayed or not completed. *Id*. at 781-82.

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 DEP's proposed revenue increase in this proceeding, and that the Comprehensive Settlement is in the public interest and should be approved. *Id*. at 1897-98.

Performance Incentive Mechanisms Settlement

On August 5, 2026, DEP, the Public Staff, and NCSEA 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 DEP filed the Settlement Testimony of witnesses Bateman and Farmer in support of the PIMs Settlement.

The PIMs Settlement consists of the following four Settled 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 DEP of $5.15 million per rate year and maximum downside penalties of $6 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 EVs, as well as additional non-tracking metric reporting obligations, and a requirement for DEP to host a PIMs Workshop prior to filing its next PBR rate case. *Id*. § II.

Public Staff witnesses Fernandez, Hill and T. Williamson testified that the Settled PIMs benefit ratepayers by creating incentives for DEP 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. 7, 1481-83.

DEP witnesses Bateman and Farmer 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. 10, 510-12.

Direct Current Fast Charing Stipulation

On August 5, 2026, DEP, 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 on or after January 1, 2027. DCFC Stip. § II.1- II.2.

DEP witnesses Byrd and Beveridge testified in support of the DCFC Stipulation. Tr. vol. 10, 291-93. Witnesses Byrd and Beveridge stated that the DCFC Stipulation is a balanced compromise that provides an equitable resolution of this issue and request that the Commission approve the DCFC Stipulation in its entirety. *Id*. at 293.

Walmart witness Chriss also testified in support of the DCFC Stipulation and commended DEP and the Public Staff for working with Walmart to develop the DCFC Pilot. Tr. vol. 8, 443-44.

Distribution Line Extension Plan Stipulation

On August 6, 2026, NCHBA filed the DLEP Stipulation between DEP, NCHBA, and Public Staff regarding DEP's DLEP and CIAC policy. The DLEP governs how DEP extends distribution facilities to serve new customers, including cost allocation for line extensions. Tr. vol. 10, 283. 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 89-99. 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*. DEP, NCHBA, and the Public Staff agreed that under DEP's existing DLEP and policy, grid improvements upstream from a new residential real estate development, including grid modernization projects and other offsite facilities upgrades (e.g., substation upgrades), may be treated as "Construction Costs" for purposes of the CIAC calculation under DEP's DLEP only to the extent that (i) they are not included within the scope of DEP'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. 10, 285-286. DEP 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 DEP's DLEP.

First, the DLEP Stipulation provides that DEP'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 cost up front.

Second, the DLEP Stipulation provides that DEP'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. 10, 285.

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. 10, 89-99. 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. 10, 286. 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's Exhibit CWM 1 and DEP Rate Design Panel's Byrd-Beveridge Rebuttal Exhibit 3. *Id*. DEP does not object to the Aggregation Proposal. No other party opposed the DLEP Stipulation.

Discussion and Conclusions

Because not all parties to this docket have adopted the stipulations outlined above, the standards set out by the North Carolina Supreme Court in *State ex rel. Utilities Commission v. Carolina Utilities Customers Association, Inc.*, 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 Comprehensive Settlement, the PIMs Settlement, the DCFC Stipulation, and the DLEP Stipulation result from the give-and-take negotiations between the stipulating parties and represent compromises that are just and reasonable to each party. The Commission has fully evaluated the provisions of these stipulations, the testimony proffered by parties in support of these stipulations cited above, and the 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. 7-12

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

The evidence supporting these findings of fact is contained in DEP's verified PBR Application and Form E-1; the testimony and exhibits of the public witnesses; the testimony and exhibits of DEP 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 DoD/FEA witness Reno; the testimony and exhibits of Walmart witness Chriss; the testimony and exhibits of NCSEA witness Lin; the testimony and exhibits of CIGFUR II witness Collins; and the entire record in this proceeding.

Summary of Evidence

DEP'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. However, the Commission has not attempted to recount every statement of every witness in this Order. Below, the Commission summarizes the prefiled testimony of the various witnesses and addresses testimony received at the hearings.

Long-Term Debt

The embedded cost of DEP's long-term debt is undisputed in this proceeding. In her second supplemental testimony, DEP witness Jiggetts presented DEP's embedded cost of debt as of March 31, 2026, at 4.23%. Tr. vol. 7, 1028.

Capital Structure

In DEP witness Heath's direct testimony, he proposed using a capital structure of 53.0% equity and 47.0% long-term debt. Tr. vol. 8, 875. Witness Heath testified that DEP'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, DEP's capital structure was 55.0% common equity and 45.0% long-term debt. *Id*. at 876.

Witness Heath discussed the current credit ratings and forecasted capital needs of DEP and emphasized the importance of DEP's continued ability to meet its financial objectives. *Id*. at 881. Witness Heath noted that DEP 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 866. Therefore, to continue to provide safe, reliable, and cost-effective electric service to its customers, DEP must be able to recover prudently incurred costs, attract sufficient capital, and preserve its financial standing with investors and credit rating agencies. *Id*. at 867. 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 866. 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 DEP maintain strong, investment-grade ratings to assure its financial strength and flexibility and ensure access to capital on reasonable terms. *Id*. at 868.

Discussing DEP's financial objectives, witness Heath addressed specific objectives that support DEP's financial strength and flexibility, including: attaining at least a 53.0% common equity for DEP on a financial capitalization basis; ensuring timely recovery of prudently incurred costs; maintaining sufficient cash flows to meet obligations; and maintaining a sufficient return on equity to fairly compensate shareholders for their invested capital. *Id*. at 867. Witness Heath further testified that the ability to attract capital (both debt and equity) on reasonable terms is vitally important to DEP and its customers, and each of these specific objectives helps DEP both to maintain its investment-grade credit ratings and meet its overall financial objectives. *Id*. at 867-68.

In his direct testimony, DEP witness Coyne testified that based upon his analysis DEP's requested 53% equity / 47% long-term debt capital structure was appropriate. Witness Coyne compared DEP'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 DEP. He concluded that DEP's requested capital structure was reasonable and consistent with industry standards. *Id*. at 1020-21.

Of the intervenor witnesses, only Public Staff witness Walters, CUCA witness LaConte, and DoD/FEA witness Reno addressed capital structure. Based upon their analyses, they recommended a capital structure with a lower equity portion – 51% equity in the case of witnesses Walters and LaConte and 50.0% equity in the case of witness Reno. Tr. vol. 7, 1643; tr. vol. 8, 317, 496. Witness Walters also testified that DEP'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. 7, 1738. Witness Walters evaluated DEP's financial strength and concluded the Public Staff's recommended weighted average cost of capital would support an investment grade bond rating for DEP. *Id*. at 1740, 1742.

Similarly, CUCA witness LaConte testified that DEP's average equity ratio since its last base rate case increase was approved in August 2023 has been significantly below the authorized 53% yet DEP maintained its credit ratings. Tr. vol. 8, 353. Witness LaConte testified that a reasonable capital structure for DEP is 51.0% equity and 49.0% debt, which she testified she determined by reviewing DEP's historical capital structure since 2023 and the authorized common equity ratios for the companies in her proxy group. *Id*. at 355. Witness LaConte further stated her opinion that DEP could maintain its strong credit ratings and implement its capital expenditure program with her recommended capital structure. *Id*.

DoD/FEA witness Reno testified that DEP should be required to manage its capital structure such that it maintains an equity ratio of 50.00%, which she asserted "is consistent with industry averages and reduces the financial burden on ratepayers." *Id.* at 513. Witness Reno testified that DEP's proposed equity ratio of 53% exceeds the maximum of the range of annual average equity ratios approved by regulatory commissions for regulated electric utilities. *Id.* at 512. Witness Reno further stated that her recommendation was based on a review of more than 40 state commission-approved decisions or settlements using a 50.00% common equity ratio, which included natural gas and electric distribution cases. *Id*. at 513-14. Witness Reno noted that these decisions do not establish a mechanical rule that every regulated utility receives a 50.00% equity ratio but instead show that such a capital structure is a reasonable and well-established ratemaking tool when necessary to balance utility financial integrity with customer cost protection. *Id*. at 514.

On rebuttal, DEP witness Heath took issue with the intervenor witnesses' capital structure recommendations. Witness Heath noted that witness Walters and Reno's 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. *Id*. at 889. In response to witnesses Walters, LaConte, and Reno, 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 890.

Witness Heath also responded to witness LaConte's recommendation, which is based on the capital structures of her proxy group as well as DEP's actual quarterly capital structures. Witness Heath explained how DEP manages its capital structure to the authorized structure, which prior to August 2023, was 52% equity and 48% debt. *Id*. at 891-92. 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 892. Witness Heath noted in particular that DEP often makes a large debt issuance early in the calendar year, which is consistent with witness LaConte's Table 5. *Id*.

DEP witness Coyne testified that DEP'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 1031. 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 1150. 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 1151. In response to witness Reno's concerns regarding double leverage, DEP witness Coyne explained that investors value the consolidated entity on a "sum-of-the-parts" basis, expecting each operating segment to provide its appropriate, risk-adjusted return, consistent with the standalone regulatory principle that requires that the utility rates reflect the costs, risks, and financial requirements of the operating utility that provides regulated service to customers. Therefore, under both financial and regulatory principles, it is the subsidiary utility's operating risk that defines the capital structure and cost of capital, not the parent company. *Id*. at 1152. 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 1155-56.

Return on Equity

DEP'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	9.50%[2]
AGO Witness Cassara	7.4%[3]
DoD/FEA Witness Reno	9.29%
CUCA Witness LaConte	9.52%[4]
NCJC, et al. Witness Kihm	9.1%

Walmart witness Chriss, CIGFUR II 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.

DEP Direct Testimony

DEP 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, 952. He testified that regulated utilities rely primarily on common stock and long-term debt to finance long-lived property, plant, and equipment. *Id*. at 955. He further explained that the allowed rate of return for a regulated utility is based on its weighted average cost of capital, where the costs of the individual sources of capital (i.e., debt and equity) are weighted by their respective book values. *Id.* 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 955. Witness Coyne concluded that the Commission's decision in this case should provide DEP 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 on reasonable terms; and sufficient to ensure the financial soundness of DEP's electric utility operations. *Id*. at 955-56.

In estimating a fair ROE for DEP, 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. *Id.* at 949. He specifically noted:

[2] Public Staff witness Fahey recommends a downward adjustment in the rate of return on equity if DEP'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 DEP's proposed MYRP is approved.

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

> 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 949-50.

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 949.

Witness Coyne also testified that he considered DEP'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 950.

Intervenor Direct Testimony (Rate of Return Expert Analysis)

The intervenor ROE expert witnesses generally criticized DEP 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. 7, 1681. Public Staff witness Walters recommended a ROE of 9.50% based on a capital structure of 51% common equity and 49% long-term debt. *Id*. at 1644. Witness Walters testified that DEP'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 10.0%. *Id*.

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 June 5, 2026. *Id*. at 1690. 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*. 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 1691. For his sustainable growth DCF model, he estimated the long-term growth rate based on DEP's current market-to-book ratio and on Value Line's three- to five-year projections of earnings, dividends, earned returns on book equity, and stock issuances. *Id*. at 1695. 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;

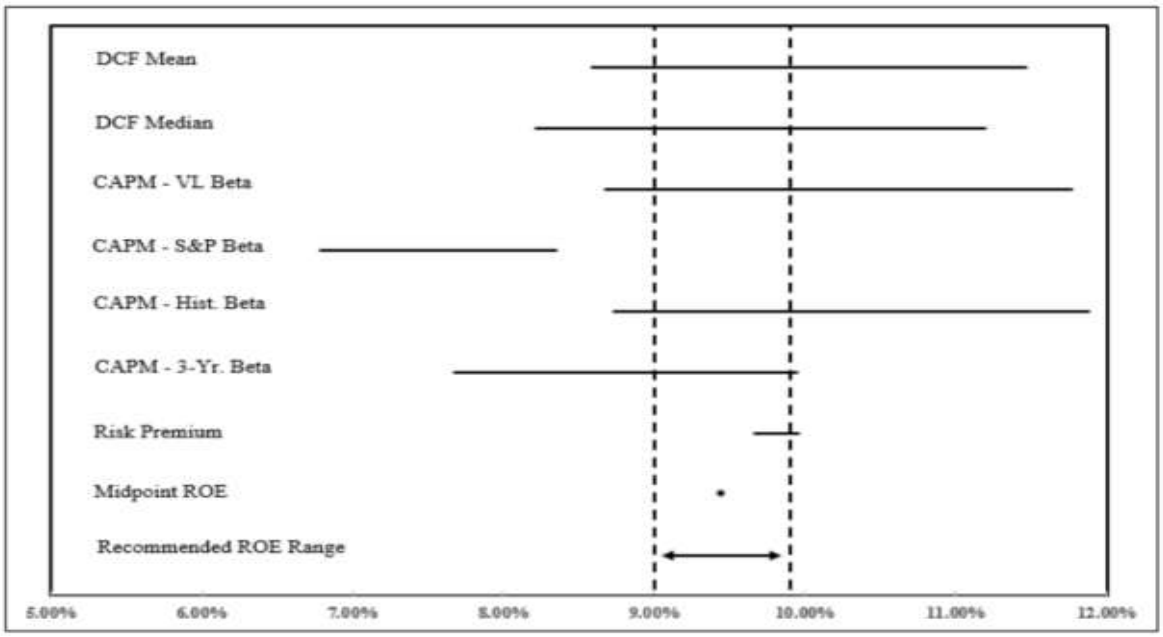
(2) a transition period, consisting of the next five years (i.e., years six through ten); and (3) a long-term growth period starting in year 11 and extending into perpetuity. *Id*. at 1697.

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 1701-02.

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 1702-03. In addition, he evaluated the yield spread between utility bonds and Treasury bonds. *Id*. at 1704. 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 5.84% to produce a 9.98% return on common equity. *Id*. at 1705.

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 1717. 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*. 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 4.96% as recommended by Kroll. *Id*. at 1720. 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 2.20% before subtracting the 4.80% projected risk-free rate to arrive at 6.20%. *Id*. at 1721. 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 9.10% average of his estimated MRPs of 9.2% and 9.0%. *Id*. at 1722. Witness Walters testified that as his average expected market return of 11.62% exceeds the long-term market expectations of several financial institutions, his MRPs are reasonable, if not high-end estimates. *Id*. at 1723-24.

Witness Walters concluded that the appropriate equity cost rate for DEP based on companies in his proxy group is in the 9.00% to 10.00% range, recommending the midpoint of 9.5%. *Id*. at 1728-29. Witness Walters summarized his findings in the following chart:



Id. at 1728.

Witness Walters testified that DEP's PBR Application would shift risk from shareholders to ratepayers by reducing regulatory lag. *Id*. at 1730. As such, he recommended a ROE in the lower half of his range. *Id*. at 1734. He also pointed to potential quantifications (and valuations of those quantifications) of the impact on ROE of an MYRP. *Id*. at 1732.

Public Staff witness Fahey testified in detail about the relatively lower risk DEP 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 1832. 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 1834. 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 1840. Witness Fahey reviewed other North Carolina laws that are favorable to public electric utilities, including 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 1841-43. 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 1856.

Witness Fahey noted that North Carolina statutory law requires the Commission to assess whether granting PBR affects consumer and investor risk. *Id*. at 1859 (citing N.C.G.S. § 62-133.16(c)(1)(a). Based on his analysis, he recommended that if the Commission approves DEP's MYRP, the Commission should make a specific, downward

adjustment to the return on common equity that places DEP's return on equity below recent nationwide averages. *Id*. at 1866.

AGO Direct Testimony

AGO witness Cassara recommended that the Commission reject the framework DEP used to develop its return on common equity proposal of 10.95%. Tr. vol. 9, 402. 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*. 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 421.

Witness Cassara recommended a ROE of 7.4%. *Id*. at 405. Witness Cassara noted that he adopted DEP witness Coyne's proxy group for his analyses, adjusted to remove Dominion Energy and NextEra Energy due to the merger between the two companies that was announced in May 2026. *Id*. at 467. 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 469. He further testified that he did not incorporate forecasted interest rates and used beta coefficients reported by Yahoo! Finance and Zacks. *Id*. at 469-70. The low, high, and average estimates of witness Cassara's CAPM analysis were 6.61%, 7.24%, and 6.93%, respectively. *Id*. at 473. Witness Cassara's DCF analysis resulted in an average return on equity of 6.95% for the constant growth model, and 7.76% for the multi-stage DCF. *Id*. at 481.

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, DEP's financial strength and credit rating, rates of return on common equity authorized by state regulatory commissions, and DEP's business and regulatory risk. Tr. vol. 8, 318. Witness LaConte referenced principles established by the United States Supreme Court for determining a fair return on capital for regulated monopolies. *Id*. at 318-19. Witness LaConte also highlighted DEP's current credit ratings and current economic conditions. *Id*. at 319-20.

Witness LaConte calculated a range of return on equity for DEP using a combination of methodologies: three DCF analyses and two CAPMs. The results of these analyses produced an average return on equity of 9.52%. *Id*. at 330. First, her DCF analysis involved the use of a proxy group of ten 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 335. 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: 9.9.62% (low estimate), 10.35% (mean estimate), and 11.29% (high estimate). *Id*. Witness LaConte's two-stage

DCF produced a return on equity of 10.14%, and her multi-stage DCF produced a range of results from 7.87% to 8.26%. *Id*. at 336-37. 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 7.31% and a projected MRP of 7.39%. *Id*. at 339. Her CAPM analyses resulted in an estimated return on equity of 10.16% using the historical MRP and 9.83% using the projected MRP. *Id*. at 341.

DoD/FEA Direct Testimony

DoD/FEA witness Reno testified that DEP's cost of equity must be estimated, which she calculated by deriving average expected market returns for her proxy group of electric utility companies with comparable risk. Tr. vol. 8, 516. Witness Reno also recounted current macroeconomic conditions and expectations. *Id*. at 498-505.

Witness Reno ultimately recommended a ROE of 9.29%, which she testified was the midpoint of her DCF results. *Id*. at 497. Witness Reno testified that she calculated a range of return on equity for DEP using three different DCF analyses — constant growth DCF Earnings Per Share (EPS), constant growth DCF, (EPS, Dividends Per Share (DPS), and Book Value Per Share (BVPS)), and sustainable growth DCF — which she checked with a CAPM analysis. Witness Reno's DCF results ranged from 8.77% to 9.22% and her CAPM results from 7.31% to 10.52%. *Id*. For the growth-rate component of her constant-growth DCF analysis, witness Reno testified that she took the average of analysts' forecasts from Value Line, Yahoo Finance, Zacks, and CNN Money, which she then refined by averaging Value Line's dividends per share and book value per share estimates with the previously estimated earnings growth rate projections weighted equally. *Id*. at 533. She noted that these calculations produced an average growth rate of 5.79%. *Id*. Witness Reno stated that she applied the CAPM model to serve as a check on the reasonableness of her DCF results. *Id*. at 539.

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 market-to-book 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. 8, 632. Like AGO witness Cassara, witness Kihm also testified on the difference between rate of return on equity and cost of equity for a utility. *Id*. at 634-39. 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 DEP. *Id*. at 695. However, witness Kihm testified that return on equity ignores DEP'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, 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 696.

Intervenor Direct Testimony (Experts Without Specific Analysis)

As noted above, Walmart witness Chriss, CIGFUR II 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 DEP's proposed ROE was significantly higher than rates of return approved by the Commission since 2019. Tr. vol. 8, 417. Likewise, witness Chriss testified that DEP's proposed ROE is significantly higher than most reported ROE decisions by utilities commissions from 2023 to the present. *Id*. at 418-19. Witness Chriss testified that according to S&P Global Market Intelligence, the average of 147 reported utility rate case ROEs authorized by commissions to investor-owned utilities (IOUs) 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*. at 419.

CIGFUR II Witness Collins

CIGFUR II witness Collins recommended that the Commission reject DEP's proposed return on equity of 10.95%. Tr. vol. 9, 641. 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*. Witness Collins testified that DEP's requested return on common equity was materially above recent industry averages for vertically integrated electric utilities, and he further stated that DEP maintained strong investment-grade credit ratings and continuous access to capital markets at returns well below 10.95%. *Id*. at 643.

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. Tr. vol. 8, 452. Witness Lin further testified that DEP'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 452-54.

DEP Rebuttal Testimony

In DEP witness Bowman's rebuttal testimony, she testified that DEP heard customers' concerns about affordability and made adjustments to its initial application designed to mitigate the rate impact on customers without jeopardizing DEP's ability to make reliability investments and serve North Carolina's growth. Tr. vol. 7, 751. Witness

Bowman testified that the primary rate mitigant DEP 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 DEP recognized that the reduction would meaningfully reduce the revenue requirement and keep DEP within witness Coyne's range of reasonableness. *Id*. at 752.

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 June 30, 2026, data. Tr. vol. 8, 1028. He provided a chart comparing the results of his direct testimony analysis with his analysis on rebuttal:

	Sep 30 '25 Data	**June 30 '26 Data**
DCF	10.92%	11.11%
CAPM	11.67%	11.54%
Risk Premium	10.48%	10.60%
Expected Earnings	11.57%	11.62%
Mean of All Methods	**11.16%**	**11.22%**
Flotation Costs	0.09%	0.09%
ROE – Model Results	**11.25%**	**11.31%**
Range Including Flotation Costs	**10.57%-11.76%**	**10.69%-11.71%**
Recommended ROE	**10.95%**	**10.95%**

Id. at 1055.

Witness Coyne noted that DEP's updated return on equity request of 10.48% is lower than his direct and rebuttal model results (excluding flotation costs). *Id*. at 1057. 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 DEP given DEP's investment risk profile and the current higher interest rate environment. *Id*. at 1028, 1054.

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 and Reno'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 1030; *see Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591 (1944) (*Hope*) and *Bluefield Water Works & Improvement Co. v. Public Service Commission*, 262 U.S. 679 (1923) (*Bluefield*).

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 1058. 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 1061. 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 1080-81. Witness Coyne noted that limiting growth in the DCF to long-term GDP was, in his view, an unfounded constraint. *Id*. at 1081.

As it pertained to witness Walters' CAPM model, DEP 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 1089. 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*.

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 DEP. *Id*. at 1065. Witness Coyne noted that the removal of EIX actually biases the proxy group towards excluding the risks associated with severe weather. *Id*. 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 1079.

Witness Coyne criticized the testimony of AGO witness Casara. Witness Coyne stated that witness Cassara's extreme recommendation "would jeopardize the financial integrity of DEP and almost certainly lead to a credit rating downgrade for DEP, as well as be detrimental to existing shareholders of DEP's parent company." *Id*. at 1028. Witness Coyne explained that witness Cassara's discussion of the market to book 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 1037. 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 1039. 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 1040. 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 1074.

In response to witness Cassara's CAPM model, DEP 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 30-year Treasury yield of 4.91% increases witness Cassara's CAPM results by approximately 60 basis points. *Id*. at 1087-88. 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 1090.

In response to NCJC, et al. witness Kihm, DEP witness Coyne emphasized that there are real world consequences of setting the authorized return lower than what is fair and reasonable. *Id*. at 1036. 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 1037-39, 1090.

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 1127. Witness Coyne noted that Duke Energy, the parent company of DEP, issues common equity and incurs costs associated with those issuances that apply to its subsidiaries, including DEP. *Id*.

Witness Coyne further disputed the contentions of witnesses Walters, Fahey, LaConte, Cassara, Reno, and Burgess that PBR and other regulatory mechanisms in North Carolina, including MYRPs, reduce DEP's business risk and regulatory lag, thereby justifying a downward adjustment to the return on equity. *Id*. at 1129. 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 1130. 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 1132-33. Witness Coyne further noted that his analysis and recommendation incorporated the effect of regulatory risk. *Id*. at 1136. Witness Coyne also noted that the Commission addressed these same arguments in the Sub 1300 Order

and stated that the Public Staff offered no new evidence to support a quantitative downward adjustment. *Id*. at 1135.

DEP witness Bateman also addressed intervenor recommendations that the availability of PBR in North Carolina warrants a downward adjustment to DEP's otherwise authorized ROE. Echoing witness Coyne's analysis as well as the Commission's rejection of downward adjustment in the Sub 1300 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. 10, 440. She also refuted 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, and that other states 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, imposing more risk than in other jurisdictions. *Id.* at 440-47. Similarly, DEP witness Coyne noted that Public Staff witness Fahey's focus on limiting his comparison to MYRP frameworks designed precisely like DEP'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. 8, 1136-37.

In DEP witness Heath's rebuttal testimony, witness Heath criticized intervenor return on equity recommendations, explaining that a reduction in authorized return on equity to 7.40% (Cassara), 9.10% (Kihm), 9.29% (Reno) 9.50% (Walters), or 9.52% (LaConte), especially when combined with a reduction in the equity component of the capital structure from DEP's proposed 53% to 51% (Walters and LaConte) or 50% (Reno), would weaken the qualitative (i.e., less constructive regulatory environment) and quantitative (i.e., weaker credit metrics) aspects of DEP's credit quality and diminish its overall financial health, likely increasing future costs to customers. *Id*. at 885. 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 900.

Witness Heath provided an overview of market dynamics since DEP'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 906-07. 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*. at 885, 900.

DEP Settlement Testimony

DEP witness Coyne testified in support of the Comprehensive Settlement. *Id*. at 1160-61. 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 1161. 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 DEP a fair and reasonable allowed return on equity in the context of the broader settlement. *Id*. at 1162.

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 DEP the opportunity to maintain its financial health and credit ratings to the benefit of DEP and its customers. *Id*. at 935. Witness Heath also noted that DEP'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 DEP's ability to effectively manage regulatory risk within a constructive regulatory environment. *Id*. Witness Heath explained that strong credit ratings allow DEP to finance capital projects under more favorable terms, which helps reduce borrowing costs and keep prices affordable for customers. *Id*. at 938. Witness Heath also testified to the benefit of the MYRP, which he indicated has played a critical role in DEP's financial health. *Id*. at 938-39.

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, DEP's embedded cost of long-term debt (4.23%) 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 7.18%. 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

DEP's embedded cost of long-term debt was testified to by DEP witness Jiggetts and is 4.23%. Tr. vol. 7, 1028. The Public Staff testified DEP's proposed long-term debt rate was reasonable and well supported. *Id.* at 1643. The long-term debt cost rate is undisputed, and the Commission accepts it as reasonable and appropriate for use in this case.

Capital Structure

DEP's previously authorized capital structure was 53% common equity and 47% long-term debt. In its PBR Application, DEP requested that same capital structure be approved for use in this case, and its request was supported by the testimony of DEP 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 CUCA witness LaConte, and 50% by DoD/FEA witness Reno. Tr. vol. 7, 1643; tr. vol. 8, 317, 496. The Public Staff, CUCA, and DoD/FEA 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 DEP's capital structure. The Commission takes into account that neither the AGO nor NCJC, et al. offered evidence or recommendations contrary to DEP'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 DEP's need to attract capital so as to maintain the safety, adequacy, and reliability of its service.

DEP's future capital needs are substantial. Witness Heath estimated DEP's capital need over the 2026-2028 period at over $13 billion, including $12.7 billion in projected capital expenditures and $1.2 billion in debt retirements. Tr. vol. 8, 879. The capital investments are needed to ensure continued reliability of DEP's electric grid and will fund replacing and upgrading aging infrastructure, developing new generation resources, and grid modernization. *Id*. at 884. Numerous witnesses at the evidentiary hearing in this case emphasized the unprecedented load growth being experienced by DEP. *See*, *e.g.*, DEP witness Heath, *id.* at 878 ("DEP is in a period of significant capital investment necessary to provide cost-effective, safe, and reliable service to its customers in a time of rising

costs, load growth, and rapidly evolving state and federal requirements."); Public Staff Policy Panel, Tr. vol. 7, 1145 ("Public Staff is cognizant that North Carolina is facing substantial load growth … and that substantial grid improvements are necessary to accommodate new generation and maintain or improve reliability for existing and new customers."); Public Staff witnesses Metz and Thomas, *id.* at 1135 ("[T]he amount of anticipated load growth is staggering[.]"); Public Staff witness Lucas, Tr. vol. 9, 163 ("[We] have unprecedented load growth[.]").

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 DEP a fair and reasonable allowed return on equity in the context of the broader settlement. Tr. vol. 8, 1162. With rapid load growth and its associated capital projects comes risk. Moody's, one of the two credit rating agencies that rates DEP's debt, notes that one of DEP's principal credit challenges is "Potential pressure on credit metrics due to rising debt to fund high capital expenditures." Heath Reb. Ex. 3 at 2.

DEP is operating "below the [Moody's] downgrade threshold", which puts pressure on its credit metrics. Tr. vol. 8, 908 Such pressure creates concerns for the rating agencies about whether DEP can actually raise the amount of capital it needs and keep the integrity of its balance sheet in place for the long term. *Id*. at 908-09. 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, DEP proposed an 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 9.52%. *Id.* at 316; tr. vol. 9, 403. Public Staff witness Walters' recommendation was no more than 9.50%, the mid-point of his ROE range of 9.0% to 10.0%. Tr. vol. 7, 1642. In its rebuttal case, DEP 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 DEP's proposed rate increase due to customer affordability concerns. *Id.* at 751. 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 DEP'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 Return on Equity

The baseline for establishing an appropriate ROE is the constitutional foundation established by the United States Supreme Court's decisions in. As summarized by the Commission in its order in DEP'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 1300 Order at 154; *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. 484, 495, 739 S.E.2d 541, 548 (2013) (*Cooper I*). The Commission must exercise its subjective judgment to balance two competing ROE-related factors – the economic conditions facing DEP's customers and DEP's need to attract equity financing on reasonable terms in order to continue providing safe and reliable service. Sub 1300 Order at 156. 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 1300 Order at 169-71, *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 DEP'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 II* 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 DEP in this case.

Evaluation of Testimony from ROE Expert Witnesses for Stipulating Parties

The Commission's charge in setting an allowed rate of return on equity is to set the level high enough that the utility can attract the capital required to provide safe and reliable service. Counterbalancing this, the Commission must also ensure that the authorized ROE results in the lowest possible rates consistent with this charge. In this proceeding, DEP has stipulated to a cost of equity lower than it requested, and no other party has supported a higher allowed ROE. As such, the Commission concludes that the stipulated 9.8% ROE is high enough to allow the Company to recover its cost of equity and attract new capital. The Commission must next independently determine that the evidence does not support allowance of a lower ROE. As set forth below, the Commission finds and concludes that a 9.8% allowed ROE is supported by the greater weight of the evidence and should be approved.

[5] The Commission acknowledges, but gives little weight to, the ROE testimony and evidence submitted by parties that did not perform the financial model analysis. For example, both Walmart witness Chriss and CIGFUR II witness Collins refer in their testimony to industry average ROEs, tr. vol. 8, 418-20; tr. vol. 9, 641, 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.

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, DEP, CUCA, and DoD/FEA.

Public Staff witness Walters testified that, based upon his analyses and the various methodologies employed by him in those analyses, he estimated DEP's current market ROE to be in the range of 9.00% to 10.0%. Tr. vol. 7, 1646. The stipulated ROE is within this range, albeit at the higher end. But, in evaluating the entirety of the cost of capital 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 10.0%, as well as CUCA witness LaConte, whose recommended ROE (based on mean results) ranged from 8.10% to 10.35%. 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, DEP 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 DEP 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 DEP.

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's and Walters' analyses used the same proxy group and used the DCF, CAPM, and Risk Premium methodologies to derive their range of reasonable ROEs. These methodologies are precisely the type of rigorous analysis 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

[6] The mean of his constant growth DCF model (sustainable growth analysis) mean was 9.71% and in his Risk Premium analysis, using "A"-rated utility bonds, witness Walters derived a 9.98% ROE for 3-month average yields and 9.89% for 6-month average yields.

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 does both (1) bolster 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 be in the upper half of Walters' ROE range. Further, the Commission finds the fact that both Coyne and Walters used the same proxy group and similar analyses to evidence the reasonableness of these proxy groups and analyses underlying the stipulated ROE, further supporting 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. 8, 1055. 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 1161. 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 is further buttressed by his live testimony at the evidentiary hearing, where he reiterated that whatever his own estimate of market-based cost of capital for the utility, the utility and other parties "may decide that some other ROE or other provision is sufficient for them in total to be able to attract the capital they need." *Id*. at 1180-81. He noted that this is "the case here, in the context of this Settlement." *Id*. at 1181. 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. 8, 330. The average of witness LaConte's analytic results is 9.52%.

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 II

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 DEP's cost of equity as 7.40%. Tr. vol. 9, 405. NCJC, et al. witness Kihm calculated DEP's cost of equity as 7.70%, but, notwithstanding that calculation, recommended an ROE of 9.10%. Tr. vol. 8, 630-31. 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 would not, on this record, 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 DEP'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 9.10% recommendation no weight.

Witness Kihm himself describes his testimony as "light on models and long on qualitative analysis." *Id*. at 645. The Commission, however, has already determined, in agreement with DEP witness Coyne, 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. *Id*. at 1158. 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 DEP — he pegs at 7.70% — and the "return on equity" for DEP, 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. 8, 634-39; tr. vol. 9, 432-43. 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. 9, 435. 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 DEP 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. 8, 1039 (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), 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 DEP will impact DEP's ability to compete for capital upon reasonable terms with other business enterprises, including other regulated utilities. *See*, *e.g.*, tr. vol. 8, 1028. DEP 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 DEP the opportunity to maintain its financial health and credit ratings. *Id*. at 935. 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 DEP's financial strength, and further evidence of a constructive regulatory environment. Just as importantly, the fact that [DEP], 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 [DEP]'s ability to achieve its financial objectives.

Id. at 936-937.

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 DEP. While maximizing DEP'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.

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

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, DEP'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 DEP's capital projects. Rather, ROE is the cost DEP 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. DEP 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 DEP's cost of equity. Tr. vol. 8, 960-66.

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. 7, 1746. 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 DEP'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. 9, 458. 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 462-63.

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. 8, 328-29.

DoD/FEA witness Reno similarly recounted regional and national economic conditions, testifying that North Carolina's economy is performing better than the national average in certain categories while facing pressures in others, which should be considered when evaluating customer impacts in this proceeding *Id*. at 506-08.

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 Comprehensive Settlement takes meaningful steps toward addressing these concerns, which is one of the reasons that the Commission approves them. The 68 basis point reduction in ROE from DEP's rebuttal position (10.48%) to the stipulated 9.80% by itself significantly reduces DEP's revenue requirement. Further, the fact that the stipulated ROE is below the lower bound of DEP's rebuttal testimony further 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 DEP's requested revenue requirement as compared to both DEP's direct and rebuttal testimonies. Standing alone, this will result in lower customer bills. The stipulated return on equity also reflects that DEP's ROE is being held flat since the Sub 1300 Order, which in the Commission's judgment further addresses affordability concerns. In addition, the Comprehensive Settlement obligates DEP 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 DEP maintains a comprehensive suite of affordability programs for low-income customers as discussed extensively by DEP witness Colley. Tr. vol. 7, 807-12.

Considering the changing economic conditions and their effects on DEP's customers, the Commission recognizes the financial difficulty that an increase in DEP's rates may create for some of DEPs 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 DEP's customers in reaching its decision regarding DEP'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 DEP 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 DEP 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 DEP's control may necessitate — and indeed have necessitated — the need for DEP to access and invest significant sums during atypical and volatile market conditions. *See*, *e.g.*, tr. vol. 8, 906-08. The Commission must weigh the impact of changing economic conditions on DEP's customers against the benefits that those customers derive from DEP'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 DEP's customers and the contribution of the ROE to those rates, but the Commission must balance the burden against DEP'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 DEP's customers — DEP'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 DEP'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 DEP's customers will experience in paying DEP's adjusted rates. The Commission further concludes that a 9.80% ROE will allow DEP to continue 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 DEP'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. Utilis. 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 Company, 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 in 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 DEP 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. 13-15

Depreciation

The evidence supporting these findings of fact is contained in DEP's verified PBR Application and Form E-1; the testimony and exhibits of DEP 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.

DEP witness Spanos sponsored the 2024 Depreciation Study. Spanos Direct Ex. 1; tr. vol. 7, 447, 449. 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. 7, 449. Witness Spanos testified that certain life span estimates had changed since the Commission last approved DEP's depreciation rates. *Id*. at 456.

Section II, ¶ 6 of the Comprehensive Settlement provides that the Stipulating Parties agree to implement DEP's 2024 Depreciation Study as originally proposed by DEP, adjusted to reflect the Public Staff's proposed adjustments, including recommended adjustments to DEP'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 DEP or the Public Staff. Comp. Settl. § II.6. The Stipulating Parties further agree that DEP will use good faith estimates reflecting a 10% contingency factor for purposes of the settlement schedules, and in a compliance filing, DEP's depreciation consultant will apply the agreed-upon assumptions in his model to develop the final depreciation rates to be implemented by DEP. *Id.* § II.6.a. Finally, the Stipulating Parties agree that their agreement is made solely for purposes of reaching settlement in this proceeding and shall not be construed as an admission by, or agreement of, DEP that the Public Staff's proposed adjustments are appropriate or should be adopted in future proceedings. *Id*. § II.6.b.

In its rebuttal case, DEP 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. 7, 752-53. Witness Jiggetts testified that the withdrawal reduced DEP's requested revenue requirement by $28 million, with depreciation expense calculated using the rates approved by the Commission in Docket No. E-2, Sub 1300. *Id*. at 1056. Witnesses Spanos and Kopp did not oppose the withdrawal, while standing by their respective studies and rebutting the Public Staff's proposed adjustments. *Id*. at 493, 525, 623, 634-35. The Comprehensive Settlement reverses that position. *Id*. at 1099-1100. DEP's settlement schedules update depreciation rates to those proposed by the Public Staff and apply a 10% contingency factor, which decreases the traditional base rate revenue requirement by approximately $7.1 million

relative to DEP's rebuttal position of maintaining currently approved depreciation rates. Jiggetts Comp. Settl. Ex. 2 at 20, l. 15; Ex. 3 at 166-67. Approximately $3.0 million (North Carolina retail) of the associated depreciation expense reflects DEP's good faith estimate of the effect of the 10% contingency factor, which will be replaced by the recalculated depreciation rates in DEP's compliance filing. Jiggetts Comp. Settl. Ex. 3 at 168, l. 7.

Summary of Evidence

Coal Plant Retirement Dates

DEP 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. 7, 455. Witness Spanos testified that he used these factors to evaluate DEP's recommended retirement dates and agreed that they were reasonable. *Id*. at 456. The 2024 Depreciation Study identified the following retirement dates for DEP's coal plants:

Unit	Probable Retirement Date
Mayo Unit 1	December 31, 2030
Roxboro Unit 1	December 31, 2028
Roxboro Unit 2	December 31, 2033
Roxboro Unit 3	December 31, 2033
Roxboro Unit 4	December 31, 2028

Spanos Direct Ex. 1 at 57.

Witness Spanos testified that since the last approved depreciation rates in DEP's previous rate case, Mayo Unit 1 and Roxboro Units 2, 3, and 4 have life spans that are planned to be longer. Tr. vol. 7, 456. Based on the Commission's order in the prior case, Mayo Unit 1's probable retirement date changed from 2028 to 2030, Roxboro Unit 2 changed from 2028 to 2033, Roxboro Unit 3 changed from 2027 to 2033, and Roxboro Unit 4 changed from 2027 to 2028. *Id*. Witness Spanos testified that the new life span for the units are reasonable and consistent with both DEP's plans as well as industry expectations. *Id*.

Public Staff witness Thomas addressed coal plant retirements and associated life spans in his direct testimony. Witness Thomas testified that the retirement dates for DEP's coal fleet in the 2024 Depreciation Study are consistent with the 2023 Carbon Plan and Integrated Resource Plan (CPIRP) and the 2025 CPIRP. Tr. vol. 7, 1525-26. Accordingly, witness Thomas testified that the Public Staff believes that these retirement dates are appropriate for establishing depreciation rates in this proceeding. *Id*. at 1526-27.

Net Salvage

DEP 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. 7, 457, 493.

Witness Spanos testified that net salvage must be incorporated in depreciation, as it represents the future cost that is expected to be incurred by DEP. *Id*. at 495. 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 495-97. Witness Spanos testified that the net salvage percentages estimated in DEP'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 DEP's operating personnel and general knowledge and experience of industry practices; and general industry trends. *Id*. at 458.

Regarding net salvage, the parties presented four main topics of disagreement: (1) Sutton plant decommissioning costs; (2) Weatherspoon cooling pond closure costs; (3) contingency; and (4) the estimated future net salvage percentage for Account 369.00 – Services. Witness Spanos testified that, for DEP's power plants, the Public Staff proposed to maintain the weighted net salvage percentages that are based on the interim survivor curve and probable retirement dates and varies the development of the total net salvage component for generating accounts. *Id*. at 498-99. These other components include exclusion of various costs, such as (1) components of the Weatherspoon generating facility, (2) the majority of the decommissioning costs associated with the Sutton generating facility, and (3) the contingency factor of all facilities. *Id*. at 499. Additionally, Public Staff witness McCullar proposed a different net salvage estimate for Distribution Account 369.00 – Services. *Id*. at 491, 509-10.

Sutton Plant Decommissioning Costs

Witness Lucas recommended that the Commission not allow DEP to recover its proposed Sutton plant decommissioning costs of $6,149,100 and proposed that DEP instead be allowed to recover only $247,000 because DEP was unable to provide any documentation or calculations to support the higher amount. *Id.* at 1603. To determine the Public Staff's recommended amount, witness Lucas testified that he used the gross decommissioning costs for the Sutton Plant in the prior decommissioning study that was filed in the Sub 1142 case, scaled up the 5% indirect cost to reflect the new 11% indirect cost percentage in the 2024 Decommissioning Study, and removed the 20% contingency. *Id*. at 1603-04.

In rebuttal, witness Kopp testified that witness Lucas mischaracterizes what the $6,149,100 represented. *Id.* at 631. Witness Kopp testified that the Sutton coal and gas units have already been demolished, and therefore, the dismantling and demolition costs for the Sutton plant were correctly and intentionally excluded from the decommissioning cost estimates in the Decommissioning Study. *Id*. Witness Kopp testified that the $6,832,300 gross cost (and the $6,149,100 net cost after salvage credit) represents the value of the remaining on-site materials and supplies inventory, and the costs to remove this inventory are still a necessary component of the process to fully and safely decommission a site. *Id*. at 632. Witness Kopp testified that this asset class was treated identically to other sites, and a standard 10% inventory salvage credit was applied, resulting in a net inventory book value of $6,149,100. *Id*.; *see also* tr. vol. 7, 500.

Weatherspoon Cooling Pond Closure Costs

Witness Lucas recommended that the Commission not allow DEP to include $26.5 million for Weatherspoon cooling pond closure costs. *Id.* at 1604. He noted that witness Spanos recommended that this closure cost not be included in this rate case on page 375 of the 2024 Depreciation Study, and that this cost removal should have been reflected in the Decommissioning Study. *Id*.

In rebuttal, witness Spanos testified that the $26.5 million associated with the Weatherspoon cooling pond closure has been excluded from the weighted net salvage component proposed by DEP, as noted in a footnote at the bottom of Table 3 presented on page VIII-3 of the 2024 Depreciation Study. *Id.* at 499. Witness Spanos testified that the costs to close the Weatherspoon cooling pond should still be recovered in rates, and that the cooling pond closure amount should not be anticipated to stay in service until the end of the facilities' life. *Id*. at 500. Witness Spanos testified that the closure costs were removed from the 2024 Depreciation Study for purposes of developing the weighted net salvage accrual to remove the escalation component to the date of that asset's retirement; however, those costs are still expected to be prudently incurred to facilitate closure of the asset and should accordingly be recovered in rates. *Id*.

Witness Kopp also disagreed with witness Lucas's recommendation, testifying that, although Weatherspoon's coal-fired steam units were retired in 2011, the cooling pond is an active site environmental obligation that must be closed, at an estimated physical cost of $26,551,000. *Id.* at 633. Witness Kopp testified that, because the Decommissioning Study is an engineering document designed to identify and quantify the total physical and environmental cost liabilities of decommissioning DEP's fleet, excluding the cooling pond closure cost would result in an incomplete, artificially low projection of DEP's actual environmental liabilities, even if a different accounting mechanism is used to recover those costs. *Id*. at 633-34.

Contingency

DEP's Decommissioning Study includes a 20% adder for contingency. Speros Direct Ex. 4; tr. vol. 7, 1601. Similar to Public Staff witness Thomas, witness Lucas recommended that DEP 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. 7, 1601-02. Witness Lucas testified that DEP could recover the actual reasonable and prudent costs, even if they exceed DEP's Decommissioning Study estimates, in the same manner as other costs are recovered in a rate case, after decommissioning is complete. *Id*. at 1602. Witness Lucas noted that this position was not a departure from Public Staff testimony in previous cases, as witness McCullar had previously recommended that DEP not recover decommissioning contingency on page 13, line 16 of her testimony filed in the Sub 1142 case. *Id*. at 1603.

In rebuttal, witness Spanos testified that contingency costs are a standard component of decommissioning studies. *Id.* at 502. 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, and that there is no precedent preventing DEP from proposing an updated contingency factor based on an updated decommissioning study. *Id*. Finally, given that contingencies have approached or exceeded 20% in many instances in recent years, witness Spanos testified that a 20% contingency factor is more appropriate. *Id*. Witness Spanos further noted that the Sub 1142 case cited by witness Lucas ultimately resulted in a 10% contingency factor as a result of a settlement between the parties, and that in DEP's most recent rate case, Docket No. E-2, Sub 1300, witness McCullar recommended the continued use of the approved 10% contingency factor. *Id*. at 504-05.

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, a 20% contingency is typically applied to cover a greater level of logistical and structural complexity. *Id.* at 624. Witness Kopp testified that the standard contingency range for estimates like decommissioning studies is 15% to 30%, so the 20% contingency in DEP's Decommissioning Study is on the lower-middle end of this range. *Id*. at 625. Witness Kopp testified that, while witness McCullar may have proposed a 0% contingency in a previous docket, that proposal does not represent Commission precedent or sound cost-estimating practice. *Id*. at 626. Witness Kopp also noted that witness Lucas's 0% contingency recommendation contradicted his own testimony in other recent filings, such as the DEC rate case in Docket No. E-7, Sub 1276, where witness Lucas explicitly recommended a 10% contingency factor. *Id*. Witness Kopp testified that witness Lucas did not offer any engineering or cost-estimating basis to explain why his previous 10% contingency was appropriate in previous testimony but is now invalid in this case. *Id*. Witness Kopp testified that regulatory precedent in other states supported the inclusion of contingency. *Id*. at 628. He addressed witness Lucas's argument that DEP 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 628-29. Witness Kopp testified that doing otherwise, as witness Lucas suggested, 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*. at 629. 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*. Witness Kopp testified that DEP's historical experience with decommissioning projects confirms the necessity of the 20% contingency factor, as actual decommissioning costs have frequently met or exceeded the planning-level estimates prepared in previous studies, even when those studies included a 20% contingency. *Id*. at 630.

Net Salvage for Distribution Account 369.00 – Services

Public Staff witness McCullar proposed the continued use of the currently approved -30% estimate future net salvage percentage for Account 369 – Services. *Id.* at 1625. Witness McCullar's proposed net salvage estimate for this account, along with

DEP's proposed net salvage estimate and the currently approved net salvage percentage, are included in Table 1 of her testimony and shown below.

Table 1: Comparison of Proposed Estimated Future Net Salvage Percentage Recommendations

Account	Description	Current Approved	DEP Proposal	Public Staff Proposal
369.00	Services	-30%	-40%	-30%

Id. at 1625.

Witness McCullar testified that this estimate is more reasonable than DEP's proposed figure because the Public Staff's estimated future net salvage percentage will allow DEP an appropriate recovery of its actual costs, will contribute to building the book reserve for future retirement costs, and is more reasonable for customers. *Id*. Witness McCullar stated that her recommendation resulted in an annual accrual that is seven times the average actual net salvage costs recently incurred by DEP. *Id*. at 1627-28. She testified that her recommendation provides recovery of estimated cost of removal expected to be incurred in the near future and builds the book reserve for estimated future cost of removal associated with future retirements. *Id*. at 1628. Witness McCullar testified that since the Public Staff's proposed net salvage annual accrual is seven times recent net salvage costs, the Public Staff is not proposing to simply expense the net salvage costs. *Id*.

Witness McCullar testified that her analysis and witness Spanos's analysis both followed similar steps of reviewing the historic net salvage data and other information provided by DEP, their previous experience, and the use of informed judgment. *Id*. at 1620-21. Witness McCullar pointed out that the difference in their proposals is most likely related to the use of informed judgment. *Id*. at 1621. Additionally, witness McCullar testified that 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. 7, 510. 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 Public Staff's approach is premised on the idea that net salvage accruals should be similar to, if not the same as, recent net salvage costs and that future net salvage levels will be the same. *Id*. at 511. However, witness Spanos testified that net salvage accruals are intended to allocate future net salvage costs over the life of DEP's assets and therefore should not be expected to be the same as recent net salvage costs. *Id*. He noted that Public Staff's net salvage methodology fails to recognize that the level of net salvage is not static and will change over time, and that Public Staff's methodology will not recover expected increases in future net salvage until after they occur, resulting in intergenerational inequity as future customers will be paying for the costs of assets that have already been retired. *Id*. at 512. Witness Spanos noted that the overall data on pages VIII-115 and VIII-116 of the 2024 Depreciation Study show that the average annual net salvage amount has been negative 48 percent over the last

46 years, and negative 61 percent over the last five years; given this trend, DEP's estimate of negative 40 percent is already conservative. *Id*. at 513. Witness Spanos also noted that the texts cited by witness McCullar, as well as FERC and the USOA, support the methodology he uses for DEP's depreciation study. *Id*. at 514-19. He further testified that the Public Staff's proposed estimates for these accounts are not representative of DEP data. *Id*. at 511.

General Plant Amortization Periods

Witness Spanos testified that general plant amortization accounting is used for general plant accounts that include a large number of units with a relatively low unit cost, and because the cost of tracking retirements for every single asset (such as every computer or chair owned by the utility) typically exceeds the benefit of doing so, most utilities use (and most commissions have approved) general plant amortization for these accounts. Tr. vol. 7, 505. Witness Spanos testified that when using general plant amortization, an amortization period is established based on the expected average life of assets in the account, and when an asset reaches the end of that amortization period, it is retired. *Id*. Witness Spanos testified that in this case, DEP has proposed using general plant amortization in the 2024 Depreciation Study for the same accounts that use general plant amortization under DEP's currently approved rates. *Id*. at 506. Witness Spanos testified that he recommended the same amortization periods for DEP that were proposed for DEC in Docket No. E-7, Sub 1329, because it is reasonable to have consistency between the two companies for these similar types of assets. *Id*.

DEP proposed changing the amortization period for Account 391 – Office Furniture and Equipment from the currently approved 20 years to 15 years, and the amortization period for Account 397 – Communication Equipment from the currently approved 20 years to ten years. *Id.* at 1630. Public Staff witness McCullar recommended the continued use of the currently approved 20-year amortization period for both accounts. *Id*. at 1636. Witness McCullar testified that, since the Commission approved DEP's use of amortization accounting in the Sub 1142 proceeding, the Commission has consistently approved settlements that continued the use of 20-year amortization periods for these accounts, including in the Sub 1300, Sub 1219, and Sub 1142 proceedings. *Id*. at 1631-33. Witness McCullar testified that the amortization periods proposed by DEP for these two accounts are not based upon the service life estimates previously used for the asset under depreciation accounting because the approved service life for Account 391 was 20 years and the approved service life for Account 397 was 27 years. *Id*. at 1635. She further testified that she previously filed testimony in the Sub 1142 case discussing the previously approved 20-year service life for Account 391 and the previously approved 27-year service life for Account 397 based on data provided by DEP in Docket No. E-2, Sub 1025. *Id*. at 1635-36. Based on the analysis she previously provided in the Sub 1142 case and because DEP did not provide any information supporting a change to the currently approved amortization periods for these accounts, witness McCullar recommends the continued use of the currently approved 20-year amortization periods for these accounts. *Id*. at 1636. Witness McCullar testified that this results in a reduction to DEP's proposed annual accrual related to Reserve Adjustment for Amortization, as reflected in McCullar Exhibit 1. *Id*. at 1636-37.

In rebuttal, witness Spanos disagreed with witness McCullar's longer amortization periods, reiterating that it is most reasonable to use the same amortization periods that are currently approved for DEC. Tr. vol. 7, 506. Witness Spanos further testified that witness McCullar is simply maintaining the amortization periods that were approved in a previous settlement, when an amortization period should reflect the most reasonable useful life of the assets in each account. *Id*. at 507.

Witness Spanos testified that Account 391 contained a combination of furniture and equipment, but that there is a significantly higher percentage of equipment in the account because the majority of the assets in the account, the assets most recently added to the account, and the assets expected to be added to the account going forward are all office equipment. *Id*. Witness Spanos testified that office equipment is expected to have a useful life between 10 and 15 years, and therefore, a shorter 15-year amortization period is most appropriate. *Id*.

Witness Spanos testified that Account 397 contains communication equipment, which is heavily technology-based and expected to be replaced much sooner than the 20 years proposed by witness McCullar. *Id.* Therefore, witness Spanos testified that a useful life longer than 10 years is not consistent with the useful life of these assets. Witness Spanos noted that there is a high level of additions for new assets in this account being installed, but since the current approved amortization period is 20 years, there are no retirements that have been recorded. *Id*.

Finally, witness Spanos noted that for both Account 391 and 397, witness McCullar provided direct testimony in May 2026 in the pending DEC case, Docket No. E-7, Sub 1329. *Id.* at 508. Witness Spanos testified that, in that case, he proposed the same estimates that are being proposed for this case for Accounts 391 and 397, and witness McCullar proposed no adjustment to his proposed amortization period for either account. *Id*.

Deferral of Impact of Accelerated Depreciation for Subcritical Coal Plants

In Docket No. E-2, Sub 1300, DEP 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 Mayo and Roxboro Units 3 and 4 in the 2021 Depreciation Study. Tr. vol. 7, 1005. House Bill 951 (S.L. 2021-165) allowed DEP 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 1300 Order, DEP 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. *Id*.

In this proceeding, DEP 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 (Senate Bill 266), which amended N.C.G.S. § 62-172 to allow DEP to

securitize 100% of the remaining net book value of subcritical coal facilities upon retirement. Tr. vol. 7, 1005-06; tr. vol. 8, 27. The annual depreciation deferral is $63.527 million on a North Carolina retail basis. Jiggetts Comp. Settl. Ex. 3 at 139.

The Public Staff did not recommend any adjustment to DEP'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. 8, 37.

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 DEP in the 2024 Depreciation Study sponsored by witness Spanos, modified to reflect the Public Staff's proposed adjustments, including those Public Staff adjustments made to DEP's 2024 Decommissioning Study, except that a 10% contingency factor shall be applied in lieu of the contingency percentages proposed by either DEP 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 DEP, which will then be included in DEP's compliance filing to this Commission.

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

In reaching this conclusion, the Commission notes that 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 adopts witness McCullar's proposed net salvage estimate for Account 369, and her proposed 20-year amortization periods for Accounts 391 and 397, and reflects the Sutton and Weatherspoon decommissioning cost adjustments recommended by Public Staff witness Lucas. *See* tr. vol. 7, 1604, 1618, 1637; tr. vol. 8, 37. The probable retirement dates for DEP's coal units were not contested. *See* tr. vol. 7, 498, 1526-27. The 10% contingency factor falls between DEP's originally proposed 20% and the Public Staff's proposed 0%, and is the same contingency factor agreed upon in DEP's prior rate cases and reflected in current rates. *See* tr. vol. 7, 502, 504-05. Considering all of the evidence, including the competing testimonies of witnesses Spanos, Kopp, Lucas, and McCullar, the Commission concludes that these provisions of the Comprehensive Settlement are just and reasonable to all parties in light of all the evidence presented.

In addition, based on the entire record in this proceeding, the Commission concludes that it is appropriate to grant DEP's request to defer to a regulatory asset 100% of the impact of accelerating the depreciation of DEP's subcritical coal plants based on the 2021 Depreciation Study for an annual deferral of $63.527 million on a North Carolina

retail basis. This preserves DEP's ability 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. 16

Base Period Plant-Related Items

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

Summary of Evidence

Generation Capital Investments

DEP witness Walsh described DEP's traditional (fossil) and renewable fleet and the operational performance of those assets during the test year. Tr. vol. 7, 239-41, 249-51. Witness Walsh testified regarding the major capital projects undertaken by DEP for maintenance of the fossil and renewable fleets since DEP's last general rate case in Docket No. E-2, Sub 1300, which was a three-year MYRP (2023 Rate Case). *Id*. at 245-47. 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 explained that DEP 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 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 244-45. Witness Walsh addressed how DEP ensures generating assets remain operationally reliable during extreme weather and "peak load" demand events and how DEP's processes and weather preparedness helped it prepare for Hurricane Helene. *Id*. at 241-44. Witness Walsh described how DEP controls and mitigates O&M expense increases. *Id*. at 247-49. He testified to his opinion that DEP prudently incurred capital and O&M costs to operate the traditional/renewable fleets and that DEP prudently operated the traditional/renewables fleet during the test period. *Id*. at 249, 250-51.

DEP witness Flippin described DEP'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. *Id.* at 166-67, 169-75. Witness Flippin provided an update on Duke Energy's plans related to subsequent license renewal (SLR) for the existing nuclear fleet. *Id*. at 167-68. She testified to the exceptional

performance of DEP's nuclear fleet during the test period, how DEP ensures that the fleet remains operationally reliable during extreme weather and "peak load" demand events, and initiatives DEP has undertaken to increase nuclear operational efficiency. *Id*. at 201-03. Witness Flippin discussed the significant cost drivers impacting O&M expense for the fleet and how DEP manages O&M costs for the nuclear units. *Id*. at 195-98, 203.

Public Staff witnesses Thomas and the Renewables Panel reviewed DEP's capital investments in its generation fleet. Witness Thomas reviewed DEP's steam and natural gas plant in service during the historical period and did not recommend any adjustments to these investment costs. *Id.* at 1510-11, 1527-28. The Renewables Panel reviewed historic period solar, battery, and hydro capital plant in service and recommended an adjustment to one battery project. *Id.* at 1210-18. The Renewables Panel's recommendation is addressed in more detail below.

Person County Combined Cycle Construction Work in Progress

DEP witness Jiggetts explained that pro forma NC-3050 adjusts rate base to include CWIP related to baseload generation projects as allowed per N.C.G.S. § 62-133(b)(1). *Id.* at 990. The only CWIP included in this adjustment is that associated with the construction of the Person County CC. *Id*. As of March 31, 2026, the CWIP balance for Person County CC was approximately $566 million system and $364 million on a North Carolina retail basis. Jiggetts 2d Supp. Direct Ex. 3 at 172.

Public Staff witness Lawrence testified that the Person County CC Units 1 and 2 currently under construction were selected within the integrated resource planning process as an asset that was to serve both DEC and DEP customers. Tr. vol. 7, 1549-50, 1578-80. As such, he proposed that the amount for DEP's CWIP pro forma adjustment only include the portion of the DEP share, which would decrease the CWIP pro forma by approximately $341 million system. *Id*. at 1550.

In her rebuttal testimony, DEP witness Jiggetts testified that DEP disagrees with the Public Staff's proposed adjustment to remove a portion of Person County CC CWIP. She stated that the Person County CC project is a generating asset for DEP, and as such DEP included the full CWIP associated with the asset in this case. *Id.* at 1053. She noted that the joint dispatch of assets between DEP and DEC is addressed by the Joint Dispatch Agreement as established and approved by the Commission. *Id*. Nevertheless, in the interest of customer affordability, DEP agreed in rebuttal to remove approximately $341 million (system) from the CWIP amounts from this case. *Id*. Witness Jiggetts indicated that the $341 million will continue to accrue allowance for funds used during construction (AFUDC), and DEP reserved the right to seek recovery of this amount as part of a CWIP rider under S.L. 2025-78 (Senate Bill 266) or in a future proceeding. *Id*. at 1053-54.

The Comprehensive Settlement memorializes DEP's agreement to accept the Public Staff's reduction of CWIP in rate base, as agreed in the rebuttal testimony of witness Jiggetts. Comp. Settl. § II.7. The Stipulating Parties also agreed that CWIP

amounts included in rate base will stop accruing AFUDC at the date upon which new rates in this proceeding are effective and that CWIP amounts not included in rate base will continue to accrue AFUDC. *Id*. Per the Comprehensive Settlement, DEP may seek to include CWIP amounts not included in rate base in this proceeding in rate base in future rate case proceedings or proceedings under S.L. 2025-78 (Senate Bill 266). *Id*. As a result of the settled adjustment, the Person County CC CWIP included in rate base is approximately $225.2 million on a system basis ($144.8 million North Carolina retail), compared to the approximately $566.3 million system ($364.0 million North Carolina retail) included in DEP's second supplemental filing. Jiggetts Comp. Settl. Ex. 3 at 172-73.

Nuclear M&S Inventory

Public Staff witness Lawrence recommended removal of the nuclear materials and supplies (M&S) inventory that has been on hold for four or more years. Tr. vol. 7, 1582. He explained that M&S inventory is included in rate base but not depreciated. *Id*. at 1581. Witness Lawrence testified that the parts are unusable in their current condition and have been for a significant amount of time. *Id*. at 1582.

In her rebuttal, witness Flippin disagreed with the Public Staff's recommendation. Witness Flippin explained that this inventory is held to support plant operations and is therefore of benefit to customers, regardless of the duration of the hold. She noted that removing this inventory solely on the length of the hold period does not reflect why the hold status exists and how nuclear inventory management works. Witness Flippin continued that including items 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 Flippin noted that the Public Staff cited no policy, standard, or precedent to support its recommendation. *Id.* at 218-20.

The Comprehensive Settlement provides that DEP will accept the Public Staff's adjustment, reducing nuclear M&S inventory (approximately $7.5 million system) for inventory on quality hold greater than four years. Comp. Settl. § II.34.

Riverside Battery Energy Storage System

DEP witness Tompson testified regarding the forecasted costs and construction timeline for the Riverside Battery Energy Storage System (BESS) project. Witness Tompson explained that the updated cost and schedule forecast for Riverside reflects increased costs and a revised in-service date due to engineering and design challenges. Tr. vol. 7, 369. Witness Tompson also highlighted the benefits that the Riverside project will deliver for customers and described DEP's efforts to ensure full investment tax credit (ITC) eligibility for the project. *Id*. at 373-74. Furthermore, witness Tompson noted that DEP has improved internal processes related to constructing batteries in a variety of settings. *Id*. at 375. He pointed out that developing and executing the Riverside project

provided DEP with the invaluable experience of supporting bulk system needs with a distribution-connected battery. *Id*. at 375.

The Renewables Panel testified that Riverside BESS project costs increased by 41%, and the project was delayed nineteen months. *Id.* at 1195. The delay was due in part to an original engineering design that was incomplete, problematic, and missing design elements. *Id*. at 1215. Additionally, the Renewables Panel testified that DEP hired a contractor who was not licensed in North Carolina. *Id*. at 1216. The Renewables Panel recommended that the Commission disallow $430,418 in original engineering design costs and costs to store battery components for the Riverside project. *Id*. at 1217. Citing DEP's project oversight role, the Renewables Panel concluded that the Commission should hold DEP responsible for costs related to the contractor challenges and redesign work. *Id*. at 1216-17.

DEP witness Tompson disagreed with the Renewables Panel's recommendation to disallow certain Riverside project costs. *Id.* at 391-92. Witness Tompson responded that the Renewables Panel did not contend that DEP acted imprudently or unreasonably in identifying the contractor issues or in the steps it took to address them. *Id*. at 392. Witness Tompson posited that the Renewables Panel concluded that DEP's review and milestone oversight allowed it to identify design-related issues early in the process prior to completion and acknowledged that DEP took appropriate corrective steps to address and resolve the issues. *Id*.

The Comprehensive Settlement provides that DEP will accept the Public Staff's adjustment to remove $0.4 million in system plant costs associated with the Riverside BESS. Comp. Settl. § II.33.

Transmission and Distribution Base Period Investments

In their direct testimonies, DEP witnesses Guyton and Fogg discussed DEP's distribution and transmission investments since its last general rate case. DEP witness Guyton testified that DEP has invested approximately $2.0 billion in distribution system additions since the currently effective PBR approved by the Commission in Docket No. E-2, Sub 1300 (PBR1), which included investments made as part of DEP's MYRP1. Tr. vol. 8, 714. Witness Guyton testified that approximately 35% of DEP's distribution investments were comprised of MYRP1 projects and the remaining 65% of the distribution investments were for serving new customers, lighting installations, and reactive maintenance and service restoration. *Id*. at 715. Witness Guyton explained that the MYRP1 distribution investments include projects in the following categories: (1) Substation and Line, which includes twelve sub-programs; (2) Retail and System Capacity; (3) Hazard Tree Removal; (4) Other non-distribution MYRP1 Projects. *Id*. at 728.

In his direct testimony, witness Fogg testified that since DEP's PBR1, DEP has made targeted investments in its transmission system totaling approximately $740 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. Tr. vol. 7, 87. He explained that the majority of the spend was for reliability & integrity work (35%) and capacity improvements (26%). *Id*. at 87-88. In terms of transmission MYRP1 investments, he explained that the transmission projects included grid investments critical to maintaining and improving the transmission system which provides the connection between DEP's generation facilities and its distribution system and customers and that the projects included investments in system intelligence, hardening and resiliency, transformer and breaker upgrades, and capacity and customer planning. *Id*. at 93.

In his direct testimony, Public Staff witness Lawrence did not take issue with any of the base period transmission investments, other than the land purchase discussed below. *Id.* at 1545-47. In their direct testimony, the Distribution Panel took issue with some of the distribution capital investments made by DEP since its last rate case, as discussed in more detail below. Specifically, the Public Staff Distribution Panel took issue with certain Substation Optimization investments and the inclusion of a portion of the NextGen GIS project in rate base.

Substation Optimization

In his direct testimony, DEP witness Guyton 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. 8, 728. More specifically, he explained that the work consists of the following twelve sub-programs which are summarized in Guyton Direct Exhibit 5 and were discussed in detail in his direct testimony filed in Docket No. E-2, Sub 1300:

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

Id. at 728-29.

He 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 729. 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 DEP's reliability performance given these investments. Tr. vol. 7, 1336. He testified that the Public Staff understands that distribution system upgrades are necessary and various 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 DEP 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 substation and circuits. *Id*. at 1359. However, he testified that the Public Staff is concerned that upgrading the distribution system has become somewhat of an enabler of capital spending for DEP when coupled with the use of an MYRP. *Id*. 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*. at 1360. 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*. Witness T. Williamson testified that he identified a group of 13 DEP retail substations, including the Falls 230kV substation, with better than average reliability that highlight the Public Staff's concern with prioritization of reliability upgrades and the substantial increase in distribution spending over the last several years. *Id*. at 1361-62. While the Public Staff did not make any recommendations to disallow any of the base Substation Optimization investments, witness T. Williamson testified it is unlikely they would recommend approval of those same projects today for a future MYRP. *Id*. at 1362.

On rebuttal, DEP witness Guyton disagreed with the Distribution Panel's conclusions and recommendation regarding DEP's Substation Optimization work testifying that average is not the target and that customers are not best served if DEP only invests on circuits and substations after they fall below a historical "average," that reliability metrics alone do not capture risk and condition, and also ignore resiliency benefits of the work performed. Tr. vol. 8, 789. He testified that DEP'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 that a system managed only to avoid below average performance is a system permanently trending towards decline. *Id*. 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*. 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*. at 789-90. Witness Guyton further testified that completed MYRP1 Substation Optimization work was already producing measurable reliability benefits. *Id*. at 800. Specifically, for the 100 MYRP1 Rate Year 1 Substation Optimization substations placed in service by the end of 2024, witness Guyton testified that SAIDI improved by approximately 13% and SAIFI improved by approximately 18%, compared to a 0.7% SAIDI worsening and a 1.6% SAIFI worsening for substations without Substation Optimization improvements. *Id*.

Though not explicitly addressed in the Comprehensive Settlement, the Public Staff did not make any base adjustments for Substation Optimization projects. However, the Public Staff's concerns regarding base Substation Optimization investments in part informed their recommendations as they relate to MYRP2 Substation Optimization projects, as discussed further herein in Evidence and Conclusions for Finding of Fact No. 31 and as resolved in the Comprehensive Settlement.

NextGen GIS

In his direct testimony, DEP witness Guyton testified that the DEP Geospatial Information System (GIS) Replacement project, an enterprise-wide project, was previously approved for inclusion in the DEP MYRP1 but due to the timing of the estimated in-service date of the December 2026, was not within the window for inclusion in the DEP MYRP1. *Id.* at 751-52. 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.* at 752. 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 so a full replacement of the current GIS system is needed to ensure the continuation of a resilient and reliable electric grid. *Id*. He explained that the total capital cost for the project in the MYRP2 is $29.7 million. *Id*. In her second supplemental testimony, DEP witness Abernathy testified DEP made an adjustment to reflect that Phase 1 of the NextGen GIS project went into service in February 2026 and therefore should not be included in the estimate for MYRP2 for this project. Tr. vol. 7, 925. 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*.

In the Public Staff's Distribution Panel's direct testimony, the panel recommended the removal of approximately $19.7 million in costs related to DEP's NextGen GIS program for the portion placed in service in March 2026 on the basis that it is not used and useful. *Id*. at 1397-98. The Distribution Panel agreed with DEP's supporting documentation that replacing its current GIS software, GE Smallworld, is necessary due to the lack of ongoing support and new features, as well as the inability to integrate with newer technology. However, based on DEP's historic performance and discovery responses, the Distribution Panel does not agree that the project is partially placed in service or that it will be completed on schedule to include in DEP's proposed MYRP2 timeline. Accordingly, the Distribution Panel does not consider the project used and useful from a ratepayer perspective. *Id*. at 1394, 1398.

In his rebuttal testimony, DEP witness Teckenbrock addresses the Distribution Panel's contention that the $19.7 million portion placed in service on March 31, 2026, is not used and useful because the project is not yet fully in service for DEP's customer or employees and will not be fully operational until June 2027. *Id.* at 640. Witness Teckenbrock testified that the Distribution Panel's position does not reflect how a large, enterprise-wide system like NextGen GIS is actually built and brought into operation. *Id*. at 641. 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*. 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*.

In his rebuttal testimony, DEP witness Speros addressed the Distribution Panel's recommendation from an accounting and ratemaking perspective. *Id.* at 427. He testified that under Duke Energy's capitalization policy and consistent with FERC's 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 approximately $20 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 427, 431-34. 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 433-34. He explained that 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*. at 434. 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, DEP witness Jiggetts testified that if the Commission believes recovery should be deferred until the entire project is placed in service in 2027, DEP respectfully requests an accounting order that allows it to establish a regulatory asset to defer the

depreciation expense it will incur on the $19.7 million system ($15.4 million North Carolina retail) in project costs, property taxes, as applicable, and a return on this investment, for full recovery in a future rate proceeding. *Id.* at 1055.

Section II, ¶ 32 of the Comprehensive Settlement provides that the Stipulating Parties agree to remove the NextGen GIS project from the base case and the MYRP in this proceeding. Comp. Settl. § II.32. The Stipulating Parties further agree that DEP 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*.

Land Purchases

Public Staff witness Lawrence testified that in his investigation into the land and land rights DEP has acquired, he found several projects that were initially included for recovery in this proceeding, which DEP appropriately moved to FERC Account 105 – Plant Held for Future Use prior to the capital cut-off. *See id.* at 1546. However, he noted one project, Project E22037301, which is the acquisition of land for a future 230kV substation in Morrisville, North Carolina that was not moved to FERC Account 105 until after the capital cut-off and is therefore included in the requested amount for recovery in this proceeding. *Id*. He recommended the removal of approximately $3.1 million from DEP's plant in service to reflect the appropriate booking of the cost but clarified that his recommendation is not the result of a prudence determination regarding the need for the property. *Id*. at 1546-47.

Witness Lawrence noted that while the issue in this proceeding is limited in nature, he found the issue to be more widespread in the DEC proceedings, and recommended that given the impending business combination, DEP complete an audit in the same manner he recommended for DEC. *Id*. at 1547.

In his response to witness Lawrence's concerns regarding the classification of land, DEP witness Speros described DEP's capitalization policies and accounting guidelines used to classify land as Plant in Service (FERC Account 101), which is included in rate base, versus Plant Held for Future Use (FERC Account 105), which is not included in rate base nor otherwise include in recovery in this rate case. *Id*. at 437-39. He explained that DEP evaluates properties associated with identified utility projects based on their specific facts and status under Duke Energy's Capitalization Policy. *Id*. at 439. Pursuant to that 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. *Id*. at 438-39. Land and land rights held for future use are recorded to FERC Account 105 when purchased if construction is planned to occur beyond 12 months. *Id*. at 437-38. Witness Speros testified that while DEP's Asset Accounting group is willing to meet with the Public Staff to provide an overview of DEP's procedures for booking land purchases, DEP disagrees that there is a systematic issue warranting an audit or potential refunds. *Id*. at 439.

In rebuttal, DEP agreed to remove Project E22037301 (the Morrisville 230kV substation project) from plant in service and record it in FERC Account 105 instead. Tr. vol. 7, 439, 1053. In the Comprehensive Settlement, DEP reiterated its agreement to accept the Public Staff's adjustment removing the identified land purchase from rate base, and the Public Staff agreed to forgo its request for an external audit of land in rate base. Comp. Settl. § II.30.

Discussion and Conclusions

Based on the entire record in this proceeding, the Commission concludes that the costs related to DEP's investments in its fossil, renewable, and nuclear fleet assets as well as its transmission and distribution investments made during the test period, as adjusted by the Comprehensive Settlement, should be recovered. The Commission also concludes that the Comprehensive Settlement's resolutions of issues relating to Person County CC CWIP, nuclear M&S inventory, Riverside BESS, NextGen GIS, and land purchases are reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

Base Period Accounting Adjustments

The evidence supporting this finding of fact is contained in DEP's verified PBR Application and Form E-1; the testimony and exhibits of DEP witnesses Abernathy, Bateman and Farmer (PBR Policy Panel), Guyton, Jiggetts, Caldwell, 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 Policy Panel, and the Public Staff Renewables Panel; the testimony and exhibits of AGO witness Burgess; and the testimony and exhibits of DoD/FEA witness Larkin-Connolly; the Comprehensive Settlement; and the entire record in this proceeding.

Summary of Evidence

Payroll and Benefits Operations and Maintenance

The Public Staff Accounting Panel proposed an adjustment to reduce payroll costs to DEP, DEC, and DEBS of 0.52%, 1.19%, and 1.36%, respectively, and stated that it was based on experience from the Sub 1300 case. Tr. vol. 8, 44. The Public Staff testified that, in its view, prior workforce reductions immediately following its last rate case meant that customers paid rates approved in the last DEP rate case that were artificially high due to inflated payroll and benefits, which resulted in greater earnings to the utility. *Id*. at 43-44.

DEP witness Caldwell rebutted the Public Staff's contention and testified that DEP continuously reviews its operations for improvement opportunities to address evolving business needs to better serve its customers, which result in workforce adjustments. Tr. vol. 7, 616. Witness Caldwell also explained that the staffing reductions referenced by the Public Staff were a result of a broader enterprise restructuring and noted that the gap of several months between the DEP rate case order and these staffing actions undermines any characterization of them as a response to the rate case. *Id*. at 616-17.

In the Comprehensive Settlement, DEP and the Public Staff agree that no adjustments will be made to Payroll and Benefits O&M, and DEP confirms that it has no plan, at this time, for a workforce reduction subsequent to this rate case. Comp. Settl. § II.15.

Incentive Compensation

In DEP witness Caldwell's direct testimony, she testified that DEP included in its cost of service incentive compensation at target levels that are assigned or allocated to DEP. Tr. vol. 7, 589. The Public Staff Accounting Panel testified that incentive compensation in DEP's Short-Term Incentive Plan (STIP) and the Long-Term Incentive Plan (LTIP) related to EPS and Total Shareholder Return (TSR) metrics should be excluded because they benefit shareholders and not customers. Tr. vol. 8, 49. Similarly, DoD/FEA witness Larkin-Connolly recommended that the EPS and TSR-related incentive compensation be removed from the recovery of STIP and LTIP plan expenses for executives in addition to the 50% removal of salary and benefit expenses already proposed by the Company. *Id*. at 587. In rebuttal, DEP 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. 7, 604-05.

In the Comprehensive Settlement, DEP agreed to exclude from the 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.13.

Executive Compensation

In its PBR Application, DEP made an adjustment in its test year to remove 50% of the compensation of the top five Duke Energy executives with the highest level of compensation allocated to DEP. DEP witness Caldwell explained in her direct testimony that while DEP believes these costs are reasonable, prudent, and appropriate to recover from customers, DEP has, for purposes of this case, made an adjustment to this item. Tr. vol. 7, 589.

The Public Staff Accounting Panel recommended a compensation adjustment to remove an additional 25% based on its review of Duke Energy's Regulated Electric & Gas Capitalization Guidelines (Guidelines). Tr. vol. 8, 46. The Accounting Panel asserted that based on the Guidelines, management's "charge" is primarily to benefit shareholders. *Id*. at 47.

In her rebuttal testimony, witness Caldwell explained that DEP has an obligation to both its shareholders and customers to make fiscally responsible decisions, and that DEP's financial performance is essential to customers receiving reliable and safe electric service efficiently at a reasonable price. Tr. vol. 7, 611. Witness Caldwell testified that the Guidelines are not a management philosophy document and the Public Staff's Accounting Panel's use of brief excerpts as a statement of executive priorities is not a fair or accurate reading of the Guidelines. Witness Caldwell asserted that the Public Staff conveniently

overlooks the 2026 Duke Energy Proxy Statement, which clearly explains that Duke Energy's leadership considers customers and customer rates as central to the business. Witness Caldwell also stated that the Guidelines, which were cited by the Public Staff, also discuss the need to balance shareholder and customer interests. *Id*. at 611-12. She concluded that it is not appropriate for executive compensation to be reduced by an additional 25% on top of the Company's 50% adjustment. *Id*. at 614.

In the Comprehensive Settlement, DEP agreed to remove an additional 25% (for a total of 75%) of the executive compensation expenses allocated to DEP for the top five executives as proposed by the Public Staff. Comp. Settl. § II.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 DEP. Tr. vol. 8, 54. In her rebuttal testimony, DEP witness Caldwell noted that that DEP is required to have a Board of Directors and that the costs of being an IOU, including Board of Directors costs, are in fact costs of service. Tr. vol. 7, 618-19.

In the Comprehensive Settlement, DEP agreed to remove 50% of Board of Director expenses allocated to DEP as proposed by the Public Staff. Comp. Settl. § II.12.b.

Ongoing Bad Debt Expense

DEP witness Jiggetts explained that DEP 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. 7, 997. DEP witness Speros explained that the bad debt deferral is coming to an end, DEP will recover an ongoing amount in rates based on the actual bad debt experienced during the test year, which in this case is 2024. *Id*. at 442. To set an ongoing uncollectible expense in this case, as stated by the Public Staff Accounting Panel, DEP used the adjusted bad debt expense of the Test Year of 0.6834%. Tr. vol. 8, 74.

The Public Staff Accounting Panel testified that DEP should use the 2025 actual bad debt percentage of 0.4776% to set its ongoing level of uncollectible expense because it is more representative of the current North Carolina retail level of bad debt expense. *Id*. Applying this 2025 uncollectible rate would result in an estimated $8.948 million reduction to the revenue requirement as compared to using the 2024 uncollectible rate. *Id*. at 75.

In his rebuttal testimony, witness Speros testified that DEP'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. 7, 442. He argued that the Public Staff has not demonstrated any imprudence or anomaly in 2024 figures bad debt expense would justify departing from using the test year bad debt expense. *Id*. Witness Speros stated that while DEP believes the test year bad debt expense is representative of ongoing bad debt expense levels, if the Commission were to update it, the 2025 amount should be adjusted to exclude reserve adjustment credits. *Id*. at 442-43. The normalized 2025 bad debt

expense, excluding these non-recurring reserve adjustments, would be $28.8 million North Carolina retail. *Id*. at 443.

In the Comprehensive Settlement, DEP and the Public Staff agreed to an ongoing bad debt expense amount of approximately $27.9 million (North Carolina retail) and an uncollectibles rate of 0.585%. Comp. Settl. § II.8.

Multiyear Rate Plan 1 Pro Forma

In her direct testimony, DEP witness Abernathy explained that the DEP'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 date but will be placed in service prior to the end of MYRP1. Tr. vol. 7, 894. 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 for the MYRP2 Plan Period, an annual revenue requirement must be included in the base rates effective January 1, 2027. *Id*.

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. 8, 39. However, they recommended two adjustments to this pro forma: (1) an adjustment to remove $0.969 million in net incremental O&M; and (2) an adjustment to reduce $29.704 million in plant and $0.704 million in accumulated depreciation related to projects placed or to be placed in service from April 1, 2026, to December 31, 2026. *Id*. at 39-40.

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 omitted from MYRP1 (in NC3030) or yet to come into service (in NC3060), to be included in the MYRP2 Rate Year 1 increase in order to ensure that MYRPs enforce cost containment. Tr. vol. 9, 368-71.

In her rebuttal testimony, DEP witness Bateman addressed witness Burgess's objection to the MYRP1 Pro Forma and testified that he misses the alignment between revenue and costs. DEP 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. 10, 464.

In her rebuttal testimony, witness Abernathy testified that DEP agreed to make the Public Staff's adjustment to O&M to address affordability concerns as set forth in the rebuttal testimony of DEP witness Bowman. Tr. vol. 7, 940. She noted that DEP agreed

to make the second adjustment to plant because it is a correction that DEP previously identified and it would be appropriate to correct in any event. *Id*.

The Comprehensive Settlement memorializes DEP's agreement to the MYRP1 Pro Forma (NC3060) adjustments reflected in DEP's rebuttal, removing approximately $0.969 million (North Carolina retail) of net incremental O&M and reducing plant by approximately $29.7 million (North Carolina retail) and accumulated depreciation by approximately $0.704 million (North Carolina retail) for substituted, separately assigned, and base case projects. Comp. Settl. § II.11.

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 Comprehensive Settlement. The Commission agrees that the MYRP1 Pro Forma, as modified by the Comprehensive Settlement, 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, DEP removed 50% of corporate-related aviation expenses allocated to DEP in the test period that are not related to aerial patrol. Tr. vol. 7, 987. DEP witness Jiggetts testified that DEP believes these costs were reasonable, prudent, and appropriate to recover from customers, but elected to remove them in this case, as DEP has in its last three rate cases. *Id*. at 987, 1062.

The Public Staff Accounting Panel recommended removal of an additional 25% of corporate aviation expenses, on the basis that DEP purchased, rather than leased, new aircraft, and that discretionary Board travel has increased compared to the levels in DEP's last base rate case. Tr. vol. 8, 55-57.

DoD/FEA witness Larkin-Connolly recommended removing all aviation from this case, asserting that: (1) corporate aviation expenses are imprudent based primarily on a cost comparison between DEP's corporate aircraft operations and estimated commercial airline fares; and (2) the flights are not directly related to the provision of electric service. *Id*. at 585-86.

In her rebuttal testimony, DEP witness Jiggetts noted that while depreciation expense increased as a result of the new aircraft purchases, that increase was partially offset by reduction in lease expense. Tr. vol. 7, 1062. 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 1062-63.

Witness Jiggetts also disagreed with DoD/FEA's recommended disallowance of all aviation expenses. *Id*. at 1088-89. She explained that commercial airfares vary significantly, which is not captured in DoD/FEA's metric, and corporate aviation provides flexibility and access to support damage assessment, restoration coordination and operational support throughout the dispersed customer/geographical area. *Id*. at 1089. She also noted that DoD/FEA's adjustment did not reduce aviation expenses to their calculated level but rather removed 100% of aviation expense which she asserted is unreasonable. *Id*. She acknowledged that while some aviation expense is related to Board travel, DEP's aviation resources also support utility operations including damage assessment, facility visits, outage support and other operational travel. *Id*. She concluded that DEP's removal of 50% of allocated aviation expenses addresses DoD/FEA's concerns about Board travel and commercial versus corporate travel. *Id*.

In the Comprehensive Settlement, the Stipulating Parties, including DoD/FEA, agreed with removal of 50% of the aviation expenses as included in DEP's initial application in conjunction with the agreement to: (1) remove an additional 25% (for a total of 75%) of the executive compensation expenses allocated to DEP for the top five executives, and (2) remove 50% of Board of Director expenses allocated to DEP as proposed by the Public Staff. Comp. Settl. § II.12. The Commission concludes that the Comprehensive Settlement provides a reasonable resolution of this issue for purposes of this proceeding.

Regulatory Fee

In her direct testimony, DEP witness Jiggetts explained that rates currently charged to customers based on the Sub 1300 Order reflect the regulatory fee in effect during that proceeding of 0.1475%. Tr. vol. 7, 996. Effective July 1, 2024, the regulatory fee changed to 0.17%. *Id*. At that time, DEP 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*. The projected amounts were updated to actuals in DEP's second supplemental filing. *Id*. at 1037. DEP's pro forma adjustment NC5030 amortizes the deferral balance over two years. *Id*. at 996. No party contested pro forma NC5030 or DEP'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 Comprehensive Settlement, DEP 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. Comp. Settl. § II.14.

Tax Rate Change

In her direct testimony, DEP witness Jiggetts explained that DEP 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. 7, 999. 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 1038. DEP proposed to flow back to customers excess deferred income taxes of approximately $47.1 million over a two-year period, starting on January 1, 2027, concurrent with new rates effective in this case. *Id*. No party contested this adjustment or DEP'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, in his direct testimony, DEP witness Guyton proposed an adjustment to distribution vegetation O&M expenses to reflect known and measurable contract pricing increases that affect the cost per mile for planned ROW maintenance. Tr. vol. 8, 724. DEP also requested additional O&M funding related to wildfire mitigation activities, underground utility line locator services, and the operation of DEP's T&D vehicle fleet. *Id*. at 725. No party challenged the request related to the distribution vegetation management O&M and distribution vehicle fleet O&M but the Public Staff proposed adjustments to DEP's request related to wildfire O&M and underground utility line locator services. Tr. vol. 7, 1365. Specifically, the Public Staff Distribution Panel challenged the wildfire O&M request because it contends it is not known and measurable because DEP began tracking its wildfire costs in 2025 and as such, no related costs are included in the 2024 Test Year. *Id*. at 1366. In addition, the Public Staff Distribution Panel testified that data was still being gathered to further develop its wildfire risk plan. *Id*. at 1366-67. Therefore, the Public Staff recommended that the Commission disallow the requested distribution and transmission incremental O&M and allow DEP 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 1367. In regard to the underground locate service pro forma request, the Distribution Panel testified that while DEP's vendor was the low bid winner in 2023, the vendor requested a modification to the contract in 2024, that DEP allowed an increase in the locate ticket rate, and that DEP should not have allowed the underground-line-locate-services vendor to alter the contract after it was executed. *Id*. at 1367-68. Therefore, the Distribution Panel recommended a reduction to DEP's requested pro forma based on the five-year average compound annual growth rate for locate ticket costs. *Id*. at 1368.

In his rebuttal testimony, with respect to the wildfire O&M adjustment, DEP witness Guyton testified that while DEP maintains that this work is important, DEP agrees as an additional rate mitigation measure in this case in addition to others further discussed in the rebuttal testimony of witness Kendal Bowman, to remove this pro forma adjustment from the case. Tr. vol. 8, 826. Concerning the locate services O&M adjustment, witness Guyton testified that DEP had no practical alternative to renegotiating the terms of the agreement because the vendor, USIC, had issued a notice of termination that would take

effect within 90 days, was the only single provider large enough to handle the volume of locate services across DEP'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 827. Further, even after the contract renegotiation, witness Guyton testified that the rates agreed upon remained competitive with current market rates. *Id*.

In the Comprehensive Settlement, DEP and the Public Staff agreed to remove approximately $5.1 million (North Carolina retail) incremental wildfire spend and to allow recovery of DEP's remaining requested spend, subject to a regulatory liability for any underspend over the cumulative two-year MYRP period. Comp. Settl. § II.29.

Hydro Operations and Maintenance

The Public Staff Renewables Panel recommended a reduction to test year O&M by $984,447 to account for increased O&M expenses at the Walters Hydro facility related to Hurricane Helene restoration and increased obsolete and damaged inventory write-offs during the Test Year that are not expected to be ongoing. The Public Staff's recommendation normalizes the hydro O&M based on actual O&M from 2021-2025. Tr. vol. 7, 1218.

In her rebuttal testimony, DEP witness Jiggetts explained 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. *Id*. at 1065. 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. *Id*. If the Public Staff adjusts for what they identify as a "non-recurring expense," consistency requires corresponding adjustments for any credits or expense offsets during the test year. *Id*.

In the Comprehensive Settlement, the Public Staff agreed to accept DEP's filed position to resolve the hydro O&M adjustment. Comp. Settl. § II.16.

Coal Reliability Assurance Operations and Maintenance Adjustment

In his direct testimony, DEP witness Walsh supported DEP's requested adjustment to test year O&M expense of approximately $9.3 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 DEP's aging coal units. Tr. vol. 7, 265. 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 DEP'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 DEP'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 these operating conditions for these aging plants increase the operational wear and tear

on the units as they cycle on and off more frequently and as a result increase their maintenance costs. *Id*. at 266. Witness Walsh stated that as of December 31, 2024, DEP invested approximately $6.125 million on a North Carolina retail basis, compared to the $6.0 million approved by the Commission for CRA work in PBR1 and more 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. *Id*. at 267. He cited DEP's ability to conduct targeted refurbishment and repair work to large equipment breakers and soot blowers, as well as targeted expansion and joint and duct work at all four Roxboro coal units and Mayo. He added in another example that winterization work, including repairs to instrumentation lines and to boiler and turbine room doors and windows to prevent air leakage, will ensure reliability during the cold weather months. *Id*.

With respect to the adjustment requested in this case, witness Walsh stated that DEP uses historical performance data to analyze factors that most affect coal plant reliability and that this analysis, in combination with original equipment manufacturer recommendations, accepted industry standards, and internal engineering assessments, to identify and prioritize projects with the greatest opportunity to maintain or improve operational reliability. *Id*. at 268. Witness Walsh stated that, based on this evaluation, DEP 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 that the adjustment reflects costs associated with ensuring adequate operations staff remain available to continue to safely operate the plants. *Id*.

Public Staff witness Thomas discussed DEP's execution of CRA work approved in the 2023 Rate Case (Docket No. E-2, Sub 1300) and coal unit performance since the previous case. Tr. vol. 7, 1518-22. Witness Thomas testified that DEP's request for increased CRA O&M is justified, with the caveat that the Public Staff is concerned about coal reliability, particularly as the retirement dates of some units are extended and the utilization of these plants increases. *Id*. at 1522. 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. *Id*. at 1523. He also noted that the magnitude of the CRA O&M increase requested in DEP's PBR Application is significant and there is a risk of DEP recovering the requested increase in revenues from ratepayers, while being unable to complete all the capital and O&M projects within the MYRP period. *Id*.

While witness Thomas concluded that O&M expenses in the Test Year appeared to be in line with historic levels, he recommended removing a portion of the funding included in DEP's coal reliability assurance pro forma adjustment. *Id*. at 1524. Witness Thomas testified that DEP's existing internal process to handle emergent work should be followed to cover this work, benefitting from the addition of the significant increase to CRA O&M funding, and that DEP had not presented sufficient evidence that the additional amount per year, without any specific projects identified, is necessary. *Id*. at 1524-25.

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. *Id*. at 1525. Finally, he recommended that DEP continue to submit annual reports on its CRA O&M expenses *Id*. at 1524.

In his rebuttal testimony, witness Walsh emphasized that the Public Staff did not raise any concern with the CRA work DEP has previously executed or plans to complete in the future, or that the planned CRA work is not needed, prudent, or reasonable. Tr. vol. 7, 296. Witness Walsh addressed the general managed account, explaining that based on DEP'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. *Id*. at 297. He added that DEP 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 fire protection system maintenance, hoist repair, and motor-operated valve maintenance at Mayo and boiler tube repairs, boiler insulation and lagging repairs, HVAC system maintenance, and coal and ash handling systems maintenance at Roxboro. 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. *Id*. He noted that this approach exemplifies DEP's prudent and experienced day-to-day operation of these units. *Id*. Finally, he stated that DEP does not object to continued CRA reporting. *Id*. at 298.

In the Comprehensive Settlement, the Stipulating Parties agreed to increase DEP's O&M by $10.1 million (North Carolina retail) to support coal reliability work, and agreed that DEP will create a regulatory liability for any under-spend over the cumulative two-year MYRP period. The Stipulating Parties also agreed that DEP will not seek a similar coal reliability pro forma in the next general rate case, though neither party shall be 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.31. 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 DEP and DEC's Public L2 Charging Pilot. Tr. vol. 8, 98. Throughout the implementation of the Phase 1 ET Pilots, DEP and DEC 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. *Id*. at 99. On December 19, 2025, in Docket Nos. E-7, Sub 1195 and E-2, Sub 1197, DEP and DEC filed a motion requesting that the Commission authorize DEP 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, DEP filed a motion to establish a new docket (E-2, Sub 1405) for its request for an accounting order and to consolidate that request with this rate case. In her second supplemental testimony, DEP witness Jiggetts explained that, upon the sale of the L2 charging assets, the unrecovered net book value was transferred to a regulatory asset to be amortized using the depreciation expense currently included in customer rates until fully recovered. Tr. vol. 7, 1036.

The Public Staff agrees with DEP'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 DEP remove test period O&M net of test period revenues associated with the charging infrastructure to reflect that DEP no longer has to maintain those assets. Tr. vol. 8, 98-99. In her rebuttal testimony, DEP witness Jiggetts testified that no adjustment was reflected in the Public Staff's calculations as the expense adjustment was small and could be applied against the $1 million allowance established by DEP in this case. Tr. vol. 7, 1085-86. Witness Jiggetts also indicated that DEP agrees with this recommendation, and DEP believes no additional adjustment is needed in this proceeding. *Id*. at 1086.

There is no party that opposed DEP's request. The Public Staff agrees that DEP should be permitted to establish a regulatory asset to recover the remaining net book value of the L2 charging infrastructure, Tr. vol. 8, 98, and its recommendation regarding test period O&M and revenues associated with the assets is resolved by the $1 million allowance DEP included in this case, Tr. vol. 7, 1085-86. Based on the foregoing, the Commission finds good cause to grant DEP's motion to consolidate its request for an accounting order with this proceeding and hereby approves DEP's request to establish a regulatory asset for the remaining net book value of the L2 charging infrastructure, less any proceeds received from the sale of such assets, and to amortize the regulatory asset using the depreciation expense currently included in customer rates until the balance reaches zero. Further, the Commission finds good cause to close Docket No. E-2, Sub 1405.

Transmission Cost Allocation Adjustment

DEP 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. 10, 378. 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 in DEC's then-pending rate case in Docket No. E-7, Sub 1276 and decrease the revenue requirement by the same amount for DEP's then-pending rate case in Docket No. E-2, Sub 1300. (First TCA Adjustment). *Id*. at 378-79. 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 of DEP, DEC, and Duke Energy Florida, LLC. *Id*. at 379. 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. *Id*. Witness Bateman testified that DEP proposed to extend the TCA Stipulation to continue to address the rate differences between DEC and DEP. *Id*. at 380. DEP proposed 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 DEC is proposing a corresponding adjustment in Docket No. E-7, Sub 1329. *Id*. 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 DEP's PBR Application of a three-year average of net power flows. Tr. vol. 7, 1923-24. 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 the instant case, excluding its multi-year rate plan projects, which would result in an updated pro forma adjustment of $47.1 million on a system basis, a $7.1 million (system) increase over DEP's proposed $40 million, or approximately $4.7 million (North Carolina retail). *Id*. at 1924.

On rebuttal, DEP witness Bateman testified that DEP agreed with Public Staff witness Metz's recommendation to increase DEP's pro forma adjustment to the TCA Adjustment to $47.1 million on a system basis. Tr. vol. 10, 466. Witness Bateman also testified that DEP would work with Public Staff to memorialize an extension of the TCA Stipulation to be filed in this proceeding. *Id*.

In the Comprehensive Settlement, the Stipulating Parties agreed to a pro forma adjustment to continue the TCA Adjustment (Second TCA Adjustment), resulting in a pro forma adjustment that decreases the revenue requirement for DEP in this proceeding and increases the revenue requirement for DEC in the ongoing DEC rate case proceeding in Docket No. E-7, Sub 1329 by approximately $31.2 million on a North Carolina retail basis. Comp. Settl. § II.39.

Rate Case Expense

DEP witness Jiggetts testified that DEP's pro forma adjustment NC5020 amortizes over a two-year period the incremental rate case costs incurred and projected to be incurred for the instant proceeding, as well as costs incurred associated with the ongoing appeals for the prior rate case. Tr. vol. 7, 996. Over-amortizations associated with rate case expenses for Docket Nos. E-2, Sub 1219 and E-2, Sub 1300 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 DEP 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. *Id.* at 1160. 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 1161. The Public Staff Policy Panel further testified that rate case spending is largely within DEP's control, and because the vast majority of rate case expense is paid by ratepayers, there is little incentive for DEP to control overspending or the inefficient use of outside counsel and consultants. *Id*. at 1164.

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. 8, 66. The Public Staff Accounting Panel also recommended removing the appeal costs related to DEP'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*. at 67.

On rebuttal, DEP witness Bateman testified that North Carolina rate cases are intensively litigated regulatory proceedings, and the burden of proof on every issue rests with DEP. Tr. vol. 10, 451. Witness Bateman also testified that DEP 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 456. 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 459-60.

In the Comprehensive Settlement, DEP agreed to remove rate case appeal costs for E 2, Sub 1300 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.38.a-c. DEP 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.38.d-e. Lastly, DEP agreed to update its projected balance with actuals through the filing of proposed orders in this docket (exclusive of any additional expenses related to the further [large load] tariff process proposed below if such process is approved or otherwise allowed by the Commission), subject to Public Staff's review. *Id*. § II.38.f.

Discussion and Conclusions

In their respective settlement testimonies, DEP witness Jiggetts and DEP PBR Policy Panel witnesses Bateman and Farmer explained that the Comprehensive Settlement, taken as a whole, reflects a fair, just, and reasonable resolution of the issues in this proceeding. Tr. vol. 7, 1109; tr. vol. 10, 499-500. 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 DEP's proposed revenue increase in this proceeding, and that the Comprehensive Settlement is in the public interest and should be approved. Tr. vol. 7, 1897-98.

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

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 18-20

Federal Funding

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

Summary of Evidence

In her second supplemental direct testimony, DEP witness Abernathy noted that DEP continues to actively pursue opportunities to apply for grants coming out of federal programs related to the IIJA, IRA, and other programs offered by the DOE. Tr. vol. 7, 927. She indicated that while DEP has proactively applied for these opportunities, it has not yet received any funding from these programs. *Id*.

Witness Abernathy explained the accounting treatment for IRA and IIJA grants that was approved in the Sub 1300 Order. *Id*. The Commission approved DEP's request for an accounting order to defer any incremental revenue requirement impacts, including benefits and costs, associated with the IRA and IIJA. Tr. vol. 7, 996-97; Sub 1300 Order at 217. DEP has not received any grants to date but has incurred incremental costs which have been deferred and are included in pro forma NC5060 and proposed to be amortized over two years. Tr. vol. 7, 927, 996-97.

No party contested this pro forma adjustment or DEP's proposed two-year amortization period. The Commission concludes that DEP's requested recovery of the deferred costs over a two-year period is just and reasonable and consistent with the Sub 1300 Order.

Witness Abernathy testified that, other than the deferral approved in the Sub 1300 Order, DEP 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. *Id*. at 927-28. She testified that certain MYRP2 projects are part of pending DOE grant applications. *Id*. at 928. With respect to grant funding going forward, DEP requests approval to continue to defer all incremental costs related to pursuing grant funding. *Id*. If DEP 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*. If the capital project receiving the grant was in service as of March 31, 2026, or is a MYRP2 project approved in this case, DEP 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 June 2026 the DOE awarded DEP up to $28.4 million under its "Restoring Reliability: Coal Recommissioning and Modernization" grant program for DEP's Roxboro Station Reliability Assurance Initiative. *Id*. at 1514. Applying a pro rata share of the grant to each project included in the grant application, witness Thomas calculated that approximately $10.3 million of the grant is associated with MYRP2 projects and recommended reducing those MYRP2 project costs by that amount. *Id*. at 1514-15. Witness Thomas disagreed with DEP'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 DEC's MYRP1, with DEP able to seek any shortfall in its next general rate case. *Id*. at 1515-16. In rebuttal, witness Abernathy opposed the adjustment because the amount and timing of the grant remained uncertain and testified that deferring the depreciation and return associated with any DOE award DEP actually receives would still give customers the full benefit of the grant. *Id*. at 933, 946. In the Comprehensive Settlement, the Stipulating Parties agreed to remove from MYRP2 the costs for the portion of the Roxboro Coal Reliability Initiative 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 DEP may seek recovery of the actual undepreciated value of the projects in future rate cases. Comp. Settl. § II.47; tr. vol. 7, 950.

CUCA witness LaConte recommended a regulatory liability to track savings from DOE loans obtained by DEP during MYRP2 to be returned to customers. Tr. vol. 8, 317. Witness Abernathy responded that, while DEP has submitted a pre-application for DOE loans, DEP has not received any of these loans and does not yet know the terms related to the loans that may ultimately be obtained. Tr. vol. 7, 946-47. She explained that given the savings related to these loans are due to the avoidance of costs from presumably higher interest rate financing that would be obtained if DEP did not receive the DOE loans, it would be difficult to quantify the costs that are avoided by obtaining a DOE loan in between rate cases, since there is no way to know what other debt may have been issued. *Id*. at 947. Witness Abernathy concluded that ultimately, the cost of debt and overall capital structure is evaluated and updated in a base rate case based on the outstanding debt at that time, and, as such, a regulatory liability would be inappropriate. *Id*.

Discussion and Conclusions

Other than the Roxboro DOE grant, which the Comprehensive Settlement resolves, no party contested DEP's proposed accounting treatment for grants going forward. The Commission concludes that DEP'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 DEP obtains a grant, DEP 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, DEP 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 that DEP can recover incremental costs incurred to actively pursue grant funding for the benefit of customers. Because the Comprehensive Settlement already removes from MYRP2 the Roxboro Coal Reliability Initiative project costs expected to be funded by the DOE grant, the regulatory liability treatment described above should not apply to that portion of the Roxboro grant, and, consistent with Section II.47 of the Comprehensive Settlement, DEP shall not defer any shortfall in that funding.

With respect to DOE loans, the Commission agrees with witness Abernathy that savings related to DOE loans received between rate cases, if any, would be difficult to quantify, and a regulatory liability to track such loans would therefore be inappropriate. However, DEP should include any approved DOE loans in its embedded cost of debt in future rate case applications or work with the Public Staff to ensure that the benefits, net of any incremental costs to obtain or comply with DOE loans received, are credited to customers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

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 DEP's 2019 Rate Case;[8] DEP's verified PBR Application and Form E-1; the testimony and exhibits of DEP witnesses Jiggetts and Hill; the testimony and exhibits of Public Staff witness Lucas; the Comprehensive Settlement; and the entire record in this proceeding.

Summary of Evidence

In its initial application, DEP requested to recover $600.8 million at a system level ($371.8 million North Carolina retail) in CCR expenditures from April 1, 2023, through March 31, 2026. Tr. vol. 7, 302, 994-95. DEP witness Hill provided testimony on DEP's activities since the last rate case to close ash basins and landfills, along with other CCR management units for the period. *Id*. at 302-03. Witness Hill testified that the actual and forecasted activities, as well as costs incurred, were reasonable and prudent. *Id*. at 303. Moreover, he testified that DEP implemented its plans in accordance with closure and corrective action plans that have been approved by relevant state environmental

[8] Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice, *Application by Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina,* Nos. E-2, Sub 1193 and E-2, Sub 1219 (N.C.U.C. Apr. 16, 2021).

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 provides that closure and corrective action plans for DEP's Roxboro and Mayo sites to be approved by DEQ are reasonable, prudent, in the public interest, and consistent with law, and DEP's closure activities have been performed in accordance with DEQ-approved plans. *Id*. at 307-08.

DEP witness Jiggetts presented DEP's request to amortize deferred costs associated with the CCRs and to continue deferring costs related to compliance with coal ash regulations. *Id*. at 992-95. Witness Jiggetts testified as to the key components of the CCR Settlement and the associated adjustments made in this case to comply with the CCR Settlement. *Id*. at 993-94. She explained that the CCR costs sought for recovery are based upon actual costs incurred from April 1, 2023, through June 30, 2025, and updated amounts through March 31, 2026, that were provided in the second supplemental filing made on May 6, 2026. *Id*. at 994, 1037. As updated, these costs, less the adjustments, total approximately $573 million on a system basis and $354 million on a North Carolina retail basis. *Id*. at 1037; Jiggetts 2d Supp. Direct Ex. 3 at 196. Witness Jiggetts also testified that DEP proposed to offset the ending deferral balance by the over-amortization of tranche 2 of deferred environmental costs established in Docket No. E-2, Sub 1219 of $22.6 million. Tr. vol. 7, 995. She testified that DEP's adjustment amortizes the net deferred balance over a five-year period. *Id*.

Public Staff witness Lucas investigated and discussed DEP's management of CCRs and the operation of DEP's CCR beneficiation projects. *Id*. at 1592-99. After performing a thorough review, witness Lucas concluded that DEP's CCR management and disposal practices, including beneficiation, since the last rate case are reasonable and prudent. *Id*. at 1599.

In the Comprehensive Settlement, the Stipulating Parties agreed to extend the amortization of deferred CCR costs from five years to eight years. Comp. Settl. § II.10; tr. vol. 7, 1102.

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 DEP has complied with the CCR Settlement and made the agreed-upon adjustments in this case to reflect that settlement. The Commission approves DEP's proposal to offset the ending deferral balance by the over-amortization of tranche 2 of deferred environmental costs established in Docket No. E-2, Sub 1219, 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 Section II, ¶ 17 of the Comprehensive Settlement and the Commission's conclusions regarding carrying costs set forth below, the return accrued during the deferral period shall be compounded annually. Tr. vol. 7, 1107. Further, consistent with Section III.F of the CCR Settlement, the return on the unamortized balance during the amortization period shall be calculated

using DEP's embedded cost of debt approved in this Order, adjusted as appropriate to reflect the deductibility of interest expense, a return on equity 150 basis points below the return on equity approved in this Order, and a capital structure of 48% debt and 52% equity. *See* Jiggetts Comp. Settl. Ex. 2 at 6; tr. vol. 7, 993.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 22-30

Storm Costs

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

Summary of Evidence

Storm Normal Expenses

In prior DEP rate cases, including Docket No. E-2, Subs 1023, 1142, 1219 and 1300, the Commission approved a calculation of storm normal expenses based upon a 10-year average of storm costs, after removing costs associated with major storms and adjusting for inflation, for inclusion in rates. DEP witness Jiggetts explained the methodology for the calculation of storm normal in this case. Tr. vol. 7, 999, 1038. The resulting amount to include in rates per DEP's calculation is approximately $23.822 million. Jiggetts Comp. Settl. Ex. 3 at 264. No party disputes DEP's methodology for calculating storm normal expenses to include in rates. The Commission concludes that the appropriate North Carolina retail normalized annual level of storm costs to include in DEP's rates in this case is $23.822 million.

Two-Year Amortization of Storm Securitization Regulatory Assets and Liabilities

With respect to the 2020 Storm Securitization, DEP initially projected a regulatory liability balance as of January 1, 2027, of approximately $1.0 million related to servicing and administration fee overcollections. Tr. vol. 7, 1000-01. As updated with actuals through March 31, 2026, the regulatory liability totaled approximately $1.128 million. Jiggetts Comp. Settl. Ex. 3 at 272, 274; tr. vol. 7, 1039. After netting a $107,000 over-amortization of the prior tranche, the balance for amortization is approximately $1.021 million. Jiggetts Comp. Settl. Ex. 3 at 272. DEP proposed a two-year amortization. *Id*. No party opposed this treatment.

With respect to the 2024 Storm Securitization, DEP did not include adjustments for up-front financing costs or servicing and administration fees in its initial filing because amounts had not been finalized. Tr. vol. 7, 1000. Those costs were finalized before the March 31, 2026, capital cut-off, and DEP recorded a regulatory asset for under-recovered upfront bond issuance costs of approximately $78,000. Jiggetts Comp. Settl. Ex. 3 at 276; tr. vol. 7, 1039. After applying a $73,000 over-amortization of the prior tranche, the net

balance for amortization is approximately $151,000. Jiggetts Comp. Settl. Ex. 3 at 272. DEP proposed a two-year amortization. *Id*. Servicing and administration fees associated with the 2024 Storm Securitization have not been finalized and are not included in this proceeding; those amounts will be tracked and addressed in a future proceeding. Jiggetts Comp. Settl. Ex. 3 at 275; tr. vol. 7, 1039. No party opposed this treatment.

The Commission concludes that the two-year amortization of the 2020 Storm Securitization regulatory liability for servicing and administration fee overcollections (net balance of approximately $1.021 million) and the two-year amortization of the 2024 Storm Securitization regulatory asset for upfront bond issuance cost undercollections (net balance of approximately $151,000) are supported by the evidence, are just and reasonable, and should be approved.

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

In its initial filing, DEP projected a regulatory liability balance of $79.8 million to true-up Hurricane Debby and 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. 7, 1001. DEP witness Culbreth subsequently updated the Hurricane Debby and Helene true-up figures in her supplemental direct testimony to reflect finalized actual costs in the amount of approximately $353.1 million and addressed Winter Storm Fern. *Id*. at 545, 549. Witness Jiggetts' second supplemental testimony updated the Hurricane Helene regulatory liability to $68.5 million as of January 1, 2027, including returns on the overcollection. *Id*. at 1039. Witness Jiggetts also requested an accounting order to defer to a regulatory asset the incremental O&M costs of Winter Storm Fern, which struck DEP's service territory in January 2026 and which she estimated at approximately $62.2 million on a North Carolina retail basis, as well as any additional incremental storm costs incurred in 2026 that exceed the annual storm deductible, with carrying costs at DEP's authorized after-tax weighted average cost of capital (WACC) and recovery over five years beginning with the rates effective date. *Id*. at 1040-41. In rebuttal, DEP reduced the proposed amortization period for the Hurricane Helene overcollection from five years to two years, which reduced the revenue requirement by $20.7 million. *Id*. at 1073.

DEP witness Culbreth testified that DEP's approach for calculating incremental O&M and capital costs for Hurricane Debby and 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. *Id*. at 539-43, 555.

The Public Staff Accounting Panel testified that it did not support the use of the Florida Rule in this proceeding and that DEP had not fully demonstrated that the Florida Rule is more accurate than the existing method, recommending that the methodology issue be left open until DEP's next general rate case. Tr. vol. 8, 60-61, 90-91.

The Public Staff Accounting Panel also opposed DEP's proposed deferral of estimated Winter Storm Fern costs because the costs were not presented until DEP's May 6, 2026 second supplemental filing and remained estimates, so the Public Staff could not confirm whether, or by how much, they exceeded the annual storm deductible; the Public Staff recommended instead that DEP seek a deferral of actual Winter Storm Fern costs in or before its next general rate case, and, alternatively, that any regulatory asset be amortized over ten years beginning the month after the storm. *Id*. at 62-63. The Public Staff further opposed DEP's request to defer additional 2026 storm costs, testifying that deferral accounting should be granted only for an actual extraordinary event after the Commission can assess the storm, its magnitude, and its relationship to other storms and the storm deductible for the year. *Id*. at 64-65. In rebuttal, witness Jiggetts testified that DEP had notified the Public Staff of its intent to include Winter Storm Fern in this case, that Winter Storm Fern costs (more than $87 million North Carolina retail) clearly exceed the $27.4 million North Carolina retail storm deductible, and that once the deductible has been exhausted by an actual storm, deferral of additional 2026 major storm costs would not be speculative pre-approval. Tr. vol. 7, 1073-76.

In rebuttal, DEP witness Culbreth testified that the prior methodology omits a category of incremental costs and that the Florida Rule had already been subject to audit and investigation by the Public Staff in the prudency review proceeding in Docket Nos. E-2, Sub 1362, in which DEP sought Commission approval of actual storm recovery costs due to Hurricanes Zeta and Ian and Winter Storm Izzy and estimated storm recovery costs due to Hurricanes Debby and Helene. *Id*. at 560-61. DEP 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. *Id*. at 1072.

DEP and the Public Staff also disagreed on the appropriate carrying cost methodology for the Hurricane Debby and Helene true-up. DEP proposed an undiscounted after-tax weighted average cost of capital, while the Public Staff recommended a monthly discounted after-tax weighted average cost of capital. Tr. vol. 7, 1071. Applying its recommended methodology together with the traditional cost calculation method, the Public Staff calculated an annual Hurricane Debby and Helene refund of $4.524 million over the remaining 225 months (18.75 years) of the bond recovery period, compared to DEP's proposed annual refund of $14.9 million for five years based on the Florida Rule and an undiscounted after-tax WACC. Tr. vol. 7, 1071-72; tr. vol. 8, 60-61.

In the Comprehensive Settlement, the Stipulating Parties agreed that the Hurricane Helene over-securitization amount would be the amount reflected in DEP's filing in this case ($68.456 million overcollection plus $5.802 million return on the overcollection, calculated using DEP's proposed incremental O&M calculation), for purposes of this case only. Comp. Settl. § II.26. DEP also agreed to include Winter Storm Fern incremental storm costs of $62.188 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 DEP's next general rate case and agreed that these costs will not incur any carrying costs. *Id*. §§ II.24-II.25. The Stipulating Parties further agreed to net the Hurricane Helene over-securitization amount against the Winter Storm Fern incremental storm costs, resulting in a $12.070 million credit to customers (differences due to rounding), to be

amortized over 18.75 years with the unamortized balance included in rate base. Comp. Settl. §§ II.23, II.27; Jiggetts Comp. Settl. Ex. 3 at 270, 272; tr. vol. 7, 1103. The Stipulating Parties also agreed to annual compounding of the return accrued during the deferral period on the Hurricane Helene (post-securitization bond issuance) deferral. Comp. Settl. § II.17.

The Stipulating Parties also agreed that DEP will use the traditional method for calculating incremental storm operations and maintenance costs on a going-forward basis for 2026 through DEP's next general rate case. *Id*. § III.3.

Storm Reserve

In DEP's most recent storm securitization proceedings, Docket Nos. E-2, Sub 1362 and E-2, Sub 1370, DEP agreed to evaluate the potential for establishing storm reserves to serve as an alternative or complementary recovery tool. Tr. vol. 7, 1000, 1006-07. In its initial application, DEP proposed to establish and fund a storm reserve that, as described by DEP 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. *Id*. at 1006. DEP proposed to collect $30 million per year to be recorded to a regulatory liability for the benefit of customers. *Id*. at 1007. As DEP incurs future incremental storm costs, they will be recorded as an offset to the accumulated reserve once storm costs exceed the normal range of fluctuation. *Id*.

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. 8, 89. In her rebuttal testimony, DEP 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. 7, 1077.

In the Comprehensive Settlement, DEP agreed to withdraw its request to establish a storm reserve in this proceeding. Comp. Settl. § II.28.

Discussion and Conclusions

No party opposed the provisions of the Comprehensive Settlement related to the recovery of storm costs. Based on the entire record, the Commission concludes that the Comprehensive Settlement's resolution of storm cost recovery is just and reasonable to all parties in light of all the evidence presented and should be approved. The Commission notes that the Comprehensive Settlement resolves DEP's request to defer Winter Storm Fern costs by including the estimated $62.188 million in the revenue requirement, without carrying costs and subject to audit and true-up in DEP's next general rate case, and nets that amount against the Hurricane Helene over-securitization amount.

The Comprehensive Settlement does not address DEP's request for authority to defer incremental costs of storms occurring in 2026 after Winter Storm Fern.

See tr. vol. 7, 1040-41, 1075-76. Consistent with the Public Staff's recommendation, the Commission declines to grant deferral authority for storms that have not yet occurred, without prejudice to DEP's ability to request deferral accounting treatment for a specific storm after it occurs. *See* tr. vol. 8, 64-65.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 31

Multiyear Rate Plan 2 Capital Investments

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

Summary of Evidence

In its PBR Application, DEP 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

DEP 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. 7, 96. 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 reliability improvements are selected and grouped within the MYRP2 transmission projects based on the areas that provide the greatest value to customers. *Id*. at 101.

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. The investments are designed to improve grid awareness by modernizing transmission system communication capabilities which will increase operator and engineer visibility of system conditions.

2. The Substation Hardening & Resiliency (H&R) project creates 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 substation rebuilds.

3. The Transmission Line H&R project creates 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 scope also includes rebuilding aged and end of life transmission lines segments as well as replacing targeted wood transmission poles with stronger steel poles.

4. The Breaker Replacement project strategically replaces degraded and outdated oil circuit breakers with circuit breakers that utilize modern gas and vacuum technologies, increasing system resiliency through rapid outage recovery and reducing the environmental footprint.

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

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.

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 96-98.

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 for the projects. *Id*. at 99-100. He also testified that in addition to the information

presented in his direct testimony and exhibits, DEP also provided detailed project information along with supporting workpapers, as required by Commission Rule R1-17B, including subsection (d)(2)j. *Id*. at 100.

Witness Fogg testified that to calculate the benefits of MYRP2 transmission projects, DEP used a Cost Benefit Analysis (CBA) methodology at the project location level for the majority of its proposed transmission MYRP2 projects. *Id*. at 102. 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 that 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 103. He explained that since DEP'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 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 U.S. Department of Energy and widely adopted across the industry for reliability planning, investment justification, and regulatory filings. *Id*. at 103-04. He testified that DEP used the same approach for calculating CBA's for MYRP2 transmission projects as it did for MYRP1. *Id*. at 104. For projects where a CBA was not performed, witness Fogg explained that the work underlying the project is required as part of DEP's obligation to serve and/or to comply with NERC reliability standards. *Id*. at 102-03.

Finally, in his direct testimony, witness Fogg explained that due to DEP's experience with transmission project execution in MYRP1, DEP advanced many individual projects further along in the project development lifecycle before including them in MYRP2, resulting in more accurate cost and in-service estimates. *Id*. at 95-96.

In witness Fogg's supplemental testimony, witness Fogg provided updates for certain MYRP2 transmission project locations consistent with the parameters set forth in Commission Rules R1-17B(f), and removed 10 transmission project task/locations, updated 36 project task/locations to reflect material changes in scope or schedule, updated 43 project task locations with initial or updated capital costs equal to or greater than $10 million to update cost estimates, and provided corrections for certain projects task/locations. *Id*. at 112-13. Collectively, the updates to the transmission project

task/locations in the MYRP2 resulted in a decrease of $36.6 million to the system amount of capital expected to be placed in service for the MYRP2 projects. *Id*. at 114.

DEP witness Fogg's Supplemental Direct Exhibit 3 provides the total updated projected in-service costs for the proposed MYRP2 Transmission Project as follows:

1. Breakers – $60,421,020;
2. Capacity and Customer Planning – $89,570,527;
3. Substation Hardening & Resilience – $251,079,315;
4. System Intelligence – $29,017,399;
5. Transmission Line Hardening & Resilience – $301,045,156
6. Transformers – $65,156,726;
7. Vegetation Management – $ 79,520,552.

Fogg Supp. Direct Ex. 3.

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 DEP's proposed MYRP Transmission projects of approximately $875.8 million. *Id*.

Public Staff witness Lawrence testified that he reviewed the transmission plant capital projects that DEP proposed for inclusion in MYRP2 which total approximately $875.8 million. Tr. vol. 7, 1545-46. 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 1548-49.

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 DEP used state-level data to evaluate the financial benefits of outage risk reduction. *Id*. at 1558-59. 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 1557-58. However, witness Lawrence recognized there are inherent challenges to more granular data because the transmission system is intended to facilitate the transfer of energy over large areas to a large number of customers. *Id*. at 1558. He criticized DEP's delineation between using NC and SC 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 DEP customers would be assigned different benefits simply based on which state they are located in. *Id*. at 1558-59. He recommended that the benefits assigned to each customer group should take more granular information into consideration where reasonable and possible. *Id*. at 1559. 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 1 does not establish its need or the true cost to customers, especially when considering non-energy benefits. *Id*. at 1559-60. He recommended that in future MYRP proceedings, should DEP use 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 1560.

Witness Lawrence testified that DEP did not demonstrate that the proactive replacement of the distribution oil and transmission oil breakers, at the pace proposed, is appropriate as an MYRP program. *Id*. at 1567. He testified that he requested information regarding the replacements and failures of the distribution oil and transmission oil breakers dating back to 2015. *Id*. at 1561. Distribution oil breaker failures totaled 11, with an average service life of 39.72 years before failure. *Id*. Transmission oil breakers failures totaled five with an average service life of 51.95 years before failure. *Id*. at 1565. While he testified that he does not necessarily recommend that breakers should only be replaced after failure, he explained that the predictive failure of breakers is less straightforward than something such as a transformer. *Id*. at 1567. He asked that in its rebuttal testimony, DEP 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 DEP did not offset any of the costs of its proposed transmission MYRP2 programs with operating benefits. *Id*. at 1568. 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). and that despite projecting billions in savings through the CBAs, DEP has not identified any operating benefits resulting from the work it proposed to complete on the transmission projects. *Id*. at 1568-69. Despite DEP'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 lack of data from DEP because DEP does not track O&M costs for individual projects. *Id*. at 1569-71. 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 — DEP should include in its rebuttal testimony a comprehensive quantification of the operational benefits customers will receive for the Breaker Replacement Program, and should DEP be unable to quantify these operational benefits, he recommended disallowance of approximately $60.4 million for the Breaker Replacement Program for purposes of MYRP2. *Id*. at 1572-73.

In his rebuttal testimony, DEP witness Fogg responded to Public Staff witness Lawrence's recommendations concerning DEP's CBAs, the Breaker Replacement Program, and O&M benefits. *Id*. at 118. With respect to DEP's cost benefit analyses, he testified that DEP'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 120. He explained that the fact that the ICE calculator estimates higher direct economic losses from outages for commercial and industrial customers than for residential customers does not mean that DEP'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 DEP's CBAs as insufficiently granular misunderstands how DEP's transmission value models work in that 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 DEP agrees with witness Lawrence that a CBA greater than one is not, by itself, the sole basis for establishing transmission project need. *Id*. at 121. Finally, he concluded that witness Lawrence's criticisms do not demonstrate that DEP's CBAs produce inaccurate or unreliable results, and they provide no basis to reject or discount DEP's MYRP2 transmission investments. *Id*.

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 119. He stated that the program prevents failures that would otherwise occur in a fleet of approximately 500 oil-filled breakers that have been in service for an average of 51 years, well beyond their recognized industry service life of approximately 40 years. *Id*. He explained that DEP does not pace its Breaker Replacement Program based on observed failures or service life 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 DEP'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 DEP'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*. at 119-20. 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*. at 120.

Section III, ¶ 4 of the Comprehensive Settlement provides that DEP 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. Comp. Settl. § III.4. No intervenor took issue with this provision of the Comprehensive Settlement.

Section II, ¶ 45 of the Comprehensive Settlement provides that the Stipulating Parties agree to reduce DEP's Breaker Replacement Program and one project under DEP's Transformer Replacement Program by approximately $31 million (system) and DEP provided the Public Staff with a list of the specific projects selected for removal, and the removal of such projects is reflected in the Abernathy Settlement Exhibits. *Id*. § II.45. No intervenor took issue with this provision of the Comprehensive Settlement.

After having carefully reviewed all the evidence in the record on DEP's transmission MYRP2 proposal in this docket, and based on that evidence, the Commission finds that DEP's transmission MYRP2 projects, as adjusted by the Comprehensive Settlement, are needed to maintain and improve the safe and reliable delivery of electric service to DEP'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 that 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 DEP's commitment in the Comprehensive Settlement 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 DEP to file a report (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 examples of 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 DEP's calculations of T&D costs and benefits, including DEP's use of the ICE calculator.

The Commission further finds that the Comprehensive Settlement's reduction to the Breaker Replacement Program project costs sought in MYRP2 as set forth in the Abernathy Settlement Exhibits, reasonably resolves the issues raised with respect to these projects. Accordingly, the Commission concludes that DEP's transmission 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 that the evidence supports approval of the Comprehensive Settlement's provisions regarding these transmission MYRP projects as just, reasonable, and in the public interest.

Grid Planning & Integration

DEP witness Holeman testified in support of the inclusion of GP&I investments in DEP's MYRP2 as part of DEP's PBR Application. Tr. vol. 7, 48. Witness Holeman specifically supported the need, benefits, and costs for the following grid investments included in DEP's MYRP2: (1) Red Zone Expansion Plan (RZEP) Projects, (2) Network Upgrade Projects, and (3) Enterprise Technology Projects. *Id*. 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 49, 54-55. He explained that the GP&I projects enable DEP to execute the 2023-2024 CPIRP on the Commission-approved schedule. *Id*. at 52. To comply with the Commission's December 30, 2022 Order, DEP has taken significant actions to successfully implement the CPIRP, including the advancement of the GP&I Projects. *Id*. at 53.

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 DEP's transmission system at the pace and volume required by the CPIRP. *Id*. at 58-59. 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 57-58. Because these network upgrades are significant, witness Holeman testified that many projects often withdraw from the interconnection queue after interconnection studies identify costly network upgrades, and these large network upgrade costs are therefore impeding generator interconnections of resources needed to execute the CPIRP. *Id*. at 58. Witness Holeman noted that DEP included nine RZEP Projects in MYRP1, and DEP included a second phase of RZEP Projects in MYRP2, including five line rebuilds. Holeman Direct Ex. 2; tr. vol. 7, 59-60. 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. 7, 62. Moreover, witness Holeman noted that the increase in transmission capability resulting from RZEP projects will help enable solar resources located in the red zone to charge stand-alone battery storage that is located closer to load centers, preventing curtailment of excess renewable energy. *Id*.

Witness Holeman testified that DEP used a cost benefit analysis methodology at the project location level for RZEP Projects in MYRP2. *Id*. at 63. 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*. DEP based the expected financial benefits primarily on customer savings from reliability risk reduction estimated using historic outage information, data from the Interruption Cost Estimate Calculator, and a decision analytics software tool used for modeling critical infrastructure investments. *Id*. Customer reliability risk reduction benefits, which cannot be passed directly to customers, represent inherent savings to customers realized by avoiding outage events or reducing outage severity. *Id*. at 63-64. A BCR of the NPV of total benefits over cumulative costs greater than 1.0 indicates the project or program should deliver tangible business value. *Id*. at 63. The RZEP BCR is 31.0, and the cumulative net benefits are $61,294,856,366. Holeman Direct Ex. 3 at 6.

Witness Holeman also addressed the Network Upgrade Projects, which consist of improvements to transmission lines, substations, and other facilities to support interconnection of new DEP-owned and -operated generation. Tr. vol. 7, 65. Witness Holeman explained that the Network Upgrade Projects are needed to mitigate congestion identified by interconnection studies, and that the related generation resources are needed to ensure reliability and security for DEP's customers. *Id*. at 66. Further, DEP must construct the Network Upgrade Projects pursuant to DEP's Joint Open Access Transmission Tariff on file at FERC, and failure to construct any required Network Upgrades results in liability. *Id*. Witness Holeman testified that DEP identified the Network Upgrade Projects using DEP's state- and FERC-approved interconnection procedures. *Id*. at 67. 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 68. 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 DEP'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, that are designed to enhance DEP's existing distribution planning platform to leverage certain grid edge assets to support reliability. *Id*. at 69. 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 electric vehicles, customer-sited solar, and other grid edge distributed energy resources. *Id*. He testified that the Energy Orchestration Project implements a control platform in the form of a software package that allows DEP, with customer permission, to control and dispatch certain grid edge distributed energy resources and customer-sited assets. *Id*. at 69-70. Witness Holeman explained that the Enterprise Technology Projects will optimize how DEP models, forecasts, and plans to use certain grid edge distributed energy resources and customer-sited assets. *Id*. at 70. 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 71. Witness Holeman also addressed other customer benefits, including customer savings resulting from DEP

deferring or avoiding traditional transmission and distribution investments. *Id*. at 72. Witness Holeman testified that DEP estimated the Enterprise Technology Projects' costs based on the comprehensive scope required to implement these Projects across DEP and its public utility affiliates. *Id*. at 73. Witness Holeman argued that due to the nature of the Enterprise Technology Projects, the work cannot be directly charged to a specific jurisdiction because the same work is performed for the benefit of DEP and its affiliates. *Id*. Thus, to determine the estimated portion of DEP's costs, DEP 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 DEP and its affiliates. *Id*.

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). *Id*. at 75. Witness Holeman testified that DEP removed: three Energy Orchestration project locations from MYRP2 because DEP completed the work prior to March 31, 2026; one Network Upgrade project location and four RZEP project locations because the projects' in-service dates moved outside of the MYRP2 window due to schedule optimization; and two Network Upgrade projects locations and two RZEP project locations because the projects were no longer needed. *Id*. at 78. Additionally, DEP updated three RZEP project locations because the in-service dates for these project locations have shifted by more than three months. *Id*. DEP also updated cost estimates and schedules for ten RZEP project locations where DEP's initial or updated capital cost is equal to or greater than ten million dollars. *Id*. at 78-79. Finally, DEP also updated 18 GP&I project locations to correct errors or omissions. *Id*. at 79. In summary, the overall net result of DEP's updates to its GP&I MYRP2 projects is a decrease in costs of $55.3 million to the system amount of capital expected to be placed in service for the MYRP2 projects. *Id*. at 79.

DEP witness Holeman's Supplemental Direct Exhibit 1 provided the total updated projected in-service costs for the proposed MYRP Grid Planning and Integration Programs as follows:

1. Energy Orchestration - $0
2. Integrated Grid Planning - $7,676,193;
3. Network Upgrades - $32,361,739;
4. Red Zone Expansion Plan - $231,875,481.

Holeman Direct Supp. Ex. 1.

The modifications to the proposed MYRP Grid Planning & Integration projects described in witness Holeman's supplemental direct testimony and accompanying exhibits, resulted in an updated estimated capital cost to DEP's proposed MYRP Grid Planning & Integration projects of approximately $272 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 DEP witness Fogg

because the GP&I projects are largely for the interconnection of generation resources identified through planning processes such as DEP's FERC-approved generator interconnection study process, the CPIRP process, and the Carolinas Transmission Planning Collaborative. Tr. vol. 7, 1574. 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*. at 1575. With respect to the IGP program, witness Lawrence testified that DEP has developed thorough documentation for this project, which provides information in much greater detail than other MYRP2 project documentation that 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*. He further noted that the IGP is an enterprise-wide software program that will allow DEP and other Duke Energy utilities to evaluate, plan, and control customer-sited equipment in an efficient manger, and DEP has only included its share of the relevant costs for recovery. *Id*. 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 does not recommend any adjustments related to those projects. *Id*. at 1575-76. 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 believed the Integration programs are needed and provide benefits to customers, he also contended the CBA does not provide a comprehensive view of the benefits customers will receive. *Id*. at 1576.

Based on the entire record in this proceeding, the Commission finds that DEP'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 DEP'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 that 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 that 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. The Commission acknowledges Public Staff's criticism of DEP's use of the ICE calculator to determine benefits to customers, and accepts DEP's commitment in the Comprehensive Settlement 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. The Commission concludes that DEP'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 that the evidence supports approval of the Comprehensive Settlement's provisions regarding those projects as just, reasonable, and in the public interest.

Distribution

DEP witness Guyton testified in support of DEP's proposed MYRP2 distribution capital investments. Tr. vol. 8, 740-53. He 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, and address customer demand and load growth. *Id*. at 712. Witness Guyton testified that DEP's proposed MYRP2 distribution and other non-T&D projects total $1.5 billion, consisting of approximately $1.395 billion in distribution projects and $0.129 billion in other non-T&D projects supporting distribution operations. Guyton Direct Ex. 2 at 2; tr. vol. 8, 741.

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, which includes ten sub-programs, totals $1.056 billion, and consists of geographically-based projects involving a combination of ongoing work necessary to deliver essential grid capabilities; (2) Retail and System Capacity, which totals $0.316 billion and consists of retail substation upgrades and system distribution-line capacity upgrades 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, which totals $0.024 billion 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; and (4) other non-distribution MYRP2 Projects, which total $0.129 billion and consist of the Automated Distribution Management System (ADMS) Closed-Loop Fault Isolation and Service Restoration (FISR) project, Towers, Shelters & Power Supply projects, the GIS Replacement project, a facilities project, and a Wildfire Mitigation project that support distribution operations and enable continued safe, reliable, and resilient grid operations. Guyton Direct Ex. 4 at 1, Ex. 5 at 3-24, Ex. 6 at 3-15; tr. vol. 8, 741-44, 751-53.

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. 8, 744-45. He also testified that in addition to the information presented in his direct testimony and exhibits, DEP also provided detailed project information along with supporting workpapers, as required by Commission Rule R1-17B, including subsection (d)(2)(j). *Id*. at 744.

Witness Guyton explained that DEP's Substation and Line projects consist of the following ten sub-programs. *Id*. at 742:

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 $109.9 million. *Id*. at 5.

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. *Id*. at 7-9. The total capital cost for this program is approximately $476.9 million and includes Capacity Upgrade work performed in both the Substation and Line program as well as the Area Capacity Upgrade Projects program. *Id*. at 8.

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. *Id*. at 10-12. The total capital cost for this program is approximately $21.0 million. *Id*. at 11.

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 13-15. The total capital cost for this program is approximately $227.4 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 13-15. The total capital cost for this program is approximately $191.8 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 13-15. The total capital cost for this program is approximately $34.5 million. Guyton Direct Ex. 4 at 1.

7. Hardening and Resiliency: Long Duration Interruptions, 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 13-15. The total capital cost for this program is approximately $7.2 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 16-19. The total capital cost for this program is approximately $94.8 million. Guyton Direct Ex. 4 at 1.

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. Guyton Direct Ex. 5 at 20-21. 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 $199.8 million. Guyton Direct Ex. 4 at 1.

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. Guyton Direct Ex. 5 at 22-24. The total capital cost for this program is approximately $31.7 million and includes work being executed within the Substation and Line program as well as the Capital Hazard Tree Projects program. *Id*. at 22-23.

With respect to the non-T&D projects, witness Guyton explained that these include DEP's allocated share of the cost of the ADMS Closed-Loop FISR project, Towers, Shelters & Power Supply projects, the GIS Replacement project, a facilities project, and a Wildfire Mitigation project. Tr. vol. 8, 751-52. Specifically, the non-T&D projects include:

- The ADMS Closed Loop FISR project, which minimizes outage impacts by automatically identifying an outage and selecting a switching plan to isolate the fault and restore power to as many customers as possible in moments. Like other advanced applications, this self-healing system relies on an accurate digital model of the grid to support analyses and quickly evaluate solutions to restore service to customers. Guyton Direct Ex. 6 at 5-7. The total capital cost for this project is approximately $7.9 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, land mobile radio, and other strategic high-capacity wireless technologies. *Id*. at 8-10. The total capital cost for these projects is approximately $27.2 million. *Id*. at 9.

- The NextGen GIS project, which replaces DEP's current obsolete core GIS with a new cloud-based platform, GIS toolset, and interfaces to critical systems. This replacement will provide more reliable, accessible, and timely GIS data while leveraging technology to improve the effectiveness, efficiency, and quality of operations. Guyton Direct Ex. 5 at 3-5. The total capital cost for this project is approximately $29.7 million. *Id*. at 3.

- The Corporate Facilities projects, which consist of operations centers that are the workplace for distribution, transmission, lighting, and fleet staff that

support the electric grid's construction and maintenance. These centers are being updated to meet the needs of growing towns and cities, as well as support the significant grid improvements taking place to better serve customers. *Id*. at 11-12. The total capital cost for these projects is approximately $62.3 million. *Id*. at 11.

- The Wildfire Mitigation program, which includes a software solution and 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 13-15. The total capital cost for this project is approximately $1.6 million. *Id*. at 14.

Witness Guyton testified that DEP selected MYRP2 Substation and Line distribution projects using its grid-planning process and ISOP tools, which evaluate substations and circuits for reliability, capacity, automation and communications, and voltage-regulation needs. Tr. vol. 8, 742. These ISOP tools evaluated each distribution substation and its associated circuits for current and historical operating performance, as well as gaps to critical grid capabilities. *Id*. Ultimately, witness Guyton testified that DEP's MYRP2 distribution projects were identified through a data-driven grid planning process and consist of specific programmatic solutions that can be identified, scoped, and placed in service during the applicable MYRP2 rate years. *Id*. at 729, 742-43.

Witness Guyton also testified that DEP calculated the benefits of certain MYRP2 distribution projects using CBAs developed at the program level. *Id*. at 747. As discussed above in the Transmission MYRP2 section, DEP's CBA methodology compares the NPV of monetized financial benefits over an established period to the NPV of cumulative costs over that same 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 DEP used the same general approach for calculating CBAs for MYRP2 distribution projects as it used for MYRP1. *Id*. at 749.

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 747. 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*. at 747-48. Witness Guyton testified that the ICE Calculator is a useful tool for valuing reliability improvements, and that the underlying data supporting this model is derived from extensive, statistically representative utility customer surveys. He further testified that the ICE Calculator has undergone multiple rounds of validation and refinement through ongoing updates led by Lawrence Berkeley National Laboratory and Resource Innovations. *Id*. at 749. He explained that, since DEP's last rate case, a major update referred to as ICE Calculator 2.0 was released in April 2025, and that 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*. at 749-50.

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*. at 750. 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. He added that the U.S. Department of Energy endorses its use and that it is widely adopted across the industry for reliability planning, investment justification, and regulatory filings. *Id*. Witness Guyton also explained that customer reliability risk-reduction benefits are savings customers realize by avoiding outages or reducing their severity. *Id*. at 748. Because these benefits take the form of fewer and/or shorter outages, DEP cannot pass these savings directly to customers as a bill credit or other direct payment; rather, customers realize the benefits through improved reliability. *Id*. at 748

For programs where a CBA was not performed, witness Guyton explained that the work is required as part of DEP's obligation to serve through prudent and safe utility practices. *Id*. at 748. Specifically, DEP 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. He noted, however, that the costs for this work are incorporated into the CBA Portfolio Summary, demonstrating an overall net positive value of the portfolio even when including costs from projects with no quantified benefits. *Id*. at 748-49.

Finally, witness Guyton explained that DEP's experience with MYRP1 directly informed the development, selection, planning, and prioritization of MYRP2 distribution projects. *Id*. at 736-37. He testified that in most cases, the distribution projects included in MYRP2 are more fully developed than those in MYRP1 and are therefore more accurate. *Id*. at 736. Witness Guyton further testified that, when determining selection of MYRP2 Substation and Line projects, cost estimates benefited from prior work completed for similar projects at similar locations. *Id*. at 737.

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 755. Pursuant to Rule R1-17B(f), witness Guyton testified that DEP updated (1) the schedule for one project task/location to reflect a material change, (2) the cost estimates for 22 project tasks/locations with capital costs equal to or greater than $10 million, and (3) certain project information to correct errors. *Id*. at 757. Witness Guyton testified that DEP neither added nor removed any MYRP2 distribution projects or project locations. *Id*. at 759. Collectively, the updates resulted in a net increase of $34.9 million to the amount of capital expected to be placed in service for the MYRP2 distribution projects. *Id*. at 761.

Witness Guyton's Supplemental Direct Exhibit 3 provides the updated MYRP2 distribution project costs and related non-T&D project costs that support distribution operations. Guyton Supp. Direct Ex. 3. As updated in Guyton Supplemental Direct

Exhibit 3, the total projected in-service costs for the MYRP2 distribution projects and related non-T&D projects sponsored by witness Guyton are approximately $1.559 billion.

1. Approximately $1.081 billion for Substation and Line projects;
2. Approximately $315.9 million for Retail and System Capacity projects;
3. Approximately $23.7 million for Hazard Tree Removal projects; and
4. Approximately $138.7 million for other non-T&D projects.

Id. at 1-8.

The Public Staff Distribution Panel reviewed DEP's MYRP2 distribution capital portfolio and raised concerns regarding the pace, prioritization, and cost justification of certain distribution investments. Tr. vol. 7, 1314-15, 1383-84, 1387-88. In particular, the Public Staff Distribution Panel expressed concern that DEP's distribution capital spending had increased substantially since 2015 while reliability metrics such as SAIDI, SAIFI, and Customers Experiencing Multiple Interruptions (CEMI) had not shown corresponding improvement. *Id*. at 1336, 1350-52, 1358. As such, the Public Staff Distribution Panel made several recommendations regarding DEP's Substation Optimization program, in addition to reducing DEP's proposed distribution MYRP2 capital by approximately $279.5 million (17%). *Id*. at 1399. The Distribution Panel further provided testimony regarding MYRP1 Substation Optimization projects, expressing concern but not recommending further action.[9]

Regarding implementation and planning for the Substation Optimization program, referred to in DEP witness Guyton's testimony as the MYRP Substation and Line projects, the Public Staff Distribution Panel testified that it was concerned that many of the substations and circuits targeted for Substation Optimization investment were already performing better than the system average in terms of service quality. *Id*. at 1360-61. Public Staff witness T. Williamson noted that, though DEP witness Guyton stated these investments are justified by estimating the monetary value to customers of an avoided outage, these benefits do not put downward pressure on rates. *Id*. at 1360. Witness T. Williamson further asserted that, based on average SAIDI and SAIFI, Substation Optimization projects executed since 2021 have left the distribution system's reliability stagnant rather than improving. *Id*. at 1363-64. Witness Thomas echoed the concern that DEP's Substation Optimization program may misplace capital spending and discussed this effect on MYRP2 distribution projects. *Id*. at 1387-90.

Because of its concerns regarding DEP's execution of Substation Optimization projects, the Public Staff Distribution Panel recommended moving forward that the Commission require DEP to complete a reliability report for each Substation Optimization project with an estimated cost of $200,000 or greater. *Id*. at 1337. The Distribution Panel further testified that it was not proposing that the reliability report be filed, but rather that it be kept by DEP and provided to the Public Staff upon request when the utility seeks

[9] The Public Staff's discussion of MYRP1 Substation Optimization projects is addressed herein in the Evidence and Conclusions for Finding of Fact No. 16.

cost recovery for the project. *Id*. at 1413-14. 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 customer minutes interrupted (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.

The Distribution Panel also recommended that the Commission require DEP prioritize Substation Optimization projects for substations and circuits that have five-year average non-MED SAIDI and non-MED SAIFI worse than the five-year system averages, with additional priority given to circuits that experience persistently high non-MED CEMI-6 and non-MED CEMI-8. *Id*. at 1414-15.

Regarding adjustments to MYRP2 Substation Optimization capital, the Public Staff Distribution Panel recommended reducing DEP's proposed Substation and Line program by approximately $258.6 million (24%). The reductions include approximately $89.1 million from Capacity, $23.2 million from SOG, $49.2 million from Hardening and Resiliency, and removal of the Equipment Retrofit package totaling $97.1 million. *Id*. at 1387. 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 72 substations and 275 attached circuits included in DEP's MYRP2 request. *Id*. at 1389. The Distribution Panel proposed exclusion of reliability-focused 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*. This resulted in a reduction of projects across MYRP2 of approximately $72.4 million. *Id*. In terms of its adjustments to 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 summer peak load decline over the past three years. *Id*. at 1391. The Distribution Panel

also removed the Capacity package from any circuits where they also recommended removing the SOG package. *Id*. With respect to the 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 DEP 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 DEP clarified no replacements were proposed due to safety concerns. *Id*. at 1389-90.

The Distribution Panel also recommended the Commission disallow cost recovery of historic period investments in the NextGen GIS project and remove the program from MYRP2[10] because of cost increases, schedule changes, and uncertainty of completion. *Id*. at 1391-97. 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 1394. However, given the historic performance and based on discovery responses from DEP, the Distribution Panel testified that it does not have confidence that the NextGen GIS project will be completed on schedule to include in DEP's proposed MYRP2 timeline. *Id*. The Distribution Panel also testified that it had IT resource concerns regarding the proposed business combination between DEP and DEC and the work required to merge billing and other complex IT systems before "Legal Day 1" of the merger which takes effect January 1, 2027, a mere six months before NextGen GIS is due to go in service. *Id*. at 1396-97.

The Public Staff Distribution Panel also raised concerns regarding DEP's CBAs for certain MYRP2 distribution investments. *Id*. at 1381-83. In particular, the Public Staff Distribution Panel asserted that only approximately 2% of the customer reliability benefits from avoided or shortened outages reflected in DEP's CBAs accrue to residential customers, while approximately 98% accrue to nonresidential customers. *Id*. at 1383. The Public Staff Distribution Panel further noted that residential customers are anticipated to pay approximately 70% of North Carolina distribution costs under DEP's proposed COSS. Witness Thomas asserted that this creates a significant mismatch between who pays for the projects and who benefits. *Id*. at 1383-84. 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*.

In rebuttal, witness Guyton responded to the Public Staff Distribution Panel's testimony and the recommended reductions to DEP's MYRP2 distribution capital investments. Tr. vol. 8, 769-830. 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

[10] 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. 16.

condition, equipment age, criticality, capacity needs, load growth, resiliency, operational flexibility, and the benefits of coordinated project execution. *Id*. 765-66, 781-82, 788-90.

With respect to the Distribution Panel's criticisms of DEP's Substation Optimization investments, in his rebuttal testimony, DEP witness Guyton testified that he did not agree with the Distribution Panel's concerns that DEP has invested in substations the Public Staff characterized as already performing better than the system average. *Id*. at 788-89. Witness Guyton provided further information on how DEP selects and prioritizes its Substation and Line MYRP projects using the Grid Plan and how, contrary to the Distribution Panel's claims, this data-driven approach does prioritize selection of circuits with historically poorer SAIDI and SAIFI metrics. *Id*. at 792. 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*. He testified that simply deferring investment at "better-than-average" substations until they become problems would lead to a cycle of reactive spending that fails to account for the natural degradation of assets across the broader system. He further testified that, without continued investment in circuits that currently perform at or above average, those assets will deteriorate over time and offset any gains achieved on the worst performing circuits. *Id*. at 793. 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 794. He explained that DEP 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*. at 795.

Regarding the Public Staff's recommendation to prioritize Substation Optimization work for substations and circuits based on five-year historic reliability metrics, witness Guyton testified that this recommendation would unnecessarily narrow the Grid Plan's review and prioritization process. He testified that the Grid Plan already prioritizes third- and fourth-quartile circuit level reliability while also considering five-year forward-looking forecasted load growth and reliability degradation. *Id*. at 797. He explained that re-prioritizing projects midstream, as the Distribution Panel suggests, can increase total cost from multiple deployments to the same site, disrupt outage planning, and extend risk exposure. *Id*. at 798. With respect to the Public Staff's recommendation that DEP generate a reliability report, available when called upon by the Public Staff, witness Guyton testified that he disagrees that this is appropriate or necessary. In his view, the Public Staff's conclusions regarding DEP's reliability performance do not account for the full range of planning considerations reflected in the Grid Plan. *Id*. at 799. Second, he testified that the Public Staff's recommendation would have DEP focus solely on reliability metrics and ignore several other important factors that are appropriately considered as part of DEP's project planning and prioritization, which DEP has carefully and thoughtfully reviewed and prioritized as part of the Grid Plan. *Id*. Further, he testified that the Public Staff already has this information which was provided to the Public Staff 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 $258.6 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 814-15. 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 DEP's planning tools, and SOG-related capacity upgrades that enable automatic load transfers for reliability and resiliency purposes. *Id*. at 817-18. 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 818-19. Regarding the Public Staff's recommended removal of Equipment Retrofit, witness Guyton testified that benefits were based on historical equipment outages at transformers, arrestor stations and riser poles tracked by DEP and quantified in the cost benefit analysis presented in DEP Guyton Direct Exhibit 7. *Id*. at 822.

DEP witness Guyton further responded in rebuttal to the Public Staff Distribution Panel's criticism of DEP's CBAs. *Id*. at 823-25. 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*. During the hearing, witness Guyton further explained this distinction, testifying that residential customers would avoid approximately 12 million CMI annually, compared to 2 million CMI for nonresidential customers. *Id*. at 844-45. 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*.

In his rebuttal testimony, DEP witness Teckenbrock responded to the Public Staff Distribution Panel's recommendation to remove the NextGen GIS project from MYRP2. Tr. vol. 7, 637-52. Witness Teckenbrock testified that the increase in the DEP 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 639. He further testified that the forecasted in-service date remains squarely within the MYRP2 period, and that the six-month schedule adjustment from the in-service date forecasted when the project was proposed as part of DEC's MYRP1 reflects refinements informed by the completed implementation for Duke Energy's Midwest gas operations. *Id*. at 645-46. 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 that DEP 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 645-50.

The Comprehensive Settlement resolved the distribution MYRP2 project-specific issues between DEP and the Public Staff. DEP and the Public Staff agreed to reduce the Substation and Line program by approximately $136.1 million (system) and DEP provided the Public Staff with a list of the specific projects selected for removal, and the removal of such projects is reflected in the Abernathy Settlement Exhibits. Comp. Settl. § II.46. The Comprehensive Settlement also addressed the Public Staff's concerns regarding CBAs by providing that in DEP's next general rate case, DEP will include additional support for its CBA process, including formulas and technical explanations of value models. *Id*. § III.4. The Comprehensive Settlement provides that the NextGen GIS project is removed from MYRP2 and that there will be no additional reductions to DEP's MYRP2 projects in this proceeding. *Id*. §§ II.32, II.53.

The Commission gives significant weight to the compromise agreements reflected in the Comprehensive Settlement. 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 DEP 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 DEP's proposed MYRP2 distribution projects, as adjusted by the Comprehensive Settlement, are needed to maintain and improve the safe and reliable delivery of electric service to DEP'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 Comprehensive Settlement's removal of certain MYRP2 Distribution Substation and Line program projects and the removal of the NextGen GIS project reasonably resolve the issues raised with respect to these projects. Accordingly, the Commission finds that DEP's distribution MYRP2 projects, as adjusted by the 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 Comprehensive Settlement's provisions regarding those projects as just, reasonable, and in the public interest.

Fossil/Hydro

DEP witness Walsh testified in support of the 91 traditional and hydro projects included in the proposed MYRP2, the process used to select the projects, and the method by which DEP calculated projected costs for the projects. The estimated expenditure for these projects is $521 million. Tr. vol. 7, 258-65. Witness Walsh testified that DEP 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. *Id*. at 258. 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 259. After scoring, DEP 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 DEP applying additional scrutiny to projects considered for MYRP2. This included additional regional management oversight and a focus on projects that are required to maintain reliable operations. *Id*. at 260. He added that DEP'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*. 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. 7, 258-65; Walsh Direct Ex. 2.

Witness Walsh also provided an update on the status of DEP's execution of the 91 traditional and hydro projects included in MYRP1. Tr. vol. 7, 251-58. Witness Walsh described how DEP managed and controlled the costs and schedules of these projects. He explained why certain projects were cancelled or their in-service dates shifted. For example, he noted that the Smith Unit 6 AGP Peaker Upgrade project was cancelled due to the determination that its scope could be included as part of the MYRP1 Smith Unit 6 Hot Gas Path Inspection project that went in service in December 2023. *Id*. at 256. In another example, he noted that the schedule for the Sutton Lake Makeup System project was delayed from Rate Year 1 to Rate Year 2 due to material delivery issues with back-ordered breakers. *Id*. Witness Walsh's Exhibit 1 provided DEP's MYRP project quarterly report for the quarter ended June 30, 2025. Walsh Direct Ex. 1.

In his supplemental testimony, witness Walsh provided an update on the traditional/hydro MYRP1 projects through the end of PBR1's Rate Year 2 ending September 30, 2025, which was not available at the time of his direct testimony. Additional details regarding these updates were provided in witness Walsh's Supplemental Direct Exhibit 1. Tr. vol. 7, 272-76; Walsh Supp. Direct Ex. 1.

Witness Walsh also updated certain traditional and hydro MYRP2 projects in accordance with Commission Rule R1-17B(f). Tr. vol. 7, 276-78. Witness Walsh testified that DEP did not propose to include any additional traditional or hydro projects in the MYRP2. He identified the two projects that moved beyond the MYRP2 period due to a shift in maintenance outage schedules, which brought the updated total of proposed projects to 89. *Id*. at 277. He also identified four projects with adjusted in-service dates due to updated outage schedules, material lead times, and refined project scope. *Id*. 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. *Id*. at 277-78. Witness Walsh's Supplemental Exhibit 2 provided updated details for the MYRP2 projects and identified the reason for the stated project changes. Walsh Supp. Direct Ex. 2.

Public Staff witness Thomas testified to his review of DEP's proposed coal and natural gas MYRP projects. Tr. vol. 7, 1513-15. Witness Thomas recommended a reduction to the projected cost of certain Roxboro coal projects by $10.3 million to reflect the DOE grant award announced in June 2026 for the Roxboro Station Reliability Assurance Initiative. 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 credit customers for the award now, similar to the treatment of Infrastructure Investment and Jobs Act awards in the 2023 Rate Case, and DEP can recover any difference from actual costs in its next rate case. *Id*. at 1516.

Witness Thomas also 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 an amount reflecting projected 2028 O&M savings for the Roxboro complete coal crusher replacement project and $167,320 for proposed heat rate upgrade and advanced gas path projects at DEP's Asheville and Wayne County natural gas plants. Tr. vol. 7, 1513-14, 1531-32.

In his rebuttal testimony, witness Walsh emphasized that out of 89 coal, natural gas, and hydro MYRP2 projects, the Public Staff recommended reductions to only a handful of coal and natural gas projects, with none of the recommendations based upon an assertion that the project was not beneficial to customers, unreasonable, or imprudent to execute. *Id*. at 292. He noted further that the Public Staff raised no concerns with any hydro MYRP projects. *Id*.

With respect to the Public Staff's recommendation regarding the Roxboro DOE award, witness Walsh testified in rebuttal that negotiations between Duke Energy and the DOE regarding the specifics of the award are still ongoing. He stated that until those negotiations are complete, neither the amount DEP will receive nor the projects that will be funded will be known. Witness Walsh argued that the appropriate and prudent course is to proceed based on the information known today and adjust rates as needed at a future time. *Id*. at 293.

Witness Walsh addressed the Public Staff's recommended reduction to O&M costs for several MYRP2 projects based on "projected savings" noted in the supporting documentation for these projects. *Id*. at 294-95. Witness Walsh testified that the recommendation does not recognize the purpose of the O&M savings projections included in Evaluator documents and CBAs. He testified that these projections are for project comparison purposes, to evaluate which project design alternative should be pursued, or whether to execute a project at all. He stated that any "savings" identified are not ongoing savings that should be applied to the test year; rather, DEP applies those dollars to address other needs at the station or the fleet. Witness Walsh stated that if DEP forfeited all O&M dollars "saved" by capital projects across the traditional/renewable fleet,

the stations would cease to function reliably. He concluded that it is good utility practice, and DEP's normal day to day practice, to optimize funds where they are needed most to keep units reliable; if costs are saved in one area, they are applied elsewhere to meet other needs. *Id*. at 295.

The Comprehensive Settlement provides that costs associated with the portion of the Roxboro Coal Reliability Initiative 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 DEP may seek recovery of the actual undepreciated value of the projects in future rate cases. Comp. Settl. § II.47. The Comprehensive Settlement also provides for acceptance of the Public Staff's adjustments to on-going O&M related to the Roxboro Coal Crusher Replacement Project and Heat Rate Upgrade Projects, resulting in reductions of approximately $0.004 million and $0.167 million (system), respectively. *Id*. § II.52. The Comprehensive Settlement provides that there will be no additional reductions beyond those specified in the Stipulations to the MYRP2 projects in this proceeding. *Id*. § II.53.

Based on the entire record in this proceeding, the Commission finds that DEP's proposed fossil and hydro MYRP2 projects as adjusted by the Comprehensive Settlement are needed to maintain and improve the safe and reliable delivery of electric service to DEP's customers. The Commission also finds that these proposed MYRP2 projects are needed to maintain and improve 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 Comprehensive Settlement's removal of the portion of the Roxboro project costs expected to receive DOE funding reasonably resolves this issue, and that its reductions to O&M associated with certain Roxboro, Asheville, and Wayne County projects reasonably resolves the issue regarding projected O&M savings for those projects. Accordingly, the Commission finds that DEP's fossil and hydro MYRP2 projects as adjusted by the 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 substantial evidence in the record supports approval of the Comprehensive Settlement's provisions.

Nuclear

DEP witness Flippin testified in support of the 21 nuclear projects that DEP included in the proposed MYRP2, the process DEP used to select the projects, and the method by which DEP calculated projected costs for the projects. Tr. vol. 7, 187. Witness Flippin testified that DEP selected these projects based on their importance to safety, reliability, equipment condition, and confidence in cost and schedule estimates. *Id*. She added that DEP applied lessons learned from MYRP1 projects to the selection of MYRP2 projects. One key lesson was the value of selecting projects that are in-flight or have similar scopes to recently completed projects, which leads to increased cost and schedule predictability. *Id*. She added that 17 of the 21 projects selected for MYRP2 are underway and have

progressed through internal management review, thereby increasing predictability and confidence of their costs and schedules, while three projects are part of multi-year efforts with well-defined scopes. *Id*. at 187-88. She testified that another key lesson learned by DEP was the value of selecting frequently performed routine maintenance activities where the plants have a history of executing similar work. *Id*. at 188. Based on this experience, DEP included two routine preventive activities in MYRP2. *Id*. Witness Flippin explained that the projected costs for the MYRP2 nuclear projects were obtained from DEP'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. *Id*. She explained that all of the MYRP2 nuclear projects offer operating benefits by enabling DEP to maintain safe and reliable operation of the nuclear plants by addressing aging systems and equipment for critical baseload resources. *Id*. at 189.

Witness Flippin provided an overview of the MYRP2 nuclear projects in addition to sponsoring Flippin Direct Exhibit 2, which provided details of the projects. Flippin Direct Ex. 2; tr. vol. 7, 190-95. She testified that DEP prudently and reasonably selected these projects for investment, as they will enable DEP to maintain the nuclear fleet in a reliable and efficient condition for the benefit of customers. Tr. vol. 7, 190. Witness Flippin testified that the Brunswick and Robinson plants are executing multiple projects that will allow both sites to extend their operating licenses for an additional 20 years and operate safely and reliably through the end of their extended license periods, and that the Harris plant is executing multiple projects that will allow the site to maintain safe and reliable operation. *Id*. at 190-95.

Witness Flippin also provided an update on the status of DEP's execution of the 24 nuclear projects included in MYRP1. *Id.* at 180-86. She explained the reasons for shifts in in-service dates and costs for certain projects, including four projects that are being placed in-service after December 1, 2026, causing these to be included in DEP's MYRP2 project list. *Id*. at 180. These include the Brunswick Unit 1 plant process computer (PPC) project and Harris and Robinson emergency response facility information system (ERFIS) and PPC systems replacement projects that were shifted to MYRP2 due to delays in receipt of materials and technical deliverables from the primary equipment supplier. *Id*. The fourth project is the replacement of the Harris 'A' unit auxiliary transformer, which was changed from occurring in one refueling outage in 2024 to being spread over three consecutive refueling outages from 2024-2027 in order to reduce overall project risk and achieve shorter refueling outage durations. *Id*. She also noted that the Harris circulating water pump cable replacement project was canceled and will no longer be completed due to identification of an unacceptable single point vulnerability during execution, which requires the scope, cost, and schedule of this project to be re-evaluated and a new solution to address the pump cable to be implemented in the future. *Id*. at 181. Witness Flippin's Exhibit 1 contained DEP's MYRP project quarterly report for the quarter ended June 30, 2025. Flippin Direct Ex. 1.

In her supplemental testimony, witness Flippin provided an update on the nuclear MYRP1 projects through the end of PBR1's Rate Year 2 ending September 30, 2025, which was not available at the time of her direct testimony. Witness Flippin noted that five

of the 24 approved MYRP1 projects were approved with in-service dates in Rate Year 2; two of these projects were placed into service during Rate Year 2 at a total cost of approximately $32 million. Tr. vol. 7, 209. Two of the three remaining projects will be placed in-service during Rate Year 3: (1) the Brunswick containment atmosphere control tanks, for which challenges with the electrical, instrumentation and controls, and engineering design delayed the project implementation date; and (2) the Brunswick radio system and console replacement, for which vendor challenges arising from cyber security requirements led to delays in engineering and implementation. *Id*. at 209-10. Lastly, the Robinson ERFIS and PPC replacement project experienced delays with the receipt of material and technical deliverables from its primary equipment supplier, so DEP plans to carry this project over into the MYRP2 project list. *Id*. at 210. Witness Flippin noted the total estimate for these three remaining projected is approximately $60.4 million compared to the approved MYRP1 total estimate of $42.6 million. *Id*. at 209.

Witness Flippin also discussed the five MYRP1 projects with a total cost estimate of approximately $62.2 million that were approved with in-service dates during Rate Year 3. *Id*. at 210. DEP still projected four of these five projects to be placed into service during Rate Year 3, with a total cost of approximately $49.2 million. Witness Flippin testified that DEP shifted the in-service date of the Brunswick distributed information control systems platform replacement from Rate Year 3 to October 2026 and updated its total cost estimate to be approximately $20.2 million. *Id*. Witness Flippin explained that the primary driver of the cost changes for these projects was the technological advancements related to the Robinson intrusion detection system equipment that occurred since that project was initiated; to ensure the Robinson intrusion detection system is and remains technically robust, these technological advancements were incorporated into the design, resulting in an increased project cost. *Id*. at 210-11. Witness Flippin sponsored Flippin Supplemental Direct Exhibit 1, which contained additional details on the actual and projected in-service dates and costs for DEP's nuclear MYRP1 projects. Flippin Supp. Direct Ex. 1; tr. vol. 7, 211.

Witness Flippin also updated certain MYRP2 nuclear projects in accordance with Commission Rule R1-17B(f). Witness Flippin testified that DEP did not propose to include any additional nuclear projects in the MYRP2, did not identify any nuclear projects that were no longer needed or were moved out of the MYRP2 period, and did not identify any such projects requiring updates to in-service dates. Tr. vol. 7, 211. Witness Flippin supported updated cost estimates for four nuclear MYRP2 projects that were originally estimated to cost more than $10 million: the two Brunswick and Robinson SLR applications, the Brunswick main steam isolation valve upgrade, and the Robinson south service water header piping replacement. *Id*. at 212-13. She explained that the cost estimates for the Brunswick and Robinson SLR projects were updated due to a change in the Nuclear Regulatory Commission's projected time to review SLR applications, which has been reduced from 18 to 12 months. *Id*. at 213. The Brunswick main steam isolation valve upgrades project cost estimate was updated because DEP's initial application omitted a portion of the estimated project contingency. *Id*. Lastly, the Robinson south service water header piping replacement project received additional funding authorization since the initial application, and additional updated documentation was also provided for

this project. *Id*. Witness Flippin sponsored Flippin Supplemental Direct Exhibit 2, which provided updated details for the MYRP2 projects and identified the reason for the changes to certain projects. Flippin Supp. Direct Ex. 2; tr. vol. 7, 212.

While Public Staff witness Thomas recommended an across-the-board reduction of $1.31 billion across RY1 and RY2, he did not raise any objection to any specific nuclear project identified for DEP's proposed MYRP2. Tr. vol. 7, 1489-1506. Similarly, DoD/FEA witness Larkin-Connolly also expressed concerns with the magnitude of DEP's MYRP2 budget, recommending the Commission direct DEP to file an updated capital plan with expenditure levels more consistent with those approved for MYRP1; though he also did not take issue with any specific nuclear project identified in DEP's MYRP2. Tr. vol. 8, 565-67.

Public Staff witness Thomas also recommended removal of 100% of MYRP project contingency from the revenue requirement in this proceeding but likewise did not cite concerns specific to DEP's proposed nuclear projects; rather, witness Thomas raised concerns over the burden contingency allowance generally places on ratepayers. Tr. vol. 7, 507-09. DoD/FEA witness Larkin-Connolly also recommended budget contingencies in the MYRP2 be removed from the MYRP2 rate base, expressing concerns over the use of permitting contingency recovery generally rather than its use with any specific proposed nuclear projects. Tr. vol. 8, 567-73.

In her rebuttal testimony, witness Flippin also noted that no party challenged the need for the proposed nuclear MYRP2 projects to maintain safe and reliable operations. Tr. vol. 7, 217. She also argued that project contingency is not always 100% utilized and is a critical aspect of project planning and execution that allows DEP to properly estimate the in-service cost of a project. *Id*. at 232. Witness Flippin stated that the proposed contingency amounts for the nuclear MYRP2 represent approximately 10% of the total in-service costs of the DEP's proposed MYRP2 projects, and that excluding these amounts would likely result in actual project in-service costs having a larger difference from the estimated in-service costs for the nuclear MYRP2 projects DEP proposed. *Id*. at 233.

Based on the entire record in this proceeding, the Commission finds DEP's proposed nuclear MYRP2 projects are needed to maintain and improve the safe and reliable delivery of electric service to DEP's customers and are needed 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. Accordingly, the Commission finds that DEP's nuclear MYRP2 projects satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a), and the evidence supports approval of those projects as just, reasonable, and in the public interest.

Solar

DEP witness LaRoche supported DEP's utility-owned solar and solar paired with storage (SPWS) investments, including the investments approved in DEP's MYRP1 and the investments proposed in MYRP2. Tr. vol. 7, 327-41. He began by providing an update

on DEP's two MYRP1 projects, Red Bud Solar and Asheville Solar. He explained that Red Bud Solar was placed in service in October 2025 and is operational, and Asheville Solar is materially under construction with an estimated in-service date of December 2026. *Id*. at 328-31. In his supplemental testimony, he explained the steps DEP has taken to mitigate cost increases for these two projects considering the bankruptcy of the original Engineering, Procurement, and Construction (EPC) contractor, Blue Ridge Power. Actions included taking over permits and subcontracts, securing replacement EPC firms, and recovering credit securities posted under the original EPC agreements to offset project costs. *Id*. at 344-45. Witness LaRoche also provided testimony regarding the two solar projects DEP has proposed for MYRP2: Robinson Solar and Cedar Falls (a SPWS facility). *Id*. at 334-36. He explained how DEP used its MYRP1 experience to inform the development and construction timelines for these MYRP2 projects, and the benefits that customers will receive from these proposed MYRP2 projects. *Id*. at 338-39. In his Supplemental Testimony, witness LaRoche provided updates on the MYRP2 projects, including projected in-service costs and dates. *Id*. at 346-48.

The Public Staff did not challenge the overall reasonableness or prudence of DEP's MYRP1 solar projects or historic solar plant. The Public Staff Renewables Panel did, however, note that the timing of the Blue Ridge Power bankruptcy caused DEP to effectively double pay for certain services rendered to Red Bud Solar. The Renewables Panel acknowledged Duke's appropriate crediting of the $3,033,229 received as credit security payment thus far and recommended that DEP continue to credit any amount recovered through the Blue Ridge Power bankruptcy proceeding against project costs. *Id*. at 1211-12. Regarding DEP's proposed MYRP2 solar projects, the Public Staff Renewables Panel testified that the two solar projects are supported by the 2024 CPIRP Order. *Id*. at 1200. The Renewables Panel further testified that the MYRP2 solar projects were procured through the Commission-approved 2022 and 2023 Solar Procurement Requests for Proposals. Because these competitive bidding processes ensured that expected costs were the lowest available to meet the capacity need, the Renewables Panel concluded that the costs are reasonable. *Id*. at 1201-02.

On rebuttal, DEP witness LaRoche responded to the Public Staff Renewables Panel regarding DEP's MYRP1 and MYRP2 solar projects, as well as to DoD/FEA witness Larkin-Connolly. He explained that DEP has mitigated the cost and schedule impacts of Blue Ridge Power's bankruptcy and confirmed that DEP will credit additional costs recovered to customers. Tr. vol. 7, 354-55. Witness LaRoche also rebutted witness Thomas's recommendation for a blanket reduction of approximately $1.3 billion from DEP's MYRP2 estimated in-service costs, as well as the recommendation to remove 100% of DEP's MYRP2 project contingency. *Id*. at 356, 362. He testified that the MYRP2 solar and SPWS projects are late-stage and mature, with fully executed interconnection agreements, all long-lead and major equipment secured, and EPC contractors selected and authorized. He testified that these actions reflect sound project development and execution planning. *Id*. at 362-63.

The Commission gives significant weight to the compromise agreements reflected in the Comprehensive Settlement. The Comprehensive Settlement's solar and SPWS provisions are the product of good-faith, give-and-take negotiations among the Public

Staff and DEP and represent a reasonable resolution of the disputed issues regarding the appropriate level of MYRP2 solar and SPWS investment.

Based on the entire record in this proceeding, the Commission finds that DEP's proposed solar MYRP2 projects, as adjusted by the Comprehensive Settlement, are needed to maintain and improve the safe and reliable delivery of electric service to DEP'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 Comprehensive Settlement's reduction of the contingency to 25% of the amounts included in DEP's second supplemental testimony reasonably resolves the issues raised with respect to MYRP2 solar projects. Accordingly, the Commission finds that DEP's solar MYRP2 projects, as adjusted by the 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). Finally, the Commission concludes that the evidence supports approval of the Comprehensive Settlement's provisions regarding those projects as just, reasonable, and in the public interest.

Battery Storage

DEP witness Tompson testified in support of DEP's MYRP2 BESS investments. Witness Tompson outlined DEP's foundational MYRP1 BESS portfolio execution and described how lessons learned from that experience supported the planning and development of the proposed MYRP2 BESS portfolio. Tr. vol. 7, 367-80. He 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 five BESS projects: HF Lee Energy Storage 1 (HF Lee 1), HF Lee Energy Storage 2 (HF Lee 2), New Hill Energy Storage (New Hill), Red Bud Energy Storage (Red Bud), and Williamsboro Energy Storage (Williamsboro). *Id*. at 375.

Tompson Exhibit 2 provides detailed information on each proposed investment, including the reason, scope, estimated cost, and projected in-service month and year. Tr. vol. 7, 375. Witness Tompson explained that the MYRP2 portfolio includes five additional battery energy storage projects that align with near-term system needs identified in DEP's integrated resource plans and will provide nearly 550 megawatts (MW) of new storage capacity. *Id*. at 367. His testimony highlights 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 377. Witness Tompson testified further that the proposed MYRP2 portfolio reflects lessons learned from MYRP1, including a shift toward larger-scale projects to capture economies of scale, improved cost and schedule forecasting based on execution experience, and process improvements from constructing batteries in varied settings. *Id*. at 374-75. For the New Hill project, DEP evaluated vendor bids and project-specific risks to develop cost estimates. For the remaining proposed MYRP2 projects, DEP developed estimates based on industry benchmarking, matching the approach used in the IRP process. *Id*. at 378.

In his supplemental direct testimony, witness Tompson provided an update on four of DEP's proposed MYRP2 BESS projects, including updated cost estimates, in-service dates, and ITC assumptions. *Id*. at 382-83. These updates reflect a collective increase of approximately $9 million to the system amount of capital expected to be placed in service for the proposed MYRP2 projects. *Id*. at 383.

The Public Staff Renewables Panel testimony presented findings and recommendations regarding BESS MYRP1 execution and the proposed BESS MYRP2 projects. *Id*. at 1199-1217. For BESS MYRP1 execution, the Renewables Panel recommended that the in-service capital for the Riverside BESS MYRP1 project be reduced by $430,418. *Id*. at 1217. For the MYRP2 BESS portfolio, the Renewables Panel recommended: (1) the removal of HF Lee 2 and the Williamsboro Microgrid; (2) a downward adjustment to the cost estimate for Red Bud to remove tariff-related costs; and (3) a downward adjustment to the HF Lee 1 cost estimate to remove battery equipment costs. *Id*. at 1200-10. The Renewables Panel testified that the Williamsboro Microgrid should be removed because most of the historical outages it is intended to address are vegetation-related. The Renewables Panel asserted that other projects on the distribution system, such as the vegetation management program, may substantially improve circuit reliability and thereby reduce the need for the microgrid. *Id*. at 1204-05. The Renewables Panel also cited cost concerns stemming from its experience with recently completed microgrid projects in DEC. *Id*. at 1205. Regarding the Red Bud cost estimates, the Renewables Panel testified that they were concerned about the inclusion of "Liberation Day" tariffs in the Class 5 cost estimate and recommended the tariff-related costs be excluded due to the dynamic and evolving policy changes surrounding those tariffs. *Id*. at 1202-03. The Renewables Panel also recommended removing battery equipment costs from HF Lee 1 to ensure the costs are not duplicative. *Id*. at 1206-07. The Renewables Panel further recommended removal of HF Lee 2 from the MYRP2 BESS portfolio because DEP had not provided sufficient support for the expected in-service date. *Id*. at 1209. Finally, the Renewables Panel recommended that DEP and DEC begin incorporating a utility-only-ownership procurement Request for Proposals (RFP) for BESS into its annual solar and SPWS RFP process to ensure the most cost-effective projects are built to meet generation needs. *Id*. at 1208-09.

CIGFUR II witness Collins raised concerns about MYRP2 BESS project cost and delivery risks which can challenge forecasted schedules and costs. Tr. vol. 9, 598-602. 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 actual in-service costs lower than approved for recovery; and (3) a return of project-level underspend to customers. *Id*. at 601-02.

Witness Tompson's rebuttal testimony responded to the various Public Staff and intervenor recommendations regarding DEP'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. 7, 389-90. Responding to Public Staff witness Thomas's recommended blanket

reduction to MYRP2 capital projects, witness Tompson explained that DEP developed and submitted cost estimates based on the best information and operational data available as part of the PBR Application. *Id*. at 394. These estimates reasonably incorporated learnings and on-the-ground information gained from executing the foundational MYRP1 BESS portfolio. *Id*. at 394-95. Witness Tompson also highlighted that the MYRP2 BESS estimates are competitive with MYRP1 project costs and reasonable relative to 2024 industry prices. *Id*. at 393. Witness Tompson disagreed with the Public Staff Renewables Panel's recommended removal of HF Lee 2 due to concerns surrounding the in-service date, as DEP provided an updated project schedule and it would be unreasonable and inconsistent with the MYRP framework to remove HF Lee 2 from the MYRP2 portfolio. *Id*. at 400-02. Witness Tompson also disagreed with the recommended removal of the Williamsboro Microgrid, as DEP stands behind the reliability need for the microgrid and has confidence in its cost estimate. *Id*. at 403. Witness Tompson disagreed with the recommended removal of Red Bud tariff costs. Though he acknowledged the Supreme Court's February 2026 ruling against Liberation Day tariffs, he noted that new tariffs took effect the next day. Witness Tompson therefore concluded it is reasonable to expect some tariff impact on battery costs. *Id*. at 403-04. Witness Tompson further disagreed with the recommended removal of HF Lee 1 battery equipment costs, arguing that the Public Staff Renewables Panel mistook the movement of battery price-increase costs from the Class 4 estimate into the project risk register for double-counting. He added that battery material costs remain at risk of increasing. *Id*. at 404-05. Witness Tompson also disagreed with the recommended incorporation of a utility-only-ownership procurement RFP for BESS into its annual solar and SPWS RFP process, as an RFP is unlikely to produce the benefits Public Staff described in its testimony. *Id*. at 406. Regarding witness Collins' testimony, witness Tompson explained that DEP does not expect its actual costs for MYRP2 battery storage projects to vary to the extent suggested in witness Collins' testimony and that his recommended proposals contradict the MYRP statutory framework under N.C.G.S. § 62-133.16, which provides for prospective capital investment with Commission prudence review. *Id*. at 408-09.

Section II, ¶ 48 of the Comprehensive Settlement provides that HF Lee 2 BESS and O&M shall be included in MYRP2. Section II, ¶ 49 of the Comprehensive Settlement accepts Public Staff's adjustment to the HF Lee 1 BESS project related to escalation price. Section II, ¶ 50 of the Comprehensive Settlement provides that the Williamsboro Microgrid project is removed from the MYRP2. Section II, ¶ 51 of the Comprehensive Settlement accepts the battery "Liberation Day" tariff adjustment proposed by the Public Staff at an amount reduced by 50%. Section II, ¶ 53 of the Comprehensive Settlement provides that there will be no additional reductions to MYRP2 projects.

Based on the entire record in this proceeding, the Commission finds that DEP's proposed BESS MYRP2 projects, as adjusted by the Comprehensive Settlement, are needed to maintain and improve the safe and reliable delivery of electric service to DEP'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 that they are consistent with the near-term battery storage needs identified through the Commission-approved resource planning process. The Commission also finds that these projects 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 Comprehensive Settlement's removal of the Williamsboro Microgrid from MYRP2, and the Stipulating Parties' resolution of the remaining BESS issues through the Comprehensive Settlement, reasonably resolves the issues raised with respect to these projects. Accordingly, the Commission finds that DEP's BESS MYRP2 projects, as adjusted by the 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). The Commission concludes that the evidence supports approval of the 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 DEP's MYRP2 project contingency costs on the basis that contingency is a budgeting tool that should not be included in rates prospectively. This removal represents an approximately $500 million reduction to capital costs in MYRP2. Tr. vol. 7, 1490-91. Witness Thomas testified that DEP included contingency for most of the proposed MYRP projects, with individual estimates varying across project function but with total contingency representing 11.7% of DEP's entire MYRP2 capital cost estimate. *Id*. at 1506-07. Witness Thomas acknowledged that contingency is an important part of budgeting. However, he argued it is not appropriate to include in MYRP project cost estimates as it places upward pressure on rates while reducing incentives to complete projects under budget. He further testified that customers may pay for unused contingency until the next general rate case, which is inherently unjust and unreasonable to ratepayers. He stated that ratepayers will not be credited for that overpayment, whereas the utility can come in for its next rate case and request an increase for any cost overruns. *Id*. at 1507-09.

DEP witnesses Fogg, Guyton, Walsh, Flippin LaRoche, and Tompson addressed witness Thomas's contingency recommendation in their rebuttal testimony. Witness Fogg testified that DEP's MYRP2 transmission projects carry contingency equaling approximately 11.4% of total estimated in-service costs. He stated that this contingency amount is reasonable, consistent with industry, and accounts for cost-estimate uncertainty and known and unforeseen project risks. *Id*. at 159. Similarly, with respect to distribution projects, witness Guyton testified that contingency is a standard construction industry risk management tool, not a DEP-invented mechanism, and DEP's approximately 11% of in-service costs for distribution project contingency represents a reasonable amount given known and unknown project uncertainties. Tr. vol. 8, 812-13.

DEP witness Flippin testified that the proposed removal of 100% of the contingency from the MYRP2 nuclear projects' cost estimates would artificially lower cost estimate values and does not account for why project contingency amounts are included in the MYRP2 cost estimates. He stated that contingency amounts represent a critical aspect of project planning and execution that allows DEP to properly estimate a project's in-service costs. Tr. vol. 7, 232-33. Witness Flippin stated that contingency represents approximately 10% of the total in-service costs of DEP's nuclear projects. *Id*. at 233.

DEP witness LaRoche testified regarding solar project contingency and stated that some level of contingency is prudent and beneficial to cover cost estimate uncertainty and/or project risks. He also testified that the contingency amounts included for MYRP2 solar projects are a reasonably low amount. *Id*. at 362.

Regarding battery storage projects, witness Tompson testified in his rebuttal testimony that DEP included contingency amounts for identified uncertainties and risks of energy storage projects with Class 3 or 4 estimates. Regarding Class 5 estimates, he stated that DEP used contingency rates based on experience with Class 4 projects. *Id*. at 398. He added that contingency amounts merely quantify risk and estimate uncertainties that could impact total project costs and are needed to develop risk-informed cost estimates. *Id*. at 399. He testified that he opposed the removal of the contingency for many of the same reasons as outlined by DEP's other operational witnesses. *Id*.

Finally, DEP witness Walsh testified that the proposed contingency amounts for the traditional/hydro MYRP2 projects are reasonable based on the facts known at the time the cost estimates were filed. He further stated that contingency represents approximately 4.1% of the total in-service costs of DEP's traditional/hydro MYRP2 projects. *Id*. at 291. Witness Walsh added that DEP does not establish contingency amounts arbitrarily; rather, contingency amounts are set based on DEP's internal engineering guidelines for project risk assessment and align with industry project management best practices. *Id*.

Section II, ¶ 42 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 DEP's second supplemental filing (subject to the project removals discussed further in the Comprehensive Settlement). Comp. Settl. § II.42. 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 expert witness hearing, DEP, the Public Staff, and intervenors provided extensive testimony regarding the appropriate level of MYRP2 capital investment and contingency. Positions ranged from support for DEP's original estimates to significant 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 DEP'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 DEP to complete many of the MYRP2 projects and provide reliable service to its customers. Therefore, in sum, the Commission approves DEP'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. 32-33

Cost Allocation

The evidence supporting these findings of fact is contained in DEP's verified PBR Application and Form E-1; the COSS Stipulation; the testimony and exhibits of DEP witness Hager; the joint testimony and exhibits of the Public Staff Rates Panel; the testimony and exhibits of CIGFUR II witness Collins; the testimony and exhibits of CUCA witness McGlothlin; the testimony and exhibits of Walmart witness Chriss; the testimony and exhibits of DoD/FEA witness Blank; 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

DEP Direct Testimony

COSS Overview

In her direct testimony, DEP witness Hager described the purpose of a COSS and how costs are assigned pursuant to such study. Tr. vol. 8, 121. Witness Hager explained that the COSS is used to align the total costs incurred by DEP 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 DEP's revenues, expenses, and rate base to the regulatory jurisdictions and to customer classes that caused such costs to be incurred. *Id*. Costs are first grouped according to their function. *Id*. at 123. 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*. Once all costs and revenues are assigned, the COSS identifies the return on investment that DEP has earned for each customer class during the test period, and these returns can then guide rate design. *Id*. at 121.

The COSS Stipulation

On October 24, 2025, the COSS Stipulating Parties filed the COSS Stipulation with the Commission in the instant proceeding and in DEC's pending rate case in Docket No. E-7, Sub 1329. *Id*. at 118-19. The COSS Stipulation provides that DEP 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 119. Because transmission demand does not have average or excess energy components, the transmission demand factors at the customer class level are equivalent to the 12 CP calculation. *Id*. The COSS Stipulation also provides that, for purposes of allocating production demand costs on a jurisdictional basis as well as to North Carolina retail rate classes, DEP will make an adjustment to exclude certain curtailable/interruptible loads in the event they were not curtailed at the twelve system peak hours during the test year. *Id*. The COSS Stipulation only applies in the current DEP rate case in Docket No. E-2, Sub 1380 and in the DEC rate case in Docket No. E-7, Sub 1329. The COSS Stipulating Parties are free to advocate for different methodologies in future rate cases. COSS Stip. § II.E. DEP 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. 8, 119. The Commission approved the 2022 COSS Stipulation among DEP, DEC, the Public Staff, CIGFUR II, and CIGFUR III employing the same methodology for allocating the DEP and DEC's production and transmission demand-related costs in Docket Nos. E-2, Sub 1300 and E-7, Sub 1276. Sub 1300 Order at 35-36; Sub 1276 Order at 36-37. The COSS Stipulating Parties urged 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 jurisdiction. Tr. vol. 8*,* 128. The 12 CP method allocated the fixed portion of production and transmission demand-related costs to the North Carolina retail, South Carolina retail, and wholesale jurisdictions based upon each jurisdiction's coincident peak responsibility occurring during the test years twelve monthly peaks, otherwise known as the 12 CP allocator. *Id*.

Witness Hager testified that DEP believes employing the 12 CP method is appropriate because it is consistent with DEP's integrated resource planning. *Id*. at 129-30. Further, she argued that by averaging the twelve monthly peaks, the 12 CP method is less volatile than a single coincident peak, particularly in regard to weather. *Id*. Witness Hager also testified that 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 129.

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 132. DEP 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 133. 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 its maximum demand regardless of the time of the system peak. *Id*. Witness Hager explained that each rate class's non-coincident demand likely occurs at different times from other classes, and the sum of the non-coincident class peaks is different from the systemwide peak demand. *Id*.

Witness Hager also noted that the A&E method is an accepted method of allocating demand-related production costs in Missouri, Arkansas, and Texas, and she argued that it is a reasonable method for allocating demand-related production costs to the North Carolina retail classes in this case. *Id*. at 135. DEP modified the A&E method described in the NARUC Electric Utility Cost Allocation Manual to conform the A&E allocators to the 12 CP method used at the North Carolina retail jurisdictional level. *Id*.

Removal of Certain Curtailable/Interruptible Loads

The COSS Stipulation provides that for purposes of allocating production demand costs on a jurisdictional basis as well as to the North Carolina retail rate classes, DEP agrees to make an adjustment to exclude curtailable/interruptible loads for the riders specified therein if they were not curtailed at the twelve monthly system peak hours during the test year. COSS Stip. § II.B. Hager Direct Exhibit 1 contains a description of the curtailable/interruptible load that was removed in accordance with the COSS Stipulation. Tr. vol. 8, 135. DEP witness Hager explained that aligning firm load with firm capacity to serve that load is consistent with the principle of cost causation. *Id*. at 135. In developing its IRP, DEP does not plan for or purchase capacity for the curtailable load of customers, and the utility can curtail interruptible service so that it does not contribute to the system peak. *Id*. at 135-36. As such, interruptible load does not determine how much DEP must invest in capacity to meet the system peak. *Id*. at 136. Witness Hager testified that if all possible curtailable load is curtailed in the test year during system peaks, there is no need for adjustment; revenues and load both reflect only firm load. *Id*. However, there can be a mismatch between revenues and loads if there is some non-firm load in the test year peaks. *Id*. Accordingly, DEP has removed non-curtailed non-firm load present during the Test Year peaks where its presence would create a mismatch with revenues. *Id*. Witness Hager noted that this adjustment ensures a matching of firm load with firm load revenues. *Id*.

Distribution Costs

DEP witness Hager testified that most distribution investments are identified and then directly assigned to the state in which they are located. *Id*. at 137. 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*.

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 demand. *Id*. Witness Hager noted that several different NCP

allocators are developed to account for the different levels of the distribution system where customers may take service 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, and commercial districts; they do not function as a single integrated system in meeting system peak demand. *Id*. at 137-38. 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*. at 138. 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

DEP 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*. Witness Hager testified that these costs are allocated using DEP'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

DEP 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*. DEP also included in this category a portion of distribution costs that it identified as customer-related, such as meters and service drops in FERC accounts 369 and 370, respectively, and a portion of transformers in FERC account 368. *Id*. at 138-39. Some costs for distribution lines and poles in FERC accounts 364-67 were also identified as customer-related. *Id*. at 139. The remaining distribution plant and associated costs were classified as demand-related. *Id*.

Witness Hager testified that a portion of distribution costs related to FERC accounts 364-68, including costs of poles, towers, fixtures, overhead and underground conductors, and transformers, are customer-related. *Id*. 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 DEP's Minimum System study allowed DEP 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" DEP to install some amount of distribution assets. *Id*. at 139-40. The concept used by DEP in developing its Minimum System study was to consider what distribution assets would be required if every customer had only a minimum level of usage. *Id*. at 140. This allows DEP to assess how much of its distribution system is installed simply to ensure that electricity can be delivered to each customer. *Id*. Once minimum system costs are identified, all distribution costs over this amount and direct assignments of those extra costs are determined to be driven by demand. *Id*. Witness Hager testified that the use of the Minimum System method is required by the PBR Statute, specifically N.C.G.S. § 62-133.16(b). *Id*. at 140-41.

Public Staff Direct Testimony

The Public Staff Rates Panel recommended that the Commission approve the COSS Stipulation. Tr. vol. 7, 1228. 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 1234. 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 1235. They testified that this approach is consistent with the 2022 COSS Stipulation that was accepted by the Commission in the Sub 1300 Order. *Id*. at 1234-35. The Rates Panel also testified that incorporating an energy component in a COSS 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 1235.

The Rates Panel elaborated on the 12 CP and Modified A&E methodologies. *Id*. at 1236-37. Specifically, they testified that the 12 CP method moderates the impacts of weather extremes from one month or one season. *Id*. at 1236. 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 consider the average demand component in determination of production related demand 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 served by a utility 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*. 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. *Id*. at 1237. 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*.

The Rates Panel also testified that the Modified A&E Method allows DEP to account for certain customers' ability to curtail during peak hours. *Id*. at 1238. As described in Section II.B of the COSS Stipulation, adjustments to the COSS may be made to exclude certain curtailable or interruptible loads from the COSS calculations if they were not curtailed during one of the 12 monthly system peak hours during the test year. *Id*. As a result, the Rates Panel testified that DEP reviewed its curtailable loads and made adjustments in this proceeding to applicable rate schedules and riders to adjust system peak loads.

In sum, the Public Staff, through the testimony of the Rates Panel, recommended that the Commission approve the COSS Stipulation filed in this proceeding on October 24, 2025, which proposed 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. *Id*.

CIGFUR II Direct Testimony

CIGFUR II witness Collins testified that CIGFUR II 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. 9, 572-73. Witness Collins noted that in DEP'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*. at 573 (quoting Sub 1300 Order at 91, 95). Witness Collins explained how the Modified A&E method allocates based on 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 577.

Witness Collins further clarified that CIGFUR II'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*. at 578. Witness Collins noted that because DEP'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*. 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*. 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 II supports the COSS Stipulation because it preserves the methodology approved in DEP'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, he testified that CUCA accepts the results of DEP's COSS consistent with the COSS Stipulation for the purpose of this proceeding. Tr. vol. 8, 379.

While witness McGlothlin did 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 379-80. Witness McGlothlin also noted that cost-based rates are required under the PBR Statute. *Id*. at 380.

In his analysis, witness McGlothlin argued that DEP is not reducing interclass subsidization to the greatest extent practicable. *Id*. at 381. He found that the large general service (LGS), seasonal and intermittent service (S&I), and Lighting classes are moving further away from cost, and noted that LGS is the only class that would receive an increase on its already-present subsidization of other classes. *Id*. 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 382.

Walmart Direct Testimony

While Walmart is not a COSS Stipulating Party, Walmart witness Chriss testified that Walmart does not oppose the COSS Stipulation or DEP's proposed production capacity cost allocation methodology. *Id.* at 425. Witness Chriss explained that the A&E method is, in his experience, an objective, transparent, and reasonable production plant cost allocator. *Id*. at 426.

DoD/FEA Direct Testimony

DoD/FEA witness Blank testified that he disagreed with the use of 12 CP and believes the use of an A&E approach would be better. *Id*. at 598-99. However, he noted that because these allocation methods resulted from a stipulation among several parties

representing the interests of diverse customer groups, he did not oppose the other parties that have agreed to the 12 CP method. *Id*.

Witness Blank also recommended that the Commission order DEP to provide the COSS presented in E-1, Item 45c on a parity basis in future rate case filings, arguing this is an important component of the record and stating that DEP objected to DoD/FEA's request for these filings on the grounds that they were not available. *Id*. at 598. He argued that without a class COSS showing the class revenues necessary for each class to achieve parity with the system ROR, parties lack an important source of information needed to evaluate the DEP's proposed revenue allocation. *Id*. at 603.

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 DEP's customer classes. Tr. vol. 9, 382. 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. *Id*. 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. *Id*. at 383. 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 384. 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*. He argued that this change emphasizes the importance of temporal analysis of energy generation and consumption in order to align cost causation with temporal energy costs, as costs are increasingly caused by energy use throughout the day and season rather than being driven by a limited number of high demand hours throughout the year. *Id*.

Therefore, witness Burgess recommended the Commission require DEP to use the Probability of Dispatch (POD) methodology to allocate demand-related production costs. *Id*. at 385, 395. 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. *Id*. 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*.

Witness Burgess performed his own POD allocation analysis for DEP's production costs and testified that his results allocate significantly less demand-classified production costs to residential customers, with an equivalent increase in the allocation for LGS customers. *Id*. at 385-87. He stated that residential allocation from his POD method is 9% lower than DEP's results, and his cumulative large general service allocations are 7.6% higher than DEP's allocators, reducing the residential class's total cost of service

by $114 million and increasing the large general service customer class costs by $98 million. *Id*. As a result of these findings, witness Burgess recommends the Commission reject DEP's proposed use of Modified A&E allocation methodology for production costs and instead adopt the AGO's POD-based COSS, or alternatively direct DEP to conduct its own POD analysis and prepare a new COSS using the results. *Id*. at 388-89.

Witness Burgess also took issue with DEP'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 in the Minimum System model. *Id*. at 389. Specifically, witness Burgess testified that DEP utilized NCP-Customer, calculating NCP as the sum of all individual customer peaks. *Id*. at 389-90. He stated that this is not a common methodology for calculating NCP for cost allocation of distribution resources, as it is best used for distribution facilities with low load diversity, such as secondary voltage lines and transformers. *Id*. at 390. Instead, witness Burgess recommended NCP-Class, the aggregated peak load for a particular class. *Id*. at 391. Witness Burgess testified that NCP-Customer harms more diverse classes by assigning them greater costs than they would be assigned using the more common NCP-Class methodology. *Id*. The NCP-Class methodology acknowledges the load diversity of customers within a class — particularly for residential customers — where customers use electricity at different times. *Id*. at 390-91. Therefore, witness Burgess recommended that the Commission require DEP to modify its NCP methodology for distribution system assets to use the NCP-Class or diversified NCP method. *Id*. at 393, 395.

As a result of his proposed modifications, witness Burgess also recommended that the Commission require DEP to prepare a new set of revenue apportionment results based on a COSS that uses the POD methodology to allocate demand-related production costs and the NCP Class methodology to allocate demand-related distribution costs. *Id*. at 395. He stated that his recommendations are necessary to ensure that DEP's MYRP2 rates do not allocate costs in a manner that is inequitable and overly burdensome to most residential customers, and argued that his recommended POD and Class NCP-based COSS provides a better method for allocating costs that achieves this outcome. *Id*. at 395-96.

NCJC, et al. Direct Testimony

NCJC, et al. witness Wilson opposed both DEP's jurisdictional method for allocating production and transmission costs and class allocation methods for allocating production costs. Tr. vol. 10, 18. Witness Wilson testified that DEP's jurisdictional and class allocation methods take different views of generation and transmission capital costs. *Id*. For jurisdictional purposes, he stated that costs are fixed and allocated using 12 CP. *Id*. For class purposes, he noted that DEP acknowledges an energy component. As a result, witness Wilson argued that DEP 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 DEP does not classify or allocate at the jurisdictional level any generation or transmission capital costs as energy-related, even though DEP 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 31. Witness Wilson further argued that 12 CP is biased toward wholesale customers and against retail customers. *Id*. at 33. For support, witness Wilson pointed to DEP and DEC's business 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*. at 34. Witness Wilson further 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 37-38.

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 DEP'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 20.

Witness Wilson also testified that the Modified A&E Method produces inequitable results when large new production capacity investments are required by the addition of high-load factor large loads. *Id*. at 20-21. He stated that the addition of these high-load factor large loads will cause the relative share of costs allocated to low-load factor customer classes to diminish less than their share of the system coincident peak, and this is inequitable when considering that near-term investments are driven more by new loads than older ones. *Id*.

Witness Wilson recommended DEP utilize the Hourly Cost Model (HCM) method for jurisdictional and class production cost allocation. *Id*. at 21-22. 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*. at 21. 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. *Id*. 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. *Id*. at 21-22. Adopting the HCM method, he argued, is well-suited to support the adoption of cost-based load flexibility programs for large loads. *Id*. at 22.

Witness Wilson recommended that the Commission require DEP to analyze the effect of different jurisdictional and class cost allocation methods on the proportion of

generation and transmission costs borne by wholesale and retail customers and specifically recommended a detailed evaluation of the HCM method for both jurisdictional and class allocation. *Id*. at 68. Further, he stated that the resulting jurisdictional and class revenue requirements should be considered as allocation factors for transmission costs, although it may be reasonable to maintain 12 CP consistently across jurisdictional and class allocation methods for a period of time before fully considering that option. *Id*.

While recognizing that the PBR Statute requires the Minimum System method, witness Wilson took issue with DEP's implementation of the Minimum System method for allocation of distribution costs. *Id*. at 113. Witness Wilson testified that DEP'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 DEP'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 113-14. Witness Wilson identified three 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; and (3) adjust the secondary class cost allocation to reflect peak load carrying capability. *Id*. at 118-22.

DEP Rebuttal Testimony

On rebuttal, witness Hager testified that DEP's method for allocating demand-related production costs is reasonable. Tr. vol. 8, 155-56. In response to witness Wilson's contention that DEP's jurisdictional cost allocation created an "unstable jurisdictional outcome," by not classifying or allocating any generation or transmission capital costs as energy related at the jurisdictional level, witness Hager testified that it is not clear how witness Wilson's proposal to allocate more generating and transmission capital costs as energy-related, which she stated is by definition variable, is more stable than DEP's methodology. *Id*. at 147. Witness Hager further explained that reallocation of costs is a natural consequence of combining DEP and DEC unrelated to a specific cost allocation method and that to the extent wholesale customers are allocated lower costs under the 12 CP method does not demonstrate inequity, bias, or arbitrary cost shifts but rather analytical outcomes due to the fact that wholesale customers have the ability to shift load from the monthly peaks. *Id*. at 147-49. In response to witness Wilson's concerns regarding DEP's use of "inconsistent methodologies" 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 149. Witness Hager also explained how DEP allocates battery storage and CPRE-related costs and argued that their different treatments demonstrate sound cost of service practices. *Id*. at 150-51.

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 NARUC Cost Allocation Manual or in the more recently published Regulatory Assistance Project Cost of Service Manual. *Id*. at 153. Witness Hager also testified that the POD method has not seen industry acceptance despite having been around for over 30 years, with only Xcel Colorado employing a modified version of the methodology due to its concerns over curtailing renewable energy production. *Id*. at 154. In addition to not being commonly used, witness Hager testified 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 be incurred over many years. *Id*. 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 155. 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*. 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 157.

In response to witness Wilson's concerns regarding DEP'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 which assumptions are proper. *Id*. at 159-60. 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 secondary level. *Id*. at 159. Thus, primary system assets are required to serve customers receiving power from the secondary system and therefore appropriately included in the Minimum System. *See id*.

Regarding DEP's use of the NCP methodology for allocating demand-related distribution costs, witness Hager testified that using the NCP-Customer method results in higher costs to the more diverse residential customer class, but she asserted that this reason alone is not a basis for rejecting use of the NCP-Customer methodology. *Id*. at 161. She argued that while there is no perfectly correct answer for addressing how distribution assets are "caused," DEP's methodology is reasonable. *Id*.

Finally, witness Hager argued that the filing of cost of service studies at parity as recommended by DoD/FEA witness Blank is not necessary. *Id*. at 166. Given that DEP adheres to the principle of gradualism as described in witness Byrd's testimony, the requested filing would not align with the proposed rate design. *Id*. at 166-67. In their rebuttal testimony, DEP witnesses Byrd and Beveridge agreed with witness Hager's view and added that DEP provides supporting workpapers for their rate design proposals that afford intervenors the opportunity to review and respond with alternative proposals without imposing the unnecessary burden on DEP of creating multiple versions of the COSS. Tr. vol. 10, 283. Witnesses Byrd and Beveridge testified that witness Blank's recommendation would create a burdensome and unnecessary precedent for DEP to create multiple versions of COSS that they argued will not yield any meaningful outcomes because the company does not intend to design rates for these various scenarios. *Id*.

During the evidentiary hearing, Presiding Commissioner McKissick asked witness Hager to describe the complexity and effort involved in conducting a COSS. Tr. vol. 8, 182-88. She explained that Duke Energy maintains a dedicated team of full-time employees in the Carolinas who work on cost of service year-round, underscoring that it is far from a simple, mechanical process. *Id*. at 182-83. She stated that the work begins with gathering extensive customer, meter, and load research data, then moves into a detailed review of every FERC account and sub-account as reported in FERC Form 1 — carefully determining allocation methods, handling state-specific disallowances and contra accounts, and ensuring that costs recovered through riders are neither double-counted nor omitted. *Id*. at 183-84. From there, DEP layers in pro forma adjustments, calculates a return on equity by customer class, and coordinates with rate design staff to align results with the requested rate of return. *Id*. *at* 185. DEP files at least four versions of the COSS with its E-1 filings and is also required to submit alternative methodologies in both North Carolina and South Carolina. *Id*. at 185-86. Witness Hager testified that the alternative methodologies proposed by two intervenors (AGO and NCJC, et al.) were viewed by DEP as inconsistent with cost causation principles and therefore DEP did not see any reason to expend a tremendous amount of time pursuing those methodologies. *See id.* at 187-88. "For someone to say, well, let's just try a whole different method of – of doing cost of service. Let's – you know, let's change it up, how hard can that be. And the answer is it's really pretty hard." *Id*. at 187.

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 these methodologies 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 DEP 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 for the purpose of this proceeding 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. 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 is approved.

The Commission further finds and concludes that DEP'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 DEP's study rests on unsupported secondary-line assumptions and improperly includes primary distribution costs. The Commission gives greater weight to witness Hager's rebuttal testimony, which explained that DEP's Minimum System methodology reflects a detailed, well-considered construct that necessarily reflects certain reasonable 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 to be reasonable for the purpose of this proceeding.

In addition, the Commission finds and concludes that DEP's use of NCP-Customer to allocate distribution plant asset costs is reasonable, supported by the record, and should be adopted. The Commission acknowledges witness Burgess's argument that NCP-Customer harms more diverse classes, but the Commission gives greater weight to witness Hager's explanation that although no allocator perfectly captures distribution cost causation, DEP's NCP-Customer methodology is reasonable for purposes of this proceeding.

Accordingly, the Commission accepts the cost allocation methodologies used by DEP in its COSS for purposes of this proceeding.

Finally, with respect to parties' recommendations that would require DEP to produce and/or file additional cost of service studies, the Commission finds persuasive witness Hager's testimony regarding the time and detail associated with preparing a COSS and declines to impose additional requirements in this proceeding. In addition, the Commission finds that given the January 1, 2027, effective date of the business combination of DEC and DEP, it is appropriate at this time to align the deadlines for the annual cost of service studies that DEP and DEC are required to file by extending DEP's annual COSS filing date from April 30 to May 31 to match DEC's annual deadline.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 34-35

Distribution Line Extension Plan

The evidence supporting these findings of fact is contained in the testimony and exhibits of DEP witnesses Byrd and Beveridge; the testimony and exhibits of NCHBA witnesses Millis, Wiggins, and Olive; the DLEP Stipulation; and the entire record in this proceeding.

Summary of Evidence

DEP witness Byrd testified in his direct testimony that DEP was proposing changes to the DLEP to adopt DEC's language by removing all language related to unit/per foot

costs, adding clarifying language with respect to Idle Facilities, and making additional adjustments to ensure consistency and alignment. Tr. vol. 10, 229-30.

Public Staff witnesses Thomas and T. Williamson testified that they had no objections to the changes proposed by DEP. Tr. vol. 7, 1412-1413. NCHBA witness Millis testified that the DLEP, and specifically any resulting CIAC costs, impact home builders and home prices. Tr. vol. 8, 208. NCHBA witness Millis recommended targeted modifications to DEP's DLEP, as shown in his Exhibit CWM-1. *Id*. at 207, 211-13. NCHBA witness Wiggins testified regarding the impact that CIAC can have on an individual residential real estate development. *Id*. at 225-26. NCHBA witness Olive testified that the modifications to DEP'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 255-59.

DEP witnesses Byrd and Beveridge testified in their rebuttal testimony that DEP 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. 10, 284-85. Witnesses Byrd and Beveridge further testified that DEP 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 DEP'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 285-86. DEP witnesses Byrd and Beveridge indicated that DEP does not oppose NCHBA's proposal to aggregate the CIAC calculation on a cumulative, development-wide basis for residential real estate developments. *Id*. at 286.

On August 6, 2026, NCHBA filed the DLEP Stipulation between DEP, NCHBA, and Public Staff regarding DEP's DLEP and CIAC policy. Tr. vol. 7, 36. The DLEP governs how DEP extends distribution facilities to serve new customers including cost allocation for line extensions. Tr. vol. 10, 283. Under the DLEP, a revenue credit that is based on projected customer revenue over a defined period (currently three years) is compared to the cost of installing new facilities. Tr. vol. 8, 270-71. 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 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 258. DEP, NCHBA, and the Public Staff agreed that under DEP'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 DEP's DLEP only to the extent that (1) they are not included within the scope of DEP'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. § 2.B. DEP 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 DEP's DLEP. First, the DLEP Stipulation provides that DEP'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 exceed the cost of providing standard design, the customer is not responsible for paying any cost upfront via CIAC. Second, the DLEP Stipulation provides that DEP'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."

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 DEP Rate Design Panel's Byrd-Beveridge Rebuttal Exhibit 3. DEP 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 Wiggins 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 DEP 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. 36-46

Rate Design

The evidence supporting these findings of fact is contained in DEP's verified PBR Application and Form E-1; the testimony and exhibits of DEP witness Byrd; the rebuttal testimony and exhibits of DEP witnesses Byrd and Beveridge; the joint testimony and exhibits of the Public Staff Rates Panel, the settlement testimony and exhibits of Public Staff witnesses Metz, Zhang, Thomas, and Fahey; the testimony and exhibits of CIGFUR II witness Collins; the testimony and exhibits of CUCA witness McGlothlin; the testimony and exhibits of Walmart witness Chriss; the testimony and exhibits of EDF witnesses Lenell and Pol; the testimony and exhibits of DoD/FEA witness Blank; the Comprehensive Settlement; the DCFC Stipulation; and the entire record in this proceeding.

Summary of Evidence

DEP's Performance-Based Rate Application and Direct Testimony

In his amended direct testimony, DEP witness Byrd explained that DEP proposed modest changes to DEP's residential and nonresidential rate design. The only change proposed for residential customers is the closure of Rider RECD. Tr. vol. 10, 190. For nonresidential customers, DEP proposed to: (1) align demand charges with DEC, so they will be based on 30-minute intervals rather than 15-minute intervals; (2) terminate Schedule General Service – Thermal Energy Storage (GS-TES), Schedule Agricultural Post-Harvest Processing – Experimental Thermal Energy Storage (APH-TES), Rider 57 (Supplementary and Interruptible Standby Service), Rider 7 (Standby and Supplementary Service), and Rider 9 (Highly Fluctuating Loads) on December 31, 2028, which are underutilized and/or have been closed to new customers for extended periods; (3) modify the standby service riders as required in the Commission's order in Docket No. E-2, Sub 1300; (4) freeze Schedule CH-TOUE; (5) remove seasonal pricing from Schedule Large General Service – Time-of-Use (LGS-TOU); and (6) modify Rider SS (Supplementary and Firm Standby Service) to better accommodate zero-export solar installations. *Id*. at 190, 200-03. Similarly, DEP only proposed modest changes to its Outdoor Lighting and Street and Public Lighting schedules. *Id*. at 226-27. Witness Byrd also explained that DEP proposed 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*. at 191.

DEP witness Byrd also presented DEP'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 to ensure no class experiences disproportionate increases. *Id*. at 216-17. The Public Staff Rates Panel described DEP's five-stage methodology: First, DEP determines the test year financial perspective. Tr. vol. 7, 1245-48. Next, DEP 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 1246. Then, DEP 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. *Id*. 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*. at 1246-47. After this adjustment, DEP 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 1247. Finally, as a new component to the proposed revenue apportionment methodology, DEP applies a 3% cap to ensure that no class experiences an increase that is more than 3% above the NC-retail determined increase. *Id*. at 1247-48. The surplus/deficiency 25% variance adjustment is not impacted by this cap. *Id*. at 1248.

DEP proposed increasing the BCC for all residential, general service, and industrial schedules. For residential service, DEP proposed to raise the Residential BCC for all residential schedules from the current $14.00 per month charge to $15.50 per month in Rate Year 1 and to $16.00 in Rate Year 2. Tr. vol. 10, 195-96. For the general and industrial schedules, DEP proposed an increase of monthly BCC rates from $22.00 per month to $24.50 for Rate Schedule SGS, an increase from $30.00 to $33.00 per month for Rate Schedule MGS, an increase from $39.00 to $42.00 for Rate Schedule MGS-TOU, and an increase from $30.00 to $33.00 per month for Schedule SI. *Id*. at 220-22, 225.

DEP proposed to close Rider RECD, which provides a 5% discount to residential customers whose dwellings comply with Energy Star standards, to new residential customers effective January 1, 2027, and terminate Rider RECD effective March 31, 2029. *Id*. at 198-99. DEP witness Byrd testified that DEP continues to encourage efficient and energy consumption in residences, and this can be done through modernized TOU rates that provide refined price signals that better reflect system costs and effectively supersede Rider RECD's volumetric discount approach. *Id*. He also testified that any revenue differences from the termination of Rider RECD would be included in the decoupling rider. *Id*. Because Rider RECD is simply a rider and customers take service on one of DEP's other available core tariffs, the transition will not require customers to take any action. *Id*. at 200. DEP proposed to terminate the rider over two years after it closes to new residential customers so that customers who make the effort to apply during 2026 can benefit from the Rider for at least two years before termination. *Id*. at 199.

For the Hourly Pricing Schedule (Schedule HP), witness Byrd testified that DEP is providing customers with the ability to request a Customer Baseline (CBL) update after 12 months instead of waiting 48 months. *Id*. at 201. He stated that reducing the threshold to 12 months encourages adoption and price-response because customers can benefit from the variable price components of the rate on an accelerated timeline. *Id*. He noted the proposed change only provides for an additional customer option and does not require CBL modifications or require a CBL modification earlier. *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 196. As witness Byrd explained, demand charges are necessary to address cost-causation alignment across customers with different load

factors, which is especially true for nonresidential customers. *Id*. Thus, DEP proposed to transition from 15-minute intervals to 30-minute intervals to match the Commission-approved demand charge structure for DEC. *Id*. at 197. Witness Byrd testified that moving from 15-minute intervals to 30-minute intervals will reduce administrative differences between DEP's and DEC's rate schedules and that fewer customers will be impacted by moving DEP into alignment with DEC, and no such change will be required for DEC. *Id*.

For Outdoor Lighting, DEP proposed excluding the cost of transformers serving certain light fixtures from Extra Facilities Charges given their potential to serve future loads. *Id*. at 226. Witness Byrd also testified that to align with DEC, DEP proposed requiring that broken fixtures identified and designated for repair must be restored to operable condition within five business days from the date of designation. *Id*.

Public Staff Direct Testimony

Overall Rate Design and Revenue Apportionment

The Public Staff Rates Panel recommended the Commission accept DEP's revenue apportionment approach, stating that "with respect to gradualism, the application of a 25% variance adjustment is reasonable compared to impacts associated with full moving each class to full COSS or applying no movement at all" and finding that the class-level rates of return resulting from DEP's proposal are reasonable. Tr. vol. 7, 1252, 1254. The Public Staff further noted that DEP's approach "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 by any particular rate class." *Id*. at 1254.

Basic Customer Charge

The Public Staff recommended approval of the BCC increases for Rate Year 1 and Rate Year 2 and acknowledged that the "increases proposed by DEP present a reasonable change in the BCC with respect to the full customer-related fixed cost recovery as indicated in the COSS." *Id*. at 1260. They stated that increasing the BCC would reduce intraclass cross-subsidization from higher-usage customers to lower usage customers and would improve alignment with cost causation by ensuring that more fixed costs are appropriately recovered through fixed charges. *Id*.

Net Metering Bridge and Solar Choice Rider Modifications

The Public Staff proposed the following wording changes to the NMB and RSC riders:

> 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 1278.

The Public Staff also proposed the following wording changes to 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. at 1279.

The Public Staff proposed these changes to allow batteries paired with net-metered solar or small generation to support reliability and participate in DEP-sponsored Demand-Side Management (DSM) programs. *Id*. The Public Staff argued that the current rider language restricts the manner in which customers may use BESS and the proposed edits are necessary to allow customer's to operate their BESS as intended. *Id*.

Rider RECD

The Public Staff did not object to closing Rider RECD. The Public Staff Rates Panel testified that Rider RECD had been in effect since 1981, and approximately 310,550 customers were taking service under it as of 2024. *Id*. at 1262. The Public Staff determined that gradually reducing the discount for participating customers before termination would mitigate potential rate shock. *Id*. at 1263. Accordingly, while supporting DEP's proposal to close Rider RECD, the Public Staff recommended reducing the Rider RECD discount from 5% to 2.5% at the beginning of Rate Year 2 to reduce potential rate shock to customers as a result of the rider closure. *Id*. Additionally, the Public Staff recommended that all current Rider RECD customers be notified of all approved tariff modifications by bill insert or email to ensure that customers are aware of major changes to or closure of the tariff. *Id*. at 1263-64.

Schedules GS-TES, APH-TES, and CH-TOUE

The Public Staff recommended the Commission deny DEP's request to close Schedules GS-TES and APH-TES. *Id*. at 1269. The Public Staff Rates Panel explained that Schedule GS-TES currently has five customers taking service under this tariff, and it is a voluntary rate schedule designed for nonresidential customers with thermal energy storage systems used for space conditioning through the use of chillers, boilers, pumps, or fans, and it uses an on- and off- peak demand and energy rate structure that incentivizes customers to avoid high demand during the peak period. *Id*. at 1266. Schedule APH-TES is a voluntary rate schedule similar to GS-TES, and it is designed specifically for post-harvest processing of fruits and vegetables and currently has only one customer taking service under this schedule. *Id*. Both Schedules GS-TES and APH-TES have been closed to new participants since October 1, 2023. *Id*. at 1267. The Rates Panel testified that it understood the administrative burdens of having a rate schedule open only for a small number of customers but countered that accepting DEP's

change would cause an unreasonable 40-50% increase in those customers' bills in a narrow period and necessitates the need for a glidepath strategy to gradually move customers to new rate schedule options. *Id*. at 1268. Thus, the Public Staff recommended that DEP (1) evaluate through the stakeholder process in Docket Nos. E-2, Sub 1383 and E-7, Sub 1332 (Business Combination Stakeholder Process) the possibility of offering GS-TES and APH-TES in both DEP's and DEC's service territories; and (2) provide a glidepath for closing the GS-TES and APH-TES Schedules in DEP's next general rate case. *Id*. at 1269.

The Public Staff recommended the Commission approve DEP's request to close CH-TOUE to new customers, subject to certain conditions. *Id*. at 1272. The Public Staff Rates Panel explained that CH-TOUE is a voluntary rate schedule offered to churches that have demands greater than 30 kW but less than 1,000 kW, and approximately 250 customers currently take service under this tariff. *Id*. at 1270. The Rates Panel stated that CH-TOUE has the same demand range as the MGS rate schedules but offers a rate option that does not have a demand component, and instead only charges participants based on an on- and off-peak energy rate. *Id*. DEP proposed closing this rate schedule to new participation, which the Public Staff understood as the first step toward closure of the rate schedule in a future rate case proceeding. *Id*. at 1271. Analysis conducted by the Rates Panel demonstrated that closure of Schedule CH-TOUE would increase these customers' rates by 20-55% depending on the selected alternate rate schedule, and the Public Staff expressed its concern with the lack of a proposed glidepath for customers currently on CH-TOUE. *Id*. at 1271-72.

Accordingly, while the Public Staff recommended the Commission approve DEP's request to close Schedule CH-TOUE to new participants, it also recommended that DEP (1) evaluate making this tariff available in both DEP and DEC's service territory through the Business Combination Stakeholder Process and (2) provide a glidepath for closure of this rate schedule to provide for a more seamless transition if DEP proposes to close CH-TOUE in its next general rate case. *Id*. at 1272.

Riders 7, 57, and 9; Schedule LGS-TOU; and Rider SS

The Public Staff supported DEP's proposed termination of Riders 7 and 57, which are legacy standby service riders serving a limited number of nonresidential customers that maintain their own on-site generation resources. *Id*. at 1273-74. One customer takes service under Rider 7, which has been closed to new participants since 1987, and two customers remain on Rider 57, which has been closed to new customers since 1993. *Id*. at 1273. DEP stated that Rider 7 customers can instead be served under Rider SS while Rider 57 customers can instead by served under Rider NFS (Supplementary and Non-Firm Standby Service), and proposed a transition period through December 31, 2028, over which it will work directly with the three affected customers to facilitate migration to the appropriate standby service rider. *Id*. at 1273-74.

The Public Staff recommended the Commission approve DEP's request to close Rider 9 to new participants, subject to certain conditions. *Id*. at 1275. The Public Staff explained that Rider 9 is a supplemental tariff that a customer may elect to participate in

if it meets certain qualifications, with 47 customers currently taking service *Id*. at 1274. Typical participating customers operate equipment such as X-ray machines, electric furnaces, and welding equipment that causes highly fluctuating or intermittent loads. *Id*. Similar to its recommendations for transitioning other rate schedules, the Public Staff recommended DEP evaluate (1) the viability of offering Rider 9 in both DEP and DEC's service territory in the Business Combination Stakeholder Process; and (2) provide a glidepath for closure of this rider in its next general rate case if DEP proposes to close Rider 9 at that time. *Id*. at 1275.

The Public Staff also explained that Schedule LGS-TOU, a nonresidential rate option available for customers with demands greater than 1,000 kW, offers an energy and demand structure focused on both when and how much electricity is used during the billing period. *Id*. at 1275-76. The Public Staff Rates Panel testified that it supports DEP's proposal to simplify LGS-TOU by removing its seasonal aspect, applying on-peak and mid-peak demand rates to the same hours during summer and non-summer months. *Id*. at 1276.

Further, the Public Staff also supports DEP's proposed tariff redesign of Rider SS, which is DEP's Supplementary and Firm Standby Service Rider that is available in conjunction with applicable residential and nonresidential rate schedules for customers that utilize on-site generation resources and require supplemental or standby service from DEP when the customer's generation is unavailable. *Id*. at 1276-78. Specifically, the Public Staff supports DEP's proposal to (1) expand Rider SS availability to residential customers interested in behind-the-meter solar generation that do not intend to export excess energy to the grid; (2) clarify the billing of Rider SS by defining "intermittent generation" as generation equipment with a planning capacity factor of less than 60% and "non-intermittent generation" as generation equipment with a planning capacity factor of 60% or greater; and (3) eliminate the Generation Reservation Charge for all Intermittent Generation served under Rider SS. *Id*. at 1277.

Future Tariff Modifications

The Public Staff recommended that DEP undertake the following in its next general rate case: (1) investigate and report in its direct testimony whether the Standard Residential Service Schedule RES should continue to include both seasonal and an 800-kWh threshold for winter months; and (2) investigate and report in its direct testimony whether there is a need for a rate schedule like DEC's OPT-V rate tariff option for legacy DEP customers. *Id*. at 1279-80.

Other Intervenor Direct Testimony

Overall Rate Design and Revenue Apportionment

Walmart witness Chriss testified that Walmart "does not oppose [DEP]'s proposed revenue allocation methodology." Tr. vol. 8, 414.

CUCA witness McGlothlin argued that DEP's proposed revenue allocation method does not reduce interclass subsidization to the greatest extent practicable and instead proposed at least a 50% reduction in the rate of return variance. *Id.* at 381-82. He also

recommended 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, which he argued would move all classes closer to cost. *Id*. at 382.

CIGFUR II witness Collins also argued that DEP should employ at least a 50% reduction in the rate of return variance. Tr. vol. 9, 579-80. Witness Collins argued that a 50% reduction is "practicable" within the meaning of N.C.G.S. § 62-133.16(b), as he found it does not produce unreasonable harm to any customer class. *Id*. at 580. CUCA acknowledged that DEP's proposed 25% reduction is more than double the approved 10% reduction in DEP's prior rate case in Docket No. E-2, Sub 1300, and argued that this increase reflects a recognition that the prior 10% reduction left too much subsidy in place. *Id*. In light of DEP's proposed increase, CUCA argued that the controlling question under the statute is not whether a proposed reduction exceeds the last one, but whether a larger reduction is practicable, and further argued that the fact that a reduction is larger than the prior one is not evidence that it is impracticable. *Id*. at 582.

Schedule HP and LGS-TOU

CUCA witness McGlothlin testified in support of DEP's proposal to expand the Schedule HP Load Response Adjustment (LRA) window from 48 months to 12-48 months. Tr. vol. 8, 384. He explained that, in the LRA process, DEP adjusts a customer's CBL based on demonstrated load reductions on days when Hourly Capacity Prices are in effect, and that expanding the window would enable a customer to request an LRA within 12 months instead of waiting up to four years. *Id*. Witness McGlothlin argued that these changes would further incentivize Schedule HP customers to be price responsive in reducing load, which benefits all customers during times of grid stress, and recommended DEP's proposal be adopted. *Id*. at 384.

DoD/FEA witness Blank also Blank testified that DoD/FEA supported approval of DEP's proposal to allow its customers to request an updated Customer Baseline Load after 12 months because this change is optional and customer driven. Tr. vol. 8, 601. DoD/FEA also supported DEP's proposal to eliminate seasonal pricing from Schedule LGS-TOU, agreeing with DEP and the Public Staff that this change is an administrative simplification as the proposed LGS-TOU rates are no longer differentiated between summer and non-summer periods. *Id*. at 602.

Demand Intervals

With respect to demand intervals, DoD/FEA witness Blank noted that DEP proposed to calculate billing demand using a 30-minute interval rather than the current 15-minute interval for certain residential and nonresidential rate schedules. *Id*. at 601. He found that although DEP characterized the change as revenue-neutral, the proposal may still affect customer bills by changing the billing demand determinants for affected customers and by increasing the applicable dollars-per-kilowatt ($/kW) demand charges to offset the overall reduction in billing demand determinants. *Id*. In his analysis, witness Blank found that, depending on the schedule and charge, the purportedly revenue-neutral adjustment to the applicable demand charge appeared to range from approximately 1%

to more than 15%, with a total system increase of approximately 3.4%, before considering other proposed changes. *Id*. Further, this proposed change could cause certain residential customers could experience bill increases of up to 5%. *Id*. at 601-02.

While DoD/FEA did not oppose DEP's demand interval modification on its merits, DoD/FEA recommended postponing DEP's proposal or implementing it only for LGS-TOU and LGS-RTP-TOU (Real Time Pricing) customers, which appear to be the rate classes least likely to experience material impacts from the change. *Id*. at 602. This recommendation is driven by the party's concern about the potential impact on certain individual customers, given the importance of affordability in the current market conditions and the need to limit customer rate impacts. *Id*. at 602.

DCFC EV Charging Pilot Rate

Through the direct testimony of witness Chriss, Walmart proposed a DCFC EV charging pilot rate. As witness Chriss explained, Walmart and DEP have had ongoing discussions regarding the development of rate design options for public-facing DCFC electric vehicle charging facilities. Tr. vol. 8, 432. Witness Chriss explained that because DEP's PBR Application was filed before the Merger Stipulation, which DEP agreed to support a DCFC EV charging rate, DEP could not propose a DCFC EV charging rate in its direct case in this docket. *Id*. at 432.

Witness Chriss testified that Walmart continues to support a DCFC EV charging pilot rate, and to that end, Walmart and DEP developed a pilot rate applicable to public-facing DCFC EVs as an alternative to Schedules MGS and LGS. *Id*. at 435. The proposed pilot rate contained a two-part structure rather than a typical three-part structure, under which the participating customer would be charged the LGS customer charge then in effect and a $/kWh energy charge. *Id*. at 435-36. In lieu of a demand charge, the energy charge is higher than a typical LGS energy charge and is designed to recover the costs of an MGS or LGS customer at a 10 percent monthly load factor. *Id*. at 436. Witness Chriss testified that this two-part structure was chosen because a tariff structure that does not include demand charges is critically important in the early stages of EV station deployment as driver knowledge of station availability and usage grows. *Id*. He also stated that the energy-only structure would create pricing certainty for charging operators, which could also lead to pricing certainty for EV drivers, as charging operators do not yet know charger utilization levels. *Id*. at 437.

Walmart recommended approval of the DCFC EV Charging Pilot Rate presented in witness Chriss's direct testimony but noted that due to the timing of its proposal, Walmart would continue to receive feedback from discussion of the DCFC EV Charging Pilot Rate with Public Staff and other parties. *Id*. at 439.

Schedule R-TOU-EV

Through the Joint Direct Testimony of witnesses Lenell and Pol, EDF recommended aligning the price signals for Schedule R-TOU-EV with DEP's other residential time-of-use rate offerings and adjusting pricing to encourage more EV owners to adopt Schedule

R-TOU-EV and provide additional options for those willing to engage in managed charging or participate in vehicle to grid offerings. Tr. vol. 9, 666. EDF also recommended that DEP conduct a study to understand how to effectively incorporate electric vehicle load not only related to residential EV but also commercial private-fleet and public fast charging load profiles, and recommended DEP use these study findings to proactively manage willing customers and pilot rate offerings that encourage active coordination. *Id*.

DEP Rebuttal Testimony

Overall Rate Design and Revenue Apportionment

Witness Byrd testified that under DEP's proposed rate design, each class moves closer to the retail average rate of return, which reduces inter-class subsidization. Tr. vol. 10, 282. As a result, classes with below-average rates of return receive above-average increases, and classes with above-average rates of return receive lower increases. *Id*. He argued that 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*.

In response to CIGFUR III witness Collins' and CUCA witness McGlothlin's recommendations of least a 50% reduction in the rate of return variance, DEP 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 DEP's last rate case and recently upheld on appeal. *Id*. at 281-82.

Schedule RECD

On rebuttal, DEP agreed with the Public Staff's modification to reduce the RECD discount from 5% to 2.5% beginning January 1, 2028, as consistent with gradualism and giving Rider RECD customers a smoother transition before the schedule sunsets on March 31, 2029. *Id*. at 271-72.

Schedules NMB and RSC

DEP agreed with Public Staff's proposed wording changes to the NMB and RSC riders that allow batteries to be paired with net-metered solar or small generation to support reliability and participate in DEP-sponsored DSM programs, and recommended approval of the proposed modifications. *Id*. at 277.

Schedules GS-TES and APH-TES

DEP agreed to maintain schedules GS-TES and APH-TES and consider options for closure of these schedules with a smooth transition for customers within the Business Combination Stakeholder Process. *Id*. at 278.

Rider CH-TOUE and Rider 9

DEP acknowledged the Public Staff's recommendation to approve DEP's request to close Schedule CH-TOUE and Rider 9 to new participants, as well as Public Staff's recommendation to consider both within the Business Combination Stakeholder Process, and stated its support for the Public Staff's recommendation. *Id*. at 278-79.

Future Tariff Modifications

DEP witnesses Byrd and Beveridge agreed with Public Staff's recommendation to evaluate certain changes to Schedule RES and to consider creating a schedule similar to DEC's Schedule OPT-V. *Id*. at 279. DEP agreed to discuss its proposed future tariff recommendations in the Business Combination Stakeholder Process, and argued that the Commission should allow that process and the next combined rate case to address these issues together. *Id*.

Demand Intervals

DEP acknowledged witness Blank's recommendation to delay conversion of demand intervals or to implement this change only for LGS and LGS-RTP-TOU customers. *Id*. DEP responded by noting that with the pending 1U business combination and subsequent efforts to achieve a combined set of rates for the combined company, the demand intervals must necessarily be the same for billing system purposes. *Id*. DEP argued that the impacts are generally small and only impact customers on demand-based rates, which does not include the vast majority of residential customers, and noted that the Public Staff did not object to DEP's plans for conversion to 30-minute demands with the exception of aspects of their proposed large load tariff. *Id*. at 279-80. Accordingly, DEP recommended the Commission reject witness Blank's proposed delay in conversion to the 30-minute demand interval. *Id*. at 280.

DCFC EV Charging Pilot Rate

DEP supported Walmart's proposed modifications and recommended approval of the DCFC EV pilot. *Id*. at 273-74. Witnesses Byrd and Beveridge explained that the pilot is the result of constructive discussions between DEP and interested stakeholders held after the Commission issued its order in Docket No. E-2, Sub 1383, and that it is reasonable to approve the DCFC EV Charging Pilot Rate. *Id*.

Schedule R-TOU-EV

DEP disagreed with EDF's recommendations to align Schedule R-TOU-EV time-of-use periods with DEP's other residential TOU offerings and to adjust pricing to encourage more EV owners to adopt Schedule R-TOU-EV. *Id*. at 274. Witnesses Byrd and Beveridge testified that DEP intentionally designed Schedule RT-EV to encourage charging from 11:00 p.m. to 5:00 a.m., diversify charging behavior across EV tariffs, and preserve stronger price signals in Schedules R-TOUD (with Demand), R-TOU, and R-TOU-CPP (with Critical Peak Pricing), as those rates provide broader on-peak and critical-peak signals, which can produce both customer savings and grid benefits. *Id*.

Witnesses Byrd and Beveridge also testified that this docket is not the proper place to evaluate EDF's recommendations related to managed charging, vehicle-to-grid technologies, and EV fleets. *Id*. at 275.

Similarly in his rebuttal testimony, with respect to EDF's recommended EV load study, DEP witness Guyton testified that DEP believes that EDF's recommendation is better suited for consideration as part of the existing Electric Transportation working group, and argued that a rate case proceeding is generally not the appropriate venue for evaluating customer programs outside of core rates and tariffs, especially when existing stakeholder working groups are already established to consider such programs. Tr. vol. 8, 828.

Stipulations and Settlement Testimony

Overall Rate Design and Revenue Apportionment

Witnesses Byrd and Beveridge testified that the Comprehensive Settlement resolved the remaining revenue requirement issues between DEP and the Public Staff, resulting in revised revenue requirements for Rate Year 0, Rate Year 1, and Rate Year 2. Tr. vol. 10, 290. 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 Byrd-Beveridge Comprehensive Settlement Exhibits 2, 2_1, and 2_2 presented the updated rate design revenues at the tariff level agreed upon in the Comprehensive Settlement, as well as the Stipulating Parties' agreement that no customer class's increase shall exceed the retail average increase by more than 2% in Rate Year 1 and by no more than 2.5% in Rate Year 2. *Id*. at 289-90. Furthermore, DEP's revenue apportionment methodology and rate design approach remained unchanged from what was proposed in direct and rebuttal testimony, as only the overall revenue levels have were updated to reflect the agreed-upon adjustments, and the same revenue apportionment and rate design approaches have been used to finalize tariff pricing. *Id*. at 290-91. Witnesses Byrd and Beveridge recommended that the Commission approve the Comprehensive Settlement in its entirety and testified that it was the result of give-and-take negotiations that resolved the issues in the case between the Stipulating Parties without the necessity of contentious litigation. *Id*. at 292. They argued further that the Comprehensive Settlement balanced the financial impact of the rate increase on DEP customers with DEP's need to recover its revenue requirement to enable DEP to fulfill its obligation to provide safe and reliable electric utility service to those customers. *Id*. at 292-93.

Public Staff witnesses Metz, Zhang, Thomas, and Fahey testified that the Public Staff reached agreement on the majority of issues in the docket. Tr. vol. 7, 1896-97. Witnesses Metz, Zhang, Thomas, and Fahey also testified that the Comprehensive Settlement is in the public interest and should be approved, as it provides several ratepayer benefits. *Id*. at 1898.

DCFC EV Charging Pilot Rate

DEP, Public Staff, and Walmart entered into the DCFC Stipulation under which DEP 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 offers an alternative, two-tier, all volumetric rate based on Schedule MGS and LGS pricing, each subject to a 10% load factor limit. *Id*. Participation in the DCFC Pilot will be limited to commercial customers operating public-facing DCFC Facilities and will terminate as of December 31, 2031, unless the Commission grants authorization to extend or modify the DCFC Pilot. *Id*. § II.3. DCFC Pilot participants that exceed the 10% load factor threshold will be notified and later become ineligible for the DCFC Pilot pursuant to the schedule set out in DCFC Stipulation Sections II.5 and II.6. *Id*. §§ II.5-II.6.

DEP witnesses Byrd and Beveridge and Walmart witness Chriss testified that each entity supported the DCFC Stipulation, which represented give-and-take among the parties, and recommended the Commission approve the DCFC Stipulation in its entirety. Tr. vol. 8, 442-44; tr. vol. 10, 293.

Discussion and Conclusions

Overall Rate Design and Revenue Apportionment

The Commission has reviewed the rate design methodology proposed by DEP 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 2% cap in Rate Year 1 and 2.5% cap in Rate Year 2, is just and reasonable and consistent with N.C.G.S. § 62-133.16(b). The Commission notes that both DEP 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 DEP'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 DEP 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 DEP's proposal to close Rider RECD to new residential customers effective January 1, 2027, and terminate Rider RECD effective March 31, 2029, as modified by the Public Staff's recommendation to reduce the Rider RECD discount from 5% to 2.5% beginning January 1, 2028. The Commission finds this modification is just, reasonable, and consistent with gradualism and provides Rider RECD customers a smooth transition to one of DEP's core tariffs. 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 Rider RECD 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, RSC, and NSC riders to allow batteries paired with net-metered solar or small generation to support reliability and participate in DEP-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 DEP-sponsored demand-side management purposes.

The Commission concludes that DEP should address the Public Staff's proposed future tariff modifications, which includes investigating whether Schedule RES should continue to include both seasonal and an 800 kWh threshold for winter months and whether there is a need for a rate schedule like DEC's OPT-V rate tariff option for legacy DEP customers, in its next general rate case and the stakeholder process directed by the Commission's 1U Order and, and that DEP shall update the Commission on the overall decisions made therein as part of its next general rate case.

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 R-TOU-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, 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 DEP 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 DEP's verified PBR Application and Form E-1; the testimony and exhibits of DEP witnesses Jiggetts, Bateman, Duff, Byrd, and Beveridge; the testimony and exhibits of Public Staff witness Fahey and the joint testimony and exhibits of 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 DEP as having project specific investments for serving new or expanded sites with contract demands of 20 MW or greater. Tr. vol. 9, 128-29. 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 $85.9 million. *Id*. at 130.

The Public Staff Large Load Panel testified that in this case, DEP is requesting to increase its rates in part to account for the $85.9 million in Dedicated Facilities. *Id*. at 133-34. In addition, they stated that these customers have not, in most cases, begun taking service or have not reached their maximum contract demand. *Id*. at 134. 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. *Id*.

The Large Load Panel testified that they are recommending removal of $85.9 million of costs related specifically to Dedicated Facilities that solely serve these six large load customers, which they allege should have been recovered from these customers as CIAC. *Id*. at 135. In addition, some of the $85.9 million is classified as Excess Facilities and is recovered through an EFC collected from the customer. In DEP's supplemental testimony, it included approximately $4.7 million of EFC revenue in pro forma NC1030B. *Id*. Because it would not be appropriate to remove the $85.9 million in plant while keeping the partially offsetting EFC revenue, the Large Load Panel also recommends reducing this $4.7 million of EFC revenue to zero. *Id*. at 135-36.

The Large Load Panel also recommended that the Commission require DEP to develop a CIAC process 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. *Id*. at 139.

The Large Load Panel disagreed with the characterization of DEP (and DEC, who together are Duke) of the Large Load Impact Analysis as 'unchallenged', and testified that under certain circumstances large load customers could put downward pressure on rates

for other customers, but this downward pressure "only exists if the utility has sufficient spare capacity or if the marginal cost to construct or provide additional capacity is less than the embedded cost of the existing system." *Id.* at 77-78. The Large Load Panel described a variety of concerns the Public Staff had with Duke's Large Load Impact Analysis. First, the analysis uses the preliminary base portfolio instead of the near term action plan (NTAP) that Duke put forward, which differs. Second, the analysis only assigns new gas generation costs but excludes fuel supply costs and other generation sources, resulting in a mismatch between the generation evaluated and the generation planned to be built. Third, the analysis assumes that the customer operates at 95% load factor every day for the full contract term and that only the costs of the customer's load factor are assigned to the large load customers rather than the full system designed to serve the large load customer's peak load. *Id.* at 78-79. The Public Staff argued that assigning new natural gas generation units, which have lower capital costs compared to other units, discounts the costs of the capacity and energy needed to serve the large loads. *Id*. at 83. 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, or 20% reduction, and a cost to other ratepayers for a decade. *Id*. at 80-82. The Public Staff recommended that future updates to this analysis should include the comprehensive costs to construct and operate the generating units, noting that Duke's current analysis is missing costs such as gas transportation costs. *Id*. at 83-84. The Large Load Panel also noted that Duke's Large Load Impact Analysis does not seem to reflect the same 16 ESAs included in the Spring 2026 Large Load Report. *Id*. at 85. Additionally, the Public Staff testified that Duke's High Load Portfolio Bill Impact analysis does not factor in the additional generation units needed for reliability purposes. *Id*. at 85-87. 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 over the 15 year period. *Id*. at 87-88. The Large Load Panel testified that their sensitivity demonstrated a large load customer would need to perform at an 83% load factor for every hour of every day for 15 years to have a nominal net $0 impact to other customers, and that this number is likely higher when accounting for the time value of money. *Id*. at 87-89. The Large Load Panel concluded that Duke's large load impact analysis reached a tenuous result and the purported claims may not materialize. The Large Load Panel warned that "the next ten years, and perhaps longer, present significant cost risks to existing customers." *Id*. at 89-90.

Public Staff witness Fahey and AGO witness Burgess both recommended that DEP 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. Tr. vol. 7, 1814-18; tr. vol. 9, 378. Similarly, CUCA witness McGlothin noted that DEP proposed to set rates through 2028 based on adjusted test-year 2024 billing determinants even though DEP is also projecting significant sales growth. Witness McGlothin proposed that DEP be required to update its billing determinants prior to setting rates for Rate Year 2 in a compliance filing. Tr. vol. 8, 369-72.

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. 7, 1805. 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*. 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*. at 1806. DEP 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*. at 1807.

Public Staff witness Fahey raised concerns about DEP's methodology in the context of PBR2, arguing that DEP'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 1809-10. Specifically, he noted that DEP 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 1809. He explained that failing to credit those contracted sales against the class revenue requirement allows DEP to collect revenues above what is needed to earn its approved ROE, effectively shifting risk onto other ratepayers. *Id*. 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*. at 1810. 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 1812-13. Accordingly, witness Fahey recommended that the Commission require DEP 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 1814-18.

AGO witness Burgess recommended that DEP be required to adjust the billing determinants used to calculate MYRP2 rates to account for expected load growth during MYRP2 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 DEP does not obtain windfall profits by locking in high rates before significant sales growth is expected to materialize. Tr. vol. 9, 378.

CUCA witness McGlothlin testified that because DEP projects significant growth in retail sales during the timeframe of MYRP2, DEP should be required to update its billing determinants prior to implementing Rate Year 2 base rates. Otherwise, to the extent DEP 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, 369-72.

In her rebuttal testimony, witness Bateman testified that DEP disagrees with these recommendations because they deviate from the revenue requirement calculation under North Carolina's PBR framework. Tr. vol. 10, 447. 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*. at 447-48. While DEP 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*. at 448. 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*.

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*. She noted that the PBR Rule also requires that DEP 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*. at 448-49. 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 DEP because North Carolina's PBR framework already prevents any form of windfall through the ESM. *Id*. at 449-50.

In their rebuttal testimony, DEP witnesses Byrd and Beveridge addressed the Public Staff's recommended disallowance of certain large load interconnection costs from DEP's rate base, specifically costs tied to "Dedicated Facilities" that solely serve large load customers as well as their argument that DEP needs a more rigorous CIAC analysis and should not waive CIAC requirements. Tr. vol. 10, 258-64. Witnesses Byrd and Beveridge testified that DEP strongly disagrees, asserting that its CIAC methodology is a well-established practice applied consistently and non-discriminatorily to all transmission-connected customers. *Id*. at 259. 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. *Id*. at 259. For transmission-connected customers, DEP assesses the revenue that a customer is projected to provide at full load over one year, and so long as such revenues exceed the interconnection costs of providing standard service, then the customer's revenues are deemed sufficient. *Id*. at 260. DEP notes that the same revenue-credit logic underlies its distribution-connected customer policy (the Distribution Line Extension Plan), and that there is no basis for applying revenue credits to one class of customers but not the other. *Id*. at 260-61.

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. *Id*. at 261. 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 responded that larger projects also generate substantially higher revenues, and argued the Public Staff did not provide a "coherent explanation for why the revenue credit approach does not optimally scale" to account for both higher costs and higher revenues. *Id*. at 262.

Witnesses Byrd and Beveridge added that DEP'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. *Id*. at 263. DEP's Large Load Impact Analysis submitted in the CPIRP estimates that large load customers cover their costs, including generation and transmission costs, and contribute net revenue benefiting other customers. *Id*. DEP also disagrees with several of the Public Staff's criticisms of the Large Load Impact Analysis. *Id*. at 264-68.

In her rebuttal testimony, DEP witness Jiggetts indicated that DEP agrees that to the extent plant placed in service will be recovered from revenues collected from large load customers, the plant and revenues should be reflected in the revenue requirement. Tr. vol. 7, 1054. She confirmed that DEP made an adjustment to update extra facilities revenues associated with existing large load customers in its second supplemental filing based on this principle. *Id*. She testified that because the revenues collected from these existing large load customers will more than offset the revenue requirement associated with the plant investments, DEP believes these plant investments, totaling approximately $49 million at a system level, should remain in rate base in this proceeding for the benefit of all customers. *Id*.

The Comprehensive Settlement provides that revenues in the customer growth pro forma and the corresponding interconnection facilities for a certain large load customer shall be included in the rate case and allocated to all customer classes. Comp. Settl. § II.3. The revenues included are $9.382 million and the revenue requirement associated with the interconnection facilities is $5.781 million, resulting in a net benefit of $3.602 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*.

DEP agreed to remove from this case the interconnection facilities relating to two specific large load customers identified by the Public Staff in its direct testimony as agreed to by DEP in the rebuttal testimony of witness Jiggetts, resulting in a reduction in rate base of $0.72 million on a North Carolina retail basis. *Id*. § II.4. The Comprehensive Settlement provides that DEP may seek recovery of the North Carolina retail portion of the associated undepreciated plant balance in a future rate case 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 DEP's next rate case. *Id*.

Finally, the Comprehensive Settlement requires DEP 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 DEP'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 DEP's verified PBR Application and Form E-1; the testimony and exhibits of DEP 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 DEP's last rate case in Docket No. E-2, Sub 1300, the Commission granted DEP authority to continue to defer incremental bad debt expense from April 1, 2023, for future recovery. In the Sub 1300 Order, the Commission determined that, because DEP was still incurring incremental bad debt expense, it was appropriate for DEP to continue to defer those costs incurred after March 31, 2023, and required DEP to credit on a monthly basis through the next general rate case any payments associated with the deferred bad debts and to report semiannually the amounts recorded to the deferral and the payments received. Sub 1300 Order at 197, 241 (Ordering ¶ 47). DEP intends to end the deferral as of the rates effective date in this proceeding. Tr. vol. 7, 997. DEP witness Jiggetts testified that the deferral balance sought for recovery in this case is based on deferral of incremental bad debt expense through March 31, 2026, with returns calculated up to the rates effective date of January 1, 2027. *Id*. at 998. DEP proposed to amortize the deferral balance at the rates effective date over five years. *Id*. at 997. Witness Jiggetts noted that DEP will seek recovery of incremental bad debt expense from April 1, 2026, through December 31, 2026, in a future rate case proceeding. *Id*. at 998.

The Public Staff agrees that DEP should cease the bad debt deferral but testified that the deferral should cease as of August 31, 2024, instead of December 31, 2026. Tr. vol. 8, 69. 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 DEP 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 69-70. Because DEP's installment plans have been limited to 12 months or less since March 2022, and 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, in the Public Staff's view, the latest month for any bad debt deferral to be COVID-related should have ended by August 2024. *Id*. at 70. The Public Staff noted that DEP sought to recover $55.75 million of incremental bad debt expense recorded from April 1, 2023, through March 31, 2026, plus a $10.03 million return, for a total of $65.78 million. *Id*. at 68-69. The Public Staff considered the $33.11 million of incremental bad debt expense for April 2023 through August 2024 "relatively reasonable," but proposed to exclude the $22.64 million deferred from September 2024 through March 2026, along with the $10.03 million return, for a total adjustment of $32.67 million. *Id*. at 70-71.

The Public Staff agrees with the five-year amortization period as proposed by DEP but does not believe DEP should be authorized to include the unamortized bad debt deferral balance in rate base. *Id*. at 69. The Public Staff also recommended that DEP not be permitted to earn a return on the deferred bad debt balance from April 2023 forward. *Id*. The Public Staff stated that excluding the unamortized balance from rate base is consistent with the Commission's treatment of the COVID bad debt deferral in the Sub 1300 Order. *Id*. at 72.

In her rebuttal testimony, DEP 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 Sub 1300 Order. Tr. vol. 7, 1057-58. She testified that the Commission directed the deferral to continue through the next general rate case, which is this proceeding. *Id*. at 1058. In addition, absent continuation of the deferral, DEP's ongoing level of bad debt expense included in customer rates would have been $42 million higher to reflect DEP's test year level of bad debt expense in that case. *Id*. Witness Jiggetts testified that the deferral sought for recovery in this case, approximately $66 million, compares to the $126 million that would have been collected from customers over three years had the 2022 level of bad debt expense been included in base rates. *Id*. at 1058-59.

Witness Jiggetts also opposed the Public Staff's recommendation to deny a return during the deferral period and the amortization period. *Id*. at 1060-61. She testified that to the extent bad debt expense has exceeded the amount in rates from April 2023 forward, that excess has been funded by DEP's investors, and they are entitled to a return on that capital until the balance is recovered. *Id*.

DEP witness Speros testified that DEP continued to experience elevated levels of bad debt compared to pre-pandemic levels throughout the deferral period which supported DEP's request to recover the deferred incremental bad debt balance for the full period authorized by the Commission. *Id*. at 440-41. From an accounting perspective, the Commission authorized DEP to defer incremental bad debt above the amount embedded in base rates until new base rates from this proceeding become effective. *Id*. at 441. Once that regulatory authorization was granted, DEP 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, DEP witness Colley described how DEP's credit policies evolved gradually from 2020 through 2025 in direct response to sustained elevated arrears. *Id*. at 822-28. During and after the pandemic, DEP 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 DEP's Share the Light Fund to help qualifying customers pay their energy bills. *Id*. at 824. He testified that while DEP 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 824-25. Customers were eligible for multiple opportunities to defer or restructure balances and past-due levels increased. *Id*. at 825.

As DEP observed sustained increases in arrears following the pandemic, it took proactive steps to refine credit policies. *Id*. at 825. 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. *Id*. at 820-21. That evolution shows that the impact of the pandemic on customer payment behavior did not end on any fixed date. *Id*. at 821. It persisted and required a measured, ongoing response. *Id*. Witness Colley testified that DEP was still implementing substantial credit policy tightening in late 2025, more than a year after the Public Staff's proposed August 2024 cutoff. *Id*. at 826-27.

In the Comprehensive Settlement, the Stipulating Parties agree that DEP'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.9; tr. vol. 7, 1100. 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. Comp. Settl. §§ II.9, II.17; tr. vol. 7, 1100-01.

Under the Comprehensive Settlement, the Stipulating Parties agree that DEP 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. 7, 1101. If the actual deferral for such period is less than $12 million, DEP will defer the difference to be returned to customers in the next rate case. *Id*. If the actual deferral equals or exceeds $12 million, DEP will not collect additional amounts from customers in the next rate case. *Id*. Based on these terms, the projected North Carolina retail deferral balance at the rates effective date is approximately $61.6 million, resulting in annual amortization expense of approximately $12.3 million, and the bad debt deferral adjustment reduces the base rate revenue requirement by approximately $8.7 million relative to DEP's rebuttal position. Jiggetts Comp. Settl. Ex. 2 at 20, l. 19, Ex. 3 at 234-35. The Stipulating Parties also agreed to an ongoing bad debt

expense of approximately $27.9 million North Carolina retail and an uncollectibles rate of 0.585%. Comp. Settl. § II.8; tr. vol. 7, 1099.

Discussion and Conclusions

The Commission accepts the Stipulating Parties' agreement regarding DEP's bad debt deferral as fair, just and reasonable, and in the public interest. The record reflects a genuine dispute between DEP and the Public Staff regarding the appropriate end date for the deferral authorized in Docket No. E-2, Sub 1300, with the Public Staff recommending an August 31, 2024, cutoff, and DEP 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 December 31, 2026. The Commission further finds 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 the Stipulating Parties' agreement (as contained in Section II, ¶ 17 of the Comprehensive Settlement) 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 Section II, ¶ 9 of the Comprehensive Settlement and agrees that the deferred balance shall be amortized over five years.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 55

Lead-Lag Study

The evidence supporting this finding of fact is contained in DEP's verified PBR Application and Form E-1; the testimony and exhibits of DEP witnesses Jiggetts and Speros; the joint testimony and exhibits of the Public Staff Accounting Panel; the Sub 1300 Order; the Comprehensive Settlement; and the entire record in this proceeding.

Summary of Evidence

In DEP's last rate case, DEP 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 DEP's next rate case application. In accordance with this settlement, which was approved by the Commission, DEP 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 DEP's Form E-1. Tr. vol. 7, 415, n. 1 (citing Amended Agreement and Stip. of Partial Settl. ¶ 32, No. E-2, Sub 1300 (May 2, 2023)); Sub 1300 Order at 23, 65-66, 239.

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. 7, 414. 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). *Id*. The revenue lag is compared to the expense lead and the net result is applied to each category of cost of service to determine DEP's cash working capital requirements. *Id*. at 414-15.

Speros Direct Exhibit 3 presents the calculation of DEP'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 DEP pays expenses and when it receives revenues. *Id*. at 415. 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 DEP's North Carolina retail operations. *Id*. Based on this analysis, DEP's cash working capital requirement for investor funds for North Carolina retail operations is $315.5 million. *Id*. at 415-16. This amount is included in the cash working capital component of rate base. Jiggetts Direct Ex. 2 at 4.4; tr. vol. 7, 416.

Witness Jiggetts explained how DEP adjusts cash working capital to incorporate the impact of the other pro forma adjustments using the updated lead-lag study provided by witness Speros. DEP 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. 7, 998. 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 Comprehensive Settlement. Jiggetts Comp. Settl. Ex. 3 at 243-45; tr. vol. 7, 1023, 1038, 1104.

The Public Staff noted that in the current proceeding, DEP submitted a lead-lag study based on 12 months of historical data ending December 31, 2023. Tr. vol. 8, 40. DEP computed cash working capital using the lead-lag method and then adjusted it to fully reflect all of DEP's proposed adjustments before the amount of the proposed rate increases. *Id*. at 40-41. The Public Staff Accounting 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*. at 41. The Public Staff's adjustment to cash working capital under present rates was approximately $37 million in rate base. *Id*.

In her rebuttal testimony, witness Jiggetts confirmed that the Public Staff used the lead-lag method supported by DEP's lead-lag study to calculate cash working capital, and DEP and the Public Staff do not have any dispute regarding the lead-lag days included in the study. Tr. vol. 7, 1056. However, because DEP did not agree with all of the Public

Staff's other proposed adjustments, DEP could not agree with the total dollar amounts of the Public Staff's cash working capital adjustments. *Id*.

In the Comprehensive Settlement, the Stipulating Parties agreed to update cash working capital and inflation adjustments based on other agreed-to adjustments and agreed on the calculation used by DEP in its PBR Application. Comp. Settl. § II.63.

Discussion and Conclusions

The Commission finds and concludes that DEP complied with the directive in the Sub 1300 Order to prepare an updated lead-lag study and incorporated the results of that study into its filing in this case. The Comprehensive Settlement provides that the Stipulating Parties 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 DEP'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 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 DEP's verified PBR Application and Form E-1; the Comprehensive Settlement; the testimony and exhibits of DEP witness Guyton; the joint testimony and exhibits of 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 DEP 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. 7, 1316.

In DEP witness Guyton's rebuttal testimony, witness Guyton explained that DEP 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. 8, 787. Witness Guyton clarified that for outage cause coding, DEP follows Commission-approved and industry-standard methodologies for MED classifications. *Id*.

In Section III, ¶ 2 of the Comprehensive Settlement, DEP agreed to report system reliability metrics quarterly, including CEMI-2, CEMI-4, CEMI-6, CEMI-8, MAIFIe, and the number of MEDs in its quarterly reliability reporting. Tr. vol. 7, 1895; tr. vol. 8, 846.

Multiyear Rate Plan Quarterly Reporting

In Section II, ¶ 44 of the Comprehensive Settlement, DEP 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. Tr. vol. 10, 503.

Discussion and Conclusions

The Comprehensive Settlement establishes certain reporting obligations. Specifically, Section III, ¶ 2 of the Comprehensive Settlement obligates DEP to include additional reliability metrics as part of its Quarterly Reliability Reports filed in Docket No. E-100, Sub 138A. Section II, ¶ 44 of the Comprehensive Settlement obligates DEP 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 or otherwise addressed above. Based upon the record evidence and consistent with the Comprehensive Settlement, the Commission finds and concludes that the reporting obligations outlined in Sections II and III of the Comprehensive Settlement 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 DEP 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

DEP witness Colley presented testimony (adopting the prefiled testimony of witness Quick) describing DEP'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. 7, 807-08, 819 n.1.

Regarding the Customer Assistance Program (CAP) pilot, witness Colley testified that the program was approved by the Commission in Docket No. E-2, Sub 1300 as a three-year pilot providing a $42 monthly bill credit to eligible low-income customers. Tr. vol. 7, 812. Approximately 33,000 customers were enrolled as of 2025, with enrollment expected to increase to approximately 41,000 by 2026. *Id*. Witness Colley clarified that the CAP pilot was funded through the customer assistance rider and is a different structure than what is being proposed and what continues today as the Share the Light program. *Id.* at 860-61.

Witness Colley testified regarding agency partnerships, noting that since January 2024, DEP customers have received approximately $43 million in agency pledges, including over $1.6 million from the Share the Light Fund. *Id.* at 811. DEP's Payment Navigator program received approximately 16,000 calls and guided over 700 agency referrals between June 2024 and June 2025, connecting customers with available financial assistance. *Id*. at 812.

DEP witness Bowman testified regarding DEP's commitment to affordability for its customers, including enhanced incentives and on-bill credits for energy-efficiency participation, income-qualified weatherization and neighborhood energy-saving programs, free home energy assessments, rebates, demand-response bill credits, and incentives for solar or batter installations. *Id.* at 757. DEP witness Bowman also 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 and an increase of approximately $6 per month in Rate Year 2. *Id.* at 868.

In their testimony, the Public Staff Policy Panel explained that DEP'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. *Id.* at 1170-71. They highlighted that 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 1172.

Section II, ¶ 60 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.60; tr. vol. 7, 833. It also provides that DEP will file an annual report by April 1, starting in 2028. The report 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. Tr. vol. 7, 833.

Discussion and Conclusions

The Commission has carefully considered the evidence regarding affordability presented in this proceeding, including the testimony of DEP 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 DEP's service territory and in consumer statements of position filed in this proceeding.

The Commission finds that the provisions of the Comprehensive Settlement, which include a substantial aggregate reduction in DEP's revenue request, the MYRP Refund Rider, and $10 million in shareholder contributions, in conjunction with DEP'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 Comprehensive Settlement, are necessary to serve customers reliably. The rate increases resulting from these investments are moderated by the reductions to DEP's requested revenue requirement reflected in the Comprehensive Settlement.

The Commission encourages DEP to continue to explore all avenues to reduce costs for customers and 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. 59-66

Riders

The evidence supporting these findings of fact is contained in DEP's verified PBR Application and Form E-1; the testimony and exhibits of DEP witnesses Jiggetts, Sykes, Byrd, and Speros; the testimony and exhibits of Public Staff witness Metz and the joint testimony and exhibits of the Public Staff Accounting Panel; the testimony and exhibits of CUCA witness McGlothlin; Public Staff Late-Filed Exhibit 1; the Comprehensive Settlement; and the entire record in this proceeding.

Summary of Evidence

DEP witness Sykes testified in support of establishing a PTC Rider so that customers receive the benefits of any PTCs generated and monetized under the IRA associated with both nuclear and non-nuclear facilities such as solar and hydroelectric. Tr. vol. 9, 24-27. Witness Sykes proposed to flow back $40 million (North Carolina retail) per year of PTCs through the PTC Rider in 2027 and 2028, and thereafter to update the rider annually to return PTCs monetized or used, net of costs incurred to achieve the PTC benefits, over a four-year amortization period with a levelized return at DEP's last authorized weighted average cost of capital. *Id*. at 25-26. Public Staff witness Metz testified that the Public Staff supports DEP's proposed PTC rider but recommended that DEP not include non-outage incremental O&M expense for prevailing wages as a decrement to the PTC amounts and discontinue all prevailing wage deferrals effective January 1, 2027. Tr. vol. 7, 1929-30. He further noted that ongoing discussions are needed in a future rider proceeding regarding how to account for incremental labor costs associated with the rider. *Id*. Witness Metz also noted that, with the DEC and DEP combination anticipated to take effect January 1, 2027, careful attention will be needed in

the next general rate case to allocate legacy and future PTCs according to the contributions of each legacy utility's ratepayers, and he suggested that the DEC and DEP PTC riders operate in identical fashion to the extent possible. *Id*. at 1930. CUCA witness McGlothlin generally supported the establishment of a PTC Rider but recommended that costs already included in base rates or charged against earnings be excluded from the PTC Rider, that DEP provide sufficient documentation of any incremental costs in its PTC Rider updates, and that the Commission consider a cap disallowing incremental costs exceeding 10% of the PTC value unless DEP demonstrates that they are reasonable and necessary. Tr. vol. 8, 386-88. In rebuttal, DEP witness Sykes testified that recovery of incremental costs is reasonable, that DEP'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. 9, 45-52. Witness Sykes also testified that the stipulation establishing DEC's Nuclear PTC Rider in Docket No. E-7, Sub 1276 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 46-49.

In the Comprehensive Settlement, the Stipulating Parties agreed to establish the PTC Rider as proposed by DEP, provided that DEP 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 deferred beyond January 1, 2027, and all deferred incremental costs may be netted in the PTC Rider, subject to review by the Public Staff. The Stipulating Parties further agreed to increase the fixed annual amount of PTCs flowed back to customers through the PTC Rider for 2027 and 2028 from DEP's originally proposed $40 million per year to $120 million per year. If DEP is unable to monetize or use PTCs equal to the agreed-upon $120 million per year, DEP shall accelerate the flowback of North Carolina State Excess Deferred Income Tax to true up the shortfall. Comp. Settl. § II.20; tr. vol. 7, 783, 1107-08.

At the evidentiary hearing, Presiding Commissioner McKissick requested that the Public Staff file a late-filed exhibit setting forth the amount of PTCs received by DEP to be flowed back to customers and the periods associated therewith. Tr. vol. 7, 1914. In response, the Public Staff filed Late-Filed Exhibit 1, which, upon consultation with DEP, provided the requested information, including the total grossed-up amount of PTCs monetized for 2024 to 2025, DEP's estimated additional credit amounts to be monetized for 2026 to 2027, and an illustration of the proposed PTC Rider settlement framework showing the timing of each tranche until PTCs are fully flowed back to ratepayers. Public Staff Late-Filed Ex. 1.

DEP witness Jiggetts testified that, pursuant to Ordering ¶ 54 of the Sub 1300 Order, DEP continued to record revenues received for deferred costs beyond the approved amortization period and proposed to return the resulting net over-amortization balance to customers over a two-year period through the RAL Rider. Sub 1300 Order at 242 (Ordering ¶ 54); tr. vol. 7, 966, 995-96, 1010. Based on an estimated North Carolina retail over-amortization balance of approximately $25.8 million as of December 31, 2026, Rider RAL-3 would return approximately $13.9 million to customers

in each of 2027 and 2028. Jiggetts 2d Supp. Direct Ex. 5 at 1; Jiggetts Comp. Settl. Ex. 1. Witness Byrd testified that the RAL-3, PTC, BPM, and pension riders would each be set as a uniform per-kWh rate for all rate schedules and updated annually, with the pension rider initially set at zero. Tr. vol. 10, 228. The Public Staff Accounting Panel recommended approval of the RAL-3 rider, and no party opposed it. Tr. vol. 8, 106. In the Comprehensive Settlement, the Stipulating Parties agreed that DEP 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. Comp. Settl. § II.19.

DEP witnesses Jiggetts and Sykes testified in support of DEP's proposal to establish a BPM Rider similar to DEC's existing BPM Rider. Tr. vol. 7, 966; tr. vol. 9, 27-28. They explained that the BPM Rider is a new decrement rider for DEP whereby the North Carolina retail allocated share of net revenues from certain non-firm wholesale sales are shared with retail customers. Tr. vol. 7, 1011; tr. vol. 9, 27. Witness Sykes provided additional detail, explaining how the BPM operates and how its establishment for DEP would create alignment with DEC. Tr. vol. 9, 27-29. As with DEC's BPM Rider, 90% of the net revenues from BPM sales and 100% of non-firm point-to-point transmission revenues would be flowed back to North Carolina retail customers, with an initial total decrement of (0.005) cents per kWh. *Id*. The Public Staff Accounting Panel supported DEP's request to establish an annual BPM Rider similar to DEC's but encouraged DEP to be mindful of its internal costs to implement and operate the rider, noting that the net sales should outweigh the costs, or the rider would be a net burden to ratepayers. Tr. vol. 8, 95-96. DEP estimated that the BPM Rider would flow back approximately $2 million of net revenues in 2027. *Id*. at 96. In the Comprehensive Settlement, the Stipulating Parties agreed that DEP shall establish the annual BPM Rider as proposed in the initial application, provided that DEP shows in each rider filing that the BPM Rider is net cost effective for DEP to implement and maintain. Comp. Settl. § II.21.

DEP 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 DEP's control. Tr. vol. 7, 423-25, 1009. 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 that a pension rider would create single-issue ratemaking outside of a full rate case. Tr. vol. 8, 92-94. 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 that the deferral of asset gains and losses under ASC 715 supports rather than undermines the argument for a rider. Tr. vol. 7, 443-44. 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 444-45. In the Comprehensive Settlement, DEP agreed to withdraw its proposed pension rider. Comp. Settl. § II.18.

DEP witness Jiggetts testified that the JAAR was first established in 2015 by the North Carolina General Assembly in Senate Bill 305, which allowed DEP to recover the North Carolina retail portion of all reasonable and prudent costs incurred to acquire,

operate, and maintain the proportional interest in electric generating facilities purchased from a joint agency through an annual rider. Tr. vol. 7, 1010-11; tr. vol. 9, 21. DEP witness Sykes testified that DEP proposed to incorporate prospective amounts that would otherwise be recovered through the JAAR into base rates and to eliminate the annual rider. Tr. vol. 9, 22. DEP would continue to seek recovery of the rolling recovery factor balances, by customer class, in the annual JAAR until such time as the experienced over-recovery (or under-recovery) by customer class has been returned to (or recovered from) customers. *Id*. Acquisition costs included for recovery in the JAAR associated with plant in service as of the acquisition date are levelized for the benefit of customers. *Id*. at 23. DEP proposed to maintain the levelization of those costs as discussed by witness Sykes. Pro forma adjustment NC3070 removes electric plant in service and accumulated depreciation from rate base, adjusts depreciation and amortization expense and income taxes for the Test Year, and adds the levelized revenue requirement associated with the applicable assets. Tr. vol. 7, 992.

The Public Staff Accounting Panel supported moving the JAAR into base rates and eliminating the rider. Tr. vol. 8, 96-97. The Public Staff noted that the net revenue requirement requested by DEP for the JAAR in pro forma NC3070 was $2.356 million and that, after the JAAR is moved into base rates, DEP will file one or more JAAR rider proceedings to true up the remaining balances. *Id*. at 97. At the evidentiary hearing, Public Staff witness Zhang addressed the timing of this rate case proceeding and annual JAAR proceeding under Docket No. E-2, Sub 1397 before the Commission. *Id.* at 109-10. Witness Zhang explained that the JAAR rider rates set in that proceeding for the rate period beginning December 1, 2026, would include both a prospective component and the rolling recovery factor, or experience modification factor, component, and that the prospective component would remain in effect only for December 2026. If the Commission approves moving the prospective component to base rates as proposed, the JAAR rates would be revised effective January 1, 2027, to reflect just the rolling recovery factor component. The annual JAAR rider would need to be filed at least one more time to address any over or under recovery through the end of December 31, 2026, and JAAR rider rates would continue to include only the amount needed to resolve any remaining over or under recovery balances. *Id*. at 110, 112-14.

No party opposed this proposal, and witness Zhang testified that moving the JAAR into base rates was agreed upon by the parties. *Id*. at 113. Additionally, DEP agreed to withdraw its pending appeal related to the 2025 JAAR Rider proceeding, Docket No. E-2, Sub 1354, upon approval of the Comprehensive Settlement without material modification, and agreed to support holding that appeal in abeyance so that the appellees are not required to begin briefing until after the Commission issues its decision in this proceeding. Comp. Settl. § II.22; tr. vol. 7, 783, 1108. The Commission finds that the incorporation of the JAAR into base rates, the termination of the separate JAAR rider, and the withdrawal of the pending appeal involving the 2025 JAAR rider proceeding is just and reasonable and should be approved.

Discussion and Conclusions

No party opposed the rider-related provisions of the Comprehensive Settlement. CUCA, which raised concerns about the PTC Rider, and the Public Staff, which opposed the pension rider, are Stipulating Parties. The Commission concludes that the establishment of the PTC Rider, the establishment of the RAL Rider, the establishment of the BPM Rider, DEP's withdrawal of its proposed pension rider, the incorporation of amounts previously recovered through JAAR into base rates, and DEP's withdrawal of its pending JAAR appeal as set forth in the Comprehensive Settlement, are just and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 67-68

Carrying Costs

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

Summary of Evidence

The Public Staff Accounting Panel testified that in this proceeding, DEP calculates carrying costs by dividing 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. 8, 77-78. DEP calculates carrying costs in this manner on, among other items, the true-up of Hurricanes Helene and Debby storm costs securitized in Docket No. E-2, Sub 1370, the storm securitization servicing and administrative fee and upfront bond issuance cost true-ups, Winter Storm Fern costs, the CCR deferral, and the bad debt expense deferral. *Id*. at 77. The Accounting Panel indicated that the Public Staff has raised concerns in several dockets regarding how DEP 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 76-77.

The Public Staff argued that DEP's carrying cost methodology overstates the appropriate return because DEP applies the full annual WACC on a monthly basis and compounds that return each month. *Id*. at 78. 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*. at 78-79. Using an illustrative $100,000 deferral balance and DEP's Commission-approved after-tax WACC of 6.6499%, the Public Staff showed that DEP's method produces an effective annual return of 6.8564%, compared with 6.6499% under the Public Staff's discounted method. *Id*. at 79-80. The Public Staff noted that DEP already uses the discounting method it recommends to calculate the monthly return on the JAAR. *Id*. at 80. The Public Staff made adjustments to carrying costs on the Hurricane Helene and Debby costs true-up, the CCR deferral, and the COVID bad debt deferral in this case. *Id*. at 80. The Public Staff recommended denial of

DEP's request to defer Winter Storm Fern costs and therefore made no carrying cost adjustment for those costs. *Id*.

In her rebuttal testimony, DEP witness Jiggetts disagreed with the Public Staff, testifying that DEP's methodology applies the Commission-approved after-tax WACC to deferred balances on a monthly basis because DEP finances those balances continuously, and that the Public Staff's discounting method would deny DEP full recovery of its authorized return. Tr. vol. 7, 1079. 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 1080. 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 DEP's investors and its customers. *Id*.

In the Comprehensive Settlement, 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. Comp. Settl. § II.17. 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 Comprehensive Settlement, 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. Comp. Settl. § II.17; tr. vol. 7, 1107. The carrying cost methodology does not apply to Winter Storm Fern costs, which, under the Comprehensive Settlement, will not incur any carrying costs. Comp. Settl. § II.25.

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 Comprehensive Settlement. The Commission notes that the appropriate methodology for calculating carrying costs has been a disputed issue between DEP and the Public Staff in a number of recent dockets and appreciates the Stipulating Parties reaching a resolution that applies to the Stipulating Parties not only to the true-up and deferrals identified in the Comprehensive Settlement but also to future deferrals and riders through the next two general rate cases. The Commission concludes this resolution is reasonable and in the public interest and accordingly accepts the carrying cost methodology set forth in the Comprehensive Settlement.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 69

Quality of Service

The evidence supporting this finding of fact is contained in DEP's verified PBR Application and Form E-1; the testimony and exhibits of DEP 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

DEP witnesses Guyton and Fogg testified to the performance of DEP's T&D system during the base period. Witness Fogg testified that DEP's transmission system performed well, and current reliability metrics show that the transmission system is performing strongly, and DEP is seeking to continue transmission investments to expand capacity, meet energy demand, and strengthen the grid. Witnesses Fogg and Guyton noted that DEP 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. 7, 89-90; tr. vol. 8, 716. Witness Fogg testified that the primary drivers for the OHMY-SA performance are vegetation, transformer equipment, and animal outages. Tr. vol. 7, 90. Witness Guyton testified that DEP's operational investments since PBR1 have reduced the frequency and impact of outages, and DEP is providing safe and reliable service. Witness Guyton cited noticeable improvements in DEP's SAIDI and SAIFI metrics for 2024 and noted that DEP's investments since the last rate case have contributed to reduced frequency and impacts of outages, including the continued implementation of Self-Optimizing Grid. Tr. vol. 8, 718.

In the Public Staff Distribution Panel's direct testimony, Public Staff testified that it is concerned that DEP's service quality is not improving for customers. Tr. vol. 7, 1336. The Distribution Panel recommended DEP 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. *Id*. at 1316.

In his direct testimony, DEP witness Colley testified that in addition to providing safe and reliable electric service, DEP continues to invest in people, processes, and technology to meet its evolving customer expectations. Tr. vol. 7, 801. Witness Colley explained that DEP'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*. Witness Colley described the enhancements DEP 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 805-06.

Witness Colley further described the customer care teams, which are specialized to provide support to residential and business customers. Witness Colley testified that DEP'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 DEP's nonresidential and residential customers. *Id*. at 803-804. 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*. at 804.

Witness Colley also testified about the programs DEP 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 807-12. Witness Colley also described the ways in which DEP 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 waiving connection fees and security deposits for customers relocating due to impacts of Hurricane Helene. *Id*. at 815-16.

Through the Comprehensive Settlement, DEP agreed to report system reliability metrics quarterly, including CEMI-2, CEMI-4, CEMI-6, CEMI-8, MAIFIe and the number of major event days. Comp. Settl. § III.2; tr. vol. 7, 1895, tr. vol. 8, 846.

In DEP Witness Bowman's settlement testimony, she testified that the Comprehensive Settlement is a fair and balanced outcome for both DEP and its customers, and the compromises achieved therein will allow DEP to keep rates competitive, maintain the reliability DEP'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. 7, 779, 785.

Discussion and Conclusions

In recognition of the policy of the State of North Carolina "to promote adequate, reliable and economical utility service" codified at N.C.G.S. § 62-2(2) and in accordance with the Commission's general supervisory authority established in N.C.G.S. § 62-32, and recognizing that the Commission found DEP'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 DEP is adequate. No party other than the Public Staff presented evidence on DEP's service quality.

Additionally, no party other than the Public Staff presented evidence critical of DEP's quality of service. Based on the foregoing, the Commission concludes that DEP provides adequate service to customers.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 70-72

Base Fuel and Fuel-Related Factors

The evidence supporting these findings of fact is contained in DEP's verified PBR Application and Form E-1; the testimony and exhibits of DEP witness Sykes; the joint testimony and exhibits of the Public Staff Accounting Panel, and the testimony and exhibits of Public Staff witness Lawrence; the testimony and exhibits of AGO witness Burgess; the testimony and exhibits of CIGFUR II witness Collins; the Comprehensive Settlement; and the entire record in this proceeding.

Summary of Evidence

DEP witness Sykes supported DEP'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, page 1. Tr. vol. 9, 16-18. Witness Sykes proposed to use the total prospective fuel and fuel-related cost factors approved in Docket No. E-2, Sub 1341. *Id*. at 19. Witness Sykes explained that these factors represented the fuel-related amounts that DEP is collecting from its North Carolina retail customers through its approved rates as of the filing date of the PBR Application and related testimony. *Id*. at 17. Witness Sykes explained that DEP's request related to non-fuel revenues only, and would neither increase nor decrease rates related to the recovery of fuel costs. *Id*. at 16-19. He also testified that if DEP had the opportunity to incorporate the base fuel factors pending Commission approval in Docket No. E-2, Sub 1358, which would include the impacts of S.B. 266, it may elect to do so, in which case all fuel and fuel-related costs would be included in DEP's prospective fuel factor and the adjustment required under N.C.G.S. § 62-133.2(a)(4) would no longer apply. *Id*. at 20.

In his supplemental direct testimony, witness Sykes proposed updated base fuel factors by customer class derived using the total prospective fuel and fuel-related cost factors approved in Docket No. E-2, Sub 1358, and effective beginning December 1, 2025. *Id*. at 30-31. Witness Sykes explained that DEP updated the pro forma adjustment for NC2010 to reflect the revised base fuel factors proposed in his supplemental testimony, further addressed in the supplemental testimony of DEP witness LaWanda Jiggetts. *Id*. at 32. He also explained that, since the 2025 Fuel Proceeding concluded after the enactment of S.B. 266, the approved fuel rates reflected additional costs allowed for recovery under S.B. 266, as opposed to including those costs in base rates, and the DEP was electing to reflect those approved fuel factors in this proceeding. *Id*.

Public Staff witness Lawrence testified that, based on his review, he recommended the Commission approve DEP's pro forma adjustments to NC2010, which adjusts fuel costs to approved rates, and NC2020, which adjusts purchased power costs serving wholesale customers. Tr. vol. 7, 1576-78.

Public Staff witness Metz testified that he had investigated DEP's revisions to its wholesale contract with the Fayetteville Public Works Commission (FPWC), which is the largest municipal electric system in North Carolina and the largest municipal electric system served by either DEP or DEC in the Carolinas. *Id*. at 1930-31. He noted that FPWC owns its 265 MW generating facility, the Butler-Warner Gas Plant (Butler-Warner) and sells the plant's output to DEP. *Id*. at 1931. Witness Metz testified that, based on his review, the amendments to DEP's wholesale contract did not result in any material harm, but he noted that the prudence of DEP's purchases and their costs will be addressed in annual fuel proceedings. *Id*. at 1932.

AGO witness Burgess recommended that the Commission reduce or eliminate changes to DEP's base rates that he claimed were due to unnecessary or unreasonable pro forma adjustments to 2024 costs. Tr. vol. 9, 356. He asserted that the increase in 2024 per-book costs over DEP's projection from the prior year was primarily driven by

abnormally high fuel and purchased power costs, which accounted for over 90% of the total cost discrepancy. *Id*. at 357. Witness Burgess testified that he did not believe this increase in test year costs and revenue could be adequately explained by a change in billing determinants, since DEP's kWh consumption did not increase between the MYRP1 and MYRP 2 test years, and stated the increase must therefore be due to other factors. *Id*. at 358. He explained that one major source of high costs during the 2024 test year was Fuel and Purchased Power costs, which were 64% higher than anticipated, including $284 million in deferred fuel costs tied to unique events such as Winter Storm Elliot and the Russia-Ukraine war and which skewed per-book costs and revenues higher for that year. *Id*. at 359. Witness Burgess stated that, while DEP made pro forma adjustments to remove some of these abnormal fuel and purchased power costs from the test year, he was concerned that other simultaneous accounting adjustments to non-fuel costs had the effect of keeping adjusted test year costs at an arbitrarily high level. *Id*. He also expressed concern regarding the use of recent rider rates to estimate base fuel expenses instead of relying on the per-book values, which appear to use a more standardized approach to cost accounting. *Id*. at 362. Witness Burgess recommended that DEP instead set its base fuel costs using the most recent per-book fuel expense for a full calendar year and set the NC2010 fuel adjustment to zero the expenses, including any deferred fuel costs, which he claimed would provide greater assurance of separate fuel cost treatment independent of retail sales estimates. *Id*. at 362-63. Witness Burgess stated that any over- or under-collection of fuel costs would accrue to the deferred fuel balance and be addressed through the fuel rider, which he asserted would not pose an undue burden on DEP since the fuel rider is now subject to quarterly updates. *Id*. at 363.

CIGFUR II witness Collins recommended that the Commission eliminate DEP's accrual of interest on fuel under-recoveries that fall within the scope of the quarterly fuel true-up mechanism. Tr. vol. 9, 638. He argued that once the quarterly adjustment mechanism is in operation, the historical justification for accruing interest on the carried balance largely disappears, and that eliminating the interest accrual is consistent with the principle that ratepayers should pay only for the costs they cause. *Id*.

On rebuttal, DEP witness Sykes provided testimony 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. *Id*. at 38-40. He explained that non-fuel base rate cases ensure that base rates include neither an increase nor a decrease related to the recovery of fuel costs, and that fuel and fuel-related costs have been recovered from North Carolina retail customers through an annual fuel rider mechanism since the 1980s. *Id*. at 38. Witness Sykes also noted that S.B. 266 recognizes that interest shall be applied to both over- and under-recovered fuel balances and also mandates quarterly reporting to the Commission, with which DEP has complied. *Id*. at 39.

Witness Sykes testified that DEP agreed with the Public Staff that capacity costs associated with the FPWC's Butler-Warner facility should be addressed in DEP's annual fuel rider proceeding and that DEP was committed to working with the Public Staff to ensure those costs are recovered appropriately. *Id*. at 40. He also noted that the Public Staff otherwise supported DEP's fuel-related pro forma adjustments in this proceeding. *Id*.

In response to AGO witness Burgess, DEP witness Sykes explained that DEP 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) dictates how base fuel factors are established in a general rate case and how the increment or decrement fuel factors are determined in an annual fuel proceeding, and how these factors work together to recover DEP's fuel expense. *Id*. at 41. He further explained that DEP 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, DEP was limited to using the most recently approved fuel factors from Docket No. E-2, Sub 1358, consistent with past practice. *Id*. at 41-42.

In response to CIGFUR II witness Collins, DEP witness Sykes testified that S.B. 266 requires DEP 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), noting that these costs have always been incurred by DEP and that S.B. 266 acknowledges this reality by requiring that interest be applied to an under-recovered fuel balance. *Id*. at 44-45. 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. *Id*. at 45. Finally, witness Sykes noted that quarterly fuel filings also do not eliminate the financing costs incurred during the deferral period on fuel. *Id*.

In the Comprehensive Settlement, the Stipulating Parties agreed to work together on a proposal to finalize DEP'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-2, Sub 1398. Comp. Settl. § II.35. In addition, the Stipulating Parties agreed that DEP 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 the current DEP fuel rider, or in the pending DEP fuel rider for rates effective December 1, 2026, in Docket No. E-2, Sub 1398. *Id*. § II.36. Finally, the Stipulating Parties agreed to meet and discuss the appropriate calculation of interest under N.C.G.S. § 62-133.2. *Id*. § II.37.

Discussion and Conclusions

The Commission gives significant weight to ¶¶ 35-37 of Section II of the Comprehensive Settlement regarding DEP's fuel updates, the testimony of DEP witness Sykes, and the testimony of Public Staff witness Lawrence and the Public Staff Accounting Panel. In doing so, the Commission rejects AGO witness Burgess' recommendations regarding DEP's base fuel costs in this proceeding for the reasons set forth in DEP witness Sykes' testimony and instead adopts the provisions of the Comprehensive Settlement related to DEP's fuel updates as reasonable and appropriate. Accordingly, the Commission finds and concludes that the Stipulating Parties shall work together on a proposal to finalize DEP's fuel treatment in DEP's compliance filing, the intent of which will be to update the base fuel factors to reflect the Commission's Order in Docket No. E-2, Sub 1398. The Commission further finds and concludes that DEP 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 DEP fuel rider, or in

the pending DEP fuel rider for rates effective December 1, 2026, in Docket No. E-2, Sub 1398. Finally, the Commission finds and concludes that the Stipulating Parties shall 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. 73-74

Residential Decoupling Mechanism and Earnings Sharing Mechanism

The evidence supporting these findings of fact is contained in DEP's verified PBR Application and Form E-1; the testimony and exhibits of DEP witnesses Abernathy, Byrd, and Beveridge; the testimony and exhibits of Public Staff witness Fahey and the joint testimony and exhibits of the Public Staff Rates Panel; the Comprehensive Settlement; and the entire record in this proceeding.

Summary of Evidence

Residential Decoupling Mechanism

DEP witness Abernathy provided direct testimony on DEP'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. 7, 896. The following Rate Schedules are affected by the RDM: RES, R-TOU, R-TOU-CPP, R-TOUD, and R-TOU-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 DEP estimates the number of residential customers for each month for each rate year. *Id*. at 896-98. 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 using the methodology that the Commission approved for MYRP1. *Id*. at 898-902.

Witness Abernathy explained that DEP 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 DSM/EE Cost Recovery and Utility Incentive Mechanism in Docket No. E-2, Sub 931. *Id*. at 901; s*ee* Order Approving Revisions to DSM/EE Cost Recovery and Utility Incentive Mechanisms, *Application of Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to G.S. 62.133.9 and Commission Rule R8-69*, No. E-2, Sub 931 (N.C.U.C. May 22, 2024). Witness Abernathy also explained that the RDM 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 902; *see also* Order Amending Commission Rule R1-17B, *Rulemaking Proceeding to Implement Performance-Based Regulation of Electric Utilities*, No. E-100, Sub 178 (N.C.U.C. Aug. 13, 2025).

Public Staff witnesses D. Williamson and Fernandez testified that N.C.G.S. § 62-133.16 authorizes the Commission to approve an RDM designed to break the link between revenues and the consumption of electricity. Tr. vol. 7, 1284. 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 1285. Witnesses D. Williamson and Fernandez recommended that instead of using North Carolina Department of Transportation data to estimate the number of EVs in DEP's service territory, DEP should use only EVs registered to customers enrolled in DEP's recently approved Schedule R-TOU-EV to determine the number of EVs on its system for purposes of calculating the RDM. *Id*. at 1289-90.

In their rebuttal testimony, DEP 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 R-TOU-EV would deny DEP the full EV revenue exclusion allowed by the PBR Statute. Tr. vol. 10, 276-77.

In the Comprehensive Settlement, the Stipulating Parties agreed to accept the Public Staff's position that only sales under DEP's EV-specific rate, as modified or superseded from time to time, should be included in the calculation to exclude EV sales margin from the RDM and ESM. Comp. Settl. § II.54 .

Earnings Sharing Mechanism

DEP witness Abernathy testified in support of the ESM, which is a component of the MYRP. Tr. vol. 7, 903-06. Witness Abernathy explained that if DEP'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 903.

Witness Abernathy testified that for purposes of the ESM calculation, in accordance with the PBR Statute, DEP adjusts earnings for weather, DSM/EE incentives, and PIMs. *Id*. at 904. DEP also adjusts earnings for EV sales, the Second TCA Adjustment, and amounts related to the ESM rider, if applicable. *Id*. at 904-05.

Witness Abernathy noted that DEP is not proposing any changes to the ESM methodology approved in MYRP1 and therefore proposed 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*. Witness Abernathy stated that if the business combination of DEP and DEC is approved, the ESM cannot be calculated separately for each utility and requests the ESM be calculated on a combined utility basis going forward if the business combination is approved. *Id*. at 905.

Public Staff witness Fahey testified that he disagreed with DEP'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. *Id.* at 1787-96. When calculated in that manner, he noted that the ESM would have returned over $29 million to ratepayers in rate year one of DEP's MYRP1. *Id*. at 1788. 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 1788-89. He indicated that when rate base is growing, using an end of period analysis results in an underestimation of the earned return. *Id*. at 1790-91. 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 DEP's approved capital structure. *Id*. at 1790. He noted that the Commission had taken a similar approach with respect to the ESM available to water and sewer utilities. *Id*. at 1791-94.

Witness Fahey also recommended that the Commission reject DEP's proposal to exclude EV sales from the ESM calculation, as it is not required by the statute and allows DEP to retain a greater total of earnings as sales from EVs increase. *Id*. at 1798-99.

Finally, witness Fahey opposed DEP's proposal to combine the DEP and DEC ESMs beginning January 1, 2027. *Id*. at 1799-1800. He noted that the ESM is the only element of rates that DEP and DEC 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 1799-1800. 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 underpayment to one utility's customers and an overpayment to the other, resulting in a cross-subsidy. *Id*. at 1801.

In her rebuttal testimony, DEP 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 DEP's deferral requests. *Id.* at 943-44. She concluded that DEP's methodology is consistent with standard ratemaking and is a reasonable way to evaluate earnings. *Id*. at 943. 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 945. She testified that DEP 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, DEP would have a disincentive to offer programs to encourage EV adoption. *Id*.

In the Comprehensive Settlement, the Stipulating Parties agreed that EV sales, calculated using DEP's EV-specific rate, should be excluded from the ESM calculation. Comp. Settl. § II.54. The Stipulating Parties also agreed that the Second TCA Adjustment will be added to the calculation of the earnings test under the ESM for both DEP and DEC. *Id*. § II.40.f. In addition, the Stipulating Parties agreed to use a 13-month average rate base and DEP's approved capital structure for purposes of calculating the ESM. *Id*. §§ II.55-II.56.

The Comprehensive Settlement also provides that DEP and DEC 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.57.

Discussion and Conclusion

The Commission concludes that the RDM and ESM proposed by DEP as modified by the Comprehensive Settlement are consistent with the PBR Statute and with the Commission's rules. Further, the Commission concludes that the proposal to exclude EV sales from the RDM and ESM as specified by the Comprehensive Settlement is reasonable and should be approved. The Commission notes that reflecting the Second TCA Adjustment in the ESM for DEP is reasonable and consistent with the treatment of the First TCA Adjustment included in PBR1.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 75

Performance Incentive Mechanisms

The evidence supporting this finding of fact is contained in DEP's verified PBR Application; the testimony and exhibits of DEP witnesses Bateman, Farmer, and Guyton; the testimony and exhibits of the Public Staff PIMs Panel; the testimony and exhibits of CIGFUR II 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

DEP 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. 10, 391-93. Witness Farmer testified that DEP's proposed PIMs reflect the experience and learnings from PBR1 and, where possible, feedback from its stakeholder engagement meeting. *Id*. at 389-91.

According to DEP, 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 DEP to reduce peak load based on the estimated winter peak kW reduction resulting from new customer enrollment in DEP's dynamic and time differentiated rate programs. *Id*. at 391, 398.

DEP testified that the Reliability PIM is essentially identical to the existing PIM approved as part of PBR1. The Reliability PIM holds DEP accountable to maintain service reliability as measured by SAIDI (excluding MEDs). This PIM is downside-only to DEP and features graduated penalties to be distributed to customers if DEP 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. DEP'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 DEP's control and adjusting the tiers to reflect updated historical SAIDI experience. *Id*. at 399-400.

DEP testified that the Renewables Integration PIM involves three metrics to incent and reward DEP. The DERs Integration Metric A will provide graduated rewards to DEP for exceeding targets for the number of net-metered DER customers interconnected to the DEP 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 DEP 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 DEP 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 DEP's control. *Id*. at 400-03.

Finally, DEP 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 404.

DEP proposed a PIMs portfolio with $5.4 million in maximum upside rewards and $5.4 million in maximum downside penalties. *Id*. at 405.

In addition to the PIMs, DEP also proposed to continue 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 407-08. DEP also proposed to discontinue two tracking metrics for average residential non-pay disconnection percentage and ratio of average residential bill/federal poverty level. *Id*. at 409.

The Public Staff PIMs Panel expressed concerns with DEP's approach to PIMs and testified that DEP's proposed PIMs would reward actions that DEP should perform without the need for incentives, and that the rewards and penalties proposed by DEP are at levels not likely to provide any meaningful performance change by DEP. Tr. vol. 7, 1425. The Public Staff testified that in the first two rate years under PBR1, DEP earned only a small fraction of the available PIMs rewards and paid no penalties, while DEP was proposing lower PIMs incentives in connection with its PBR Application in this case. *Id*. at 1425-26.

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 1441-42. 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 DEP but with a reduced $5 incentive for customers who remain continuously enrolled in eligible TOU rates from the prior rate year; and (3) eliminating DEP's proposed cap of 50,000 eligible annual enrollments and instead applying a maximum annual reward cap of $1.25 million. *Id*. at 1443-44.

Regarding the Renewables Integration PIM, the Public Staff testified that it should be eliminated in its entirety. *Id*. at 1448. As to Metric A, the Public Staff testified that DER adoption is largely customer driven and DEP 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 DEP's control, and DEP had previously represented that the revenues from the sale of CEEAs would benefit all ratepayers. Regarding Metric C, although the Public Staff originally proposed a version of this PIM in PBR1, the Public Staff testified that DEP'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 DEP for work it is already doing. *Id*. at 1449-50.

Regarding the Reliability PIM, the Public Staff supported the PIM with several modifications. *Id*. at 1451. 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 DEP's five distribution zones. *Id*. at 1453-57. Regarding the Customer Service PIM, the Public Staff opposed this PIM on the basis that: (1) DEP'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) DEP did not provide quantitative support that the proposed $1.5 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 DEP via digital channels. *Id*. at 1457-61.

The Public Staff proposed two 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; and (2) the Facilities Study Timing PIM, an upside-only PIM designed to encourage efficient and accelerated facilities studies related to interconnecting new generation. *Id*. at 1462, 1466-67. 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 1473.

NCSEA witness Lin and CIGFUR II witness Collins both testified in support of fuel PIMs. NCSEA witness Lin testified to a Fuel Cost Efficiency PIM, in which DEP 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. Tr. vol. 8, 466-67. NCSEA witness Lin argued that his proposed Fuel Cost Efficiency PIM

is consistent with the requirements of the PBR Statute. *Id*. at 476-77. 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 449. CIGFUR II 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. Tr. vol. 9, 632-37.

CUCA witness McGlothlin testified in support of a Rate Competitiveness PIM which would either reward or penalize DEP for changes in the competitive ranking of its rates relative to other IOUs in the Southeast region. Tr. vol. 8, 372-76. 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 373-75. CUCA witness McGlothlin testified that DEP'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 376.

In its rebuttal testimony, DEP's PBR Policy Panel explained that DEP's proposed PIMs reflect a measured and thoughtful approach to advance meaningful policy goals as DEP, interested stakeholders and the Commission continue to gain experience from PBR1 PIMs. Tr. vol. 10, 467. Regarding the Time Differentiated and Dynamic Rate Enrollment PIM, the DEP 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 471. 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, DEP objected to the Public Staff's proposed zone-based approach and proposed tiers. *Id*. at 472-73. As to the Renewables Integration PIM, the PBR Policy Panel reiterated its support for this PIM. *Id*. at 473-76. Likewise, the PBR Policy Panel affirmed the basis for the Customer Service PIM as proposed. *Id*. at 477-78. The DEP PBR Policy Panel opposed the Public Staff's two proposed PIMs. As to the RFP Utility Ownership PIM, the DEP 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 DEP's control and doesn't preclude disallowance in a rate case, but was open to discussing the PIM with the Public Staff. *Id*. at 478-80. As to the Facilities Study Timing PIM, the DEP PBR Policy Panel testified that DEP is not opposed to such a PIM concept and was open to further dialogue with the Public Staff. *Id*. at 480. Finally, DEP 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 480-81.

In rebuttal testimony, DEP's PBR Policy Panel also testified that the fuel PIMs proposed by NCSEA and CIGFUR II are not appropriate for several reasons. The PBR Policy Panel explained that DEP 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 DEP'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 DEP's actions are found to be imprudent. *Id.* at 482-88.

In rebuttal testimony, DEP witness Farmer opposed CUCA's proposed Rate Competitiveness PIM on the grounds that the Commission already rejected a nearly identical proposal in DEC's PBR 1 case. Witness Farmer testified that DEP strives to keep its rates as low as is reasonably possible and is proud that its rates are below the national average. However, DEP cannot control what rates are established for utilities in other states and therefore the proposed CUCA PIM is not "solely or primarily" within DEP's control and is not appropriate as a PIM under N.C.G.S. § 62-133.16(c)(3). Furthermore, witness Farmer explained that CUCA witness McGlothlin's PIM baseline would be based upon only three years of history, the "typical bill" he bases his PIM upon excludes a variety of rate options, including the types that many CUCA members are on, and the PIM's proposed calculation pays no attention to differing customer mix among peer utilities. *Id*. at 488-89.

In rebuttal testimony, DEP 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 DEP's MYRP 1 performance. The MYRP Timely Completion PIM is downside only and holds DEP accountable for completing MYRP projects on a timely basis by establishing tiered penalties in the form of basis point reductions for DEP's ROE used to set the top of the ESM band. *Id*. at 490-93.

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 DEP of $5.15 million per rate year and maximum downside penalties of $6 million per rate year. *Id.* at 508. The PIMs Settlement also provides a requirement for DEP 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. *Id*. at 512-13. DEP also agreed to submit quarterly and annual Circuit Performance Reports as well as a program utilization tracking report. *Id*. Public Staff witnesses Fernandez, Hill and T. Williamson testified that the Settled PIMs will guide utility performance and protect customers, and DEP witnesses Bateman and Farmer 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. 7, 1482; tr. vol. 10, 510-12.

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 $1.25 million per rate year. Tr. vol. 7, 1482-84; tr. vol. 10, 509. Witness Farmer also testified that this PIM targets and advances operational efficiency and cost savings, and it encourages DEP to design and seek approval of dynamic and time-differentiated rate designs. Tr. vol. 10, 510-11. In the PIMs Settlement, DEP 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. *Id*. at 509.

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 $1.2 million in rewards per rate year and maximum $6 million in penalties per rate year. Per the PIMs Settlement, the incentive structure is based on a negotiated SAIDI midpoint of 140 minutes and a deadband and sliding scale of rewards/penalties. The Reliability PIM holds DEP accountable to maintain or improve SAIDI for the benefit of all customers. Tr. vol. 7, 1483-84; tr. vol. 10, 509, 511.

Facilities Study PIM

This is a new PIM as proposed by Public Staff with a modification in the PIMs Settlement to include all projects for which an interconnection study is required by state or FERC regulation. 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 $1.5 million per rate year. As discussed in the testimony of the Public Staff PIMs Panel and the settlement testimony of the PBR Policy Panel, this PIM encourages DEP to complete required facilities studies faster, which could lead to bringing needed new generation sources online more quickly. Tr. vol. 7, 1482, 1484; tr. vol. 10, 510-11.

Vegetation Management PIM

This is a new PIM that rewards DEP 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 DEP of $120,000 for each 1% reduction to the 5-year average (2021-2025) DVM cost per mile with maximum rewards of $1.2 million per rate year. The second year of this PIM includes a 2% general inflation factor increase. The upside-only structure of this PIM was not proposed in the direct testimony of the Public Staff or DEP. This PIM targets and advances operational efficiency and cost savings through a shared savings incentive structure. Tr. vol. 7, 1482-83; tr. vol. 10, 510, 512.

PIMs Workshop

The PIMs Settlement provides that DEP will host a PIMs workshop to be completed prior to the filing of its next PBR rate case. PIMs Settl. § II. Topics will include learnings from PIMs performance to date and potential PIM proposals from interested participants, including the fuel efficiency PIM proposed by NCSEA. DEP 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, DEP 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. Tr. vol. 7, 1483; tr. vol. 10, 513.

Tracking Metrics

DEP witness Farmer provided direct testimony stating that DEP 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 DEP's progress in furthering important policy goals. Tr. vol. 10, 407.

In the PIMs Settlement, DEP, the Public Staff, and NCSEA 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. In addition, DEP will maintain its existing Call Center answer rate tracking metric and add the number of web portal and/or mobile application logins to track customer interactions through major digital channels. Finally, in lieu of a tracking metric, DEP will make an annual report as proposed by the Public Staff for the Duke Program Utilization Tracker. In addition, DEP will provide a report showing the number of unique customers enrolled in multiple programs or participating at any point during the calendar year. *Id*.

Discussion and Conclusions

Upon review of the testimony of DEP and the Public Staff regarding the PIMs Settlement, the Commission concludes that the PIMs Settlement is the product of give-and-take negotiations between DEP, the Public Staff, and NCSEA 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.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 76-77

Multiyear Rate Plan Refund Rider

The evidence supporting these findings of fact is contained in DEP's verified PBR Application and Form E-1; the testimony and exhibits of DEP witnesses Bowman, Abernathy, and Bateman; the joint testimony and exhibits of the Public Staff Policy Panel and the testimony and exhibits of Public Staff witness Thomas; the testimony and exhibits of CIGFUR II witness Collins; the joint settlement testimony and exhibits of the Public Staff Settlement Panel; the Comprehensive Settlement; and the entire record in this proceeding.

Summary of Evidence

As discussed above, in its PBR Application, DEP 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. Tr. vol. 7, 1145. The Public Staff Policy Panel does not fundamentally disagree that DEP needs to make significant capital expenditures; however, the Public Staff Policy Panel expressed concerns regarding in-service delays of DEP's MYRP1 projects. Witness Thomas asserted that MYRP1 rates were calculated based on projected in-service dates, but the depreciation expense and a return do not begin accumulating on DEP's books until the assets are placed in service. *Id*. at 1136-40. The Public Staff Policy Panel argued that, without a true-up mechanism, operational and customer MYRP1 benefits are delayed and the risk of project execution is inappropriately placed on the ratepayer. *Id*. at 1138-39, 1142. In the Public Staff's opinion, the ESM provides some guardrails against excess overearning by the utility but is insufficient to address the Public Staff's concerns. *Id*. at 1143-44.

To reach this conclusion, Public Staff witness Thomas compared the actual completion rate and costs of projects in MYRP1 Rate Years 1 and 2 against estimates in MYRP1, evaluating the projects on both a count basis and cost basis. *Id*. at 1494-1501. When considering estimated costs, witness Thomas concluded that 62% of Rate Year 1 projects were placed in service in Rate Year 1 and 19% in Rate Year 2. He further concluded that 46% of Rate Year 2 projects were placed in service in Rate Year 2. *Id*. at 1498-99. Overall, witness Thomas calculated $1.1 billion in capital costs for projects from Rate Years 1 and 2 that were included in rates but not completed by the end of Rate Year 2. *Id*. at 1501. The Public Staff Policy Panel noted that these findings are similar to what the Public Staff found in its investigation of DEC's MYRP1. *Id*. at 1137.

Based upon his analysis of DEP's performance in MYRP1 Rate Years 1 and 2, Public Staff witness Thomas recommended an across-the-board reduction in the MYRP2 capital costs of approximately $1.31 billion assuming a similar rate of delay to the

in-service dates of MYRP2 projects. *Id*. at 1502-04. Witness Thomas's recommendation is based upon an 18% and 52% reduction to most proposed MYRP2 Rate Year 1 and 2 project costs, respectively, reflecting the share of MYRP1 Rate Year 1 and 2 projects not placed in service by the end of Rate Year 2. Projects at the "build gate" stage were excluded and the reduction was halved for projects at the "commit gate" stage, resulting in reductions of $215 million in Rate Year 1 and $1.1 billion in Rate Year 2. *Id*. 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 1505. Witness Thomas testified that the Public Staff considered, but rejected, a performance incentive mechanism for timely project completion like the one approved for Aqua North Carolina, Inc., primarily because the statutory 1% limit on PIM impacts for electric utilities would severely limit ratepayer mitigation. *Id*. at 1504-05.

CIGFUR II witness Collins raised concerns about MYRP2 BESS projects considering industry-wide cost and delivery risks particular to BESS projects that could challenge forecasting schedules and costs for these projects. Tr. vol. 9, 600-01. He recommended the Commission adopt guardrails for the MYRP2 BESS projects, including a claw-back mechanism that would be triggered by project cancellation, delayed in-service date, material change in configuration, or actual in-service costs less than costs approved for recovery. *Id*. at 601-02, 612.

On rebuttal, DEP witnesses Bowman, Abernathy, and Bateman challenged the Public Staff's analysis of DEP's MYRP1 project execution as relying on an unreasonably strict and impractical perspective by measuring whether a project was completed in the exact month originally forecasted. Tr. vol. 7, 746-47, 770-71, 931-32, 935-39; tr. vol. 10, 431-32. This standard, witness Bowman stated, does not reflect how complex utility capital programs of this size 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. Tr. vol. 7, 770-71. Witness Bowman pointed to DEP's obligation to continually assess MYRP projects and ensure customer benefits are maximized throughout the execution phase. *Id*. at 770. 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 customers' best interest and argued that such a standard is inconsistent with Commission Rule R1-17B and the Commission's expectations of water utilities. Tr. vol. 7, 771-73; tr. vol. 10, 431, 437-38, 490.

In rebuttal, witness Abernathy performed an alternative analysis calculating the MYRP1 projects completed within three months of the projected in-service dates. Tr. vol. 7, 936-37. Using that measure, 71% of the MYRP1 projects placed in service were placed in service early or within three months of their estimated in-service dates. *Id*. at 937. Witness Abernathy testified that, as of March 2026, DEP had placed approximately $3.3 billion of MYRP1 plant in service, approximately 84% of the $3.9 billion of approved capital for that period, and expects to complete 90% of the MYRP1 projects, and place in service 94% of the approved capital, by December 31, 2026. *Id*. at 934-35. Witnesses Bateman and Farmer added that this was achieved despite Hurricane Helene, a once-in-a-century storm that caused extensive

devastation in the western part of the State during MYRP1 Rate Year 1 and diverted crucial resources. Tr. vol. 10, 432.

As an alternative to the Public Staff's across-the-board MYRP2 reduction, which witness Bateman argues is arbitrary and not permitted under the PBR Statute, DEP proposed a Timely MYRP Completion PIM modeled on a PIM approved by the Commission for water utilities. *Id*. at 490-91. 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.* at 490-93. Witness Bateman estimated the maximum penalty translates to a range of approximately $25 million to $30 million. *Id*. at 493.

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.43; Comp. Settl. Ex. 1. 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. Comp. Settl. § II.43; Comp. Settl. Ex. 1. at 2. These ratios are combined to produce a composite factor, calculated as one minus the product of the revenue requirement ratio and the project completion ratio, which is multiplied by the difference between the revenue requirement included in rates and the actual revenue requirement for completed MYRP projects to produce the refund amount to be returned to customers through the MYRP Refund Rider. If the actual revenue requirement equals or exceeds the amount in rates, the rider is set to zero. Comp. Settl. Ex. 1. at 2, 4 (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.43. Specifically, the MYRP Refund Rider will be filed annually in conjunction with DEP's annual PBR riders, will apply to MYRP2 Rate Year 1 and Rate Year 2 projects, and will cover a previous Rate Year for which funds are collected, analyzed in aggregate. *Id*. § II.43a-b. Refunds will be paid to customers over a 12-month period, with interest at the A2/P2 commercial paper rate at the federally published monthly average and will be allocated to customer classes based on the amount of total MYRP revenue allocated to each class. *Id*. § II.43.d. DEP will also file quarterly reports showing the percentage of MYRP projects placed in service each quarter and their respective costs during each Rate Year. *Id*. § II.44. Considering the MYRP Refund Mechanism, DEP agreed to withdraw the MYRP Timely Completion PIM proposed in its rebuttal testimony. Comp. Settl. § II.58; tr. vol. 10, 504.

DEP witness Bowman testified that the MYRP Refund Mechanism strikes the appropriate balance between facilitating needed investment for reliability and ensuring customer rate impacts remain reasonable. Tr. vol. 7, 782. DEP witness Bateman likewise testified that DEP was able to make critical investments that are difficult to execute at scale under traditional ratemaking on a timely basis for customers. Tr. vol. 10, 502. While DEP 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*. Witness Bateman further explained how DEP 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 502-04. 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*. at 504.

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. 7, 1897.

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 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. *See* Order Approving Partial Settlement Agreement and Stipulation, Deciding Contested Issues, Approving Water and Sewer Investment Plan, Granting Partial Rate Increases, and Requiring Customer Notice, *Application by Aqua North Carolina, Inc., for Authority to Adjust and Increase 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 117-118 (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 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 DEP'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 these reasons, the MYRP Refund Mechanism (including the MYRP Refund Rider) is considered 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. 78

Performance-Based Regulation

The evidence supporting this finding of fact is contained in DEP's verified PBR Application and Form E-1; the joint testimony and exhibits of the DEP 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

DEP's PBR Application seeks approval of performance-based regulation including the proposed two-year MYRP beginning on January 1, 2027, and ending December 31, 2028. Tr. vol. 10, 370. DEP witness Bateman testified that in addition to the two-year MYRP, which includes an ESM, DEP's PBR Application includes an RDM, PIMs, and tracking metrics. *Id*. Witness Bateman testified that DEP's PBR Application is in the public interest because the PBR framework best supports DEP'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 371-72. 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 372.

Prior to execution of the Comprehensive Settlement, the Public Staff Policy Panel testified that DEP's PBR Application does not appear to be in the public interest. Tr. vol. 7, 1129,1133-34. While the Public Staff Policy Panel does not fundamentally disagree that DEP 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 DEP's capital spending outside of the MYRP framework. *Id*. at 1153-58. 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 1146. 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 DEP witnesses. *Id*. at 1145-46. 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 1146.

On rebuttal, DEP witness Bateman affirmed that DEP'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. 10, 418-27. Specifically, witness Bateman testified that the Public Staff's contrary assertion rests on two premises with which DEP disagrees: (1) an overly rigid assessment of DEP'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 415. As discussed above, as to MYRP1 execution, witness Bateman testified DEP'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 431-32. 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 434. 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 428. The PBR Statute does not allow for a fully forecasted test year in which DEP 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 428-29.

As described in greater detail elsewhere in this Order, the Comprehensive Settlement and PIMs Settlement modify DEP's PBR Application to address several items raised in the proceeding. As part of the Comprehensive Settlement, DEP 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. *Id.* at 502-04. 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 DEP and DEC. Comp. Settl. §§ II.54-II.57. Lastly, DEP 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.43.

In her settlement testimony, DEP witness Bateman testified that DEP believes the Comprehensive Settlement balances the financial impact of the rate increase on DEP customers with DEP's need to recover the costs required to continue fulfilling its obligation to provide safe and reliable electric utility service to customers. Tr. vol. 10, 500. She explained that the Comprehensive Settlement modifies DEP'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*. at 501. Witness Bateman testified that, like every part of the Comprehensive Settlement, the MYRP Refund Rider is a product of give and take. *Id*. at 502. She testified that DEP is proud of its execution under MYRP1 and has learned valuable lessons that will strengthen its execution results under MYRP2, but DEP also heard parties in this proceeding and their concerns about MYRP1 projects that were delayed or canceled, even if for reasons outside of DEP's control. *Id*. Therefore, DEP agreed to the MYRP Refund Rider, and witness Bateman testified that DEP 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. 7, 1897-98.

Discussion and Conclusions

The PBR Statute requires a PBR application to include three elements: (1) a 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, DEP 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 DEP with the opportunity to earn a reward to be collected from customers, and expose DEP 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 DEP regarding the MYRP projects and costs, as well as the rate of return that DEP 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 DEP as part of the Comprehensive Settlement. All Stipulating Parties agree that the Comprehensive Settlement (including the modifications to DEP's proposed PBR Application), taken in its entirety, is in the public interest. The Commission finds that DEP's PBR Application, as modified by the Comprehensive Settlement and PIMs Settlement, results in rates that are fair to both DEP 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 DEP's PBR Application as modified by DEP's rebuttal testimony, 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. 79

Revenue Requirement

The evidence supporting this finding of fact is contained in DEP's verified PBR Application and Form E-1; the Comprehensive Settlement; the testimony and exhibits of DEP witnesses Jiggetts and Abernathy; the joint testimony and exhibits of the Public Staff Accounting Panel; DEP Late-Filed Exhibit 2; and the entire record in this proceeding.

Summary of Evidence

The Comprehensive Settlement provides for certain accounting adjustments that the Stipulating Parties have agreed upon and the Commission has approved in this Order. The settlement issues that impact the revenue requirement in the Comprehensive Settlement are detailed in Jiggetts Comprehensive Settlement Exhibit 2, which provides sufficient support for the annual revenue required on the issues agreed to in the Comprehensive Settlement. Jiggetts Comp. Settl. Ex. 2; tr. vol. 7, 1096-97.

Discussion and Conclusions

After giving effect to the approved stipulations, the Commission concludes that DEP should recalculate the required annual revenue requirement consistent with the Commission's findings herein within ten days of the issuance of this Order. DEP is further directed to file with the Commission the final base rate revenue requirement and the final revenue requirements for Rate Years 1 and 2 in Excel format with detailed footnotes and

supporting documentation, the same format as Jiggetts Comprehensive Settlement Exhibit 1. The Commission directs DEP to work with the Public Staff to verify the accuracy of the calculations, and the filing should reflect any corrections identified by DEP and agreed upon by the Public Staff.

The Commission concludes that the annual revenue requirement for DEP for Rate Years 1 and 2 will allow DEP 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. 80-98

Large Loads, Data Centers, and the DC Schedule

The evidence supporting these findings of fact is contained in DEP's verified PBT Application and Form E-1; the testimony and exhibits of DEP witnesses Byrd, Beveridge, Hager, and Duff; the joint testimony and exhibits of the Public Staff Large Load Panel; the testimony and exhibits of AGO witness Brant; the testimony and exhibits of CIGFUR 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, CUCA, Digital Realty, DoD/FEA, 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 Carolinas, 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-7, Sub 1329 and E-7, Sub 1355 on November 16, 2026.

Summary of Evidence

DEP Direct Testimony

In his direct testimony, DEP witness Byrd testified DEP's current Schedules LGS-TOU and LGS-HLF provide appropriate tariff options for large load and high load factor customers that already align prices with cost of service. Tr. vol. 10, 194. Witness Byrd explained that Schedule LGS-HLF, which serves high load factor customers, provides for significant fixed cost recovery through demand charges, reflecting the unit cost from DEP's COSS. *Id*. As a result, witness Byrd argued, "new tariffs designed for 'large loads' would most likely be designed similar to Schedule LGS-HLF, rendering such new tariffs duplicative and unnecessary." *Id*. Witness Byrd explained DEP 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 DEP's Schedule LGS-HLF or LGS-TOU customers begin to exhibit similar load profiles that are materially different from other customers on existing schedules, DEP may then determine whether it needs to separate such customers onto a new tariff within a separate rate class. *Id*. at 194-95.

DEP witness Hager testified in her direct testimony that in a COSS, system costs are first grouped according to their function, such as generation, transmission, distribution, and customer service. Tr. vol. 8, 123. 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 cost causation principles. *Id*.

Public Staff Direct Testimony

The Public Staff Large Load Panel testified regarding DEP'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. 9, 66-76, 90-95, 104-128.

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. Tr. vol. 9, 66. The Large Load Panel recognized the 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 67. 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 within a timeframe of a little over two years *Id*. at 68, 158. The Large Load Panel noted Duke's recent modeling data adds approximately 13GW of gas-fired capacity to Duke's 35 GW of generation capacity and plans to retire 8.0GW of coal capacity. *Id.* at 70. The Panel compared large loads to large cities in North Carolina, noting that Raleigh had an approximate peak load of 2,000 MW in 2025 and Chapel Hill a peak load of 400 MW. *Id.* at 71. The Panel expressed concern 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 70. 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.* 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 74-75.

The Large Load Panel testified that accommodating these new large loads will require DEC and DEP to invest billions of dollars in new generation, transmission, and distribution facilities. *Id*. at 68. The 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 102. 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. *Id*. at 68-69. 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 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. 9, 96. 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*. The Panel also emphasized that the North Carolina Governor, NARUC, NERC, and FERC, and other states have taken action on large loads, underscoring the importance of an immediate solution to integrating large electric loads. *Id.* at 96-101.

The Large Load Panel testified DEP currently relies on five separate mechanisms to manage large loads: existing rate tariffs (Schedules LGS, LGS-TOU, HP, LGS-HLF, and LGS-RTP, which is closed to new customers); Letter Agreements; ESA Applications; Service Regulations; and the Line Extension Plan. *Id.* at 73, 90-91. However, the Large Load Panel found none of the four ESAs reviewed for DEP's North Carolina territory elected the LGS-HLF rate tariff. *Id*. at 92. The Large Load Panel testified many of these mechanisms can be applied inconsistently, varying from customer to customer at DEP's discretion without Commission oversight. *Id.* at 92-93. The Large Load Panel also testified DEP 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 93. The Large Load Panel concluded these existing mechanisms are not sufficient to protect all customers and ensure just and reasonable rates. *Id*. at 139. At the evidentiary hearing, the Public Staff reiterated its concern regarding the terms of the ESA changing over time

so different customers had different requirements, as well as concern that Duke can change the terms of the ESA at any time. *Id.* at 181.

In their direct testimony, the Large Load Panel provided a review of the Large Load Impact Analysis Duke provided in their rebuttal in the CPIRP proceeding, acknowledging that they are not opposed to the premise of the analysis and that downward pressure on rates from increased sales only exists if the utility has sufficient spare capacity or the marginal cost to construct is less than the embedded cost of the existing system. Tr. vol. 9, 76-78. The Public Staff had several concerns with the underlying assumptions and inputs. First, the analysis used the preliminary base portfolio instead of the requested NTAP. Second, the analysis looked 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, and the analysis excluded the additional infrastructure costs to provide fuel for the gas generation units. Third, the analysis assumed customers operate at 95% of contracted demand constantly for 15 years and only the costs of the customers' load factor are assigned to the customers, not the full system designed to serve peak load. *Id.* at 79-90. The Public Staff found that aligning the resources to the NTAP results in a net benefit decrease of half a billion dollars, and a minimum bound sensitivity that assumed 75% billing demand resulted in a net cost of $1.8 billion. *Id*. at 80. To achieve a net $0 nominal impact, the large load customers would have to maintain a constant 83% load factor for 15 years, but as the analysis does not account for the time value of money, this breakeven point may be higher. *Id.* at 88. The Panel recommended that Duke provide a more comprehensive analysis in rebuttal. *Id.* at 87.

The Large Load Panel recommended adoption of a new large load tariff, Schedule LL, to mitigate the previously identified risks from large load customers. Tr. vol. 9, 93. 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 by existing customers after January 1, 2027, with a load factor of 80% or more. *Id.* at 104-07, 113. 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*. at 107-13.

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. Tr. vol. 9, 118-19. To protect against this possibility, the Large Load Panel recommended that the Commission require DEP 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 that for DEP 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 116. 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 117. 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 DEP 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 117-18. 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*.

The Large Load Panel testified DEP's existing ESA Application is reasonable for the most part but should be standardized and allowed to become a public pro forma application for transparency and uniformity. Tr. vol. 9, 121. The Panel added that the ESA provides contractual protections and terms, and the Schedule LL tariff formalizes protection for other customers from stranded asset costs. *Id.* at 122. The Large Load Panel recommended that the pro forma ESA Application be amended to add a Local Reliability Requirements section that requires DEP 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 124-25. The Public Staff's proposed pro forma ESA includes a financial security requirement for 60-80% of the Extra Facilities and Required Facilities cost, depending on contracted demand. *Id.* at 125-26. The Public Staff's recommended revisions to the Service Regulations includes CIAC charges and determines portions of revenue from the customer should apply to CIAC. *Id*. at 126-27. The Large Load Panel further recommended that DEP should seek Commission approval before deviating from the standard ESA terms. *Id*. at 127.

In its review of DEP's existing CIAC determination method for six large load customers, the Panel recommended DEP refine cost allocation for its system capital expenditures because investment in new generation units and transmission and distribution costs will increase as more customers connect to the system. Tr. vol. 9, 131. The Panel recommended disallowance of the costs of dedicated facilities to serve these customers, noting that the large load customers are the only customers that benefit in the present and costs should be paid by the cost causers, not general ratepayers. *Id.* at 136-37. The Public Staff stated that

> DEP has not adequately considered the scale of the costs it incurred, the timing mismatch between costs and revenues, how those costs are allocated between customer classes, and the new customer's use of the existing system. Further, DEP should have known that a more detailed

> analysis was necessary for [large load customers] to avoid inappropriately shifting costs to other ratepayers.

Tr. vol. 9, 132.

The Large Load Panel recommended that DEP 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 to allow the Commission and the Public Staff to monitor ESAs and evaluate any potential issues in a timely manner. *Id.* at 127-28. The Large Load Panel also recommended that DEP 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 DEP the flexibility it needs to serve potential customers while also ensuring Commission oversight of every large load customer ESA. *Id*. During the evidentiary hearing, the Panel added that a party could request a waiver of terms of the pro forma ESA and tariff if it had a unique circumstance. *Id.* at 147.

The Panel noted that in the DEC MYRP rate case, DEC aligned with the Public Staff on the need for a large load tariff and proposed a large load tariff in rebuttal. *Id*. at 94. The Panel testified that they agree with some aspects of DEC's proposed tariff but stated that the Public Staff's proposal offers better ratepayer protections, provides reasonable and fair terms, and is just and reasonable and should be adopted. *Id.* at 95, 115. Duke noted that many provisions in the Public Staff's proposed tariff are already present in existing ESAs of customers over 100 MW. *Id.* at 114.

During the evidentiary hearing, the Panel was asked about the methodology of allocating required facilities costs, and acknowledged there may need to be further investigation into the determination of benefits to the customer and the larger system, noting that different customers require different facilities. *Id.* at 155-57. Public Staff witness Lucas added that Duke has signed the equivalent of about three nuclear power plants of new load, which will also be served by transmission and distribution assets, and as this is unprecedented Duke Energy will have a lot of work to do to separate what costs will be for these large loads, what costs will benefit some of the customers, and what costs will not benefit other customers. *Id.* at 158. Public Staff witness Dr. Weaver noted the Public Staff provides guidance in its testimony on improving the CIAC process, but acknowledges Duke will have to develop the step-by-step specific process. *Id.* at 159.

Public Staff witness Lucas disagreed about the unfairness to a customer if its expectations or obligations changed, noting that all customers have to expect changes, and read from the Panel's Exhibit 4, Page 1, ¶ 7:

> 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 or by Order of the regulatory authority having jurisdiction.

Tr. vol. 9, 161-62.

However, the Panel was not aware of any precedent of the Commission altering the terms of an ESA. *Id.* at 163-64. The Panel did acknowledge that the Commission retains inherent authority to oversee rates and terms and regulation under its control. *Id.* at 165.

The Commission asked the Large Load Panel about how DEP's existing and proposed LGS-TOU and LGS-HLF rates reflect the cost of new large load customers. Public Staff witness Lucas stated that the LGS-HLF tariff works well with very high load factor customers, as demand charges are higher and thus customers pay more for the facilities they use. However, the Public Staff didn't think the tariffs were sufficient as customers have an option to pick and choose which serves them best financially, and the tariffs were not designed to recover the very large amount of generation and transmission required to serve them. Ultimately, witness Lucas stated, some of the tariffs are in the right direction and the Public Staff's proposal is a good thing to add on top of the rate tariffs to bring fairness to all customers. *Id.* at 169.

The Panel also added that assigning generation to an existing customer is difficult due to plant retirements, improved reliability and efficiency of new plants, and the challenge of disentangling the impact to generation from a large load when running a resource planning model. *Id.* at 170. When questioned about the process for reviewing the prudency of CIAC, the Public Staff stated that a complaint could be filed and the Public Staff would review it. *Id.* at 183-84.

Other Intervenor Direct Testimony

AGO witness Burgess testified that 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. *Id.* at 340-42. AGO witness Brant testified that DEP's existing approach and rates shift significant costs and risks onto other ratepayers and gives DEP significant discretion to negotiate terms without Commission review. *Id.* at 206. Witness Brant stated that 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 210-211. 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, then 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 214. Witness Brant testified that DEP 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 226-227.

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 220-23. 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 DEP 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 DEP to update its large load interconnection process to minimize speculative projects; and (5) require DEP to update customer programs to increase large load flexibility participation. *Id.* at 198-99. Witness Brant also proposed an incremental generation charge for large load customers, supplying examples of different frameworks used in Arizona, Florida, and Minnesota. *Id.* at 220-21, 266-76. Witness Brant stated these jurisdictions recognize that 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; consequently, many jurisdictions are altering their ratemaking practices to address incremental costs with different forms of cost allocation, including direct allocation of costs. *Id.* at 222-23.

Witness Brant testified that relying on individual ESAs without a governing tariff is insufficient because it lacks consistency, transparency, and Commission oversight. *Id.* at 228-30. Witness Brant testified "ratepayer protection should not depend on how DEP negotiates a particular agreement or on the relative bargaining power of the parties at the time of contracting." *Id.* at 229. Witness Brant recommended a new rate class for large loads, as it would "require DEP 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 235. At the evidentiary hearing, witness Brant argued for a rate class for customers over 100 MW due to the incremental infrastructure required to serve them that is greater in magnitude than that for customers of 20-100 MW. *Id*. at 265-66. Witness Brant also agreed with the Public Staff that traditional methodologies of assuming social benefits is no longer the case and it is appropriate to direct assign those transmission costs. *Id.* at 273.

CIGFUR witness Collins testified introducing a large load tariff in this proceeding would be "premature" and recommended that the Commission defer development of any tariff and rate class to a separate proceeding. Tr. vol. 9, 595-98.

EDF witnesses Lenell and Pol testified DEP should develop a holistic rate and tariff design framework for data centers over 50 MW, due to their unique operational characteristics, that includes optional demand response and ring-fencing clean energy portfolios. *Id.* at 665-66. At the evidentiary hearing, witnesses Lenell and Pol noted 50 MW is a common threshold and it captures the majority of large economic development growth. *Id.* at 754-55. Witnesses Lenell and Pol noted that DEP is projecting growth from large loads to constitute over 63% of the cumulative load growth to the year 2040 and data centers over 50MW will comprise 5.8% of DEP's winter peak and 13.7% of sales by 2030. *Id.* at 672, 678. 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 676.

EDF witnesses Lenell and Pol testified large load customers, in particular data centers, use the system differently than other customers. *Id.* at 679, 744-45. Data centers

in DEP have an average estimated load factor of approximately 90%, while manufacturing customers in DEP have an estimated load factor closer to 79%. *Id.* at 680. Witnesses Lenell and Pol testified data center customers have a unique investment cycle where they rerack facilities every three to five years, introducing different load densities with each generation of reracking. *Id.* at 744. Witnesses Lenell and Pol noted that DEP's LGS-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 and uniform load than the LGS-TOU rate schedule. *Id.* at 692. 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 684. Reflecting the unique nature of the large data center customers, witnesses Lenell and Pol also recommended DEP evaluate and introduce a new rate class. *Id.* at 690, 745-46.

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, 694-96. They recommended the Commission develop a tariff with clear and publicly available terms that uniformly apply to all subjected customers. *Id*. Witnesses Lenell and Pol presented and discussed large load tariff design elements common between and unique to several utilities, including assignment of incremental costs. *Id.* at 696-702, 749-53. Witnesses Lenell and Pol recommended the Commission require DEP to support its claims the existing framework is adequate and recommended requiring a tiered tariff framework. *Id.* at 705-707. 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 707.

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. *Id.* at 537-38. Witness Dr. Berry testified that large load customers contribute to new and existing costs, thereby reducing the amounts other customers pay. *Id*. at 538-39. Witness Dr. Berry agreed with DEP that a new rate schedule for large load customers is not immediately necessary given existing rate structures are based on cost of service but testified that 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 537. She recommended approval of DEP'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 534.

Google witness Dr. Berry noted that as of the time of the filing of her testimony, no party had filed a proposed LL Tariff. *Id.* at, 543. Anticipating that the Public Staff may file a similar proposal in the DEP proceeding as in the DEC proceedings, witness Dr. Berry provided comments related to the proposed tariffs. *Id*. at 544. Witness Dr. Berry explained that the Public Staff proposal related to curtailment is unworkable as the requirement to

curtail during non-emergency hours is inconsistent with the Environmental Protection Agency's restrictions on back-up generators. *Id.* at 545-48. Witness Dr. Berry recommended if a curtailment provision is included in the LL Tariff, the Commission adopt a proposal similar to what DEC proposed in its rate case proceeding, as it allows alternative curtailment options and it is limited to use in periods of emergency. *Id*. Witness Dr. Berry also raised several concerns related to the Public Staff's proposed Required Facilities Charge, noting that the proposal lacks sufficient direction for how to determine the charge. *Id*. at 548-51. Witness Dr. Berry noted Google is not opposed to the direct assignment of costs, such as for Dedicated Facilities, and that Google supports the Public Staff's underlying goal that there is a need to demonstrate that the costs to serve large load customers are not being shifted to other ratepayers. *Id*. at 552.

Microsoft witness Gabel-Frank testified the impact of large or growing load may increase or reduce average system costs and large load tariffs are being considered to address uncertainty and cost recovery. *Id.* at 765-68. He recommended that the Commission direct DEP to open an expedited stakeholder process to evaluate large load customer impacts and customer-driven mechanisms. *Id*. at 764, 782-83. 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 766-68. Witness Gabel-Frank reviewed the Public Staff's proposed large load tariff in the DEC rate case, and commented the proposal lacks a clear methodology to determine cost allocation, does not specify the role of curtailment to the overall framework, and does not fully address the interaction of various provisions. *Id.* at 770-78. At the evidentiary hearing, witness Gabel-Frank clarified he did not recommend a specific approach within a large load tariff and reiterated the need for an accelerated process. *Id.* at 789.

NCJC, et al. witness Wilson testified DEP'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. Tr. vol. 10, 83. Witness Wilson stated Duke's large load impact analysis does not consider variable or fuel costs, assumes no impact on existing system assets or contract demand reductions, and has a timing mismatch between costs and benefits. *Id.* at 62-67. 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 103-04. At the expert hearing, witness Wilson opined financial security mechanisms are critical to address back-end risks from a potential large decline of demand driven by a single sector, adding that an exit fee needs to be large enough to recover costs so that there are not costs shifted onto other customers. *Id.* at 136, 168-69. Witness Wilson differentiated data centers from other large loads such as military bases or automobile manufacturers, stating that large portions of data center facilities are built with a refresh cycle of approximately five years. *Id.* at 141. 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 77, 103. However, he noted that it may be appropriate to wait to establish a new class until enough customers exist so that confidential information is not revealed,

and in the meantime to set an initial rate schedule based on Schedule LGS-HLF. *Id.* at 104-06. Schedule LGS-TOU has lower demand charges and higher energy charges, and thus during the ramping period, customers under that schedule are contributing less to fixed costs than under LGS-HLF; specifying the rate schedule as LGS-HLF thus matches the rate that is appropriate to the requested service requirements. *Id.* at 166. During the evidentiary hearing, witness Wilson added that questions about legacy customers and defining eligibility for a new customer class becomes more difficult if deferred to the next rate case. *Id.* at 137-39. In terms of establishing a large load tariff aimed solely at computational loads, witness Wilson instead recommended the tariff be based on the impact to the system and noted that a high load factor requirement should exclude nearly all manufacturing. *Id.* at 148-49.

Witness Wilson recommended a 20-year contract term, noting that DEP's current 15-year minimum is insufficient because generation resources are procured for terms of 20 to 35 years. Id. at 87-88. 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, warning of the potential for low- or no-cost reductions and the impact of contract reductions of large loads over 1 GW. *Id.* at 92-99. For the new large load class, witness Wilson recommended setting two thresholds, one for loads above 25 MW with load factors over 85%, and another for all loads over 100 MW. *Id.* at 104-05.

Witness Wilson stated that 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 DEP'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 92. At the evidentiary hearing, witness Wilson testified that large loads should be responsible for the generation costs to meet their load plus the planning reserve margin, as well as responsible for both long-term transmission network upgrade costs and the costs of construction to manage the stress on the system while the network upgrades are occurring. *Id.* at 130-33.

DEP Rebuttal Testimony

DEP witness Duff testified regarding the unprecedented large load growth driven by data centers and advanced manufacturing in DEP's service territory. Tr. vol. 7, 678. Witness Duff explained 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. *Id.* at 679. DEP witness Duff testified that DEP decided to file a LL Tariff in its rebuttal testimony after reviewing intervenor testimony, including the Public Staff's proposed Schedule LL, and noting that there was broad agreement that a tariff structure would "enhance regulatory clarity and stakeholder confidence." *Id.* at 688.

Witness Duff further testified that DEP 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 689. 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 682-83. DEP witness Duff testified that DEP incorporated temporary curtailment provisions in its ESAs for customers above 100 MW in early 2025, and these provisions are currently structured as a five-year commitment that could be reduced at DEP's discretion based on resource planning considerations. *Id*. at 683-84. Witness Duff noted that DEP's proposal provided that large load customers should be able to petition the Commission for an exemption from, or modification to, curtailment requirements because of the dissimilar operational risks presented by these customers. *Id*. at 685. DEP is also continuing to explore alternative curtailment and other load flexibility options. *Id*. at 684.

Witness Duff emphasized that for customers that have already signed ESAs, DEP 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 693-94. 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*.

DEP witnesses Byrd and Beveridge presented DEP'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. 10, 244; 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. 10, 243. DEP witnesses Byrd and Beveridge stated the LLT is not a standalone tariff with distinct demand and energy charges but rather requires service under LGS-TOU or LGS-HLF. *Id*. at 244. Those tariffs include demand and energy charges designed to recover the full cost of service for larger customers. *Id*. DEP is open to a separate rate schedule or class in the future but stated that establishing one at this time would be premature because large loads have not been studied within a COSS. *Id*. DEP's LLT adds incremental performance and credit protections to reflect the unique risks applicable to serving large load customers. *Id*. at 245.

DEP'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 100 MW; (b) minimum billing demand equal to 75% of contract demand based on the ESA load ramp; (c) termination damages equal to 15% 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) mandatory curtailment provisions for the first five years of service, and (g) contract termination notice provisions with automatic contract annual contract extensions and one penalty-free contract reduction. *Id*. at 245-46. While DEP recommends the Commission approve the LLT in this proceeding, DEP proposes the LLT serve as a model framework if the Commission were to order a separate docket. *Id*. at 255. At the evidentiary hearing, DEP witness Byrd explained that DEP's tariff has a lower termination damage percentage than the DEC tariff because of the historic differences of fixed cost recovery through demand charges. *Id.* at 302.

While DEP's proposed LLT incorporates many of the Public Staff's proposed Schedule LL, such as tiered performance measures based on project size, minimum billing demand at 75% of contract demand, mandatory curtailment rights, and security requirements, DEP asserted its proposal is more balanced. *Id.* at 248. DEP witnesses Byrd and Beveridge opposed the eligibility criteria of the Public Staff's proposed LL Tariff arguing that "[r]etroactively altering those terms would undermine the regulatory certainty that is essential to attracting and retaining economic development interest in North Carolina." *Id.* at 255. Witnesses further noted DEP's liquidated damage payments for early termination are smaller than those proposed by the Public Staff, which require payment of all remaining minimum bills, because the assets liquidated damages are seeking to cover will retain value after the customer terminates. *Id.* at 249, 252. Witnesses Byrd and Beveridge argued that the Public Staff proposal results in large load customers paying both embedded and incremental costs because large load customers would be paying 100% of transmission and distribution system facilities costs to serve their load. *Id. at* 248. In response to the Public Staff's recommendation to modify DEP's CIAC analysis for allocating costs to large load customers, witnesses Byrd and Beveridge asserted the Public Staff provided little to no direction on how DEP is to implement the analysis. *Id.* at 256.

Witnesses Byrd and Beveridge testified the Commission should reject certain large load proposals that directly assign incremental generation costs to large load customers, imposing additional termination damages, or lengthen the contract terms. *Id.* at 250-53. They testified that DEP 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*. In addition, Duke'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*. 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 DEP'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 DEP time to adjust its resource plan. *Id*. At the evidentiary hearing, witnesses Byrd and Beveridge stated that termination damages provide cash and a chance to adjust the resource plan so the gas plant can be used for other customers, and account for plant retirements, the reserve margin, and normal growth. *Id.* at 322-23. 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*. at 252. Finally, witnesses Byrd and Beveridge noted that in its next rate case, DEP will 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 253-54.

In her rebuttal testimony, DEP witness Hager testified that creating a separate rate class for large load customers would have limited impact to other customer classes. Tr. vol. 8, 164. Further, NCJC, et al. witness Wilson stated "DEP does not have much or any historical test year data for large load customers on which to design rates." Tr. vol. 8, 164; tr. vol. 10, 105. Witness Hager testified the present COSS approach allocates costs to the various customer classes across the DEP system in a reasonable manner, consistent with methodologies and principles of cost causation which are vetted and reassessed in each rate case, and concluded the current approach is appropriate and leads to a just and reasonable outcome. Tr. vol. 8, 164.

At the expert witness hearing, DEP witness Hager stated that for a COSS determining customer classes depends at least in part on grouping similarly situated customers. *Id.* at 172-73. Witness Hager added a COSS is very involved and time-consuming and takes a substantial amount of data to gather and analyze. *Id.* at 182-88. If a new large load class was created, witness Hager testified, residential rates would be unaffected and the main class impacted is the one from which the new class is pulled. *Id.* at 189-90.

Stipulations and Settlement Testimony

The Comprehensive Settlement at ¶ 41, provides that the Stipulating Parties, including DEP; the Public Staff; CIGFUR II and III; Walmart; NCSEA; CUCA; DoD/FEA; and EDF, 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 Duke Energy-led stakeholder process, wherein Duke submits summary of stakeholder feedback; all parties file comments, including comments on Public Staff and DEP's proposed tariffs and, if desired, alternative large load tariff proposals; and all parties file reply comments. Comp. Settl. § II.41.a.-d.

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 DEP (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 appreciates the parties' willingness to participate in a stakeholder process per the Comprehensive Settlement and encouraged them to do so on a voluntary basis, it indicated that it does not believe it is necessary to order the parties to do so.

Public Staff's Proposed Tariff

The Public Staff continued to support its proposed large load tariff. Public Staff Initial Comments at 6. EDF stated 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 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, Duke argued the Public Staff provided no methodology for cost allocation of system assets and provided no analysis showing 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 the Public Staff's curtailment provisions now more closely match Duke's proposed provisions, they remain concerned 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 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 the Public Staff's customer-specific revenue calculation could be challenging to implement and easily gamed by Duke and large load customers. *Id.* at 3.

Amazon supported certain aspects of proposals put forth by the Commission, Duke, and the Public Staff. 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 contended 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 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

Duke stated embedded cost of service methodology should remain the primary basis for allocating revenue requirements to customer classes along 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 prior notice. *Id.* at 20-21.

Duke continued to support its proposed tariff in its Initial Reply Comments, stating 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. Duke Initial Comments 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 proposal where its tariff overlay applied only to agreements signed on or after January 1, 2027. CUCA Initial Comments at 11. Digital Realty argued 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. *Id.* 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 that the 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 financeability 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 that 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 Transition 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 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. Public Staff Initial Comments 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 when costs are incurred to 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 that 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. Amazon Initial Comments 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 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 Initial Comments at 2-3. CIGFUR 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 that generation costs should be subject to an 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 that the tariff proposed by the Commission substantially departs from existing rate and contractual frameworks, and before making that change, the Commission should have a fully developed 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 that the Commission's proposal is a much closer construct to an exemplary version of a data center tariff in that it 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 reflect 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 that LLTs 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 that 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, to 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, and noted it could support an independent third-party as long as costs are not prohibitive. Walmart Initial Comments at 8-9. 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 that they are 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 zero manufacturing customers currently served on DEP Schedule LGS-HLF. *Id.* at 32.

The Public Staff proposed a tariff overlay in the DEC and DEP proceedings since 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 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 that "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 that 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 that cost allocation is determined at the tariff level, and thus a distinct tariff 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, CUCA, DoD/FEA (DEP ONLY), Digital Realty, Google, and Microsoft all supported a tariff overlay. Andale and Amazon noted that 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, stating that 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 that 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 that 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. CIGUR agreed that there is a lack of evidence to support the creation of a new rate class, reiterating that DEP and DEC have existing tariffs for large load customers, and that the tariff overlay allows a customer to select the most appropriate rate schedule for their needs. CIGFUR Initial Comments at 4-5. Digital Realty stated that Duke' existing large load rate and contractual framework adequately compensates Duke for the costs to serve the large load customers and protects other customers against risks. Digital Realty initial comments at 3. Digital Realty suggested that a separate proceeding is necessary to determine cost allocation questions and to retain existing rate schedules. *Id*. at 7-8. DoD/FEA stated it was premature to establish qualifying data-center load as a separate rate class and recommended examining the issue in the next general rate case. DoD/FEA Initial Comments at 7-8. Google also supported the tariff overlay structure, noting that Duke's witness testified that DEC's current rate schedules reflect the costs of service for large load customers, and stated that no party presented evidence based on cost of service to support a specific rate class. Google Initial Comments at 7. Microsoft argued that rate classes should be defined by the classes' 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 was not in favor of 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 pointed out that as termination damages are tied to rate schedules, allowing customers to select rate schedules creates a strong incentive for customers to select rate schedules with lower demand charges and thus lower minimum bills for termination damages. *Id.* at 4-5. EDF also recommended that qualifying data center customers be established as a new and separate class. *Id.* at 27. Another recommendation from EDF was for 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, but if a tariff was adopted applicable to large loads, the Commission should exempt existing manufacturing and industrial customers. Nucor Initial Comments at 3.

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, selecting that which results in the lowest bill, 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 that "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 that 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 that 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 that 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 stated 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. They explained that under the distribution line extension policy, interconnecting customers are given credit for their future revenue when determining the appropriate amount of CIAC payments, and they argued that no party has articulated why transmission-interconnecting customers should not receive the same treatment and what policy or cost-based reasons drive the differential treatment of transmission interconnection costs. *Id.* at 14. Duke argued that diverging from long-standing cost allocation principles based on cost causation could have unintended consequences, that it fails to recognize that no customer is ever served by a single asset but instead served by the entire system, and that it fails to recognize that use of the system changes over time. *Id.* at 15. They also assert that there is no definitive evidence that 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 that the cost of Dedicated Facilities, as well as the allocable share of the cost of Required Facilities, could be recovered via 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 argued that 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 customer's bill payments. *Id.* The Public Staff pointed out that 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 via 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 that 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 that large loads should be financially responsible for "but for" costs and that these costs should be recovered via 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 that 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 that 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 that 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 that 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 reduced termination charge, notification period, and financial security requirements. Amazon Initial Comments at 23; Andale Initial Comments at 13.

CCEBA, CEBA, and Nucor did not provide comments on direct assignment of "but for" costs.

CIGFUR 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 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 at 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.* at 46. 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 an 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. states 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 50 MW 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." Amazon Initial Comments 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. Amazon Initial Comments 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. Amazon Initial Comments 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 recommended setting eligibility thresholds for all loads over 150MW and load factors over 80%, so that extremely large load customers would be appropriately captured. CIGFUR Initial Comments at 6. CIGFUR 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 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 as not all requirements of the tariff may be appropriate for all new large load customers. *Id.* However, CIGFUR 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 100 MW 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.

DoD/FEA supported effective protections for large loads, but also wanted to ensure that any future qualifying federal facility can obtain electric service without unnecessary delays and any tariffs recognize that stranded asset risks are materially different with longstanding federal load. DoD/FEA Initial Comments at 4. DoD/FEA recommended any new large-load tariff apply prospectively only to new qualifying data-center load of 50 MW or greater, with existing customers and load expressly grandfathered. *Id*. at 6. Additionally, DoD/FEA stated that renewals, extensions, replacement, or routine amendments "of existing ESAs should not, by itself, cause an established customer to become subject to the new tariff, and incremental load should trigger the tariff only where that incremental load independently satisfies the applicable size and qualifying data-center criteria." *Id*. at 6-7. The tariff should precisely define how demand and load factor is measured and be calculated on an annual basis, as well as consider aggregation and later operational changes that could result in changes to applicability under the tariff. *Id*. at 14-16. Finally, DoD/FEA recommended that objective and administrable eligibility and aggregation standards be adopted, with an explicit permission for narrowly tailored alternative contractual mechanisms for federal agencies where necessary to comply with federal law. *Id*. at 9. For example, federal customers are prohibited from obligating funds beyond what has been appropriated by Congress, and thus an alternative mechanism to provide economic protection may be more practical. *Id*. at 23.

In regard to grandfathering, DoD/FEA stated that there is a straightforward rationale supporting such a provision.

> Existing customers have operated on DEP's system under established tariffs, and their loads have already been incorporated into utility planning, infrastructure development, cost allocation, and ratemaking. The principal risks the new large-load tariffs are intended to address are materially different and principally prospective, including substantial investment undertaken in anticipation of new load, uncertainty regarding whether that

load will materialize as forecast, rapid load ramps, and potential stranded costs if the customer subsequently reduces or terminates service.

DoD/FEA Initial Comments at 19-20.

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.* at 3. 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. *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 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 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 provide 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 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 Clean Customer Tariff 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 Clean Customer Tariff and recommended a stakeholder process to develop the proposal. *Id.* at 6-7. Similarly, CCEBA, in its initial amicus curiae comments, requested that the proposed large load tariff include the possibility for a voluntary CTT 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 pointed 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, DoD/FEA, Google, and Microsoft.

In the LLT Stipulation, the 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, Ex. 1. The 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 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 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 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 DEP'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 DEP'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 9, 78-90. 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 DEP'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 DEP 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 within a timeframe of a little over two years. *Id.* at 70, 158. Data centers represent 92% of the 6.7 GW of load covered by ESAs. 2026 DEC Order at 207;

- 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. 9, 707;

- 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 685-87;

- The Public Staff's Large Load Panel noted large load additions pose risks to grid stability from sudden disconnection and DEP must also manage reconnection following a system outage. *Id.* at 70-71. The Panel also highlighted that large load customers could increase capacity and fuel costs for all other customers during periods of peak demand. *Id.* 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 67-70;

- The Public Staff's Large Load Panel's testimony highlighting the mismatch between the lifecycle and cost of DEP 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. 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 DEP currently relies on five separate mechanisms to manage large loads: existing rate tariffs (Schedules LGS, LGS-TOU, HP,LGS-HLF, and LGS-RTP); Letter Agreements; ESA Applications; Service Regulations; and the Line Extension Plan. Tr. vol. 9, 90-91. The Large Load Panel testified many of these mechanisms have been applied inconsistently, varying from customer to customer at DEP's discretion without Commission oversight. *Id.* at 90-93. The Large Load Panel also testified that it is concerned that DEP 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 93. The Large Load Panel concluded these existing mechanisms are not sufficient to protect all customers and ensure just and reasonable rates. *Id.* at 139;

- 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. *Id.* at 676-77. 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 694-96. They recommended that the Commission develop tailored rate structures for large loads, noting that DEP'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 697-704. Witnesses Lenell and Pol recommended the Commission require DEP to support its claims that the existing framework is adequate and recommended requiring a tiered tariff framework. *Id.* at 705-07; and

- NCJC, et al. witness Wilson's testimony that DEP'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. Tr. vol. 10, 69, 83-84. 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 103-06. 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 24, 105-06.

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. 9, 74. In contrast, AGO witness Brant, CIGFUR 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 14, 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 denied the petitions to intervene filed by CCEBA and Digital Realty, but granted each amicus curiae status. The Commission also granted CEBA's separate motion for amicus curiae status. By allowing these organizations to participate in the comment process, the Commission broadened the range of policy perspectives it could consider.

The Commission is persuaded by, and gives substantial weight to, the Public Staff's recommendation for DEP's existing ESA Application to become a public pro forma standardized application for transparency and uniformity, with any deviations subject to Commission approval. *Id.* at 121-28. The Commission notes that DEP confirmed that no customers are currently taking service under Rate Schedule LGS-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 DEP negotiates a particular agreement or on the relative bargaining power of the parties at the time of contracting." *Id.* at 228-30. 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. *Id.* at 694-95. 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. 10, 78-82. In addition, the Commission gives substantial weight to the testimony of witness Wilson that an ESA will still be necessary for customer-specific terms and terms that should apply to all large load customers should be within a Commission-approved tariff. *Id.* at 106. The Commission also gives some weight to the testimony of Google witness Dr. Berry a large load tariff is the appropriate mechanism for ensuring transparency and consistency but disagrees that a rate case is not the appropriate

proceeding to evaluate such a proposal. Tr. vol. 9, 537, 543. 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. *Id.* at 96. 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 DEP'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 DEP 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 DEP 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 combined cycle or small modular nuclear reactor facilities. Tr. vol. 9, 68-69. 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 DEP or by Commission Order, and this notice is written in the standard ESA language. *Id.* at 161-62.

In addition, the Commission gives significant weight to the testimony of DEP witness Hager that DEP does not have much or any historical test year data on large load customers on which to design rates. Tr. vol. 8, 164. The Commission gives some weight to the testimony of CIGFUR witness Collins that the tariff should avoid unintended consequences for existing large customers, such as interclass and intraclass subsidies between old and new customers. Tr. vol. 9,t 595, 650-651. 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 DEP, 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. *Id*. § 62-2.

DEP seems to recognize this reality, notwithstanding its contentions to the contrary. As evidenced in the record, the form ESA which 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.

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 DEP 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 LGS-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 DEP 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 DEP's new rates after issuance of this Order) that meets the threshold criteria. Tr. vol. 9, 113. 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 XL 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 DEP witness Hager that large load customers did not make up a meaningful portion of DEP's customer base in the test year. Tr. vol. 8, 164.

In addition, the Commission gives significant weight to the recommendation of AGO witness Brant to proactively establish a tariff before large loads interconnect and costs are incurred. Tr. vol. 9, 228. 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 212.

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 DEP 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 payment 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 electric service that DEP 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 DEP 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 DEP's system through three primary factors: (i) the unprecedented scale and speed at which they are seeking to interconnect to the DEP system and consume electricity; (ii) the risk of the unprecedented speed and scale at which they might leave the DEP system; and (iii) 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. For clarity, the Commission is relying upon a publication from recent white paper from the North American Electric Reliability Corporation (NERC), which regulates the reliability of the transmission grid for the definition of data centers. NERC, Large Loads Task Force, *Characteristics and Risks of Emerging Large Loads* (July 2025); 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).

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 DEP's system by data centers to be controlled in a manner that largely prevents other DEP 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 DEP's LGS-HLF rate schedule. According to EDF witnesses Lenell and Pol, DEP's LGS-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 and uniform load than the LGS-TOU rate schedule. Tr. vol. 9, 692.

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). 2026 DEC Order at 207. 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. 9, 707. 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 739. Witnesses Lenell and Pol concluded on these bases that a data center-only large load tariff is appropriate and reasonable. *Id.* at 741.

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 NERC's recent white paper, which 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 at 59.

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. 9, 690. 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. 9, 210-14. 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 217-18. 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 218-19. 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 225-27. 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., 685-87. 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. *Id.* at 73, 158-61.

Even if a data center customer remains on the DEP system for the full initial term of its contract, the Public Staff highlighted the mismatch between the lifecycle and cost of DEP 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. 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, DEP'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. 9, 68-69.

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 DEP'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 DEP'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 90%, which is significantly higher than the estimated 79% load factor for large manufacturing loads in Duke's territory. Tr. vol. 9, 680. 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 681.

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." *Id*. at 97-98. 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 DEP 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 DEP in its initial tariff overlay, as well as the varying tiered approaches proposed by AGO witness Brant, NCJC, et al. witness Wilson, and DEP in its initial tariff overlay.

The Commission gives substantial weight to the testimony of EDF witnesses Lenell and Pol that DEP should develop a holistic rate and tariff design framework for data centers over 50 MW, due to their unique operational characteristics. Tr. vol. 9, 665-66. They noted that 50 MW is a common threshold and it captures the majority of large economic development growth. *Id.* at 754-55. Witnesses Lenell and Pol explained that DEP is projecting growth from large loads to constitute over 63% of the cumulative load growth to the year 2040, and data centers over 50MW will comprise 5.8% of DEP's winter peak and 12.6% of sales by 2030. *Id*. at 672, 678. 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 676.

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 typical demand of the majority of traditional commercial and industrial customers and marks the threshold at which DEP needs to make substantial investments. The Commission agrees that balance is needed between mitigating risks and disproportionately burdening smaller customers and hampering economic development. Tr. vol. 9, 104-15.

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, *Id.* at 198, 206, 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 because they are designed for generic large loads rather than data centers in particular. The Commission acknowledges that witness Wilson stated 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 customers with high loads and s (greater than 85%) are sufficiently distinct from other large customers and should be evaluated separately. Tr. vol. 10, 104.

The Commission gives little weight to the eligibility thresholds and tiered structure proposed by DEP 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 more 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 the DC Schedule are based on Schedule LGS-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 load 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 Demand 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 requirement shall be subject to the Risk Mitigation Provisions. Any new customers that meet the threshold load requirement 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. 9, 107-09. 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 five years for all loads of 20 MW or more. *Id.* at 242-43. 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. *Id.* at 88. 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 DEP'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. *Id.* at 252-53.

The Commission gives substantial weight to the recommendation of DEP 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. *Id.* at 245. 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 ratepayers 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. 10, 259-60. The Commission is persuaded that it is appropriate and reasonable for each DC Customer to fully pay the costs of Dedicated Facilities.

DEP witness Byrd explained that if service to a customer is beyond the standard level of service, the customer is expected to contribute capital costs to those facilities. Tr. vol. 12, 39. DEP requires up-front funding for non-network upgrade costs, which are

refunded to the large load customer after the customer has met certain milestones. *Id.* at 258. 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 gives some weight to the testimony of Google witness Dr. Berry that direct assignment of sole-use Dedicated Facilities can be part of an overall cost allocation methodology and is used in numerous jurisdictions. Tr. vol. 9, 552. The Commission agrees that determining direct assignment of costs for transmission facilities and other infrastructure that benefits other customers is complex, but is not persuaded that direct assignment of Dedicated Facilities, as defined by the Public Staff, is similarly complicated.

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 DEP 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 DEP. If an ESA is terminated prior to energization, any unspent funds from the advanced funds will be retained by DEP and applied towards the liquidated damage liability owned 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 DEP 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. *Id.* at 108. 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 DEP witness Duff. *Id.* at 692.

Although CIGFUR witness Collins did not have a proposal for a large load tariff in this proceeding, in the DEC rate case (Docket No. E-7, Sub 1329) 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. Order Adopting Stipulations in Part, Granting Partial Rate Increase, Granting Accounting Order, and Requiring Public Notice, *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, Subs 1329 & 1355, at 271 (N.C.U.C. Nov. 16, 2026) (DEC 2026 Order). 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. 9, 696-97.

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 DEP's existing terms could undermine the effectiveness of minimum contract demand in protecting customers from stranded assets. Tr. vol. 10, 91-92. 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 99. 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 DEP to reflect the change in resource planning or find a similar load to match the loss, if possible. Tr. vol. 9, 109-12. 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. *Id.* at 238, 244-45. 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.

The Commission gives little weight to the recommendation of Google witness Dr. Berry to broaden the Public Staff's recalculation of termination charges to include the use of assets by any customer, as this shifts risk to other customers. *Id.* at 554.

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 93-100. The Commission gives this recommendation some weight but is not persuaded that customers should be assessed larger minimum charges after reducing their contracted demand.

The Commission gives significant weight to the early termination provision recommended by DEP 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 significant weight to DEP'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 it is reasonably to require a customer to notify DEP 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 DEP, 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. 9, 109-10. 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. *Id.* at 241. 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 DEP'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 93-100. 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.

DEP 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. DEP also allows one penalty-free reduction of up to 20% after seven years of service with 12 months' notice. *Id.* at 244-47. 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 warned that the absence of reasonable curtailment measures for large load customers could increase loss of load risk for other ratepayers. The Public Staff therefore recommended including mandatory curtailment provisions as a tool for system operators to maintain reliability during certain situations, specifically identifying two potential choices, either 95% curtailment of contracted demand for 50 hours per year or 50% of contracted demand for 100 hours per year. These choices align with the temporary provisions in proforma ESAs, limited to five years. Tr. vol. 9, 110. The Commission gives significant weight to the Public Staff's recommendation regarding the need for curtailment.

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. *Id.* at 241-42. Witness Brant also recommended that DEP develop a tariff option or rider to compensate very large load customers for committing to defined levels of dispatchable load reduction. *Id*. at 262. 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.

Regarding the curtailment provisions in the large load tariff proposed in the DEC rate case, Google witness Dr. Berry recommended DEC's curtailment provision if it is applied during emergency hours because the provision can be modified to fit a customer's ability to respond and includes an alternative option to accelerate capacity resources. *Id.* at 548. The Commission gives this recommendation significant 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 DEP 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: (1) curtailment of 95% of contract load for up to 50 hours per year for the load ramp period plus one year of service, (2) curtailment of 50% of contract load for up to 100 hours per year for the load ramp period plus one year of service, or (3) 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

DEP witness Byrd testified that the Company did not propose a specific rate schedule for large load customers because the current rate schedules LGS-TOU and LGS-HLF "provide appropriate tariff options for large load and high load factor customers

that already align prices with cost-of-service." Tr. vol. 10, 194. As a result, witness Byrd explained, new tariffs designed specifically for "large loads'" would "most likely be designed similar to Schedule LGS-HLF, rendering such new tariffs duplicative and unnecessary." *Id*. Witness Byrd also noted that Schedule LGS-HLF provides for significant fixed cost recovery through demand charges. *Id.* The Commission gives significant weight to the testimony of DEP witness Byrd that Schedule LGS-HLF is designed for very large high load factor customers.

The Public Staff stated that large load customers may currently take rates under five rate schedules, Tr. vol. 9, 90-91, though one has been closed to new participants since April 2023. Tr. vol. 10, 224. The Public Staff's proposed Schedule LL allowed customers under the tariff to elect service under the four available rate schedules. Public Staff Large Load Panel Ex. 3. The Public Staff noted that in their review of the ESAs in DEP's North Carolina territory, none of those customers plan to take service under LGS-HLF. *Id*. at 92, 103. The Commission gives significant weight to the Public Staff's acknowledgement that DEP's LGS-HLF rate schedule works well for very high load factor customers, as that rate schedule has higher demand charges and thus the customers under that rate schedule pay more for the facilities they use, and if a customer has the option of different rate schedules, the customer will choose the rate schedule under which it pays the least or is more operationally advantageous. *Id*. at 92, 169.

The Commission gives some weight to the concerns raised by AGO witness Brant regarding the adequacy of DEP's existing LGS-TOU and LGS-HLF tariffs. *Id.* at 225. 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 the legacy rates have differences in impact to system planning and safeguards though standard tariff characteristics. *Id.* at 734. The Commission also gives significant weight to the testimony of witnesses Lenell and Pol that the LGS-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 and uniform load than the LGS-TOU rate schedule.

The Commission also gives significant weight to the recommendation of witness Wilson to set an initial rate schedule based on Schedule LGS-HLF, as he notes this would be relatively simple and avoids the need to re-evaluate DEP's rate designs. Tr. vol. 10, 105. The Commission is also persuaded that customers selecting Schedule LGS-TOU, with its lower demand charges and higher energy charges, are contributing significantly less to system fixed costs than the customers would be under LGS-HLF, and agrees with witness Wilson that it is appropriate to put relevant customers on a rate that reflects the costs of providing service to them, which for this proceeding would be Schedule LGS-HLF.

In rebuttal, DEP proposed Schedule LLT, which does not include a separate rate class but requires customers to take service on Schedule LGS-TOU or Schedule

LGS-HLF. *Id.* at 244-45. DEP also offered in rebuttal that in the next rate case, DEP can evaluate rates that reflect large load customers once enough are taking service to develop meaningful results. *Id.*

The Commission finds that Schedule LGS-HLF provides more appropriate price signals and reflection of the cost of service for large load customers with very high load factors than Schedule LGS-TOU. The Commission also notes that Schedule LGS-HLF recovers greater fixed costs through demand charges than other LGS schedules, which recover fixed costs through energy charges, and thus minimum bills based on Schedule LGS-HLF recover a greater portion of the infrastructure needed to serve DC Customers. Based on the evidentiary record, the Commission concludes that the DC Schedule includes the appropriate rate schedule, based on Schedule LGS-HLF, for electric service DC Customers.

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 DEP witness Hager's testimony that there is insufficient test-year data to support the establishment of a separate customer class. Tr. vol 8,163-64. 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.* at 164-65. In rebuttal, DEP proposed Schedule LLT, which does not include a separate rate class but requires customers to take service on Schedule LGS-TOU or Schedule LGS-HLF. Tr. vol 10, 241-46. DEP stated in rebuttal that it is open to the potential for a separate rate schedule or class in the future but maintained that establishing such a rate schedule or class at this time would be premature, because large load have not been yet studied within a COSS. *Id.* at 244-45.

The Commission gives significant weight to the Public Staff's acknowledgement in the DEC Rate Case that 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. DEC 2026 Order at 268.

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. 10, 104, 127. The Commission also agrees with witness Wilson that defining a class later presents questions and ambiguity concerning legacy customers and determining the characteristics of that class. *Id.* at 138-39.

In sum, the evidence in this proceeding, particularly the testimony of DEP 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, DEP 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 DEP 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 DEP 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 DEP 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 DEP'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 DEP'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 DEP 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 DEP 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 DEP 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 DEP'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 DEP'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 date 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:

> Some risk of stranded assets has always existed within the system, but the scale of the risk presented by 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 for stranded assets in the event load does not materialize or is not sustained as expected. Absent strong protections that ensure that those customers causing large, expedited investment are ultimately responsible for paying for that investment, a significant risk exists that the remaining customer base will be forced to bear those costs.

Tr. vol. 9, 69.

In response to the Commission's August 14, 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 DEP 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 DEP 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 DEP 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 DEP needs to serve DC Customers' demand and because Duke's operating companies, including DEP, 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, DEP referenced a Large Load Impact Analysis (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. 10, 263. Duke itself assumed in the 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 DEP 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 DEP 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 DEP 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 a DC Customer with a 500 MW Billing Demand executes an electric service agreement with DEP 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 DEP 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 NERC for managing incidental sudden disconnection and reconnection of load to avoid grid disturbances.[CITE] 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 to this proceeding 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* Partial Proposed Order of Microsoft Corp. at 3 (Oct. 1, 2026). 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. 9, 72. 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 No. 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. 9, 208-09.

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.

DEC 2026 Order at 283-84.

CIGFUR 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*. The Commission agrees with CIGFUR 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 9, 96. The Commission further notes that participants in the Task Force included representatives of several intervening parties in this docket, including Duke, Google, Amazon Web Services, EDF, NCSEA, and the Public Staff[11].

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 COSS Stipulation, the DLEP 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 proposed by DEP in this case, which are based on the 2024 Depreciation Study as originally proposed, updated 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 DEP or Public Staff — shall be, and are hereby approved;

3. That DEP's depreciation consultant shall apply the agreed-upon assumptions in his model to develop the final depreciation rates to be implemented by

[11] *See* https://governor.nc.gov/documents/files/nc-energy-policy-task-force-2026-report/open.

DEP, and DEP shall file the final depreciation rates, together with supporting workpapers, as part of its compliance filing for review by the Public Staff;

4. That DEP's request for an accounting order for approval to defer to a regulatory asset 100% of the impact of accelerating the depreciation of DEP's subcritical coal plants based on the 2021 Depreciation Study, as permitted by S.L. 2025-78, for an annual deferral of $63.527 million on a North Carolina retail basis, preserving DEP's ability to recover 100% of the net book value of the subcritical plants through securitization, shall be, and is hereby approved;

5. That DEP's plant-related capital investments in the base period general/intangible, transmission, distribution, fossil/hydro, nuclear, solar, and storage assets, as adjusted in the Comprehensive Settlement, shall be included in rates for the base period;

6. That DEP's requests to amortize costs associated with its CCR obligations incurred from April 1, 2023, through March 31, 2026, net of the over-amortization of tranche 2 of deferred environmental costs established in Docket No. E-2, Sub 1219, 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;

7. That the Commission authorizes the continuation of the CCR deferral in accordance with the CCR Settlement;

8. That, consistent with Section III.F of the CCR Settlement, the return on the unamortized balance of deferred CCR costs during the amortization period shall be calculated using DEP's embedded cost of debt approved in this Order, adjusted as appropriate to reflect the deductibility of interest expense, a return on equity 150 basis points below the return on equity approved in this Order, and a capital structure of 48% debt and 52% equity;

9. That the agreed-upon accounting adjustments outlined in the Comprehensive Settlement shall be, and are hereby, approved;

10. That DEP's rates during the MYRP Rate Period shall reflect a rate of return on equity of 9.80%, an embedded cost of debt of 4.23%, and a capital structure consisting of 53% common equity and 47% long-term, for a rate of return of 7.18%;

11. That DEP shall recover the balance of the bad debt deferral, including actual deferral amounts from April 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 DEP 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; if the actual deferral for that period is less than $12 million, DEP shall defer the difference as a regulatory liability to be returned to customers in its next general rate case, and if the actual deferral equals or exceeds $12 million, DEP shall not collect any additional amount for that period from customers in its next general rate case;

14. That DEP is allowed to collect in rates its North Carolina retail normalized annual level of storm costs in the amount of approximately $23.822 million;

15. That DEP shall amortize over two years the net regulatory liability of approximately $1.021 million for servicing and administration fee overcollections related to the 2020 Storm Securitization and the net regulatory asset of approximately $151,000 for under-recovered upfront bond issuance costs related to the 2024 Storm Securitization;

16. That the Hurricane Helene over-securitization amount, netted against the Winter Storm Fern incremental storm costs, resulting in a $12.070 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 Winter Storm Fern incremental costs shall be 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 DEP's next general rate case;

19. That DEP shall use the traditional method for calculating the incremental storm O&M costs for 2026 through DEP's next general rate case;

20. That DEP's request for authority to defer incremental costs of storms occurring in 2026 after Winter Storm Fern is denied, without prejudice to DEP's ability to request deferral accounting treatment for a specific storm after it occurs;

21. That the return accrued during the deferral period for the COVID bad debt, CCR, and Hurricane Helene (post-securitization bond issuance) deferrals shall be compounded annually;

22. That DEP shall use annual compounding when accruing a return, if applicable, for deferrals (both regulatory assets and liabilities) and riders through DEP's next two general rate cases, which may be achieved either by (a) applying monthly compounding at a discounted rate to achieve the effect of annual compounding, or (b) applying annual compounding at the annual rate;

23. That DEP's motion to consolidate its request for an accounting order relating to L2 public charging infrastructure in Docket No. E-2, Sub 1405 with this docket is granted;

24. That the Commission authorizes DEP 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 DEP's request to recover the deferred revenue requirement impacts, including benefits and costs, associated with the IRA and IIJA, over a two-year amortization period;

26. That the Commission authorizes DEP'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 DEP obtains a grant, DEP 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 an approved MYRP2 project, the Commission authorizes DEP's request to 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 DEP's accounting for the DOE grant for the Roxboro Coal Reliability Initiative shall be governed by Section II.47 of the Comprehensive Settlement, and DEP shall not defer any shortfall in that funding;

28. That DEP shall include the terms of any DOE loans it obtains in the calculation of its embedded cost of debt in its next general rate case application, or shall work with the Public Staff to ensure that the benefits of any such DOE loans, net of any incremental costs to obtain or comply with the loans, are credited to customers;

29. That DEP's Lead-Lag Study filed as Speros Direct Exhibit 2 shall be, and is hereby, approved for purposes of calculating the cash working capital amounts to be included in DEP's rates;

30. That DEP 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;

31. That the Commission finds DEP's quality of service to be adequate;

32. That the shareholder financial contribution, detailed in the Comprehensive Settlement shall be, and is hereby approved;

33. That the revisions to rate schedules, as proposed by DEP or as modified by the revenue adjustments set forth in the Comprehensive Settlement or otherwise modified herein shall be, and are hereby approved;

34. That the revisions to the service riders, as proposed by DEP or otherwise specifically modified herein, shall be, and are hereby approved;

35. That the Basic Customer Charges, as set forth in the direct testimony of DEP witness Byrd, shall be, and are hereby approved;

36. That Rider RECD shall be closed to new residential customers effective January 1, 2027;

37. That the Rider RECD discount shall be reduced from 5% to 2.5% beginning January 1, 2028, and Rider RECD will close on March 31, 2029;

38. That the NMB, RSC, and NSC riders shall be modified as proposed by Public Staff;

39. That DEP shall establish a DCFC Pilot in accordance with the DCFC Stipulation;

40. That DEP shall, as part of its next general rate case, report on the recommendations of the Public Staff to investigate and report on whether Schedule RES should continue to include both seasonal and an 800 kWh threshold for winter months and whether there is a need for a rate schedule like DEC's OPT-V rate tariff option for legacy DEP customers;

41. That DEP's proposed MYRP, reflecting the projected costs associated with the Transmission, Distribution, Grid Planning & Integration, Fossil/Hydro, Nuclear, Solar, and Storage as adjusted by the Comprehensive Settlement, as reflected in Abernathy Comprehensive Settlement Exhibits 1 and 2, is just and reasonable and adopted in its entirety;

42. That within 180 days of the issuance of this order, DEP shall file the Cost-Benefit Report;

43. That DEP's proposed RDM, as modified by the Comprehensive Settlement, is consistent with N.C.G.S. § 62-133.16 and Commission Rule R1-17B and is hereby approved;

44. That DEP's proposed ESM, as modified by the Comprehensive Settlement, is consistent with N.C.G.S. § 62-133.16 and Commission Rule R1-17B and is hereby approved;

45. That DEP's proposed PIMs, as modified by the PIMs Settlement, are consistent with N.C.G.S. § 62-133.16 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 DEP 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 DEP fuel rider, or in the pending DEP fuel rider case for rates effective December 1, 2026;

47. That DEP will meet with the Stipulating Parties to discuss the appropriate calculation of interest under N.C.G.S.§ 62-133.2;

48. DEP shall adhere to the reporting obligations outlined in Sections II and III of the Comprehensive Settlement;

49. That DEP shall implement the MYRP Refund Mechanism and Rider; as set forth in Section II.43 and Exhibit 1 of the Comprehensive Settlement, and shall file the MYRP Refund Rider annually in conjunction with its annual PBR riders;

50. That DEP shall establish the PTC Rider as proposed by DEP and modified by the Comprehensive Settlement;

51. That as part of DEP's compliance filing, DEP shall submit an updated Sykes Exhibit 1 calculating the PTC Rider rate as modified by the Comprehensive Settlement;

52. That DEP shall implement a Rider RAL-3 to refund to customers over a two-year period the net over-amortization of expired regulatory assets and liabilities;

53. That DEP shall establish a BPM Rider as proposed by DEP, provided that DEP shows in each rider filing that the BPM Rider is net cost effective for DEP to implement and maintain;

54. That DEP shall move recovery of the prospective costs previously included in the JAAR, including the continued levelization of the applicable acquisition costs, into base rates effective January 1, 2027. DEP shall file revised JAAR rider compliance tariffs in Docket No. E-2, Sub 1397 removing the prospective component from the JAAR rates, effective for service rendered on and after January 1, 2027. The Joint Agency Asset rolling recovery factor approved in Docket No. E-2, Sub 1397 shall remain in effect through November 30, 2027. DEP shall continue to file annual JAAR rider proceedings pursuant to N.C.G.S. § 62-133.14 and Commission Rule R8-70 to true up any over- or under-recovery of JAAR costs incurred through December 31, 2026, and the JAAR shall terminate once all remaining over- or under-recovery balances have been resolved;

55. That, consistent with Section II.22 of the Comprehensive Settlement, DEP shall withdraw its pending appeal related to the 2025 JAAR Rider proceeding, Docket No. E-2, Sub 1354, and shall file a copy of its notice of withdrawal in Docket No. E-2, Sub 1354 within 30 days of the issuance of this Order;

56. That, within ten days of the issuance of this Order, DEP shall recalculate its base rate revenue requirement and its revenue requirements for Rate Years 1 and 2 consistent with this Order, working with the Public Staff to verify the accuracy of the calculations, and shall file the final revenue requirements in Excel format with detailed footnotes and supporting documentation, in the same format as Jiggetts Comprehensive Settlement Exhibit 1, reflecting any corrections identified by DEP and agreed upon by the Public Staff;

57. That, within 30 days of this Order, DEP 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;

58. That as part of DEP's compliance filing, DEP shall submit the final list of MYRP2 projects approved in this Order;

59. That as part of DEP's compliance filing, DEP shall submit updated RDM and ESM templates reflecting the terms of the Comprehensive Settlement;

60. That DEP 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. DEP 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;

61. That DEP shall file its annual COSS for 2026 no later than May 31, 2027, to align with the timing of DEC's annual cost of service filing;

62. That the Chief Clerk is directed to close Docket No. E-2, Sub 1405;

63. That the DC Schedule is hereby approved and adopted, effective upon the issuance of this Order, except that any Monthly Rate modifications, including any Transformation Discount modifications, and Rider modifications otherwise applicable to the proposed Schedule LGS-HLF implemented pursuant to this Order, shall also be incorporated into the DC Schedule;

64. That DEP 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;

65. That DEP shall propose within 90 days of this Order a modification to DEP's economic development riders to allow service on the DC Schedule, maintaining proportionate impacts across rate schedules;

66. That DEP 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;

67. That the interim standard ESA attached to this Order as Appendix B is hereby approved and adopted, effective with the issuance of this Order;

68. 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;

69. 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 DEP 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;

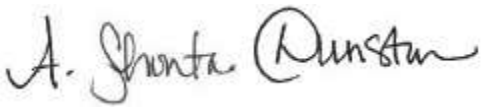
70. That DEP shall treat DC Customers as a class for reporting purposes and track the revenues and costs of DC Customers following the issuance of this Order; and

71. That DEP shall provide a 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



A. Shonta Dunston, Chief Clerk

Commissioner Donald R. van der Vaart, dissenting in part and concurring in part.

Commissioner Floyd B. McKissick, Jr. and John Gajda, concurring.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1380
DOCKET NO. E-2, SUB 1405

Commissioner Donald R. van der Vaart, concurring in part and dissenting in part:

This Order sets the rules for how North Carolina will pay for what may be the largest build-out of power plants in the State's history. I join the majority in a number of respects. But on the most important question those rules must answer—who pays if the customers who caused that build-out leave—I cannot agree with the majority's answer. Nor can I agree with the 9.80 percent return on equity the majority approves, which does not reflect the risk this Order shifts from Duke to its customers.

The data center tariff should not obscure the rate increase this Order approves for every DEP customer. The Order raises DEP's base rates by $317.6 million, with further increases under the multiyear rate plan, bringing the cumulative increase to approximately $337.5 million by the second rate year even after rider adjustments.[12] The first-year impact appears modest largely because of a two-year credit for production tax credits that ends in 2028.[13] The reduction from DEP's original request also looks larger than the permanent savings. Some items reduce the current revenue requirement by moving costs to later years or later proceedings rather than eliminating them.[14] Customers should not mistake a lower bill today for a cost that has disappeared. The increase should be smaller still. A return on equity set at the level the evidence supports would reduce it by tens of millions of dollars a year, for the reasons I explain in Part VII.

I. What Is at Stake

In a little over two years, Duke has signed contracts for about 6.7 gigawatts of new load across its Carolinas systems, nearly all of it data centers. The Public Staff also

[12] Jiggetts Comprehensive Settlement Exhibit 2, p. 5.

[13] Comprehensive Settlement ¶ 20(a) (increasing the production tax credit flowed back to customers for 2027 and 2028 to $120 million per year).

[14] See Part VII, infra.

reports approximately 7.9 gigawatts of potential large load in advanced development.[15] For perspective, the peak demand of the entire City of Raleigh is about 2 gigawatts.[16] The signed data center load alone is more than three times that.

The Duke-wide pipeline illustrates the scale of the capital at stake. Using the Commission's own cost estimate for a new natural gas plant, plus the extra capacity utilities must keep in reserve, generation needed to serve 6.7 gigawatts would cost roughly $18 to $19 billion.[17] This is an order-of-magnitude illustration of Duke-wide generation investment, not a forecast of the amount attributable to DEP's North Carolina customers. It also excludes transmission, financing during construction, fuel, and operating costs.

Those plants are built to last about 35 years. The data centers' contracts run for 15. The mismatch is like financing a house over 35 years for a tenant who promises to stay only 15. The question this Order must answer is who pays the remaining balance when the tenant leaves.

II. What the Majority Orders

Under the majority's approach, Duke finances the power plants, places the investment in rate base, and earns its authorized return through rates for as long as that investment remains in rate base.

While a data center remains on the system, it pays monthly bills that contribute toward those costs, including a minimum bill whether or not it uses all the power it reserved. It pays up front only for facilities dedicated to it alone, such as its own substation. For transmission network upgrades, it posts a bank letter of credit and later pays only the portion assigned directly to it as a contribution in aid of construction.

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[15] DEP Tr. vol. 9 at 70, 158 (Public Staff Large Load Panel).

[16] Id. at 71.

[17] 6,700 MW × $2,357/kW (the Anderson County combined cycle proxy the majority adopts) = approximately $15.8 billion. Duke plans peaking capacity for a 22 percent reserve margin on large load demand, DEP Tr. vol. 9 at 88 (Public Staff Large Load Panel); 22 percent of 6,700 MW (1,474 MW) at $1,708/kW (Rowan County CT, Docket No. E-7, Sub 1330) to $2,433/kW (Smith CT, Docket No. E-2, Sub 1395) adds approximately $2.5 to $3.6 billion. These are construction costs only; they exclude financing during construction, operating costs, fuel, and transmission, and therefore understate the total.

The data center must also post Security—cash, a bank letter of credit, or a qualifying parent guarantee—for certain amounts that may become due if it leaves. When service ends, it owes a "Stranded Generation Charge," which the majority describes as protection against the power plant costs left behind.

In short, the majority's approach rests on a hope: that the data center will stay for the life of the plants built to serve it, or, if it leaves, that it will be able to pay what the Order requires when it goes. I recognize that the majority has done far more than the Agreement and Stipulation of Settlement on Large Load Tariff (LLT Stipulation) proposed, and in several respects I join it. The LLT Stipulation, entered into by Duke and the data center companies and joined by the Public Staff, among others, would have required a departing data center to pay nothing at all for the power plants it left behind at the end of its contract.[18] But even if the majority's hope is fully realized, the remaining ratepayers will still be left paying much of the bill.

III. Why I Cannot Agree

The exit charge pays only about half of the remaining investment. Return to the mortgage. When a tenant leaves with 20 years left, paying off the remaining balance retires the debt. The majority's formula does something different. It takes the remaining annual depreciation of the plant and discounts those future depreciation amounts back to the date of departure. It does not include the authorized return Duke will continue to earn on the portion of the investment that remains in rate base. In the majority's own example, a 500-megawatt data center leaves after 15 years with about $674 million of generation investment still on the books, but pays only about $338 million.[19] The other $335.4 million remains in rate base. The remaining ratepayers must then pay that balance, plus Duke's authorized return on the declining balance—about $640 million in future bills from that

[18] LLT Stipulation (Oct. 6, 2026), Ex. 1 (proposed Large Load Tariff) (providing liquidated damages only upon early termination and no charge for undepreciated generation upon expiration of the contract term).

[19] Order $67,357 per MW-year is the straight-line depreciation of the proxy unit. For 500 MW over the 20 remaining years, the undiscounted total, which equals the remaining book value, is $673.6 million; discounted at 7.7% it is $338.2 million. Discounting the full cost—depreciation and return—at the utility's cost of capital yields the remaining book value; discounting depreciation alone yields about half of it.

one customer alone. And that is the result even when the departing customer pays every dollar the Order requires.

The scale is clearer in the following Duke-wide illustration:[20]

Scenario (Duke-wide illustration)	What the data centers pay when they leave	Generation investment left in rate base for remaining ratepayers	Approximate future bills paid by remaining ratepayers
They stay for the full 35-year plant life	No exit payment	$0	$0
They leave after 15 years and pay every dollar the Order requires	About $4.5 billion in Stranded Generation Charges	About $6 billion	About $11–12 billion
They leave after 15 years and the Stranded Generation Charge is uncollectible	$0 from the Stranded Generation Charge	About $10.5–11 billion	About $20 billion

Under the approach I would adopt, the last two columns would be zero because the data centers would fund the generation they cause before it enters net rate base. Under the majority's approach, this Duke-wide illustration shows the difference. If all 6.7 gigawatts left after 15 years and every customer paid the required Stranded Generation Charge, roughly $6 billion of generation investment would still remain in rate base for other ratepayers to support. If the charges were not collectible, the exposure would be much larger.

Collateral is not payment. Collateral is only security for a payment that may come due later. Meanwhile, Duke finances the plant and recovers the investment through rates.

[20] Undepreciated investment is 20/35 of original generation cost at the end of year 15. Future bills are depreciation plus a pretax return of approximately 8.7% on the declining balance, derived from the capital structure, return on equity, and cost of debt approved in this Order, in nominal dollars. The "pay every dollar" row assumes all customers pay the Stranded Generation Charge (about $4.5 billion in total) and that those payments reduce rate base. The "uncollectible" row assumes no recovery from the Stranded Generation Charge, as could occur with an uncollectible parent guaranty; cash or a qualifying bank letter of credit would reduce that loss. The first row assumes, as the majority does, that the rates paid during service recover the cost of the plant; Part V.E explains why the record does not establish that. All figures are illustrative, Duke-wide, and assume the vacated capacity is not needed for other customers.

While the data center remains, it pays some share of those costs. If it leaves before the investment is retired, the balance not covered by the Stranded Generation Charge—and the return on that balance—remains to be collected from the ratepayers who stay. Nor does the record establish that the monthly bills paid while the data center is here will cover its full cost: the Public Staff calculated that, at the 75 percent minimum-billing level, large loads would impose about $1.8 billion of net costs on other customers over fifteen years, and that these loads would have to operate at roughly an 83 percent load factor in every hour of every day for fifteen years merely to break even.[21] The Stranded Generation Security may also be only a parent-company promise whose strength must still be tested years from now. And that particular Security need not be posted until as late as 2029.

Fifteen years is a long time. The witnesses in this case testified that data centers replace their equipment every three to five years.[22] The majority itself gives substantial weight to testimony that these hardware refresh cycles lead a data center to reassess "its business case for continuing to operate."[23] Over fifteen years, the computers, the way they are used, where they are located, and the companies that own them will all change in ways no one can predict. I believe that many of the facilities seeking service today, and perhaps many of the companies that own them, will not exist in their present form fifteen years from now. When they leave, whatever they do not pay, the families, small businesses, and manufacturers who remain will.

The Commission's role. Duke's interests are well represented in this proceeding, as they should be. Duke has a legitimate duty to its shareholders, and it is unsurprising that it would prefer an arrangement in which billions of dollars of new generation remain in rate base and earn an authorized return. As one witness put it, the utility would want the investment in its rate base "because they would certainly earn on that rate base."[24] The data center companies, too, are ably represented and understandably seek to

[21]DEP Tr. vol. 9 at 80, 88 (Public Staff Large Load Panel).

[22]DEP Tr. vol. 9 at 744 (EDF witnesses Lenell and Pol); DEP Tr. vol. 10 at 141 (NCJC et al. witness Wilson).

[23]Order.

[24]DEP Tr. vol. 9 at 288–89 (AGO witness Brant).

minimize their costs. The Public Staff and the Attorney General advocate for the using public, but neither their participation nor any settlement can substitute for this Commission's independent judgment. In the end, it falls to this Commission to be the counterweight—to ensure that the utility's legitimate duty to its shareholders, and the data centers' legitimate interest in lower costs, do not become an obligation of the families, small businesses, and manufacturers who remain on the system. That is a responsibility of this Commission, not of the utility or the data centers.

A better approach. The data center should pay for the power plants and transmission its load requires up front, before they are built. The customer-funded portion would not enter net rate base, Duke would earn no return on capital supplied by the customer, and there would be no customer-caused investment left to strand. If, when the data center leaves, the Commission determines that some or all of those facilities have become system assets needed to serve other load, an appropriate portion of the customer's contribution can be refunded. Several of the companies that will be served under this tariff have publicly pledged to "build, bring, or buy the new generation resources necessary to serve their load" and to "pay for demand and infrastructure requested whether they use the electricity or not."[25] The approach I would adopt asks no more of them than that.

The sections that follow explain where I join the majority, and then set out in more detail the errors in the majority's treatment of the costs caused by data center customers, its decision to defer establishing a rate class for those customers, and its determination of the return on equity.

IV. Where I Concur

I join the majority in several important respects, and I do so because each reflects the principle on which this dissent rests: that the customers who cause costs should bear them.

[25]President's Ratepayer Protection Pledge (Mar. 4, 2026), as described by the Public Staff Large Load Panel, DEP Tr. vol. 9 at 96.

A tariff for data centers. I join the majority's decision to adopt a rate schedule and supplemental tariff provisions that apply specifically to data center customers. The record amply supports treating data centers differently from other large customers. Data centers operate at load factors of roughly 90 percent, compared with roughly 79 percent for manufacturing; they replace their computing equipment every three to five years; they require exceptionally high levels of reliability; and their protective equipment can disconnect hundreds of megawatts from the grid in an instant.[26] They are seeking to interconnect at a size and speed without precedent on this system. Those are differences in the cost and risk of service, and they justify a distinct schedule under N.C.G.S. § 62-140. I also join the majority's rules aggregating facilities under common ownership or control and aggregating increases in demand over time, which prevent a customer from avoiding the tariff by adding load in increments, and its requirement that data center customers disclose and obtain approval of their ride-through and reconnection plans.

Applicability without regard to the date of an ESA. The majority correctly declines to exempt customers from the DC Schedule based on the date on which an electric service agreement or letter agreement was signed. As the majority recognizes, those agreements expressly make service subject to changes in rates and terms "by order of, the North Carolina Utilities Commission,"[27] and parties may not contract around the Commission's regulatory jurisdiction. More fundamentally, the majority holds that "[c]ustomers 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."[28] I agree, and I would follow that principle to its conclusion in Part VI below. I also agree with the majority that applying the DC Schedule to customers that have signed agreements but have not yet taken service raises no issue of retroactive

[26]DEP Tr. vol. 9 at 680, 744 (EDF witnesses Lenell and Pol); DEP Tr. vol. 10 at 141 (NCJC et al. witness Wilson); DEP Tr. vol. 9 at 70–71 (Public Staff Large Load Panel) (describing the simultaneous loss of 1.5 GW of data center load). *See also* Order (findings regarding the distinct operational characteristics and risks of data center loads).

[27]Tr. Ex. vol. 9, Large Load Panel Ex. 4 at 1 (ESA ¶ 7); Order.

[28]Order (citing N.C.G.S. § 62-133.16(a)(1), (b)).

ratemaking, because those customers have no past use of utility service to which a new charge could attach.[29]

The combined cycle proxy. I join the majority's selection of a natural gas combined cycle unit as the proxy for the generation required to serve these customers. That choice is consistent with a point I have made in several prior dissents: when the costs of firming and reliability are fully counted, intermittent resources are not the least-cost means of serving load that must be met every hour of every day.[30] When the majority had to put a price on the cost of firm, around-the-clock service, it chose a combined cycle unit, not solar or solar paired with storage. I welcome that recognition. I would add only, as explained in Part V, that the proxy should include the reserve capacity built alongside the combined cycle unit.

First steps. Finally, I agree with the majority's requirements that data center customers pay in advance for facilities that serve them alone, post a letter of credit for transmission network upgrades, and be tracked as a class for reporting purposes. Each is a step in the right direction. My disagreement is that the majority stops short of the step that matters most.

V. The Costs Caused by Data Center Customers Should Be Paid by Data Center Customers

A. The governing standards

The General Assembly has directed that, in a proceeding such as this one, the Commission allocate the utility's revenue requirement among customer classes "based upon the cost causation principle," and that interclass subsidization be "minimized to the greatest extent practicable."[31] Rates must be just and reasonable, and no customer or class may be given an unreasonable preference or advantage over another.[32] Where, as

[29]Order (citing State ex rel. Utils. Comm'n v. Edmisten, 291 N.C. 451, 468, 232 S.E.2d 184, 194 (1977)).

[30]See, e.g., Docket No. E-2, Sub 1369 (Dec. 11, 2025) (van der Vaart, dissenting) (noting DEP's admission that its cost data for standalone solar include "no firming or regulating reserves" and its identification of a combustion turbine as the reliability proxy for firming capacity); Docket No. E-100, Sub 211 (Aug. 17, 2026) (van der Vaart, concurring in part and dissenting in part) ("generation during a designated window is not the same thing as capacity").

[31]N.C.G.S. § 62-133.16(a)(1), (b).

[32]N.C.G.S. §§ 62-130(a), 62-131(a), 62-140(a).

here, a stipulation is not joined by all parties, the Commission may not simply adopt it; it must reach its own independent conclusion, supported by substantial evidence, on each contested issue.[33] And the Commission's order must contain findings and conclusions, and the reasons for them, "upon all the material issues of fact, law, or discretion presented in the record."[34] An order that fails these requirements is subject to reversal as affected by error of law, unsupported by competent, material, and substantial evidence, or arbitrary or capricious.[35]

The majority acknowledges these principles, and in other parts of its decision relies on them. It invokes the cost causation principle to reject grandfathering. It agrees that "ratepayer protection should not depend on how DEP negotiates a particular agreement or on the relative bargaining power of the parties at the time of contracting."[36] And it rejects at least one party's proposal precisely because it "shifts risk to other customers."[37] The question is whether the majority applies those principles to the provisions it adopts. In several material respects, it does not.

B. The Stranded Generation Charge does not recover what the majority says it recovers

The majority adopts the Stranded Generation Charge, in its own words, "for the recovery of undepreciated generating asset costs" when a data center customer's service ends.[38] It identifies the risk the charge addresses as the "approximately 20 years of depreciation **that** must be funded by DEP's other ratepayers who remain on the system" if a customer leaves at the end of its contract.[39] It endorses the Public Staff's warning that, absent strong protections ensuring that "those customers causing large, expedited investment are ultimately responsible for paying for that investment, a significant risk

[33]State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, 348 N.C. 452, 466, 500 S.E.2d 693, 703 (1998) (CUCA I).

[34]N.C.G.S. § 62-79(a).

[35]N.C.G.S. § 62-94(b).

[36]Order (quoting DEP Tr. vol. 9 at 228–30).

[37]Order (rejecting Google witness Berry's proposal to broaden termination charges).

[38]Order.

[39]Order.

exists that the remaining customer base will be forced to bear those costs."[40] And it finds that the provisions it adopts "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 DEP's other ratepayers are not subsidizing the cost and risk" these customers impose.[41] The charge the majority adopts does not accomplish those purposes, for four reasons.

First, the formula omits the return. The starting figure—$67,357 per megawatt-year—is simply the straight-line depreciation of the proxy combined-cycle plant. The formula multiplies that depreciation amount by the years left after the contract ends and discounts those future depreciation payments back to the date of departure. What it never adds is the authorized return Duke continues to earn on the undepreciated plant that remains in rate base. After the data center leaves, the remaining ratepayers therefore continue to pay two things: the unrecovered depreciation and the return on the declining balance. If both components were included and discounted at the same cost of capital, their present value would equal the remaining book value. Discounting depreciation alone necessarily produces less.

The majority's own example shows the shortfall. Of $673.6 million in undepreciated investment, a 500-megawatt customer leaving after fifteen years pays $338.2 million. The other $335.4 million remains in rate base. The remaining customers must recover that amount, with a return, over the following twenty years. The Order does not explain why roughly half of the investment should remain with the very customers the charge is supposed to protect. Nor does it find that the vacated capacity will be needed by them. To the contrary, the Public Staff warned that remaining customers "may then be paying for an asset that they may not otherwise have needed."[42] The Order's finding that these protections are sufficient cannot be reconciled with its own calculation. A finding

[40]Order (quoting DEP Tr. vol. 9 at 69).

[41]Order.

[42]Order (citing Public Staff Large Load Panel Conf. Ex. 1).

contradicted by the Order's own example is not supported by substantial evidence, and a result left unexplained is arbitrary.[43]

The record offered a straightforward alternative. AGO witness Brant recommended that a departing customer pay "the greater of all remaining undepreciated costs of infrastructure built to serve the customer or all remaining monthly minimum bills."[44] The majority gave that recommendation little weight because it preferred to treat early termination and the normal end of service as different events.[45] That may justify two different charges. It does not explain why the end-of-service charge should retire only about half of the remaining investment.

Second, the proxy omits the reserve. Serving new firm load requires capacity to meet the load and additional capacity held in reserve. The record shows that Duke plans peaking capacity equal to about 22 percent of this very large load demand.[46] Yet the Stranded Generation Charge is calculated only on the customer's contract demand. For a 500-megawatt customer, the omitted reserve capacity represents roughly another $190 million to $270 million of generation investment, and the majority does not explain why it is excluded.

Third, the proxy omits other caused costs. The Anderson proxy is an overnight construction-cost estimate. It does not include financing costs during construction, and it cannot capture any amount by which the plants actually built exceed the proxy estimate. Those additional costs do not disappear; to the extent they are caused by the data center load and not recovered from it, they remain with the general body of ratepayers.

Fourth, the discount rate is not explained consistently. The DC Schedule says to use "the utility's weighted average cost of capital approved by the Commission,"[47] yet the Order approves an overall rate of return of 7.18 percent while its example uses 7.7

[43]N.C.G.S. §§ 62-79(a), 62-94(b)(5), (6).

[44]Order (summarizing DEP Tr. vol. 9 at 238, 244–45).

[45]Order.

[46]DEP Tr. vol. 9 at 88 (Public Staff Large Load Panel).

[47]DC Schedule, Definitions ("Discount Factor").

percent, described as the approved WACC "grossed up for tax purposes."[48] The Order does not show how that 7.7 percent figure was derived, and the Commission's order in DEC's companion case uses the identical 7.7 percent although the overall rate of return approved for DEC differs from that approved for DEP.[49] This is not the central defect—a different discount rate cannot fix a formula that discounts depreciation while omitting return—but a charge of this magnitude should at least use an input that is clearly defined and supported.

An estimate that can only go down. The majority calls the current charge an interim estimate that will later be replaced by a stakeholder-developed methodology. But if that later methodology produces a lower charge, the customer's payment and Security "shall be reduced accordingly"; the Order contains no parallel provision allowing the estimate to increase.[50] Nothing in the record explains why an interim estimate may be corrected only in the customer's favor. Because the final methodology may take a year or more, much of the contracted data center load may begin service under the interim formula. The practical effect could be to make today's understated estimate a ceiling. The Order also does not say how a Stranded Generation Charge, once collected, will be credited for the benefit of the ratepayers who continue to support the plant—whether through a reduction to rate base, a regulatory liability, or some other mechanism.

C. Security, timing, and the gap before the end of the contract

The Security behind these obligations may be non-interest-bearing cash, a letter of credit, or a guaranty from a parent company rated A- or better, at the customer's choice.[51] Those forms are not equivalent. Cash or a qualifying bank letter of credit can remain available even if the customer fails; a parent guaranty is only as strong as the parent that stands behind it. I acknowledge that the interim ESA requires replacement of Security that ceases to qualify and permits Duke to draw an expiring letter of credit that

[48]Order.

[49]Compare Order (DEP overall rate of return of 7.18%) with Docket No. E-7, Sub 1329, Order at __ (DEC overall rate of return of 7.34%), of which the majority takes judicial notice.

[50]Order; DC Schedule, Stranded Generation Charge.

[51]DC Schedule, Definitions ("Security").

is not renewed. But Security can secure only what the tariff requires to be paid, and the tariff requires roughly half of the undepreciated investment. Security for the Stranded Generation Charge need not be posted until the later of November 16, 2029, or sixty days after energization. A customer that fails before then may leave no Stranded Generation Security at all. Where Security is cash, the DC Schedule provides that it bears no interest, and the Order does not say whether it reduces rate base or receives any other ratemaking treatment, even as Duke continues to earn its full return on the plant the cash secures.[52]

The Order also leaves a gap when a customer leaves early. The majority itself explains that liquidated damages are not intended to recover undepreciated generation: it rejected witness Brant's proposal because "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."[53] But the Stranded Generation Charge covers only the years after the scheduled end of the contract term.[54] That leaves the years between an early departure and the scheduled contract end. During that period, the tariff does not require payment of the undepreciated generation investment; it requires liquidated damages equal to 25 percent of the remaining minimum bills, a billing measure rather than a measure of the plant left behind. Duke's witnesses explained that termination damages provide cash and time to adjust the resource plan because generation and transmission assets may be used for other customers.[55] That may happen in a growing system. But it is not protection if it does not. By the majority's own design, the generation costs of an early-departing customer for those intervening years fall to the remaining ratepayers. At a minimum, the Remainder Years for the Stranded Generation Charge should begin when service actually ends.

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[52] The DC Schedule defines Security to include "non-interest bearing cash security." The Order does not specify the ratemaking treatment of that cash. By contrast, Commission Rule R12-4 provides for interest on ordinary residential customer deposits. At a minimum, the Commission should specify whether cash Security reduces rate base, bears interest, or receives some other treatment so that the benefit of the funds accrues to the customers whose risk the Security is intended to protect.

[53] Order.

[54] DC Schedule, Definitions ("Remainder Years").

[55] Order (summarizing testimony of DEP witnesses Byrd and Beveridge, DEP Tr. vol. 10 at 322–23).

D. Transmission network upgrades

The majority's treatment of transmission network upgrades follows the same pattern. Within sixty days of signing its electric service agreement, a data center customer must post a bank letter of credit equal to Duke's estimate of the full cost of the network upgrades needed to serve it. But a letter of credit is security, not payment. Duke still finances the upgrades. Until and except to the extent a portion is paid as CIAC, the investment remains in rate base and is recovered through rates. The customer pays as CIAC only the "Customer Portion" that is later directly assigned to it, and that payment may be delayed for as long as 36 months after service begins. As with the Stranded Generation Charge, a later methodology can reduce the estimated Customer Portion but the tariff contains no parallel upward true-up. Once the customer reaches 75 percent of contract demand, the network-upgrade letter of credit declines each year and reaches zero at the end of the contract. Duke may draw it upon early termination. If the contract simply expires, no draw occurs, and any portion of the upgrades that was never directly assigned remains in rate base.[56]

E. The record does not support the majority's finding that data center rates will recover the costs these customers cause

The majority finds that its provisions ensure data centers pay charges "sufficient to recover the costs that are appropriately allocated to data centers." The record does not establish that. DC Schedule rates are based on Schedule LGS-HLF, which recovers an allocated share of embedded, system-average costs; it is not a calculation of the incremental cost of the new generation and transmission built for this unprecedented load. The Public Staff calculated that, at the 75 percent minimum-billing level, large loads would impose approximately $1.8 billion of net costs on other customers over fifteen years, and that these loads would have to operate at approximately an 83 percent load factor in every hour of every day for fifteen years merely to break even.[57] NCJC et al. witness Wilson similarly testified that Duke's analysis "may not demonstrate that large load revenues will cover the incremental cost of service," because customers can reduce demand charges

[56]DC Schedule, Required Facilities Costs (Transmission Network Upgrades).

[57]DEP Tr. vol. 9 at 80, 88 (Public Staff Large Load Panel).

without a corresponding reduction in system demand costs.[58] No Duke witness supplied a breakeven analysis, and the majority cites none. The Order therefore finds that these rates are sufficient without an analysis demonstrating that proposition. Whether the rates these customers pay will recover the costs they cause is a material issue under N.C.G.S. §§ 62-133.16(b) and 62-79(a). A finding on that issue unsupported by any analysis in the record, and contrary to the only analysis that was offered, cannot stand under N.C.G.S. **§ 62-94(b)(5).**

F. The better course: payment in advance for the facilities these customers cause

The approach I would adopt is neither novel nor punitive. The Commission requires up-front payment from customers who cause new facilities whenever the revenue they will produce does not justify the investment; in this very Order, it approves a Distribution Line Extension Plan under which a residential developer pays a contribution in aid of construction for any shortfall between projected revenues and the cost of the facilities it requires.[59] The majority applies the same principle to facilities that serve a data center alone. The question is why the principle stops there, at the smallest component of the cost, and does not reach generation, the largest.

The record put that question squarely before the Commission. The Commission's own Order Requesting Comments proposed a model tariff under which large load customers would make substantial deposits in advance toward the facilities required to serve them—a proposal that, as the Public Staff's and Microsoft's comments reflect, reached generation.[60] The Attorney General recommended that data centers pay network improvements not needed "but for" the data center as up-front contributions in aid of construction, and that deposits not refunded during the initial term be treated as contributions in aid of construction.[61] The AGO and NCJC supported direct allocation of generation costs through up-front payments refunded as the customer's load

[58]DEP Tr. vol. 10 at 64–65 (NCJC et al. witness Wilson).

[59]Order (DLEP Stipulation).

[60]Order (describing the Appendix A model tariff and ESA Deposit, and the Public Staff's and Microsoft's comments urging that generation be excluded).

[61]Order (summarizing AGO comments).

materializes.[62] The Public Staff recommended that the "but-for" costs of serving these customers "be paid for in their entirety by the customer," and observed that allowing payment over time "would not align when costs are incurred to when they are paid, thus unfairly impacting other ratepayers."[63] The majority does not explain why it declined to extend up-front payment to generation; it says only that the complexities of a standard methodology are best resolved in a stakeholder process.[64] That is a reason to refine the amount, not a reason to forgo the obligation. Its silence on a proposal of this consequence, raised by the Commission itself and by the parties charged with representing the using public, is a failure to make the findings N.C.G.S. § 62-79(a) requires.

The objections raised in comments do not justify that silence. Duke and some data center companies argued that a customer paying in advance for generation would pay twice—once through its contribution and again through demand charges that recover embedded generation costs. The answer, as the Public Staff suggested, is a billing structure that isolates the generation component of the demand charge, so that a customer that has paid for its generation is credited accordingly.[65] That is a matter of rate design, and it is one more reason to establish the class now, as explained in Part VI. Others argued that up-front payment would discourage economic development. Perhaps it would discourage some. But the companies that will be served under this tariff are among the most highly capitalized in the world, several of them have publicly pledged to "build, bring, or buy the new generation resources necessary to serve their load," and none has shown that it cannot finance its own power supply at a cost lower than the utility's cost of capital grossed up for taxes. Economic development is a legitimate goal, but the statutes do not permit it to be pursued by assigning the cost of one customer's facilities to every other customer without a finding that doing so is just and reasonable.

[62]Order.

[63]Order (summarizing Public Staff Initial Comments at 26–29).

[64]Order.

[65]Order (summarizing Public Staff Initial Comments at 26–27).

Under the approach I would adopt, the data center customer would pay, as a contribution in aid of construction, the cost of the generation (including reserve capacity), transmission, and other facilities its load requires, before they are built. Those facilities would not enter net rate base. Duke would earn no return on capital it did not supply. Nothing would remain to strand. If, when the customer departs, the Commission finds on evidence that the facilities are needed to serve other load, an appropriate portion of the contribution can be refunded. That structure honors the cost causation principle, protects every other customer in every scenario, and requires of the data center companies only what they have publicly promised.

In sum, the majority's treatment of the costs caused by data center customers (1) adopts a Stranded Generation Charge that, by the majority's own example, recovers roughly half of the undepreciated investment it is meant to recover, contradicting the majority's finding that its provisions are sufficient to recover these customers' costs; (2) excludes reserve capacity and other caused costs without findings; (3) rests on a discount rate that is inconsistently defined and unsupported by the record; (4) leaves undepreciated generation unrecovered for the years between an early departure and the scheduled end of the contract; (5) finds, without supporting analysis and contrary to the only analysis offered, that data center rates will recover the costs these customers cause; and (6) fails to address the up-front payment proposals in the record. Each is an error under N.C.G.S. §§ 62-79(a) and 62-94(b), and together they leave the general body of ratepayers bearing costs caused by others, contrary to N.C.G.S. § 62-133.16(b).

VI. A Data Center Rate Class Should Be Established Now

The majority directs that data center customers be tracked as a class for reporting purposes and determines that "creating a large load rate class in the next rate case is appropriate."[66] It declines to establish the class now because, it says, "the record [is] devoid of evidence that there is sufficient data for the creation of a new rate class in this proceeding."[67] The majority's own reasoning refutes that conclusion.

[66] Order.

[67] Id.

The majority has done everything required to establish a data center class except the one thing a class does. It has defined data center customers. It has found, at length, that they differ materially from other customers in their load factors, reliability requirements, equipment cycles, operating behavior, and the risks they present to the system.[68] It has given them their own rate schedule and their own risk provisions. And it has directed that their costs and revenues be tracked separately. What it has not done is allocate costs to them as a class.

The majority's other findings point the same way. It holds that customers with similar cost characteristics and risk profiles "should be placed in the same customer class."[69] It acknowledges that a separate class "establishes a mechanism to ensure that revenues, costs, investments, and risks are tracked and appropriately reflected in rates."[70] It recognizes that DEP witness Hager's objection—that there is insufficient test-year data—"reflects the issue of collecting data for the rates established for this proceeding, but not the principle of a rate class."[71] It gives significant weight to the Public Staff's acknowledgment that placing 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."[72] It "agrees with witness Wilson that defining a class later presents questions and ambiguity concerning legacy customers and determining the characteristics of that class."[73] And witness Wilson recommended establishing a new large load class "even given the lack of customers and data."[74]

Having found all of that, the majority still defers the class. Its stated reason—insufficient data—goes to designing class-specific rates, not to defining who belongs in the class. The majority has already supplied the definition. A class does not need a test

[68]Order.

[69]Order.

[70]Order.

[71]Order (discussing DEP Tr. vol. 8 at 163–64).

[72]Order; see Docket No. E-7, Sub 1329, Order (citing DEC Tr. vol. 15 at 52–53), of which the majority takes judicial notice.

[73]Order (citing DEP Tr. vol. 10 at 138–39).

[74]Order (citing DEP Tr. vol. 10 at 77, 103).

year of history; the Commission in this very Order approves rates for future rate years on forecasts. Initial rates can remain exactly where the majority puts them now, on Schedule LGS-HLF, and be refined in the next rate case as actual data accumulate. The concern that class data could reveal confidential customer information applies equally to the reporting class the majority already creates, and the Commission routinely has tools to protect confidential information.

Deferring the class has real consequences. Until a separate class exists, data center customers remain inside the broader Large General Service class for cost allocation. If the costs they cause exceed the revenues they produce—as the Public Staff's analysis indicates they may—the shortfall is initially absorbed within that broader class and can then affect revenue apportionment among other classes. The tracking required by the majority may reveal the shortfall, but tracking alone does not assign it back to the customers who caused it. That is the intraclass and interclass subsidization the Public Staff warned of,[75] and that N.C.G.S. § 62-133.16(b) directs the Commission to minimize. Establishing the class now would also make it easier to credit data centers that pay for generation up front, avoiding any double recovery through demand charges.

The reasons that justify a separate tariff for data centers are the same reasons that justify a separate class. The majority's conclusion does not follow from its findings, and an order whose conclusion is contradicted by its own findings is arbitrary and capricious and fails to state the reasons N.C.G.S. § 62-79(a) requires. I would establish the data center class now, defined as the majority defines DC Customers, with initial rates set on Schedule LGS-HLF.

VII. Return on Equity

I also dissent from the majority's approval of a 9.80 percent return on equity. The return must be sufficient to maintain the utility's financial integrity and attract capital on reasonable terms, and commensurate with returns on investments of comparable risk.[76] In setting the return for a multiyear rate plan period, the Commission "shall consider any

[75]DEP Tr. vol. 9 at 93 (Public Staff Large Load Panel).

[76]Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n, 262 U.S. 679, 692–93 (1923); FPC v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944); N.C.G.S. § 62-133(b)(4).

increased or decreased risk to either the electric public utility or its ratepayers."[77] And where, as here, the return is set by a stipulation not joined by all parties, the Commission must reach its own independent determination on the evidence.[78]

The evidence. DEP requested 10.95 percent, which it later reduced to 10.48 percent. DEP's witness Coyne testified to a range of 10.57 to 11.76 percent.[79] The 9.80 percent the majority approves is below every point in that range; witness Coyne supported it not on the basis of his cost of capital analysis but on the basis of "the give-and-take inherent in any settlement," testifying that the parties "may decide that some other ROE or other provision is sufficient for them in total."[80] That is a description of a negotiated outcome, not a determination of the cost of equity. Public Staff witness Walters estimated DEP's cost of equity in the range of 9.00 to 10.00 percent, recommended the midpoint of 9.50 percent, and testified that because DEP's PBR application would shift risk from shareholders to ratepayers, the return should be set in the lower half of his range.[81] Public Staff witness Fahey testified that North Carolina's multiyear rate plan framework shifts financial risk from the utility to its customers.[82] AGO witness Brant and CUCA witness LaConte each recommended a downward adjustment if a multiyear rate plan is approved.[83] The other recommendations ranged from 7.4 to 9.52 percent.[84]

The majority's reasoning. The majority places the return in the upper half of witness Walters' range. It does so by relying on individual model results within his analysis rather than on his conclusion; on witness Coyne's settlement testimony; on the stipulation itself as evidence; and on a national average of authorized returns. It also finds that the multiyear rate plan refund rider "shifts the risk of timely project execution from ratepayers

[77]N.C.G.S. § 62-133.16(c)(1)a.

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

[79]Order (citing DEP Tr. vol. 8 at 949).

[80]Order (citing DEP Tr. vol. 8 at 1161, 1180–81).

[81]Order (citing DEP Tr. vol. 7 at 1728–34).

[82]Order (citing DEP Tr. vol. 7 at 1832).

[83]Order nn.3–4.

[84]Order at (AGO witness Cassara, 7.4%; NCJC et al. witness Kihm, 9.1%; DoD/FEA witness Reno, 9.29%; CUCA witness LaConte, 9.52%).

to DEP."[85] But the majority never weighs the far larger shift of risk in the other direction. The witness on whose analysis the majority principally relies concluded that the PBR framework reduces DEP's risk and recommended a return below his midpoint. The majority does not explain why it rejects that conclusion while relying on his range.

Nor does the majority consider the risk this Order shifts through the DC Schedule. Minimum bills, long contract terms, liquidated damages, Security, contributions toward network upgrades, and a charge on departure each protect Duke from the consequences of a large customer's failure or departure. Whatever their limits as protections for ratepayers, they are real protections for the utility, and they reduce the risk associated with the largest capital program in its history. The statute requires the Commission to consider decreased risk in setting the return. The Order contains no finding that it did so with respect to these provisions.

Finally, the settlement's reduction of DEP's requested increase should not be treated as though every dollar were a permanent reduction in cost. Some items reduce the current revenue requirement by changing when costs are recovered. For example, certain construction work in progress is excluded from current rate base but continues to accrue AFUDC for potential later recovery, and coal-ash costs are recovered over eight years instead of five.[86] Those changes lower today's revenue requirement without necessarily lowering the ultimate cost. Other settlement concessions are genuine reductions. The point is simply that the negotiated 9.80 percent return should not be treated as self-proving merely because it was part of a package that lowered the immediate increase.

On this record, I would set the return on equity at 9.50 percent under the framework the majority adopts. That is the recommendation of the witness whose range the majority principally relies on, reached after considering the reduced risk created by the multiyear

[85] Order.

[86] See Jiggetts Rebuttal Exhibit 2, p. 5; Jiggetts Comprehensive Settlement Exhibit 2, p. 5; Comprehensive Settlement § II.10. The settlement includes both permanent concessions and items that change the timing of recovery; the text distinguishes the two rather than treating every reduction in the current revenue requirement as an eliminated cost.

rate plan, and it is consistent with the statute's direction to consider that risk. Under the approach to data center costs I would adopt—full up-front funding of the generation and transmission caused by the new load—Duke's exposure would fall further. That additional reduction in risk should produce a still lower return. I would set it at 9.25 percent, which remains within witness Walters' range of 9.00 to 10.00 percent and below his midpoint, as he recommended. The record does not fix a precise number for a structure the majority did not adopt, but materially reducing shareholder risk should materially reduce the return required to attract capital. At 9.25 percent, the difference from the 9.80 percent approved by the majority would be approximately $68 million per year; at 9.50 percent, approximately $37 million per year.[87] By relying on the stipulation and on witness Coyne's settlement testimony in place of an independent determination, and by failing to consider the decreased risk resulting from the multiyear rate plan and the DC Schedule, the majority errs under CUCA I and N.C.G.S. § 62-133.16(c)(1)a.

VIII. Conclusion

The majority has done much that is right. It has adopted a tariff tailored to data centers, rejected grandfathering, required data centers to pay for facilities that serve them alone, and recognized that stranded generation is a real risk. But the central protection falls short: even when a departing data center pays every dollar required, roughly half of the remaining proxy generation investment can stay in rate base for the ratepayers who remain. The majority also defers the class that would assign data center costs transparently and approves a return that does not account for all of the risk shifted away from the utility. The result is that the general body of ratepayers remains the ultimate backstop for power plants built to serve a small number of very large customers.

I would require data center customers to pay in advance for the generation, reserve capacity, and transmission their load requires, refundable only upon a showing that those facilities are later needed to serve others; establish the data center class now; and set the return on equity at 9.50 percent under the majority's framework, or at 9.25 percent if

[87] Based on the settlement's reduction of $83.8 million in base revenue for the 68-basis-point reduction from 10.48% to 9.80%, or approximately $1.23 million per basis point. Jiggetts Comprehensive Settlement Exhibit 2, p. 5.

data center customers fully fund the facilities their load requires. At a minimum, I would set the Stranded Generation Charge equal to the undepreciated balance of the proxy capacity, including reserve, without discounting; begin the charge when service actually ends; require that every payment be credited for the benefit of remaining ratepayers through a reduction to rate base or an equivalent mechanism; and require Stranded Generation Security before energization in cash or a qualifying bank letter of credit.

For these reasons, I concur in part and respectfully dissent in part.

/s/ Donald R. van der Vaart
Commissioner Donald R. van der Vaart

DOCKET NO. E-2, SUB 1380
DOCKET NO. E-2, SUB 1405

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 Progress, LLC
(North Carolina Only)

NC Original Leaf No. __

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.

This Schedule is not available: (1) for breakdown, standby, or supplementary service unless used in conjunction with the applicable standby or generation service rider for a continuous period of not less than one year; (2) for resale service, except as otherwise provided in NCGS § 62-3; (3) for electric service in conjunction with Incremental Power Service Rider IPS, Dispatched Power Rider No. 68, Standby & Supplementary Service Rider No. 7, or Supplementary & Interruptible Standby Service Rider No. 57; or (4) for electric service in conjunction with Large General Service (Real Time Pricing) Schedule LGS-RTP.

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 Progress, 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, Monthly Rate, Riders, Determination of Billing Demand, Power Factor Adjustment, Sales Tax, Payments, General, 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.

APPENDIX A

Duke Energy Progress, LLC NC Original Leaf No. __
(North Carolina Only)

TYPE OF SERVICE

The types of service to which this Schedule is applicable are alternating current, 60 hertz, three-phase 3 or 4 wires, at Company's standard voltages of 480 volts or higher. When a customer desires two or more types of service, which types can be supplied from a three-phase 4 wire type, without voltage transformation, only the one of these two types necessary for Customer's requirements will be supplied.

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.

MONTHLY RATE

I.	Basic Customer Charge	$210.00
II.	Energy Charge per kWh	2.592¢
III.	Demand Charge per kW of Billing Demand	$29.55

Transformation Discounts:
When Customer owns the step-down transformation and all other facilities beyond the transformation which Company would normally own, except Company's metering equipment, the charge per kW of Billing Demand and per kWh will be reduced in accordance with the following:

Transmission Service Transformation Discount	Distribution Service Transformation Discount
$1.20/kW	$0.78/kW
$0.00017/kWh	$0.00007/kWh

Transmission: For a customer to qualify for the Transmission Service Transformation Discount, the customer must own the step-down transformation and all other facilities beyond the transformation which the Company would normally own, except the Company's metering equipment, necessary to take service at the voltage of the 69 kV, 115 kV, or 230 kV transmission line from which the customer received service.

Distribution: For a customer to qualify for the Distribution Service Transformation Discount, the customer must own the step-down transformation and all other facilities beyond the transformation which the Company would normally own, except the Company's metering equipment, necessary to take service from the distribution line of 12.47 kV or higher from which the customer receives service. The distribution service source must be from a general distribution line and must be from other than a transmission-to-distribution substation built primarily for the customer's use in order to qualify for the Distribution Service Transformation Discount. A general distribution line is a 12.47 kV or higher voltage distribution line built to serve the general area and not built primarily to serve a specific customer.

The Company shall have the option to install high-side metering equipment or low-side metering equipment compensated for Customer-owned transformer and line losses.

Any facilities which the Company provides above those which the Company would normally have utilized to service a customer's Contract Demand shall be considered as Extra Facilities. Any Company-owned protection system installed when service is directly from the Company's 69 kV, 115 kV, or 230 kV transmission system or a distribution line of 12.47 kV or higher shall be considered Extra Facilities.

If changing conditions on the Company's electrical system make continuation of the current delivery voltage impractical, the customer shall be responsible for all costs for the conversion beyond the point of delivery except any Company-owned metering equipment. At the time of the conversion, the Company reserves the right to provide service at one of its available voltages.

If subsequent changes in the use of the Company's facilities occur which cause the reclassification of either transformers or lines, the customer's entitlement to the discount may be changed.

RIDERS

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. 601	Rider BA
Leaf No. 602	Rider JAA
Leaf No. 604	Rider EDIT-4
Leaf No. 605	Rider CPRE
Leaf No. 609	Rider ESM
Leaf No. 610	Rider PIM

The monthly bill shall include a CAR Adjustment (Leaf No. 611) to fund the Customer Assistance Program Credit Program for residential customers that qualify for the Low Income Energy Assistance Program (LIEAP) or Crisis Intervention Program (CIP) as is further explained in Leaf No. 718

Storm Securitization charge will be added to the monthly bill based on the currently approved cents/kWh incremental rate as shown in the Storm Securitization Rider (Leaf No. 607 Rider STS).

Renewable Energy Portfolio Standard (REPS) Adjustment:
The monthly bill shall include a REPS Adjustment based upon the revenue classification. Upon written request, only one REPS Adjustment shall apply to premises serving the same customer for all accounts of the same revenue classification. If a customer has accounts which serve in an auxiliary role to a main account on the same premises, no REPS charge should apply to the auxiliary accounts regardless of their revenue classification (see Leaf No. 601 Annual Billing Adjustments Rider BA).

DETERMINATION OF BILLING DEMAND
The Billing Demand shall be the maximum kW registered or computed, by or from Company's metering facilities, during any 30-minute interval within the current billing month. However, the Billing Demand shall not be less than the greater of: (1) 90% of the maximum monthly 30-minute demand during the preceding 11 billing months, or (2) 75% of the Contract Demand (subject to the load ramp schedule in the

ESA) until such time as the Billing Demand first equals or exceeds the effective Contract Demand, or (3) 50,000 kW.

POWER FACTOR ADJUSTMENT
When the power factor in the current billing month is less than 85%, the monthly bill will be increased by a sum equal to $0.32 multiplied by the difference between the maximum reactive kilovolt-amperes (kVAr) registered by a demand meter suitable for measuring the demands used during a 15-minute interval and 62% of the maximum kW demand registered in the current billing month.

SALES TAX
To the above charges will be added any applicable North Carolina Sales Tax.

PAYMENTS
Bills are due when rendered and are payable within 25 days from the date of the bill. If any bill is not so paid, the Company has the right to suspend service in accordance with its Service Regulations. In addition, any bill not paid on or before the expiration of twenty-five (25) days from the date of the bill is subject to an additional charge of 1% per month as provided in Rule R12-9 of the Rules and Regulations of the North Carolina Utilities Commission.

GENERAL
Service rendered under this Schedule is subject to the provisions of the Service Regulations of the Company on file with the state regulatory commission.

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.

APPENDIX A

Duke Energy Progress, LLC
(North Carolina Only)

NC Original Leaf No. __

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 the 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

INTERIM STANDARD FORM OF ELECTRIC SERVICE AGREEMENT

Application For Supply of Electricity

1. The undersigned, hereinafter called "Customer," hereby applies to Duke Energy Progress, 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.

APPENDIX B

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 Progress, LLC

By _____

Mail Bill to:

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.

APPENDIX B

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.