BIENNIAL REPORT OF THE

NORTH CAROLINA UTILITIES COMMISSION

TO

THE GOVERNOR OF NORTH CAROLINA

AND

THE JOINT LEGISLATIVE OVERSIGHT COMMITTEE ON AGRICULTURE AND NATURAL AND ECONOMIC RESOURCES

AND

THE SENATE APPROPRIATIONS COMMITTEE ON AGRICULTURE, NATURAL, AND ECONOMIC RESOURCES

AND

THE CHAIRS OF THE HOUSE OF REPRESENTAITIVES APPROPRIATIONS COMMITTEE ON AGRICULTURE AND NATURAL AND ECNOMIC RESOURCES

REGARDING

PROCEEDINGS FOR ELECTRIC POWER SUPPLIERS INVOLVING ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT PROGRAMS, COST RECOVERY AND INCENTIVES
(Pursuant to N.C.G.S. § 62-133.9(i))

Date Due: September 1, 2025
Date Submitted: August 29, 2025

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[1] Effective May 12, 2017, as part of corporate-wide rebranding process, Virginia Electric and Power Company changed its d/b/a names in North Carolina from Dominion North Carolina Power to Dominion Energy North Carolina.

R8-68 Incentive Programs for Electric Public Utilities and Electric Membership Corporations, Including Energy Efficiency and Demand-Side Management Programs

R8-69 Cost Recovery for Demand-Side Management and Energy Efficiency Measures of Electric Public Utilities

EXECUTIVE SUMMARY

The Utilities Commission is providing this report to the Governor and the Joint Legislative Oversight Committee on Agriculture and Natural and Economic Resources, the Senate Appropriations Committee on Agriculture, Natural, and Economic Resources, and the chairs of the House of Representatives Appropriations Committee on Agriculture and Natural and Economic Resources pursuant to N.C.G.S. § 62-133.9(i), which requires the Commission to submit a summary of proceedings conducted under N.C.G.S. § 62-133.9 during the preceding two fiscal years on or before September 1 of odd-numbered years. The report spans the time period July 1, 2023, through June 30, 2025. This report is divided into five sections, one for each of the proceeding types that the Commission conducted relative to N.C.G.S. § 62-133.9 from July 1, 2023, through June 30, 2025.

Throughout this report, references are made to various Commission dockets. Readers who wish to review the official record of any proceeding may do so by visiting the Commission's web site at www.ncuc.gov, selecting "Dockets" from the main menu, selecting "Docket Search," and then entering the appropriate docket number.

N.C.G.S. § 62-133.8(a) contains the following definitions that apply to this report:

> "Demand-side management" means activities, programs or initiatives undertaken by an electric power supplier or its customers to shift the timing of electricity use from peak to non-peak demand periods. "Demand-side management" includes, but is not limited to, load management, electric system equipment and operating controls, direct load control, and interruptible load.
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> "Energy efficiency measure" means an equipment, physical, or program change implemented after 1 January 2007 that results in less energy used to perform the same function. "Energy efficiency measure" includes, but is not limited to, energy produced from a combined heat and power system that uses nonrenewable energy resources. "Energy efficiency measure" does not include demand-side management.

In order to provide background and context, this report includes information for some Commission proceedings that occurred in prior fiscal years, which was also included in previous reports. In addition, this report acknowledges demand-side management (DSM) and energy efficiency (EE) program applications that have been recently filed with the Commission but are still pending by June 30, 2025.

North Carolina General Statutes § 62-133.9 was enacted as part of Session Law 2007-397 (Senate Bill 3), which established the Renewable Energy and Energy Efficiency Portfolio Standard (REPS) for North Carolina's electric power suppliers. Session Law 2023-138 (Senate Bill 678), codified at N.C.G.S. § 62-133.8, amended the REPs by expanding it to be the Clean Energy and Energy Efficiency Portfolio Standard (CEPS). Electric power suppliers can implement EE and DSM measures to fulfill portions of their CEPS obligations. Section 4(a) of Senate Bill 3, codified as N.C.G.S. § 62-133.9, specifies that each electric power supplier shall implement DSM and EE measures and use supply-side resources to establish the least cost mix of demand reduction and generation measures that meet the electricity needs of its customers. Each electric power supplier that is required to file an Integrated Resource Plan (IRP) must include within that plan an assessment of DSM and EE and is required to submit cost-effective options that require participant incentives to the Commission for approval.

North Carolina General Statutes § 62-133.9(d) provides that the Commission shall, upon petition of an electric public utility, approve an annual rider to the electric public utility's rates to recover all reasonable and prudent costs incurred for adoption and implementation of new DSM and new EE measures. Recoverable costs include, but are not limited to, all capital costs, including cost of capital and depreciation expenses, administrative costs, implementation costs, incentive payments to program participants, and operating costs. Upon petition by an electric public utility, the Commission shall approve an annual rider to the utility's rates to allow it to recover all reasonable and prudent costs incurred for new DSM and EE measures, which are defined as programs instituted after January 1, 2007, including subsequent amendments. Further, the Commission may approve incentives to electric public utilities for adopting and implementing new DSM and EE measures. Section 62-133.9(e) of the General Statutes states that the Commission is to determine the appropriate assignment of costs of new DSM and EE measures and shall assign those costs only to the class or classes of customers that directly benefit from the programs. Section § 62-133.9(f) of the General Statutes provides that none of the costs of new DSM or EE measures shall be assigned to any industrial customer that notifies its utility that it has implemented or will implement alternative DSM and EE measures and elects not to participate in the utility's new DSM and EE measures.

Section One of this report covers three orders that modified Commission rules regarding DSM and EE over the review period. Section Two discusses assessments of the potential for DSM and EE that Dominion Energy North Carolina (DENC) and Duke Energy Carolina (DEC) and Duke Energy Progress (DEP, collectively with DEC, Duke) included as part of their respective IRP and Consolidated Carbon and Integrated Resource Plan (CPIRP) filings. Section Three provides information on several new

DSM/EE programs that the Commission has approved or has pending by the end of this review period. Section Four covers the annual rider applications that DENC, DEC, and DEP each filed. Those riders allow the companies to recover their DSM/EE program costs as well as incentives. At the end of the two years covered by this report, DEC and DEP had outstanding DSM/EE Rider proceedings pending before the Commission. Section Five covers the changes to DSM/EE cost recovery and incentive mechanisms (Mechanism) for DENC and Duke. Attached as Appendix A are the applicable Commission Rules for the scope of this report, which are listed in the table of contents.

As of June 30, 2025, the DSM/EE riders for residential customers are as follows:

Electric Public Utility	**DSM/EE Rider Charges for Residential Customer Using 1,000 kWh** (including the North Carolina Regulatory Fee)
DENC[2]	$1.58/month
DEC[3]	$4.93/month
DEP[4]	$7.67/month

SECTION 1: AMENDMENTS TO THE COMMISSION'S RULES

There were three orders regarding amendments to the Commission's rules during the two-year period covered by this report.

Order Adopting Commission Rule R8-60A and Amending Commissions Rules R8-60, R8-67 and R8-71

On December 30, 2022, the Commission issued its Order Adopting Initial Carbon Plan and Providing Direction for Future Planning (Initial Carbon Plan) in Docket No. E-100, Sub 179. The Initial Carbon Plan provided that "[f]or regulatory efficiency, the Commission deems it reasonable and necessary to consolidate its IRP planning function pursuant to N.C.G.S. § 62-110.1(c) and its Carbon Plan development and execution oversight function pursuant to N.C.G.S. § 62-110.9." To this end, Ordering ¶ 2, subparts a through e, of the Initial Carbon Plan directed Duke to engage with the Public Staff – North Carolina Utilities Commission (Public Staff) and any interested stakeholders to propose a new rule governing the CPIRP, subject to certain parameters contained in the subparts of Ordering ¶ 2, and to file the proposed rule with the Commission by no later than April 28, 2023, in a new and separate proceeding. *Id.* at 130.

On April 28, 2023, Duke filed its initial comments and proposed rules in Docket No. E-100, Sub 191. In its filing, Duke proposed a new rule applicable to the Commission's review and approval of Duke's proposed biennial CPIRPs — proposed Commission Rule

[2] Docket No. E-22 Sub 711
[3] Docket No. E-7 Sub 1305
[4] Docket No. E-2 Sub 1342

R8-60A — and proposed revisions to Commission Rules R8-60, R8-67, and R8-71. In its April 28, 2023 filing, Duke also requested that it be released from compliance with resource planning directives contained in Commission IRP orders issued prior to the effective date of N.C.G.S. § 62-110.9.

The Public Staff's intervention was recognized pursuant to N.C.G.S. § 62-15(d) and the North Carolina Attorney General's Office (AGO) filed a Notice of Intervention on May 17, 2023. In addition, the Commission permitted the intervention of the following groups: Carolina Industrial Group for Fair Utility Rates II (CIGFUR II) and the Carolina Industrial Group for Fair Utility Rates III (CIGFUR III)(collectively, CIGFUR); Avangrid Renewables, LLC; the Carolina Utility Customers Association, Inc. (CUCA); TotalEnergies Renewables USA, LLC and the Clean Energy Buyers Association (CEBA); the Fayetteville Public Works Commission; the North Carolina Sustainable Energy Association (NCSEA); ElectriCities of North Carolina, Inc. (ElectriCities), North Carolina Eastern Municipal Power Agency, and North Carolina Municipal Power Agency Number (collectively ElectriCities et al.), the North Carolina Electric Membership Corporation (NCEMC) and the Carolinas Clean Energy Business Association (CCEBA); the Southern Alliance for Clean Energy (SACE), the Sierra Club, and the Natural Resources Defense Council (NRDC) (collectively, SACE et al.).

On November 20, 2023, the Commission issued an order in Docket No. E-100, Sub 191 adopting Rule R8-60A and amending R8-60, R8-67, and R8-71. The revisions to Rule R8-60 clarify that the Rule will now only apply to DENC. The revisions to Rules R8-67 and R8-71 provide procedures for the filing of annual compliance plans for CEPS and CPRE, as these plans were formerly filed in the IRP docket pursuant to Rule R8-60. The purpose of R8-60A is to implement the provisions of N.C.G.S. §§ 62-2(a)(3a), 62-110.1, and 62-110.9. Notably, Rule R8-60A(f)(5) states:

> Demand-Side Management and Energy Efficiency. — The electric public utilities shall include an assessment of the portfolio of existing and future grid edge resources including demand-side management and energy efficiency programs consistent with the most recently filed DSM/EE cost recovery rider filed by the electric public utilities pursuant to Rule R8-69 and G.S. 62-133.9(c). The electric public utilities shall appropriately reflect grid edge resources as either load modifiers or as a resource considered on the supply side based upon the operating characteristics of the resource. For purposes of utility planning, the electric public utilities shall model energy efficiency as a load modifying resource, ensuring its priority in utility planning. The electric public utilities' modeling of the load modification associated with energy efficiency shall include low, base, and high cases.

Order Amending Rule R8-60

On October 2, 2023, pursuant to N.C.G.S. § 62-31 and Commission Rules R1-4 and R1-5, DENC filed a Petition for Rulemaking in Docket No. E-100 Sub 196. DENC requested that the Commission initiate a proceeding to amend Commission Rule R8-60 to revise the date by which DENC must submit its biennial IRPs and update reports to the Commission. DENC sought to amend Commission Rule R8-60 for the purpose of harmonizing its North Carolina IRPs with its Virginia IRPs. DENC explained that changes in Virginia law resulted in Dominion Energy's IRP filings obligations in Virginia and North Carolina being out of sync. Accordingly, DENC requested that the Commission revise its Rule R8-60 to allow DENC to file its full IRPs on or by October 15 in even-numbered years starting in 2024. On February 8, 2024, the Commission issued an order amending Rule R8-60 to change the due date of the IRP from September 1 to October 15.

Order Modifying Commission Rules R8-64, R8-65, R8-66 and R8-67

On June 21, 2024, in Docket No. E-100, Sub 113, the Commission issued an order modifying several Commission Rules in response to Session Law 2023-138, Part I of which amends N.C. Gen. Stat. § 62-133.8 by expanding REPS to CEPS and making conforming changes to other sections of Chapter 62. The changes consisted primarily of changing "REPS" to "CEPS" and "renewable" to "clean" in the Commission Rules.

SECTION 2: UTILITIES' DSM AND EE ASSESSMENTS FILED AS PART OF THEIR INTEGRATED RESOURCE PLANS

North Carolina General Statutes § 62-133.9(c) states the following:

> Each electric power supplier to which G.S. 62-110.1 applies shall include an assessment of demand-side management and energy efficiency in its resource plans submitted to the Commission and shall submit cost-effective demand-side management and energy efficiency options that require incentives to the Commission for approval.

DENC's assessment of DSM and EE are found in Chapter 3.2.5 and Appendix 3D-3I of DENC's IRP application. DEC and DEP's assessment of DSM and EE are found in Appendix H of Duke's CPIRP. The following are summaries of the assessments included in each application.

DENC

On October 15, 2024, in Docket No. E-100, Sub 204, DENC filed its IRP. DENC stated that it offers over 40 energy savings programs for residential customers, income-and age-qualified residential customers, and non-residential customers. Energy savings from DENC's DSM programs are forecasted to save and reduce energy requirements by 1,306 gigawatt hours (GWh) in 2024 and by total of 2,500 GWh by 2029. From a demand perspective, DSM programs are projected to reduce the summer capacity needs by 314 megawatts (MW) in 2024 and by a total of 553 MW by 2029.

From a modeling perspective, DENC accounted for savings from its active DSM programs along with forecasted growth to those programs as a downward adjustment to the load forecast. To develop the energy and capacity reductions used in its primary portfolios, DENC used the EE savings targets proposed for 2026–2028 from a prior docket establishing EE targets.[5] DENC continued to increase the savings forecast throughout the remaining 15-year planning horizon, which is a 10% annual increase in cumulative persistent savings, starting from 2023 actual savings.

DENC relies on a DSM stakeholder process established by the Grid Transformation and Security Act of 2018 (GTSA) to generate new program ideas, which it then develops into concrete program proposals to be evaluated for cost-effectiveness. If the programs are cost-effective based on the modeling results or otherwise legislatively stated to be in the public interest, the programs are filed with the Virginia State Corporation Commission (VSCC) for approval. Programs that meet the statutory criteria in Virginia are then, when feasible on a smaller scale, brought forth in the following year to the Commission for consideration. DENC conducts evaluation, measurement, and verification (EM&V) of all active DSM programs and files the annual EM&V report with the VSCC and Commission in June of each year. Results are shown for the prior calendar year on specific metrics, including program participation, spending, energy, and demand savings.

DENC notes that as part of its long-term plan for energy efficiency measures, it has projected spending at least 15% of all DSM-related spending on programs targeted towards low-income, elderly, and veteran populations. The continued implementation of active DSM programs is aimed to further carbon intensity reduction goals, reduce the number of renewable energy credits required for renewable portfolio standard compliance, and benefit participating customers through lower energy usage and resulting bills.

Duke

On August 17, 2023, in Docket No. E-100, Sub 190, Duke filed its Petition for Approval of 2023-2024 CPIRP; in its filing, Duke provided an appendix titled Grid Edge and Customer Programs. Grid edge programs include EE and DSM programs, certain rate designs, voltage control efforts, renewable energy programs, electric transportation programs, and behind-the-meter generation and storage. Duke described how grid edge and customer programs are intended to provide customers with a variety of options to manage their electric use to both reduce monthly bills and provide value to the electric grid.

Duke explained that its CPIRP modeling assumes that one percent of eligible load can be saved through EE. The 2023 EE forecast is based on an updated market potential study performed by an independent third party. To achieve the amount of EE modeled in the CPIRP, Duke states that, in the near-term, it will need to obtain regulatory approvals associated with (1) the addition of new programs and measures, (2) necessary modifications associated with the valuation of EE benefits, and (3) longer-term, broader modifications to expand the number of customers participating in Duke's EE programs. Duke's forecasting methodology around EE continues to treat it as a priority resource by considering its contribution as a load modifier.

[5] Case No. PUR-2023-00227 in the VSCC docket system.

Demand response (DR) plays a key role in helping customers manage their energy costs and usage, adding value to the grid and planning for a reliable and resilient energy future. Duke plans to employ customer sited resources as grid resources to meet peak needs, maximize renewable generation, and minimize fuel cost volatility on a more frequent basis. The historic use of DR to avoid building generation needed for a small quantity of peak hours per year continues and evolves.

Voltage optimization is the coordinated control of substation and power line equipment to manage voltage and power factor on distribution circuits. Voltage optimization capabilities lead to less peak load on the grid and improvements to the grid's ability to respond to dynamic system conditions while delivering reduced distribution line losses.

Rate design factors include technology support, desire for options, grid dynamics, and distributed energy technology. New time-of-use periods and specific rate design elements, such as Critical Peak Pricing, include callable events (typically limited to a specific number per year) with high price signals that together encourage customer load reduction during times of grid constraint to avoid higher energy prices. Customers will be able to reduce loads passively (with programmable or smart devices) or actively (through responding to called events) during such grid constraint events, providing beneficial firm capacity reduction.

Duke explains that electric vehicles (EVs) present a set of challenges and opportunities for the utility sector that is both complex and, in some ways, unprecedented. EV adoption has increased 50% year-on-year since 2020, leading to over 54,000 EVs on the road in Duke's North Carolina and South Carolina footprint as of the end of 2022.

Behind-the-meter generation and storage refer to customer-sited resources, primarily solar and solar paired with storage. The growth in behind-the-meter resources has been fostered in large part by legislative activities in the Carolinas, notably South Carolina Act 236 of 2014, South Carolina Act 62 of 2019, and North Carolina Session Law 2017-192. By the end of 2022, approximately 1% of Duke residential customers in North Carolina had installed solar and/or solar paired with storage.

Duke has also initiated rapid prototyping for grid edge and customer programs beyond EE and DSM to meet the growing need to be able to test and prototype offerings around new technologies.

SECTION 3: NEW DSM AND EE PROGRAMS

North Carolina General Statutes § 62-133.9 defines "new," as it relates to a DSM or EE measure, to mean a DSM or EE measure that is adopted and implemented on or after January 1, 2007, including subsequent changes and modifications. Cost recovery for new DSM and EE measures is subject to N.C.G.S. § 62-133.9. This section lists the new DSM and EE programs that have been approved by the Commission during the two-year period covered by this report.

DENC

On November 22, 2023, DENC requested approval to implement the Phase 8 Home Retrofit Program Bundle (Home Retrofit Program Application), the Phase 9 Non-Residential Prescriptive Program Bundle (Non-Residential Prescriptive Program Application), and the Phase 11 Residential Income and Age Qualifying Program Bundle (Residential Income and Age Qualifying Program Application).[6] The Home Retrofit Program Bundle incorporates existing program measures and introduces new measures including the replacement of Electric Baseboard Heating with Air Source Heat Pump, High Efficiency Room AC Upgrades, and Shower Thermostats. DENC explained that it is bundling its programs that are similar in nature in program offerings and implemented by the same vendor where practicable and feasible. This consolidation is intended to streamline the program offering into one program instead of two separate stand-alone programs, improving the customer experience. The Non-Residential Prescriptive Program Bundle will provide qualifying non-residential customers in DENC's North Carolina service territory with incentives for the installation of refrigeration, commercial kitchen equipment, HVAC improvements, window film installation and maintenance, and other program-specific EE measures. The Residential Income and Age Qualifying Program Bundle combines DENC's low-income program offerings and adds several new program measures, creating a bundled program to provide qualifying residential customers with in-home energy assessments and installation of select energy-savings measures. The bundled program approach will allow homes to be treated more comprehensively and offer qualifying customers the opportunity to implement a wider variety of energy efficiency measures during the in-home energy assessment stage. The Public Staff was the only intervenor in these dockets and recommended approval of each program. The Commission approved the program bundles on January 22, 2024, and DENC began to launch the programs in March of 2024.

On March 4, 2024, DENC requested approval to implement the Phase 11 Residential Efficient Products Marketplace Program (Residential Efficient Products Marketplace Program Application) in Docket No. E-22, Sub 693. The Public Staff was the only intervenor in this docket and recommended approval of the program. The Commission approved the program bundles on April 22, 2024, and DENC began to launch the program in June of 2024.

Duke

PowerPair

On June 21, 2023, in Docket Nos. E-7 Sub, 1261 and E-2, Sub 1287, Duke filed an application for approval of PowerPair Solar and Battery Installation Pilot Program. This application was in response to the Commission's order declining to approve Duke's proposed Smart $aver Solar Energy Efficiency Program (Smart $aver Order) in the same docket. In its Smart $aver Order, the Commission directed Duke to develop a pilot

[6] Docket Nos. E-22, Sub 683, E-22, Sub 682, and E-22, Sub 684, respectively.

program to evaluate operational impacts to the electric system, if any, of behind the meter residential solar plus energy storage.

Duke stated that, in accordance with the Smart $aver Order, it developed PowerPair in collaboration with the Public Staff and numerous other stakeholders. Duke further stated that it convened meetings with the stakeholders and received extensive comments and feedback about the program and that the application reflects the stakeholders' input.

On January 11, 2024, the Commission issued an order approving the PowerPair Pilot Program with conditions and approving modifications to EnergyWise and Power Manager residential load control programs. Duke was directed to file annual status reports on PowerPair and the Battery Control Options and a final report. In addition, Duke shall include in the final PowerPair report: (1) information on the total cost of installation of the participants' solar panels and batteries; (2) the bill impacts on customers who were participants in the pilot; (3) the bill impacts on customers who were not participants; and (4) a recommendation as to whether the program should be continued, modified, or discontinued. The Commission also concluded that Duke should investigate the availability of other North Carolina rebate programs for the installed equipment and coordinate its efforts on PowerPair with such other rebate programs.

Duke submitted its initial joint annual status report on May 12, 2025. The report states that DEC has accepted 1,357 applications and DEP has accepted 1,900 applications, each subsequently awarded a PowerPair reservation. As of March 31, 2025, DEC had a total remaining capacity of 18,046 kW and DEP had a total remaining capacity of 12,666 kW out of a total capacity of 30,000 kW capacity for each DEC and DEP.

Income Qualified Residential Load Control Programs

On September 11, 2023, DEC and DEP filed separate applications for approval of their Income Qualified Residential Load Control Programs in Docket Nos. E-2, Sub 927 and E-7, Sub 1032. In its filings, Duke stated that the programs are intended to provide income-qualified customers with a DSM program opportunity. Enrolling customers can choose between two options: (1) a load control device provided by Duke; or (2) the installation of an eligible thermostat that will be customer-owned following enrollment in the program. If the customer chooses the thermostat option, the customer will receive the thermostat at no cost, and the thermostat will be installed and registered at no cost to the customer. As a result of its review, the Public Staff stated that the programs have the potential to encourage capacity savings, are consistent with Duke's IRPs, and are in the public interest. On November 28, 2023, the Commission issued an order approving the programs.

Innovation Pilot Program

Duke's Mechanism for DSM and EE programs approved by the Commission's order on May 22, 2024, in Docket Nos. E-2, Sub 931 and E-7, Sub 1032, provided that beginning in Vintage 2025, Duke's DSM/EE Portfolio shall include a DSM/EE Innovation Program. This program will have an annual budget that shall not exceed one million dollars each for DEC and DEP, which shall be utilized by Duke to test and evaluate new EE technologies and equipment and program designs in a rapid manner. In Duke's most recent rider applications,[7] Fields Exhibit 6 provided an explanation of potential tests, projects, or pilots that Duke is going to perform in 2025. These projects included Commercial Building Load Optimization Solutions, Smart $aver Emerging and Underutilized Technologies, Multi-Family Savings Persistence, Evaluating DR Capabilities of Connected Variable Capacity Heat Pumps, Energy Monitoring Hardware/Software Test, and K-12 ENERGY STAR Student Toolkit.

Mechanism Review Modifications

In compliance with the Commission's May 22, 2024 order, Duke filed with the Commission a consolidated application for modifications to existing DSM and EE programs in Docket Nos. E-2, Sub 931 and E-7, Sub 1032. Modifications were requested to account for increased customer incentives, new DSM and EE measures, updated program design to enhance customer experience, and streamlined tariff offerings that provide alignment across programs and tariff designs. These modifications were approved by the Commission on October 21, 2024.

Phase I Electric Transportation Pilot Programs

The Phase I Electric Transportation Pilot Programs were approved by the Commission on November 24, 2020, in Docket Nos. E-2, Sub 1197 and E-7, Sub 1195. On October 31, 2024, Duke filed a request to extend the term of the pilots, which the Commission approved on November 22, 2024. On February 21, 2025, Duke filed a second request to extend the end date of the Electric Vehicle School Bus (EVSB) Pilot Program for an additional 12 months to ensure that it would be able to fully evaluate the Vehicle to Grid (V2G) capabilities across the entire fleet of buses enrolled in the pilot program. The Commission approved the extension through June 30, 2026.

Phase II Electric Transportation Pilot Programs

On December 19, 2024, the Commission issued an Order Allowing Withdrawal and Discontinuation of Proposed Phase II Electric Transportation Pilot Programs in Docket Nos. E-2, Sub 1197 and E-7, Sub 1195. In Duke's Motion to Withdraw and Discontinue, Duke indicated that, due to limited opportunities to leverage federal funding for the objectives of the pilots and its belief that promoting managed charging for North Carolina EV drivers is paramount, it is in the public interest to discontinue the development of the Phase II ET Pilots.

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[7] Docket Nos. E-7, Sub 1313, 1314, 1315, 1316 and E-2, Sub 1354, 1355, 1356, 1357, and 1358.

EV Time-Of-Use Pilot

On December 18, 2023, Duke filed an application for approval of a residential EV off-peak charging program (OPC) in Docket Nos. E-2, Sub 1334 and E-7, Sub 1301. In support of Duke's application, it stated that the OPC Program is intended to provide residential customers with a financial incentive to charge their EVs during off-peak hours. On April 15, 2024, the Public Staff filed its comments. While the Public Staff agreed that the OPC Program would likely encourage off-peak charging habits and facilitate estimation of kilowatt-hours associated with EV charging, the Public Staff disagreed with Duke's assertion that the monthly bill credit offered to customers constituted a rate or rate design under the Time Differentiated and Dynamic Rate Enrollment Performance Incentive Mechanism. On April 15, 2025, Duke filed an application for approval of Residential EV Time-of-Use (TOU-EV) Pilot Rates and Notice of Withdrawal of Application for the OPC Program. In Duke's April 15, 2025, application, it stated that in response to the input from the Public Staff, it had developed a new TOU-EV rate proposal.[8]

DEC

Electric Vehicle-to-Grid Program

On August 16, 2022, DEC filed an application for approval of its V2G program in Docket No. E-7, Sub 1275, which the Commission approved in an order issued on April 11, 2023. In its application, DEC explained that V2G Pilot participants would be individually metered residential customers who lease a qualifying EV[9] and install the necessary EV supply equipment at their residences. On November 22, 2023, DEC filed a motion requesting to postpone implementation of the V2G Pilot until January 1, 2025, which the Commission approved on December 11, 2023. In its motion, DEC explained that high inflation and lingering supply chain constraints caused a slowdown in the production of new vehicles, including EVs. DEC stated that since filing the V2G Pilot application, it has observed significant differences in the projected and actual number of EV deliveries, home integration kit installations, and the number of customers choosing to lease versus purchasing eligible vehicles. On July 1, 2024, DEC filed its semi-annual report and motion to withdraw and discontinue the V2G pilot. In DEC's motion, DEC stated that it has not observed any material changes in market conditions, the adoption of Ford F150 Lightning EVs, or the development of bi-directional V2G and notes that it does not believe that conditions will change significantly by January 1, 2025. On December 19, 2024, the Commission issued an order allowing the withdrawal and discontinuation of DEC's V2G Pilot. The Commission's order directed that DEC shall continue its development of managed charging programs, including but not limited to V2G bi-directional charging programs, and file applications with the Commission when it considers them ready for implementation, either as pilot programs or full-scale commercial programs in one or both of its North Carolina service territories.

[8] On July 8, 2025, the Commission issued an Order approving the TOU-EV Pilot Rates.

[9] DEC anticipated that the Ford F150 Lightning would be the only qualifying EV for the V2G pilot.

DEP

PowerShare Nonresidential Load Curtailment Program

On June 17, 2025, DEP filed an application for approval of PowerShare Nonresidential Load Curtailment Program in Docket No. E-2, Sub 931. Due to a need for winter capacity resources, DEP proposed a DSM solution that will allow it to attract customer participation in a program that can cost effectively address reducing system peaks in the winter. DEP's existing approved DSM program is the summer-focused Commercial, Industrial, and Governmental Demand Response Automation Rider, which targets large customers. DEP believes that the proposed PowerShare Program will increase customer participation and allow it to build an important and needed demand-side winter resource moving forward. The program furthers the goals in the stipulation entered into on July 22, 2024, in Docket No. E-100, Sub 190, among DEP, DEC, the Public Staff, Walmart Inc. (Walmart), and CCEBA, which the Commission approved the in Docket No. E-2, Sub 931 by order dated November 1, 2024. The following provisions appeared in the Stipulation:

> 44. The Companies agree to work with interested parties to attempt to develop a program that would incentivize non-residential customers to invest in on-site generation and/or storage in manner that provides net system benefits, with the goal of filing such programs with the Commission by no later than September 2025.
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> 45. The Stipulating Parties agree that the Companies will work with interested parties to develop a suite of non-residential DSM programs using the DSM/EE Mechanism approved by the Commission in Docket Nos. E-7, Sub 1032 and E-2, Sub 931 with the goal of filing such programs with the Commission no later than September 2025.

DEP explains that the program is virtually identical to DEC's nonresidential PowerShare offering. By June 30, 2025, this matter was still pending before the Commission.

SECTION 4: COMMISSION PROCEEDINGS REGARDING DSM/EE COST RECOVERY

North Carolina General Statutes § 62-133.9(d) allows a utility to petition the Commission for approval of an annual rider to recover (1) the reasonable and prudent costs of new DSM and EE measures and (2) other incentives to the utility for adopting and implementing new DSM and EE measures. Further, Commission Rule R8-69(b) provides that the Commission will conduct an annual proceeding for each electric utility to establish an annual DSM/EE rider to recover DSM and EE related costs and utility incentives.

DENC

During the two-year period of July 1, 2023, through June 30, 2025, DENC had two such proceedings before the Commission. Below is a discussion of each proceeding.

Docket No. E-22, Sub 676

On August 15, 2023, DENC filed its application for approval of DSM/EE cost recovery rider. The annual rider recovered the utility's forecasted costs during the rate period of February 1, 2024, through January 31, 2025, and an experience modification factor (EMF) rider shall recover the difference between the utility's actual reasonable and prudent costs incurred and actual revenues realized during the test period of January 1, 2022, through December 31, 2022. DENC's portfolio of DSM and EE programs for which rate period cost recovery was sought in this proceeding includes:

- Residential Air Conditioner Cycling (Sub 465)
- Small Business Improvement (Sub 538)
- Non-Residential Prescriptive (Sub 543)
- Non-Residential Heating and Cooling Efficiency Program (Sub 574)
- Non-Residential Lighting Systems and Controls Program (Sub 573)
- Non-Residential Window Film (Sub 570)
- Non-Residential Office (Sub 572)
- Non-Residential Small Manufacturing (Sub 571)
- Residential Appliance Recycling (Sub 569)
- Residential Home Energy Assessment (Sub 567)
- Residential Efficient Products Marketplace (Sub 568)
- Residential Smart Thermostat (EE) (Sub 595)
- Residential Smart Thermostat (DR) (Sub 594)
- Residential Energy Efficiency Kits (Sub 592)
- Residential Home Retrofit (Sub 593)
- Small Business Improvement Enhanced (Sub 596)
- Non-Residential New Construction (Sub 591)
- Residential Income and Age Qualifying (Sub 608)
- Residential Smart Home (Sub 618)
- Residential Virtual Audit (Sub 619)
- Residential Water Savings (EE) (Sub 621)
- Residential Water Savings (DR) (Sub 620)
- Non-Residential Building Automation (Sub 614)
- Non-Residential Building Optimization (Sub 615)
- Non-Residential Engagement (Sub 616)
- Non-Residential Enhanced Prescriptive (Sub 617)
- Non-residential Lighting Systems and Controls (Sub 666)

In its application, DENC sought recovery of $4,018,188, comprised of the Rider C revenue requirement of $3,285,714 and Rider CE revenue requirement of $732,474. As proposed, DENC's rider would result in the following charges, including the regulatory fee.

Residential	0.1317 cents/kWh
Small General Service and Public Authorities	0.1787 cents/kWh
Large General Service	0.1616 cents/kWh

Intervenors in this proceeding were the Public Staff, Carolina Industrial Group for Fair Utility Rates I (CIGFUR I), and CUCA. The Public Staff filed testimony and exhibits on November 7, 2023, and recommended approval of DENC's proposed rates.

The expert witness hearing was cancelled by the Commission's order dated November 21, 2023. The Commission held a public witness hearing for this matter on November 28, 2023, and no public witnesses appeared at the hearing.

On January 14, 2024, the Commission issued its order approving the billing factors as listed above and as proposed by DENC in its application.

Docket No. E-22, Sub 711

On August 13, 2024, DENC filed its application for approval of DSM and EE cost recovery rider. The annual rider recovered the utility's forecasted costs during the rate period from February 1, 2025, through January 31, 2026, and an experience modification factor (EMF) rider shall recover the difference between the utility's actual reasonable and prudent costs incurred and actual revenues realized during the test period from January 1, 2023, through December 31, 2023. DENC's portfolio of DSM and EE programs for which rate period cost recovery was sought in this proceeding includes:

- Residential Air Conditioner Cycling (Sub 465)
- Non-Residential Heating and Cooling Efficiency Program (Sub 574)
- Non-Residential Lighting Systems and Controls Program (Sub 573)
- Non-Residential Window Film (Sub 570)
- Non-Residential Office (Sub 572)
- Non-Residential Small Manufacturing (Sub 571)
- Residential Appliance Recycling (Sub 569)
- Residential Home Energy Assessment (Sub 567)
- Residential Efficient Products Marketplace (Sub 568)
- Residential Smart Thermostat (EE) (Sub 595)
- Residential Smart Thermostat (DR) (Sub 594)
- Residential Energy Efficiency Kits (Sub 592)
- Residential Home Retrofit (Sub 593)
- Small Business Enhanced (Sub 596)
- Non-Residential New Construction (Sub 591)
- Residential Income Age Qualifying (Sub 608)
- Residential Smart Home (Sub 618)

- Residential Virtual Audit (Sub 619)
- Residential Water Savings (EE) (Sub 621)
- Residential Water Savings (DR) (Sub 620)
- Non-Residential Building Automation (Sub 614)
- Non-Residential Building Optimization (Sub 615)
- Non-Residential Engagement (Sub 616)
- Non-Residential Enhanced Prescriptive (Sub 617)
- Non-residential Lighting Systems and Controls (Sub 666)
- Residential Income and Age Qualifying Bundle (Sub 684)
- Residential Efficient Products Marketplace (Sub 693)

In its rider application, DENC sought recovery of $4,234,239, comprised of the Rider C revenue requirement of $4,035,376 and Rider CE revenue requirement of $198,863. As proposed, DENC's rider would result in the following charges, including the regulatory fee.

Residential	0.1583 cents/kWh
Small General Service and Public Authorities	0.1655 cents/kWh
Large General Service	0.1292 cents/kWh

Intervenors in this proceeding were the Public Staff, CIGFUR I, and CUCA. The Public Staff filed testimony and exhibits on October 29, 2024, and recommended approval of DENC's proposed rates.

The expert witness hearing was cancelled by the Commission's Order dated November 14, 2024. The Commission held a public witness hearing for this matter on November 19, 2024, and no public witnesses appeared.

On January 31, 2025, the Commission issued its order approving the billing factors as listed above and as proposed by DENC in its application.

DEC

During the two-year period from July 1, 2023, through June 30, 2025, DEC had three such proceedings before the Commission. Below is a discussion of each proceeding.

Docket No. E-7, Sub 1285

On February 28, 2023, DEC filed an application for the approval of its DSM/EE Rider 15 and associated testimony and exhibits, requesting recovery of the following: (1) a prospective component consisting of the estimated revenue requirements for Vintage 2024 programs, as well as estimated net lost revenue (NLR) related to Vintages 2021 through 2023 and (2) an EMF component representing true-ups of Vintages 2016 through 2022. On April 28, 2023, DEC filed supplemental testimony and exhibits. In its supplemental filings, DEC requested Commission approval of the following annual billing factors (₵/kWh including gross receipts and regulatory fee):

Residential Billing Factors

Rider 15 Prospective Component	0.4320	cents/kWh
Rider 15 EMF Component	(0.0503)	cents/kWh

Non-Residential Billing Factors

Prospective Components:		
Vintage 2021 EE participant	0.0313	cents/kWh
Vintage 2022 EE participant	0.0468	cents/kWh
Vintage 2023 EE participant	0.0802	cents/kWh
Vintage 2024 EE participant	0.3869	cents/kWh
Vintage 2024 DSM participant	0.0897	cents/kWh
EMF Components*:*		
Vintage 2018 EE Participant	(0.0001)	cents/kWh
Vintage 2018 DSM Participant	0.0000	cents/kWh
Vintage 2019 EE Participant	(0.0014)	cents/kWh
Vintage 2019 DSM Participant	(0.0001)	cents/kWh
Vintage 2020 EE Participant	(0.0068)	cents/kWh
Vintage 2020 DSM Participant	0.0002	cents/kWh
Vintage 2021 EE Participant	(0.0082)	cents/kWh
Vintage 2021 DSM Participant	(0.0073)	cents/kWh
Vintage 2022 EE Participant	(0.1732)	cents/kWh
Vintage 2022 DSM Participant	(0.0017)	cents/kWh

DEC requested approval of costs and incentives related to the following DSM and EE programs to be included in Rider 15:

Residential

- Energy Assessment Program
- EE Education Program
- Energy Efficient Appliances and Devices Program
- Residential Smart $aver EE Program
- Multifamily EE Program
- My Home Energy Report (MyHER) Program
- Income-Qualified EE and Weatherization Program for Individuals
- Neighborhood Energy Saver Program
- New Construction
- Power Manager Load Control Service Program

Non-Residential

- Non-Residential Smart $aver Energy Efficient Products and Assessment Prescriptive Program:
    - Energy Efficient Food Service Products
    - Energy Efficient HVAC Products
    - Energy Efficient IT Products
    - Energy Efficient Lighting Products
    - Energy Efficient Process Equipment Products
    - Energy Efficient Pumps and Drives Products
- Smart $aver Custom Incentive and Energy Assessment
- PowerShare Nonresidential Load Curtailment Program
- Business Energy Saver Program
- EnergyWise for Business Program
- Non-Residential Smart $aver Performance Incentive Program

Intervenors in this proceeding were the Public Staff, CIGFUR III, CUCA, and, jointly, North Carolina Justice Center (NCJC), North Carolina Housing Coalition (NCHC) and SACE (collectively, NC Justice Center, *et al*.). On May 9, 2023, the Public Staff filed its testimony and exhibits and recommended that the billing factors proposed by DEC, as set forth in Revised Miller Exhibit 1, be approved by the Commission. On May 30, 2023, the matter came for hearing as scheduled. No public witnesses appeared at the hearing.

On August 29, 2023, the Commission issued its order approving the rider billing factors as listed above and as filed in DEC's direct and supplemental testimony and exhibits for the rate period January 1, 2024, through December 31, 2024. The Commission also directed DEC and the Collaborative[10] participants to continue to work to better understand and identify potential means of addressing energy savings forecasts.

Docket No. E-7, Sub 1305

On February 27, 2024, DEC filed an application for the approval of its DSM/EE Rider 16 and associated testimony and exhibits, requesting recovery of the following: (1) a prospective component consisting of the estimated revenue requirements for Vintage 2025 programs, as well as estimated NLR related to Vintages 2022 though 2024; and (2) an EMF component representing true-ups of Vintages 2019 through 2023. On May 8, 2024, DEC filed supplemental direct testimony and exhibits. In its supplemental filings, DEC requested Commission approval of the following annual billing factors (₵/kWh including gross receipts and regulatory fee):

<u>Residential Billing Factors</u>

Rider 16 Prospective Component	0.5012	cents/kWh
Rider 16 EMF Component	(0.0079)	cents/kWh

[10] The Collaborative refers to Duke's DSM and EE stakeholder group, as defined in its Mechanism found in Docket Nos. E-7, Sub 931 and E-7, Sub 1032.

Non-Residential Billing Factors

Prospective Components:		
Vintage 2022 EE participant	0.0079	cents/kWh
Vintage 2023 EE participant	0.0369	cents/kWh
Vintage 2024 EE participant	0.0929	cents/kWh
Vintage 2024 DSM participant	0.3591	cents/kWh
Vintage 2025 EE participant	0.1161	cents/kWh
EMF Components*:*		
Vintage 2018 EE Participant	(0.0011)	cents/kWh
Vintage 2018 DSM Participant	(0.0002)	cents/kWh
Vintage 2019 EE Participant	0.0007	cents/kWh
Vintage 2019 DSM Participant	0.0000	cents/kWh
Vintage 2020 EE Participant	(0.0049)	cents/kWh
Vintage 2020 DSM Participant	(0.0016)	cents/kWh
Vintage 2021 EE Participant	(0.0900)	cents/kWh
Vintage 2021 DSM Participant	0.0003	cents/kWh
Vintage 2022 EE Participant	(0.0767)	cents/kWh
Vintage 2022 DSM Participant	(0.0020)	cents/kWh
Vintage 2023 EE Participant	(0.1554)	cents/kWh
Vintage 2023 DSM Participant	0.0143	cents/kWh

DEC requested approval of costs and incentives related to the following DSM and EE programs to be included in Rider 16:

Residential

- EE Education Program
- Energy Efficient Appliances and Devices Program
- Income-Qualified High-Energy Use Pilot
- Income-Qualified EE and Weatherization Program for Individuals
    - Neighborhood Energy Saver Program
    - Weatherization
- Multifamily EE Program
- Energy Assessments Program
- New Construction Program
- Smart $aver – Early Replacement and Retrofit
- Smart $aver Program
- My Home Energy Report (MyHER)
- Income-Qualified Power Manager
- Power Manager Load Control Service Program

Non-Residential

- Non-Residential Smart $aver Energy Efficient Products and Assessment Prescriptive Program:
    - Energy Efficient Food Service Products
    - Energy Efficient HVAC Products
    - Energy Efficient Lighting Products
    - Energy Efficient Process Equipment Products
    - Energy Efficient Pumps and Drives Products
- Smart $aver Custom Incentive and Energy Assessment
- Smart $aver Performance Incentive Program
- Business Energy Saver Program
- EnergyWise for Business Program
- PowerShare Program

Intervenors in this proceeding were the Public Staff, CIGFUR III, and CUCA. On May 20, 2024, the Public Staff filed its testimony and exhibits and recommended that the billing factors proposed by DEC, as set forth in Revised Miller Exhibit 1, be approved by the Commission. In addition, the Public Staff provided comments regarding the verification of NLRs for measures installed after the test year but before the new base rates became effective. On May 29, 2024, DEC filed rebuttal testimony and exhibits, responding to the Public Staff's comments on NLR. On June 10, 2024, the matter came for hearing as scheduled. No public witnesses appeared at the hearing.

On August 20, 2024, the Commission issued its order approving the rider billing factors as listed above and as filed in DEC's supplemental direct testimony and exhibits to go into effect for the rate period from January 1, 2025, through December 31, 2025. Regarding NLR, the Commission found and concluded that there was no evidence of double counting of NLR in the rates proposed by DEC in this proceeding. The Commission concluded that the parties should discuss and resolve the issue surrounding the exchange of information between the parties in the next general rate case to ensure no double counting of NLR in any future DEC DSM/EE rider proceeding.

Docket No. E-7, Sub 1314

On February 25, 2025, DEC filed an application for the approval of its DSM/EE Rider 17 and associated testimony and exhibits, requesting recovery of the following: (1) a prospective component consisting of the estimated revenue requirements for Vintage 2026 programs, as well as estimated NLR related to Vintages 2023 through 2025; and (2) an EMF component representing true-ups of Vintages 2021 through 2024. On March 13, 2025, DEC filed supplemental direct testimony and exhibits. On May 6, 2025, DEC filed second supplemental direct testimony and exhibits. In its second supplemental filings, DEC requested Commission approval of the following annual billing factors (¢/kWh including gross receipts and regulatory fee):

<u>Residential Billing Factors</u>

Rider 16 Prospective Component	0.4578	cents/kWh

Rider 16 EMF Component	0.0503	cents/kWh

Non-Residential Billing Factors

Prospective Components:		
Vintage 2023 EE participant	0.0174	cents/kWh
Vintage 2024 EE participant	0.0420	cents/kWh
Vintage 2024 DSM participant	0.0624	cents/kWh
Vintage 2025 EE participant	0.3294	cents/kWh
Vintage 2026 EE participant	0.1864	cents/kWh
EMF Components*:*		
Vintage 2021 EE Participant	(0.0015)	cents/kWh
Vintage 2021 DSM Participant	0.0007	cents/kWh
Vintage 2022 EE Participant	(0.0258)	cents/kWh
Vintage 2022 DSM Participant	(0.0004)	cents/kWh
Vintage 2023 EE Participant	(0.0038)	cents/kWh
Vintage 2023 DSM Participant	0.0006	cents/kWh
Vintage 2024 EE Participant	(0.0886)	cents/kWh
Vintage 2024 DSM Participant	0.0265	cents/kWh

DEC requested approval of costs and incentives related to the following DSM and EE programs to be included in Rider 17:

Residential

- EE Education Program
- Energy Efficient Appliances and Devices Program
- Income-Qualified High-Energy Use Pilot
- Income-Qualified EE and Weatherization Assistance
- Neighborhood Energy Saver Program
- Multi-Family EE Program
- Energy Assessments Program
- New Construction Program
- Smart $aver – Early Replacement and Retrofit
- Smart $aver Program
- My Home Energy Report
- Income-Qualified Power Manager
- Power Manager Load Control Service Program
- DSM/EE Innovation Program

Non-Residential

- Non-Residential Smart $aver Energy Efficient Products and Assessment
- Smart $aver Performance Incentive Program
- Business Energy Saver Program

- EnergyWise for Business Program
- PowerShare Program
- DSM/EE innovation Program

Intervenors in this proceeding were the Public Staff, CIGFUR III, and CUCA. On May 13, 2025, the Public Staff filed its testimony and exhibits and recommended that the billing factors proposed by DEC, as set listed above and set forth in Second Revised Miller Exhibit 1, be approved by the Commission. On May 30, 2025, the Commission issued an order canceling the expert witness hearing scheduled for June 3, 2025. As of June 30, 2025, the matter was still pending before the Commission.

DEP

During the two-year period from July 1, 2023, through June 30, 2025, DEP had three such proceedings before the Commission. Below is a discussion of each proceeding.

Docket No. E-2, Sub 1322

On June 13, 2023, DEP filed an application and the associated testimony and exhibits of its witnesses for the approval of a DSM/EE rider to recover reasonable and prudent DSM and EE costs, including program costs, net lost revenues, incentives, and an EMF. On August 24, 2023, DEC filed supplemental testimony and exhibits. On August 28, 2023, DEC filed corrected supplemental testimony and exhibits. DEP requested the rider and EMF to allow it to recover $141,190,853 of DSM and EE expenses, NLR, and incentives. This amount includes the estimated over-collection of ($24,884,526) associated with test period activities during the period beginning January 1, 2022, and ending December 31, 2022, and an estimated $166,075,379 for expenses, NLR, and incentives to be incurred during the rate period from January 1, 2024, through December 31, 2024. DEP requested that the Commission approve the following total annual billing factor adjustments (with the regulatory fee included).

Residential	0.629	cents/ kWh
General Service EE	0.358	cents/ kWh
General Service DSM	0.042	cents/ kWh
Lighting	0.000	cents/ kWh

DEP requested approval for the recovery of costs, and utility incentives where applicable, related to the following DSM/EE programs:

<u>Residential</u>

- EE Education Program
- Multi-Family EE Program
- MyHER Program
- Neighborhood Energy Saver Program
- Residential Smart $aver EE Program

• New Construction Program
• Load Control (EnergyWise)
• Save Energy and Water Kit (now part of the EE Appliances and Devices Program)
• Energy Assessment Program
• Low-Income Weatherization Pay for Performance Pilot Program
• Energy Efficient Appliances and Devices Program

<u>Non-Residential</u>

• Non-Residential Smart $aver Energy Efficient Products and Assessments Program
• Non-Residential Smart $aver Performance Incentive Program
• Small Business Energy Saver Program
• Commercial, Industrial, and Governmental (CIG) Demand Response Automation
• EnergyWise for Business

<u>Residential and Non-Residential</u>

• EE Lighting
• Distribution System Demand Response (DSDR)

Intervenors in this proceeding as of the date of this report were as follows: the Public Staff, CIGFUR II, CUCA. On August 29, 2023, the Public Staff filed its testimony and exhibits and recommended that the billing factors proposed by DEP, as set forth in Revised Miller Exhibit 1, be approved by the Commission. The Public Staff also provided testimony to address concerns related to the calculation of non-participant spillover (NPSO), specifically in the Non-Residential Smart $aver Custom Program EM&V report. On September 9, 2023, DEC filed its rebuttal testimony and revised exhibits to respond to the Public Staff's concerns on NPSO calculations. On September 19, 2023, the hearing came before the Commission as scheduled. No public witnesses appeared at the hearing.

On December 19, 2023, the Commission issued its order approving the rider billing factors as listed above and as filed in DEP's rebuttal testimony and exhibits for the rate period January 1, 2024, through December 31, 2024. The Commission also approved the NPSO calculations reflected in DEP's rebuttal testimony and agreed to by the Public Staff.

Docket No. E-2, Sub 1342

On June 11, 2024, DEP filed an application and the associated testimony and exhibits of its witnesses for the approval of a DSM/EE rider to recover reasonable and prudent DSM and EE costs, including program costs, net lost revenues, incentives, and an EMF. On July 19, 2024, DEP filed supplemental direct testimony and exhibits. On August 23, 2025, DEP filed second supplemental direct testimony and exhibits. DEP requested the rider and EMF to allow it to recover $158,291,336 of DSM and EE expenses, NLR, and incentives. This amount includes the estimated over-collection of

($14,806,708) associated with test period activities during the period beginning January 1, 2023, and ending December 31, 2023, and an estimated $173,098,044 for expenses, NLR, and incentives to be incurred during the rate period from January 1, 2025, through December 31, 2025. DEP requested that the Commission approve the following total annual billing factor adjustments (with the regulatory fee included).

Residential	0.767	cents/ kWh
General Service EE	0.233	cents/ kWh
General Service DSM	0.041	cents/ kWh
Lighting	(0.022)	cents/ kWh

DEP requested approval for the recovery of costs, and utility incentives where applicable, related to the following DSM and EE programs:

Residential

- Energy Efficient Appliances and Devices Program
- Energy Efficiency Education
- Energy Efficiency Lighting
- Residential Smart $aver EE
- Income-Qualified EE and Weatherization Assistance
- Multi-Family EE
- Multi-Family New Construction Tariffed On-Bill Pilot
- Neighborhood Energy Saver program
- Energy Assessment Program
- New Construction Program
- Save Energy and Water Kit Program
- Smart $aver – Early Replacement and Retrofit
- MyHER Program
- Load Control Program (EnergyWise)
- Income-Qualified EnergyWise Home

Non-Residential

- EE Lighting
- Non-Residential Smart $aver Custom
- Non-Residential Smart $aver Prescriptive
- Non-Residential Smart $aver Performance
- Business Energy Saver Program
- CIG Demand Response Automation Program
- EnergyWise for Business

Intervenors in this proceeding, as of the date of this report, were the Public Staff, CIGFUR II, and CUCA. On August 26, 2024, the Public Staff filed its testimony and exhibits and recommended that the billing factors proposed by DEP, as set forth in Second Revised Miller Exhibit 1, be approved by the Commission. The Public Staff also recommended that the Commission order DEP to file additional information supplementing Fields Exhibit 2 regarding NLR and two recommendations regarding robust surveying and consistent methodology in future EM&V reports. On September 4, 2024, DEP filed its rebuttal testimony and exhibits, agreeing with the Public Staff's recommendations on the EM&V process and additional information on NLR. On September 13, 2024, the Commission issued an order cancelling the expert witness hearing. A public witness hearing was held on September 16, 2024, and no public witnesses appeared.

On November 13, 2024, the Commission issued its order approving the rider billing factors as listed above and as filed in DEP's second supplemental direct testimony and exhibits for the rate period January 1, 2025, through December 31, 2025.

Docket No. E-2, Sub 1357

On June 10, 2025, DEP filed an application and the associated testimony and exhibits of its witnesses for the approval of a DSM/EE rider to recover reasonable and prudent DSM and EE costs, including program costs, net lost revenues, incentives, and an EMF. DEP requested the rider and EMF to allow it to recover $156,624,013 of DSM and EE expenses, NLR, and incentives. This amount includes the estimated over-collection of ($4,555,999) associated with test period activities during the period beginning January 1, 2024, and ending December 31, 2024, and an estimated $161,180,011 for expenses, NLR, and incentives to be incurred during the rate period from January 1, 2026, through December 31, 2026. DEP requested that the Commission approve the following total annual billing factor adjustments (with the regulatory fee included).

Residential	0.769	cents/ kWh
General Service EE	0.197	cents/ kWh
General Service DSM	0.044	cents/ kWh
Lighting	0.011	cents/ kWh

DEP requested approval for the recovery of costs and utility incentives, where applicable, related to the following DSM and EE programs:

<u>Residential</u>

- Energy Efficiency Education
- Energy Efficient Appliances and Devices Program
- Residential Smart $aver EE
- Income-Qualified EE and Weatherization Assistance
- Income-Qualified High-Energy Use Pilot
- Multi-Family EE
- Multi-Family New Construction Tariffed On-Bill Pilot
- Neighborhood Energy Saver program
- Energy Assessment Program
- New Construction Program

- Smart $aver – Early Replacement and Retrofit
- MyHER Program
- Load Control Program (EnergyWise)
- Income-Qualified EnergyWise Home
- DSM/EE Innovation Program

Non-Residential

- Non-Residential Smart $aver Energy Efficiency Products and Assessment
- Non-Residential Smart $aver Performance Incentive Program
- Business Energy Saver Program
- EnergyWise for Business
- CIG Demand Response Automation Program
- DSM/EE Innovation program

Intervenors in this proceeding are the Public Staff, CIGFUR II, and CUCA. As of June 30, 2025, the matter was still pending before the Commission.

SECTION 5: COST RECOVERY MECHANISMS

DENC

DENC did not have a revision to its DSM/EE cost recovery and incentive mechanism during the scope of this report. The previous mechanism review concluded by the Commissioner's order dated March 19, 2022, in Docket No. E-22, Sub 464, which directed the Public Staff to initiate its next formal review not later than May 1, 2026.

Duke

The Commission's October 20, 2020 order in Docket Nos. E-2, Sub 931 and E-7, Sub 1032 directed the Public Staff to initiate a joint formal review of Duke's Mechanisms not later than May 1, 2024, unless requested to do so earlier by the Commission, DEC, DEP, or another interested party.

In its Initial Carbon Plan Order, the Commission directed Duke to initiate a docket to fully review the DEC and DEP Mechanisms, including consideration of four specific enablers:

- Updating the inputs underlying the cost benefit test in the Mechanisms;
- Using the as-found baseline for EE measures;
- Changing the definition of low-income customer; and
- Developing guidelines for expedited regulatory approval of DSM/EE programs.

On April 27, 2023, Duke filed a letter in the above-captioned dockets initiating the Commission-directed review of the Mechanisms.

On December 18, 2023, the Commission held a technical conference, receiving presentations from and asking questions of the following parties on the existing Mechanisms and on the work of the DSM/EE Mechanism review stakeholder process: Duke; the Public Staff; CIGFUR; Walmart; CUCA; SACE; NRDC; South Carolina Coastal Conservation League (CCL); Sierra Club; and NCSEA. Additionally, pursuant to prior notice to the parties, the Commission asked a representative with the Regulatory Assistance Project to make a presentation on DSM/EE cost recovery and incentive approaches in other jurisdictions.

Initial comments on the Mechanisms were filed on January 26, 2024, by Duke; the Public Staff; the AGO; CIGFUR; CUCA; Walmart; and jointly by SACE, NRDC, CCL, Sierra Club, NCJC, NCHC, and NCSEA (collectively, Efficiency Advocates).

On April 1, 2024, Duke and the Public Staff filed reply comments.

On April 5, 2024, the Commission issued an Order Scheduling Technical Conference, directing the parties to make presentations to the Commission on the following topics: the impact of the uncontested issues on Duke's DSM/EE riders, the two contested issues, discussed in more detail below, and whether the proposed Mechanisms were expected to reduce the number of large commercial and industrial customers opting out of participation in Duke's DSM/EE programs pursuant to N.C. Gen. Stat. § 62-133.9(f) and Commission Rule R8-69(d). On April 15, 2024, Walmart and CIGFUR submitted letters outlining their positions regarding opt-outs by industrial and large commercial customers. The second technical conference was held on April 22, 2024. Duke, the Public Staff, the AGO, CUCA, CIGFUR, Walmart, and the Efficiency Advocates gave presentations and answered questions from the Commissioners.

On May 22, 2024, the Commission issued an order approving the revised DEC and DEP Mechanisms to be effective for DSM and EE costs and utility incentives associated with time periods beginning on and after January 1, 2025. The order outlines the following issues as to which there is consensus: the Portfolio Performance Incentive (PPI) modifier Measure Life Adjustment Factor, inclusion of a program return incentive, other incentives, updating system benefit inputs, the as-found baseline, the definition of low-income customer, expedited regulatory approval, recovery of NLRs, non-energy benefits and carbon reduction benefits, the DSM/EE Collaborative, NPSO, a one-time reconsolidation, amortization, and true-ups.

The two contested issues were tiered PPI and the Active Load Management Program (ALM). The Commission agreed with Duke and the Efficiency Advocates that the ALM represents an innovative approach for managing existing and future grid-balancing needs in North Carolina. The Commission concluded that the definition of ALM and the language of the proposed incentive structure for the ALM should be included in the proposed Mechanisms and approved such inclusion. The ALM language provided that, beginning in 2025, Duke will begin to identify and, following Commission approval, implement up to 20 MW of capacity under ALM. Regarding tiered PPI, the Commission agreed with the position of the majority of the parties that a shared savings incentive is appropriate for every tier of the PPI. The Commission found that the proposed tiered PPI Performance Scale, as supported by Duke, the Public Staff, and the Efficiency Advocates, strikes an appropriate balance.

The Commission further ordered the Public Staff to initiate a joint formal review of Duke's mechanisms not later than December 31, 2028, unless requested to do so earlier by the Commission, DEC or DEP, or another interested party. The Public Staff's review should specifically address whether the incentives in the Commission-approved Mechanisms are producing significant DSM and EE results; whether the customer rate impacts from the DSM/EE rider are reasonable and appropriate; whether overall portfolio performance targets should be adopted or revised; whether the Innovation Program should be revised or discontinued; and any other relevant issues that may be identified during the review process.

APPENDIX A

Rule R8-60. INTEGRATED RESOURCE PLANNING AND FILINGS.

(a) Purpose. — The purpose of this rule is to implement the provisions of G.S. 62-2(3a) and G.S. 62-110.1 with respect to least cost integrated resource planning by a public utility furnishing electric service in North Carolina that is not designed as an "electric public utility" under G.S. 62-110.9.

(b) Applicability. — This rule is applicable to Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina.

(c) Integrated Resource Plan. — Each utility shall develop and keep current an integrated resource plan, which incorporates, at a minimum, the following:

(1) a 15-year forecast of native load requirements (including any off-system obligations approved for native load treatment by the Commission) and other system capacity or firm energy obligations extending through at least one summer or winter peak (other system obligations); supply-side (including owned/leased generation capacity and firm purchased power arrangements) and demand-side resources expected to satisfy those loads; and the reserve margin thus produced; and

(2) a comprehensive analysis of all resource options (supply-and demand-side) considered by the utility for satisfaction of native load requirements and other system obligations over the planning period, including those resources chosen by the utility to provide reliable electric utility service at least cost over the planning period.

Each utility shall include an assessment of demand-side management and energy efficiency in its integrated resource plan. G.S. 62-133.9(c). In addition, each utility's consideration of supply-side and demand-side resources, including alternative supply-side energy resources, and the provision of reliable electric utility service at least cost shall appropriately consider and incorporate the utility's obligation to comply with the Renewable Energy and Energy Efficiency Portfolio Standard (REPS). G.S. 62-133.8.

(d) Purchased Power. — As part of its integrated resource planning process, each utility shall assess on an on-going basis the potential benefits of soliciting proposals from wholesale power suppliers and power marketers to supply it with needed capacity.

(e) Alternative Supply-Side Energy Resources. — As part of its integrated resource planning process, each utility shall assess on an on-going basis the potential benefits of reasonably available alternative supply-side energy resource options. Alternative supply-side energy resources include, but are not limited to, hydro, wind, geothermal, solar thermal, solar photovoltaic, municipal solid waste, fuel cells, and biomass.

(f) Demand-Side Management. — As part of its integrated resource planning process, each utility shall assess on an on-going basis programs to promote demand-side management, including costs, benefits, risks, uncertainties, reliability and customer acceptance, where appropriate. For purposes of this rule, demand-side management consists of demand response programs and energy efficiency and conservation programs.

(g) Evaluation of Resource Options. — As part of its integrated resource planning process, each utility shall consider and compare a comprehensive set of potential resource options, including both demand-side and supply-side options, to determine an integrated resource plan that offers the least cost combination (on a long-term basis) of reliable resource options for meeting the anticipated needs of its system. The utility shall analyze potential resource options and combinations of resource options to serve its system needs, taking into account the sensitivity of its analysis to variations in future estimates of peak load, energy requirements, and other significant assumptions, including, but not limited to, the risks associated with wholesale markets, fuel costs, construction/implementation costs, transmission and distribution costs, and costs of complying with environmental regulation. Additionally, the utility's analysis should take into account, as applicable, system operations, environmental impacts, and other qualitative factors.

(h) Filings.

(1) By October 15, 2024, and every two years thereafter, each utility subject to this rule shall file with the Commission its then current integrated resource plan, together with all information required by subsection (i) of this rule. This biennial report shall cover the next succeeding two-year period.

(2) By October 15 of each year in which a biennial report is not required to be filed, an update report shall be filed with the Commission containing an updated 15-year forecast of the items described in subparagraph (c)(1), as well as a summary of any significant amendments or revisions to the most recently filed biennial report, including amendments or revisions to the type and size of resources identified, as applicable.

(3) Each biennial and update report filed shall be accompanied by a short-term action plan that discusses those specific actions currently being taken by the utility to implement the activities chosen as appropriate per the applicable biennial and update reports.

(4) If a utility considers certain information in its biennial or update report to be proprietary, confidential, and within the scope of G.S. 132-1.2, the utility may designate the information as "confidential" and file it under seal.

(i) Contents of Biennial Reports. — Each utility shall include in each biennial report the following:

(1) Forecasts of Load, Supply-Side Resources, and Demand-Side Resources. The forecasts filed by each utility as part of its biennial report shall include descriptions of the methods, models, and assumptions used by the utility to prepare its peak load (MW) and energy sales (MWh) forecasts and the variables used in the models. In the biennial reports, the forecasts filed by each utility shall include, at a minimum, the following:

(i) The most recent ten-year history and a forecast of customers by each customer class, the most recent ten-year history and a forecast of energy sales (MWh) by each customer class, and the most recent ten-year history and a forecast of the utility's summer and winter peak load (MW);

(ii) A tabulation of the utility's forecast for at least a 15-year period, including peak loads for summer and winter seasons of each year, annual energy forecasts, reserve margins, and load duration curves, with and without projected supply or demand-side resource additions. The tabulation shall also indicate the projected effects of demand response and energy efficiency programs and activities on the forecasted annual energy and peak loads on an annual basis for a 15-year period, and these effects also may be reported as an equivalent generation capacity impact; and

(iii) Where future supply-side resources are required, a description of the type of capacity/resource (MW rating, fuel source, base, intermediate, or peaking) that the utility proposes to use to address the forecasted need.

(2) Generating Facilities. — Each utility shall provide the following data for its existing and planned electric generating facilities (including planned additions and retirements, but excluding cogeneration and small power production):

(i) Existing Generation. — The utility shall provide a list of existing units in service, with the information specified below for each listed unit. The information shall be provided for a 15-year period beginning with the year of filing:

a. Type of fuel(s) used;

b. Type of unit (e.g., base, intermediate, or peaking);

c. Location of each existing unit;

d. A list of units to be retired from service with location, capacity and expected date of retirement from the system;

e. A list of units for which there are specific plans for life extension, refurbishment or upgrading. The reporting utility shall also provide the expected (or actual) date removed from service, general location, capacity rating upon return to service, expected return to service date, and a general description of work to be performed; and

f. Other changes to existing generating units that are expected to increase or decrease generation capability of the unit in question by an amount that is plus or minus 10%, or 10 MW, whichever is greater.

(ii) Planned Generation Additions. — Each utility shall provide a list of planned generation additions, the rationale as to why each listed generation addition was selected, and a 15-year projection of the following for each listed addition:

a. Type of fuel(s) used;
b. Type of unit (e.g. MW rating, baseload, intermediate, peaking);
c. Location of each planned unit to the extent such location has been determined; and
d. Summaries of the analyses supporting any new generation additions included in its 15-year forecast, including its designation as base, intermediate, or peaking capacity.

(iii) Non-Utility Generation. — Each utility shall provide a separate and updated list of all non-utility electric generating facilities in its service areas, including customer-owned and stand-by generating facilities. This list shall include the facility name, location, primary fuel type, and capacity (including its designation as base, intermediate, or peaking capacity). The utility shall also indicate which facilities are included in its total supply of resources. If any of this information is readily accessible in documents already filed with the Commission, the utility may incorporate by reference the document or documents in its report, so long as the utility provides the docket number and the date of filing.

(3) Reserve Margins. — The utility shall provide a calculation and analysis of its winter and summer peak reserve margins over the projected 15-year period. To the extent the margins produced in a given year differ from target reserve margins by plus or minus 3%, the utility shall explain the reasons for the difference.

(4) Wholesale Contracts for the Purchase and Sale of Power.

(i) The utility shall provide a list of firm wholesale purchased power contracts reflected in the biennial report, including the primary fuel type, capacity (including its designation as base, intermediate, or peaking capacity), location, expiration date, and volume of purchases actually made since the last biennial report for each contract.

(ii) The utility shall discuss the results of any Request for Proposals (RFP) for purchased power it has issued since its last biennial report. This discussion shall include a description of each RFP, the number of entities responding to the RFP, the number of proposals received, the terms of the proposals, and an explanation of why the proposals were accepted or rejected.

(iii) The utility shall include a list of the wholesale power sales contracts for the sale of capacity or firm energy for which the utility has committed to sell power during the planning horizon, the identity of each wholesale entity to which the utility has committed itself to sell power during the planning horizon, the number of megawatts (MW) on an annual basis for each contract, the length of each contract, and the type of each contract (e.g., native load priority, firm, etc.).

(5) Transmission Facilities. — Each utility shall include a list of transmission lines and other associated facilities (161 kV or over) which are under

construction or for which there are specific plans to be constructed during the planning horizon, including the capacity and voltage levels, location, and schedules for completion and operation. The utility shall also include a discussion of the adequacy of its transmission system (161 kV and above).

(6) Demand-Side Management. — Each utility shall provide the results of its overall assessment of existing and potential demand-side management programs, including a descriptive summary of each analysis performed or used by the utility in the assessment. The utility also shall provide general information on any changes to the methods and assumptions used in the assessment since its last biennial report.

(i) For demand-side programs available at the time of the report, the utility shall provide the following information for each resource: the type of resource (demand response or energy efficiency); the capacity and energy available in the program; number of customers enrolled in each program; the number of times the utility has called upon the resource; and, where applicable, the capacity reduction realized each time since the previous biennial report. The utility shall also list any demand-side resource it has discontinued since its previous biennial report and the reasons for that discontinuance.

(ii) For demand-side management programs it proposes to implement within the biennium for which the report is filed, the utility shall provide the following information for each resource: the type of resource (demand response and energy efficiency); a description of the new program and the target customer segment; the capacity and energy expected to be available from the program; projected customer acceptance; the date the program will be launched; and the rationale as to why the program was selected.

(iii) For programs evaluated but rejected the utility shall provide the following information for each resource considered: the type of resource (demand response or energy efficiency); a description of the program and the target customer segment; the capacity and energy available from the program; projected customer acceptance; and reasons for the program's rejection.

(iv) For consumer education programs the utility shall provide a comprehensive list of all such programs the utility currently provides to its customers, or proposes to implement within the biennium for which the report is filed, including a description of the program, the target customer segment, and the utility's promotion of the education program. The utility shall also provide a list of any educational program it has discontinued since its last biennial report and the reasons for discontinuance.

(7) Assessment of Alternative Supply-Side Energy Resources. — The utility shall include its current overall assessment of existing and potential alternative supply-side energy resources, including a descriptive summary of

each analysis performed or used by the utility in the assessment. The utility shall also provide general information on any changes to the methods and assumptions used in the assessment since its most recent biennial or update report.

(i) For the currently operational or potential future alternative supply-side energy resources included in each utility's plan, the utility shall provide information on the capacity and energy actually available or projected to be available, as applicable, from the resource. The utility shall also provide this information for any actual or potential alternative supply-side energy resources that have been discontinued from its plan since its last biennial report and the reasons for that discontinuance.

(ii) For alternative supply-side energy resources evaluated but rejected, the utility shall provide the following information for each resource considered: a description of the resource; the potential capacity and energy associated with the resource; and the reasons for the rejection of the resource.

(8) Evaluation of Resource Options. — Each utility shall provide a description and a summary of the results of its analyses of potential resource options and combinations of resource options performed by it pursuant to subsection (g) of this rule to determine its integrated resource plan.

(9) Levelized Busbar Costs. — Each utility shall provide information on levelized busbar costs for various generation technologies.

(j) Contents of Update Reports. — In addition to the information required by sections (h)(2)-(4) of this rule, each utility shall include in its update report data and tables that provide the following data for the planning horizon: (1) the information required by sections (i)(1) and (2) of this rule, including the utility's load forecast adjusted for the impacts of any new energy efficiency programs, existing generating capacity with planned additions, uprates, derates, and retirements, planned purchase contracts, undesignated future resources identified by type of generation and MW rating, renewable capacity, demand-side management capacity, and any resource gap; (2) cumulative resource additions necessary to meet load obligation and reserve margins; and (3) projections of load, capacity, and reserves for both the summer and winter periods. A total system IRP may be filed in lieu of an update report for purposes of compliance with this section.

(k) Review of Biennial Reports. — Within 150 days after the later of either October 15 or the filing of each utility's biennial report, the Public Staff or any other intervenor may file an integrated resource plan or report of its own as to any utility or may file an evaluation of or comments on the reports filed by the utilities, or both. The Public Staff or any intervenor may identify any issue that it believes should be the subject of an evidentiary hearing. Within 60 days after the filing of initial comments, the parties may file reply comments addressing any substantive or procedural issue raised by any other party. A hearing to address issues raised by the Public Staff or other intervenors may be scheduled at the discretion of the Commission. The scope of any such hearing shall be limited to such issues as identified by the Commission. One or more hearings to receive testimony from the public, as required by law, shall be set at a time and place designated by the Commission.

(l) Review of Update Reports. — Within 60 days after the later of either October 15 or the filing of each utility's update report required by section (j) of this rule, the Public Staff or any other intervenor may file an update report of its own as to any utility. Further, within the same time period the Public Staff shall report to the Commission whether each utility’s update report meets the requirements of this rule. Intervenors may request leave from the Commission to file comments. Comments will be received or expert witness hearings held on the update reports only if the Commission deems it necessary. The scope of any comments or expert witness hearing shall be limited to issues identified by the Commission. One or more hearings to receive testimony from the public, as required by law, shall be set at a time and place designated by the Commission.

(m) By January 15 of each year, each utility individually or jointly shall hold a meeting to review its biennial or update report with interested parties.

(NCUC Docket No. E-100, Sub 54, 12/8/88; NCUC Docket No. E-100, Sub 78A, 04/29/98; 08/11/98; NCUC Docket No. M-100, Sub 128, 10/27/99; NCUC Docket No. E-100, Sub 113, 2/29/08; NCUC Docket No. E-100, Sub 113, 3/13/08; NCUC Docket No. E-100, Sub 126, 4/11/2012; NCUC Docket No. M-100, Sub 140, 12/03/13; NCUC Docket No.E-100, Sub 111, 7/20/2015; NCUC Docket No. E-100, Sub 126, 6/13/2016; NCUC Docket Nos. E-100, Subs 126 & 157; 11/13/2019; NCUC Docket No. E-100, Sub 191; 11/21/2023; NCUC Docket No. E-100, Sub 196; 2/8/2024.)

Rule R8-60A. BIENNIAL INTEGRATED RESOURCE PLANNING AND CARBON PLAN FILINGS.

(a) Purpose. — The purpose of this rule is to implement the provisions of G.S. 62-2(a)(3a), 62-110.1 and G.S. 62-110.9. The Carbon Plan constitutes the least cost integrated resource planning process for electric public utilities subject to G.S. 62-110.9 and the process for assessing and updating the integrated resource plan and the Carbon Plan for those utilities are therefore consolidated. The consolidated integrated resource plan and Carbon Plan (CPIRP) shall be reviewed every two years and may be adjusted as necessary in the determination of the Commission and the electric public utilities.

(b) Applicability. — This rule is applicable to Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, each of which is an “electric public utility” as defined in G.S. 62-110.9.

(c) Definitions. — As used in this rule, the following definitions shall apply:

(1) “Base Planning Period” shall mean the 15-year period from the start of the year following the date the CPIRP is filed.

(2) “Carbon Neutrality Planning Horizon” shall mean the period beyond the Base Planning Horizon that is designed to ensure that the electric public utilities remain on the least cost path towards achieving carbon neutrality (as defined by G.S. 62-110.9(ii)) consistent with the requirements of G.S. 62-110.9.

(d) Consolidated Carbon Plan and Integrated Resource Plan. — An electric public utility shall develop and keep current a proposed CPIRP to determine the planned generation and resource mix that complies with the requirements set forth in G.S. 62-110.9. The CPIRP shall incorporate, at a minimum, the following:

(1) Base Planning for Native Load Requirements and Firm Planning Obligations. — The CPIRP shall include a forecast of native load requirements for the Base Planning Period (including known and quantified load reduction measures taken by wholesale customers pursuant to their FERC-jurisdictional wholesale power contracts) and other system capacity or firm energy obligations extending through at least one summer and one winter peak; supply-side resources (including owned or leased generation capacity and firm purchased power arrangements) and grid edge resources (including demand-side management programs, rate designs, voltage control, customer-sited generation and storage, and energy efficiency) expected to satisfy those loads; and the reserve margin thus produced.

(2) Long-Term Planning for Carbon Neutrality. — The CPIRP shall include a longer-term planning forecast beyond the Base Planning Period that is designed to ensure that the electric public utilities remain on a path that complies with the provisions set forth in G.S. 62-110.9. For purposes of analyzing resource needs to achieve carbon neutrality beyond the Base Planning Period, the electric public utilities may use simplifying assumptions and analytical approaches recognizing the inherent uncertainty in long-range planning and the ability to make planning adjustments in future updates to the CPIRP.

(3) Modeling Resource Needs Over Base Planning Period and Carbon Neutrality Planning Horizon. — The CPIRP shall include, at a minimum, a comprehensive analysis of all resource options (demand-side and supply-side) considered by the electric public utilities to serve native load requirements and firm planning obligations during the Base Planning Period and the Carbon Neutrality Planning Horizon in a manner that maintains or improves upon the adequacy and reliability of the existing grid as required by G.S. 62-110.9(3). The electric public utilities shall analyze potential resource options and combinations of resource options to serve its system needs, taking into account the sensitivity of their analysis to variations in future estimates of peak load, energy requirements, and other significant assumptions, including, but not limited to, the risks associated with extreme weather conditions, fuel costs, construction/implementation costs, and the costs of complying with environmental regulations. Additionally, this analysis should account for, as applicable, system operations, compliance with state and federal regulations, and other qualitative factors.

(4) Resource Portfolios. — Each updated CPIRP shall include several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, energy storage, and other technologies available to meet the electric public utilities' service obligations during the Base Planning Period and the Carbon Neutrality Planning Horizon. For each resource portfolio, the electric public utilities shall identify planned resource additions and retirements, projected carbon emission reductions, present value revenue requirements over the Base Planning Period and the Carbon Neutrality Planning Horizon and explain whether, and if so to what extent, the electric public utilities plan to use offsets as allowed by G.S. 62-110.9 as part of the least cost path to achieving carbon neutrality. In addition, each CPIRP filed prior to 2030 shall include at least one resource portfolio that achieves the 70% reduction in carbon dioxide emissions by 2030.

(5) Evaluation of Resource Options. — As part of its CPIRP process, each electric public utility shall consider and compare a comprehensive set of potential resource options, including both demand-side and supply-side options, to determine the least cost combination (on a long-term basis) of resource options for reliably meeting the anticipated needs of its system in achieving the State's authorized carbon reduction goals. The CPIRP should include an assessment of power generation, transmission and distribution, grid modernization, energy storage, energy efficiency measures, demand-side management, and the latest technological breakthroughs to achieve the least cost path consistent with the requirements of G.S. 62-110.9.

(6) Ensuring Resource Adequacy and Reliability. — Each updated CPIRP shall describe how the proposed CPIRP ensures that generation and resource changes presented in the plan maintain or improve upon the adequacy and reliability of the existing grid. This analysis should address the electric public utilities' assessment of and plans to maintain appropriate planning reserve margins and maintain or improve the resource adequacy of their systems.

(7) Resource Selection. — Each updated CPIRP shall identify the generation facilities and other resources proposed to be selected by the Commission pursuant to and subject to the requirements of G.S. 62-110.9(2). To the extent resources are selected based upon resource diversity, the electric public utilities shall provide additional support for their decisions based on the costs and benefits of alternatives to achieve the authorized carbon reduction goals and meet the requirements of G.S. 62-110.9.

(8) Execution. — Each updated CPIRP shall include a near-term action plan that the electric public utilities propose to execute over the near term, identifying specific demand-side and supply-side development, procurement, and retirement activities, including upgrades to the transmission system necessary to interconnect new supply-side resources. The proposed near-term action plan should identify whether it is sufficient to support all of the resource portfolios identified pursuant subsection (d)(4). If the proposed near-term action is not sufficient to support any of the identified resource portfolios, the CPIRP shall identify any additional activities that would be necessary. The CPIRP should also identify longer-term resource planning risks, strategies, or other considerations that the electric public utilities are monitoring that could impact achieving the State's carbon reduction goals in a manner that complies with the requirements set forth in G.S. 62-110.9.

(e) Filings.

(1) By September 1, 2023, and every two years thereafter, the electric public utilities shall file with the Commission their proposed CPIRP, together with all information required by subsection (f) of this rule. This CPIRP shall propose resources to be selected and a near-term action plan to be approved by the Commission for execution prior to Commission approval of the next succeeding CPIRP. Contemporaneous with filing the CPIRP, the electric public utilities make available complete CPIRP modeling input and output data files, as well as their method underlying the use of all modeling software and process steps utilized in the CPIRP, to the Public Staff and intervenors, subject to appropriate confidentiality protections.

(2) Each CPIRP shall include an update on the progress the electric public utilities have made to advance the near-term action plan in the most recently approved CPIRP.

(3) If an electric public utility considers certain information in its biennial comprehensive CPIRP to be proprietary, confidential, and within the scope of G.S. 132-1.2, the electric public utility may designate the information as “confidential” and file it under seal.

(f) Contents of Biennial CPIRP. — The electric public utilities shall include in each updated CPIRP the following:

(1) Forecasts of Load, and Demand-Side and Supply-Side Resources. — The forecasts filed as part of the CPIRP shall include descriptions of the methods, models, and assumptions used by the electric public utilities to prepare their gross and net peak load in megawatts (MW) and energy sales (MWh) forecasts and the variables used in the models. The forecasts filed by the electric public utilities shall include, at a minimum, the following:

(i) The most recent ten-year history and a forecast of customers by each customer class, the most recent ten-year history and a forecast of energy sales (MWh) by each customer class, and the most recent ten-year history and a forecast of the electric public utility’s summer and winter peak load (MW);

(ii) A detailed calculation of the impact of grid edge resources on gross load, including comparably quantified and verified information provided by wholesale customers within the electric public utility’s balancing area, and an explanation of why those resources are treated as load modifying or as a resource modeled on the supply side;

(iii) The electric public utility's forecast for at least the Base Planning Period, including peak loads for summer and winter seasons of each year, annual energy forecasts, reserve margins, and load duration curves, with and without projected demand-side or supply-side resource additions. The forecast shall also indicate the projected effects of grid edge resources on the forecasted annual energy and peak loads on an annual basis for the Base Planning Period, and these effects also may be reported as an equivalent generation capacity impact; and

(iv) For new technologies that may have significant impacts on the electric public utility's net load forecast, such as sector or process electrification or load modifying technologies, the electric public utility should provide a description of the forecast methodology and projections.

(2) Generating Facilities and Energy Storage. — The electric public utilities shall provide the following data for their owned existing and planned electric generating facilities (including planned additions and retirements, but excluding cogeneration and small power production) and energy storage systems:

(i) Existing Generation. — The electric public utilities shall include a list of existing generation resources in service, with the information specified below for each listed resource. The information shall be provided for the Base Planning Period:

a. Type of fuel(s) used by each generating unit;

b. Generating unit characteristics (type of unit, *i.e.,* CT, nuclear, etc., summer and winter capacity ratings, in-service date, and planned retirement date, if applicable);

c. Location of each existing generating unit;

d. A list of generating units for which there are specific plans for life extension, refurbishment, or upgrading. The reporting electric public utility shall also provide the expected (or actual) date the unit is, or is expected to be, removed from service, the general location, the capacity rating upon return to service, the expected return to service date, and a general description of the work to be performed on the unit; and

e. Other changes to existing generating units that are expected to increase or decrease generation capacity of the unit in question by an amount that is plus or minus 10%, or 10 MW, whichever is greater.

(ii) Existing Energy Storage. — The electric public utilities shall include a summary of their existing energy storage in service, with the information specified below for each technology. The information shall be provided for the Base Planning Period:

a. Storage technology (pumped storage hydro, battery, etc.); and

b. Aggregate power capacity and designed storage duration.

(iii) Planned Generation. — The electric public utilities shall include a list of planned generation resource additions, the rationale as to why each listed resource addition was selected, and the following for each listed addition:

a. Type of fuel(s) used by each generating unit;

b. Generating unit characteristics (type of unit, i.e., CT, battery, etc., summer and winter capacity ratings, in-service date, and planned retirement date, if applicable);

c. Location of each planned generating unit to the extent such location has been determined; and

d. Summaries of the analyses supporting any new generation additions included in the forecast for the Base Planning Period, including its designation as baseload capacity, if applicable.

(iv) Planned Energy Storage Additions. — The electric public utilities shall include a list of planned energy storage additions, the rationale as to why each listed resource addition was selected, and the following for each listed addition:

a. Storage technology (pumped storage hydro, battery, etc.); and

b. Aggregate power capacity and designed storage durations.

(3) Non-Utility Generation. — The electric public utilities shall provide a summary of all non-utility electric generating facilities and energy storage in their service areas, including customer-owned and stand-by generating facilities. This summary shall aggregate capacities by generation type (solar, hydro, biomass, etc.).

(4) Wholesale Contracts for the Purchase and Sale of Power. —

(i) The electric public utilities shall include a list of firm wholesale purchased power contracts currently in effect, including the primary fuel type, capacity (including the designation as base, intermediate, or peaking capacity), location, expiration date, treatment of the wholesale resource in CPIRP modeling after expiration, and volume of purchases actually made since the last CPIRP for each contract.

(ii) The electric public utilities shall discuss the results of any Request for Proposals (RFP) that the electric public utilities have issued for purchases of solar generation from third parties and for acquisition for utility ownership and, as applicable, RFPs for acquisition, transfer, or engineering, procurement and construction of other selected generation or storage resources since the last CPIRP. This discussion shall include a description of each RFP, the number of entities responding to the RFP, the number of proposals received, the terms of the proposals, and an explanation of why the proposals were accepted or rejected. The discussion shall also address how the results of the most recent RFP completed during the biennial CPIRP period are incorporated into the electric public utilities' analysis of their long-range energy and capacity needs. If any of this information is readily accessible in documents already filed with the Commission, the electric public utilities may incorporate by reference the document or documents in the CPIRP, so long as the electric public utilities provide the docket number and the date of filing.

(iii) The electric public utilities shall include a list of the wholesale power sales contracts for the sale of capacity or firm energy for which the electric public utilities have committed to sell power during the Base Planning Period, the identity of each wholesale entity to which the electric public utilities have committed itself to sell power during the planning horizon, the number of MWs on an annual basis for each contract, the length of each contract, and the type of each contract (e.g., native load priority, firm, etc.).

(5) Demand-Side Management and Energy Efficiency. — The electric public utilities shall include an assessment of the portfolio of existing and future grid edge resources including demand-side management and energy efficiency programs consistent with the most recently filed DSM/EE cost recovery rider filed by the electric public utilities pursuant to Rule R8-69 and G.S. 62-133.9(c). The electric public utilities shall appropriately reflect grid edge resources as either load modifiers or as a resource considered on the supply side based upon the operating characteristics of the resource. For purposes of utility planning, the electric public utilities shall model energy efficiency as a load modifying resource, ensuring its priority in utility planning. The electric public utilities' modeling of the load modification associated with energy efficiency shall include low, base, and high cases.

(6) Transmission System Planning and Facilities. —

(i) Transmission System Planning - The electric public utilities shall discuss the adequacy of the transmission system and identified future transmission needs (100 kV and above). With respect to future needs, the electric public utilities shall include an overview of the electric public utilities' local and regional transmission planning process, a discussion of how the most recently approved CPIRP was incorporated into the electric public utilities' transmission planning processes, and discussion of the identified needs, as well as planned transmission lines and facilities, appearing in the most recent local transmission planning report that, as identified in that report, could reasonably be placed into service during the Base Planning Period.

(ii) Planned Improvements - The electric public utilities shall include a list of planned, new or to be upgraded, transmission lines (100 kV or over) and transformers (low side voltage 100 kV or over) which are under construction or for which there are specific plans to be constructed during the Base Planning Period, including the capacity and voltage levels, location, and schedules for completion and operation.

a. The electric public utilities shall describe how applicable planned improvements may enable specific siting of new resources or provide expected and planned impacts to other resource interconnection constraints or operations of the systems.

(iii) Non-wires alternatives — The electric public utilities shall provide an overall assessment methodology for non-wires alternatives, including a descriptive summary of analysis performed or used by the electric public utilities in the assessment of alternative solutions to transmission constraints that may be more cost-effective, such as locating generation in less constrained areas or strategically locating energy storage resources or the dispatch of distributed energy resources of the wholesale customers located within the electric public utilities' balancing area to the extent the electric public utilities have rights to dispatch, operate, and control such resources in the same manner as the electric public utilities' own resources.

(7) Modeling of System Operations. — The electric public utilities shall provide a discussion of or applicable study addressing how electric public utility relationships and system interconnections are modeled in the CPIRP including how relevant planning and operation functions influence modeling, such as modeled balancing areas and interconnections, joint dispatch agreements, energy exchange markets, and other future operating efficiencies planned by the electric public utilities during the Base Planning Period.

(i) The electric public utilities shall also include, as applicable, a discussion of other planning factors influencing CPIRP modeling, such as corporate emission reduction goals or generation resource restrictions, legal or regulatory requirements from other authorities or jurisdictions that materially impact the resource plan, and the impact of these factors on the electric public utilities' long-range resource plans over the Base Planning Period and Carbon Neutrality Planning Horizon, as applicable.

(ii) The electric public utilities shall discuss the results that are expected from integrated (generation, transmission and/or distribution) systems planning processes, how integrated systems planning is used in the CPIRP process, and the impact of it and their wholesale customers' distributed energy resources and non-traditional solutions on resource planning and load forecasting.

(8) Modeling of Generating and Energy Storage Resources. — The electric public utilities shall include an overall modeling framework and methodology for existing and potential generating and storage resources, including a descriptive summary of material assumptions and analysis performed or used by the electric public utilities in the assessment. The electric public utilities shall also provide general

information on any changes to the methods and assumptions used in the assessment since the most recently approved CPIRP, including supportive studies impacting assessment and selection of resources.

(i) To the extent that an updated unit retirement analysis is conducted as a part of the CPIRP, the electric public utilities shall include a descriptive summary of material assumptions and analysis performed that may impact the retirement date modeled such as transmission requirements or replacement resource needs to enable executable retirement of resources.

(9) Maintaining or Improving Upon the Adequacy and Reliability of the Existing Grid. — The electric public utilities shall provide a description of, and justification for, the methodology by which the CPIRP will demonstrate that adequacy and reliability of the system will be maintained or improved throughout the Base Planning Period and Carbon Neutrality Planning Horizon. To the extent that the electric public utilities' standards for quantifying that the reliability of the system has been maintained has changed, the electric public utilities shall discuss the reasons for the changes to these standards, including impacts to resource adequacy studies, effective load carry capability studies, or other applicable reliability studies. The electric public utilities shall also describe coordination efforts with their wholesale customers to utilize their resources to maintain or improve reliability.

(10) Load, Capacity, and Reserve Tables. — The electric public utilities shall provide a table for a reference portfolio that shows, for both winter and summer peaks, the available capacity, wholesale purchases and sales, capacity from non-utility generation, load (gross and net of grid edge resources), retirements, new capacity additions, and estimated reserve margin for each year of the Base Planning Period.

(i) The electric public utilities shall calculate and provide a description of, and justification for, the methodology by which the electric public utilities determine a first year of avoidable capacity need (First Year of Avoidable Capacity).

(11) Evaluation of Resource Portfolios and Selection of Resources. — The electric public utilities shall provide a description and a summary of the results of their analyses of potential resource options and combinations of resource options (demand-side and supply-side), including relevant information pertaining to portfolio costs (present value of revenue requirements and average retail customer bill impact analyses),

operability and reliability, and CO_2 emissions. Taking into account the resource portfolios presented in the proposed CPIRP, the electric public utilities shall designate resources for selection by the Commission as the proposed near-term action plan for implementation by the electric public utilities following the Commission's final order on the proposed CPIRP. The near-term action plan required by this Rule should discuss the specific actions the electric public utilities propose to take over the near-term to progress carbon emissions reductions in a least-cost manner, while maintaining or improving reliability of the grid and continue executing least cost planning, including actions to preserve optionality for future potential resources that could help achieve these objectives in future updates to the CPIRP.

(12) Stakeholder Engagement Report – The electric public utilities shall provide a summary of its stakeholder engagement conducted pursuant to the plan described in section (h).

(g) Procedure for Review.

(1) At the time the electric public utilities file their proposed CPIRP with the Commission pursuant to subsection (e), the electric public utilities shall also file with the Commission testimony and exhibits of expert witnesses supporting the proposed CPIRP.

(2) No later than 180 days after the later of either September 1 or the filing of the electric public utilities' CPIRP, the Public Staff and intervenors may file testimony and exhibits of expert witnesses commenting on, critiquing, or giving alternatives to the electric public utilities' proposed CPIRP.

(3) No later than 45 days after the filing of intervenor testimony and exhibits, the electric public utilities may file rebuttal testimony and exhibits of its expert witnesses.

(4) The Commission shall schedule an expert witness hearing to review the CPIRP proposals beginning on the second Tuesday in May following the electric public utilities' proposed CPIRP filing. The scope of any such hearing may be limited to issues as identified by the Commission. The Commission will also schedule one or more hearings to receive testimony from the public at a time and place of the Commission's designation.

(5) The Commission will issue an order adopting the next CPIRP by no later than December 31 of the year after the year in which the proposed CPIRP is filed with the Commission.

(h) The electric public utilities individually or jointly shall provide notice to the Commission of their plans for engaging with interested parties at least 200 days in advance of its planned biennial CPIRP. The notice to the Commission should provide, at a minimum, information on how the utilities:

(1) Determined the timing, frequency, and location of stakeholder meetings, as well as whether to hold meetings virtually;

(2) Selected facilitators for the meetings;

(3) Notified stakeholders about the meetings; and

(4) Planned the structure and content of the meetings.

(NCUC Docket No. E-100, Sub 191, 11/21/2023.)

Rule R8-67. CLEAN ENERGY AND ENERGY EFFICIENCY PORTFOLIO STANDARD (CEPS).

(a) Definitions.

(1) The following terms shall be defined as provided in G.S. 62133.8: “Combined heat and power system”; “demand-side management”; “electric power supplier”; “new renewable energy facility”; “renewable energy certificate”; “renewable energy facility”; “renewable energy resource”; and “incremental costs”; “clean energy facility”; “clean energy resource”; and “new clean energy facility”.

(2) For purposes of determining an electric power supplier’s avoided costs, “avoided cost rates” mean an electric power supplier’s most recently approved or established avoided cost rates in this state, as of the date the contract is executed, for purchases of electricity from qualifying facilities pursuant to Section 210 of the Public Utility Regulatory Policies Act of 1978. If the Commission has approved an avoided cost rate for the electric power supplier for the year when the contract is executed, applicable to contracts of the same nature and duration as the contract between the electric power supplier and the seller, that rate shall be used as the avoided cost. Therefore, for example, for a contract by an electric public utility with a term of 15 years, the avoided cost rate applicable to that contract would be the comparable, Commission-approved, 15-year, longterm, levelized rate in effect at the time the contract was executed. In all other cases, the avoided cost shall be a good faith estimate of the electric power supplier’s avoided cost, levelized over the duration of the contract, determined as of the date the contract is executed, taking into consideration the avoided cost rates then in effect as established by the Commission. In any event, when found by the Commission to be appropriate and in the public interest, a good faith estimate of an electric public utility’s avoided cost, levelized over the duration of the contract, determined as of the date the contract is executed, may be used in a particular CEPS cost recovery proceeding. Determinations of avoided costs, including estimates thereof, shall be subject to continuing Commission oversight and, if necessary, modification should circumstances so require.

(3) “Energy efficiency measure” means an equipment, physical, or program change that when implemented results in less use of energy to perform the same function or provide the same level of service. “Energy efficiency measure” does not include demand-side management. It includes energy produced from a combined heat and power system that uses non-clean resources to the extent the system:

(i) Uses waste heat to produce electricity or useful, measurable thermal or mechanical energy at a retail electric customer’s facility; and

(ii) Results in less energy used to perform the same function or provide the same level of service at a retail electric customer’s facility.

(4) “Year-end number of customer accounts” means the number of accounts within each customer class as of December 31 for a given calendar year

determined in a manner approved by the Commission pursuant to subsection (c)(4) or determined in the same manner as that information is reported to the Energy Information Administration, United States Department of Energy, for annual electric sales and revenue reporting.

(5) "Utility compliance aggregator" is an organization that assists an electric power supplier in demonstrating its compliance with CEPS. Such demonstration may include, among other things, filing CEPS compliance plans or reports and participating in NC-RETS on behalf of the electric power supplier or a group of electric power suppliers.

(b) CEPS compliance plan.

(1) Each year, beginning in 2008, each electric power supplier or its designated utility compliance aggregator shall file with the Commission the electric power supplier's plan for complying with G.S. 62133.8(b), (c), (d), (e) and (f). The plan shall cover the calendar year in which the plan is filed and the immediately subsequent two calendar years. At a minimum, the plan shall include the following information:

(i) a specific description of the electric power supplier's planned actions to comply with G.S. 62133.8(b), (c), (d), (e) and (f) for each year;

(ii) a list of executed contracts to purchase renewable energy certificates (whether or not bundled with electric power), including type of clean energy resource, expected MWh, and contract duration;

(iii) a list of those planned or implemented energy efficiency and demand side management measures that the electric power supplier plans to use toward CEPS compliance, including a brief description of each measure, its projected impacts, and a measurement and verification plan if such plan has not otherwise been filed with the Commission;

(iv) the projected North Carolina retail sales and year-end number of customer accounts by customer class for each year;

(v) the current and projected avoided cost rates for each year;

(vi) the projected total and incremental costs anticipated to implement the compliance plan for each year;

(vii) a comparison of projected costs to the annual cost caps for each year;

(viii) for electric public utilities, an estimate of the amount of the CEPS rider and the impact on the cost of fuel and fuel-related costs rider necessary to fully recover the projected costs; and

(ix) to the extent not already filed with the Commission, the electric power supplier shall, file a clean energy facility registration statement pursuant to Rule R866 for any facility it owns and upon which it is relying as a source of power or RECs in its CEPS compliance plan. Duke Energy Carolinas, LLC and Duke Energy Progress, LLC shall file such statement on or before September 1 of each year. Virginia Electric Power Company, d/b/a Dominion Energy North Carolina, shall file such statement on or before October 15 of each year.

(2) Duke Energy Carolinas, LLC and Duke Progress, LLC shall file in a docket to be established by the Commission, its CEPS compliance plan on or before September 1 of each year. Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina shall file in a docket to be established by the Commission, its CEPS compliance plan on or before October 15 of each year.

(3) Approval of the CEPS compliance plan shall not constitute an approval of the recovery of costs associated with CEPS compliance or a determination that the electric power supplier has complied with G.S. 62 133.8(b), (c), (d), (e), and (f).

(4) A CEPS compliance plan filed by an electric power supplier not subject to Rule R860 or Rule R8-60A shall be for information only.

(c) CEPS compliance report.

(1) Each year, beginning in 2009, each electric power supplier or its designated utility compliance aggregator shall file with the Commission a report describing the electric power supplier's compliance with the requirements of G.S. 62133.8(b), (c), (d), (e) and (f) during the previous calendar year. The report shall include all of the following information, including supporting documentation:

(i) the sources, amounts, and costs of renewable energy certificates, by source, used to comply with G.S. 62133.8(b), (c), (d), (e) and (f). Renewable energy certificates for energy efficiency may be based on estimates of reduced energy consumption through the implementation of energy efficiency measures, to the extent approved by the Commission;

(ii) the actual North Carolina retail sales and year-end number of customer accounts by customer class;

(iii) the current avoided cost rates and the avoided cost rates applicable to energy received pursuant to long-term power purchase agreements;

(iv) the actual total and incremental costs incurred during the calendar year to comply with G.S. 62133.8(b), (c), (d), (e) and (f);

(v) a comparison of the actual incremental costs incurred during the calendar year to the per-account annual charges (in G.S. 62133.8(g)(4)) applied to its total number of customer accounts as of December 31 of the previous calendar year;

(vi) the status of compliance with the requirements of G.S. 62133.8(b), (c), (d), (e) and (f);

(vii) the identification of any renewable energy certificates or energy savings to be carried forward pursuant to G.S. 62133.8(b)(2)f or (c)(2)f;

(viii) the dates and amounts of all payments made for renewable energy certificates; and

(ix) for electric membership corporations and municipal electric suppliers, reduced energy consumption achieved in each year after

January 1, 2008, through the implementation of energy efficiency or demand-side management programs, along with the results of each program's measurement and verification plan, or other documentation supporting an estimate of the program's energy reductions achieved in the previous year pending implementation of a measurement and verification plan. Supporting documentation shall be retained and made available for audit.

(2) Each electric public utility shall file its annual CEPS compliance report , together with direct testimony and exhibits of expert witnesses, on the same date that it files (1) its cost recovery request under Rule R8-67(e), and (2) the information required by Rule R855. The Commission shall consider each electric public utility's CEPS compliance report at the hearing provided for in subsection (e) of this rule and shall determine whether the electric public utility has complied with G.S. 62133.8(b), (d), (e) and (f). Public notice and deadlines for intervention and filing of additional direct and rebuttal testimony and exhibits shall be as provided for in subsection (e) of this rule.

(3) Each electric membership corporation and municipal electric supplier or their designated utility compliance aggregator shall file a verified CEPS compliance report on or before September 1 of each year. The Commission may issue an order scheduling a hearing to consider the CEPS compliance report filed by each electric membership corporation or municipal electric supplier, requiring public notice, and establishing deadlines for intervention and the filing of direct and rebuttal testimony and exhibits.

(4) In each electric power supplier's initial CEPS compliance report, the electric power supplier shall propose a methodology for determining its cap on incremental costs incurred to comply with G.S. 62-133.8(b), (c), (d), (e) and (f) and fund research as provided in G.S. 62-133.8(h)(1), including a determination of year-end number of customer accounts. The proposed methodology may be specific to each electric power supplier, shall be based upon a fair and reasonable allocation of costs, and shall be consistent with G.S. 62-133.8(h). The electric power supplier may propose a different methodology that meets the above requirements in a subsequent CEPS compliance report filing. For electric public utilities, this methodology shall also be used for assessing the per-account charges pursuant to G.S. 62-133.8(h)(5).

(5) In any year, an electric power supplier or other interested party may petition the Commission to modify or delay the provisions of G.S. 62133.8(b), (c), (d), (e) and (f), in whole or in part. The Commission may grant such petition upon a finding that it is in the public interest to do so. If an electric power supplier is the petitioner, it shall demonstrate that it has made a reasonable effort to meet the requirements of such provisions. Retroactive modification or delay of the provisions of G.S. 62133.8(b), (c), (d), (e) or (f) shall not be permitted. The Commission shall allow a modification or delay only with respect to the electric power supplier or group of electric power suppliers for which a need for a modification or delay has been demonstrated.

(6) A group of electric power suppliers may aggregate their CEPS obligations and compliance efforts provided that all suppliers in the group are subject to the same CEPS obligations and compliance methods as stated in either G.S. 133.8(b) or (c). If such a group of electric power suppliers fails to meet its CEPS obligations, the Commission shall find and conclude that each supplier in the group, individually, has failed to meet its CEPS obligations.

(d) Renewable energy certificates.

(1) Renewable energy certificates (whether or not bundled with electric power) claimed by an electric power supplier to comply with G.S. 62133.8(b), (c), (d), (e) and (f) must have been earned after January 1, 2008; must have been purchased by the electric power supplier within three years of the date they were earned; shall be retired when used for compliance; and shall not be used for any other purpose. A renewable energy certificate may be used to comply with G.S. 62133.8(b), (c), (d), (e) and (f) in the year in which it is acquired or obtained by an electric power supplier or in any subsequent year; provided, however, that an electric public utility must use a renewable energy certificate to comply with G.S. 62133.8(b), (d), (e) and (f) within seven years of cost recovery pursuant to subsection (e)(10) of this Rule.

(2) For any facility that uses both clean energy resources and non-clean energy resources to produce energy, the facility shall earn renewable energy certificates based only upon the energy derived from clean energy resources in proportion to the relative energy content of the fuels used.

(3) Renewable energy certificates earned by a clean energy facility after the date the facility's registration is revoked by the Commission shall not be used to comply with G.S. 62133.8(b), (c), (d), (e) and (f).

(4) Renewable energy certificates must be issued by, or imported into, the renewable energy certificate tracking system established in Rule R8-67(h) in order to be eligible RECs under G.S. 62-133.8.

(e) Cost recovery.

(1) For each electric public utility, the Commission shall schedule an annual public hearing pursuant to G.S. 62133.8(h) to review the costs incurred by the electric public utility to comply with G.S. 62133.8(b), (d), (e) and (f). The annual rider hearing for each electric public utility will be scheduled as soon as practicable after the hearing held by the Commission for the electric public utility under Rule R855.

(2) The Commission shall permit each electric public utility to charge an increment or decrement as a rider to its rates to recover in a timely manner the reasonable incremental costs prudently incurred to comply with G.S. 62133.8(b), (d), (e) and (f). The cost of an unbundled renewable energy certificate, to the extent that it is reasonable and prudently incurred, is an incremental cost and has no avoided cost component.

(3) Unless otherwise ordered by the Commission, the test period for each electric public utility shall be the same as its test period for purposes of Rule R855.

(4) Rates set pursuant to this section shall be recovered during a fixed cost recovery period that shall coincide, to the extent practical, with the recovery

period for the cost of fuel and fuel-related cost rider established pursuant to Rule R855.

(5) The incremental costs will be further modified through the use of a CEPS experience modification factor (CEPS EMF) rider. The CEPS EMF rider will reflect the difference between reasonable and prudently incurred incremental costs and the revenues that were actually realized during the test period under the CEPS rider then in effect. Upon request of the electric public utility, the Commission shall also incorporate in this determination the experienced over-recovery or underrecovery of the incremental costs up to thirty (30) days prior to the date of the hearing, provided that the reasonableness and prudence of these costs shall be subject to review in the utility's next annual CEPS cost recovery hearing.

(6) The CEPS EMF rider will remain in effect for a fixed 12month period following establishment and will carry through as a rider to rates established in any intervening general rate case proceedings.

(7) Pursuant to G.S. 62130(e), any over-collection of reasonable and prudently incurred incremental costs to be refunded to a utility's customers through operation of the CEPS EMF rider shall include an amount of interest, at such rate as the Commission determines to be just and reasonable, not to exceed the maximum statutory rate.

(8) Each electric public utility shall follow deferred accounting with respect to the difference between actual reasonable and prudently-incurred incremental costs and related revenues realized under rates in effect.

(9) The incremental costs to be recovered by an electric public utility in any cost recovery period from its North Carolina retail customers to comply with G.S. 62133.8(b), (d), (e), and (f) shall not exceed the per-account charges set forth in G.S. 62133.8(h)(4) applied to the electric public utility's year-end number of customer accounts determined as of December 31 of the previous calendar year. These annual charges shall be collected through fixed monthly charges. Each electric public utility shall ensure that the incremental costs recovered under the CEPS rider and CEPS EMF rider during the cost recovery period, inclusive of gross receipts tax and the regulatory fee, from any given customer account do not exceed the applicable per-account charges set forth in G.S. 62133.8(h)(4).

(10) Incremental costs incurred during a calendar year toward a current or future year's CEPS obligation may be recovered by an electric public utility in any 12month recovery period up to and including the 12-month recovery period in which the RECs associated with any incremental costs are retired toward the prior year's CEPS obligation, as long as the electric public utility's charges to customers do not exceed, in any 12-month period, the per-account annual charges provided in G.S. 62133.8(h)(4). A renewable energy certificate must be used for compliance and retired within seven years of the year in which the electric public utility recovers the related costs from customers. An electric public utility shall refund to customers with interest the costs for renewable energy certificates that are not used for compliance within seven years.

(11) Each electric public utility, at a minimum, shall submit to the Commission for purposes of investigation and hearing the information required for the CEPS compliance report for the 12-month test period established in subsection (3) normalized, as appropriate, consistent with Rule R855, accompanied by supporting workpapers and direct testimony and exhibits of expert witnesses, and any change in rates proposed by the electric public utility at the same time that it files the information required by Rule R855.

(12) The electric public utility shall publish a notice of the annual hearing for two (2) successive weeks in a newspaper or newspapers having general circulation in its service area, normally beginning at least 30 days prior to the hearing, notifying the public of the hearing before the Commission pursuant to G.S. 62133.8(h) and setting forth the time and place of the hearing.

(13) Persons having an interest in said hearing may file a petition to intervene setting forth such interest at least 15 days prior to the date of the hearing. Petitions to intervene filed less than 15 days prior to the date of the hearing may be allowed in the discretion of the Commission for good cause shown.

(14) The Public Staff and other intervenors shall file direct testimony and exhibits of expert witnesses at least 15 days prior to the hearing date. If a petition to intervene is filed less than 15 days prior to the hearing date, it shall be accompanied by any direct testimony and exhibits of expert witnesses the intervenor intends to offer at the hearing.

(15) The electric public utility may file rebuttal testimony and exhibits of expert witnesses no later than 5 days prior to the hearing date.

(16) The burden of proof as to whether the costs were reasonable and prudently incurred shall be on the electric public utility.

(f) Contracts with owners of clean energy facilities.

(1) The terms of any contract entered into between an electric power supplier and a new solar electric facility or new metered solar thermal energy facility shall be of sufficient length to stimulate development of solar energy.

(2) Each electric power supplier shall include appropriate language in all agreements for the purchase of renewable energy certificates (whether or not bundled with electric power) prohibiting the seller from remarketing the renewable energy certificates being purchased by the electric power supplier.

(g) Metering of clean energy facilities.

(1) Except as provided below, for the purpose of receiving renewable energy certificate issuance in NC-RETS, the electric power generated by a clean energy facility shall be measured by an electric meter supplied by and read by an electric power supplier. Facilities whose renewable energy certificates are issued in a tracking system other than NC-RETS shall be subject to the requirements of the applicable state commission and/or tracking system.

(2) The electric power generated by an inverter-based solar photovoltaic (PV) system with a nameplate capacity of 10 kW or less may be estimated using generally accepted analytical tools.

(3) The electric power generated by a clean energy facility interconnected on the customer's side of the utility meter at a customer's location may be measured by (1) an ANSI-certified electric meter not provided by an electric power supplier provided that the owner of the meter complies with the meter testing requirements of Rule R8-13, or (2) another industry-accepted, auditable and accurate metering, controls, and verification system. The data provided by such meter or system may be read and self-reported by the owner of the clean energy facility, subject to audit by the Public Staff. The owner of the meter shall retain for audit for 10 years the energy output data.

(4) Thermal energy produced by a combined heat and power system or solar thermal energy facility shall be the thermal energy recovered and used for useful purposes other than electric power production. The useful thermal energy may be measured by meter, or if that is not practicable, by other industry-accepted means that show what measurable amount of useful thermal energy the system or facility is designed and operated to produce and use. Renewable energy certificates shall be earned based on one certificate for every 3,412,000 British thermal units (Btu) of useful thermal energy produced. Meter devices, if used, shall be located so as to measure the actual thermal energy consumed by the load served by the facility. Thermal energy output that is used as station power or to process the facility's fuel is not eligible for RECs. Thermal energy production data, whether metered or estimated, shall be retained for audit for 10 years.

(h) North Carolina Renewable Energy Certificate Tracking System (NCRETS)

(1) Definitions

(i) "Balancing area operator" means an electric power supplier that has the responsibility to act as the balancing authority for a portion of the regional transmission grid, including maintaining the loadtogeneration balance, accounting for energy delivered into and exported out of the area, and supporting interconnection frequency in real time.

(ii) "Multi-fuel facility" means a clean energy facility that produces energy using more than one fuel type, potentially relying on a fuel that does not qualify for REC issuance in North Carolina.

(iii) "Participant" means a person or organization that opens an account in NC-RETS.

(iv) "Qualifying thermal energy output" is the useful thermal energy: (1) that is made available to an industrial or commercial process (net of any heat contained in condensate return and/or makeup water); (2) that is used in a heating application (e.g., space heating, domestic hot water heating); or (3) that is used in a space cooling application (i.e., thermal energy used by an absorption chiller).

(2) A renewable energy certificate (REC) tracking system, to be known as NC-RETS, is established by the Commission. NCRETS shall issue, track, transfer and retire RECs. It shall calculate each electric power supplier's CEPS obligation and report each electric power supplier's CEPS accomplishments, consistent with the compliance report filed under Rule

R8-67(c). NCRETS shall be administered by a third-party vendor selected by the Commission. Only RECs issued by or imported into NCRETS are qualifying RECs under G.S. 62-133.8.

(3) Each electric power supplier shall be a participant in NC-RETS and shall provide data to NC-RETS to calculate its CEPS obligation and to demonstrate its compliance with G.S. 62-133.8. An electric power supplier may select a utility compliance aggregator to participate in NC-RETS on its behalf and file CEPS compliance plans and compliance reports, but the supplier shall nonetheless remain responsible for its own compliance. For reporting purposes, an electric power supplier or its utility compliance aggregator may aggregate the supplier's compliance obligations and accomplishments with those of other suppliers that are subject to the same obligations under G.S. 62133.8.

(4) Each clean energy facility or new clean energy facility registered by the Commission under Rule R8-66 shall participate in NC-RETS in order to have RECs issued, or in another REC tracking system in order to have RECs issued and transferred into NC-RETS, but no facility's meter data for the same time period shall be used for simultaneous REC issuance in two such systems. Beginning June 1, 2011, clean energy facilities registered in NCRETS may only enter historic energy production data for REC issuance that goes back up to two years from the current date. Facilities that produce energy using one or more clean energy resource(s) and another resource that does not qualify toward CEPS compliance under G.S. 62-133.8 shall calculate on a monthly basis and provide to NC-RETS the percentage of energy output attributable to each fuel source. NC-RETS will issue RECs only for energy emanating from sources that qualify under G.S. 62133.8.

(5) Each balancing area operator shall provide monthly electric generation production data to NC-RETS for clean and new clean energy facilities that are interconnected to the operator's electric transmission system. Such balancing area operator shall retain documentation verifying the production data for audit by the Public Staff.

(6) Each electric power supplier that has registered clean energy facilities or new clean energy facilities interconnected with its electric distribution system and that reads the electric generation production meters for those facilities shall provide monthly the facilities' energy output to NC-RETS, and shall retain for audit for 10 years that energy output data. Municipalities and electric membership corporations may elect to have the facilities' production data reported to NC-RETS and retained for audit by a utility compliance aggregator.

(7) A clean energy facility or new clean energy facility that produces thermal energy that qualifies for RECs shall report the facility's qualifying thermal energy output to NC-RETS at least every 12 months. A clean energy facility or new clean energy facility that reports its data pursuant to Rule R867(g)(3) shall report its energy output to NC-RETS at least every 12 months.

(8) The owner of an inverter-based solar photovoltaic system with a nameplate capacity of 10 kW or less may estimate its energy output using generally

accepted analytical tools pursuant to Rule R8-67(g)(2). Such an owner, or its agent, of this kind of facility shall report the facility's energy output to NCRETS at least every 12 months.

(9) All energy output and fuel data for multi-fuel facilities, including underlying documentation, calculations, and estimates, shall be retained for audit for at least ten years immediately following the provision of the output data to NC-RETS or another tracking system, as appropriate.

(10) Each electric power supplier that complies with G.S. 62-133.8 by implementing energy efficiency or demand-side management programs shall use NC-RETS to report the energy savings of those programs. Municipal power suppliers and electric membership corporations may elect to have their energy savings from their energy efficiency and demand-side management programs reported to NC-RETS by a utility compliance aggregator, and to have their reported savings consolidated with the reported savings from other municipal power suppliers or electric membership corporations if and as necessary to permit aggregate reporting through their utility compliance aggregator. Records regarding which electric power supplier achieved the energy efficiency and demand-side management, the programs that were used, and the year in which it was achieved, shall be retained for audit.

(11) All Commission-approved costs of developing and operating NCRETS shall be allocated among all electric power suppliers based upon their respective share of the total megawatt-hours of retail electricity sales in North Carolina in the previous calendar year. Each electric power supplier, or its utility compliance aggregator, shall, within 60 days of NC-RETS beginning operations, and by June 1 of each subsequent year, enter its previous year's retail electricity sales into NC-RETS, which sales will be used by NC-RETS to calculate each electric power supplier's CEPS obligations and NC-RETS charges. NC-RETS shall update its billings beginning each July based on retail sales data for the previous calendar year. Such NCRETS charges shall be deemed to be costs that are reasonable, prudent, incremental, and eligible for recovery through each electric public utility's annual rider established pursuant to G.S. 62133.8(h).

(12) Each account holder in NC-RETS shall pay the NC-RETS administrator for service according to the following fee schedule:

  (i) $0.01 for each REC export to an account residing in a different REC tracking system.

  (ii) $0.01 for each REC retired for reasons other than compliance with G.S. 62-133.8.

(13) The Commission shall adopt NC-RETS Operating Procedures. The Commission shall establish an NC-RETS Stakeholder Group that shall meet from time to time and which may recommend changes to the NCRETS Operating Procedures and NC-RETS.

(14) All data retention requirements of this Rule R8-67(h) may be accomplished via retention of electronic documents.

(NCUC Docket No. E-100, Sub 113, 2/29/08; NCUC Docket No. E-100, Sub 113, 3/13/08; NCUC Docket No. E-100, Subs 113 & 121, 1/31/11; NCUC Docket No. E-43, Sub 6, E100, Sub 113, EC-33, Sub 58, EC-83, Sub 1, 5/14/2012; NCUC Docket No. E-100, Sub 191; 11/21/2023; NCUC Docket No. E-100, Sub 113, 6/21/24.)

Rule R8-68. INCENTIVE PROGRAMS FOR ELECTRIC PUBLIC UTILITIES AND ELECTRIC MEMBERSHIP CORPORATIONS, INCLUDING ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT PROGRAMS.

(a) Purpose. — The purpose of this rule is to establish guidelines for the application of G.S. 62-140(c) to electric public utilities and electric membership corporations and G.S. 62-133.9 to electric public utilities that are consistent with the directives of those statutes and consistent with the public policy of this State as set forth in G.S. 62-2.

(b) Definitions.

(1) Unless listed below, the definitions of all terms used in this rule shall be as set forth in Rule R8-67(a), or if not defined therein, then as set forth in G.S. 62-3, G.S. 62-133.8(a) and G.S. 62-133.9(a).

(2) “Consideration” means anything of economic value paid, given, or offered to any person by an electric public utility or electric membership corporation (regardless of the source of the “consideration’’) including, but not limited to: payments to manufacturers, builders, equipment dealers, contractors including HVAC contractors, electricians, plumbers, engineers, architects, and/or homeowners or owners of multiple housing units or commercial establishments; cash rebates or discounts on equipment/appliance sales, leases, or service installation; equipment/ appliances sold below fair market value or below their cost to the electric public utility or electric membership corporation; low interest loans, defined as loans at an interest rate lower than that available to the person to whom the proceeds of the loan are made available; studies on energy usage; model homes; and payment of trade show or advertising costs. Excepted from the definition of “consideration” are favors and promotional activities that are de minimis and nominal in value and that are not directed at influencing fuel choice decisions for specific applications or locations.

(3) “Costs” include, but are not limited to, all capital costs (including cost of capital and depreciation expenses), administrative costs, implementation costs, participation incentives, and operating costs. “Costs” does not include utility incentives.

(4) “Electric public utility” means a person, whether organized under the laws of this State or under the laws of any other state or country, now or hereafter owning or operating in this State equipment or facilities for producing, transporting, distributing, or furnishing electric service to or for the public for consumption. For purposes of this rule, “electric public utility” does not include electric membership corporations.

(5) “Net lost revenues” means the revenue losses, net of marginal costs avoided at the time of the lost kilowatt-hour sale(s), or in the case of purchased power, in the applicable billing period, incurred by the electric public utility as the result of a new demand-side management or energy efficiency measure. Net lost revenues shall also be net of any increases in revenues resulting from any activity by the electric public utility that causes a customer to increase demand or energy consumption, whether or not that activity has been approved pursuant to this Rule R8-68.

(6) "New demand-side management or energy efficiency measure" means a demand-side management or energy efficiency measure that is adopted and implemented on or after January 1, 2007, including subsequent changes and modifications to any such measure. Cost recovery for "new demand-side management measures" and "new energy efficiency measures" is subject to G.S. 62-133.9.

(7) "Participation incentive" means any consideration associated with a new demand-side management or energy efficiency measure.

(8) "Program" or "measure" means any electric public utility action or planned action that involves the offering of consideration.

(9) "Utility incentives" means incentives as described in G.S. 62-133.9(d)(2)a-c.

(c) Filing for Approval.

(1) Application of Rule.

(i) Prior to an electric public utility or electric membership corporation implementing any measure or program, the purpose or effect of which is to directly or indirectly alter or influence the decision to use the electric public utility's or electric membership corporation's service for a particular end use or to directly or indirectly encourage the installation of equipment that uses the electric public utility's or electric membership corporation's service, and prior to any electric power supplier to which Rule R8-60 applies implementing any new or modified demand-side management or energy efficiency measure, the electric public utility or the electric membership corporation, as applicable, shall obtain Commission approval, regardless of whether the measure or program is offered at the expense of the shareholders, ratepayers, or third-party.

(ii) This requirement shall also apply to measures and programs that are administered, promoted, or funded by the electric public utility's or electric membership corporation's subsidiaries, affiliates, or unregulated divisions or businesses if the electric public utility or electric membership corporation has control over the entity offering or is involved in the measure or program and an intent or effect of the measure or program is to adopt, secure, or increase the use of the electric public utility's public utility services.

(iii) Any application for approval by an electric public utility or electric membership corporation of a measure or program under this rule shall be made in a unique sub-docket of the electric public utility's or electric membership corporation's docket number.

(2) Filing Requirements. — Each application for the approval shall include:

(i) Cover Page. — The electric public utility or electric membership corporation shall attach to the front of an application a cover sheet generally describing:

a. the measure or program;

b. the consideration to be offered;

c. the anticipated total cost of the measure or program;

d. the source and amount of funding to be used; and
e. the proposed classes of persons to whom it will be offered.

(ii) Description. — The electric public utility or electric membership corporation shall provide a description of each measure and program, and include the following:

a. the program or measure's objective;
b. the duration of the program or measure;
c. the targeted sector and eligibility requirements;
d. examples of all communication materials to be used with the measure or program and the related cost for each program year;
e. the estimated number of participants;
f. the impact that each measure or program is expected to have on the electric public utility or electric membership corporation, its customer body as a whole, and its participating North Carolina customers; and
g. any other information the electric public utility or electric membership corporation believes is relevant to the application, including information on competition known by the electric public utility or the electric membership corporation.

(iii) Additionally, an electric public utility shall include or describe:

a. the measure's proposed marketing plan, including a description of market barriers and how the electric public utility intends to address them;
b. the total market potential and estimated market growth throughout the duration of the program;
c. the estimated summer and winter peak demand reduction by unit metric and in the aggregate by year;
d. the estimated energy reduction per appropriate unit metric and in the aggregate by year;
e. the estimated lost energy sales per appropriate unit metric and in the aggregate by year; and
f. the estimated load shape impacts.

(iv) Costs and Benefits. — The electric public utility or electric membership corporation shall provide the following information on the costs and benefits of each proposed measure or program: (a) the estimated total and per unit cost and benefit of the measure or program to the electric public utility or electric membership corporation, reported by type of benefit and expenditure (e.g., capital cost expenditures; administrative costs; operating costs; participation incentives, such as rebates and direct payments; and communications costs, and the costs of measurement and verification) and the planned accounting treatment for those costs and benefits; (b) the type, the maximum and minimum amount of participation incentives to be made to any party, and the reason for any participation incentives and other consideration and to whom they will be offered, including schedules listing participation incentives and other consideration to be offered; and (c) service limitations or conditions planned to be imposed on customers who do not participate in the measure. With respect to communications costs, the electric public utility or electric membership corporation shall provide detailed cost information on communications materials related to each proposed measure or program. Such costs shall be included in the Commission's consideration of the total cost of the measure or program and whether the total cost of the measure or program is reasonable in light of the benefits.

(v) Cost-Effectiveness Evaluation. — The electric public utility or electric membership corporation shall provide the economic justification for each proposed measure or program, including the results of all cost-effectiveness tests. Cost-effectiveness evaluations performed by the electric public utility or electric membership corporation should be based on direct or quantifiable costs and benefits and should include, at a minimum, an analysis of the Total Resource Cost Test, the Participant Test, the Utility Cost Test, and the Ratepayer Impact Measure Test. In addition, an electric public utility shall describe the methodology used to produce the impact estimates as well as, if appropriate, methodologies considered and rejected in the interim leading to the final model specification.

(vi) Commission Guidelines Regarding Incentive Programs. — The electric public utility or electric membership corporation shall provide the information necessary to comply with the Commission's Revised Guidelines for Resolution of Issues Regarding Incentive Programs, issued by Commission Order on March 27, 1996, in Docket No. M-100, Sub 124, set out as an Appendix to Chapter 8 of these rules.

(vii) Integrated Resource Plan. — When seeking approval of a new demand-side management or new energy efficiency measure, the electric public utility shall explain in detail how the measure is consistent with the electric public utility's integrated resource plan filings pursuant to Rule R8-60.

(viii) Other. — Any other information the electric public utility or electric membership corporation believes relevant to the application, including information on competition known by the electric public utility or the electric membership corporation.

(3) Additional Filing Requirements. — In addition to the information listed in subsection (c)(2), an electric public utility filing for approval of a new or modified demand-side management or energy efficiency measure shall provide the following:

(i) Costs and Benefits. – The electric public utility shall describe:

a. any costs incurred or expected to be incurred in adopting and implementing a measure or program to be considered for recovery through the annual rider under G.S. 62-133.9;

b. estimated total costs to be avoided by the measure by appropriate capacity, energy and measure unit metric and in the aggregate by year;

c. estimated participation incentives by appropriate capacity, energy, and measure unit metric and in the aggregate by year;

d. how the electric public utility proposes to allocate the costs and benefits of the measure among the customer classes and jurisdictions it serves;

e. the capitalization period to allow the utility to recover all costs or those portions of the costs associated with a new program or measure to the extent that those costs are intended to produce future benefits as provided in G.S. 62-133.9(d)(1).

f. The electric public utility shall also include the estimated and known costs of measurement and verification activities pursuant to the Measurement and Verification Reporting Plan described in paragraph (ii).

(ii) Measurement and Verification Reporting Plan for New Demand-Side Management and Energy Efficiency Measures. — The electric public utility shall be responsible for the measurement and verification of energy and peak demand savings and may use the services of an independent third party for such purposes. The costs of implementing the measurement and verification process may be considered as operating costs for purposes of Commission Rule R8-69. In addition, the electric public utility shall:

a. describe the industry-accepted methods to be used to evaluate, measure, verify, and validate the energy and peak demand savings estimated in (2)(iii)c and d above;

b. provide a schedule for reporting the savings to the Commission;

c. describe the methodologies used to produce the impact estimates, as well as, if appropriate, the methodologies it considered and rejected in the interim leading to final model specification; and

d. identify any third party and include all of the costs of that third party, if the electric public utility plans to utilize an independent third party for purposes of measurement and verification.

(iii) Cost recovery mechanism. — The electric public utility shall describe the proposed method of cost recovery from its customers.

(iv) Tariffs or rates. — The electric public utility shall provide proposed tariffs or modifications to existing tariffs that will be required to implement each measure or program.

(v) Utility Incentives. — When seeking approval of new demand-side management and energy efficiency measures, the electric public utility shall indicate whether it will seek to recover any utility incentives, including, if appropriate, net lost revenues, in addition to its costs. If the electric public utility proposes recovery of utility incentives related to the proposed new demand-side management or energy efficiency measure, it shall describe the utility incentives it desires to recover and describe how its measurement and verification reporting plan will demonstrate the results achieved by the proposed measure. If the electric public utility proposes recovery of net lost revenues, it shall describe estimated net lost revenues by appropriate capacity, energy and measure unit metric and in the aggregate by year. If the electric public utility seeks recovery of utility incentives, including net lost revenues, apart from its recovery of its costs under G.S. 62-133.9, it shall file estimates of the utility incentives and the net lost revenues associated with the proposed measure for each year of the proposed recovery. If the electric public utility seeks only the recovery of net lost revenues apart from its recovery of combined costs and utility incentives, it shall file estimates of net lost revenues for each year of the proposed recovery period.

(d) Procedure.

(1) Automatic Tariff Suspension. – If an electric public utility files a proposed tariff or tariff amendment in connection with an application for approval of a measure or program, the tariff filing shall be automatically suspended pursuant to G.S. 62-134 pending investigation, review, and decision by the Commission.

(2) Service and Response. — The electric public utility or electric membership corporation filing for approval of a measure or program shall serve a copy of its filing on the Public Staff; the Attorney General; the natural gas utilities, electric public utilities, and electric membership corporations operating in the filing electric public utility's or electric membership corporation's certified territory; and any other party that has notified the electric public utility or electric membership corporation in writing that it wishes to be served with copies of all filings. If a party consents, the electric public utility or electric membership corporation may serve it with electronic copies of all filings. Those served, and others learning of the application, shall have thirty (30) days from the date of the filing in which to petition for intervention pursuant to Rule R1-19, file a protest pursuant to Rule R1-6, or file comments on the proposed measure or program. In comments, any party may recommend approval or disapproval of the measure or program or identify any issue relative to the program application that it believes requires further investigation. The filing electric public utility or electric membership corporation shall have the opportunity to respond to the petitions, protests, or comments within ten (10) days of their filing. If any party raises an issue of material fact, the Commission shall set the matter for hearing. The Commission may determine the scope of this hearing.

(3) Notice and Schedule. — If the application is set for hearing, the Commission shall require notice, as it considers appropriate, and shall establish a procedural schedule for prefiled testimony and rebuttal testimony after a

discovery period of at least 45 days. Where possible, the hearing shall be held within ninety (90) days from the application filing date.

(e) Scope of Review. — In determining whether to approve in whole or in part a new measure or program or changes to an existing measure or program, the Commission may consider any information it determines to be relevant, including any of the following issues:

(1) Whether the proposed measure or program is in the public interest and benefits the electric public utility's or electric membership corporation's overall customer body;

(2) Whether the proposed measure or program unreasonably discriminates among persons receiving or applying for the same kind and degree of service;

(3) Evidence of consideration or compensation paid by any competitor, regulated or unregulated, of the electric public utility or electric membership corporation to secure the installation or adoption of the use of such competitor's services;

(4) Whether the proposed measure or program promotes unfair or destructive competition or is inconsistent with the public policy of this State as set forth in G.S. 62-2 and G.S. 62-140; and

(5) The impact of the proposed measure or program on peak loads and load factors of the filing electric public utility or electric membership corporation, and whether it encourages energy efficiency.

(f) Cost Recovery for New Measures. —Approval of a program or measure under Commission Rule R8-68 does not constitute approval of rate recovery of the costs of the program or measure. With respect to new demand-side management and energy efficiency measures, the costs of those new measures, approved by application of this rule, that are found to be reasonable and prudently incurred shall be recovered through the annual rider described in G.S. 62-133.9 and Rule R8-69. The Commission may consider in the annual rider proceeding whether to approve the inclusion of any utility incentive pursuant to G.S. 62-133.9(d)(2)a-c. in the annual rider.

(NCUC Docket No. E-100, Sub 113, 2/29/08; NCUC Docket No. E-100, Sub 113, 3/13/08; NCUC Docket No. E-100, Subs 113 & 121, 1/31/11; NCUC Docket No. M-100, Sub 140, 12/03/13.)

Rule R8-69. COST RECOVERY FOR DEMAND-SIDE MANAGEMENT AND ENERGY EFFICIENCY MEASURES OF ELECTRIC PUBLIC UTILITIES

(a) Definitions.

(1) Unless listed below, the definitions of all terms used in this rule shall be as set forth in Rules R8-67 and R8-68, or if not defined therein, then as set forth in G.S. 62-133.8(a) and G.S. 62-133.9(a).

(2) "DSM/EE rider" means a charge or rate established by the Commission annually pursuant to G.S. 62-133.9(d) to allow the electric public utility to recover all reasonable and prudent costs incurred in adopting and implementing new demand-side management and energy efficiency measures after August 20, 2007, as well as, if appropriate, utility incentives, including net lost revenues.

(3) "Large commercial customer" means any commercial customer that has an annual energy usage of not less than 1,000,000 kilowatt-hours (kWh), measured in the same manner as the electric public utility that serves the commercial customer measures energy for billing purposes.

(4) "Rate period" means the period during which the DSM/EE rider established under this rule will be in effect. For each electric public utility, this period will be the same as the period during which the rider established under Rule R8-55 is in effect.

(5) "Test period" shall be the same for each public utility as its test period for purposes of Rule R8-55, unless otherwise ordered by the Commission.

(b) Recovery of Costs.

(1) Each year the Commission shall conduct a proceeding for each electric public utility to establish an annual DSM/EE rider. The DSM/EE rider shall consist of a reasonable and appropriate estimate of the expenses expected to be incurred by the electric public utility, during the rate period, for the purpose of adopting and implementing new demand-side management and energy efficiency measures previously approved pursuant to Rule R8-68. The expenses will be further modified through the use of a DSM/EE experience modification factor (DSM/EE EMF) rider. The DSM/EE EMF rider will reflect the difference between the reasonable expenses prudently incurred by the electric public utility during the test period for that purpose and the revenues that were actually realized during the test period under the DSM/EE rider then in effect. Those expenses approved for recovery shall be allocated to the North Carolina retail jurisdiction consistent with the system benefits provided by the new demand-side management and energy efficiency measures and shall be assigned to customer classes in accordance with G.S. 62-133.9(e) and (f).

(2) Upon the request of the electric public utility, the Commission shall also incorporate the experienced over-recovery or under-recovery of costs up to thirty (30) days prior to the date of the hearing in its determination of the DSM/EE EMF rider, provided that the reasonableness and prudence of

these costs shall be subject to review in the utility's next annual DSM/EE rider hearing.

(3) Pursuant to G.S. 62-130(e), any over-collection of reasonable and prudently incurred costs to be refunded to an electric public utility's customers through operation of the DSM/EE EMF rider shall include an amount of interest, at such rate as the Commission determines to be just and reasonable, not to exceed the maximum statutory rate. The beginning date for measurement of such interest shall be the effective date of the DSM/EE EMF rider in each annual proceeding, unless otherwise determined by the Commission.

(4) The burden of proof as to whether the costs were reasonably and prudently incurred shall be on the electric public utility.

(5) Any costs incurred for adopting and implementing measures that do not constitute new demand-side management or energy efficiency measures are ineligible for recovery through the annual rider established in G.S. 62-133.9.

(6) Except as provided in (c)(3) of this rule, each electric public utility may implement deferral accounting for costs considered for recovery through the annual rider. At the time the Commission approves a new demand-side management or energy efficiency measure under Rule R8-68, the electric public utility may defer costs of adopting and implementing the new measure in accordance with the Commission's approval order under Rule R8-68. Subject to the Commission's review, the electric public utility may begin deferring the costs of adopting and implementing new demand-side management or energy efficiency measures six (6) months prior to the filing of its application for approval under Rule R8-68, except that the Commission may consider earlier deferral of development costs in exceptional cases, where such deferral is necessary to develop an energy efficiency measure. Deferral accounting, however, for any administrative costs, general costs, or other costs not directly related to a new demand-side management or energy efficiency measure must be approved prior to deferral. The balance in the deferral account, net of deferred income taxes, may accrue a return at the net-of-tax rate of return approved in the electric public utility's most recent general rate proceeding. The return so calculated will be adjusted in any rider calculation to reflect necessary recoveries of income taxes. This return is not subject to compounding. The accrual of such return of on any under-recovered or over-recovered balance set in an annual proceeding for recovery or refund through a DSM/EE EMF rider shall cease as of the effective date of the DSM/EE EMF rider in that proceeding, unless otherwise determined by the Commission. However, deferral accounting of costs shall not affect the Commission's authority under this rule to determine whether the deferred costs may be recovered.

(c) Utility Incentives.

(1) With respect to a new demand-side management or energy efficiency measure previously approved under Rule R8-68, the electric public utility may, in its annual filing, apply for recovery of any utility incentives, including,

if appropriate, net lost revenues, identified in its application for approval of the measure. The Commission shall determine the appropriate ratemaking treatment for any such utility incentives.

(2) When requesting inclusion of a utility incentive in the annual rider, the electric public utility bears the burden of proving its calculations of those utility incentives and the justification for including them in the annual rider, either through its measurement and verification reporting plan or through other relevant evidence.

(3) An electric public utility shall not be permitted to implement deferral accounting or the accrual of a return for utility incentives unless the Commission approves an annual rider that provides for recovery of an integrated amount of costs and utility incentives. In that instance, the Commission shall determine the extent to which deferral accounting and the accrual of a return will be allowed.

(d) Special Provisions for Industrial or Large Commercial Customers.

(1) Pursuant to G.S. 62-133.9(f), any industrial customer or large commercial customer may notify its electric power supplier that: (i) it has implemented or, in accordance with stated, quantifiable goals, will implement alternative demand-side management or energy efficiency measures; and (ii) it elects not to participate in demand-side management or energy efficiency measures for which cost recovery is allowed under G.S. 62-133.9. Any such customer shall be exempt from any annual rider established pursuant to this rule after the date of notification.

(2) At the time the electric public utility petitions for the annual rider, it shall provide the Commission with a list of those industrial or large commercial customers that have opted out of participation in the new demand-side management or energy efficiency measures. The electric public utility shall also provide the Commission with a listing of industrial or large commercial customers that have elected to participate in new measures after having initially notified the electric public utility that it declined to participate.

(3) Any customer that opts out but subsequently elects to participate in a new demand-side management or energy efficiency measure or program loses the right to be exempt from payment of the rider for five years or the life of the measure or program, whichever is longer. For purposes of this subsection, “life of the measure or program” means the capitalization period approved by the Commission to allow the utility to recover all costs or those portions of the costs associated with a program or measure to the extent that those costs are intended to produce future benefits as provided in G.S. 62-133.9(d)(1).

(e) Annual Proceeding.

(1) For each electric public utility, the Commission shall schedule an annual rider hearing pursuant to G.S. 62-133.9(d) to review the costs incurred by the electric public utility in the adoption and implementation of new demand-side management and energy efficiency measures during the test period, the revenues realized during the test period through the operation of the annual rider, and the costs expected to be incurred during the rate period

and shall establish annual DSM/EE and DSM/EE EMF riders to allow the electric public utility to recover all costs found by the Commission to be recoverable. The Commission may also approve, if appropriate, the recovery of utility incentives, including net lost revenues, pursuant to G.S. 62-133.9(d)(2) in the rider.

(2) The annual rider hearing for each electric public utility will be scheduled as soon as practicable after the hearing held by the Commission for the electric public utility under Rule R8-55. Except as otherwise ordered by the Commission each electric public utility shall file its application for recovery of costs and appropriate utility incentives at the same time that it files the information required by Rule R8-55.

(3) The DSM/EE EMF rider will remain in effect for a fixed 12-month period following establishment and will continue as a rider to rates established in any intervening general rate case proceeding.

(f) Filing Requirements and Procedure.

(1) Each electric public utility shall submit to the Commission all of the following information and data in its application:

(i) Projected North Carolina retail monthly kWh sales for the rate period.

(ii) For each measure for which cost recovery is requested through the DSM/EE rider:

a. total expenses expected to be incurred during the rate period in the aggregate and broken down by type of expenditure, per appropriate capacity, energy and measure unit metric and the proposed jurisdictional allocation factors;

b. total costs that the utility does not expect to incur during the rate period as a direct result of the measure in the aggregate and broken down by type of cost, per appropriate capacity, energy and measure unit metric, and the proposed jurisdictional allocation factors, as well as any changes in the estimated future amounts since last filed with the Commission;

c. a description of the measurement and verification activities to be conducted during the rate period, including their estimated costs;

d. total expected summer and winter peak demand reduction per appropriate measure unit metric and in the aggregate;

e. total expected energy reduction in the aggregate and per appropriate measure unit metric.

(iii) For each measure for which cost recovery is requested through the DSM/EE EMF rider:

a. total expenses for the test period in the aggregate and broken down by type of expenditure, per appropriate capacity, energy and measure unit metric and the proposed jurisdictional allocation factors;

b. total costs that the utility did not incur for the test period as a direct result of the measure in the aggregate and broken down by type of cost, per appropriate capacity, energy and measure unit metric, and the proposed jurisdictional allocation factors, as well as any changes in the estimated future amounts since last filed with the Commission;

c. a description of, the results of, and the costs of all measurement and verification activities conducted in the test period;

d. total summer and winter peak demand reduction in the aggregate and per appropriate measure unit metric, as well as any changes in estimated future amounts since last filed with the Commission;

e. total energy reduction in the aggregate and per appropriate measure unit metric, as well as any changes in the estimated future amounts since last filed with the Commission;

f. a discussion of the findings and the results of the program or measure;

g. evaluations of event-based programs including the date, weather conditions, event trigger, number of customers notified and number of customers enrolled; and

h. a comparison of impact estimates presented in the measure application from the previous year, those used in reporting for previous measure years, and an explanation of significant differences in the impacts reported and those previously found or used.

(iv) For each measure for which recovery of utility incentives is requested, a detailed explanation of the method proposed for calculating those utility incentives, the actual calculation of the proposed utility incentives, and the proposed method of providing for their recovery and true-up through the annual rider. If recovery of net lost revenues is requested, the total net lost kWh sales and net lost revenues per appropriate capacity, energy, and program unit metric and in the aggregate for the test period, and the proposed jurisdictional allocation factors, as well as any changes in estimated future amounts since last filed with the Commission.

(v) Actual revenues produced by the DSM/EE rider and the DSM/EE EMF rider established by the Commission during the test period and for all available months immediately preceding the rate period.

(vi) The requested DSM/EE rider and DSM/EE EMF rider and the basis for their determination.

(vii) Projected North Carolina retail monthly kWh sales for the rate period for all industrial and large commercial accounts, in the aggregate, that are not assessed the rider charges as provided in this rule.

(viii) All workpapers supporting the calculations and adjustments described above.

(2) Each electric public utility shall file the information required under this rule, accompanied by workpapers and direct testimony and exhibits of expert

witnesses supporting the information filed in this proceeding, and any change in rates proposed by the electric public utility, by the date specified in subdivision (e)(2) of this rule. An electric public utility may request a rider lower than that to which its filed information suggests that it is entitled.

(3) The electric public utility shall publish a notice of the annual hearing for two (2) successive weeks in a newspaper or newspapers having general circulation in its service area, normally beginning at least thirty (30) days prior to the hearing, notifying the public of the hearing before the Commission pursuant to G.S. 62-133.9(d) and setting forth the time and the place of the hearing.

(4) Persons having an interest in any hearing may file a petition to intervene at least 15 days prior to the date of the hearing. Petitions to intervene filed less than 15 days prior to the date of the hearing may be allowed in the discretion of the Commission for good cause shown.

(5) The Public Staff and other intervenors shall file direct testimony and exhibits of expert witnesses at least 15 days prior to the hearing date. If a petition to intervene is filed less than 15 days prior to the hearing date, it shall be accompanied by any direct testimony and exhibits of expert witnesses the intervenor intends to offer at the hearing.

(6) The electric public utility may file rebuttal testimony and exhibits of expert witnesses no later than 5 days prior to the hearing date.

(NCUC Docket No. E-100, Sub 113, 2/29/08; NCUC Docket No. E-100, Sub 113, 3/13/08; NCUC Docket No. E-100, Subs 113 & 121, 1/31/11; NCUC Docket No. E-100, Sub 160, 10/11/18.)