BIENNIAL REPORT OF THE

NORTH CAROLINA UTILITIES COMMISSION

TO

THE GOVERNOR OF NORTH CAROLINA

AND

THE JOINT LEGISLATIVE COMMISSION ON GOVERNMENTAL OPERATIONS

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, 2021
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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.

EXECUTIVE SUMMARY

The Utilities Commission is providing this report to the Governor and the Joint Legislative Commission on Governmental Operations 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 every two years on September 1st. The report is to cover proceedings during the preceding two fiscal years, which for this report span the time period July 1, 2019, through June 30, 2021. 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, 2019, through June 30, 2021.

Throughout this report reference is 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.net, selecting "Dockets" from the main menu, selecting "Docket Search," and then entering the appropriate docket number.

North Carolina General Statute Section 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.
>
> "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, and that was included in previous reports. In addition, this report acknowledges demand-side management (DSM) and energy efficiency (EE) program applications that have been filed with the Commission recently and which fall into the next reporting period.

North Carolina General Statute Section 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. Electric power suppliers can implement EE and DSM measures to fulfill portions of their REPS obligations. Section 4.(a) of Senate Bill 3, codified as N.C.G.S. § 62-133.9, specifies that electric power suppliers shall use DSM and EE measures and supply-side resources to establish the least cost mix of demand reduction and generation measures that meets the electricity needs of their 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.

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 includes only those programs instituted after January 1, 2007. Further, the Commission may approve incentives to electric public utilities for adopting and implementing new DSM and EE measures. 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. Finally, none of the costs of new DSM or EE measures shall be assigned to an industrial or large commercial 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.

On May 1, 2020, the State's electric power suppliers provided assessments of the potential for DSM and EE as part of their IRPs[2].

Senate Bill 3 allows electric power suppliers to use energy savings from new EE and DSM programs toward their REPS obligations. During the two fiscal years covered by this report, the Commission approved several new programs and approved modifications to or re-opened a number of programs.

During the two fiscal years covered by this report, DENC, DEC and DEP each filed annual rider applications, and 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 DENC[3], DEC[4] and DEP[5] had outstanding DSM/EE Rider proceedings pending before the Commission.

As of the end of the period covered by this report, the DSM/EE riders for residential customers are as follows:

[2] Docket No. E-100, Sub 165.
[3] Docket No. E-22, Sub 604, filed August 10, 2021.
4 Docket No. E-7, Sub 1249.
[5] Docket No. E-2, Sub 1273.

Electric Public Utility	**DSM/EE Rider Charges for Residential Customer Using 1,000 kWh** (including the North Carolina Regulatory Fee (NCRF))
DENC	$1.051/month
DEC	$5.185/month
DEP	$6.540/month

SECTION 1: AMENDMENTS TO THE COMMISSION'S RULES

There were no amendments during the two-year period covered by this report.

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

North Carolina General Statute Section 62-133.9(c) requires each electric power supplier to which N.C.G.S. § 62-110.1[6] applies to include an assessment of DSM and EE in its IRP.

During 2020, IRPs were filed by the following electric public utilities in Docket No. E-100, Sub 165:

1. DENC
2. DEC
3. DEP

The following is a summary of each electric power supplier's DSM/EE assessment that was included in its IRP.

1. <u>DENC</u>

In its IRP, DENC listed the then currently approved EE and DSM programs in North Carolina as:

- Air Conditioner Cycling Program
- Non-Residential Distributed Generation Program
- Income and Age Qualifying Home Improvement Program
- Residential Appliance Recycling Program
- Residential Efficient Products Marketplace Program
- Residential Home Energy Assessment Program
- Non-Residential Small Manufacturing Program
- Non-Residential Office Program
- Non-Residential Heating and Cooling Efficiency Program
- Non-Residential Lighting Systems and Controls Program
- Non-Residential Window Film Program
- Small Business Improvement Program
- Non-Residential Prescriptive Program

The Company stated that it has proposed additional programs in North Carolina and was also considering the following future programs:

- Residential Customer Engagement Program
- Residential Smart Thermostat Program (DR)
- Residential Smart Thermostat Program (EE)
- Residential Electric Vehicle EE/DR Program

[6] Session Law 2013-187, which took effect July 1, 2013, exempts all electric membership corporations (EMCs) from the Commission's integrated resource planning proceedings.

- Residential Electric Vehicle Peak Shaving Program
- Residential Energy Efficiency Kits Program
- Residential Home Retrofit Program
- Residential Manufacturing Housing Program
- Residential New Construction Program
- Residential/Non-Residential Multifamily Program
- Non-Residential Midstream EE Products Program
- Non-Residential New Construction Program
- Small Business Improvement Enhanced Program
- House Bill 2789 Program (Heating and Cooling/Health and Safety Component)

DENC stated that it had reviewed and rejected the following programs:

- Non-Residential HVAC Tune-Up Program
- Energy Management System Program
- Energy Star^{R} New Homes Program
- Geo-Thermal Heat Pump Program
- Home Energy Comparison Program
- Home Performance with Energy Star^{R} Program
- In-Home Energy Display Program
- Premium Efficiency Motors Program
- Residential Refrigerator Turn-In Program
- Residential Solar Water Heating Program
- Residential Water Heater Cycling Program
- Residential Comprehensive Energy Audit Program
- Residential Radiant Barrier Program
- Residential Lighting Program (Phase II)
- Non-Commercial Refrigeration Program
- Cool Roof Program
- Non-Residential Data Centers Program
- Non-Residential Curtailable Service Program
- Non-Residential Custom Incentive
- Enhanced Air Conditioner Direct Load Control Program
- Residential Programmable Thermostat Program
- Residential Controllable Thermostat Program
- Residential New Homes Program
- Voltage Conservation
- Residential Home Energy Assessment
- Non-Residential Re-Commissioning Program
- Non-Residential Compressed Air System Program
- Non-Residential Strategic Energy Management
- Non-Residential Agricultural EE
- Non-Residential Telecommunication Optimization

In response to a notice filed by DENC requesting termination of the Small Business Improvement (SBI) Program , the Commission issued an Order terminating the SBI Program on May 19, 2021. The SBI program was replaced by the SBI Enhanced Program, which was approved by the Commission on February 9, 2021. The new SBI Enhanced program will offer an updated version of many of the same measures that were associated with the SBI Program. DENC stated that the requested closure and replacement program were necessary to comply with administrative requirements of the Virginia State Corporation Commission (VSCC) associated with the Company's Virginia energy efficiency program portfolio.

The Company provided a forecasted energy and capacity savings in 2021 due to its DSM and EE programs of 966,392 MWh (Energy Savings) (System-wide for Virginia and North Carolina).

2. DEC

In its 2020 IRP filing in Docket No. E-100, Sub 165, DEC stated that it uses EE and DSM programs in its IRP to efficiently and cost-effectively alter customer demands and reduce the long-run supply costs for energy and peak demand. These programs can vary greatly in their dispatch characteristics, size and duration of load response, certainty of load response, and level and frequency of customer participation. In general, programs are offered in two primary categories: EE programs that reduce energy consumption and DSM programs that reduce peak demand (demand-side management or demand response programs and certain rate structure programs). Following are the EE and DSM programs available through DEC as of December 31, 2019:

Residential EE:

- Energy Assessments
- Energy Efficiency Education
- Energy Efficient Appliances and Devices
- Multi-Family Energy Efficiency
- My Home Energy Report
- Income-Qualified Energy Efficiency and Weatherization
- Smart $aver® Energy Efficiency

Residential DSM:

- Power Manager

Non-Residential EE:

- Non-Residential Smart $aver® Prescriptive
- Non-Residential Smart $aver® Custom
- Non-Residential Smart $aver® Custom Assessment
- Non-Residential Smart $aver® Performance Incentive

- Small Business Energy $aver®

Non-Residential DSM:

- PowerShare®
- EnergyWise for Business
- Interruptible Service (IS)
- Standby Generator (SG)

DEC stated in its IRP that it has not rejected any cost-effective programs as a result of its EE and DSM program screening. DEC noted that it had discontinued its PowerShare CallOption program due to a lack of customer interest in 2018.

DEC stated that it is continually seeking to enhance its EE and DSM portfolio by: (1) adding new programs or expanding existing programs to include additional measures, (2) program modifications to account for changing market conditions and new M&V results, and (3) other EE pilots.

The Company further stated in its IRP that aggressive marketing campaigns have been launched to make customers aware of DEC's EE and DSM programs, successfully increasing customer adoption. The Company provided a forecasted energy and capacity savings in 2021 due to its DSM and EE programs of 1,679,020 MWh (Energy savings).

3. DEP

DEP listed its current portfolio of DSM/EE programs in its IRP as follows:

Residential EE:

- Residential New Construction
- Neighborhood Energy $aver® (Low-Income)
- My Home Energy Report
- Multi-Family Energy Efficiency
- Energy Efficient Education
- Energy Efficient Appliances and Devices
- Residential Energy Assessments
- Residential Smart $aver® Energy Efficiency

Residential DSM:

- EnergyWise Home

Non-Residential EE:

- Non-Residential Smart $aver® Energy Efficiency Products and Assessment
- Non-Residential Smart $aver® Performance Incentive

- Small Business Energy $aver®

Non-Residential DSM:

- CIG Demand Response Automation
- EnergyWise Business
- Large Load Curtailable Rates and Riders

Combined Residential/Non-Commercial

- Distribution System Demand Response (DSDR)
- Energy Efficient Lighting

The Company noted that is has not rejected any cost-effective DSM/EE programs or measures since the last biennial IRP was filed.

DEP stated that it is continually seeking to enhance its EE and DSM portfolio by: (1) adding new programs or expanding existing programs to include additional measures, (2) program modifications to account for changing market conditions and new M&V results, and (3) other EE pilots.

DEP stated in its IRP that aggressive marketing campaigns have been launched to make customers aware of DEP's EE and DSM programs, successfully increasing customer adoption. The Company provided a forecasted energy and capacity savings in 2021 due to its DSM and EE programs of 777,345 MWh (Energy savings).

SECTION 3: NEW DSM AND EE PROGRAMS

Senate Bill 3 allows electric public utilities to use energy savings from new EE programs toward their REPS obligations. Electric public utilities must file new program applications with the Commission. Programs initiated after the passage of Senate Bill 3 are considered “new.” This section lists the new DSM and EE programs that have been approved by the Commission for each utility during the two-year period covered by this report.

DENC’s New DSM and EE Programs

On July 12, 2019, in Docket Nos. E-22, Subs 567, 568, 569, 570, 571, 572, 573 and 574, DENC filed an application requesting approval of the following DSM and EE programs: 1) Residential Home Energy Assessment Program; 2) Residential Efficient Products Marketplace Program; 3) Residential Appliance Recycling Program; 4) Non-Residential Window Film Program; 5) Non-Residential Small Manufacturing Program; 6) Non-Residential Office Program; 7) Non-Residential Lighting Systems and Controls Program; and 8) Non-Residential Heating and Cooling Efficiency Program. Summaries of the programs are as follows:

1) RESIDENTIAL HOME ENERGY ASSESSMENT PROGRAM – This program is designed to provide an in-home energy assessment. DENC stated that the average value of the incentive each eligible participant will receive is $82 per participant. The actual incentives received will vary by participant depending on the measures that are actually installed as a result of the assessment.

2) RESIDENTIAL EFFICIENT PRODUCTS MARKETPLACE PROGRAM – This program is designed to provide rebates for the purchase of energy efficient appliances and products through an online or retail store. DENC stated that the average value of the incentive was $2 per applicant. In comments provided by the Public Staff, it was noted that DENC projects that at least 95% of the rebates will be given for lighting measures. The remaining 5% will be given for the purchase of various household appliances.

3) RESIDENTIAL APPLIANCE RECYCLING PROGRAM - This program will provide an incentive to recycle older less efficient refrigerators and freezers. DENC stated that the appliance must be in working order at the time the appliance is received. The average modeled incentive for the program is $20 per appliance. In comments provided by the Public Staff, they noted that DENC stated its intention to recycle at least 95% of the materials from the appliances.

4) NON-RESIDENTIAL WINDOW FILM PROGRAM – This Program is a reinstatement of a previous program that was cancelled pursuant to a Commission order dated October 16, 2018 in Docket No. E-22, Sub 509 resulting from actions taken by the Virginia State Corporation Commission. At that time the Company and Public Staff agreed that the Company could not

cost-effectively offer a window film program on a North Carolina-only basis. The Non-Residential Window Film Program will reinstate the same measures that were part of the previous program. The average modeled incentive for the Program was $1 per square foot of window.

5) NON-RESIDENTIAL SMALL MANUFACTURING PROGRAM – This program is designed to provide small manufacturing customers with incentives to install a variety of energy efficient air compression-related measures following an accessing by a contract vendor. DENC stated that the average modeled incentive for the program was $9,465 per participant.

6) NON-RESIDENTIAL OFFICE PROGRAM - This program is designed to provide small office customers with a variety of measures related to lighting and HVAC following an assessment with a contract vendor. The average modeled incentive for the program, according to DENC, was $6,374 per each participant. It was noted that approximately 90% of the participation and savings for the program are associated with HVAC-related measures, including measures that optimize the scheduling and temperature controls of the HVAC equipment itself.

7) NON-RESIDENTIAL LIGHTING SYSTEMS AND CONTROLS PROGRAM – This program is to replace the current North Carolina-only program that was approved by the Commission on October 16, 2018, in Docket No. E-22, Sub 508. This program will reinstate the system-wide program and update the measures offered. The average modeled incentive per participant was $2,456.

8) NON-RESIDENTIAL HEATING AND COOLING EFFIENCY PROGRAM – This program is intended to replace the current North Carolina-only program that was approved by the Commission on October 16, 2018, in Docket No. E-22, Sub 507. This program will reinstate the system-wide program and update the measures offered. The average modeled incentive per participant was $1,901.

The Public Staff was the only party to file comments on the programs. In its comments, the Public Staff recommended that the Commission approve the programs and noted that the programs appear to be cost effective, are to be included in future DENC IRPs, and are in the public interest. On November 13, 2019, the Commission issued an order approving the programs as new DSM and EE programs.

On November 13, 2020, in Docket Nos. E-22, Subs 591, 592, 593, 594, 595, and 596, DENC filed an application requesting approval of the following DSM and EE programs: 1) Non-Residential New Construction Program; 2) Residential Energy Efficiency Kit Program; 3) Residential Home Retrofit Program; 4) Residential Smart Thermostat Management (DR) Program; 5) Residential Smart Thermostat Management Program; and 6) Small Business Improvement Enhanced Program.

Summaries of the six programs are as follows:

1) NON-RESIDENTIAL NEW CONSTRUCTION PROGRAM – This program is designed to provide qualifying owners with incentives to install EE measures within their new construction projects. The average modeled incentive for the program was $18,754 per participant. The actual incentives received by the participant depend upon the measures installed by the participant.

2) RESIDENTIAL EE KIT PROGRAM – This program is designed to provide residential customers that have new customer accounts the opportunity to receive an EE Welcome Kit. Each welcome kit contains a Tier 1 power strip and an educational insert which contains information and tools for the customer to complete self-service EE projects. The average modeled incentive for the program was $51 per participant. The actual incentives received by the participant depend upon the measures installed by the participant.

3) RESIDENTIAL HOME RETROFIT PROGRAM – This program is intended for high energy users and is to incentivize customers to conduct a comprehensive, whole house diagnostic home energy assessment to be performed by a certified contractor. The average modeled incentive for the program was $379 per participant. The actual incentives received by the participant depend upon the measures installed by the participant.

4) RESIDENTIAL SMART THERMOSTAT MANAGEMENT (DR) PROGRAM – This program is meant to incentivize customers to allow DENC to shift or reduce their HVAC load during peak demand. The average modeled incentive for the program was $35 per participant. The actual incentives received by the participant depend upon the measures installed by the participant.

5) RESIDENTIAL SMART THERMOSTAT MANAGEMENT (EE) PROGRAM – Participants in this program will have the opportunity to purchase a qualifying smart thermostat and to enroll in a daily email program that will help them take advantage of energy savings. The average modeled incentive for the program was $54 per participant. The actual incentives received by the participant depend upon the measures installed by the participant.

6) SMALL BUSINESS IMPROVEMENT ENHANCED PROGRAM – This program is designed to provide small business customers with an energy use assessment and tune-up or re-commissioning of electric heating and cooling systems, along with financial incentives for installation of specific EE measures. The average modeled incentive for the program was $3,161 per participant. The actual incentives received by the participant depend upon the measures installed by the participant.

The Public Staff was the only party to file comments on the programs. In its comments, the Public Staff recommended that the Commission approve the programs and noted that the programs appear to be cost effective, are to be included in future DENC

IRPs and are in the public interest. On February 9, 2021, the Commission issued an order approving the programs as new DSM and EE programs.

<u>DEC's New DSM and EE Programs</u>

On September 21, 2017, in Docket No. E-7, Sub 1155, DEC filed an application requesting approval of a Residential New Construction Program as a new EE program under N.C.G.S. § 62-133.9 and Commission Rule R8-68. DEC stated in its application that the program is designed to allow DEC to target residential builders in order to encourage the use of EE building practices and appliances/equipment for new home construction. The Program is identical to the DEP program, also known as the Residential New Construction program, approved by the Commission in Docket No. E-2, Sub 1021. The Public Staff filed comments recommending Commission approval of the program as an EE program. On June 7, 2019, DEC filed a motion to withdraw the program due to concerns voiced by the natural gas utilities regarding some unintended consequences of the program design. On January 27, 2020, the Commission conducted a hearing on the matter and allowed parties to file comments. Both Piedmont Natural Gas and Public Service Company of North Carolina have intervened as parties to the docket. As of the date of this report, the matter is still pending before the Commission.

Other new DEC programs approved or modified by the Commission are as follows[7]:

1) RESIDENTIAL APPLIANCES AND DEVICES PROGRAM - New measures were added to the program.

2) NON-RESIDENTIAL SMART $AVER PRESCRIPTIVE PROGRAM - New measures were added to the program along with incentive changes.

3) RESIDENTIAL ENERGY ASSESSEMENT PROGRAM - New measures were added to the program. These added measures included specialty lighting, water-reducing measures, blower door tests, and Wi-Fi enabled smart thermostats, which the participant could request at the time of the initial energy assessment.

4) INCOME QUALIFIED ENERGY EFFICIENCY AND WEATHERIZATION ASSISTANCE FOR RESIDENTIAL NEIGHBORHOODS PROGRAM - Changes made to the program included: add new measures to the Program; (2) change the name of the program to mirror the name of DEP's comparable program; and (3) clarify the Company's ownership of any environmental, EE, and demand reduction benefits and attributes assigned to the peak demand and energy savings resulting from the program.

[7] These modifications were made in compliance with the Flexibility Guidelines approved by the Commission in Docket No. E-7 Sub 1032.

5) RESIDENTIAL POWER MANAGER LOAD CONTROL RIDER PROGRAM - Modifications included adding a “smart” thermostat-based winter-focused load control option, suspending new enrollments in the existing approved summer-only “smart” thermostat-based option, and limiting participation in the summer-only “smart” thermostat-based option to participants in place on or before December 31, 2020. Changes were also approved to allow customers who receive service under the Small Customer Generator Rider (SCG Rider) or Net Metering Rider (Rider NM) customers to participate. These customers had previously been prohibited from participating in the program.

6) RESIDENTIAL MULTI-FAMILY ENERGY EFFICIENCY PROGRAM - Modifications were made to add upgraded low flow water measures and smart thermostats to the existing list of measures offered by the program.

7) RESIDENTIAL SMART $AVER ENERGY EFFICIENCY PROGRAM - Modifications were made to the program to increase its overall cost-effectiveness. Changes to the program included: acknowledging lower actual incremental customer costs; improving trade ally participation to make it more streamlined and less costly; reducing program administration costs; and implementing a three-year transition period to a referral-only channel. DEC also removed from the tariff the listing of the maximum incentives for the measures, as well as to reduce the maximum incentive for HVAC (Heating, Ventilation, and Air Conditioning) equipment from $600 to $400.

There were no programs that were terminated or ended during the two-year period covered by this report.

<u>DEP’s New DSM and EE Programs</u>

During the two fiscal years covered by this report, DEP filed modifications or for approval of the following programs[8]:

8) Residential Appliances and Devices Program
    - New measures were added to the program.

- Non-residential Smart $aver EE Products and Assessments
    - New measures were added to the program along with incentive changes.

- Non-residential Smart $aver Prescriptive Program
    - New measures were added to the program.

DEP had no programs that were terminated or ended during the two-year period covered by this report.

[8] These modifications were made in compliance with the Flexibility Guidelines approved by the Commission in Docket No. E-2 Sub 931.

SECTION 4: COMMISSION PROCEEDINGS REGARDING DSM/EE COST RECOVERY

North Carolina General Statute Section 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 each year conduct a proceeding for each electric utility to establish an annual DSM/EE rider to recover DSM/EE related costs and utility incentives.

DSM/EE Rider Proceedings for DENC

During the two-year period of July 1, 2019 through June 30, 2021, DENC had two such proceedings before the Commission. Below is a discussion of each proceeding.

1. DENC DSM/EE Cost Recovery Rider – Docket No. E-22, Sub 577

On August 13, 2019, DENC filed its annual DSM/EE incentives and cost recovery rider application in which it sought to recover costs and incentives for the following existing programs:

- Residential Air Conditioner (AC) Cycling Program (Sub 465)
- Residential Lighting Program (Sub 468)
- Residential Home Energy Check Up Program (Sub 498)
- Residential Duct Testing and Sealing Program (Sub 497)
- Residential Heat Pump Tune-Up Program (Sub 499)
- Residential Heat Pump Upgrade Program (Sub 500)
- Residential Income and Age Qualifying Program (Sub 523)
- Residential Retail LED Lighting Program (Sub 539)
- Residential Home Energy Assessment (Sub 567)
- Residential Efficient Products Marketplace (Sub 568)
- Residential Appliance Recycling (Sub 569)
- Commercial Lighting Program (Sub 469)
- Commercial HVAC Upgrade Program (Sub 467)
- Non-Residential Energy Audit Program (Sub 495)
- Non-Residential Duct Testing and Sealing Program (Sub 496)
- Non-Residential Heating and Cooling Efficiency Program (Sub 14 507)
- Non-Residential Lighting Systems and Controls Program (Sub 16 508)
- Non-Residential Window Film Program (Sub 509)
- Small Business Improvement Program (Sub 538)
- Non-Residential Prescriptive Program (Sub 543)
- Non-Residential Window Film (Sub 570)
- Non-Residential Small Manufacturing (Sub 571)
- Non-Residential Office (Sub 572)
- Non-Residential Lighting Systems and Controls (Sub 573)

- Non-Residential Heating and Cooling Efficiency (Sub 574)

In its rider application, DENC sought recovery of $3,934,289[9]. As proposed, DENC's rider would result in the following charges, including the NCRF.

Residential	0.109 cents/kWh
Small General Service and Public Authorities	0.154 cents/kWh
Large General Service	0.097 cents/kWh

The Public Staff filed testimony, as allowed by statute, on October 22, 2019. In its testimony, the Public Staff testified that it was of the opinion that the Company has generally calculated its proposed DSM/EE billing rates (included in Rider C) and DSM/EE Experience Modification Factor (EMF) billing rates (included in Rider CE) in a manner consistent with G.S. 62-133.9, Commission Rule R8-69, and the 2017 DSM/EE cost recovery Mechanism approved by the Commission for DENC. The Public Staff recommended approval of DENC's proposed rates.

The Commission held an evidentiary hearing for this matter on November 12, 2019. No public witnesses appeared at the hearing.

On January 17, 2020, the Commission issued its order approving the revised charges as requested by DENC and the Public Staff related to DSM and EE program cost-recovery. As approved, DENC's rider resulted in the following charges per kilowatt-hours (kWh), which included the NCRF:

Residential	0.109 cents/kWh
Small General Service and Public Authorities	0.154 cents/kWh
Large General Service	0.097 cents/kWh

2. <u>DENC DSM/EE Cost Recovery Rider – Docket No. E-22, Sub 589</u>

On August 11, 2020, DENC filed its Application for Approval of DSM/EE incentives and cost recovery rider application in which it requested to recover costs and incentives for the Company's reasonable and prudent DSM/EE costs, common costs, taxes, net lost revenues (NLR), and a DSM/EE Program Performance Incentive (PPI). Specifically, DENC sought to recover costs and incentives for the following existing programs:

- Residential Air Conditioner (AC) Cycling Program (Sub 465)
- Residential Lighting Program (Sub 468)
- Residential Home Energy Check Up Program (Sub 498)
- Residential Duct Testing and Sealing Program (Sub 497)
- Residential Heat Pump Tune-Up Program (Sub 499)
- Residential Heat Pump Upgrade Program (Sub 500)

[9] Composed of Rider C revenue requirement of $3,470,280 and Rider CE revenue requirement of $464,010.

- Residential Income and Age Qualifying Program (Sub 523)
- Residential Retail LED Lighting Program (Sub 539)
- Residential Home Energy Assessment (Sub 567)
- Residential Efficient Products Marketplace (Sub 568)
- Residential Appliance Recycling (Sub 569)
- Commercial Lighting Program (Sub 469)
- Commercial HVAC Upgrade Program (Sub 467)
- Non-Residential Energy Audit Program (Sub 495)
- Non-Residential Duct Testing and Sealing Program (Sub 496)
- Non-Residential Heating and Cooling Efficiency Program (Sub 507)
- Non-Residential Lighting Systems and Controls Program (Sub 508)
- Non-Residential Window Film Program (Sub 509)
- Small Business Improvement Program (Sub 538)
- Non-Residential Prescriptive Program (Sub 543)
- Non-Residential Window Film (Sub 570)
- Non-Residential Small Manufacturing (Sub 571)
- Non-Residential Office (Sub 572)
- Non-Residential Lighting Systems and Controls (Sub 573)
- Non-Residential Heating and Cooling Efficiency (Sub 574)

DENC's Application requested an annual projected rate period revenue requirement of $ 2,567,620 to be recovered through its updated DSM/EE rider, Rider C, effective on and after January 1, 2021. DENC also requested approval of an increment to the DSM/EE EMF rider, Rider CE, in the amount of $467,202, to true up its actual costs and revenues received under Rider C rates. The Public Staff filed testimony in which it agreed with the revenue requirement and rates filed by DENC. The filed rates result in the following kWh charges: 0.1051 cents per kWh for residential customers; 0.1198 cents per kWh for small general service and public authority customers; 0.0922 cents per kWh for large general service customers; and 0.0000 cents per kWh for rate schedule 6VP customers (all including the NCRF).

On November 17, 2020, the Commission held the evidentiary hearing as scheduled. No parties other than the Public Staff intervened or presented evidence at the hearing.

On January 19, 2021, the Commission issued its Order approving DENC's requested charges related to DSM and EE program cost-recovery as discussed above. The new DSM/EE charges are to be effective February 1, 2021.

DSM/EE Rider Proceedings for DEC

During the two-year period of July 1, 2019 through June 30, 2021, DEC had three such proceedings before the Commission. Below is a discussion of each proceeding.

1. DEC DSM/EE Cost Recovery Rider – Docket No. E-7, Sub 1192

On February 26, 2019, DEC filed a petition requesting the establishment of Rider 11 to recover: (1) a prospective component consisting of the estimated revenue requirements associated with Vintage 2020 of DEC's DSM/EE programs, the second year of net lost revenues for Vintage 2019 of DEC's EE programs, the third year of net lost revenues for Vintage 2018 of DEC's EE programs, and the fourth year of net lost revenues for Vintage 2017 of DEC's EE programs; and (2) an EMF component truing up Vintage 2015, Vintage 2016, Vintage 2017, and Vintage 2018 of DEC's DSM/EE programs. In this petition DEC requested Commission approval of the following annual billing factors ($/kWh including gross receipts and NCRF):

Residential Billing Factors

Rider 11 Prospective Components	0.3892	cents/kWh
Rider 11 EMF Components	0.0956	cents/kWh

Non-Residential Billing Factors

Prospective Components:		
Vintage 2017 EE participant	0.0312	cents/kWh
Vintage 2018 EE participant	0.0549	cents/kWh
Vintage 2019 EE participant	0.0509	cents/kWh
Vintage 2020 EE participant	0.3082	cents/kWh
Vintage 2022 DSM participant	0.1101	cents/kWh
EMF Components:		
Vintage 2015 EE Participant	0.0064	cents/kWh
Vintage 2015 DSM Participant	0.0001	cents/kWh
Vintage 2016 EE Participant	0.0512	cents/kWh
Vintage 2016 DSM Participant	0.0001	cents/kWh
Vintage 2017 EE Participant	0.0645	cents/kWh
Vintage 2017 DSM Participant	0.0000	cents/kWh
Vintage 2018 EE Participant	0.0278	cents/kWh
Vintage 2018 DSM Participant	0.0077	cents/kWh

Intervenors in this proceeding were: the Public Staff, Southern Alliance for Clean Energy (SACE), North Carolina Sustainable Energy Association (NCSEA), Carolina Utility Customers Association, Inc. (CUCA), and Carolinas Industrial Group for Fair Utility Rates III (CIGFUR III).

On May 20, 2019, both the Public Staff and SACE filed testimony of its witnesses in the proceeding.

On May 28, 2019, DEC filed supplemental and rebuttal testimony of its witnesses.

The Commission held a hearing for this matter on June 11, 2019. The Commission issued an order on October 19, 2019 approving the revised DSM/EE rates as calculated in DEC's supplemental testimony. Those revised rates, to be effective January 1, 2020, were as follows:

Residential Billing Factors

Rider 11 Prospective Components	0.3891	cents/kWh
Rider 11 EMF Components	0.0944	cents/kWh

Non-Residential Billing Factors

Prospective Components:		
Vintage 2017 EE participant	0.0312	cents/kWh
Vintage 2018 EE participant	0.0549	cents/kWh
Vintage 2019 EE participant	0.0509	cents/kWh
Vintage 2020 EE participant	0.3082	cents/kWh
Vintage 2022 DSM participant	0.1101	cents/kWh
EMF Components*:*		
Vintage 2015 EE Participant	0.0064	cents/kWh
Vintage 2015 DSM Participant	0.0001	cents/kWh
Vintage 2016 EE Participant	0.0512	cents/kWh
Vintage 2016 DSM Participant	0.0001	cents/kWh
Vintage 2017 EE Participant	0.0645	cents/kWh
Vintage 2017 DSM Participant	0.0000	cents/kWh
Vintage 2018 EE Participant	0.0278	cents/kWh
Vintage 2018 DSM Participant	0.0077	cents/kWh

2. DEC DSM/EE Cost Recovery Rider – Docket No. E-7, Sub 1230

On February 25, 2020, DEC filed a petition requesting the establishment of Rider 12 to recover: (1) a prospective component consisting of the estimated revenue requirements associated with Vintage 2021 of DEC's current portfolio of DSM/EE programs, the second year of net lost revenues for Vintage 2020 of DEC's EE programs, the third year of net lost revenues for Vintage 2019 of DEC's EE programs, and the fourth year of net lost revenues for Vintage 2018 of DEC's EE programs; and (2) an EMF component truing up Vintage 2017, Vintage 2018 and Vintage 2019 of DEC's DSM/EE programs. In this petition DEC requested Commission approval of the following annual billing factors ($/kWh including the NCRF):

Residential Billing Factors

Rider 12 Prospective Component	0.4184	cents/kWh
Rider 12 EMF Component	0.1046	cents/kWh

Non-Residential Billing Factors

Prospective Components:		
Vintage 2018 EE participant	0.0137	cents/kWh
Vintage 2019 EE participant	0.0687	cents/kWh
Vintage 2020 EE participant	0.0612	cents/kWh
Vintage 2021 EE participant	0.3522	cents/kWh
Vintage 2021 DSM participant	0.1200	cents/kWh
EMF Components*:*		
Vintage 2017 EE Participant	0.0342	cents/kWh
Vintage 2017 DSM Participant	0.0000	cents/kWh
Vintage 2018 EE Participant	(0.0049)	cents/kWh
Vintage 2018 DSM Participant	(0.0014)	cents/kWh
Vintage 2019 EE Participant	(0.0225)	cents/kWh
Vintage 2019 DSM Participant	0.0018	cents/kWh

DEC requested recovery of costs associated with the following DSM/EE programs in its Rider 12:

- Energy Assessments
- EE Education
- Residential Smart $aver ® Energy Efficient Appliances and Devices
- Residential Smart $aver ® EE (formerly the HVAC EE Program)
- Multi-Family EE
- My Home Energy Report (MyHER)
- Residential Neighborhood Energy Saver (formerly Income Qualified Energy Efficiency and Weatherization Assistance)
- Power Manager
- Nonresidential Smart $aver ® Energy Efficient Products Assessments Program
- Energy Efficiency Food Service Products
- Energy Efficiency HVAC Products
- Energy Efficiency IT Products
- Energy Efficiency Lighting Products
- Energy Efficiency Process Equipment Products
- Energy Efficiency Pumps and Drives\
- Custom Incentive and Energy Assessments
- PowerShare®
- Small Business Energy Saver
- EnergyWise for Business
- Nonresidential Smart $aver ® Performance Incentive

Intervenors in this proceeding were: the Public Staff, SACE, NCSEA, CUCA, and CIGFUR III. On May 11, 2020, DEC filed supplemental testimony revising the DSM/EE rates requested. The revisions were the result of the following corrections made by DEC: (1) updates to lost revenues based on Evaluation, Measurement and Verification (EM&V) adjustments for Vintages 2018, 2019 and 2021, (2) adjustments to Vintage 2019 program costs resulting from the Public Staff of the North Carolina Utilities Commission's program cost audit and (3) inclusion of Vintage 2016 lost revenues due to inadvertent omission of exhibits from original filing. In that supplemental testimony DEC proposed the following revised DSM/EE rates, including the NCRF:

Residential Billing Factors

Rider 12 Prospective Component	0.4184	cents/kWh
Rider 12 EMF Component	0.1011	cents/kWh

Non-Residential Billing Factors

Prospective Components:		
Vintage 2018 EE participant	0.0137	cents/kWh
Vintage 2019 EE participant	0.0687	cents/kWh
Vintage 2020 EE participant	0.0612	cents/kWh
Vintage 2021 EE participant	0.3522	cents/kWh
Vintage 2021 DSM participant	0.1200	cents/kWh
EMF Components*:*		
Vintage 2016 EE Participant	0.0093	cents/kWh
Vintage 2016 DSM Participant	(0.0001)	cents/kWh
Vintage 2017 EE Participant	0.0342	cents/kWh
Vintage 2017 DSM Participant	0.0000	cents/kWh
Vintage 2018 EE Participant	(0.0049)	cents/kWh
Vintage 2018 DSM Participant	(0.0014)	cents/kWh
Vintage 2019 EE Participant	(0.0225)	cents/kWh
Vintage 2019 DSM Participant	0.0019	cents/kWh

On May 22, 2020, both the Public Staff and SACE filed testimony of its witnesses in the proceeding. On June 1, 2020, DEC filed supplemental and rebuttal testimony of its witnesses.

The Public Staff filed supplemental testimony of its witnesses on June 8, 2020. On June 9, 2020, the Commission held a hearing in this matter.

In its testimony, the Public Staff stated that it recommended that DEC's DSM/EE rider be approved, subject to making the adjustments for vintage year 2019 program costs, as well as adjustments related to the elimination of a reserve margin that DEC added to its avoided capacity benefits for vintage 2021 EE measures. The issue related to the vintage 2019 program costs resulted in an increase to 2019 PPI in the amount of $83,000 and was agreed to by DEC. DEC did not agree with the Public Staff's recommendation to eliminate the reserve margin, as DEC believes the inclusion of the 17% reserve margin is appropriate for these calculations.

On December 11, 2020, the Commission issued an Order approving the rates as set forth in DEC's revised supplemental testimony, with adjustments to be made to exclude the 17% reserve margin DEC included its calculations. The Commission ordered DEC to work with the Public Staff to calculate the impacted billing factors without DEC's proposed 17% reserve margin adder. On December 31, 2020, DEC filed the revised billing factors. The Commission approved DEC's revised billing factors, and those billing factors are as follows:

- Calendar Year 2021 (Vintage Year 2021) participants: EE increment rider of 0.3495 cents per kWh; and DSM increment rider of 0.1200 cents per kWh

- Calendar Year 2020 (Vintage Year 2020) participants: EE increment rider of 0.0612 cents per kWh; and DSM increment rider of 0.0000 cents per kWh

- Calendar Year 2019 (Vintage Year 2019) participants: EE increment rider of 0.0462 cents per kWh; and DSM increment rider of 0.0019 cents per kWh

- Calendar Year 2018 (Vintage Year 2018) participants: EE increment rider of 0.0088 cents per kWh; and DSM increment rider of (0.0014) cents per kWh

- Calendar Year 2017 (Vintage Year 2017) participants: EE increment rider of 0.0342 cents per kWh; and DSM increment rider of 0.0000 cents

- Calendar Year 2016 (Vintage Year 2016) participants: EE increment rider of 0.0193 cents per kWh; and DSM increment rider of (0.0001) cents per kWh

3. DEC DSM/EE Cost Recovery Rider – Docket No. E-7, Sub 1249

On February 23, 2021, DEC filed a petition requesting the establishment of Rider 13 to recover: (1) a prospective component consisting of the estimated revenue requirements associated with Vintage 2022 of DEC's current portfolio of DSM/EE programs, the second year of net lost revenues for Vintage 2021 of DEC's EE programs and the third year of net lost revenues for Vintage 2020 of DEC's EE programs; and the fourth year of net lost revenues for vintage year 2019 EE programs. The Rider 13 Experience Modification Factor (EMF) includes the following true-ups: 1) a true-up of Vintage 2017 DSM/EE programs, (2) a true-up of Vintage 2018 DSM/EE programs, (3) a true-up of Vintage 2019 DSM/EE programs, and (4) a true-up of Vintage 2020 DSM/EE programs. In this petition DEC requested Commission approval of the following annual billing factors ($/kWh including gross receipts and NCRF):

Residential Billing Factors

Rider 13 Prospective Component	0.4255	cents/kWh
Rider 13 EMF Component	0.0517	cents/kWh

Non-Residential Billing Factors

Prospective Components:		
Vintage 2019 EE participant	0.0122	cents/kWh
Vintage 2020 EE participant	0.0411	cents/kWh
Vintage 2021 DSM participant	0.0813	cents/kWh
Vintage 2022 EE participant	0.4102	cents/kWh
Vintage 2022 DSM participant	0.1038	cents/kWh
EMF Components*:*		
Vintage 2017 EE Participant	0.0157	cents/kWh
Vintage 2017 DSM Participant	0.0000	cents/kWh
Vintage 2018 EE Participant	0.0030	cents/kWh
Vintage 2018 DSM Participant	0.0019	cents/kWh
Vintage 2019 EE Participant	(0.0422)	cents/kWh
Vintage 2019 DSM Participant	(0.0015)	cents/kWh
Vintage 2020 EE Participant	(0.0856)	cents/kWh
Vintage 2020 DSM Participant	(0.0013)	cents/kWh

DEC requested approval of costs and incentives related to the following DSM/EE programs to be included in Rider 13:

- Energy Assessment Program
- EE Education Program
- Energy Efficient Appliances and Devices Program
- Residential Smart $aver EE Program
- Multifamily EE Program
- My Home Energy Report Program; Residential Neighborhood Energy Saver
- Power Manager Load Control Service Program
- Non-Residential Smart $aver Energy Efficient Food Service Products Program
- Non-Residential Smart $aver Energy Efficient HVAC Products Program
- Non-Residential Smart $aver Energy Efficiency IT Products Program
- Non-Residential Smart $aver Energy Efficient Lighting Products Program
- Non-Residential Smart $aver Energy Efficient Process Equipment Products Program
- Non-Residential Smart $aver Energy Efficient Pumps and Drives Products Program

- Non-Residential Smart $aver Custom Incentive and Energy Assessment Program
- PowerShare;
- Small Business Energy Saver Program
- EnergyWise for Business
- Non-Residential Smart $aver Performance Incentive Program

Intervenors in this proceeding were: the Public Staff, SACE, NCSEA, CUCA, NC Justice Center and CIGFUR III. On May 10, 2021, both the Public Staff and SACE/NC Justice Center filed testimony of its witnesses in the proceeding. On May 20, 2021, DEC filed rebuttal testimony of its witnesses. On May 28, 2021 the Commission issued an Order Excusing Expert Witnesses, Accepting Testimony, Canceling the Hearing, and Requiring Filing of Proposed Orders.

In its testimony the Public Staff expressed concern that the Find it Duke[10] channel allows all benefits to flow to the Residential Smart $aver Program, which is a residential EE program for DEC customers, when the work is not always done for an EE installation, a residential customer, or a customer of Duke Energy. As a result, the Public Staff recommended that the Company refine its referral channel accounting to allow only referral dollars specifically related to Residential EE work to be included in the referral channel for Residential Smart $aver and book other revenues appropriately. DEC provided rebuttal testimony in disagreement. DEC argued that the Public Staff's proposal would harm ratepayers. DEC noted that the Residential Smart $aver Program encourages customers to adopt high efficiency heating and cooling systems and that revenue from the Find it Duke referral channel helps offset the costs passed along to ratepayers through the DSM/EE rider.

On May 26, 2021, DEC and the Public Staff jointly filed a letter to notify the Commission that DEC and the Public Staff reached an agreement regarding the Find it Duke referral channel. The Public Staff and the Company agreed to work to resolve the issues related to the Find it Duke referral channel in the coming months and report on these efforts in their testimony filed in the 2022 DSM/EE Rider proceeding. Thus, for purposes of this 2021 DSM/EE Rider proceeding (Docket No. E-7, Sub 1249), the Public Staff and DEC agreed that DEC should not be required to make any changes to its accounting related to Find it Duke costs or revenues at this time.

On June 24, 2021, the Commission issued an Order Requiring DEC to Answer Questions Regarding its Find It Duke Program. DEC provided responses on July 23, 2021.

As of the due date of this report, the matter was still pending before the Commission.

[10] Find It Duke is a contractor referral program that Duke has instituted via its website,

DSM/EE Rider Proceedings for DEP

During the two-year period of July 1, 2019 through June 30, 2021, DEP had three such proceedings before the Commission. Below is a discussion of each proceeding.

1. DEP DSM/EE Cost Recovery Rider – Docket No. E-2, Sub 1206

On June 11, 2019, 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 forecasted DSM/EE costs, including carrying costs, NLR, PPI and an EMF. DEP requested the rider and EMF to allow it to recover $176,806,684 of DSM and EE expenses, net lost revenues, and incentives. This amount includes the estimated under-collection of $8,787,707 associated with test period activities during the period beginning January 1, 2018 and ending December 31, 2018, and an estimated $168,018,977 for expenses and incentives to be incurred during the rate period from January 1, 2020 through December 31, 2020. DEP requested that the Commission approve the following total annual billing factor adjustments (with the NCRF included):

Residential	0.595	cents/ kWh
General Service EE	0.785	cents/ kWh
General Service DSM	0.059	cents/ kWh
Lighting	0.094	cents/ kWh

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

Residential

- Appliance Recycling
- Energy Education Program
- Multi-Family EE
- My Home Energy Report (MyHER) (formerly, EE Benchmarking)
- Neighborhood Energy $aver® (Low Income)
- Residential Smart $aver EE Program
- New Construction
- EnergyWise (Load Control)
- Save Energy and Water Kit
- Energy Assessment
- Low-Income Weatherization Pay for Performance Program (Pilot implemented in January 2019)

Non-Residential

- Smart $aver® Energy Efficient Products and Assessments (formerly, EE for Business)
- Smart $aver® Performance Incentive Program

- Small Business Energy $aver®
- Commercial, Industrial, and Governmental (CIG) Demand Response Automation
- EnergyWise for Business (Load Control)

Residential and Non-Residential

- DSDR
- EE Lighting

Intervenors in this proceeding were as follows: the Public Staff, SACE, NC Justice Center, CUCA and North Carolina Housing Coalition (NCHC). On August 19, 2019 the Public Staff and NCJC/SACE witnesses filed testimony. DEP filed rebuttal testimony on August 28, 2019, and supplemental testimony on September 4, 2019. DEP's supplemental testimony updated the Company's requested billing factors were the result of (1) adjustments to the PPI generated by the EnergyWise and EnergyWise for Business programs for 18 Vintage 2017, Vintage 2018 and Vintage 2020, and the resulting reallocation of the Vintage 2018 avoided cost settlement, and (2) adjustments to DSDR program costs due to intangible depreciation expense recorded in excess of the useful life of the related assets. The combined revised rates requested by DEP are as follows:

Residential	0.554	cents/ kWh
General Service EE	0.743	cents/ kWh
General Service DSM	0.057	cents/ kWh
Lighting	0.051	cents/ kWh

The Public Staff in its testimony made note of a few concerns. The Public Staff noted that DEP 's Non-Residential Smart $aver Performance Incentive Program was facing issues with cost-effectiveness and recommended that if DEP could not make changes to cause the program to become cost-effective before its next DSM/EE Rider proceeding, that it recommended that DEP terminate the program.

The Commission held a hearing on the matter on September 9, 2019. The Commission issued an order in the proceeding on December 13, 2019, approving the DSM/EE rates as revised by DEP. The Commission further ordered DEP to provide in its next DSM/EE Rider proceeding its plans to make its Non-Residential Smart $aver Performance Incentive Program cost-effective, or to make plans to terminate the program. DEP shall address the continuing cost-effectiveness of the Non-Residential Smart $aver Performance Incentive Program and, if it is not cost-effective, provide details of plans to modify or close the program.

2. DEP DSM/EE Cost Recovery Rider – Docket No. E-2, Sub 1252

On June 9, 2020, 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 forecasted DSM/EE costs, including carrying costs, net lost revenues (NLR), program performance incentive (PPI) and an EMF. DEP requested the rider and EMF to allow it to recover $ 173,825,631 of DSM and EE expenses, net lost revenues, and incentives. This amount includes the estimated undercollection of $4,164,100 associated with test period activities during the period beginning January 1, 2019 and ending December 31, 2019, and an estimated $169,661,531 for expenses, net lost revenues, and incentives to be incurred during the rate period from January 1, 2021 through December 31, 2021. DEP requested that the Commission approve the following total annual billing factor adjustments (with the NCRF included):

Residential	0.654	cents/ kWh
General Service EE	0.700	cents/ kWh
General Service DSM	0.063	cents/ kWh
Lighting	0.088	cents/ kWh

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

Residential

- Appliance Recycling Program (Sub 970)
- EE Education Program (Sub 1060)
- Multi-Family EE Program (Sub 1059)
- My Home Energy Report (MyHER) Program (formerly the EE Benchmarking Program) (Sub 989)
- Neighborhood Energy Saver (Low-Income) Program (Sub 952)
- Residential Smart $aver EE Program (formerly HEIP) (Sub 936)
- New Construction Program (Sub 1021) 23 o Load Control Program (EnergyWise Home) (Sub 927)
- Save Energy and Water Kit Program (Sub 1085)
- Energy Assessment Program (Sub 1094)
- Low-Income Weatherization Pay for Performance Program (Sub 1187)

Non-Residential

- Non-Residential Smart $aver Energy Efficient Products and Assessment Program (formerly Energy Efficiency for 8 Business Program) (Sub 938)
- Non-Residential Smart $aver Performance Incentive Program (Sub 1126)
- Small Business Energy Saver Program (Sub 1022)
- CIG Demand Response Automation (CIG DRA) Program (Sub 953)
- EnergyWise for Business (Sub 1086)

Residential and Non-Residential

- Energy Efficient Lighting Program (EE Lighting) (Sub 970)
- Distribution System Demand Response (DSDR) Program (Sub 926)

Intervenors in this proceeding were as follows: the Public Staff, NCSEA, SACE/NC Justice Center, CUCA and CIGFUR II. The Commission held a hearing on September 15, 2020.

The Public Staff filed testimony on August 26, 2020. SACE/NC Justice Center also filed testimony. In its testimony, the Public Staff recommended certain changes to the calculations of avoided cost savings for estimated Vintage 2021 DSM/EE participation. The first change involves the elimination of a reserve margin that the Company has added to the avoided capacity benefits for Vintage 2021 EE measures. The second involves the allocation of avoided capacity benefits between summer and winter for the Company's Vintage 2021 DSM measures. The Public Staff noted that these changes affect the PPI recommended by the Public Staff in this proceeding. As a result of these recommendations, the Public Staff opposed revised billing rates for the Vintage 2021 prospective factors.

On September 4, 2020, DEP filed rebuttal testimony explaining that the Company did not agree with the Public Staff's recommendations.

On December 17, 2020, the Commission issued an Order approving revised DSM/EE rates as adjusted by the Public Staff, as follows:

Residential	0.654	cents/ kWh
General Service EE	0.701	cents/ kWh
General Service DSM	0.063	cents/ kWh
Lighting	0.088	cents/ kWh

3. <u>DEP DSM/EE Cost Recovery Rider – Docket No. E-2, Sub 1273</u>

On June 15, 2021, 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 forecasted DSM/EE costs, including carrying costs, net lost revenues (NLR), program performance incentive (PPI) and an EMF. DEP requested the rider and EMF to allow it to recover $ 189,738,629 of DSM and EE expenses, net lost revenues, and incentives. This amount includes the estimated under-collection of $12,551,970 associated with test period activities during the period beginning January 1, 2020 and ending December 31, 2020, and an estimated $177,186,661 for expenses, net lost revenues, and incentives to be incurred during the rate period from January 1, 2022 through December 31, 2022. DEP requested that the Commission approve the following total annual billing factor adjustments (with the NCRF included):

Residential	0.720	cents/ kWh
General Service EE	0.677	cents/ kWh
General Service DSM	0.053	cents/ kWh
Lighting	0.124	cents/ kWh

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

Residential

- Energy Education Program
- Multi-Family EE
- My Home Energy Report (MyHER) (formerly, EE Benchmarking)
- Neighborhood Energy $aver® (Low Income)
- Residential Smart $aver EE Program
- New Construction
- EnergyWise (Load Control)
- 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

Non-Residential

- Smart $aver® Energy Efficient Products and Assessments (formerly, EE for Business)
- Smart $aver® Performance Incentive Program
- Small Business Energy $aver®
- Commercial, Industrial, and Governmental (CIG) Demand Response Automation
- EnergyWise for Business (Load Control)

Residential and Non-Residential

- DSDR
- EE Lighting

Intervenors in this proceeding were as follows: the Public Staff, SACE, NC Justice Center, NCSEA, CIGFUR II, CUCA, National Resources Defense Council (NRDC) and NCHC.

A hearing was scheduled to be held on September 21, 2021. As of the due date of this report, the matter was still pending before the Commission.

Section 5: COST RECOVERY MECHANISMS

1. DENC - Docket No. E-22, Sub 464 (2020 review)

Pursuant to DENC's last cost recovery mechanism review in 2017, the Public Staff was requested to begin a formal review of DENC's cost recovery mechanism no later than October 1, 2019. On October 10, 2021, the Public Staff requested the Commission grant it an extension of time to begin its review. The Commission granted the Public Staff an extension of time until April 1, 2020, to initiate the review.

On January 20, 2021, the Public Staff filed a second request for an extension of time to initiate a review of DENC's cost recovery mechanism. The Public Staff requested an extension of time until January 11, 2021, to begin its review and committed to provide the Commission with an update no later than May 14, 2021. The Commission granted this second extension and required the Public Staff to provide an update on or before May 14, 2021.

On May 14, 2021, the Public Staff provided an update stating that the Public Staff discussed potential changes to the Mechanism with DENC. According to the Public Staff, both parties agreed that the Mechanism is working well and neither the Public Staff nor the Company believes substantial changes are necessary. The Public Staff did note that it proposes the following modifications to the Mechanism:

- Change to PPI percentage(s)

- Cap or floor on PPI based on margin of PPI revenue over program cost

- Change the test used to calculate the prospective cost-effectiveness of new and ongoing programs from the Total Resource Cost (TRC) Test to the Utility Cost Test (UCT)

- Revising the definition of the TRC Test to provide that non-energy benefits, as approved by the Commission, may be considered in the determination of TRC results

- Revising the determination of avoided energy cost to take the biennial avoided cost proceeding into consideration

- Miscellaneous updating of the provisions to reflect current practices and situation

- Whether there is a need for a low and moderate income customer DSM/EE market penetration study for the DENC service area

On August 13, 2021, the Commission issued an order that required the Public Staff to file a final report on or before September 15, 2021, detailing the discussions that the Public Staff has had with DENC, all recommended changes to the Mechanism agreed upon by the Public Staff and DENC, any recommended changes to the Mechanism by the Public Staff or DENC that have not been agreed upon, and a proposed effective date for any changes to the Mechanism.

As of the date of this report, this matter is still pending before the Commission.

2. DEP - Docket No. E-2, Sub 931 & DEC - E-7, Sub 1032 (2019 review combined)

On January 20, 2015, the Commission issued an Order Approving Revised Cost Recovery Mechanism and Granting Waivers (DEP Mechanism Order), in Docket No. E-2, Sub 931. The Order approved changes to the DSM/EE mechanism by which DEP recovers its DSM/EE costs and incentives. In Ordering Paragraph No. 7, the Commission directed:

> That the Public Staff shall initiate a formal review of the Company's Mechanism not later than February 1, 2019, unless requested to do so earlier by the Commission, the Company, or another interested party. The Public Staff's review should specifically address whether the incentives in the Commission-approved Mechanism 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; and any other relevant issues that may be identified during the review process.

Mechanism Order, at 7. 2

On August 23, 2017, in Docket No. E-7, Sub 1032, the Commission issued an Order Approving DSM/EE Rider, Revising DSM/EE Mechanism, and Requiring Filing of Proposed Customer Notice. The Order, among other things, revised the DSM/EE mechanism by which DEC recovers its DSM/EE costs and incentives, effective January 1, 2018.

On February 1, 2019, the Public Staff filed a motion requesting that the Commission establish a comment cycle in this docket. In that motion, the Public Staff stated that it believed that due to the similarity between DEP and DEC’s Mechanisms and DSM/EE programs, it would be appropriate to review both Mechanisms in the same proceeding.

On February 6, 2019, the Commission issued an Order that allowed the merging of the two reviews and established a comment cycle. In addition, the Commission requested that in addition to other relevant issues, the parties should address the following topics: (1) Whether the incentives in the current DEP and DEC Mechanisms are producing significant DSM and EE results, (2) Whether the customer rate impacts of the DSM/EE riders are reasonable and appropriate, and (3) Whether overall DSM/EE program portfolio performance targets should be adopted. The Order further set initial comments as due June 7, 2019, and reply comments due July 10, 2019.

A number of parties intervened in this docket: the Attorney General’s Office (AGO), NRDC, SACE, Sierra Club, SCCCL, and NCSEA. On May 30, 2019, the AGO requested an extension of time to file comments to July 10, 2019, for initial comments and August 7, 2019, for reply comments, which the Commission granted on May 31, 2019. On July, 10, 2019, parties filed their initial comments. On August 5, 2019, the Public Staff requested an extension of time to file its reply comments until September 6, 2019. The Public Staff and DEP/DEC additionally requested several more extensions of time, all granted by the Commission, ultimately extending the time to file comments until January 15, 2020.

On January 15, 2020, the Public Staff filed with the Commission its proposed modifications to DEC and DEP's current DSM/EE cost recovery mechanisms. The Public Staff noted in its filing that the intervening parties (Joint Parties) had met and collaborated on the modifications that were needed. The joint parties agreed to a number of modifications to the mechanism, many of which serve to make the two mechanisms conform to one another for DEP and DEC. The parties noted that there were a few substantive changes to the mechanisms, which are as follows:

- Addition of a Program Return Incentive (PRI) – The Joint Parties believe that one central focus of DEC's and DEP's DSM/EE efforts should be to provide low-income customers with tools to lower their electric utility bills. This focus is also consistent with Recommendation I-3 of the North Carolina Clean Energy Plan to "[e]xpand energy efficiency and clean energy programs specifically targeted at underserved markets and low-income communities." Consequently, the Joint Parties have developed the PRI, which is an incentive to encourage DEC and DEP to pursue savings from existing and new low-income DSM/EE programs, and to maintain and increase the cost effectiveness of these programs. For these types of programs, the PRI initially will be based on 10.6% of the net present value of the avoided costs savings achieved by those DSM and EE programs. The percentage ultimately used to determine the PRI for each Vintage Year will be based on the Company's ability to maintain or improve the cost effectiveness of the PRI-eligible programs over and above that initially estimated for the Vintage Year. At no time will the PRI percentage utilized fall below 2.65% or rise above 13.25%.
- Reduction of Portfolio Performance Incentive (PPI) Percentage - Currently, the PPI percentages used for DEC and DEP are 11.50% and 11.75%, respectively. The revisions to the Mechanisms reduce the PPI percentages for both Companies to 10.60%.
- Cap and Floor on PPI - The amount of pre-tax PPI allowed will not exceed or fall below the amount that produces a specified margin over the aggregate pre-tax program costs for the PPI-eligible programs. The maximum margin is set at 19.50% for Vintage Year 2022 and afterward, until completion of the next Mechanism review. Additionally, a minimum margin over aggregate pre-tax program costs for PPI eligible programs will be established at 10% for Vintage Year 2022, 6% for Vintage Year 2023, and 2.50% for Vintage Year 2024 and afterward, until completion of the next Mechanism review.
- Non-Energy Benefits – The revisions allow for the Commission to assess whether it is appropriate to use non-energy benefits in determination of cost-

effectiveness under the Total Resource Cost Test (TRC). This change is consistent with Recommendation I-1 of the NC Clean Energy Plan.

- Clarification of the Criteria for Bundling Measures within Programs – Requires bundled measures to be consistent with and related to the measure technologies or delivery channels of a program, unless otherwise ordered by the Commission.
- Use of the Utility Cost Test (UCT) – Currently, the TRC is used to calculate the prospective cost-effectiveness of new and ongoing programs. The revisions would provide that determination of the cost-effectiveness of new and ongoing programs would be calculated using the UCT.
- Recovery of PPI in Applicable Vintage Year – Currently, DEP has converted its vintage year PPI into a stream of levelized annual payments not to exceed ten years. After Vintage Year 2021, the PPI will be recovered in the applicable Vintage Years revenue requirement, though levelized annual payments from prior vintages will continue to be collected until recovered.
- Review of Avoided Transmission and Distribution (T&D) Costs – The Public Staff and DEC or DEP, as applicable, will review the avoided T&D costs no later than December 31, 2021, and make recommendations for any adjustment in the rider proceedings thereafter. Avoided T&D costs will be reviewed at least every three years and will be updated if they change by at least 20%.
- Additional Incentive and Penalty - If the Company achieves annual energy savings of 1.0% of the prior year's system retail electricity sales, in any year during the four-year 2022-2025 period, the Company will receive an additional incentive of $500,000 for that year. During that same period, if the Company fails to achieve annual energy savings of 0.5% of retail sales, net of sales associated with customers opting out of the Company’s EE programs, the Company will reduce its EE revenue requirement by $500,000.
- Minor Modification to DEP Opt-Out Provision - A minor modification was made to the opt-out provisions of the DEP Mechanism that addresses a potential unintended outcome that could occur, in the case in which there is rate element of Rider DSM/EE that is a credit.

The Joint Parties stated that they spent substantial time considering the costs and benefits of aligning DEC’s and DEP’s use of amortization for their DSM/EE operations and maintenance (O&M) expenses. They noted that DEC does not amortize these expenses, while DEP generally amortizes post-2015 O&M expenses over five years for residential customers and three years for non-residential customers. According to Joint Parties, they considered several scenarios, using a number of assumptions, to estimate the bill impact of ending or reducing the amortization periods. Their calculations indicated that ending the amortizations for new program costs entirely in 2022, when the revisions to the Mechanisms would go into effect, would result in overall residential bill increases of approximately 2.50% in that year, and increases of approximately 2.25% to 3.00% for different classes of non-residential customers. Reducing the period of amortization to two years instead of ending it would decrease the amount of rate increase to approximately 1.00% -1.20% for two years for residential customers and approximately 0.67% - 0.95% for two years for the different classes of non-residential customers. Further, the Joint Parties stated that they reviewed the impact of reducing the amortization period to three years, which they estimated to increase residential bills by approximately 0.50% for three years and non-residential bills by approximately 0.13% for two years. Finally, the Joint Parties' calculations indicated that after a period of time the increase in bills caused by ending or reducing the amortization periods would end, with the duration of the temporary increase varying under each of the scenarios above and by customer rate class from two to seven years.

Joint Parties agreed that aligning the amortization periods for DEP and DEC was a worthy goal. However, Joint Parties were also concerned about the impact of temporary rate increases on customers in light of the application for a rate increase filed by DEP in Docket No. E-2, Sub 1219. To minimize the impact on customer rates but to continue the process of aligning the amortization periods, Joint Parties proposed that the amortization period be reduced to three years in this revision of the DEP Mechanism, and that the parties consider the issue further in the next review of the Mechanisms.

Joint Parties also agreed that if the Commission finds that some level of temporary rate increases is acceptable in order to eliminate or reduce the amortization period to one or two years, that such a change would be feasible and should not have any other adverse consequences.

In addition, Joint Parties reached agreement that DEC and DEP will work with the DSM/EE Collaborative to develop a scope for a one-time study on the market penetration of EE programs with low and moderate income customers (LMI) to be performed by qualified independent third-party EM&V providers. The study will seek to estimate the LMI market penetration of its non-income qualified residential programs, as well as the market penetration of small commercial programs in neighborhoods with high LMI populations. The study will consider customer participation, energy savings, and bill impacts, as well as identifying potential market barriers. In addition, the study will be utilized by DEC and DEP to make recommendations for program enhancements designed to cost effectively increase market penetration in the targeted populations and neighborhoods. Joint Parties further stated that DEC and DEP will seek to file an initial scope and budget for the work with their 2020 rider filings, and upon Commission approval for recovery of study costs, they will have the study completed prior to the cost recovery Mechanism modifications taking effect in 2022.

Joint Parties acknowledged that certain issues were not resolved through negotiation, and stated that Joint Parties had agreed that each party may identify additional recommendations to the Commission in its comments on the proposed revisions to the Mechanisms so long as such additional recommendations do not conflict with Joint Parties' proposed revisions.

Finally, Joint Parties requested that the Commission issue an order allowing parties to file comments and reply comments on the proposed revisions to the Mechanisms and other relevant issues. The Commission issued an Order requesting comments and reply comments, to be due February 17, 2020 and March 9, 2020, respectively.

Many parties filed comments. The NRDC, SACE, Sierra Club, SCCCL, and NCSEA, (collectively Joint Commenters) filed comments stating that they support the proposed revisions filed by Joint Parties. Further, Joint Commenters made four additional recommendations for the Commission's consideration. First, Joint Commenters recommended that the Commission require a change in the discount rate used in the cost effectiveness tests for DSM/EE programs. They stated that presently each Company's weighted average cost of capital (WACC) is used. According to Joint Commenters, the WACC creates an inherent bias towards the objectives of the utility over those of consumers, reflects a shorter rate of time preference than that of the utility's customers or regulators, and does not reflect the cost of capital for DSM/EE resources, which is more akin to expenses. Joint Commenters recommended the use of a low-risk discount rate (in the range of 0% to 3%), that better aligns with customer objectives, reflects the time preference of customers and the Commission, and reflects the "cost of capital" for DSM/EE investments. Further, Joint Commenters stated that the National Standard Practice Manual (NSPM) offers a framework to assist regulatory bodies and jurisdictions in making the discount rate determination, and they recommended that this framework would serve as a useful guide for the Commission in determining whether to require the use of a discount rate different from the utility's WACC.

Second, Joint Commenters recommended that the Commission consider adopting a reporting requirement for customers who opt out of the Companies' DSM/EE programs. They noted that in the rulemaking proceeding to implement Senate Bill 3, the Commission considered whether Rule R8-69 should require customers to make a showing of whether they were pursuing DSM/EE in order to opt out of utility DSM/EE programs, and the Commission decided that it would not do so. Joint Commenters opined that since Commission Rule R8-69 was promulgated the rate of large non-residential customers opting out of the DEC and DEP DSM/EE programs has remained persistently high, noting that in 2018 51% of DEC's North Carolina non-residential load opted out of the Company's EE rider, and 55% of non-residential load opted out of DEP's EE rider. Joint Commenters stated that although the Companies have worked to improve their non-residential program offerings and have implemented other changes aimed at encouraging greater participation by large customers, these steps have not meaningfully reduced opt-outs. Joint Commenters contended that the Commission should evaluate whether it should require the Companies' opt-out customers to report to DEC or DEP their stated and quantifiable goals for the DSM or EE measures they implement at their own expense, as well as the demand and/or energy savings from those measures.

Third, Joint Commenters recommended that the Commission request a report from the Governor's Office on the results of the Clean Energy Plan (CEP) utility business model reform stakeholder process, and use the report to inform a Commission investigation into decoupling. Joint Commenters maintained that lost-revenue adjustment mechanisms (LRAMs) are an inferior way to address a utility's inherent disincentive to pursue efficiency savings that will result in lost sales, and that revenue decoupling is an alternative way to remove the utility's disincentive to pursue efficiency savings. Joint Commenters stated that more than a decade has passed since the Commission issued its Senate Bill 3 report on decoupling, in which the Commission determined that, having only issued its rules implementing Senate Bill 3 earlier that year, it was "premature to mandate new major changes to electric utility rate structures before it has been determined whether the incentives under Senate Bill 3 serve their intended purpose and are sufficient." Joint Commenters maintained that the time is right to revisit decoupling as a policy option, and that the Commission could use the information provided by the CEP to launch its analysis.

Fourth, Joint Commenters recommended that the Commission request a copy of the DEQ report on carbon-reduction policy options, and use the report to inform a Commission investigation into whether an Energy Efficiency Resource Standard (EERS) should be adopted in North Carolina. According to Joint Commenters, the CEP includes a recommendation for establishment of an EERS by 2021. They stated that research has shown that an EERS is the single most effective policy to promote energy efficiency savings.

On February 17, 2020, the Public Staff and Carolina Utility Customers Association, Inc. (CUCA) filed comments in response to Joint Commenters' recommendations. As a preliminary matter, the Public Staff stated that it strongly endorses the Joint Parties' proposed revisions to DEP and DEC's DSM/EE Mechanisms because the revisions are designed to incentivize the utilities to achieve the most net savings from DSM/EE, while also placing greater emphasis on reaching low income customers who could most benefit from additional opportunities to reduce the costs of their electric utility service. As a result, the Public Staff believes that the revisions are in the public interest and should be approved.

Further, the Public Staff noted that the recommendations of Joint Commenters would affect all of the investor-owned utilities, including Dominion Energy North Carolina, which is not a party to this proceeding, and that if the Commission considers any of the four recommendations they should be considered in a generic docket, rather than the present dockets that only apply to DEP and DEC.

The Public Staff stated that the NSPM cited by Joint Commenters recommends that jurisdictions follow six steps in determining the appropriate discount rate:

Step A: Articulate the jurisdiction's applicable policy goals.

Step B: Consider the relevance of a utility's WACC.

Step C: Consider the relevance of the average customer discount rate.

Step D: Consider the relevance of a societal discount rate.

Step E: Consider an alternative discount rate different from the utility, customer, and societal perspective.

Step F: Consider using a low-risk discount rate for EE cost-effectiveness.

The Public Staff opined that Step A, a determination of North Carolina's policy goals, would affect not only DSM/EE but almost every aspect of resource planning. According to the Public Staff, it is not appropriate to consider policy goals and changes to such goals in the context of the limited issue of discount rates. In addition, the Public Staff stated that using the utility's WACC places DSM/EE programs on a level playing field with supply-side resources, and that DEC witness Farmer noted the appropriateness of using the utility's WACC as being consistent with the Company's compensation for generation plant. Further, the Public Staff stated that it would be difficult to quantify the average customer discount rate, as required by Step C, on a customer class level, and likely impossible on an individual customer basis.

With regard to the NSPM suggestion of a low-risk discount rate for EE, the Public Staff acknowledged that the cost of most EE programs are expensed as opposed to capitalized, but stated that this does not justify the use of a low-risk discount rate since DSM/EE programs are not entirely without risk to the Company because program participation rates and energy savings may vary widely from initial projections. In addition, the Public Staff stated that the calculation of a utility's capital structure and return on equity (ROE) to determine the WACC are generally two of the most contentious issues in a general rate case, and there are recognized models - such as the Discounted Cash Flow, Risk Premium, and Capital Asset Pricing models - used to calculate ROEs, as well as many publications from which to obtain comparative statistics for other utilities. According to the Public Staff, there is little guidance on how to calculate a discount rate directed to the customers' time and risk preferences, and the Public Staff cited cautionary language in the NSPM about several factors that are subject to change.

Finally, the Public Staff stated that using a lower discount rate would likely result in higher incentive payments to the utility under both the current and proposed Mechanisms because the cost effectiveness of the programs would increase, which could result in a windfall for the utility in the form of increased incentives without a corresponding increase in DSM/EE program participation or energy savings.

The Public Staff agreed with the Joint Commenters that the number of opt out customers has had a significant impact on the non-residential DSM/EE programs and riders. On the other hand, the Public Staff stated that it is aware of many industrial and commercial customers that have opted out and have implemented EE measures at their own expense. In addition, the Public Staff noted that the statute does not require such reports, and that the Public staff does not support a reporting requirement, but encourages the utilities and the Collaborative to work to develop cost-effective programs and measures that would reduce opt-outs. Moreover, the Public Staff cited the following statement from the Commission's February 29, 2008 Order Adopting Final Rules, in Docket No. E-100, Sub 113:

> The Commission concludes that Rule R8-69 should not be revised to include either Duke's proposal to require a "substantially equivalent" test in order for customers to opt out of DSM and EE programs or ED, SACE and SELC's proposal that customers desiring to opt out be required to provide detailed descriptions of measures evaluated and measures implemented or planned together with quantified results and projections of the impact of the measures. Senate Bill 3, in general, and G.S. 62-133.8(f), in particular, do not contain any requirement that DSM or EE programs implemented by the customer or DSM or EE programs proposed to be implemented by the customer must be substantially equivalent to the programs or measures being supplied by the electric power supplier. Nor does Senate Bill 3 require customers desiring to opt out to provide detailed descriptions of measures evaluated and measures implemented or planned together with quantified results and projections of the impact of the measures. All that is required of a program used as the basis for a customer's decision to opt out is that: (1) the program have been implemented in the past or (2) that it be proposed to be implemented in the future in accordance with stated, quantified goals. Order Adopting Final Rules (SB 3 Rules Order), at 129.

The Public Staff stated that there are no changed circumstances since 2008 that necessitate re-litigation of this matter.

CUCA stated that there is no opt out reporting requirement contained in N.C.G.S. § 62-133.9(f), and contended that imposing such a reporting requirement would require a change in the statute. CUCA stated that representatives of CUCA, DEP, DEC, and other stakeholders, including a number of the Joint Commenters, were involved in the lengthy process of developing Senate Bill 3 in which the opt-out provision was negotiated. Further, CUCA noted that neither DEP nor DEC has ever required industrial customers wishing to exercise their opt-out rights to provide notice or information other than what is required under the statute, and that CUCA's members would consider a requirement to report their DSM/EE measures and savings to be a violation of their right to protect their confidential trade secret information from public disclosure. In addition, CUCA contended that following Joint Commenters' recommendation to undertake a process to develop a reporting requirement would be beyond the scope of the statute, the Commission's rules, and the stakeholder process that led up to the opt-out provision.

CUCA also noted that in 2018 51% of DEC's nonresidential load opted out of the DEC DSM/EE Rider, and 55% of DEP's non-residential load opted out, and opined that this results in a "glass half full," rather than half empty, as the situation is viewed by Joint Commenters.

Further, CUCA stated that if it is cost effective for a business to invest capital in a DSM or EE project, then the business will choose to make such investments, but a company should not be forced to invest in Duke's DSM/EE programs if such investment does not make economic sense for the company. Finally, CUCA responded to Joint Commenters' contention that the lack of reporting by opt-out customers inhibits DEC's and DEP's ability to plan for meeting their customers' electric power needs. CUCA stated that DEC and DEP have not identified in their Integrated Resource Plans a lack of opt-out customer data as an impediment to system demand and energy planning.

The Public Staff noted that investigations of decoupling mechanisms have typically been initiated upon request of the General Assembly, and that decoupling mechanisms for gas, water, and electric utilities have resulted from legislative action. In addition, the Public Staff opined that the recovery of net lost revenues is a type of decoupling, and stated that such recovery is allowed by statute and has been part of the DSM/EE rider proceedings since their initiation. Further, the Public Staff disagreed with Joint Commenters' view that the current method used for recovery of net lost revenues is "cumbersome and difficult to administer", noting that the Public Staff has been able to navigate the methodology.

The Public Staff stated that performance targets are included in the proposed Mechanisms for DEC and DEP, that an EERS is a mandate more than a target, and that such a mandate would need to come from the General Assembly.

The Commission issued its order in this proceeding on October 20, 2020. In that order, the Commission found that the revised mechanism, as proposed by the Joint Parties should be approved. The Commission also found that the time period for which the mechanism should be effective should be January 1, 2022. The Commission further found that 1)the collaborative should review and discuss the concept of a low-risk discount rate in assessing the cost effectiveness of the electric public utilities' DSM/EE program and report and should report their findings and conclusions in the next mechanism review, and that DEC and DEP should work with the DSM/EE Collaborative to develop a scope for a one-time study on the market penetration of EE programs with low and moderate income customers to be performed by qualified independent third-party EM&V providers.

The Commission also ordered the Public Staff to initiate a joint formal review of DEC's and DEP's Mechanisms not later than May 1, 2024, unless requested to do so earlier by the Commission, DEC or DEP, or another interested party.

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 the utilities in North Carolina.

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

(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 September 1, 2008, 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 September 1 of each year in which a biennial report is not required to be filed, an annual report shall be filed with the Commission containing an updated 15-year forecast of the items described in subparagraph (c)(1), as well as 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 annual 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 annual reports.

(4) Each biennial and annual report shall include the utility's REPS compliance plan pursuant to Rule R8-67(b).

(5) If a utility considers certain information in its biennial or annual 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 Reports. — Each utility shall include in each biennial report, revised as applicable in each annual 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 both the biennial and annual 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 (kWh) by each customer class;

(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 (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. 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.

(10) Smart Grid Impacts. – Each utility shall provide information regarding the impacts of its smart grid deployment plan on the overall IRP.

(i) For purposes of this requirement, the term "smart" in smart grid means a system having the ability to receive, process, and send information and/or data – essentially establishing a two-way communication protocol. (ii) For purposes of this requirement, smart grid technologies that are implemented in a smart grid deployment plan may include those that:

a. utilize digital information and controls technology to improve the reliability, security and efficiency of an electric utility's distribution or transmission system;

b. optimize grid operations dynamically;

c. improve the operational integration of distributed and/or intermittent generation sources, energy storage, demand response, demand-side resources and energy efficiency;

d. provide utility operators with data concerning the operations and status of the distribution and/or transmission system, as well as automating some operations; or e. provide customers with usage information or retail energy pricing information in order to allow them to interpret and adjust their energy consumption.

(iii) The information provided shall include:

a. A description of the technology installed and for which installation is scheduled to begin in the next five years and the resulting and projected net impacts from installation of that technology, including, if applicable, the potential demand (MW) and energy (MWh) savings resulting from the described technology.

b. A comparison to “gross” MW and MWh without installation of the described smart grid technology.

c. A description of MW and MWh impacts on a system, North Carolina retail jurisdictional, and North Carolina retail customer class basis, including proposed plans for measurement and verification of customer impacts or actual measurement and verification of customer impacts.

(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 September 1 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 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 November 30 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.)

R8-67 RENEWABLE ENERGY AND ENERGY EFFICIENCY PORTFOLIO STANDARD (REPS)

(a) Definitions.

(1) The following terms shall be defined as provided in G.S. 62-133.8: “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.”

(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, long-term, 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 REPS 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 nonrenewable 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 REPS. Such demonstration may include, among other things, filing REPS compliance plans or reports and participating in NC-RETS on behalf of the electric power supplier or a group of electric power suppliers.

(b) REPS 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. 62-133.8(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. 62-133.8(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 renewable 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 REPS 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 REPS 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, on or before September 1 of each year, file a renewable energy facility registration statement pursuant to Rule R8-66 for any facility it owns and upon which it is relying as a source of power or RECs in its REPS compliance plan.

(2) Each electric power supplier shall file its REPS compliance plan with the Commission on or before September 1 of each year.

(3) Any electric power supplier subject to Rule R8-60 shall file its REPS compliance plan as part of its integrated resource plan filing, and the REPS compliance plan will be reviewed and approved pursuant to Rule R8-60. Approval

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

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

(c) REPS 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. 62-133.8(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. 62-133.8(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. 62-133.8(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. 62-133.8(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. 62-133.8(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. 62-133.8(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 REPS 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 R8-55. The Commission shall consider each electric public utility's REPS 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. 62-133.8(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 REPS compliance report on or before September 1 of each year. The Commission may issue an order scheduling a hearing to consider the REPS 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 REPS 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 REPS 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. 62-133.8(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. 62-133.8(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 REPS obligations and compliance efforts provided that all suppliers in the group are subject to the same REPS 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 REPS obligations, the Commission shall find and conclude that each supplier in the group, individually, has failed to meet its REPS 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. 62-133.8(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. 62-133.8(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. 62-133.8(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 renewable energy resources and nonrenewable energy resources to produce energy, the facility shall earn renewable energy certificates based only upon the energy derived from renewable energy resources in proportion to the relative energy content of the fuels used.

(3) Renewable energy certificates earned by a renewable energy facility after the date the facility's registration is revoked by the Commission shall not be used to comply with G.S. 62-133.8(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. 62-133.8(h) to review the costs incurred by the electric public utility to comply with G.S. 62-133.8(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 R8-55.

(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. 62-133.8(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 R8-55.

(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 R8-55.

(5) The incremental costs will be further modified through the use of an REPS experience modification factor (REPS EMF) rider. The REPS 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 REPS rider then in effect. Upon request of the electric public utility, the Commission shall also incorporate in this determination the experienced over-recovery or under-recovery 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 REPS cost recovery hearing.

(6) The REPS EMF rider will remain in effect for a fixed 12-month 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. 62-130(e), any over-collection of reasonable and prudently incurred incremental costs to be refunded to a utility's customers through operation of the REPS 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. 62-133.8(b), (d), (e), and (f) shall not exceed the per-account charges set forth in G.S. 62-133.8(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 REPS rider and REPS EMF rider during the cost recovery period, inclusive of gross receipts tax and the NCRF, from any given customer account do not exceed the applicable per-account charges set forth in G.S. 62-133.8(h)(4).

(10) Incremental costs incurred during a calendar year toward a current or future year's REPS obligation may be recovered by an electric public utility in any 12-month 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 REPS 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. 62-133.8(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 REPS compliance report for the 12-month test period established in subsection (3) normalized, as appropriate, consistent with Rule R8-55, 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 R8-55.

(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. 62-133.8(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 renewable 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 renewable 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 renewable 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 renewable 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 renewable 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 (NC-RETS)

(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 load-to-generation 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 renewable 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. NC-RETS shall issue, track, transfer and retire RECs. It shall calculate each electric power supplier's REPS obligation and report each electric power supplier's REPS accomplishments, consistent with the compliance report filed under Rule R8-67(c). NC-RETS shall be administered by a third-party vendor selected by the Commission. Only RECs issued by or imported into NC-RETS 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 REPS 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 REPS 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. 62-133.8.

(4) Each renewable energy facility or new renewable 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, renewable energy facilities registered in NC-RETS 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 renewable energy resource(s) and another resource that does not qualify toward REPS 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. 62-133.8.

(5) Each balancing area operator shall provide monthly electric generation production data to NC-RETS for renewable and new renewable 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 renewable energy facilities or new renewable 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 renewable energy facility or new renewable 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 renewable energy facility or new renewable energy facility that reports its data pursuant to Rule R8-67(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 NC-RETS 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 NC-RETS 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 REPS 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 NC-RETS 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. 62-133.8(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 NC-RETS 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, E-100, Sub 113, EC-33, Sub 58, EC-83, Sub 1, 5/14/2012.)

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) and G.S. 62-133.9 to electric public utilities and electric membership corporations 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, or any new or modified demand-side management or energy efficiency measure, the electric public utility or the electric membership corporation 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 or electric membership corporation shall explain in detail how the measure is consistent with the electric public utility's or electric membership corporation'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.)

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. 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.)