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, 2017
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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, 2015, through June 30, 2017. 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, 2015, through June 30, 2017.

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 energy efficiency (EE) and demand-side management (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.

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 January 1, 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.

During the fall of 2016, the State’s electric power suppliers provided assessments of the potential for DSM and EE as part of their integrated resource plans (IRPs)[1].

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 10 new programs, including one pilot program, terminated seven programs, and approved modifications to a number of programs.

Senate Bill 3 further provides that, 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. Further, the Commission may approve incentives to utilities for adopting and implementing DSM and EE programs. During the two fiscal years covered by this report, DNCP, 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 both DEP[2] and DEC[3] 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:

Electric Public Utility	**DSM/EE Rider Charges for Residential Customer Using 1,000 kWh** (including the regulatory fee)
DNCP	$0.62/month
DEC	$4.30/month
DEP	$7.76/month

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 DSM/EE program applications that have been filed with the Commission recently and which fall into the next reporting period.

[1] Docket No. E-100, Sub 147.

[2] Docket No. E-2, Sub 1145.

[3] Docket No. E-7, Sub 1130.

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 (www.ncuc.net), selecting "Dockets" from the main menu, selecting "Docket Search," and then entering the appropriate docket number.

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[4] applies to include an assessment of DSM and EE in its IRP.

During 2016, IRPs were filed by the following electric public utilities in Docket No. E-100, Sub 147:

1. DNCP
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>DNCP</u>

In its 2016 IRP, DNCP listed the then currently approved DSM programs in North Carolina as:

- Air Conditioner Cycling Program
- Residential Low Income Program
- Non-Residential Energy Audit Program
- Non-Residential Duct Testing & Sealing Program
- Residential Bundle Program
  - Residential Home Energy Checkup
  - Heat Pump Upgrade Program
  - Residential Duct Testing and Sealing Program
  - Residential Heat Pump Tune-Up Program
- Non-Residential Window Film Program
- Non-Residential Lighting Systems and Controls Program
- Non-Residential Heating and Cooling Efficiency Program
- Income and Age Qualifying Home Improvement Program

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

- Voltage Conservation
- Home Energy Assessment
- Prescriptive Program for Non-Residential Customers

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

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

- Non-Residential HVAC Tune-Up Program
- Energy Management System Program
- Energy Star® New Homes Program
- Geo-Thermal Heat Pump Program
- Home Energy Comparison Program
- Home Performance with Energy Star® Program
- In-Home Energy Display Program
- Premium Efficiency Motors Program
- Programmable Thermostat 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 Re-Commissioning
- Non-Residential Curtailable Service Program
- Non-Residential Custom Incentive
- Enhanced Air Conditioner Direct Load Control Program
- Residential Controllable Thermostat Program
- Residential Retail LED Lighting Program
- Residential New Homes Program

The Company provided a forecasted energy savings in 2017 due to its DSM and EE programs of 751,226 MWh (System-wide for Virginia and North Carolina).[5]

2. <u>DEC</u>

In its 2016 IRP filing in Docket No. E-100, Sub 147, 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

[5] Per Appendix 5E provided as part of Company's IRP filing in Docket No. E-100, Sub 147 on September 1, 2016.

response programs and certain rate structure programs). Following are the EE and DSM programs available through DEC as of December 31, 2015:

Residential:

- Appliance Recycling Program
- Energy Assessments Program
- Energy Efficiency Education Program
- Energy Efficient Appliances and Devices
- Heating, Ventilation and Air Conditioning (HVAC) Energy Efficiency Program
- Multi-Family Energy Efficiency Program
- My Home Energy Report
- Income-Qualified Energy Efficiency and Weatherization Program
- Power Manager

Non-Residential:

- Non-Residential Smart $aver® Energy Efficient Food Service Products Program
- Non-Residential Smart $aver® Energy Efficient HVAC Products Program
- Non-Residential Smart $aver® Energy Efficient 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 Program
- Non-Residential Smart $aver® Custom Energy Assessments Program
- Small Business Energy Saver
- Smart Energy in Offices
- PowerShare®
- PowerShare® CallOption
- EnergyWise for Business

Pilot Program

- Business Energy Report Pilot

DEC stated in its IRP that it has not rejected any cost-effective programs as a result of its EE and DSM program screening.

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 2017 due to its DSM and EE programs of 455,532 MWh (Energy savings) and 985 MW (Capacity savings).

3. DEP

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

Residential

- Residential Home Energy Improvement
- Residential New Construction
- Residential Neighborhood Energy Saver (Low-Income)
- Residential Appliance Recycling Program
- Residential My Home Energy Report
- Residential Multi-Family Energy Efficiency
- Energy Efficient Education
- Residential Energy Efficiency Assessments
- Residential Save Energy and Water Kit
- Residential EnergyWise Home

Non-Residential

- Energy Efficiency for Business
- Small Business Energy Saver
- Business Energy Report Pilot
- EnergyWise for Business
- CIG Demand Response Automation Program

Combined Residential/Non-Commercial

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

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 2017 due to its DSM and EE programs of 344,000 MWh (Energy savings) and 476 MW (Capacity savings).

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

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.

1. DNCP's New DSM and EE Programs

On July 31, 2015, in Docket No. E-22, Sub 523, DNCP filed an application with the Commission seeking approval of a Residential Income and Age Qualifying Home Improvement Program. DNCP stated in its application that the program is designed to help reduce a participant's energy usage and peak demand. The measures provided in the program include an energy audit, light emitting diode bulbs, low flow showerheads, pipe wrap, faucet aerators, and attic insulation for qualifying participants. Program eligibility is based on either income or a combination of income and age. Customers meeting the income-based eligibility criteria must have a household income of less than 200% of the federal poverty guidelines, or be receiving assistance payments under the Work First or Supplemental Security Income programs. DNCP initially proposed that customers meeting the age-based eligibility criteria be at least 60 years of age with a household income of less than 120% of the median income. DNCP stated that the incentives available to each eligible participant are the measures listed above, which are valued at an average of $946 per participant. The Public Staff filed comments with the Commission regarding this program. In its comments, the Public Staff noted that DNCP had initially proposed different eligibility criteria for the age-based portion of the program, but after discussion the Public Staff and DNCP had agreed to use as age-based criteria the requirements that participants be at least 60 years of age with a household income of less than 250% of the federal poverty guidelines. The Public Staff recommended that the Commission approve the program, which the Commission did on October 6, 2015.

On July 20, 2016, DNCP filed an Application for Approval of a Small Business Improvement Program in Docket No. E-22, Sub 538. In its application the Company stated that the program is designed to help reduce the participant's energy usage and peak demand. The measures provided in the program for qualifying participants will be Direct Install Lighting, Prescriptive Re-commissioning, Variable Frequency Drives, Efficient Heat Pumps, and Efficient Air Conditioning Units. The average value of the incentive each eligible participant will receive for the measures listed above is $6,304. The Public Staff filed comments on the program stating that the program has the potential to encourage DSM and EE, appears to be cost effective, will be included in future DNCP IRPs, and is in the public interest. The Public Staff further recommended that the Commission approve the program as a new EE program pursuant to Commission Rule R8-68. The Commission approved the program in its Order dated October 26, 2016.

On October 31, 2016, in Docket No, E-22, Sub 539, DNCP filed a petition for approval of a Residential Retail LED Lighting Program. In that program DNCP proposed to provide an instant discount for a variety of qualifying Light-Emitting Diode (LED) light bulb purchases from participating retailers. DNCP's vendor will pay manufacturers of LED bulbs an incentive, which will enable the manufacturer to sell LED bulbs at a discount to area retailers, who then would sell the bulbs to consumers at the agreed discounted price. DNCP stated that the incentive participants will receive the incentive in the form of a discount on the price of the bulbs at the point of sale. DNCP estimated it will pay an average incentive of $3.00 per LED bulb. Customers are limited to 12 discounted bulbs per purchase. DNCP stated that it will operate the program on a North Carolina-only basis. The benefits and the costs of the program flow 100% to North Carolina ratepayers. DNCP stated that it is offering the program for a two-year period, with the intent to offer a system-wide program including a residential lighting component in the future. The Public Staff filed comments regarding this program. In its comments the Public Staff stated that DNCP proposed that the program be available to residential customers. However, the Public Staff noted that a portion of efficient lightbulbs were purchased by commercial customers in a similar program from DEP. The Public Staff recommended that costs of the program be allocated among all the customer classes (residential and non-residential) that will be participating in the program and receiving the benefits. On December 20, 2016, the Commission issued an Order approving the Residential Retail LED Lighting Program incorporating the Public Staff's recommendation of allocating program costs among all customer classes participating in the program and receiving benefits.

On August 16, 2016, in Docket Nos. E-22, Subs 495, 496, 497, 498, 499, and 500 DNCP filed a Motion to Close Commercial Energy Audit, Commercial Duct Testing and Sealing, Residential Home Energy Check Up, and Residential Heat Pump Tune-Up Programs and to Suspend Residential Heat Pump Upgrade and Residential Duct Testing and Sealing Programs, pending a request to extend these two programs in the Company's Virginia service territory. On October 19, 2016, DNCP filed an amendment to its original motion requesting approval to close the Residential Duct Testing and Sealing Program as of February 7, 2017, after the Company determined that the program would not meet the cost-effectiveness standard of the Virginia State Corporation Commission (VSCC), or the Commission on a system-wide basis. On October 19, 2016, DNCP amended its August 16, 2016 motion to propose closure, rather than suspension, of the Residential Duct Testing and Sealing program because it could not be cost-effective on a system-wide basis. In that Application, DNCP stated that it has managed and operated its EE programs on a consolidated system-wide basis in both its North Carolina and Virginia service territories. DNCP stated that its request to close or suspend these EE programs was necessitated by the VSCC's five-year limit on the availability of these EE programs in Virginia, which ended in early 2017.

On November 29, 2016, the Commission issued an order stating that DNCP is authorized to close the Commercial Energy Audit, Commercial Duct Testing and Sealing, Residential Home Energy Check-Up, Residential Heat Pump Tune-Up, and the Residential Duct Testing and Sealing programs to new participation as of February 7, 2017, and that the associated tariffs of each program may be withdrawn after

March 31, 2017. The Commission further authorized DNCP to suspend the availability of the Residential Heat Pump Upgrade Program to new participation as of February 7, 2017 and for DNCP to either seek simultaneous approvals in both Virginia and North Carolina, or provide the Public Staff with a copy of any program approval application the Company makes with the VSCC on or before it is filed with the VSCC. The Commission additionally ordered that DNCP shall implement system-wide programs in North Carolina as soon as possible after Virginia approval.

2. DEC's New DSM and EE Programs

On August 20, 2015, in Docket No. E-7, Sub 1093, DEC filed an application requesting approval of an EnergyWise for Business 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 provide small business customers with the ability to participate in demand response (DR) events. Southern Alliance for Clean Energy (SACE) filed a letter in support of DEC's application and the Public Staff filed comments recommending Commission approval of the program as a DSM program – not an EE program as requested by DEC - due to the fact that while it has the potential to produce both capacity and energy savings impacts, it is evident that the majority of the impacts reside in avoided capacity and transmission and distribution. According to the Public Staff, this indicates that the program is more of a DSM program than an EE program. On October 27, 2015, the Commission issued an order approving the program as a new DSM program.

On July 20, 2017, DEC filed in Docket No. E-7, Sub 1032 a request for approval of modifications to its Residential HVAC Energy Efficiency (EE)[6] – Air Conditioning Program (RHVAC EE) and its Residential EE Appliances and Devices Program (REEAD). DEC also requested to eliminate the Residential HVAC EE Program – Tune and Seal (RT&S) and to consolidate the surviving measures into the Residential Smart $aver® EE Program (RSSS). DEC noted that the proposed modifications to the RHVAC EE, REEAD, and RT&S programs are intended to increase the overall cost-effectiveness of the RSSS. DEC stated that it is proposing to align the structure, measures, and incentives in the program with a similar program offered by DEP, also known as RSSS. The Public Staff presented the modifications before the Commission and recommended Commission approval. The Commission issued an Order on September 11, 2017, cancelling the Residential HVAC EE Program Tune and Seal; modifying the Residential Energy Efficiency Appliance and Devices Program; replacing the Residential HVAC Energy Efficiency Program - Air Conditioning and the Residential HVAC Energy Efficiency Program – Tune and Seal, with the Residential Service – Smart $aver® Energy Efficiency Program; and approving the modifications to the Residential Service – Smart $aver® Energy Efficiency Program.

Other new programs approved or modified by the Commission are as follows:

[6] This program was previously modified by the Commission in an Order dated February 9, 2016. In that Order the Commission granted DEC's request for modifications to the program to ensure the program is cost-effective under the TRC test with a score of 1.0 or better.

- Non-Residential Smart $aver® Energy Efficient Products and Assessment Program (Docket No. E-7, Sub 1032)[7]
- Nonresidential Smart $aver® Performance Incentive Program (Docket No. E-7 Sub 1032)

DEC also submitted one pilot program that was approved during the two-year period covered by this report as follows:

- Smart Energy in Healthcare (Docket No. E-7, Sub 1141)

The following is the only program that was terminated or ended during the two-year period covered by this report:

- Business Energy Report Pilot Program (Docket No. E-7, Sub 1081)[8]

3. <u>DEP's New DSM and EE Programs</u>

During the two fiscal years covered by this report, DEP filed for approval of the following new programs:

On August 20, 2015, in Docket No. E-2, Sub 1086, DEP filed for Commission approval of its EnergyWise for Business Program as a new EE program. DEP stated in its petition that the program is designed to provide small business customers the ability to participate in demand response (DR) events. SACE filed a letter with the Commission in support of DEP's application. The Public Staff filed comments recommending Commission approval of the program as a DSM program – not an EE program as requested by DEP - due to the fact that while it has the potential to produce both capacity and energy savings impacts, it is evident that the majority of the impacts reside in avoided capacity and transmission and distribution. According to the Public Staff, this indicates that the program is more of a DSM program than an EE program. On October 27, 2015, the Commission issued an order approving the program as a new DSM program.

Other new programs for which DEP filed for approval are as follows:

- Non-Residential Smart Saver Energy Efficiency Products and Assessments (Docket No. E-2 Sub 938)[9]
- Residential Save Energy and Water Kit Program (Docket No. E-2 sub 1085)

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[7] Order issued on November 29, 2016, by the Commission, which granted DEC's request to modify the program with the exception of low cost measures at no cost, as this makes the program not cost-effective.

[8] This program was terminated on July 2, 2017, due to the pilot's decreased cost-effectiveness.

[9] This program effectively modifies and replaces the existing Commercial, Industrial and Governmental Energy Efficiency Program that was originally approved by the Commission on April 21, 2009.

- Non-Residential Smart $aver® Performance Incentive Program (Docket No. E-2, Sub 1126)

DEP received approval for the following pilot program:

- Business Energy Report Pilot (Docket No. E-2, Sub 1072)

The following DEP programs were modified by the Commission during the two-year period covered by this report:

- Neighborhood Energy Saver Program (Low-Income) (Docket No. E-2, Sub 952)
- Residential Home Energy Improvement Program (Docket No. E-2, Sub 936)[10]
- Commercial, Industrial and Governmental Demand Response Automation (Docket No. E-2, Sub 953)
- Residential New Construction Program (Docket No. E-2, Sub 1021)
- Small Business Energy Saver (Docket No. E-2 Sub 1022)

The following is the only program that was terminated or ended during the two-year period covered by this report:

- Commercial, Industrial and Governmental Energy Efficiency Program (Docket No. E-2, Sub 938)

[10] The program was modified such that it would have a TRC of greater than 1.0 by March 1, 2017, meaning that the program is considered cost-effective under the TRC test.

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 DNCP

During the two-year period of July 1, 2015 through June 30, 2017, DNCP had two such proceedings before the Commission. Below is a discussion of each proceeding.

1. <u>DNCP DSM/EE Cost Recovery Rider – Docket No. E-22, Sub 524</u>

On August 10, 2015, DNCP 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:

1. Air Conditioner Cycling Program (Docket No. E-22, Sub 465)
2. Non-Residential Energy Audit Program (Docket No. E-22, Sub 495)
3. Non-Residential Duct Testing and Sealing Program (Docket No. E-22, Sub 496)
4. Residential Home Energy Check-Up Program (Docket No. E-22, Sub 498)
5. Residential Duct Testing and Sealing Program (Docket No. E-22, Sub 497)
6. Residential Heat Pump Tune-Up Program (Docket No. E-22, Sub 499)
7. Residential Heat Pump Upgrade Program (Docket No. E-22, Sub 500)
8. Non-Residential Lighting Systems & Controls Program (Docket No. E-22, Sub 507)
9. Non-Residential Heating & Cooling Efficiency Program (Docket No. E-22, Sub 508)
10. Non-Residential Window Film Program (Docket No. E-22, Sub 509)
11. North Carolina-only Low Income Program (Docket No. E-22, Sub 463)

DNCP also sought recovery of costs for the new program, the Income and Age Qualifying program, and filed a separate program application for it in Docket No. E-22, Sub 523. DNCP requested that this program be approved and begin accepting participants in North Carolina on and after January 1, 2016. The Commission issued an Order approving the new program on October 6, 2015.

In its rider application, DNCP sought recovery of $3,170,707[11]. As proposed, DNCP's rider would result in the following charges, including the regulatory fee.

Residential	0.127 cents/kWh
Small General Service and Public Authorities	0.087 cents/kWh
Large General Service	0.084 cents/kWh
6VP	0.102 cents/kWh

The Public Staff filed testimony, as allowed by statute, on October 16 and 19, 2015.

DNCP filed supplemental testimony and exhibits on October 9, 2015, updating its proposed revenue requirement to $3,276,678[12].

In its testimony, the Public Staff noted that its review of DNCP's calculation of carrying costs in this proceeding revealed that the Company correctly excluded utility incentives from the calculation of carrying costs during the test period. However, the Company did not exclude utility incentives from the carrying cost calculations for the period between the end of the test period and the beginning date of the rate period in which the Experience Modification Factor (EMF) set in this proceeding will be refunded (January 1, 2016). Therefore, the Public Staff recommended to the Company that the calculation be revised to appropriately remove utility incentives, and the Company agreed to that recommendation in rebuttal testimony filed on October 26, 2015. The total Rider CE revenue requirement, revised for the carrying cost and interest adjustments, was ($91,603).

The Commission held an evidentiary hearing for this matter on November 2, 2015. No public witnesses appeared at the hearing.

On December 14, 2015, the Commission issued its Order approving the revised charges as requested by DNCP and the Public Staff related to DSM and EE program cost-recovery. As approved, DNCP's rider resulted in the following charges, including the regulatory fee:

Residential	0.127 cents/kWh
Small General Service and Public Authorities	0.087 cents/kWh
Large General Service	0.084 cents/kWh
6VP	0.102 cents/kWh

[11] Composed of Rider C revenue requirement of $3,413,035 and Rider CE revenue requirement of ($242,328).

[12] Composed of Rider C revenue requirement of $3,403,731 and Rider CE revenue requirement of ($127,051).

2. DNCP DSM/EE Cost Recovery Rider – Docket No. E-22, Sub 536

On August 16, 2016, DNCP 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, DNCP sought to recover costs and incentives for the following existing programs:

1. Air Conditioner Cycling Program (Docket No. E-22, Sub 465)
2. Non-Residential Energy Audit Program (Docket No. E-22, Sub 495)
3. Non-Residential Duct Testing and Sealing Program (Docket No. E-22, Sub 496)
4. Residential Home Energy Check-Up Program (Docket No. E-22, Sub 498)
5. Residential Duct Testing and Sealing Program (Docket No. E-22, Sub 497)
6. Residential Heat Pump Tune-Up Program (Docket No. E-22, Sub 499)
7. Residential Heat Pump Upgrade Program (Docket No. E-22, Sub 500)
8. Non-Residential Lighting Systems & Controls Program (Docket No. E-22, Sub 507)
9. Non-Residential Heating & Cooling Efficiency Program (Docket No. E-22, Sub 508)
10. Non-Residential Window Film Program (Docket No. E-22, Sub 509)
11. North Carolina-only Low Income Program (Docket No. E-22, Sub 463)
12. Income and Age Qualifying Home Improvement Program (Docket No. E-22, Sub 523)

DNCP also sought recovery of costs for the newly created program, Small Business Improvement Program, and filed a separate program application for it in Docket No. E-22, Sub 538. DNCP requested that this program be approved and begin accepting participants in North Carolina on and after January 1, 2017.

Contemporaneously, the Company filed a Motion to close the Phase II Commercial Energy Audit, Commercial Duct Testing and Sealing, Residential Home Energy Check-Up, and Residential Heat Pump Tune Up Programs and to suspend the Phase II Residential Heat Pump Upgrade and Residential Duct Testing and Sealing Programs pending a request to extend these two programs in the Company's Virginia jurisdiction. These motions were filed in Docket Nos. E-22, Subs 495, 496, 497, 498, 499, and 500.

DNCP's application requested an annual projected rate period revenue requirement of $1,851,369 to be recovered through its updated DSM/EE rider, Rider C, effective on and after January 1, 2017. DNCP also requested approval of a decrement DSM/EE EMF rider, Rider CE, based on an amount of ($74,595), to true up its actual costs and revenues received under Rider C rates. In rebuttal testimony, DNCP revised its requested revenue requirement to ($77,720) for Rider CE and had no changes to Rider C. DNCP stated that the revised request would result in the following kWh charges: 0.062 cents per kWh for residential customers; 0.060 cents per kWh for small general service and public authority customers; 0.054 cents per kWh for large general service customers; and 0.0000 cents per kWh for rate schedule 6VP customers (including the regulatory fee). The revisions were due to recommendations presented in the Public Staff's testimony, which was previously filed on October 24, 2016.

On November 7, 2016, the Commission held the evidentiary hearing as scheduled. No parties other than the Public Staff intervened or presented evidence at the hearing.

On December 19, 2016, the Commission issued its Order approving DNCP's requested charges related to DSM and EE program cost-recovery as discussed above.

DSM/EE Rider Proceedings for DEC

During the two-year period of July 1, 2015 through June 30, 2017, DEC had three such proceedings before the Commission. Below is a discussion of each proceeding.

1. DEC Cost Recovery Rider – Docket No. E-7, Sub 1073

On March 4, 2015, DEC filed an application for approval of its DSM/EE Rider (Rider 7) for 2016. Rider 7 encompasses components relating to both DEC's Save-a-Watt pilot approved in Docket No. E-7, Sub 831, as well as the new cost recovery mechanism and portfolio of programs approved by the Commission in Docket No. E-7, Sub 1032. The prospective components of Rider 7 include estimates of the revenue requirements for Vintage 20 DSM and EE programs under the new mechanism; and an estimate of the third year of net lost revenues for Vintage 2014 EE programs and the second year of net lost revenues for Vintage 2015 EE programs under the new mechanism. The Rider 7 EMF includes the following true-ups: a true-up of Vintage 2014 DSM and EE programs; and the final true-up of the save-a watt pilot. DEC requested that the Commission approve the following annual billing adjustments (including the regulatory fee):[13]

Residential Billing Factors

Rider 7 Prospective Component	0.3361	cents/kWh
Rider 7 EMF Component	0.0260	cents/kWh

Non-Residential Billing Factors

Prospective Components:		
Vintage 2014 EE participant	0.0256	cents/kWh
Vintage 2015 EE participant	0.0345	cents/kWh
Vintage 2016 EE participant	0.2164	cents/kWh
Vintage 2016 DSM participant	0.0709	cents/kWh
EMF Components*:*		
Vintage 2014 EE participant	0.0150	cents/kWh
Vintage 2014 DSM participant	(0.0044)	cents/kWh

[13] Amounts are per updated supplemental testimony of DEC filed on May 15, 2015.

Vintage 4 EE participant	0.0326 cents/kWh
Vintage 4 DSM participant	0.0005 cents/kWh
Vintage 3 EE participant	0.0261 cents/kWh
Vintage 3 DSM participant	(0.0017) cents/kWh
Vintage 2 EE participant	0.0148 cents/kWh
Vintage 2 DSM participant	0.0019 cents/kWh
Vintage 1 EE participant	0.0027 cents/kWh
Vintage 1 DSM participant	0.0017 cents/kWh

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

On June 2, 2015, the Commission held its evidentiary hearing in this matter as scheduled.

On August 21, 2015, the Commission issued its Order in this proceeding. In that Order, the Commission held that calculations of Rider EE as filed by DEC and revised in the supplemental testimony of its witnesses were appropriate for use. The Commission further held that in its next proceeding, the Company shall address in testimony and exhibits any adjustments to the EM&V for the Smart Energy Now Pilot and the Specialty Bulb measures in the Energy Efficient Appliance and Devices program, as well as how these adjustments, if any, affect the EMF and program impacts. The Commission also concluded that DEC should continue to use its Collaborative to work with stakeholders and discuss program offerings that could reduce the number of opt-outs.

2. <u>DEC DSM/EE Cost Recovery Rider – Docket No. E-7, Sub 1105</u>

On March 9, 2016, DEC filed an application for the approval of a DSM/EE Rider (Rider 8). Rider 8 encompassed components relating to both DEC's Save-a-Watt pilot approved in Docket No. E-7, Sub 831, as well as the new cost recovery mechanism and portfolio of programs approved by the Commission in Docket No. E-7, Sub 1032. The prospective components of Rider 8 under the new mechanism include estimates of the revenue requirements for Vintage 2017 DSM/EE programs, as well as an estimate of the second year of net lost revenues for Vintage 2016 EE programs, the third year of net lost revenues for Vintage 2015 EE programs, and the final half-year of net lost revenues for Vintage 2014 EE programs. The Rider 8 EMF includes the following true-ups: a true-up of Vintage 2014 DSM/EE programs and a true-up of Vintage 2015 DSM/EE programs under the new mechanism; and the final true-up of the Save-a-Watt pilot resulting from adjustments to impacts from the Smart Energy Now pilot agreed upon by the Company and the Public Staff. DEC requested Commission approval of the following annual billing charges, (including the regulatory fee):

Residential Billing Factors

Rider 8 Prospective Component	0.3861	cents/kWh
Rider 8 EMF Component	0.0406	cents/kWh

Non-Residential Billing Factors

Prospective Components:		
Vintage 2014 EE participant	0.0139	cents/kWh
Vintage 2015 EE participant	0.0418	cents/kWh
Vintage 2016 EE participant	0.0373	cents/kWh
Vintage 2017 EE participant	0.2437	cents/kWh
Vintage 2017 DSM participant	0.0789	cents/kWh

EMF Components*:*		
Vintage 4 EE participant	0.0004	cents/kWh
Vintage 4 DSM participant	0.0002	cents/kWh
Vintage 3 EE participant	(0.0024)	cents/kWh
Vintage 3 DSM participant	0.0003	cents/kWh
Vintage 2 EE participant	(0.0053)	cents/kWh
Vintage 2 DSM participant	0.0002	cents/kWh
Vintage 1 EE participant	0.0003	cents/kWh
Vintage 1 DSM participant	0.0002	cents/kWh
Vintage 2014 EE participant	0.0046	cents/kWh
Vintage 2014 DSM Participant	(0.0015)	cents/kWh
Vintage 2015 EE participant	0.0821	cents/kWh
Vintage 2015 DSM participant	(0.0127)	cents/kWh

Intervening parties in this proceeding were as follows: the Public Staff, NCSEA, CUCA, CIGFUR III, and SACE.

On May 26, 2016, DEC filed updated supplemental testimony and exhibits with revised requested billing charges. As a result of DEC's revisions, the revenue requirement changed for residential customers and Vintage 2015 of the Company's DSM and EE cost recovery rider. Accordingly, DEC requested revised annual billing factors of:

Residential Billing Factors

Rider 8 Prospective Component	0.3861	cents/kWh
Rider 8 EMF Component	0.0430	cents/kWh

Non-Residential Billing Factors

Prospective Components:		
Vintage 2014 EE participant	0.0139	cents/kWh

Vintage 2015 EE participant	0.0418	cents/kWh
Vintage 2016 EE participant	0.0373	cents/kWh
Vintage 2017 EE participant	0.2437	cents/kWh
Vintage 2017 DSM participant	0.0789	cents/kWh

EMF Components*:*

Vintage 4 EE participant	0.0004	cents/kWh
Vintage 4 DSM participant	0.0002	cents/kWh
Vintage 3 EE participant	(0.0024)	cents/kWh
Vintage 3 DSM participant	0.0003	cents/kWh
Vintage 2 EE participant	(0.0053)	cents/kWh
Vintage 2 DSM participant	0.0002	cents/kWh
Vintage 1 EE participant	0.0003	cents/kWh
Vintage 1 DSM participant	0.0002	cents/kWh
Vintage 2014 EE participant	0.0046	cents/kWh
Vintage 2014 DSM participant	(0.0015)	cents/kWh
Vintage 2015 EE participant	0.0821	cents/kWh
Vintage 2015 DSM participant	(0.0125)	cents/kWh

The case came on for hearing as scheduled on June 7, 2016. No public witnesses appeared at the hearing.

The Commission issued its Order in this proceeding on August 25, 2016. In that Order, the Commission approved the rates as set out in DEC's revised testimony and exhibits filed on May 26, 2016. The Commission again ordered that DEC should use its collaborative to (a) continue to discuss how to increase program participation and impacts with an emphasis on increasing the participation of opt-out eligible customers; (b) discuss the specific recommendations made by a SACE witness regarding new programs or enhancements to existing programs; (c) discuss the costs of EE programs, both over time, and as participation increases; and (d) continue to review recommendations for improving programs and increasing participation provided by the Company's EM&V consultants.

3. <u>DEC DSM/EE Cost Recovery Rider – Docket No. E-7, Sub 1130</u>

On March 8, 2017, DEC filed an application requesting the establishment of Rider 9 to recover: (1) a prospective component consisting of the estimated revenue requirements associated with Vintage 2018 of DEC's current portfolio of DSM/EE programs, the second year of net lost revenues for Vintage 2017 of DEC's EE programs, the third year of net lost revenues for Vintage 2016 of DEC's EE programs, and the final half-year of net lost revenues for Vintage 2015 of DEC's EE programs; and (2) an EMF component truing up Vintage 2014, Vintage 2015, and Vintage 2016 of DEC's DSM/EE programs. In this petition DEC requested Commission approval of the following annual billing factors (including the regulatory fee):

Residential Billing Factors

Rider 9 Prospective Component	0.4571	cents/kWh
Rider 9 EMF Component	0.1074	cents/kWh

Non-Residential Billing Factors

Prospective Components:		
Vintage 2015 EE participant	0.0197	cents/kWh
Vintage 2016 EE participant	0.0638	cents/kWh
Vintage 2017 EE participant	0.0456	cents/kWh
Vintage 2018 EE participant	0.2936	cents/kWh
Vintage 2018 DSM participant	0.0778	cents/kWh

EMF Components*:*		
Vintage 2014 EE participant	0.0005	cents/kWh
Vintage 2014 DSM participant	(0.0006)	cents/kWh
Vintage 2015 EE participant	0.0193	cents/kWh
Vintage 2015 DSM participant	(0.0024)	cents/kWh
Vintage 2016 EE participant	0.1264	cents/kWh
Vintage 2016 DSM participant	(0.0016)	cents/kWh

Intervenors in this proceeding were: the Public Staff, SACE, NCSEA, CUCA, and CIGFUR III.

On May 23, 2017, both the Public Staff and SACE filed testimony of its witnesses in the proceeding.

On May 31, 2017, DEC filed supplemental and rebuttal testimony of its witnesses.

The Commission held a hearing for this matter on June 6, 2017. As of the due date of this report, the matter was still pending before the Commission.

DSM/EE Rider Proceedings for DEP

1. DEP DSM/EE Cost Recovery Rider – Docket No. E-2, Sub 1070

On June 17, 2015, 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. In addition, DEP asked for approval of a DSM/EE EMF rider and, pursuant to Commission Rule R8-69(b)(2), recovery through the DSM/EE EMF of its post-test-year costs, including carrying costs and incentives incurred up to 30 days prior to the hearing in this proceeding. DEP stated that the rider and EMF are intended to allow DEP to recover $160,159,297 of DSM and EE expenses, net lost revenues, and incentives and that this amount includes the estimated under-collection of $15,806,668 associated with test period activities during the period beginning August 1, 2014[14], and ending December 31, 2014, and an estimated $144,352,629 for expenses and incentives to be incurred during the rate period from January 1, 2016, through December 31, 2016. DEP requested that the Commission approve the following total annual billing factor adjustments (including the regulatory fee):

Residential	0.622	cents/kWh
General Service EE	0.553	cents/kWh
General Service DSM	0.040	cents/kWh
Lighting	0.115	cents/kWh

Intervenors in this proceeding were as follows: the Public Staff, NCSEA, SACE, CUCA and CIGFUR II.

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

- Distribution System Demand Response (DSDR)
- EnergyWise
- Commercial, Industrial, and Governmental (CIG) Demand Response
- Residential Home Advantage (RHA)
- Residential Home Energy Improvement
- Residential Low Income-Neighborhood Energy Saver
- CIG EE
- Energy Efficiency Lighting (EEL)
- Residential Energy Efficiency Benchmarking (REEB), which is also known as My Home Energy Report (MyHER)
- Residential Appliance Recycling (ARP)
- Small Business Energy Saver (SBES)
- Residential New Construction
- Multi-Family EE
- EE Education
- Residential Solar Water Heating
- Residential Compact Fluorescent Light (CFL) Bulb pilot

The Public Staff filed testimony on August 31, 2015. The Public Staff noted that the Company generally had calculated the proposed riders in accordance with the methods set forth in the approved Mechanisms, as applicable, for recovery of costs, NLR,

[14] The test period is normally a 12-month period; however, to effectuate the transition from the Original Mechanism to the Revised Mechanism the test period for purposes of this proceeding is April 1, 2014, through December 31, 2014. As the test period DSM/EE costs and utility incentives for the months of April through July 2014 were already trued-up in the Company's 2014 DSM/EE Rider proceeding pursuant to Commission Rule R8-69(b)(2), the test period DSM/EE costs and utility incentives being trued up in this proceeding are only those for the months of August through December 2014.

and the PPI. The Public Staff witness noted that DEP had discovered an overstatement of the 2015 vintage year avoided transmission and distribution cost for the CIG Demand Response and EnergyWise programs. This affected the calculation of rate period PPI for those programs, and the Public Staff made a corresponding adjustment that reduced the prospective PPI by $225,179, to $18,204,469, and the billing factor for the Residential DSM/EE rate by 0.001 cents/kWh (including the regulatory fee), to 0.621 cents/kWh. No party objected to the adjustment.

The Public Staff also noted in its testimony that the Total Resource Cost (TRC) cost-effectiveness test results for the Residential Home Energy Improvement program are estimated to be below 1.0 for three out of the four years from 2013 through 2016.

Additionally, the Public Staff testified that DEP had not provided TRC results or other cost effectiveness test scores for the DSDR program since the original program application in 2008.

The Commission scheduled and held a hearing on September 15, 2015.

The Commission issued an Order in the proceeding on November 13, 2015. In that Order the Commission found it reasonable to accept the Public Staff's recommendation that the Company file TRC results for the DSDR program on or before March 31, 2016. If the TRC score is below 1.0, further proceedings may be appropriate to review the question of ongoing DSDR program cost recovery through the DSM/EE rider. The Commission further found that the Residential Home Energy Improvement Program, is not sufficiently cost-effective, and accepted the Public Staff's recommendation that the program be canceled effective March 31, 2016, unless DEP could demonstrate, before then, how the program will be modified in a manner that would have made it cost-effective in the long term, or filed a statement by March 31, 2016, that the Company expects to submit modifications on or before July 1, 2016, that would bring the cost-effectiveness above 1.0 on the TRC test. Finally, in that Order the Commission found that the appropriate total annual billing factor adjustments, including the regulatory fee, are:

Residential	0.621 cents per kWh
General Service EE	0.553 cents per kWh
General Service DSM	0.040 cents per kWh
Lighting	0.115 cents per kWh

2. <u>DEP DSM/EE Cost Recovery Rider – Docket No. E-2, Sub 1108</u>

On June 22, 2016, 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 stated in its application that the rider and EMF are intended to allow DEP to recover $191,946,270 of DSM and EE expenses, net lost revenues, and incentives. This amount includes the estimated under-collection of $28,073,885 associated with test period activities during the period beginning January 1, 2015, and ending December 31, 2015, and an estimated $163,872,385 for expenses and incentives to be incurred during the rate period from January 1, 2017 through December 31, 2017. DEP requested that the Commission approve the following annual billing factor adjustments (including the regulatory fee):

Residential	0.776	cents per kWh
General Service EE	0.618	cents per kWh
General Service DSM	0.052	cents per kWh
Lighting	0.110	cents per kWh

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

<u>Residential</u>

- Residential Home Advantage
- Appliance Recycling
- Energy Education in Schools
- Multi-Family EE
- My Home Energy Report (MyHER) (or Residential EE Benchmarking)
- Neighborhood Energy Saver (Low Income)
- Home Energy Improvement
- New Construction
- EnergyWise (Load Control)
- Save Energy and Water Kit
- Energy Assessment

<u>Non-residential</u>

- EE for Business
- Small Business Energy Saver
- Commercial, Industrial, and Governmental (CIG) Demand Response
- Business Energy Report pilot
- EnergyWise for Business (Load Control)

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

- DSDR
- EE Lighting

The following parties intervened in the proceeding: the Public Staff, CUCA, CIGFUR II, and SACE.

On July 11, 2016, DEP filed supplemental testimony of its witnesses. The Public Staff and intervenor SACE filed testimony on September 2, 2016. On September 7, 2016, DEP filed revised supplemental testimony of its witnesses, to correct errors in its calculation of Net Lost Revenue amounts applicable to the General Service Energy Efficiency rate, the correction of which results in a decrease to that rate. In that filing, the Company corrected its EMF NLR and PPI amounts to $37,249,538 and $13,138,541, respectively, and its prospective NLR and PPI estimates to $38,223,700 and $17,125,659, respectively.

On September 13, 2016, DEP filed a letter on the status of its Appliance Recycling Program. This status update was suggested by the Public Staff, with the purpose being to determine if the Company's Appliance Recycling Program could be reinstated on a cost-effective basis. In DEP's letter, DEP stated that it "continues to evaluate and consider the overall value and long-term viability of the program. Initial calculations, based on vendor proposals, indicate that ARP projects to be cost-effective. However, further evaluation is being conducted to ensure the potential vendor is financially secure and can successfully support the overall program requirements. Additionally, the Company is considering the long-term viability of the program to minimize any additional risks that could negatively impact the Company and its customers."

On September 20, 2016, the hearing was held as scheduled.

On November 15, 2016, the Commission issued its Order in this proceeding. In that Order, the Commission found that the revenue requirements for each rate class, excluding the regulatory fee, are as follows:

DSM/EE PROSPECTIVE COMPONENT:

Residential	$99,540,184
General Service EE	57,699,963
General Service DSM	5,435,508
Lighting	424,108
Total	$163,099,763

DSM/EE EMF:

Residential	$22,002,072
General Service EE	5,781,635
General Service DSM	(28,584)
Lighting	3,642
Total	$27,758,765

The Commission further found that the appropriate total annual billing factor adjustments, including the regulatory fee, are:

Rate Class	Total DSM/EE Rider
Residential	0.776 cents per kWh
General Service EE	0.607 cents per kWh
General Service DSM	0.052 cents per kWh
Lighting	0.110 cents per kWh

The Commission additionally ordered that:

1) To the extent they are not cost prohibitive, the following recommendations of Public Staff witness Williamson regarding the development of future EM&V reports are reasonable: (i) future EM&V evaluations for the Residential New Construction program, and similar programs, should consider incorporating market effect savings; (ii) if the Appliance Recycling program is resumed, future EM&V evaluations should consider use of a primary metering study consistent with the Uniform Methods Protocol to estimate per-unit energy consumption; (iii) with respect to the 2014 EM&V report for EE Lighting, the Company and Public Staff should discuss whether the assumptions on baseline wattage and Net-to-Gross methodology are appropriate or need revision; (iv) future EM&V evaluations for the Neighborhood Energy Saver program should consider use of state-level data; and (v) with respect to the 2014 EM&V report for the Small Business Energy Saver program, the Company and Public Staff should discuss the inputs of the Net-to-Gross savings calculations.
2) Based on the recommendations of SACE witness Weiss, DEP should continue to utilize its Collaborative to discuss and consider the following: (a) ways to improve current programs and to develop new programs, including an expansion of low-income programs and an enhanced multi-family program; (b) any additional potential for non-residential programs, with an emphasis on attracting opt-out eligible customers; (c) whether more detailed cost-reporting procedures and more consistent reporting of cost-effectiveness scores are feasible; and (d) means to encourage participation in cost-effective DSM/EE programs. DEP should also continue to convene its on-bill financing working group and report the progress at Collaborative meetings. In addition, based on the testimony of SACE witness Weiss, the Commission finds that DEP should utilize its Collaborative to: (a) discuss and consider ways to avoid underestimating program performance, and (b) discuss and consider ways in which it can achieve annual energy savings of at least 1% of prior-year retail sales and cumulative savings of at least 7% over the period from 2014 through 2018. The Collaborative should also discuss and attempt to produce a recommendation that addresses witness Weiss' observations that there is currently no mechanism in place to monitor and verify the alternative DMS/EE measures implemented by customers who choose not to participate in DEP's DSM/EE programs and instead opt-out. The Collaborative should also address CIGFUR's position that the only statutory obligation on opt-out customers is to notify the utility of their choice to opt-out.

3. DEP DSM/EE Cost Recovery Rider – Docket No. E-2, Sub 1145

On June 21, 2017, 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 $161,639,741 of DSM and EE expenses, net lost revenues, and incentives. This amount includes the estimated under-collection of $2,377,317 associated with test period activities during the period beginning January 1, 2016 and ending December 31, 2016, and an estimated $159,262,424 for expenses and incentives to be incurred during the rate period from January 1, 2018 through December 31, 2018. DEP requested that the Commission approve the following total annual billing factor adjustments (including the regulatory fee):

Residential	0.617	cents per kWh
General Service EE	0.599	cents per kWh
General Service DSM	0.042	cents per kWh
Lighting	0.106	cents per 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 Saver (Low Income)
- Home Energy Improvement
- New Construction
- EnergyWise (Load Control)
- Save Energy and Water Kit
- Energy Assessment

Non-Residential

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

Residential and Non-Residential

- DSDR
- EE Lighting

Intervenors in this proceeding were as follows: the Public Staff, NCSEA, SACE/NC Justice Center, CUCA, and CIGFUR II.

The Commission scheduled a hearing on September 19, 2017. As of the date of due date of this report, the matter was still pending before the Commission.

Section 5: COST RECOVERY MECHANISMS

1. DNCP - Docket No. E-22, Sub 464

On May 7, 2015, the Commission issued its Order Approving Revised Cost Recovery and Incentive Mechanism and Granting Waiver (Order on Revised Mechanism). That Order required that the Public Staff and DNCP initiate a limited review of performance incentive provisions of the Company's Mechanism, as agreed to in the Mechanism, and file on or before March 1, 2017, an updated performance incentive proposal (or separate proposals if agreement cannot be reached) for the Commission's review and approval. The Order further provided that the Public Staff will initiate a formal review of the Company's Mechanism no later than October 1, 2019, unless requested to do so earlier by any interested party.

On February 27, 2017, the Public Staff requested that the Commission grant it an extension of time to file its proposed revisions to the Mechanism. The Commission granted this request on February 28, 2017, and allowed the parties to have until March 30, 2017, to file the revisions. On March 28, 2017, the parties requested a second extension of time to file, which was granted on March 29, 2017. This second extension allowed the parties until April 20, 2017, to file their proposed revisions to the Mechanism. On April, 20, 2017, both DNCP and the Pubic Staff filed a Joint Proposal for New PPO with the Commission. Attached to the Joint Proposal as Appendix A was a revised Mechanism, with recommended additions to the Mechanism underlined and recommended deletions shown with strikethrough. DNCP and the Public Staff stated that they believe the recommended Mechanism revisions are a reasonable implementation of Paragraph 69 of the revised Mechanism that was approved in the Commission's 2015 Order. Further, they stated that the recommended changes would be applicable to DSM and EE measures and programs from Vintage Year 2017 forward, and that the revised Mechanism that was approved in the 2015 Order would be applicable to vintage years before 2017. Finally, the Public Staff and DNCP recommended that the Commission issue an Order approving their recommended revisions to the Mechanism. No other party intervened or filed comments regarding revisions to the Mechanism.

On May 22, 2017, the Commission issued its Order Approving Revised Cost Recovery and Incentive Mechanism (2017 Mechanism). The 2017 Mechanism became effective as of May 22, 2017, for projected costs and utility incentives beginning January 1, 2018, and for true-ups of costs and utility incentives beginning January 1, 2017, and is used in this proceeding to calculate the Rider C billing rates related to DSM and EE measures projected to be installed or implemented for Vintage Year 2018.

Notable changes to the revised Mechanism approved by the Commission include:

1) DNCP switched from calculating a PPI for inclusion in its DSM/EE and DSM/EE EMF riders to calculating a Portfolio Performance Incentive (PPI) beginning with Vintage Year 2017;
2) The addition of language related to the avoided cost rates used for purposes of calculating the cost-effectiveness of DSM/EE programs and measures. The

additional verbiage states that for purposes of program approval (new programs or modifications of existing programs submitted pursuant to Commission Rule R8-68), the per kW avoided capacity costs used to calculate cost effectiveness of programs and/or measures shall be determined at the time that DNCP files its petition for annual cost recovery by using comparable methodologies to those used in the most recently approved biennial avoided cost proceeding and revenues realized during the test period. In addition, these same rates will be used in the prospective cost-effectiveness tests evaluations;

3) The amount of pre-income tax PPI initially to be recovered in a vintage year for the entire DSM/EE portfolio will be 9.08% for all eligible DSM programs and 14.76% for all eligible EE programs. These percentages will be multiplied by the present value of the estimated net dollar savings associated with the portfolio installed in that vintage year, calculated by program using the UTC. The 9.08% and the 14.76% factors will be subject to review in each annual rider proceeding to ensure the continued reasonableness for the PPI as a whole. The Mechanism previously approved by the Commission allowed for a PPI of 8% for all eligible DSM programs and a PPI of 13% for all eligible EE programs;
4) The addition of language that states the PPI for each vintage year will be allocated to DSM and EE programs in proportion to the present value net dollar savings of each program for the vintage year; and
5) Several changes to the Mechanism language to delete references to old or expired information.

2. <u>DEC - Docket No. E-7, Sub 1032</u>

On October 29, 2013, the Commission issued an Order Approving DSM/EE Programs and Stipulation of Settlement. That Order, among other things, approved the Cost Recovery and Incentive Mechanism for Demand-Side Management and Energy Efficiency Programs (Mechanism) proposed by DEC and agreed to by the Public Staff, NCSEA, Environmental Defense Fund (EDF), SACE, South Carolina Coastal Conservation League, Sierra Club and Natural Resources Defense Council (NRDC, and collectively, Stipulating Parties). In addition, in Ordering Paragraph No. 11 the Commission stated that it would initiate a formal review of DEC's Mechanism not later than July 1, 2017, unless requested to do so earlier by DEC, the Public Staff or another interested party.

On July 18, 2017, SACE, South Carolina Coastal Conservation League, Sierra Club and Natural Resources Defense Council, parties to the stipulation approving the Mechanism, filed a letter stating that they do not believe that a review of the Mechanism is necessary at this time.

On July 19, 2017, the Commission issued an order requesting comments on or before August 21, 2017, and reply comments on or before September 11, 2017.

On August 18, 2017, the Stipulating Parties, and North Carolina Waste Awareness and Reduction Network, filed a letter stating that they do not propose any modifications to DEC's Mechanism, other than several revisions that were proposed by DEC and the

Public Staff in Docket No. E-7, Sub 1130, DEC's annual DSM/EE rider proceeding.

No additional comments or reply comments were filed in this docket.

On August 23, 2017, in Docket No. E-7, Sub 1130, the Commission issued an Order Approving DSM/EE Rider, Revising DSM/EE Mechanism, and Requiring Filing of Proposed Customer Notice (Sub 1130 Order). The Sub 1130 Order, among other things, approved the revisions to DEC's Mechanism recommended by DEC and the Public Staff, effective January 1, 2018. The Mechanism was revised to (1) set out how the avoided costs are determined for purposes of calculating the PPI, (2) specify the avoided costs to be used for purposes of program approval, and (3) specify the avoided costs to be used in calculating ongoing cost-effectiveness, as well as setting out a procedure for modification or closure of programs that are no longer cost-effective. Specifically in Sub 1130, paragraph 69 of the Sub 1032 Mechanism, which describes how avoided costs are determined for purposes of calculating the PPI, was revised such that for Vintage 2019 and beyond, the program-specific avoided capacity benefits and avoided energy benefits will be derived from the underlying resource plan, production cost model, and cost inputs that generated the avoided capacity and avoided energy credits reflected in the most recent Commission-approved Biennial Determination of Avoided Cost Rates as of December 31 of the year immediately preceding the annual DSM/EE rider filing date. For the calculation of the underlying avoided energy credits to be used to derive the program-specific avoided energy benefits, the calculation will be based on the projected EE portfolio hourly shape, rather than the assumed 24x7 100- megawatt (MW) reduction typically used to represent a qualifying facility (QF).

Additionally, Paragraph 19 of the Sub 1032 Mechanism was revised to specify that the avoided costs used for purposes of program approval filings would also be determined using the method outlined in revised Paragraph 69. The specific Biennial Determination of Avoided Cost Rates used for each program approval filing would be derived from the rates most recently approved by the Commission as of the date of the program approval filing. Paragraph 23 of the Sub 1032 Mechanism was revised, and Paragraphs 23A-D were added, to specify which avoided costs should be used for determining the continuing cost-effectiveness of programs and actions to be taken based on the results of those tests. Pursuant to Paragraph 23, each year the Company files an analysis of the current cost-effectiveness of each of its DSM/EE programs as part of the DSM/EE rider filing. New Paragraph 23A requires the use of the same method for calculating the avoided costs outlined in the revisions to Paragraph 69 to determine the continued cost-effectiveness for each program. Like revised Paragraph 69, Paragraph 23A specifies that the avoided capacity and energy costs used to calculate cost-effectiveness will be derived from the avoided costs underlying the most recent Commission-approved Biennial Determination of Avoided Cost Rates as of December 31 of the year immediately preceding the annual DSM/EE rider filing date. New Paragraphs 23B through 23D address the steps that will be taken if specific DSM/EE programs continue to produce Total Resource Cost (TRC) test results less than 1.00 for an extended period. For any program that initially demonstrates a TRC of less than 1.00, the Company shall include in its annual DSM/EE rider filing a discussion of the actions being taken to maintain or improve cost-effectiveness, or alternatively, its plans to terminate the program. If a program demonstrates a prospective TRC of less than 1.00 in a second DSM/EE rider proceeding, the Company shall include a discussion of what actions it has taken to improve cost-effectiveness. If a program demonstrates a prospective TRC of less than 1.0 in a third DSM/EE rider proceeding, the Company shall terminate the program effective at the end of the year following the DSM/EE rider order, unless otherwise ordered by the Commission.

On September 18, 2017, the Commission issued its order in Docket No. E-7, Sub 1032 approving the continued implementation of DEC's Mechanism without any changes other than the changes approved in the Sub 1130 Order.

3. <u>DEP - Docket No. E-2, Sub 931</u>

On June 10, 2014, DEP filed a petition requesting the Commission review DEP's Cost Recovery and Incentive Mechanism for DSM and EE programs (Mechanism). This review was a requirement of an earlier Commission order in Docket No. E-2, Sub 1002.

In its petition, DEP noted that its Mechanism is working well and producing significant and meaningful DSM and EE results.

Several parties intervened and provided comments in this proceeding: the Public Staff; SACE, NRDC, and Walmart.

On October 29, 2014, DEP, SACE, NRDC, and the Public Staff entered a Settlement Agreement on the Revised Mechanism.

On January 20, 2015, the Commission issued an Order Approving Revised Cost Recovery and Incentive Mechanism and Granting Waivers. In that Order, the Commission approved the Settlement Agreement, which is generally to be effective January 1, 2016 (Revised Mechanism). The Revised Mechanism allows DEP to recover all reasonable and prudent costs incurred and utility incentives earned for adopting and implementing new DSM and EE measures in accordance with G.S. 62-133.9, Commission Rules R8-68 and R8-69, and the additional principles set forth in the Revised Mechanism.

The Revised Mechanism contained the following items of note:

1. Waivers of the following Commission rules: a) waiver of Rule R8-69(d)(3) to (i) allow the Company to implement and manage the opt-out elections of individual commercial customer accounts with annual energy usage of not less than 1,000,000 kilowatt-hours (kWh), and any industrial customer accounts, not to participate in either the Company's DSM programs or its EE Granting Waiver, in Part, and Denying Waiver, in Part issued on April 6, 2010, in Docket No. E-7, Sub 938 for DEC; and (b) waivers of Rules R8-69(a)(4) and R8-69(a)(5) to change the test period and rate period for DEP's DSM/EE rider to align with the calendar year, for the duration of the Mechanism.

2. Beginning in DEP’s 2015 DSM/EE rider proceeding, the rate period for the proposed DSM/EE Rider will be the calendar year. Also beginning in DEP’s 2015 DSM/EE rider proceeding, the test period used in the development of the DSM/EE EMF Rider will be the calendar year.
3. Beginning with DEP’s 2015 DSM/EE rider proceeding, the annual filing date of DEP’s DSM/EE rider application, supporting testimony, and Exhibits will be no later than June 30 of each calendar year.
4. Allowed DEP to leverage common practices with DEC by adopting and incorporating the Flexibility Guidelines established for DEC in Docket No. E-7, Sub 831 and then again approved as a component of its new portfolio in Docket No. E-7, Sub 1032.
5. A provision that the Company and Public Staff shall study the issue of the appropriate avoided transmission and distribution (T&D) costs to be used in the Company’s calculations of cost-effectiveness and, if any adjustment is determined to be appropriate, the proposed adjustment shall be filed in the Company’s 2015 DSM/EE rider proceeding to be effective on a prospective basis for vintage (calendar) year 2016.
6. Modification of the amount of the pre-income-tax PPI initially to be recovered in a Vintage Year for the entire DSM/EE portfolio, excluding Programs not eligible for a PPI, to 11.75% of the present value of the estimated net dollar savings associated with the portfolio installed in that Vintage Year, calculated by Program using the UCT (and excluding Low Income Programs).
7. That DEP be allowed the opportunity to earn an additional incentive of $400,000 in any year from 2016 through 2020 in which it achieves incremental energy savings of 1% of the prior year's DEP system retail electricity sales.
8. The adoption of the protocols and application methodology for evaluation, measurement, and verification (EM&V) results that were established in the EM&V Agreement between DEC, the Public Staff and Southern Alliance for Clean Energy which was approved by the Commission in Docket No. E-7, Sub 979, and maintained as a component of DEC's new portfolio in Docket No. E-7, Sub 1032, which will allow DEC and DEP to consolidate some aspects of the EM&V process and potentially save costs.
9. Modified the Opt-out such that Opt-out eligible customers that have received DSM/EE Program incentives will be subject to the applicable DSM/EE rider and DSM/EE EMF rider billings for a period of no less than 36 months.
10. Allow for eligible non-residential customers to opt out of either or both of the DSM and EE categories of Programs as well as opt back into either or both. If a customer receives Program incentives from a Company DSM or EE Program, that customer must opt-in for a period of no less than 36 months. A customer receiving Program incentives from a DSM Program will be required to pay the DSM portion of the DSM/EE Rider for a period of not less than 36 months. A customer receiving Program incentives from an EE Program will be required to pay the EE portion of the DSM/EE Rider for a period of not less than 36 months.

The order also stated that the Public Staff should 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 order further noted that 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.

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 regulatory fee, 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; NCUC Docket No. M-100, Sub 140, 12/03/13.)

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.)