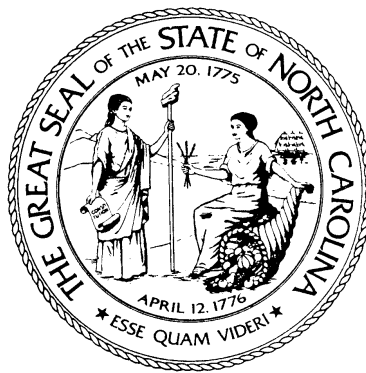


**BIENNIAL REPORT OF THE
NORTH CAROLINA UTILITIES COMMISSION
TO
THE GOVERNOR OF NORTH CAROLINA
AND
THE JOINT LEGISLATIVE UTILITY REVIEW COMMITTEE
REGARDING
PROCEEDINGS FOR ELECTRIC UTILITIES INVOLVING
ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT
PROGRAMS, COST-RECOVERY AND INCENTIVES
(Pursuant to G.S. 62-133.9(i))**



September 1, 2009



State of North Carolina Utilities Commission

COMMISSIONERS
EDWARD S. FINLEY, JR., Chairman
ROBERT V. OWENS, JR.
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Raleigh, N. C. 27699-4325

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TONOLA D. BROWN-BLAND

September 1, 2009

The Honorable Beverly Eaves Perdue
Office of the Governor
20301 Mail Service Center
Raleigh, NC 27699-0301

Senator David W. Hoyle, Co-Chair
Joint Legislative Utility Review Committee
300-A Legislative Office Building
Raleigh, NC 27601-2808

Representative Lorene T. Coates, Co-Chair
Joint Legislative Utility Review Committee
633 Legislative Office Building
Raleigh, NC 27603-5925

Dear Governor Perdue, Senator Hoyle and Representative Coates:

The Utilities Commission hereby presents for your consideration its first biennial report summarizing proceedings before the Commission involving electric utilities and their new energy efficiency and demand-side management programs. The Commission makes this report pursuant to G.S. 62-133.9(i). This report summarizes proceedings before the Commission from August 20, 2007 (the effective date of the statute) through June 30, 2009 that involve:

- 1) The Commission's rule-making to implement G.S. 62-133.9;
- 2) Utilities' assessments of energy efficiency and demand-side management;
- 3) Utilities' applications for approval of new energy efficiency and demand-side management programs; and
- 4) Utilities' requests to recover costs and incentives from customers.

The Honorable Beverly Eaves Perdue
Senator David W. Hoyle, Co-Chair
Representative Lorene T. Coates, Co-Chair
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A second report is due to you October 1, 2009, pursuant to Section 14 of Session Law 2007-397. That report will provide information regarding the actual results of cost allocations established by the Commission pursuant to:

- 1) G.S. 62-133.2(a2 and a3) – fuel and fuel-related charges;
- 2) G.S. 62-133.8(h) – renewable energy and energy efficiency portfolio standards; and
- 3) G.S. 62-133.9(e and f) – demand-side management and energy efficiency programs.

Sincerely,



Edward S. Finley, Jr., Chairman

ESFjr/KJ/mr

cc: Members of the Joint Legislative Utility Review Committee
Steven J. Rose, Committee Counsel
Bill Patterson, Committee Counsel
Heather Fennell, Assistant Committee Counsel
Mariah Matheson, Research Assistant
Robert P. Gruber, Executive Director, Public Staff
The Honorable Roy Cooper, Attorney General
Blue Ridge Electric Membership Corporation
Dominion North Carolina Power
Duke Energy Carolinas, LLC
EnergyUnited Electric Membership Corporation
GreenCo Solutions, Inc.
Halifax Electric Membership Corporation
North Carolina Electric Membership Corporation
Piedmont Electric Membership Corporation
Progress Energy Carolinas, Inc.
Rutherford Electric Membership Corporation
North Carolina State Publications Clearinghouse
North Carolina State Environmental Review Clearinghouse

INTRODUCTION

The Utilities Commission is providing this report to the Governor and the Joint Legislative Utility Review Committee pursuant to G.S. 62-133.9(i), which requires the Commission to submit a summary of proceedings conducted under G.S. 62-133.9 every two years, with the first report due September 1, 2009. The report is to cover proceedings during the preceding two fiscal years, which for this first report span the time period August 20, 2007 (the effective date of the new law) through June 30, 2009.

G.S. 62-133.9 was enacted as part of Session Law 2007-397, which established a 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 Session Law 2007-397 [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 meet the electricity needs of their customers. Each electric power supplier that is required to file an integrated resource plan (IRP) must now include in 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.

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.

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

- (2) '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.

- (4) 'Energy efficiency measure' means an equipment, physical, or program change implemented after 1 January 2007 that results in less energy used to perform the same function. 'Energy efficiency measure' includes, but is not limited to, energy produced from a combined heat and power system that uses nonrenewable energy resources. 'Energy efficiency measure' does not include demand-side management.

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2	Utilities' DSM and EE assessments filed as part of their integrated resource plans <ol style="list-style-type: none"> 1. Blue Ridge Electric Membership Corporation 2. Dominion North Carolina Power 3. Duke Energy Carolinas, LLC 4. EnergyUnited Electric Membership Corporation 5. GreenCo Solutions, Inc. 6. Halifax Electric Membership Corporation 7. North Carolina Electric Membership Corporation 8. Piedmont Electric Membership Corporation 9. Progress Energy Carolinas 10. Rutherford Electric Membership Corporation 	 7 7 8 9 9 9 10 10 11 12
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SECTION 1: RULEMAKING PROCEEDING TO IMPLEMENT G.S. 62-133.9

On August 23, 2007, the Commission issued an Order initiating a rulemaking proceeding in Docket No. E-100, Sub 113 by seeking comments from interested persons on how to implement Session Law 2007-397. The Commission also requested that the Public Staff of the North Carolina Utilities Commission (Public Staff), after considering filings made by parties, prepare and file proposed rules to implement Section 4 of the new law. Subsequently, the Commission received comments from 23 parties:

- Acciona Energy North America Corporation (Acciona);
- Appalachian Energy, LLC;
- Carolina Industrial Group for Fair Utility Rates I, II and III (CIGFUR);
- Carolina Utility Customers Association, Inc. (CUCA);
- CPV Renewable Energy Company, LLC (CPV);
- North Carolina Department of Environment and Natural Resources, Division of Water Resources (DENR);
- Virginia Electric and Power Company d/b/a Dominion North Carolina Power (Dominion);
- Duke Energy Carolinas, LLC (Duke);
- ElectriCities of North Carolina, Inc. (ElectriCities);
- Environmental Defense Fund (EDF);
- North Carolina Electric Membership Corporation (NCEMC);
- North Carolina Farm Bureau Federation, Inc. (NCFB);
- North Carolina Small Hydro Group (Small Hydro);
- North Carolina Sustainable Energy Association (NCSEA);
- North Carolina Wildlife Resources Commission (Wildlife Resources);
- Nucor Steel-Hertford, a division of Nucor Corporation (Nucor);
- Progress Energy Carolinas, Inc. (Progress);
- Southern Alliance for Clean Energy (SACE);
- Southern Environmental Law Center (SELC);
- Southern Energy Management (SEM);
- Solar Alliance;
- Sun Edison LLC (SunEdison); and
- Wal-Mart Stores East, LP (Wal-Mart).

The intervention and participation of the Public Staff was recognized in accordance with applicable law. In addition, Roy Cooper, Attorney General, filed his notice of intervention.

Other parties that were allowed to intervene include:

- Bio-Energy Conversion, LLC (Bio-Energy);
- Domtar Paper Company, LLC (Domtar);
- EcoPlus, Inc. (EcoPlus);

- Elster Integrated Solutions (Elster);
- Fibrowatt, LLC (Fibrowatt);
- William H. Lee (Lee);
- North Carolina Waste Awareness and Reduction Network, Inc. (NC WARN);
- Piedmont Natural Gas Company, Inc. (Piedmont); and
- Public Service Company of North Carolina (PSNC).

On October 26, 2007, after reviewing the comments filed by the parties, the Commission issued an Order Issuing Proposed Rules for Comment. Pursuant to the Commission's October 26, 2007 Order, initial comments were received on or before November 14, 2007, from Bio-Energy, CIGFUR, CPV, CUCA, Dominion, Duke, EDF, Electricities, NC WARN, NCEMC, NCFB, NCSEA, Nucor, Piedmont, Progress, SACE, SELC, Solar Alliance, SunEdison, Wal-Mart, Wildlife Resources, the Attorney General and the Public Staff. In addition, comments were received from Dr. John Neufeld, Professor of Economics, UNC Greensboro. Reply comments were received on or before December 17, 2007, from CPV, CUCA, CIGFUR, Dominion, Duke, EDF, Electricities, NC WARN, NCEMC, NCSEA, Nucor, Piedmont, Progress, PSNC, SACE, SELC, Small Hydro, Solar Alliance, SunEdison, Wal-Mart, the Attorney General and the Public Staff. In addition, comments were received from the Combined Heat and Power Association (CHPA) and the North Carolina Public Interest Research Group and Education Fund (NCPIRG). Supplemental comments were filed after December 17, 2007, by NCSEA, Duke and Progress.

After careful consideration of all of the comments received, the Commission issued an Order Adopting Final Rules on February 29, 2008. Rule R8-60 requires utilities to include an assessment of DSM and EE in their IRP filings. Rule R8-67 requires electric power suppliers to file annually their plans for complying with REPS, including providing a list of planned or implemented EE measures. Rule R8-67 also requires electric power suppliers to annually file a REPS compliance report in which they can initially estimate the conservation achieved by their EE programs. Such estimates are subject to true-up based on the results of independent measurement and verification (M&V) of the actual conservation achieved due to the implementation of the EE measure. Rule R8-68 requires electric public utilities or electric membership corporations to apply to the Commission for approval of new DSM and EE programs, and specifies the filing requirements and procedures, including requiring electric public utilities to specify the utility incentives they desire to recover for the program. Rule R8-69 establishes an annual process for the Commission to review and approve an electric public utility's cost recovery rider for DSM and EE program costs and utility incentives. A copy of the portions of the new rules that relate to DSM and EE (Rules R8-60, and R8-67 through R8-69) is attached as Appendix A.¹

¹On March 13, 2008, the Commission amended the final rules implementing Session Law 2007-397 to conform its statutory references to the final codification of the new law. Appendix A includes the corrected statutory references.

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

G.S. 62-133.9(c) requires each electric power supplier to which G.S. 62-110.1² applies to include an assessment of DSM and EE in its resource plan. The Commission incorporated that requirement in its Rule R8-60. On August 18, 2008, NCEMC, Blue Ridge Electric Membership Corporation, French Broad Electric Membership Corporation and Piedmont Electric Membership Corporation filed a request that the Commission waive their obligations under Commission Rules R8-60 and R8-67 to file their REPS compliance plans as part of the IRP 2008 biennial report. They requested that their REPS compliance plans instead be submitted by GreenCo Solutions, Inc.³ On August 22 and 25, 2008, Duke filed a motion requesting an extension of time through November 3, 2008, to file its 2008 IRP biennial report. On August 27, 2008, the Commission issued an order in Docket No. E-100, Sub 118 granting both requests.

During the fall of 2008, IRPs and/or REPS compliance plans were filed by the following organizations:

1. Blue Ridge Electric Membership Corporation (Blue Ridge EMC)
2. Dominion
3. Duke
4. EnergyUnited Electric Membership Corporation (EnergyUnited EMC)
5. GreenCo Solutions, Inc. (GreenCo)
6. Halifax Electric Membership Corporation (Halifax EMC)
7. NCEMC
8. Piedmont EMC
9. Progress
10. Rutherford Electric Membership Corporation (Rutherford EMC)

The following is a summary of each organization's DSM/EE assessment that was included in its IRP and/or REPS compliance plan.⁴

² G.S. 62-110.1(c) applies to public utilities, including EMCs. The following EMCs are not subject to Commission Rule R8-60 because they are headquartered outside of North Carolina: Blue Ridge Mountain EMC, Broad River Electric Cooperative, Mecklenburg Electric Cooperative, Mountain Electric Cooperative, and Tri-State Electric Membership Corporation.

³ On April 16, 2008, GreenCo Solutions, Inc. (GreenCo) was formed as a not-for-profit organization by 23 North Carolina electric membership corporations. Itself an electric membership corporation, GreenCo was formed to assist member cooperatives in complying with North Carolina's REPS, including EE program development and management. See Appendix B for a list of GreenCo's member cooperatives.

⁴The Commission is reviewing these IRPs in Docket No. E-100, Sub 118, which is pending. On July 28, 2009, the Commission issued an Order scheduling a hearing for members of the public to provide non-expert witness testimony in this proceeding the evening of August 31, 2009, in Raleigh.

1. Blue Ridge EMC

Blue Ridge EMC reported that it has three demand response programs: load control switches on air conditioners (2,350 as of 1/1/08), load control switches on water heaters (16,450 as of 1/1/08), and electric thermal storage units (1,119 as of 1/1/08) for total potential peak demand reduction of 18.9 Megawatts (MW). Blue Ridge EMC is a full requirements customer of Duke, and Duke has operational control of Blue Ridge EMC's demand response capability. Blue Ridge EMC stated that it does not plan to add any demand response programs in the biennium, but does plan to implement several EE programs, the details of which are included in GreenCo's report.

2. Dominion

Dominion reported that it offers three DSM rate tariffs that provide participant incentive payments for load reductions that Dominion can call for when capacity is needed. Dominion stated that there were 22 curtailments in 2007, with an estimated reduction of 27 MW in the summer and 29 MW in the winter. Dominion stated that it intends to request approval for changes in its rates in order to send more appropriate pricing signals to its retail customers, noting that a rate moratorium contained in a stipulation approved by the Commission in Docket No. E-22, Sub 412⁵ will end in April of 2010.

In terms of both DSM and EE, Dominion described additional programs that it proposed to implement after they have been approved by the Commissions in North Carolina and Virginia. (At this time, Dominion has not yet filed any of these programs for approval by the North Carolina Utilities Commission.) They include:

1. Residential air conditioner direct load control program
2. Commercial distributed generation program
3. Curtailment service program
4. PJM demand resource program
5. PJM interruptible load for reliability program
6. PJM economic load response program
7. Residential power cost display monitor program
8. Residential high efficiency heat pump program
9. Residential Energy Star^R new homes program
10. Residential heat pump tune-up program
11. Residential compact fluorescent lighting program
12. Commercial heating, ventilating and air-conditioning program
13. Commercial lighting program
14. Residential low-income energy audit and measure improvements program
15. Residential refrigerator turn-in program
16. Conservation voltage reduction program

⁵In the Matter of Public Staff's Petition to Institute Investigation of Rates and Charges, issued January 29, 2004.

3. Duke

Duke stated that its current DSM programs are:

1. General service and industrial optional time-of-use rates⁶
2. Hourly pricing for incremental load
3. Interruptible power service
4. Residential air conditioning direct load control
5. Residential time-of-use rates
6. Residential water heating direct load control
7. Standby generator control

These programs have a total capacity of approximately 700 MW.

Duke noted that on September 1, 2006, firm wholesale agreements took effect between Duke and Blue Ridge EMC, Piedmont EMC and Rutherford EMC. These contracts added about 48 MW of demand response to Duke's capability.

Duke stated that its existing EE programs include:

1. Residential Energy Star^R rates for new construction
2. Existing residential housing program
3. Special needs energy products loan program
4. Energy efficiency video for residential customers
5. Large business customer energy efficiency assessments
6. Large business customer energy efficiency tools

Duke stated that it uses the DSMore model to evaluate the costs, benefits and risks of DSM and EE programs and measures in order to compare them to supply-side resources. DSMore is a financial analysis tool that estimates the value of a DSM/EE measure across a wide variety of weather and cost conditions. Duke also explained that in 2006 it established EE and DSM collaborative groups consisting of stakeholders from across its service area and charged them with recommending a new set of EE and DSM programs. The collaborative efforts resulted in Duke's May 7, 2007 filing known as "save-a-watt" (Docket No. E-7, Sub 831), which is discussed more fully in Sections 3 and 4 of this report. Duke's submittals in that docket included an extensive report prepared by several consultants regarding the technical and economic potential for EE and DSM in Duke's service area. The report, dated August 31, 2007, concluded that, through planning year 2026, it was economically feasible to meet 19% of Duke's customers' electricity needs via efficiency improvements. The report recommended programs over five years that would save 1.6% of customer electricity use in 2011.

⁶For more information regarding time-of-use rates in North Carolina, see the Commission's September 1, 2008 report entitled, "Analysis of Rate Structures, Policies, and Measures to Promote Renewable Energy Generation and Demand Response in North Carolina," Commission Docket No. E-100, Sub 116.

4. EnergyUnited EMC

EnergyUnited EMC stated that it is currently studying several EE programs and anticipates releasing programs in the 2010 timeframe. EnergyUnited EMC forecasted that its new EE programs would reduce demand by 1.8 MW in 2011, growing to 4.4 MW of load reduction in 2021. In 2007 EnergyUnited EMC gave away compact fluorescent lights to members who attended its annual meeting. EnergyUnited EMC stated that it is in the process of educating its members on the value of EE, including monthly articles in its newsletter and interactive tools on its website.

In terms of DSM, EnergyUnited EMC stated that it has the following programs with customer participation as noted:

1. Residential water heaters (23,659 customers)
2. Coincident peak commercial/industrial (30 customers)
3. Residential air conditioners (26,470 customers)

EnergyUnited EMC stated that its DSM programs provide 25 MW of demand reduction.

5. GreenCo

On behalf of its 23 participating member cooperatives,⁷ GreenCo filed a REPS compliance plan that included discussion of existing EE programs as well as an extensive assessment of new EE opportunities. GreenCo stated that EE is a significant part of its members' REPS compliance strategy. GreenCo engaged a consultant who evaluated 42 potential new EE programs. GreenCo selected eight of them to pursue with its members, some via pilots:

1. Energy Star^R lighting
2. Water heater retrofit
3. Energy cost monitor
4. Community efficiency campaign
5. Energy Star^R appliances
6. Energy Star^R new construction
7. Commercial energy efficient equipment
8. Agricultural energy efficiency

6. Halifax EMC

Halifax EMC stated that it is evaluating low-cost EE programs, such as promotion of compact fluorescent light bulbs, programmable thermostats and water heater jackets. Halifax EMC stated that it plans to use the results of the EE study by GreenCo's

⁷ See Appendix B for a list of GreenCo's member cooperatives.

consultant “to the extent feasible”⁸ in determining the impact of alternatives under consideration. Halifax EMC stated that EE measures are being evaluated at local schools and energy audits are contemplated for other non-residential customers. Halifax EMC stated that one industrial customer will complete a variety of EE initiatives by the end of 2008, which should result in savings of 1,580,933 kWh. Finally, Halifax EMC stated that it is evaluating re-sizing transformers and conductors to reduce energy losses.

7. NCEMC⁹

As noted earlier, on August 18, 2008, NCEMC petitioned the Commission for permission to file its REPS compliance plan via GreenCo, rather than as part of NCEMC’s IRP. The Commission approved that request on August 27, 2008.

In its IRP filing, NCEMC stated that it would monitor the EE market research and program pilots conducted in connection with GreenCo and revise its estimates of needed power supplies accordingly.

NCEMC stated that it had invested in a statewide load management system on behalf of its members in the mid 1980s. That system uses radio signals to control residential air conditioners and water heaters and also to control customer-owned generation. Several EMCs also operate direct load control of heating systems. As a result, NCEMC is able to reduce demand by nearly 10% during peak periods, or 110 MW in 2007. Because the infrastructure for its load control switches has become obsolete, NCEMC is evaluating new DSM technologies and is looking to leverage the advanced metering infrastructure capabilities of member systems to develop programs that go beyond their current programs.

8. Piedmont EMC

As noted earlier, on August 18, 2008, Piedmont EMC requested a waiver such that its REPS compliance plan would be filed by GreenCo. The Commission granted that waiver on August 27, 2008.

In its IRP, Piedmont EMC noted that its DSM programs allow it to control about 9.5 MW of load in the summer and 6.8 MW in the winter via load control switches on air conditioners (9,300) and water heaters (6,200). Piedmont also has 430 residential and 23 commercial customers participating in time-of-use rates.

Piedmont EMC stated that it offers loans to members to replace inefficient heat pumps with high-efficiency heat pumps. They also offer a discount rate to members whose homes meet certain EE standards. Piedmont EMC offers free residential energy audits, free evaluations of members’ HVAC systems, audits for commercial and

⁸ Halifax EMC is not a participating GreenCo member organization.

⁹ See Appendix C for a list of NCEMC’s members.

industrial customers, school programs, a speakers' bureau, and education via its newsletter, brochures and web sites.

Through GreenCo, Piedmont EMC will participate in EE pilots. Piedmont EMC stated that it is an Energy Star^R Partner with the US EPA and DOE via which it will promote Energy Star^R EE products and programs.

9. Progress

In May 2007, Progress announced a goal of doubling its peak load reduction capability of about 1,000 MW through DSM and EE. Progress stated that its plan had the potential to displace the need for 1,140 MW of new electric generation over the next 10 years. To that end, Progress commissioned a DSM and EE potential assessment study that will identify the universe of programs and measures available to meet Progress's needs. Progress stated that it intends to use the rate impact measure (RIM) test to evaluate potential new DSM programs and the total resource cost (TRC) and utility cost tests (UCT) to evaluate potential new EE programs. To support its load reduction goal, Progress launched a consumer education campaign, "Save The Watts," which includes website, print and broadcast media. In addition, Progress stated that it had significantly expanded its DSM and EE organization. Progress stated that it had the following existing EE programs:

1. On-line account access
2. "Lower My Bill" toolkit
3. Energy saving tips on line
4. Home energy check (mail-in and on-line)
5. Energy efficient home
6. Contractor training for Energy Star^R standards
7. Home energy loans
8. Energy resource center on-line for commercial, industrial and government customers
9. Commercial, industrial and government account management

Similarly, Progress stated that it had the following existing DSM programs:

1. Time-of-use rates
2. Thermal energy storage rates
3. Real-time pricing
4. Curtailable rates
5. Voltage control

Progress noted that on April 29 and May 1, 2008, it filed with the Commission for approval of two new DSM programs and three new EE programs:

1. Distribution system demand response (DSDR)
2. Residential EnergyWiseTM

3. Residential home advantage new construction
4. Commercial, industrial and governmental new construction
5. Commercial, industrial and governmental comprehensive retrofit

These filings are discussed further in Section 3 of this report.

10. Rutherford EMC

On August 27, 2008, Rutherford EMC filed notice with the Commission that it has a long-term power supply contract with Duke and, therefore, Duke would be including Rutherford EMC in its REPS compliance plan.

Rutherford EMC's IRP stated that it has the following DSM programs:

1. Controllable customer-owned generation (13.5 MW)
2. Time-of-use rates
3. Switches to control air conditioners (8,836) and water heaters (14,072) which provide 8 MW of demand reduction¹⁰

In terms of EE, Rutherford EMC stated that it provided 805 members with compact fluorescent light bulbs in 2007 and also gives them to members who complain about high bills and are visited by Rutherford EMC's service personnel.

SECTION 3: NEW DSM AND EE PROGRAMS

Electric utilities whose rates are regulated by the Commission and that desire to recover DSM and EE program costs via an annual rider are required to file, for Commission approval, new DSM and EE programs. This section discusses the new programs filed with the Commission.

1. New DSM and EE Programs Proposed by Duke

On May 7, 2007, Duke filed its "save-a-watt proposal"¹¹ in which it requested approval of a portfolio of EE and DSM programs and a rider to compensate and reward the Company for EE results. (Duke's incentive and rider proposal are discussed more thoroughly in Section 4 of this report.) Duke proposed the following new programs, all of which have been approved by the Commission:

¹⁰Rutherford EMC stated that the control of water heaters was discontinued as of February 1, 2008 "since the incentives from Duke Power were cancelled."

¹¹For more information, see Docket No. E-7, Sub 831.

EE Programs		Procedural History	Program Costs and Time Period
1	Residential energy assessments	Filed 5/7/2007 Approved 2/26/2009	\$15.5 Million 2009-2013
2	Residential smart saver	Filed 5/7/2007 Approved 2/26/2009	\$22.0 Million 2009-2013
3	Low income services	Filed 5/7/2007 Approved 2/26/2009	\$24.5 Million 2009-2013
4	Energy efficiency education schools program	Filed 5/7/2007 Approved 2/26/2009	\$33.7 Million 2009-2013
5	Nonresidential energy assessments	Filed 5/7/2007 Approved 2/26/2009	\$50.6 Million 2009-2013
6	Nonresidential smart saver	Filed 5/7/2007 Approved 2/26/2009	Included in Number 5, above
DSM Programs			
7	Residential power manager	Filed 5/7/2007 Approved 2/26/2009	\$18.9 Million 2009-2013
8	Nonresidential powershare	Filed 5/7/2007 Approved 2/26/2009	\$34.6 Million 2009-2013

For these programs, Duke will spend almost \$200 million from 2009-2013.

Duke's M&V plan provides for an independent review and evaluation of its programs. Third-party evaluation professionals will design, manage, and supervise the M&V plan and evaluations. Evaluations will be based on engineering projections of savings, as well as actual field evaluations, metering, and monitoring. Duke intends to verify generally about 5% of the installed measures, focusing more on high-savings and high-priority measures. Most utilities across the country set verification levels for their programs from zero to 10% of installed measures. Duke's M&V plan conforms to the approaches described in the California Evaluation Protocols, National Action Plan for Energy Efficiency, and the International Performance Measurement and Verification Protocol.

Regarding the approval of Duke's new powershare program, the Commission decided to allow current customers on existing Duke Riders (1) Interruptible Service (IS) and (2) Standby Generation Control (SG) the opportunity to continue to participate in those DSM programs at their current contract levels. To do otherwise would require current customers under Riders IS and SG to terminate their participation in Duke's DSM programs altogether in order to exercise their right under G.S. 62-133.9(f) to opt out of Duke's cost recovery rider for new DSM and EE programs. The result of this all-or-nothing choice would likely be less DSM participation, not more – counter to the intent of Session Law 2007-397. New customers, however, as well as additional contract volumes from current Rider IS and Rider SG customers, will only be eligible to participate in powershare. In preserving this option for existing customers, the Commission will not require Duke to reopen current Rider IS to additional MW of participation.

2. New EE Programs Proposed by EnergyUnited EMC

On June 23, 2009, EnergyUnited EMC filed for approval of two programs: a residential heat pump rebate program and a commercial and industrial energy efficient lighting program. On July 23, 2009, the Public Staff requested an extension of time to review EnergyUnited EMC's proposals, citing issues involving the utility's cost-benefit tests. On July 29, 2009, the Commission granted the requested extension, and EnergyUnited EMC's proposed programs remain pending before the Commission at this time.¹²

3. New DSM and EE Programs Proposed by Progress

During the two fiscal years covered by this report, Progress filed for approval of nine DSM and EE programs or pilot programs. All have been approved by the Commission. For these programs Progress plans to spend almost \$430 million from 2007 – 2013.

EE Programs¹³		Procedural History	Program Costs and Time Period
1	Compact fluorescent light pilot	Filed 8/28/2007 Approved 9/19/2007	\$277,090 2007-2008
2	Commercial, industrial and governmental energy efficiency (new construction and retrofit)	Filed 5/1/2008 & 10/31/2008 Approved 10/14/2008 & 4/21/2009	\$59 million 2009-2013
3	Residential home advantage (new construction)	Filed 5/1/2008 Approved 10/14/2008	\$11.7 million 2008-2012
4	Residential home energy improvement (retrofit)	Filed 10/31/2008 Approved 4/30/2009	\$20 million 2009-2013
5	Residential solar water heating pilot	Filed 10/31/2008 Approved 4/30/2009	\$490,000 2009-2010
6	Neighborhood energy saver (low-income customers)	Filed 6/4/2009 Approved 8/3/2009	\$10 million 2009-2013
7	Distribution system demand response	Filed 4/29/2008 Approved 6/15/2009 Reconsideration pending	\$260 million 2007-2012
DSM Programs¹⁴			
8	Residential EnergyWise™	Filed 4/29/2008 Approved 10/14/2008	\$55.4 million 2008-2012
9	Commercial, industrial and governmental demand response automation	Filed 6/4/2009 Approved 8/3/2009	\$12.9 million 2009-2013

¹² For more information, see Docket No. EC-82, Sub 10.

¹³ For more information, see Docket No. E-2, Subs 908, 926, 928, 935, 936, 937, 938 and 952.

¹⁴ For more information, see Docket No. E-2, Subs 927, and 953.

Progress is required to file M&V reports to document the actual energy efficiency (MWh) and load reduction (MW) achieved by each program. On June 30, 2008, Progress filed an M&V report prepared by an independent consultant for the compact fluorescent light pilot. That report showed that the pilot achieved 6,706 MWh of annual energy savings and 630 kW of summer peak demand reduction. The report stated that these saving are expected to persist for 10 years.¹⁵ Progress will file M&V reports for its other EE and DSM programs over the next few years as enough installations have been achieved to result in a meaningful review.

Progress's distribution system demand response (DSDR) program presented significant policy issues for the Commission. One issue regards whether this program is appropriately designated as a DSM program or as an EE program. While Progress proposed DSDR as a DSM program, the Commission found in its Order that DSDR is an EE program because it will reduce customers' energy consumption during peak periods; i.e., it "results in less energy [being] used to perform the same function," which is the statutory definition of an EE program. The statutory definition of a DSM program is one that shifts the timing of electricity use from peak to nonpeak times. The Commission found that the DSDR program would not result in a substantial shifting of demand. The other significant policy issue presented by the DSDR program relates to cost allocation. The Commission concluded that DSDR's costs should be recovered from all retail customers that benefit; that is, all retail customers that receive power via Progress's distribution system, regardless of the "opt out" provision for industrial and large commercial customers contained in G.S. 62-133.9(f).

Several parties, including Progress, have asked the Commission to reconsider its June 15, 2009 Orders¹⁶ approving the program, and these requests are currently pending before the Commission. (See also page 20 of this report.)

On December 9, 2008, Progress, the Public Staff, Wal-Mart Stores East, LP and Sam's East, Inc. filed an agreement and stipulation of partial settlement in Progress's DSDR and DSM/EE rider and incentives proceedings. Among other things, this settlement detailed how Progress will evaluate and select potential new DSM and EE programs. Progress committed to contact each party to its most recent DSM/EE cost recovery proceeding by March 1 each year and provide them with a list and description of programs and measures either currently being considered or planned for future consideration, and seek suggestions for additional programs and measures for consideration. (This settlement is discussed in more detail in Section 4 of this report.)

¹⁵ For more information, see Docket No. E-2, Sub 908.

¹⁶ For more information, see Docket No. E-2, Subs 926 and 931.

SECTION 4: COMMISSION PROCEEDINGS REGARDING DSM/EE COST RECOVERY AND INCENTIVES FOR DUKE ENERGY CAROLINAS AND PROGRESS ENERGY CAROLINAS

1. Duke's DSM/EE Cost Recovery and Incentives Proposal

On May 7, 2007, Duke requested approval of a new “save-a-watt” approach to EE programs. In addition to approval of the new DSM and EE programs discussed in Section 3 of this report, Duke requested approval of an EE rider to compensate and reward it for verified energy efficiency results and to recover the amortization of, and a return on, 90% of the costs avoided by the save-a-watt approach. Under Duke’s proposal, the Commission would establish the rider and adjust it annually based upon updated projections of energy savings results, including projected incremental avoided costs and the actual energy savings achieved by Duke. Duke’s justification in support of its proposed rider was that recovery of 90% of avoided costs provides an appropriate incentive to Duke because it allows the Company a rate of return similar to investments in generation, yet offers a 10% discount to customers compared to the investment and on-going operations costs of electric generation facilities.

The Commission conducted evidentiary hearings in this matter beginning July 28, 2008. Many organizations intervened in opposition to Duke’s proposal, including the Public Staff and the Attorney General. Arguments opposing the proposal included that it would be too expensive for ratepayers; it would produce greater financial returns for Duke than are reasonable and necessary to encourage Duke to pursue DSM and EE; Duke’s avoided-cost-based compensation mechanism would be a major and unjustified departure from traditional rate regulation; under save-a-watt, DSM would be much more profitable than EE for Duke; save-a-watt is vastly different from and appears to be inferior to compensation methods used with electric utilities in other states; and Duke’s proposed accounting procedures and reporting format are flawed.

In an Order dated February 26, 2009, the Commission found that the evidence and arguments of the intervenors in opposition to save-a-watt were largely based on concerns regarding the earnings Duke would experience. ‘Such earnings, however, were not quantified and/or expressed, in most instances, in conventional terms of art customarily employed in rate base, rate-of-return regulation, such as “overall rate of return” and/or “return on common equity.”’ The Commission, therefore, issued an Order approving Duke’s proposed portfolio of EE and DSM programs; requesting information on unsettled matters including more data regarding the profitability of save-a-watt for Duke; and allowing the proposed rider to become effective, subject to refund.

The Commission’s Order required Duke to file supplemental information regarding the profitability of save-a-watt by March 31, 2009. The Commission requested that the Public Staff review the information and file comments by May 1, 2009. The Commission allowed Duke to implement its proposed Rider EE, subject to refund with interest if the Commission’s final order in this matter sets rates at lower levels. Effective June 1, 2009, the following Rider EE charges took effect:

Residential	0.0382 cents/kWh
Non-residential	0.0068 cents/kWh

On June 12, 2009, Duke, the Public Staff and a group of Environmental Intervenors¹⁷ filed an agreement and joint stipulation of settlement, which is currently pending before the Commission. The settlement continues to include a provision to compensate Duke for successful DSM and EE programs based on a discount to the avoided costs of a power plant, rather than Duke's actual costs to implement the programs. In addition, the settlement contains a "pay for performance" feature in which Duke's compensation would depend upon actual DSM and EE savings achieved and verified by an independent third party. Duke would remain at risk, based upon its actual performance, for recovery of its DSM and EE costs, as well as any management incentive. The settlement includes performance targets such that Duke would receive a higher level of incentive based on how well it achieves DSM and EE savings that result in bill savings for customers. Duke increased the amount of EE avoided cost savings it will target to achieve. The settlement is proposed as a four-year limited term pilot. The Company's revenues recovered on the basis of percentages of avoided costs are limited to the amount needed to produce an after-tax return on program costs between 5% and 15%, depending on its success in reaching a targeted aggregate EE and DSM avoided cost savings level. In addition, the amount of net lost revenues Duke may recover is limited to those incurred within 36 months of implementation of a particular measure, and recovery of net lost revenues is separate, and, hence, more transparent than it was under Duke's initial proposal. The settlement states that it shields ratepayers from the risk of tying rates to unknown and variable supply-side avoided costs by locking in the per-MWh and per-MW-year avoided costs (with certain exceptions).

Under the settlement, based on 85% achievement of its DSM/EE targets, Duke stated that customer Rider EE charges would be as follows:¹⁸

Customer Class	Year 1	Year 2	Year 3	Year 4
Residential	\$0.001206/kWh	\$0.001749/kWh	\$0.002787/kWh	\$0.004027/kWh
Non-Residential	\$0.000428/kWh	\$0.000579/kWh	\$0.000969/kWh	\$0.001339/kWh

The Commission required the stipulating parties to file expert witness testimony to explain the settlement, invited testimony from other intervenors, and scheduled evidentiary hearings beginning August 19, 2009, to consider the settlement. The Commission's decision in this matter is currently pending.

¹⁷The Environmental Intervenors include the Southern Alliance for Clean Energy, the Environmental Defense Fund, the Natural Resources Defense Council and the Southern Environmental Law Center.

¹⁸The rates cited include charges for gross receipts tax and regulatory fee.

2. Progress's DSM/EE Cost Recovery and Incentives Proposal

On June 6, 2008, Progress filed an application for approval of an annual DSM and EE cost recovery rider, its first such request under G.S. 62-133.9.¹⁹ Progress initially requested an annual revenue increase of \$42.6 million, effective December 1, 2008. Progress reduced its overall request to \$41.6 million August 20, 2008. Progress's request was for costs and utility incentives relative to six programs:

- 1) Compact fluorescent light pilot
- 2) Residential home advantage
- 3) Commercial, industrial and governmental new construction
- 4) Commercial, industrial and governmental retrofit (subsequently merged with the new construction program)
- 5) Distribution system demand response (DSDR)
- 6) Residential EnergyWise™

Of the \$41.6 million that Progress requested, \$1 million was for a "net lost revenue" incentive and \$6 million was for a "shared savings" incentive. The shared savings incentive would have been recovered from customers over 10 years and would have equaled 50% of the net present value of savings achieved over the lifetime of a measure, using the utility cost test method to calculate a program's net benefits.

On September 17, 2008, the Commission held a hearing for the purpose of taking testimony from interested members of the public. No public witnesses appeared, despite publication of notice.

On November 14, 2008, the Commission approved Progress's request to put its proposed rider into effect effective December 1, 2008, subject to refund with interest pending the final resolution of the proceeding. Also on November 14, 2008, Progress revised its request by proposing to capitalize its DSM and EE costs, as well as incentives, over 10 years as allowed by G.S. 62-133.9(d)(1), while earning a carrying charge on the unrecovered amounts pursuant to Commission Rule R8-69(b)(6). This reduced the first year revenue requirement of Progress's rider request from \$41.6 million to \$14.8 million by pushing costs into future years.

The following organizations intervened in Progress's DSM/EE rider proceeding:

- Attorney General
- Carolina Industrial Group for Fair Utility Rates II (CIGFUR II)
- Carolina Utility Customers Association, Inc. (CUCA)
- Environmental Defense Fund (EDF)
- Natural Resources Defense Council (NRDC)
- NC WARN

¹⁹ For more information, see Docket No. E-2, Sub 931.

- North Carolina Sustainable Energy Association (NCSEA)
- Public Staff
- Southern Alliance for Clean Energy (SACE)
- Southern Environmental Law Center (SELC)
- Wal-Mart Stores East, LP and Sam's East, Inc. (Wal-Mart)

On December 9, 2008, Progress, the Public Staff and Wal-Mart filed an agreement and stipulation of partial settlement that addressed most, but not all, of the issues among the three parties relative to the rider, as well as Progress's proposed DSDR program. Among the more important issues addressed, the settlement:

- 1) Implicitly set the annual revenue requirement for the year ending November 30, 2009, at \$10.4 million, down from \$14.8 million in Progress's revised request.
- 2) Set requirements for screening and selecting new DSM and EE programs.
- 3) Allowed for recovery of costs related to new DSM and EE programs over 10 years with a carrying charge.
- 4) Allowed Progress to collect from customers two financial incentives for pursuing DSM and EE: three years worth of net lost revenues, and a "program performance incentive."
- 5) Would be subject to review and potential modification at least every three years.

On January 7 and 8, 2009, the Commission conducted a formal hearing and took testimony from expert witnesses. The NCSEA, the Environmental Intervenors²⁰ and the Attorney General argued that the settlement did not provide for performance targets that had to be met before Progress could earn an incentive. The Environmental Intervenors also argued that Progress's incentives under the settlement are unreasonable because they are not commensurate with the Company's risk.

With regard to one unsettled issue, the Public Staff disagreed with Progress's approach to allocating DSM and EE costs among customer classes. Progress and the Public Staff disagreed as to how to interpret G.S. 62-133.9(e), which states as follows:

The Commission shall determine the appropriate assignment of costs of new demand-side management and energy efficiency measures for electric public utilities and shall assign the costs of the programs only to the class or classes of customers that directly benefit from the programs.

The Public Staff argued that the direct benefits of DSM and EE programs are the system benefits of fewer power plants and lower operating costs, and therefore all customer classes should be required to pay for all of Progress's DSM/EE costs based on their share of system benefits. Progress, on the other hand, argued that the General

²⁰The Environmental Intervenors include the Southern Alliance for Clean Energy, the Environmental Defense Fund, the Natural Resources Defense Council and the Southern Environmental Law Center.

Assembly intended that the costs of a program or measure are to be recovered from those customer classes that are eligible to participate in the program.

On June 15, 2009, the Commission issued an Order approving the settlement with modifications. The Commission disallowed recovery of any incentives for Progress's compact fluorescent light pilot and required Progress to amortize and recover its DSM/EE related administrative and general costs over three years, rather than over ten years. The Commission ordered that DSDR costs be recovered from all retail customers that benefit from DSDR, that is, all retail customers that receive power via Progress's distribution system, regardless of the "opt out" provision for industrial and large commercial customers in G.S. 62-133.9(f). The Commission's Order required the Public Staff to monitor and review Progress's incremental administrative and general costs on an ongoing basis, with particular emphasis on the effectiveness of the Company's general EE education programs, and report its findings to the Commission during Progress's future DSM/EE rider proceedings. The Commission agreed with Progress that the Assembly intended program costs to be recovered from the specific class(es) of customers eligible to participate in a given program. Finally, unless requested to do so earlier, the Commission will initiate a formal review of Progress's rider and incentive mechanisms no later than June 1, 2012.

On July 13, 2009, Progress filed a motion for reconsideration regarding the Commission's order in Progress's DSM/EE rider and incentives proceeding, as well as in its DSDR program application.²¹ Progress requested that the Commission reconsider its decisions relative to:

- 1) requiring industrial and large commercial customers to pay a portion of DSDR costs;
- 2) allocating DSDR costs between North and South Carolina based on demand; and
- 3) reporting requirements.

On July 13, 2009, CUCA also filed a motion for reconsideration in the two proceedings. On that same day, Wal-Mart filed a motion for reconsideration and notice in both proceedings. And on July 14, 2009, CIGFUR II filed a motion for reconsideration in both proceedings. On July 20, 2009, the Commission requested comments and reply comments from parties regarding the motions. On August 24, 2009, the Commission scheduled the motions for reconsideration for oral argument on September 16, 2009.

On June 4, 2009, Progress filed its second annual application for approval of DSM/EE rider.²² The Commission has scheduled this request for public hearing to be held September 16, 2009, in Raleigh, and required Progress to publish a newspaper notice of the hearing at least 30 days in advance of the hearing date. Progress is

²¹ Docket No. E-2, Subs 926 and 931.

²² Docket No. E-2, Sub 951.

requesting to recover \$24.2 million for costs and utility incentives associated with the nine DSM and EE programs listed in the table on page 14 of this report.

On July 27, 2009, Progress filed its compliance filing relative to the Commission's June 14, 2009 orders in Docket No. E-2, Subs 926 and 931. In that compliance filing, Progress proposed to set customer rates as shown in the third column below, labeled "compliance billing rate." The last column, "proposed new rate," shows Progress's proposed second annual DSM/EE rider rates, updated to comply with the Commission's decisions in Docket No. E-2, Sub 931.

Rate Class	Current Billing Rate ¹	Compliance Billing Rate ²	Proposed New Rate ³
Residential	0.074 cents/kWh	0.054 cents/kWh	0.060 cents/kWh
General Service	0.047 cents/kWh	0.045 cents/kWh	0.065 cents/kWh
Lighting	0.000 cents/kWh	0.030 cents/kWh	0.063 cents/kWh

¹DSM/EE rider charges in effect since December 1, 2008, subject to refund.

²DSM/EE rider charges reflecting the Commission's decisions relative to Progress's first DSM/EE rider request.

³DSM/EE rider charges that reflect the Commission's decisions relative to Progress's first DSM/EE rider request, as well as Progress's second annual DSM/EE rider request. Progress proposes that these rates take effect December 1, 2009. These rates include the impact of gross receipts tax and regulatory fee.

Progress requested that any rate changes from its first DSM/EE rider request be postponed until December 1, 2009, to coincide with changes pursuant to its second DSM/EE rider request, as well as the Commission's decisions regarding the pending requests for reconsideration. Progress's request in this regard is pending before the Commission.

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 Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.; Duke Energy Carolinas, LLC; Virginia Electric and Power Company, d/b/a Dominion North Carolina Power; the North Carolina Electric Membership Corporation; and any individual electric membership corporation to the extent that it is responsible for procurement of any or all of its individual power supply resources.

(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 annual 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.** — Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.; Duke Energy Carolinas, LLC; and Virginia Electric and Power Company, d/b/a Dominion North Carolina Power shall provide information on levelized busbar costs for various generation technologies.

(j) **Review.** — Within 150 days after the filing of each utility's biennial report and within 60 days after the filing of each utility's annual report of amendments or revisions, 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 14 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.

(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.)

Rule 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) “Avoided cost rates” mean an electric power supplier’s most recently approved or established avoided cost rates in North Carolina, as of the date the contract is executed, for purchases of electricity from qualifying facilities

pursuant to the provisions of 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 such a 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; provided, however, that development of such estimates of avoided cost by an electric public utility shall include consideration of the avoided cost rates then in effect as established by the Commission. 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 and, unless approved otherwise by the Commission pursuant to subsection (c)(4), determined in the same manner as that information is reported to the Energy Information Administration (EIA), United States Department of Energy, for annual electric sales and revenues reporting.

(b) REPS compliance plan.

(1) Each year, beginning in 2008, each electric power supplier 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 at least the current and 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 planned or implemented energy efficiency measures, including a brief description of the measure and projected impacts;

(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) the electric power supplier's registration information and certified statements required by Rule R8-66, to the extent they have not already been filed with the Commission.

(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 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 and direct testimony and exhibits of expert witnesses:

(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 to comply with G.S. 62-133.8(b), (c), (d), (e) and (f);

(v) a comparison of actual compliance costs to the annual cost caps;

(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 to be carried forward pursuant to G.S. 62-133.8(b)(2)f or (c)(2)f;

(viii) For each renewable energy facility providing renewable energy certificates used by the electric power supplier to comply with G.S. 62-133.8(b), (c), (d), (e) and (f): the name, address, and owner of the renewable energy facility; and an affidavit from the owner of the renewable energy facility certifying that the energy associated with the renewable energy certificates was derived from a renewable energy resource, identifying the renewable technology used, and listing the dates and amounts of all payments received from the electric power supplier and all meter readings; and

(ix) for electric membership corporations and municipal electric suppliers, reduced energy consumption achieved after January 1, 2008, through the implementation of a demand-side management program.

(2) Each electric public utility shall file its annual REPS compliance report no later than 30 days prior to the time that it files 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 shall file an REPS compliance report on or before September 1 of each year. The Commission shall 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 additional 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.

(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).

(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 calendar year 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 may be collected through fixed monthly charges, energy-based amounts per kilowatt-hour, or by a combination of both. Each electric public utility shall ensure that the incremental costs recovered under the REPS rider and REPS EMF rider during the cost recovery period from any given customer account do not exceed the applicable per-account charges set forth in G.S. 62-133.8(h)(4).

(10) Incurred costs may be recovered by an electric public utility in any year after a renewable energy certificate is acquired or obtained until the renewable energy certificate is used to comply with G.S. 62-133.8(b), (d), (e) and (f) as long as the electric public utility's total annual incremental costs incurred in that year do not exceed the per-account annual charges provided in

G.S. 62-133.8(h)(4). Incremental costs that exceed the per-account annual charges provided in G.S. 62-133.8(h)(4) in the year in which a renewable energy certificate is used to comply with G.S. 62-133.8(b), (d), (e) and (f) may not be recovered. 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 certificates, 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.

(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 with a nameplate capacity of 1 MW or less interconnected behind the utility meter at a customer's location may be measured accurately by an ANSI-certified electric meter not provided by an electric power supplier. The data provided by this meter may be read and self-reported by the owner of the renewable energy facility. The owner of the meter shall comply with the meter testing requirements of Rule R8-13.

(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 megawatt-hour for every 3,412,000 British thermal units of useful thermal energy produced.

(5) Except in those cases where the electric meter is supplied by and read by an electric power supplier, electric generation or thermal energy production data is subject to audit by the Commission, the Public Staff, or an electric power supplier.

(NCUC Docket No. E-100, Sub 113, 2/29/08; NCUC Docket No. E-100, Sub 113, 3/13/08.)

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

(a) Purpose. — The purpose of this rule is to establish guidelines for the application of G.S. 62-140(c) 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 (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 utility; 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 proposed to be used, (e) the proposed classes of persons to whom it will be offered, and (f) the duration of the proposed measure or program.

(ii) Description. — The electric public utility or electric membership corporation shall describe each measure or program, impact of 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.

(iii) 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 advertising) and the planned accounting treatment for those costs and benefits; (b) the type, amount, and 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.

(iv) 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.

(v) Communications. — The electric public utility or electric membership corporation shall provide detailed cost information on the amount it anticipates will be spent 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. To the extent available, the electric public utility or electric membership corporation shall include examples of all communication materials to be used in conjunction with the measure or program.

(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) Description. — The electric public utility shall describe:
 - a. the measure's objective;
 - b. total market potential;
 - c. the proposed marketing plan;
 - d. the targeted sector;

- e. estimated market growth throughout the life of the measure;
- f. estimated summer and winter peak demand reduction by unit metric and in the aggregate by year;
- g. estimated energy reduction per appropriate unit metric and in the aggregate by year;
- h. estimated lost energy sales per appropriate unit metric and in the aggregate by year;
- i. estimated load shape impacts;
- j. a description of market barriers to the proposed measure or program and how the electric public utility intends to address them;
- k. a description of how the measure's impacts will be evaluated, measured, and verified; and
- l. a description of 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.

(ii) 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; and benefits of the measure among the customer classes and jurisdictions it serves; and

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

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).

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 (iii).

(iii) Measurement and Verification Reporting Plan for New Demand-Side Management and Energy Efficiency Measures. — The electric public utility shall describe the industry-accepted methods to be used to measure, verify, and validate the energy and peak demand savings estimated in paragraph (i) above and shall provide a schedule for reporting the savings to the Commission. 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. If the electric public utility plans to utilize an independent third party for purposes of measurement and verification, an identification of the third party and all of the costs of that third party should be included. The costs of implementing the measurement and verification process may be considered as operating costs.

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

(v) 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.

(vi) 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.

(d) Procedure.

(1) 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 or file a protest pursuant to Rule R1-6. The filing electric public utility or electric membership corporation shall have the opportunity to respond to the petitions or protests 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.

(2) 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. — Except for those costs found by the Commission to be unreasonable or imprudently incurred, the costs of new demand-side

management or energy efficiency measures approved by application of this rule shall be recovered through the annual rider described in G.S. 62-133.9 and Rule R8-69. The Commission may also consider in the annual rider proceeding whether to approve any utility incentive pursuant to G.S. 62-133.9(d)(2)a-c.

(NCUC Docket No. E-100, Sub 113, 2/29/08; NCUC Docket No. E-100, Sub 113, 3/13/08.)

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

(a) Definitions.

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

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

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

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

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

(b) Recovery of Costs.

(1) Each year the Commission shall conduct a proceeding for each electric public utility to establish an annual DSM/EE rider. The DSM/EE rider shall consist of a reasonable and appropriate estimate of the expenses expected to be incurred by the electric public utility, during the rate period, for the purpose of adopting and implementing new demand-side management and energy efficiency measures previously approved pursuant to Rule R8-68. The expenses will be further modified through the use of a DSM/EE experience modification

factor (DSM/EE EMF) rider. The DSM/EE EMF rider will reflect the difference between the reasonable expenses prudently incurred by the electric public utility during the test period for that purpose and the revenues that were actually realized during the test period under the DSM/EE rider then in effect. Those expenses approved for recovery shall be allocated to the North Carolina retail jurisdiction consistent with the system benefits provided by the new demand-side management and energy efficiency measures and shall be assigned to customer classes in accordance with G.S. 62-133.9(e) and (f).

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

(3) Pursuant to G.S. 62-130(e), any over-collection of reasonable and prudently incurred costs to be refunded to an electric public utility's customers through operation of the DSM/EE EMF rider shall include an amount of interest, at such rate as the Commission determines to be just and reasonable, not to exceed the maximum statutory rate.

(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. However, deferral accounting of costs shall not affect the Commission's authority under this rule to determine whether the deferred costs may be recovered.

(7) In approving the first annual rider pursuant to G.S. 62-133.9 for Duke Energy Carolinas, LLC, the Commission shall consider the treatment it approved in Docket No. E-7, Sub 828, of the revenues and costs related to Duke Energy Carolinas' existing demand-side management and energy efficiency measures or programs.

(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 it has implemented or, in accordance with stated, quantifiable goals, will implement alternative demand-side management or energy efficiency measures. Any such customer may elect not to participate in new demand-side management and energy efficiency measures under G.S. 62-133.9(f). Any customer that elects this option and notifies its electric public utility will, after the date of notification, be exempt from any annual rider established pursuant to this rule.

(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.

(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 the 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). Within 30 days of the customer's election, the electric public utility shall notify the Commission of an industrial or large commercial customer that elects to participate in a new measure after having initially notified the electric public utility that it declined to participate.

(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 capacity, energy, and measure unit metric and in the aggregate; and

e. total expected energy reduction in the aggregate and per appropriate capacity, energy and 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 per appropriate capacity, energy, and measure unit metric and in the aggregate, as well as any changes in estimated future amounts;

e. total energy reduction in the aggregate and per appropriate capacity, energy and 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 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.)

MEMBERS OF GREENCO SOLUTIONS, INC.

Albemarle Electric Membership Corporation
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Brunswick Electric Membership Corporation
Cape Hatteras Electric Cooperative
Carteret-Craven Electric Cooperative
Central Electric Membership Corporation
Edgecombe-Martin County Electric Membership Corporation
Four County Electric Membership Corporation
French Broad Electric Membership Corporation
Haywood Electric Membership Corporation
Jones-Onslow Electric Membership Corporation
Lumbee River Electric Membership Corporation
Pee Dee Electric Membership Corporation
Piedmont Electric Membership Corporation
Pitt & Green Electric Membership Corporation
Randolph Electric Membership Corporation
Roanoke Electric Cooperative
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Surry-Yadkin Electric Membership Corporation
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