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NORTH CAROLINA
PUBLIC STAFF
UTILITIES COMMISSION

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Clerk's Office
N.C Utilities Commission

February 10, 2011

Ms. Renné C. Vance, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4325

Re: Docket No. E-100, Subs 128 and 129

Dear Mrs. Vance:

Enclosed for filing are twenty-one (21) copies of the confidential version of the Public Staff's comments and two (2) copies of the redacted public version.

Confidential information is located on pages 22, 26, 27, 31, and 33.

By copy of this letter, I am forwarding a copy of the redacted public version to all parties of record.

Yours very truly,

Lucy E. Edmondson

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Staff Attorney
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cc: Parties of Record

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

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N.C. Utilities Commission

DOCKET NO. E-100, SUB 128
DOCKET NO. E-100, SUB 129

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 128 In the Matter of Investigation of Integrated Resource Planning in North Carolina – 2010 DOCKET NO. E-100, SUB 129 In the Matter of 2010 REPS Compliance Plans and 2009 Compliance Reports	COMMENTS OF THE PUBLIC STAFF

NOW COMES THE PUBLIC STAFF – North Carolina Utilities Commission, by and through its Executive Director, Robert P. Gruber, and submits the following comments pursuant to Commission Rule R8-60(j). These comments address the 2010 biennial reports regarding the integrated resource planning documents (IRPs) filed by the following investor-owned utilities (IOUs): Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. (PEC); Duke Energy Carolinas, LLC (Duke); Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP); and the electric membership corporations (EMCs): the North Carolina Electric Membership Corporation (NCEMC); Rutherford EMC (Rutherford), Piedmont EMC (Piedmont), Haywood EMC (Haywood), and EnergyUnited EMC (EU). In addition, these comments address the Renewable Energy and Energy Efficiency Portfolio Standard (REPS) compliance plans filed by the State's municipal electric systems, which are not required to file IRPs,[1] GreenCo Solutions, Inc. (GreenCo),[2] Halifax EMC (Halifax), EU, and EMCs that serve North Carolina customers but are headquartered outside the State.

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[1] Pursuant to Commission Rule R8-67(b)(4), REPS compliance plans submitted by an electric power supplier not subject to Commission Rule R8-60, such as a municipal electric supplier, are for information only.

[2] GreenCo filed a consolidated 2010 REPS Compliance Plan on behalf of Albemarle EMC, Brunswick EMC, Cape Hatteras EMC, Craven-Carteret EMC, Central EMC, Edgecombe-Martin County EMC, Four County EMC, French Broad EMC (French Broad), Haywood, Jones-Onslow EMC, Lumbee River EMC, Pee Dee EMC, Piedmont, Pitt & Greene EMC, Randolph EMC, Roanoke EMC, South River EMC, Surry-Yadkin EMC, Tideland EMC, Tri-County EMC, Union EMC, and Wake EMC.

I. INTRODUCTION

Several statutes and Commission rules guide the Commission's review of the electric utilities' planning. G.S. 62-110.1(c) requires the Commission to "develop, publicize, and keep current an analysis of the long-range needs" for electricity in this State. The Commission's analysis should include: (1) its estimate of the probable future growth of the use of electricity; (2) the probable needed generating reserves; (3) the extent, size, mix, and general location of generating plants; and (4) arrangements for pooling power to the extent not regulated by the Federal Energy Regulatory Commission (FERC). G.S. 62-110.1 further requires the Commission to consider this analysis in acting upon any petition for construction. In addition, G.S. 62-110.1 requires the Commission to submit annually to the Governor and to the appropriate committees of the General Assembly: (1) a report of the Commission's analysis and plan; (2) the progress to date in carrying out such plan; and (3) the program of the Commission for the ensuing year in connection with such plan. G.S. 62-15(d) requires the Public Staff to assist the Commission in this analysis and plan.

In addition, G.S. 62-2(a)(3a) vests the Commission with the duty to regulate public utilities and their expansion in relation to long-term energy conservation and management policies. These policies include assuring that "resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions."

A. Docket No. E-100, Sub 128

On August 20, 2010, Rutherford filed a letter indicating that it had a long-term power supply agreement with Duke, its load would be reported for filing purposes within Duke's IRP, its renewable energy requirements under the REPS would be provided by Duke, and its REPS requirements would be reflected in Duke's REPS 2010 Compliance Plan. Also on August 20, 2010, PEC moved to extend the filing date for its IRP to September 12, 2010. This motion was granted by the Commission on September 1, 2010. On August 27, 2010, EU filed its 2010 IRP, its 2008 and 2009 REPS Compliance Reports, and its 2010 REPS Compliance Plan. On August 31, 2010, Halifax filed for an extension of time to file its 2010 REPS Compliance Plan and 2009 REPS Compliance Report. The Commission by Order issued on September 14, 2010, granted Halifax an extension to file these documents up to and including October 15, 2010. On August 31, 2010, Haywood filed its 2010 IRP. On September 1, 2010, Duke and DNCP filed their 2010 IRPs and REPS Compliance Plans; GreenCo filed a compliance plan on behalf of its members; and Piedmont, NCEMC, and Rutherford filed their 2010 IRPs. On September 12, 2010, PEC filed its 2010 IRP and REPS Compliance Plan. On October 15, 2010, Halifax filed its 2010 REPS Compliance Plan and 2009 REPS Compliance Report.

By Order dated December 3, 2010, the Commission scheduled a public hearing for January 24, 2011, on the filed IRPs and REPS compliance plans. On December 13, 2010, the Southern Alliance for Clean Energy (SACE) requested an evidentiary hearing on issues to be identified by the Commission. On December 17, 2010, the North Carolina Waste Awareness Reduction Network (NC WARN) made a filing in support of SACE's request for an evidentiary hearing. On December 28, 2010, PEC moved that the Commission delay ruling on SACE's request until SACE and NC WARN had identified elements of the electric power suppliers' IRPs with which they disagree and allow parties to respond to the identification of issues. On January 13, 2011, the Public Staff moved that the deadline for the filing of comments on IRPs be extended to February 10, 2011. The Commission granted this Motion on January 19, 2011. On January 24, 2011, the public hearing was held as scheduled.

In addition to the Public Staff, the following parties have intervened in Docket No. E-100, Sub 128: the Carolina Industrial Group for Fair Utility Rates I, II, III (CIGFUR); the North Carolina Sustainable Energy Association (NCSEA), the Public Works Commission of the City of Fayetteville (Fayetteville); Nucor Steel-Hertford; NC WARN; SACE; the Carolina Utility Customers Association, and the Attorney General.

B. Docket No. E-100, Sub 129

On August 23, 2010, Fayetteville filed a motion for an extension of time through October 15, 2010, to file its 2010 REPS Compliance Plan and 2009 REPS Compliance Report. The Commission granted this motion on August 24, 2010. On August 24, 2010, the Tennessee Valley Authority (TVA) filed a request to be designated as a utility compliance aggregator for Blue Ridge Mountain EMC, the Town of Murphy, Tri-State EMC, and Mountain Electric Cooperative; for waiver of certain filing requirements; and for extension of the filing date for the REPS compliance reports and plans to November 15, 2010. The Commission granted these motions on September 7, 2010. On August 25, 2010, the City of Kings Mountain filed a letter with the Commission indicating that it had a long term power supply agreement with Duke and that Duke had agreed to provide information and file any reports applicable to the City of Kings Mountain required for compliance with the REPS. The City of Concord filed a letter on September 2, 2010, indicating that it had a similar arrangement with Duke. On August 31, 2010, the Towns of Winterville and Oak City moved for an extension of the deadline for the filing of their REPS compliance plans and reports to October 15, 2010. The Commission granted these motions on September 14, 2010. On September 1, 2010, 2009 REPS compliance plans and 2010 REPS compliance reports were filed by the North Carolina Eastern Municipal Power Agency (NCEMPA) and the North Carolina Municipal Power Agency 1 (NCMPA1). On September 7, 2010, the Town of Windsor filed a letter indicating that its REPS requirements would be met by DNCP under its full requirements contract. On October 13, 2010, the Towns of Winterville and Oak City filed their 2010 REPS compliance plans and 2009 REPS compliance reports. On October 15, 2010, Fayetteville filed its 2010 REPS Compliance Plan and 2009 REPS Compliance Report. On November 12, 2010, TVA filed a 2010 REPS compliance plan and 2009 compliance report.

C. Senate Bill 3 and Commission Rules

Senate Bill 3

Senate Bill 3 (SB3) expanded the Commission's review of electric utilities' planning. First, subsection (a)(10) of SB3 provides that it is the policy of North Carolina "to promote the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard" that will: (1) diversify the resources used to reliably meet the energy needs of North Carolina's consumers, (2) provide greater energy security through the use of indigenous energy resources available in North Carolina, (3) encourage private investment in renewable energy and energy efficiency (EE), and (4) provide improved air quality and other benefits to the citizens of North Carolina. To that end, SB3 requires that each IOU, EMC, and municipality in North Carolina be subject to REPS compliance, through the use of new renewable supply-side resources, demand-side management (DSM) or EE, to varying extents. Through SB3, the Commission is required to submit a report to the Governor, the Environmental Review Commission, and the Joint Legislative Utility Review Committee on the compliance with the REPS requirements by the IOUs, EMCs, and municipalities every year.

SB3 further provides that "[e]ach electric power supplier to which G.S. 62-110.1 applies shall include an assessment of demand-side management and energy efficiency in its resource plans submitted to the Commission and shall submit cost-effective demand-side management and energy efficiency options that require incentives to the Commission for approval."[3] It specifically defines DSM as "activities, programs, or initiatives undertaken by an electric power supplier or its customers to shift the timing of electric use from peak to nonpeak demand periods" and an EE measure as "an equipment, physical or program change implemented after 1 January 2007 that results in less energy being used to perform the same function."[4] EE measures do not include DSM.[5] The Public Staff will rely upon these statutory definitions in these comments.

Commission Rules

To meet the requirements of G.S. 62-110.1, G.S. 62-2(3a), and SB3, the Commission conducts an annual investigation into the electric utilities' IRPs and REPS compliance. With regard to the IRPs, Commission Rule R8-60 requires that each of the electric utilities furnish the Commission with a biennial report in even-numbered years that contains the specific information set out in Rule R8-60(i). R8-60(h)(2) further requires that in each year in which a biennial report is not filed, "an annual report shall be filed with the Commission containing an updated 15-year forecast . . . as well as

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[3] G.S. 62-133.8(c).

[4] G.S. 62-133.7(a)(2) and (a)(4).

[5] G.S. 62-133.7(a)(4).

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." In addition, Commission Rule R8-62(p) requires that the electric utilities incorporate information in their IRP reports concerning the construction of transmission lines.

Commission Rule R8-60(h)(4) requires that each biennial and annual report include the utility's REPS compliance plan pursuant to R8-67(b). Rule R8-67(b)(3) requires that IOUs and EMCs file their REPS compliance plans as part of their IRP filings and that the Commission review and approve those plans pursuant to R8-60. According to R8-60(h)(4), approval of the REPS compliance plan as part of the IRP does not constitute an approval of the recovery of costs associated with the plan or a determination that the electric power supplier has complied with the REPS requirements. Furthermore, Commission Rule R8-67(b)(4) requires municipalities to file their REPS compliance plans for information only; they are not subject to Commission Rule R8-60.

In the following comments, in addition to addressing the IRPs and REPS compliance plans filed by the IOUs, the Public Staff addresses the IRPs filed by NCEMC, Piedmont, Rutherford, EU, and Haywood and the REPS compliance plans filed by GreenCo, Halifax, and EU in Docket No. E-100, Sub 128, pursuant to Rule R8-60.[6]

II. PEAK AND ENERGY FORECASTS

All of the utilities use accepted econometric and end-use analytical models to forecast their peak and energy needs. As with any forecasting methodology, there is a degree of uncertainty associated with models that rely, in part, on assumptions that certain historical trends or relationships will continue in the future.

The Public Staff has reviewed the utilities' 15-year peak and energy forecasts (2011–2025). The compound annual growth rates (CAGRs) for the forecasts of PEC, Duke, and DNCP are within the range of 1.2% to 1.8%. The CAGRs for NCEMC and the four independent EMCs that filed IRPs, EU, Haywood, Piedmont, and Rutherford, are within the range of 1.2% to 2.2%. The utilities' DSM and EE programs are discussed briefly below and fully in the DSM/EE section.

[6] French Broad and Blue Ridge EMC (Blue Ridge) did not file IRPs, although NCEMC did include French Broad's load forecast as an appendix to its IRP. Blue Ridge advised the Commission in a letter of July 6, 2009, that it would no longer file IRPs because it had entered into a full requirements power purchase agreement with Duke, and likewise French Broad purchases all of its power requirements from PEC. Prior to 2007, Commission Rule R8-60(b) provided that the requirement to file IRPs applied only to PEC, Duke, DNCP and NCEMC. In that year the Commission amended subsection (b), in Docket No. E-100, Sub 111, to state that the requirement also applied to "any individual electric membership corporation to the extent that it is responsible for procurement of any or all of its individual power supply resources." The Public Staff believes that French Broad and Blue Ridge, which are responsible for procuring their own power supply resources, are now required by subsection (b) to file IRPs and should begin filing them next year.

In assessing the reasonableness of the forecasts, the Public Staff first compared the most recent actual peak loads to the utilities' forecasts in the 2010 IRPs. Second, the Public Staff analyzed the accuracy of the utilities' peak demand and energy sales predictions in the 2005 IRPs in comparison to actual peak demands and actual energy sales. Third, the Public Staff reviewed several of the assumptions that underlie the forecasts and the growth rate forecasts of other adjoining utilities and forecasts for the SERC Reliability Corporation (SERC).

A. PEC

PEC's 15-year forecast predicts that its summer peaks will grow at a CAGR of 1.6%, which is the same as the projected growth rate in the 2009 IRP. Prior to the implementation of its DSM and EE programs, PEC expects its summer peaks to grow at 2.0%. The average annual growth of its summer peak, which is considered its system peak, is 213 megawatts (MW) for the next 15 years, as compared to 215 MW from last year's IRP. PEC predicts that load reductions from its DSM programs will reduce its peak load by approximately 10% in 2025.

PEC's energy sales are predicted to grow at a CAGR of 1.2%, a decrease of 0.2% from the projected growth rate in the 2009 IRP. PEC predicts that the megawatt-hour (MWH) reductions from its EE programs will reduce its energy sales by approximately 3% in 2025.

PEC's last summer peak, 12,074 MW, occurred on Wednesday, August 11, 2010, at the hour-ending 5:00 p.m. Relative to last year's IRP, the actual 2010 peak load was 156 MW lower than PEC's predicted load. At the time of the 2010 peak, PEC activated its EnergyWise Program and Commercial, Industrial, and Government Demand Response Program, which reduced its peak load by 40 MW and 5 MW, respectively, for a total reduction of 45 MW.

The Public Staff's one-year review of PEC's peak load accuracy shows that the predictions in the 2009 IRP represent a forecast with less than a 1% error.[7] The low forecast error rate was, in part, due to the system-wide average temperature of 96 degrees Fahrenheit, which was approximately equal to PEC's normal peak-day temperature. The Public Staff's five-year review of PEC's peak load and energy sales forecasting accuracy shows that the predictions in the 2005 IRP were reasonably accurate with less than a 5% forecast error.

The Public Staff believes that the economic, weather, and demographic assumptions that underlie PEC's peak and energy forecasts are reasonable and that PEC has employed accepted statistical and econometric forecasting practices. In conclusion, the Public Staff believes that PEC's peak load and energy sales forecasts are reasonable for planning purposes.

[7] The Mean Absolute Error is used to calculate the forecast error.

B. Duke

Duke's 15-year forecast predicts that its summer peaks will grow at a CAGR of 1.6%, which is the same as the projected growth rate in the 2009 IRP. Prior to the implementation of its DSM and EE programs, Duke expects its summer peaks to grow at 1.8%. The average annual growth of its summer peak, which is considered its system peak, is 322 MW for the next 15 years, as compared to 351 MW from last year's IRP. Duke predicts that load reductions from its DSM programs will reduce its peak load by approximately 9% in 2025.

Duke's energy sales are expected to grow at a CAGR of 1.8%. This growth rate in energy sales is an increase of 0.2% from the projected growth rate in the 2009 IRP. Duke predicts that the MWH savings from its EE programs will reduce its energy sales by approximately 4% in 2025.

Duke's last summer peak, 17,358 MW, occurred on Wednesday, August 11, 2010, at the hour-ending 5:00 p.m. At the time of the 2010 peak, Duke did not activate any of its DSM programs. According to its 2009 IRP, Duke could have reduced the peak by 750 MW.

The Public Staff's one-year review of Duke's peak load accuracy shows that the predictions in the 2009 IRP represent a forecast with less than a 2% error. The system-wide average temperature was 93 degrees Fahrenheit, which was approximately one degree cooler than the normal peak-day temperature. The Public Staff's five-year review of Duke's energy sales forecasting accuracy shows that the predictions in Duke's 2005 IRP were reasonably accurate with less than a 5% forecast error. However, the forecast accuracy of Duke's peak loads reflected a 5.7% forecast error. The above-average forecast error for the five-year period results from the relatively low actual peak loads reported in 2009 and 2010, which were over 8% below the predicted peak loads. These two forecast errors are mainly due to a reduction in new customers in 2010 and an even larger reduction in new customers in 2009. Duke's 2010 forecast more accurately reflects the current economic environment. The Public Staff believes that the economic, weather, and demographic assumptions that underlie Duke's peak and energy forecasts are reasonable, and that Duke has employed accepted statistical and econometric forecasting practices. In conclusion, the Public Staff believes Duke's forecasts are reasonable for planning purposes.

C. DNCP

DNCP's 15-year forecast predicts that its summer peaks will grow at a CAGR of 1.7%, which is a decrease of 0.3% from the projected growth rate in the 2009 IRP. The average annual growth of its summer peak, which is considered its system peak, is 342 MW for the next 15 years, as compared to 391 MW from last year's IRP. DNCP predicts that load reductions from its DSM programs will reduce its 2025 peak load by approximately 4%.

DNCP's energy sales are predicted to grow at an average annual rate of 1.8%. This projected growth rate in energy sales is a decrease of 0.4% from the growth rate in the 2009 IRP. DNCP predicts that the MWH savings from its EE programs will reduce its energy sales by approximately 3% in 2025.

DNCP's last summer peak, 16,783 MW, occurred on Friday, July 23, 2010, at the hour-ending 5:00 p.m. At the time of the summer peak, DNCP called on its Distributed Generation Pilot for a load reduction of 10,613 kilowatts (kWs) and its Air Conditioning Cycling Program for 249 kWs.

The Public Staff's one-year review of DNCP's peak load accuracy shows that the predictions in the 2009 IRP represent a forecast with less than a 1% error. The Public Staff's five-year review of DNCP's peak load and energy sales forecasting accuracy shows that the predictions in the 2005 IRP were reasonably accurate with less than a 5% forecast error.

The Public Staff believes that the economic, weather, and demographic assumptions that underlie DNCP's peak and energy forecasts are reasonable, and that DNCP has employed accepted statistical and econometric forecasting practices. In conclusion, the Public Staff believes that DNCP's peak load and energy sales forecasts are reasonable for planning purposes.

D. NCEMC

NCEMC's 15-year forecast predicts that its summer peaks will grow at an average annual rate of 1.8%, a decrease of 0.6% from the predicted growth rate in its 2009 IRP. The average annual growth of its summer peak, which is considered its system peak, is 58 MW.

While NCEMC is considered a summer peaking utility, its current annual system peak, 3,205 MW, occurred on Wednesday, December 15, 2010, at the hour-ending 7:00 a.m. At the time of the 2009 annual peak, NCEMC activated its DSM programs and reduced its peak by 32 MW.

NCEMC's energy sales are predicted to grow at an average annual rate of 1.7%, a decrease of 0.7% from the growth rate predicted in its 2009 IRP. NCEMC predicts that the MWH savings from its EE programs will reduce its energy sales by approximately 3% in 2025.

The Public Staff's analysis of NCEMC's peak load forecasting accuracy over the past five years indicates that the forecasts in its 2005 annual report were on average 247 MW lower than its actual system load, which equates to a 8% forecast error. Its energy sales forecast has been reasonably accurate with less than a 5% error rate. In response to the Commission's Order in Docket No. E-100, Sub 124, NCEMC revamped its load forecasting method by partnering with SAS Institute, Inc. to develop new state-of-the-art statistical models. The new peak demand models implemented by NCEMC are based on usage per customer that allow for the quantification of changes in peak demand among each of its member cooperatives that are attributable to changes in weather conditions and other factors. The Public Staff is cautiously optimistic that its concerns expressed in prior IRP dockets about the accuracy of NCEMC's forecasting methods will be resolved by this new forecasting process; however, it will still be necessary to review the forecasts for several years, contrasted with actual peak loads realized, before the impact of the changes in forecasting methodology can be fully assessed. The Public Staff believes that the current forecasts by NCEMC are reasonable for planning purposes.

E. EU

EU's 15-year forecast predicts that its winter peak, which is considered its system peak, will grow at an average annual rate of 0.9%. Its energy sales are predicted to grow at an average annual rate of 1.2%. The average annual growth of the annual peak is 6 MW over the 15-year forecast. EU's annual peak, 597 MW, occurred on Monday, January 11, 2010, at the hour-ending 7:00 a.m. EU activated two of its DSM programs at the time of its peak and reduced the load by approximately 10 MW. The Public Staff believes that the forecasts by EU are reasonable for planning purposes.

F. Haywood

Haywood's 15-year forecast predicts that its winter peak, which is considered its system peak, will grow at an average annual rate of 2.1%. Its energy sales are predicted to grow at an average annual rate of 2.0%. The average annual growth of the annual peak is 2 MW over the 15-year period. Haywood's annual peak, 93 MW, occurred on Wednesday, December 15, 2010, at the hour-ending 8:00 a.m. Haywood did not activate its DSM at the time of its peak. The Public Staff believes that the forecasts by Haywood are reasonable for planning purposes.

G. Piedmont

Piedmont's 15-year forecast predicts that its winter peak, which is considered its system peak, will grow at an average annual rate of 2.1%. The average annual growth of its summer peak is 3 MW over the 15-year period. Piedmont's energy sales are predicted to grow at an average annual rate of 2.1%. It predicts that the MWH savings from its EE programs will reduce its energy sales by approximately 4% in 2025. Piedmont's annual peak, 129 MW, occurred on Monday, January 11, 2010, at the hour-ending 7:00 a.m. It activated 1 MW of its DSM programs at the time of the winter peak. The Public Staff believes that the forecasts by Piedmont are reasonable for planning purposes.

H. Rutherford

Rutherford's 15-year forecast predicts that its winter peak, which is considered its system peak, will grow at an average annual rate of 1.4%. Its energy sales are predicted to grow at an average annual rate of 1.2%. The average annual growth of Rutherford's winter peak, which is considered its system peak, is 5 MW over the 15-year period. Rutherford's annual peak, 345 MW, occurred on Wednesday, December 15, 2010, at the hour ending 8:00 a.m. It did not activate any of its DSM programs at the time of its winter peak. The Public Staff believes that the forecasts by Rutherford are reasonable for planning purposes.

I. Summary of Load Forecasts

The following table summarizes the growth rates for the IOUs' and EMCs' system peak and energy sales forecasts based on their filings-to-date.

2011- 2025 Growth Rates
(After New EE and DSM)

	Summer Peak	Winter Peak	Energy Sales	Annual MW Growth
PEC	1.6%	1.8%	1.2%	213
Duke	1.6%	1.6%	1.8%	322
DNCP	1.7%	1.8%	1.8%	342
NCEMC	1.8%	1.7%	1.7%	58
EnergyUnited	1.0%	0.9%	1.2%	6
Haywood	2.2%	2.1%	2.0%	2
Piedmont	2.1%	2.1%	2.1%	3
Rutherford	1.4%	1.4%	1.2%	5

III. RESERVE MARGINS

A. PEC

A capacity margin is calculated by dividing reserves by the total supply resources, while a reserve margin is calculated by dividing reserves by the system firm load after the impact of DSM. PEC states that a minimum capacity margin target range of approximately 11%-13% satisfies the one day in ten year Loss of Load Expectation (LOLE) criterion and provides an adequate level of reliability. PEC further states that it considers 11% to be the minimum and acceptable capacity margin in the near term, but that 12-13% is appropriate to be used in the longer term due to forecast uncertainty. The margins are related but vary by 1% to 5% over the planning period due to generation and DSM availability. The projected capacity reserve margins range from 12% to 20% over the planning period. PEC states that these capacity margin values are the equivalent of 14% to 25% reserve margins, which were validated by the Public Staff. This implies a reserve margin target of 14% to 15% over the long term planning period. As shown in PEC's IRP, projected reserve margins exceed this targeted level significantly during the planning period and particularly during the 2011 to 2014 period. While PEC's plan details the addition of 635 MW of generation (Richmond County) in 2011 and 920 MW of generation (Wayne County) in 2013, it does not provide for a corresponding rate of retirement of other facilities. PEC notes that additional resources cannot be brought online in the exact amount needed to match load growth.

In addition to new generation to meet load growth, and facilities previously scheduled for retirement, PEC should have also incorporated retirement of additional coal-fired capacity as required by Commission Order dated January 28, 2010, in Docket No. E-2, Sub 960. The retirement plan submitted by PEC in this docket indicated that all unscrubbed coal generation would be retired by December 31, 2017. Robinson Unit 1 is not scrubbed and is not included in the planned retirements. PEC's filing should have included all required retirements. Further, Rule R8-60(i)(3) requires an explanation when the projected reserve margin in a given year differs by plus or minus 3% from the target reserve margin. PEC did not provide a specific explanation for the instances in which its projected reserve margins exceed the plus or minus 3% variance provided for in the rule. The Public Staff recommends that PEC be required to file the following with its reply comments: (1) the capacity/reserve margins that result after taking into account the Robinson 1 retirement, and (2) the specific explanation required by Rule R8-60(i)(3) for each year in which the revised projected reserve margin exceeds plus or minus 3% of the target.

B. <u>Duke</u>

Duke states that its own historical experience has shown that a 17% target planning reserve margin is sufficient and necessary to provide reliable power supplies for its North and South Carolina service area. Duke also states that from July 2005 through July 2009, generating reserves never dropped below 450 MW, but notes that there are increased risks associated with reserve margins, which include (1) increasing age of units, (2) inclusion of significant amount of renewable (which are generally less available than traditional supply side resources), (3) uncertainty related to increases in the Company's EE and DSM programs, (4) longer lead times for constructing base load units, (5) increasing environmental pressures, and (6) increases in derates of units due to hot weather and drought.

Duke's projected reserve margins vary from 16.2% to 26.2% over the planning period. Duke did not include a specific explanation for the instances in which the projected reserve margins exceed plus or minus 3%, as required by Rule R8-60(i)(3). The Public Staff recommends that Duke be required to file with its reply comments the specific explanation required by Rule R8-60(i)(3) for each year in which the revised projected reserve margin exceeds plus or minus 3% of the target.

IV. RESERVE MARGIN ADEQUACY

A. DNCP

DNCP is in the process of adding significant amounts of new capacity through its Bear Garden and Virginia City Hybrid Energy Center plants for the purpose of meeting its state-imposed obligations to provide adequate reserve margins for its customers. In addition, it is a party to the PJM Reliability Assurance Agreement Among Load-Serving Entities (RAA), which obligates it to own or acquire sufficient capacity to maintain overall reliability. PJM conducts an annual reliability assessment to determine an adequate level of capacity in its footprint to meet the target level of reliability measured with a LOLE that is equivalent to one day of outage in ten years. PJM's 2009 assessment recommended using a reserve margin of 15.3% for the entire PJM footprint. DNCP uses the PJM reserve margin guidelines in conjunction with its own load forecast to determine its long-term need for capacity. The reserve margins for the first three years of the planning period are 16.1% (2011), 16.7% (2012), and 13% (2013). Because DNCP is only obligated under the RAA to maintain a reserve margin for its portion of the PJM coincidental peak load, it used a coincidence factor of 96.3% to derive an effective reserve margin of 11% for 2014 through 2025.

B. PEC

PEC provided a description of the analysis it utilizes to develop the reserve and capacity margins it uses for planning. Responses to questions from the Public Staff indicated that the results of the analysis were not available for review and that the analysis had not been performed in a number of years.

C. Duke

Duke states that its historical experience has shown that a 17% target planning reserve margin is sufficient to provide reliable power supplies. Responses to questions from the Public Staff indicated that no analyses were available for review to justify the historical target value and that no study or analysis had been performed in a number of years. The Public Staff has investigated the impacts of incorporating a 14% target reserve margin into the reference case used in Duke's quantitative analysis and determined that the lower reserve margin would largely eliminate the need for a 370 MW combustion turbine from the generation expansion plan.

D. Summary Comments on Reserve Margin Adequacy

During the 2010 summer, several instances occurred when PEC's reserve margins dropped to low single digit values. These instances coincided with both scheduled and non-scheduled maintenance of generation units, along with abnormally hot weather conditions. No actual emergency situations resulted from these events. This illustrates the importance of the identification of the proper value to use for the reserve margin. At the same time, despite the abnormally hot weather, Duke's reserve margins stayed around 17%.

An inadequate reserve margin results in emergency situations that may lead to expensive emergency purchases or the inability to carry full customer loads in some service areas. On the other hand, a higher than necessary reserve margin results in system costs that are greater than necessary to procure, operate, and maintain excess generation facilities, which results in higher customer rates.

It has been a number of years since either Duke or PEC has conducted a comprehensive study to determine the appropriate reserve and capacity margin values to be used for the planning and operation of their respective systems, and prudent planning requires that such studies be conducted on a periodic basis. Therefore, the Public Staff recommends that the Commission require both Duke and PEC to conduct such studies as soon as practicable and incorporate the results in their IRP process and filings. The studies should determine the optimal level of reserves to provide generation reliability that considers, the obligation to serve, the value of electricity, and the effect of outages (unserved load), while minimizing the cost to ratepayers. It is recommended that the studies include, but not be limited to, sensitivity analyses for factors such as the assumed levels of forced outages of generation facilities, assumed level of costs to customers for power outages, assumed values for reliable transmission capacity, and the assumed lead time for adding new generation units. The Public Staff further recommends that the utilities keep the Public Staff updated as they develop the parameters of the studies.

V. DSM AND EE

A. General Comments

The Public Staff's review of the DSM/EE portions of the 2010 IRPs indicates that there is little difference from those filed in 2009. Duke, DNCP, NCEMC, and the independent EMCs, Haywood, Piedmont, Rutherford, and EU, generally forecast fewer DSM/EE resources (in terms of MWs and MWHs) over the planning horizon. PEC indicated a small increase in its forecast of DSM resources. All of the utilities and EMCs rely almost exclusively on the portfolio of DSM/EE programs they have designed and adopted over the last couple of years to meet their forecasted DSM/EE resources over the planning horizon, with only a few programs recently implemented or still under consideration.

As it did in its testimony in Docket No. E-100, Sub 124, in regard to the IOUs, the Public Staff encourages the utilization of DSM resources to achieve fuel savings during periods when the price of energy available for spot purchases is high. It is not evident in their IRPs that the IOUs have fully considered the use of their DSM resources to achieve fuel savings. The Public Staff recommends that the Commission require both the IOUs and EMCs to investigate this use of their DSM resources and include a discussion of the results of their investigations in their next IRPs.

Finally, the Public Staff encourages each IOU and EMC to investigate, develop, and implement all available cost-effective DSM/EE. Changes being proposed to building codes and appliance standards, as well as federal legislation regarding lighting, will substantially impact the ability to implement cost-effective DSM and EE. These changes will have a profound impact on markets for products that consume electricity and may make reliance on older market potential studies unreliable. Therefore, the Public Staff recommends that any IOU or EMC relying on a DSM/EE market potential study older than two years update its study or perform a new study and file it with its next IRP.

B. Forecasts of DSM/EE

For the first four years of 2010 IRP, Duke has included fewer DSM/EE resources than it did in its 2009 IRP. However, after 2014 the projections are greater. By 2030, Duke forecasts 633 MWs from its currently approved/implemented DSM resources, up from the 483 MWs forecast in the 2009 IRP. Projections of EE savings through 2013 are less than they were in the 2009 IRP. Additionally, the projection of EE savings for 2013 are approximately 21% less than the Year 4 Save a Watt (SAW) targets listed in paragraph D.6 of the SAW Mechanism filed in Docket No. E-7, Sub 831. The Public Staff has discussed these lowered projections with Duke, and Duke has indicated that its 2010 IRP takes a more conservative approach to the forecast of DSM and EE; however, Duke has indicated to the Public Staff that in the later years of SAW, it will enhance its EE savings estimates with additional programs.

PEC has increased the projected savings from its DSM/EE programs in its 2010 IRP as compared to its 2009 IRP. By 2024, PEC is forecasting 1,275 MWs of DSM, up from the 1,227 MWs reported in the 2009 IRP. PEC is also forecasting greater energy savings by 2024 than it reported in its 2009 IRP. These savings also include those associated with the Distribution System Demand Response (DSDR) Program.

DNCP has included fewer DSM/EE resources in its 2010 IRP than it did in its 2009 IRP. By 2024, DNCP is forecasting 810 MWs of DSM, rather than the 956 MWs reported in the 2009 IRP. DNCP is forecasting lower energy savings from DSM/EE programs through 2014 and greater energy savings after 2014.

NCEMC has included slightly fewer DSM/EE resources in its 2010 IRP than it did in its 2009 IRP. By 2024, NCEMC is forecasting 95 MWs of DSM, down from the 97 MWs reported in the 2009 IRP. NCEMC is also forecasting fewer energy savings from DSM/EE programs across the planning horizon.

Piedmont and EU included projections of DSM/EE resources that were similar to their projections in their 2009 IRPs. Haywood's projections are lower in 2010 than in 2009. Rutherford did not include any information about its DSM/EE projected savings in its 2010 IRP. Halifax is a member of NCEMC and was included in NCEMC's projections; however, Halifax is not a member of GreenCo.

B. DSM/EE Programs

Duke's 2010 list of existing DSM/EE programs is consistent with its 2009 IRP. It did not use any of its DSM programs during the summer peak day for 2010, but reports uses of its Power Manager and Power Share DSM programs during the early summer of 2010. It is the Public Staff's understanding that Duke continues to investigate the feasibility of using its DSM resources for fuel savings. Duke included energy and capacity savings projections from its portfolio of DSM and EE programs in Tables 4.1 and 4.2 of its IRP for the base case and high EE case, respectively. The data represented in these tables is derived from the DSMore model projections that Duke used to evaluate the potential of its portfolio of DSM and EE programs. The projections of savings are slightly less than the 2009 IRP in the first four years (2010 through 2013), but are slightly higher in later years.

The Public Staff also reviewed Duke's proposed Power Share Call Option program, Docket No. E-7, Sub 953, which is pending approval before the Commission. This program will provide an additional demand response option for customers who enroll load under a variety of options based on Duke's need to make economic and/or emergency curtailments. As part of its review of the cost effectiveness test results of the proposed Power Share Call Option generated by the DSMore model, the Public Staff observed that approximately 39% of the total avoided cost benefits were associated with avoided production (energy) costs, which seemed relatively high for a DSM program. The cost effectiveness of the Power Share Call Option and Duke's other Power Share and Power Manager programs approved in Docket No. E-7, Sub 831, is largely based on avoided capacity costs. Based on the Public Staff's review of these programs, it appears that elimination of the avoided energy cost benefits would not change the overall cost effectiveness of any of the programs.

Duke indicated to the Public Staff that the high level of avoided production cost benefits improperly included an amount of avoided capacity cost benefits, which were embedded in the inputs used to calculate the avoided production cost benefits. This error, which involved the DSMore calculation methodology rather than inputs from Duke, resulted in a "double-counting" of the avoided capacity cost benefits in the evaluations of the Power Share Call Option program. Duke calls this a "blended input" that led to higher avoided cost benefits for energy, and "unreasonably high values for avoided cost outputs." Duke has since corrected its calculation methodology to prevent future model runs from performing this incorrect double-counting calculation. However, the Public Staff believes that certain cost effectiveness test results filed with the Commission in other DSM program approval applications may have also included this double-counting of avoided capacity cost benefits.

Based on further discussions with Duke and representatives from Integral Analytics, LLC., the developer of DSMore software, the Public Staff believes that the double-counting of the avoided capacity cost benefits was limited to the overstatements of dollar savings from avoided production cost benefits in the cost effectiveness tests, and did not affect the assumptions of the kilowatt capacity savings from DSM programs represented in Duke's IRP. Furthermore, it is the Public Staff's understanding that the EE program evaluations were not impacted. Therefore, the Public Staff does not believe that any adjustment is needed to the IRP as a result of this issue. However, the Public Staff does believe that any erroneous cost effectiveness test results filed with the Commission in connection with previous DSM program applications should be corrected and refiled in the appropriate dockets. Further, the period during which the double-counting occurred should be identified and the effect of the issue on any data filed with the Commission should be explained.

PEC's 2010 list of existing DSM/EE programs is consistent with its 2009 IRP, and includes the Appliance Recycling and the Residential Lighting Programs approved in 2010. PEC also indicated that it was reviewing possible changes to its Residential Home Improvement Program to address lower than expected participation. PEC's DSDR program is still under development and is on track to be completed in 2012.[8] PEC utilized its EnergyWise and CIG Demand Response Programs several times during the summer season, including its summer peak day.

In its 2010 IRP, PEC indicated that it had used its DSM resources to shave peak demand during a few peak days of the summer of 2010, including the system peak day on August 11. In response to a Public Staff data request, PEC indicated that it continues to model and operate the EnergyWise program for reliability purposes and not for economic purposes. In Docket No. E-2, Sub 927, PEC filed a report that illustrated the results of testing and use of the EnergyWise program during the 2009 summer peak season. This report indicated that PEC has investigated the use of different appliance cycling strategies (50%, 75%, and 100%) and analyzed the impact of these strategies on the program's ability to reduce peak demand. Key findings from the study are: (1) the need to address the sizeable "snap-back" effect (a higher energy consumption following the control event than would otherwise be observed); (2) very few customer overrides during control events; and (3) and the need to better understand the consistency and persistence of participants' responses from year to year.

DNCP's 2010 list of existing DSM/EE programs is consistent with its 2009 IRP. DNCP used its Schedule CS (Curtailable Service), Schedule SG (Standby Generation), and residential air conditioning cycling (VA) DSM programs during the 2010 system peak. In response to a Public Staff data request, DNCP indicated that it intends to use its DSM resources to the fullest extent within the design constraints of the individual programs once all programs are approved by the Commission.

NCEMC's 2010 list of existing DSM/EE programs is similar to its 2009 IRP. In response to Public Staff data requests, NCEMC indicated that its constituent members used their DSM programs during the summer or winter peaks in 2010.

Piedmont and Haywood are members of GreenCo and have access to the portfolio of DSM/EE programs filed by GreenCo on behalf of its constituent members.

[8] See report filed in Docket No. E-2, Sub 926 on December 9, 2010.

Additionally, Haywood briefly referred to its heat pump load program and EE kits that have been included in previous IRPs. Rutherford did not include any mention of DSM/EE other than the CFL educational giveaway that it included in its 2009 IRP. EU did not include any discussion of DSM/EE in its 2010 IRP. Halifax's REPS Compliance Plan included a brief mention of its CFL EE program approved by the Commission in December 2010. Piedmont was the only independent EMC to indicate deployment of its DSM resources during the summer and winter peaks. The remaining four EMCs did not indicate whether their respective DSM resources were used during their system peaks. The Public Staff recommends that each independent EMC include a discussion in future IRPs consistent with Rule R8-60(i)(6) or include a statement if this portion of the Rule is inapplicable to it.

C. Proposed DSM/EE Programs

Duke included a brief discussion of the three DSM/EE programs pending before the Commission at the time of the filing of its IRP (Power Share Call Option, Home Energy Comparison Report, and the Residential Retrofit Pilot). Duke also incorporated savings from the Home Energy Comparison Report and the Residential Retrofit Pilot in its projections of energy savings. However, the Public Staff notes that Duke has since withdrawn its application for the Home Energy Comparison Report, but has indicated that it intends to file a modified version of this program in 2011.

Duke also included a brief discussion of three other programs that it may submit for approval in 2011: an HVAC tune up and duct sealing program, a direct install low income program similar to Progress Energy's Neighborhood Energy Saver program, and an appliance recycling program. Duke's projections of energy savings did not include these programs. Duke's 2010 IRP did not include any discussion of its Smart Energy Now application pending before the Commission, or its Residential Energy Management Pilot approved in Docket No. E-7, Sub 906.

PEC included a brief discussion of its Residential EE Benchmarking Program, currently pending before the Commission in Docket No. E-2, Sub 989.

DNCP included six DSM/EE programs for which it filed for approval on September 1, 2010: (1) Residential Low Income, (2) Residential Air Conditioning Cycling, (3) Commercial HVAC Upgrade, (4) Residential Lighting, (5) Commercial Lighting, and (6) Commercial Distributed Generation.. It discussed these DSM/EE programs, along with several others, in its 2009 IRP. DNCP indicated in its 2010 IRP that it has eight additional programs under review that may be filed in the future.

NCEMC included in its 2010 IRP 11 DSM/EE programs filed by GreenCo and approved by the Commission on August 23, 2010. GreenCo filed these programs on behalf of its constituent members and NCEMC.

As stated above, Piedmont has access to the portfolio of DSM/EE programs approved for GreenCo. In addition, Piedmont discussed its smart meter deployment, which is being used to provide a prepay program and more detailed energy usage data to customers. This program was also discussed in Piedmont's 2009 IRP. It is unclear whether Piedmont intends to treat its smart meter program as an EE program. Therefore, Public Staff recommends that Piedmont indicate in its reply comments whether it considers the smart meter program an EE program, and if so, that it file for Commission approval of the program pursuant to Rule R8-68.

Haywood also has access to the portfolio of DSM/EE programs approved for GreenCo. It included a discussion of its proposed residential energy audit program. However, no details beyond a program description were included.

EU did not discuss details of its two Commission-approved EE programs, Residential Heat Pump Rebate and Commercial and Industrial Lighting Program, in its 2010 IRP. EU did provide general reference to EE savings in its load forecast tables. Therefore, the Public Staff recommends that EU provide in its reply comments and in future IRPs a more detailed description of the participation and savings related to specific DSM and EE program, and more particularly any DSM or EE program it propose to use to meets its REPS obligations.

Rutherford did not include any discussion of proposed DSM/EE programs in its 2010 IRP.

Halifax's REPS Compliance Plan mentions its CFL promotion, heat pump rebates, and energy audits. The heat pump rebate and energy audit programs were implemented prior to August 20, 2007. Halifax received approval for the CFL program on December 14, 2010.

D. Rejected DSM/EE Programs

With the exception of DNCP, all of the IOUs and EMCs indicated that they had not rejected any DSM/EE program that had been under consideration for implementation during the 2010 IRP cycle. DNCP on the other hand, states that it considered 14 potential programs for which it is not currently recommending implementation because they were not found to be cost effective.

E. Consumer Education Programs and Changes

Duke did not include a specific discussion of its consumer education efforts beyond those associated with the individual DSM/EE programs. Through discussion with the Public Staff, Duke has agreed to address any activity or initiative that encourages or educates consumers about EE that is not part of a specific DSM/EE program in its reply comments. PEC's 2010 list of general consumer education programs is the same as included in its 2009 IRP. DNCP included details of several consumer education programs similar to those included in its 2009 IRP. The Public Staff notes that DNCP discontinued two consumer education efforts included in its 2009 IRP, its CFL education program and the Energy Saving Tip of the Day program.

NCEMC's 2010 list of general consumer education programs is the same as included in its 2009 IRP. No changes in the types of consumer information programs were mentioned by the independent EMCs that filed IRPs.

VI. EVALUATION OF RESOURCE OPTIONS

PEC, Duke, and DNCP provided information describing their analysis and evaluation of resource options as required by Rule R8-60(i)(8). The utilities use accepted production cost simulation models that have the ability to perform optimization analysis to select between different competing resource portfolios that potentially could be added in various combinations to satisfy the utility's future load requirements. The objective of these models is an identification of the least cost combination of resources as determined by an evaluation of the present value of revenue requirements for the various portfolios, while maintaining the target reserve margin. In addition to the review of the utilities' load forecasts, future DSM and EE programs, and renewable resources, the Public Staff also reviewed forecasts of fuel prices, existing generation characteristics, and the projected capital costs associated with new generation facilities used in the resource optimization models. The investigation by the Public Staff indicates that the projected operating and capital costs used in the production models and the evaluation of resource options were conducted in a reasonable manner for purposes of this proceeding.

While Duke considered scenarios that assumed the impact of enactment of greenhouse gas legislation imposing limits on carbon emissions, it did not include a low or no carbon scenario in its development of the proposed expansion plans included in this IRP. Responses to Public Staff data requests indicate that an assumption of no, or low, carbon limitations/costs results in the model selecting coal generation facilities. Based on Duke's policy decisions and perception that additional coal generation would be untenable, Duke decided not to include this type of scenario. Assumptions about future carbon legislation, however, do affect the choice between natural gas-fired combined cycle and nuclear generating plants. Because of the current likely deferral of carbon legislation, the Public Staff believes that Duke should undertake additional consideration of this issue in future IRPs. In addition, assumptions about carbon limitations and costs have a significant effect on the potential timing of new nuclear generating plants, which is a consideration under review in Docket E-7, Sub 819, with respect to Duke's pending nuclear project development application.

The filings made by NCEMC and the other EMCs did not indicate that their evaluation of resource options considered the effect of potential legislation placing limits on carbon emissions in conjunction with their individual IRPs. The Public Staff recommends that each IOU, NCEMC, and EMC required to file an IRP be required to include in its 2011 IRP scenarios with no carbon and low carbon price impacts, as well as scenarios factoring in the impact of regulation of carbon emissions; these scenarios should also be included in future IRPs submissions until such scenarios are no longer plausible.

VII. ASSESSMENT OF ALTERNATIVE SUPPLY-SIDE ENERGY RESOURCES

Commission Rule R8-60(i)(7) requires each utility to file 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. Each utility also is required to provide general information on any changes to the methods and assumptions used in the assessment since its most recent biennial or annual report. This rule applies to NCEMC and any individual EMCs to the extent that they are responsible for procurement of any or all of their power supply resources.

G.S. 62-133.8 requires all electric power suppliers, including EMCs and municipalities, to comply with the REPS by including specified amounts of renewable energy resources in their energy procurement mix. Alternatively, a supplier may comply with the REPS by reducing energy consumption through implementation of EE measures (and also DSM measures, in the case of EMCs and municipalities). Commission Rule R8-60(e) states that alternative supply-side energy resources include but are not limited to hydro, wind, geothermal, solar thermal, solar photovoltaic (PV), municipal solid waste, fuel cells, and biomass. All these resources can be used to meet part of an electric power supplier's REPS requirements.

The REPS compliance plans submitted by the State's electric power suppliers provide assessments of alternative supply-side energy resources and are discussed below.

VIII. REPS COMPLIANCE PLAN REVIEW

G.S. 62-133.8 requires all electric power suppliers to provide specified percentages of their retail sales using renewable energy resources or reduce energy consumption through implementation of EE measures. Commission Rule R8-67(b) requires electric power suppliers to file a plan on or before September 1 of each year explaining how they will meet the requirements of G.S. 62-133.8(b), (c), (d), (e), and (f). The plans must cover the current year and the next two calendar years, or in this case 2010, 2011, and 2012.

Duke, PEC, and DNCP provided an assessment of alternative supply-side energy resources as part of their REPS compliance plans. All EMCs and municipal electric suppliers in North Carolina provided plans with the exception of the Town of Fountain. The Public Staff's comments on each electric power supplier can be found in Sections A through E below.

The electric power suppliers have had some difficulty obtaining sufficient resources from swine waste and poultry waste to meet the requirements of G.S. 62-133.8(e) and (f). The filings regarding the efforts of the electric power suppliers to meet these requirements are in Docket No. E-100, Sub 113. The Public Staff's specific comments regarding energy derived from swine waste and poultry waste can be found in Section F below.

A. Duke

Duke has contracted for and banked sufficient resources to meet the general REPS requirements of G.S. 62-133.8(b) and (c) for itself and the electric power suppliers for which it is providing REPS compliance services respectively. Duke is contractually obligated to secure resources to meet all the REPS requirements of the following electric power suppliers: Rutherford, Blue Ridge, City of Dallas, Town of Forest City, City of Concord, Town of Highlands, and City of Kings Mountain (collectively, Wholesale Customers).

A large portion of the general requirement of Duke and its Wholesale Customers will be met with resources such as combined heat and power from biomass; direct firing or co-firing of biomass; refuse-derived fuel; and gas derived from landfills, wastewater treatment, and organic waste. The larger of these biomass resources are economically attractive because they typically have capacities of 20 to 100 MW capacities and operate with capacity factors of 85% to 90%.

At one time Duke was considering a demonstration project of up to three wind turbines in the Pamlico Sound, but it cancelled the program in 2010 because the costs to complete the project had become excessive. Currently, purchasing wind renewable energy certificates (RECs) generated at out-of-state facilities has proven very cost effective. Duke anticipates using these RECs to help it meet up to 25% of the general REPS requirement of G.S. 62-133.8 (b) and (c). Duke also plans to use EE RECs to meet up to 25% of the general REPS requirement.

Duke plans to meet up to 30% of the general requirements of its Wholesale Customers using energy and RECs from hydroelectric facilities and energy from the Southeastern Power Administration (SEPA).

Duke is confident that it will meet the 2010, 2011, and 2012 solar set-aside requirements by implementing the following projects:

- A 20-year agreement for a 15.5-MW solar farm in Davidson County built and operated by SunEdison.

- A distributed generation solar PV program for which Duke has received Commission approval. This program currently has 18 commercial customers as well as some residential customers.

- Purchase of out-of-state solar RECs.

- Long-term agreements to purchase solar RECs from FLS Energy's solar thermal facilities. FLS Energy has filed a letter requesting that the

Commission accept estimates of past REC generation at some solar thermal facilities. The Public Staff has recommended that the Commission not accept estimates of solar thermal RECs because of the solar thermal metering requirement of G.S. 62-133.8(d). In a similar case, the Commission agreed with the Public Staff's position in an order issued on July 21, 2010, in Docket No. RET-10, Sub 0.

For Duke, the 0.02% of sales requirement for the solar set-aside equates to 11,434 MWh in 2010 and 11,403 MWh in 2011. For 2012, the 0.07% of sales requirement equates to 40,134 MWh. Duke anticipates meeting the solar set-aside requirements with the following sources of solar energy and solar RECs projects:

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Duke notes that the declining cost of solar equipment could lead to the use of solar energy to meet the general requirements of G.S. 62-133.8(b) and (c). The Public Staff recommends, however, that solar energy should be used to satisfy the general REPS requirements only if it is lower in cost than other available alternatives.

In accordance with Rule R8-67(b)(1)(iv), Duke filed the following projections of total MWh sales to its North Carolina retail customers and Duke's Wholesale Customers. The second table provides year-end customer counts by class for each year:

	2010	2011	2012
Total MWh Sales	57,013,825	57,333,611	58,230,006

To meet the general requirement of G.S. 62-133.8(b) for 2012, Duke will need 1,720,008 RECs (3% of 2011 sales).

Number of Customers	2010	2011	2012
Residential	1,740,219	1,754,143	1,771,508
Commercial	238,628	240,895	243,141
Industrial	5,802	5,784	5,768

Duke provided the following data on its avoided costs:

Annualized Capacity and Energy Rates (cents per kWh)			
	2010	2011	2012
Variable Rate	6.40	6.40	6.40
5-Year	6.39	6.39	6.39
10-Year	6.42	6.42	6.42
15-Year	6.56	6.56	6.56

Duke provided information, as required by Rules R8-67(b)(1)(vi) and (vii), on the projected total and incremental costs anticipated to implement its compliance plan for each year, together with a comparison of these costs to the annual cost caps. This information includes its North Carolina retail customers as well as Duke's Wholesale Customers. The information provided by Duke is summarized in the following table:

	2010	2011	2012
Total costs	$11,938,130	$23,751,567	$49,224,106
Incremental costs	$6,196,090	$7,548,127	$25,082,056
Annual cost cap	$32,334,475	$32,478,330	$32,756,206

B. PEC

PEC has contracted for and banked sufficient resources to meet the general REPS requirements of G.S. 62-133.8(b) and (c) for itself and the electric power suppliers for which it is providing REPS compliance services respectively. PEC is contractually obligated to secure resources to meet all the REPS requirements of the following electric power suppliers: Town of Waynesville, Town of Sharpsburg, Town of Stantonsburg, Town of Black Creek, and Town of Lucama (collectively, Wholesale Customers).

PEC's primary method of meeting the REPS requirements for itself and its Wholesale Customers is the purchase of RECs and electricity from renewable generators. PEC maintains an open request for proposals for non-solar generation of less than 10 MW. PEC continues to evaluate the use of renewable fuels at existing generation facilities and has considered ownership of renewable generation facilities. However, at this time it has not pursued these two strategies due to the lack of cost effectiveness.

PEC plans to use EE RECs to meet up to 25% of the general REPS requirement and has purchased out-of-state wind RECs, which have proven to be very cost effective.

PEC has implemented its Commercial and Residential SunSense programs to comply with the solar set-aside requirements of G.S. 62-133.8(d). Under the Commercial SunSense program, commercial customers agree to install rooftop-mounted solar PV facilities or solar thermal water heating facilities on their property. PEC agrees to purchase all RECs and electricity generated and aims to add 5 MW per year of solar PV generation. The Residential SunSense program aims to add another 1 MW per year of solar PV generation.

For PEC, the 0.02% of sales requirement for the solar set-aside equates to 7,300 MWh in 2010 and 7,300 MWh in 2011. For 2012, the 0.07% of sales requirement equates to 25,800 MWh. PEC anticipates meeting the solar set-aside requirements with solar energy and solar RECs from the participants in its SunSense programs.

In accordance with Rule R8-67(b)(1)(iv), PEC filed the following projections of sales to its North Carolina retail customers and PEC's Wholesale Customers. It also submitted year-end customer counts by class for each year:

	2010	2011	2012
Total MWh Sales	36,434,000	36,841,000	37,501,000

To meet the general requirement of General Statute 62-133.8(b) for 2012, PEC will need 1,105,230 RECs (3% of 2011 sales).

Number of Customers	2010	2011	2012
Residential	1,106,000	1,119,000	1,136,000
Commercial	179,000	181,000	185,000
Industrial	2,000	2,000	2,000

PEC provided the following data on its avoided costs:

Annualized Capacity and Energy Rates ($ per MWH)	
2-Year	56.96
5-Year	58.29
10-Year	60.54
15-Year	61.11

PEC provided information, as required by Rules R8-67(b)(1)(vi) and (vii), on the projected total and incremental costs anticipated to implement its compliance plan for each year, together with a comparison of these costs to the annual cost caps. The information includes its North Carolina retail customers as well as its Wholesale Customers. The information provided by PEC is summarized in the following table:

	2010	2011	2012
Total costs	$25,000,000	$51,000,000	$51,900,000
Incremental costs	$13,600,000	$15,200,000	$15,000,000
Annual cost cap	$21,000,000	$21,200,000	$42,900,000

C. DNCP

DNCP plans to purchase RECs and use EE to meet the general REPS requirements of G.S. 62-133.8(b) and (c) for itself and the Town of Windsor, for which it is providing REPS compliance services. DNCP had planned to use out-of-state RECs to meet compliance requirements for the Town of Windsor. However, after discussions with the Public Staff, DNCP has agreed to obtain in-state RECs for 75% of the Town's requirements as required by G.S. 62-133.8(c)(2)(d).

DNCP intends to purchase unbundled solar RECs to meet the set-aside requirements for 2010 and 2011.. For DNCP and the Town of Windsor, the 0.02% of sales requirement for the solar set-aside equates to 816 MWh in 2010 and 820 MWh in 2011. For 2012, the 0.07% of sales requirement equates to 2,902 MWh. DNCP's plan to purchase solar RECs should be sufficient to meet its requirements.

In accordance with Rule R8-67(b)(1)(iv), DNCP filed the following projections of sales to its North Carolina retail customers and the Town of Windsor's retail customers. It also submitted year-end customer counts by class for each year:

	2010	2011	2012
Total MWh Sales	4,096,085	4,144,780	4,250,634

To meet the general requirement of General Statute 62-133.8(b) for 2012, DNCP will need 124,343 RECs (3% of 2011 sales).

Number of Customers	2010	2011	2012
Residential	104,264	105,579	107,131
Commercial	18,664	18,890	19,137
Industrial	61	60	59

After discussions with the Public Staff, DNCP provided the following revised data on its avoided costs:

Energy Rates and Annualized Capacity Rates			
	2010	**2011**	**2012**
On-Peak ($/MWh)	84.04	84.92	75.29
Off-Peak ($/MWh)	61.78	62.26	55.58
Capacity ($/kW-Year)	52.63	49.99	72.45

DNCP provided information, as required by Rules R8-67(b)(1)(vi) and (vii), on the projected total costs anticipated to implement its compliance plan for each year, with a comparison of these costs to the annual cost caps. The information provided by DNCP includes the Town of Windsor and is summarized in the following table:

	2010	2011	2012
BEGIN CONFIDENTIAL			
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
END CONFIDENTIAL			
Annual cost cap	$2,006,340	$2,030,290	$4,215,122

DNCP's total costs are the same as its incremental costs because it intends to purchase RECs that are not bundled with energy to meet its REPS requirements.

D. EMCs

GreenCo filed a REPS compliance plan on behalf of 24 of the 31 EMCs serving customers in North Carolina.[9] Three of the remaining seven EMCs were included in the plan filed by TVA. Two were covered by the plan filed by Duke, and two filed plans independently.

1. GreenCo

On behalf of its 24 members, GreenCo submitted a 2010 REPS compliance plan that describes the future plans of its members to meet the requirements of G.S. 62-133.8(c), (d), (e), and (f). Since filing its 2009 REPS compliance plan, GreenCo has agreed to provide REPS compliance services for Mecklenburg EMC and Broad River, while Blue Ridge has withdrawn from GreenCo.

GreenCo's members plan to rely on a significant contribution from EE programs to meet REPS requirements. These programs are discussed in detail above in the section covering DSM/EE resources. The following is a discussion of the renewable energy portion of GreenCo's compliance plan.

GreenCo intends to meet the solar energy requirements of G.S. 62-133.8(d) by purchasing RECs from several privately owned solar facilities as well as purchasing out-of-state solar RECs. By far, the largest source of solar RECs will be the Solar Star North Carolina II, LLC, facility near Murfreesboro, North Carolina, approved in Docket No. SP-702, Sub 0.

To help meet the general requirement of G.S. 62-133.8(c), GreenCo intends to purchase RECs from the NextEra wind energy facility in Story County, Iowa, a renewable energy facility approved in Docket No. EMP-30, Sub 0. Also, GreenCo's

[9] GreenCo filed a consolidated 2009 REPS Compliance Plan on behalf of Albemarle EMC, Broad River EMC, Brunswick EMC, Cape Hatteras EMC, Craven-Carteret EMC, Central EMC, Edgecombe-Martin County EMC, Four County EMC, French Broad EMC, Haywood EMC, Jones-Onslow EMC, Lumbee River EMC, Mecklenburg EMC, Pee Dee EMC, Piedmont, Pitt & Greene EMC, Randolph EMC, Roanoke EMC, South River EMC, Surry-Yadkin EMC, Tideland EMC, Tri-County EMC, Union EMC, and Wake EMC.

members will use their allocation of energy from SEPA to meet up to 30% of their REPS requirements as allowed by G.S. 62-133.8(c)(2)c.

In response to Commission Rule R8-67(b)(1)(iv), GreenCo submitted the following aggregated projections for its members:

	2010	2011	2012
Total MWh Sales	12,890,647	13,098,855	13,308,116

Number of Customers	2010	2011	2012
Residential	672,472	683,331	694,202
Commercial	49,608	50,428	51,238
Industrial	97	97	97

GreenCo stated that it used $50.57 per MWh as the avoided cost for all of its members in all analyses supporting the information reported in its 2010 compliance plan.

Below is a table summarizing GreenCo's projected total and incremental costs anticipated to implement the compliance plan for each year and the annual cost caps for each year.

	2010	2011	2012
Annual cost cap	$9,023,707	$9,253,620	$15,861,174
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[redacted]	[redacted]	[redacted]	[redacted]
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2. TVA

TVA filed a REPS compliance plan for Tri-State EMC, Mountain EMC, Blue Ridge Mountain EMC, and the Murphy Electric Power Board (collectively, the Distributors). It plans to comply with the requirements of G.S. 62-133.8 by obtaining out-of-state wind RECs from the Horizon Pioneer Prairie wind turbine facility, a renewable energy facility approved in Docket No. EMP-29, Sub 0. TVA also plans to create RECs from EE measures and from its hydroelectric facilities in North Carolina. To meet the solar set-aside, TVA intends to purchase solar RECs for the 2010 requirement. For 2011 and 2012, TVA plans to purchase solar RECs and generate solar RECs at its facilities in Tennessee.

In response to Commission Rule R8-67(b)(1)(iv) and (v), TVA submitted the following aggregated projections for the four Distributors:

·	2010	2011	2012
Total MWh Sales	598,243	601,904	607,347

Number of Customers	2010	2011	2012
Residential	32,821	33,267	33,720
Commercial	8,622	8,663	8,715
Industrial	8	8	8

Avoided Cost Rates for the Distributors	
January 2010 – March 2010	2.542 ¢ per kWh
April 2010 – June 2010	3.222 ¢ per kWh
July 2010 – September 2010	3.510 ¢ per kWh
October 2010	3.465 ¢ per kWh
November 2010	3.496 ¢ per kWh
December 2010 – December 2012	Not available

Below is a table summarizing the Distributors' projected total and incremental costs anticipated to implement the compliance plan for each year and the annual cost caps for each year.

	2010	2011	2012
Annual cost cap	$547,760	$553,245	$557,775
Total costs	$0	$0	$0
Incremental costs	$0	$0	$0

TVA and the Distributors plan to enter into arrangements under which TVA will provide a method for Distributors to achieve compliance through the options that TVA deems most appropriate and treat the cost of all such compliance as a cost incurred on behalf of all consumers of TVA power. Therefore, all users of TVA power will share in the cost of TVA providing the REPS compliance services. The Distributors will not incur costs incremental to the overall rate.

3. EU

EU filed a REPS compliance plan that listed the following actions to comply with the requirements of G.S. 62-133.8:

- It has contracted for the purchase of the energy and 22,000 RECs per year from the Iredell Transmission, LLC, landfill gas facility in Iredell County.
- It has a 20-year contract with SunEdison for the construction and operation of a 1-MW solar facility in Alexander County that will produce 1,600 solar RECs per year.
- It has contracted for the purchase of 28,000 RECs per year from the Salem Energy Systems, LLC, landfill gas facility in Forsyth County.

- It has made a one-time purchase of 150,000 RECs generated at an out-of-state wind turbine project.
- It has received Commission approval for two EE programs: high efficiency heat pump rebates and high efficiency lighting rebates.
- It plans to use its SEPA resources for compliance, as authorized by G.S. 62-133.8(c)(2)(c).

In response to Commission Rule R8-67(b)(1)(iv), EU submitted the following aggregated projections for its members:

	2010	2011	2012
Total MWh Sales	2,236,212	2,254,213	2,277,604

Number of Customers	2010	2011	2012
Residential	102,965	103,892	104,827
Seasonal	1,611	1,592	1,573
Commercial	16,086	16,327	16,572
Industrial	22	22	22

	2010	2011	2012
Avoided Cost Rate	$0.049 per kWh	$0.055 per kWh	$0.055 per kWh

Below is a table summarizing EU's projected total and incremental costs anticipated to implement the compliance plan for each year and the annual cost caps for each year.

	2010	2011	2012
Annual cost cap	$1,861,060	$1,882,090	$3,784,600
Total costs	$820,000	$1,000,000	$1,100,000
Incremental costs	$741,600	$912,000	$912,000

4. Halifax

Halifax plans to meet up to 30% of its overall REPS requirements through its energy purchases from SEPA. Like GreenCo, Halifax has a contract to purchase RECs from the NextEra wind energy facility in Story County, Iowa. Halifax has implemented the following EE programs: distribution of CFL light bulbs, residential energy audits, and high efficiency heat pump rebates. Halifax received Commission approval of its CFL program on December 14, 2010.

Halifax has received Commission approval of its 98.56-kW solar PV facility in Docket No. EC-33, Sub 59.

	2010	2011	2012
Annual cost cap	$187,150	$189,010	$358,426
Total costs	$369,472	$354,180	$345,925
Incremental costs	$166,105	$143,422	$134,039

5. Blue Ridge and Rutherford

Duke will meet all of Blue Ridge's and Rutherford's REPS requirements.

E. Municipalities

REPS compliance for the majority of the municipalities in the State is managed by either NCEMPA or NCMPA1. NCEMPA filed a plan on behalf of its 32 municipalities[10] and NCMPA1 filed a plan on behalf of its 19 municipalities.[11]

1. NCEMPA

NCEMPA's member municipalities have no plans to generate electricity at a renewable energy facility at least until 2018 because of their full requirements contract with PEC. (Energy purchases from SEPA are authorized by the contract with PEC, however, and serve to meet 0.3% of NCEMPA's energy requirements.) NCEMPA has implemented or will implement the following DSM and EE programs: water heater control program, heat strip control program, air conditioning control program, energy audits, EE kits, and residential and commercial time of use rate programs. Up to 5% of NCEMPA's REPS requirements will be met with these programs.

Approximately 27% of NCEMPA's power supply is purchased at wholesale from PEC as supplemental power, with the balance provided through its minority ownership in various PEC power plants. This supplemental power is provided by PEC from its overall generation mix, and PEC is expected to be in compliance with the requirements of G.S. 62-133.8(b). As it did in its compliance plan for 2009-11, NCEMPA asserts that "pursuant to the provisions of N.C. § 62-133.8(c)(2)(e), the allocation of each NCEMPA Municipality's power supply from Supplemental Power will be used by each NCEMPA Municipality to meet a concomitant portion of its REPS Requirement." NCEMPA does not contend that PEC has expressly agreed to provide NCEMPA with REPS compliance services, and PEC has specifically advised the Public Staff that it has not entered into such an agreement with NCEMPA.

[10] The following municipalities are members of NCEMPA: Apex, Ayden, Belhaven, Benson, Clayton, Edenton, Elizabeth City, Farmville, Fremont, Greenville, Hamilton, Hertford, Hobgood, Hookerton, Kinston, LaGrange, Laurinburg, Louisburg, Lumberton, New Bern, Pikeville, Red Springs, Robersonville, Rocky Mount, Scotland Neck, Selma, Smithfield, Southport, Tarboro, Wake Forest, Washington, and Wilson.

[11] The following municipalities are members of NCMPA1: Albemarle, Bostic, Cherryville, Cornelius, Drexel, Gastonia, Granite Falls, High Point, Huntersville, Landis, Lexington, Lincolnton, Maiden, Monroe, Morganton, Newton, Pineville, Shelby, and Statesville.

As noted in Docket Nos. E-100, Sub 124, and E-43, Sub 6, the Public Staff does not believe that NCEMPA can gain credit toward its REPS requirements merely by virtue of the fact that PEC is selling power to NCEMPA and that PEC is expected to comply with G.S. 62-133.8(b). If NCEMPA wishes to benefit from PEC's REPS compliance planning and gain credit for PEC's purchases of renewable power and RECs, it must enter into an agreement to purchase REPS compliance services from PEC.

NCEMPA states that it is prohibited from purchasing power outside of its contracts with PEC. Therefore, it is pursuing contracts for in-state and out-of-state unbundled solar RECs, and it has contracted for ***BEGIN CONFIDENTIAL*** [redacted] ***END CONFIDENTIAL*** to be used for compliance in 2010, 2011, and 2012. NCEMPA has told the Public Staff that since filing its REPS Compliance Plan, it has acquired additional solar RECs to meet the solar set-aside.

In accordance with Rule R8-67(b)(1)(iv), NCEMPA submitted the following aggregated projections of North Carolina retail sales and year-end customer counts by class for each year:

	2010	2011	2012
Total MWh Sales	6,835,329	6,913,548	7,048,971

Number of Customers	2010	2011	2012
Residential	228,534	231,149	235,677
Commercial	37,906	38,340	39,091
Industrial	545	551	562

NCEMPA *provided the following data on its avoided costs:*

Avoided Energy Costs		Avoided Capacity Costs	
On-Peak	Off-Peak	Jan-May, Oct-Dec	June-Sept
$/MWh	$/MWh	$/MWh	$/MWh
55.01	42.87	25.44	30.86

To facilitate comparison with other electric power suppliers, the Public Staff has used the above data to calculate a single per-MWh avoided cost figure for NCEMPA, including both energy and capacity costs. The Public Staff's calculations indicate that NCEMPA's overall avoided costs amount to $56.57 per MWh.

NCEMPA provided information, as required by Rules R8-67(b)(1)(vi) and (vii), on the projected total and incremental costs anticipated to implement its compliance plan

[12] This represents *** BEGIN CONFIDENTIAL *** [redacted] *** END CONFIDENTIAL *** that NCEMPA had contracted for at the time its compliance plan was filed. NCEMPA has advised the Public Staff that it has contracted for a larger number since the plan was filed.

for each year, together with a comparison of these costs to the annual cost caps. The information provided by NCEMPA is summarized in the following table:

	2010	2011	2012
Total costs	$4,400,000	$4,500,000	$8,000,000
Incremental costs	$3,300,000	$3,300,000	$6,600,000
Annual cost cap	$3,300,000	$3,300,000	$6,600,000

NCEMPA does not expect to reach the REC percentage goals of G.S. 62-133.8(c)(1) before hitting the cost cap for 2010, 2011, and 2012. However, NCEMPA stated that it remains committed to achieving those goals. In NCEMPA's REPS compliance proceeding for 2009, Docket No. E-48, Sub 6, the Public Staff objected to certain REPS compliance costs claimed by NCEMPA, and since that case remains open, the Public Staff expects to raise these issues again in the 2010 compliance docket. If the Commission rules in the Public Staff's favor on these issues, NCEMPA may be able to avoid reaching the cost cap and fulfill its goal.

2. NCMPA1

NCMPA1 has not built any renewable generation facilities but continues to investigate and seek proposals for this type of facility. NCMPA1 has executed contracts for the purchase of RECs from various renewable resources. Its members intend to include the delivery of energy from SEPA to meet part of their REPS requirements. NCMPA1 does not anticipate having its wholesale suppliers' assistance in meeting its members' REPS requirements.

In order to meet the solar set-aside, NCMPA1 has contracted to receive energy and RECs from a PV system in Shelby, North Carolina. It is also considering the development of other solar PV facilities, the purchase of solar RECs, and promotion of solar thermal projects at municipal facilities and customer-owned facilities. NCMPA1 appears to have sufficient solar resources to meet the solar set-aside for 2010, 2011, and 2012.

NCMPA1's members will continue, or consider, implementing several EE programs including residential, commercial, and municipal energy audits; energy efficient lighting; incentives for installation of high efficiency heat pumps and appliances; weatherization of low income housing; and issuing a request for proposals for commercial and industrial customers to design their own EE improvements. Up to 20% of NCMPA1's REPS requirement will be met with these programs in 2012. NCMPA1's members will continue, or consider, implementing several DSM programs including air conditioner load control, adjustment of substation voltage levels, shifting commercial and industrial loads from on-peak to off-peak hours, and smart grid technology.

NCMPA1's projections of its members' aggregated North Carolina retail sales and year-end customer counts by class for each year are summarized in the following tables:

	2010	2011	2012
Total MWh Sales	4,918,269	4,963,795	5,022,429

Number of Customers	**2010**	**2011**	**2012**
Residential	137,380	138,617	139,864
Commercial	24,870	25,094	25,320
Industrial	631	631	631

NCMPA1 submitted the following data on its avoided cost rates:

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[redacted]

***** END CONFIDENTIAL *****

Based on this information, the Public Staff has calculated that NCMPA1's overall avoided cost rates, including both capacity and energy costs, are as follows:

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[redacted]

***** END CONFIDENTIAL *****

The information provided by NCMPA1 pursuant to Rule R8-67(b)(1)(vi) and (vii), on the projected total and incremental costs anticipated to implement its compliance plan for each year, and on its projected annual cost caps, is as follows:

	2010	2011	2012
Total costs	$800,000	$800,000	$5,700,000
Incremental costs	$700,000	$700,000	$1,600,000
Annual cost cap	$2,900,000	$3,000,000	$6,100,000

3. Fayetteville

To meet the solar set-aside requirement in 2010, Fayetteville plans to purchase solar RECs. To meet this requirement beyond 2010, Fayetteville is in negotiations to purchase all the RECs from a 750-kW solar PV facility. Fayetteville must have obtained 407 solar RECs in 2010, obtain 415 solar RECs in 2011, and obtain 418 solar RECs in 2012.

Fayetteville submitted a plan stating that it might meet its REPS obligations during the compliance period with its purchases of wholesale power from PEC pursuant to a contract in effect through June of 2012, if allowed by the Commission. As noted above in the discussion for NCEMPA, the Public Staff objects to this approach because Fayetteville has not purchased compliance services from PEC. The contract in effect after June 2012 expressly prohibits Fayetteville from using PEC's REPS compliance actions to meet Fayetteville's REPS requirements. Fayetteville plans to meet up to 30% of its overall REPS requirements through the use of its SEPA entitlement and is considering a combined heat and power system at its Cross Creek Water Reclamation Facility Digester Complex. It also plans to earn EE RECs through efficiency improvements at its customer service center and through its $martWorks program that allows customers to have real-time monitoring and control of their energy usage.

Fayetteville has submitted the following information on its projected retail MWh sales and year-end customer counts:

	2010	2011	2012
Total MWh Sales	2,077,399	2,087,786	2,098,225

Number of Customers	2010	2011	2012
Residential	68,755	69,099	69,444
Commercial	9,399	9,493	9,578
Industrial	25	25	25

Fayetteville estimates its avoided cost rates at 2.119 cents per kWh for 2010 and 2.150 cents per kWh for 2011. For 2012, Fayetteville will use PEC's avoided costs that are approved by the Commission.

Fayetteville intends to meet the REPS compliance requirements of G.S. 62-133.8(d), (e), and (f), but may not achieve the percentage requirements of G.S. 62-133.8(c).

4. Other Municipalities

There are several municipalities not included in the filings of Duke, PEC, DNCP, NCEMPA, or NCMPA1. The Town of Enfield has signed a REPS compliance contract with Halifax. The Towns of Pinetops, Macclesfield, and Walstonburg have a full requirements wholesale contract with the City of Wilson, which, in turn, has a wholesale contract with NCEMPA, which will meet the REPS compliance requirements of these three towns. The Murphy Electric Board will have its compliance met by TVA and is included in the TVA plan described above.

The Towns of Oak City and Winterville submitted plans detailing their plans for compliance. The Town of Winterville may reach the cost cap before meeting the requirements of G.S. 62-133.8(c), (d), (e), and (f). The Town of Oak City did not explain its costs clearly enough for the Public Staff to determine whether it is likely to comply with the REPS but did state that it is primarily pursuing EE to meet the requirements of G.S. 62-133.8(c). The Town of Fountain failed to file a REPS compliance plan, *although the Public Staff has contacted the Town and called attention to the filing* requirements.

F. Swine and Poultry Waste Set-Asides

Duke, PEC, DNCP, GreenCo, NCEMPA, and NCMPA1 have formed a group (collectively, the Swine Group) to jointly request proposals for energy or RECs derived from swine waste to meet the requirements of G.S. 62-133.8(e). Duke and PEC believe that the short-listed providers that responded to the request will be able to provide enough swine waste resources to meet the 2012 requirements for the Swine Group. However, uncertainties remain and Duke and PEC cannot firmly conclude that the Swine Group's requirements will be met. These uncertainties include the high cost; the very large size of the requirement, which could lead to an overlap in fuel supply assumptions; and the lack of diversity of technology. The overlap in fuel supply is created by multiple contractors assuming that they can obtain swine waste from the same farm. The lack of diversity in technology has arisen because biogas from anaerobic digestion is the predominant method.

Duke has taken a leadership role for the Swine Group. In late January 2011, the Public Staff contacted Duke for an update on the group's ability to meet the swine waste set-aside. Duke confirmed that it had signed one contract for the delivery of energy derived from swine waste and several other contracts were close to being signed. Also, Duke has partnered with Duke University to secure funding and develop a pilot scale anaerobic digestion process using swine waste that is expected to generate 512 to 639 MWh per year.

Duke also stated that N.C. Session Law 2010-195 (Senate Bill 886) has created uncertainty in the poultry waste energy market, because this law could have different interpretations and greatly affect the cost of poultry waste RECs. Session Law 2010-195 allows biomass renewable energy facilities that meet strict size and geographic requirements to receive triple credit toward the poultry waste set-aside regardless of whether the biomass is derived from poultry waste or not.

PEC, DNCP, GreenCo, EU, Halifax, NCEMPA, NCMPA1, and Fayetteville (but not Duke) formed a group (collectively, the Poultry Group) to jointly pursue energy or RECs *derived from poultry waste to meet the requirements of G.S. 62-133.8(f). Meeting* the poultry waste set-aside has also provided challenges to the Poultry Group; some challenges are similar to those of meeting the swine waste set-aside. The high cost and lack of suppliers of energy or RECs derived from poultry waste have made it more difficult for the Poultry Group and Duke to reach an agreement with any suppliers. Potentially restrictive air emissions limits have also added uncertainty. Nevertheless, Duke will pursue meeting the 2012 requirement, but will not commit to meeting it. PEC stated that its ability to meet the poultry set-aside is promising, but it is unsure it will meet the 2012 requirement.

PEC has taken a leadership role for the Poultry Group. In late January 2011, the Public Staff contacted PEC for an update on the group's ability to meet the poultry waste set-aside. PEC confirmed that it is in negotiations for a contract with one potential supplier of energy derived from poultry waste. If the contract is executed, the EMCs and municipalities plan to pursue their own contract to provide themselves with RECs derived from poultry waste.

G. Conclusions on REPS Compliance Plans

The Public Staff believes that Duke, PEC, and DNCP can meet the general and solar REPS requirements for themselves and the electric power suppliers for which they are providing REPS compliance services for the time period covered by their REPS Compliance Plans.

Duke and PEC, as well as other electric power suppliers in North Carolina, may have difficulty meeting the swine waste and poultry waste requirements, but they are actively pursuing energy and RECs to meet these requirements for 2012.

Most of the EMCs and municipalities have submitted REPS compliance plans that satisfy most or all of the filing requirements of Commission Rule R8-67(b). Some plans – specifically those of NCEMPA and Fayetteville – reflect an incorrect understanding that their REPS requirements can be met by PEC's REPS compliance.

There are two matters not previously addressed in these comments that should be discussed. First, the Public Staff has not reviewed the methods used by the EMCs and municipalities in calculating the costs of their planned renewable purchases and EE programs. How an EMC or municipality calculates its costs affects how quickly it reaches the cost cap of G.S. 62-133.8(h)(4).

Second, G.S. 62-133.8(c)(2)(b) provides that one method of REPS compliance available to an EMC or municipality is to "[r]educe energy consumption through the implementation of demand-side management or energy efficiency measures." Commission Rule R8-67(c)(1)(i) provides that, with regard to REPS compliance, renewable energy certificates for EE may be based on estimates of reduced energy consumption through the implementation of EE measures, to the extent approved by the Commission. The Public Staff believes that it may be appropriate to clarify this rule, particularly with regard to its application to EMCs and municipalities. Unlike the IOUs, EMCs and municipalities do not undergo cost recovery proceedings under G.S. 62-133.9 and Commission Rule R8-69 for their DSM and EE programs. In those proceedings, IOUs will eventually submit detailed measurement and verification for the Commission's review at the time they seek to recover their costs and, potentially, collect an incentive. The Public Staff does not seek clarification of Rule R8-67(c)(1)(i) as part of this proceeding, but may make such a request at a later time in another proceeding.

The Commission, in an order issued on August 24, 2010, in Docket No. E-100, Sub 113, requested comments from interested parties on methods and timing of measuring and verifying the reductions in peak load and energy usage achieved by electric power suppliers through DSM and EE programs. Initial and reply comments were filed on October 15 and November 19, 2010, respectively. This matter is still pending before the Commission.

XIV. PUBLIC STAFF'S RECOMMENDATIONS

In conclusion, the Public Staff makes the following recommendations:

A. That French Broad and Blue Ridge, having withdrawn from NCEMC and taken responsibility for procuring their own power supply resources, are required by Commission Rule R8-60(b) to file IRPs and should begin filing them in 2011;

B. That PEC refile with its reply comments portions of its IRP reflecting the generating unit retirements required by the Commission's January 28, 2010 Order in E-2, Sub 960;

C. That PEC and Duke file with their reply comments the specific explanation required by Rule R8-60(i)(3) for each year in which the revised projected reserve margin exceeds plus or minus 3% of the target;

D. That Duke and PEC conduct a comprehensive study to determine the appropriate reserve and capacity margin values to be used for the planning and operation of their systems for the next IRP filing;

E. That each IOU and EMC investigate utilization of its DSM resources to achieve fuel savings and include a discussion of the results of its investigation in its next IRP;

F. That any IOU or EMC relying on a DSM/EE market potential study older than two years update its study or perform a new study that addresses current legislation and standards applicable to DSM/EE ,measures and discusses measures and programs that are deemed to be cost effective and file the update or study with its 2011 IRP;

G. That all EMCs include a full discussion in future IRPs of their DSM programs and their use of these resources as required by Rule R8-60(i)(6);

H. That Piedmont indicate in its reply comments whether its smart meter program is an EE program, and if so, file for Commission approval of the program pursuant to Rule R8-68;

I. That EU provide in its reply comments and in future IRPs a more detailed description of the participation and savings related to specific DSM and EE program, and more particularly any DSM or EE program it propose to use to meets its REPS obligations;

J. That each IOU, NCEMC, and EMC that is required to file an IRP include scenarios in its 2011 IRP with no carbon and low carbon price impacts, as well as scenarios factoring in the impact of regulation of carbon emissions; these scenarios should also be included in future IRP submissions until such time that such scenarios are no longer plausible;

K. That Duke identify in its reply comments the period during which the double counting of avoided capacity cost benefits occurred and provide an explanation of the effect of the issue, on any data filed with the Commission, including whether the error influenced Tables 4.1 and 4.2 of the IRP, and provide calculations or other necessary data supporting its response;

L. That within 30 days, Duke should file in the respective dockets of each DSM program and pilot approved by, or pending before the Commission, a calculation showing the difference between the avoided cost capacity and energy benefits as originally filed, and the avoided cost benefits recalculated using the correct calculation methodology;

M. That within 30 days, Duke should file in the respective dockets of each DSM program and pilot approved by, or pending before the Commission, a calculation of each of the four cost effectiveness tests using the correct calculation methodology, and provide an exhibit showing the inputs and results of the tests as originally filed and as corrected;

N. That Duke should provide in its reply comments a list of all dockets filed with the Commission since January 1, 2005 that included any information, input data, or output results from the DSMore model affected by the double-counting issue; and

O. That the Commission direct the Town of Fountain to file a REPS compliance plan, and the Town of Oak City to file a clearer and more specific plan, in 2011.

Respectfully submitted, this the 10th day of February, 2011.

PUBLIC STAFF
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CERTIFICATE OF SERVICE

I do hereby certify I have this day served a copy of the foregoing Comments on each of the parties of record in this proceeding or their attorneys of record in accordance with Commission Rule R1-39 by United States Mail, first class or better; by hand delivery; or by means of facsimile or electronic delivery upon agreement of the receiving party.

This the 10th day of February, 2011.

Lucy E. Edmondson