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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
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DOCKET NO. E-100, SUB 128
DOCKET NO. E-100, SUB 131

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 128 In the Matter of Investigation of Integrated Resource Planning in North Carolina – 2011 DOCKET NO. E-100, SUB 131 In the Matter of 2011 REPS Compliance Plans and 2010 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 2011 update to the 2010 biennial reports (2011 IRP) 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 following electric membership corporations (EMCs): the North Carolina Electric Membership Corporation (NCEMC)[1]; Rutherford EMC (Rutherford), Piedmont EMC (Piedmont), Haywood EMC (Haywood), and EnergyUnited EMC (EU).[2] 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,[3] GreenCo Solutions, Inc.

[1] NCEMC indicates that it provides wholesale power to 25 of the 26 electric cooperatives (EMCs) in North Carolina and is the full requirements power supplier for 20 of the cooperatives. NCEMC's 2011 IRP is filed on behalf of these 20 members. NCEMC provides partial requirements capacity and energy entitlements to 5 EMCs, Rutherford EMC (Rutherford), Piedmont EMC (Piedmont), Halifax EMC (Halifax), Haywood EMC (Haywood), and EnergyUnited EMC (EU) (collectively, the "independent EMCs"). The 26th EMC, French Broad EMC (French Broad), is not a member of NCEMC and is not required to file an individual IRP, as it has entered into a full requirements contract with PEC.

[2] Blue Ridge EMC contracts with Duke as its full requirements and REPS compliance service provider. Blue Ridge, therefore, is not required to file an IRP.

[3] 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.

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(GreenCo),[4] Halifax EMC (Halifax), EU, and EMCs that serve North Carolina customers but are headquartered outside the State.

I. INTRODUCTION

Several statutes and Commission rules guide the Commission's review of the electric utilities' resource 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."

To meet the requirements of G.S. 62-110.1 and G.S. 62-2(a)(3a), the Commission conducts an annual investigation into the electric utilities' IRP. 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 that Commission Rule. In odd-numbered years, each of the electric utilities must file an annual report updating its most recently filed biennial report. Further, Commission Rule R8-67(b) requires any electric power supplier subject to Rule R8-60 to file a REPS compliance plan as part of its IRP report. Within 150 days of the filing of each electric utility's biennial report and within 60 days of the filing of each electric utility's annual report, the Public Staff or any other intervenor may file its own plan or an evaluation of, or comments on, the electric utilities' IRP reports. Furthermore,

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[4] GreenCo filed a consolidated 2011 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, Haywood EMC, Jones-Onslow EMC, Lumbee River EMC, Pee Dee EMC, Piedmont EMC, Pitt & Greene EMC, Randolph EMC, Roanoke EMC, South River EMC, Surry-Yadkin EMC, Tideland EMC, Tri-County EMC, Union EMC, and Wake EMC. GreenCo provides REPS compliance services to Mecklenburg Electric Cooperative and Broad River Electric Cooperative, and their REPS obligations are included in the GreenCo REPS Compliance Plan.

the Public Staff or any other intervenor may identify any issue that it believes should be the subject of an evidentiary hearing.

A. S.L. 2007-397 and Commission Rules

i. S.L. 2007-397 (Senate Bill 3 or "SB3")

Senate Bill 3 expanded the Commission's review of electric utilities' resource 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 every year to the Governor, the Environmental Review Commission, and the Joint Legislative Commission on Governmental Operations on the compliance with the REPS requirements by the IOUs, EMCs, and municipalities.

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."[5] 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."[6] EE measures do not include DSM.[7] The Public Staff will rely upon these statutory definitions in these comments.

ii. 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

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

[6] G.S. 62-133.8(a)(2) and (a)(4).

[7] G.S. 62-133.8(a)(4).

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 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 IRPs concerning the construction of transmission lines.

Commission Rule R8-60(h)(4) requires that each biennial and annual IRP 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.

B. Docket No. E-100, Sub 128, 2011 IRP Update

On March 3, 2011, Blue Ridge EMC filed comments 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 for REPS compliance would be provided by Duke, and its REPS requirements would be reflected in Duke's 2011 REPS Compliance Plan. On August 17, 2011, Rutherford filed a letter indicating that Duke was its full requirements and REPS compliance provider and that its load requirements would be reflected in Duke's IRP and its REPS compliance would be reflected in Duke's REPS compliance plan. On August 24, 2011, NCEMC and GreenCo filed a joint motion to extend the filing date for submission of their 2011 IRP, 2011 REPS Compliance Plan, and 2010 REPS Compliance Report to September 19, 2011. GreenCo also noted that its annual reports will include data for Mecklenburg Electric Cooperative (Mecklenburg) and Broad River Electric Cooperative (Broad River), as these cooperatives have requested that GreenCo serve as their aggregator for such purposes. The Commission granted the requested extensions by Order on August 31, 2011.

On August 30, 2011, EU filed its 2011 IRP, 2010 REPS Compliance Report, and 2011 REPS Compliance Plan. On August 30, 2011, Haywood filed its 2011 IRP. On August 31, 2011, Rutherford filed its 2011 IRP. On September 1, 2011, Duke, PEC, and DNCP filed their 2011 IRPs and REPS Compliance Plans; and Piedmont filed its 2011 IRP. On September 19, 2011, NCEMC filed its 2011 IRP and GreenCo filed its 2011 REPS Compliance Plan and 2010 REPS Compliance Report.

On October 7, 2011, the North Carolina Waste Awareness and Reduction Network, Inc. (NC WARN) submitted its initial comments on the 2011 IRPs.

On October 20, 2011, the Public Staff moved that the deadline for the filing of initial comments on IRPs be extended to January 13, 2012, which the Commission granted by Order dated October 25, 2011.

On October 26, 2011, the Commission issued its Order Approving 2010 Biennial Integrated Resource Plans and 2010 REPS Compliance Plans (2010 IRP Order). The Order required utilities to include certain information in future IRP filings.[8]

By Order dated December 5, 2011, the Commission scheduled a public hearing for January 17, 2012 on the filed IRPs and REPS compliance plans.

C. Docket No. E-100, Sub 131

On August 31, 2011, the North Carolina Eastern Municipal Power Agency (NCEMPA), the North Carolina Municipal Power Agency 1 (NCMPA1), the Tennessee Valley Authority (TVA), and the Town of Winterville filed their 2011 REPS compliance plans and 2010 REPS compliance reports. On September 2, 2011, the Town of Oak City filed its 2011 REPS Compliance Plan and 2010 REPS Compliance Report. On October 25, 2011, the Town of Fountain filed its 2011 REPS Compliance Plan and 2010 REPS Compliance Report.

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.

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 (2012–2026). The compound annual growth rates (CAGRs) for the forecasts of Duke, PEC, and DNCP are within the range from 1.3% to 1.8%. The CAGRs for NCEMC and the four independent EMCs that filed IRPs are within the range of 0.6% and 3.8%. The utilities' DSM and EE programs are discussed briefly below and fully in the DSM and EE section.

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,

[8] As the 2010 IRP Order was issued following the filing of the 2011 IRPs, the requirements in the Order regarding information to be included in future IRP filings should be applicable to the utilities' 2012 IRPs.

the Public Staff analyzed the accuracy of the utilities' peak demand and energy sales predictions in the 2006 IRP 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 2010 IRP. Prior to the implementation of its DSM and EE programs, PEC expects its summer peaks to grow at 1.9%. The average annual growth of its summer peak, which is considered its system peak, is 201 megawatts (MW) for the next 15 years, as compared to 213 MW from last year's IRP. PEC predicts that load reductions from its DSM programs will reduce its peak load by approximately 11% in 2026.

PEC's energy sales are predicted to grow at a CAGR of 1.3%, a 0.1% increase from the projected growth rate in the 2010 IRP. PEC predicts that the megawatt-hour (MWH) reductions from its EE programs will reduce its energy sales by approximately 3% in 2026.

PEC's last summer peak of 12,094 MW occurred on Friday, July 22, 2011, at the hour-ending 3:00 p.m. At the time of the 2011 peak, PEC activated its EnergyWise Program and Commercial, Industrial, and Government Demand Response Program, which reduced its peak load by 82 MW and 15 MW, respectively, for a total reduction of 97 MW. By comparison, recognizing that the decision to activate a DSM program depends on a variety of factors, PEC's 2010 IRP projected it would have 611 MW available from its DSM programs to reduce its 2011 summer peak.

The Public Staff's one-year review of PEC's peak load accuracy shows that the predictions in the 2010 IRP represent a forecast with less than a 3% error.[9] The low forecast error rate was, in part, due to the system-wide average temperature of 101 degrees Fahrenheit, which is an above average 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 2006 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.

[9] 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 1.8%, which is a 0.2% greater growth rate than projected in the 2010 IRP. Prior to the implementation of its DSM and EE programs, Duke expects its summer peaks to grow at 1.9%. The average annual growth of its summer peak, which is considered its system peak, is 351 MW for the next 15 years, as compared to 322 MW from last year's IRP. Duke predicts that load reductions from its DSM programs will reduce its peak load by approximately 7% in 2026.

Duke's energy sales are expected to grow at a CAGR of 1.8%. This growth rate in energy sales is the same as in the 2010 IRP. Duke predicts that the MWH savings from its EE programs will reduce its energy sales by approximately 4% in 2026.

Duke's last summer peak of 17,651 MW occurred on Thursday, July 21, 2011, at the hour-ending 3:00 p.m. Duke activated approximately 121 MW of DSM programs available to lower its 2011 system peak. By comparison, recognizing that the decision to activate a DSM program depends on a variety of factors, Duke's 2010 IRP projected it would have 961 MW available from its DSM programs to reduce its 2011 summer peak.

The Public Staff's one-year review of Duke's peak load accuracy shows that the predictions in the 2010 IRP represent a forecast with less than a 1% error. The system-wide average temperature was 94 degrees Fahrenheit, which is relatively close to the normal system-wide peak-day temperature. The Public Staff's five-year review of Duke's energy sales forecasting accuracy shows that the predictions in Duke's 2006 IRP reflect a 6.1% forecast error. This average forecast error for the five-year period is due largely to the economic slowdown in the last several years.

The Public Staff believes that the economic, weather, and demographic assumptions that underlie Duke's 2011 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 2011 forecasts are reasonable for planning purposes.

C. DNCP

DNCP's 15-year forecast predicts that its summer peaks will grow at a CAGR of 1.4%, which is a decrease of 0.3% from the projected growth rate in the 2010 IRP. The average annual growth of its summer peak, which is considered its system peak, is 274 MW for the next 15 years, as compared to 342 MW from last year's IRP. DNCP predicts that load reductions from its DSM programs will reduce its 2026 peak load by approximately 4%.

DNCP's energy sales are predicted to grow at an average annual rate of 1.6%. This projected growth rate in energy sales is a decrease of 0.2% from the growth rate in the 2010 IRP. DNCP predicts that the MWH savings from its EE programs will reduce its energy sales by approximately 3% in 2026.

DNCP's last summer peak of 17,563 MW occurred on Friday, July 22, 2011, at the hour-ending 4:00 p.m. At the time of the summer peak, DNCP called on its Distributed Generation Pilot[10] for a load reduction of 10 MW and its Air Conditioning Cycling Program for a reduction of 40 MW. In its 2010 IRP, DNCP did not project the availability of any DSM resources for 2011.

The Public Staff's one-year review of DNCP's peak load accuracy shows that the predictions in the 2010 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 2006 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 1.6%, a decrease of 0.2% from the predicted growth rate in its 2010 IRP. The average annual growth of its summer peak, which is considered its system peak, is 52 MW.

While NCEMC is considered a summer peaking utility, its current annual system peak of 2,982 MW occurred on Friday, January 14, 2011, at the hour-ending 8:00 a.m. NCEMC's 2010 IRP projected 67 MW would be available from its DSM programs to reduce the winter peak.

NCEMC's energy sales are predicted to grow at an average annual rate of 1.5%, a decrease of 0.2% from the growth rate predicted in its 2010 IRP. NCEMC predicts that the MWH savings from its EE programs will reduce its energy sales by approximately 1% in 2025.

The Public Staff's one-year review of NCEMC's peak load forecast accuracy shows that the prediction in its 2010 forecast had less than a 3% forecast error. The Public Staff's review of the forecast accuracy for the past five years indicates that the forecasts in its 2006 annual report were on average 249 MW lower than its actual system load, which equates to an 8% forecast error. However, the high error rate is largely attributed to the 2007 and the 2008 predictions for peak loads, as compared to

[10] The Distributed Generation Pilot is a DSM program operating only in Dominion's Virginia jurisdiction.

an error rate of less than 5% for the 2011 prediction. NCEMC's energy sales forecast has been reasonably accurate with less than a 5% error rate. As noted in its 2010 IRP, NCEMC has 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 a per customer level that allows for the quantification of peak demand changes among each of its member cooperatives that are attributable to changes in weather conditions and other exogenous factors. The Public Staff expressed concern in prior IRP dockets about the accuracy of NCEMC's forecasting methods, and NCEMC subsequently adopted this new forecasting process. While the forecast accuracy appears to be improving, 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 system peak will grow at an average annual rate of 0.7%. Its energy sales are predicted to grow at an average annual rate of 1.0%. The average annual growth of the annual peak is 4 MW over the 15-year forecast. EU's annual peak of 642 MW occurred on Wednesday, December 15, 2010, at the hour-ending 8:00 a.m. EU activated its DSM programs and reduced the load by 17 MW at the time of its peak. The Public Staff believes that the forecasts by EU are reasonable for planning purposes.

F. Haywood

Haywood's 15-year forecast predicts that its system peak will grow at an average annual rate of 1.9%. 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 of 83 MW on Sunday January 9, 2011, at the hour-ending 9:00 a.m. Haywood activated its DSM programs and reduced the load by 0.5 MW 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 system peak will grow at an average annual rate of 1.9%. The average annual growth of its peak is 3 MW over the 15-year period. Piedmont's energy sales are predicted to grow at an average annual rate of 1.8%. Piedmont's annual peak of 124 MW occurred on Friday, July 22, 2011, at the hour-ending 6:00 p.m. At the time of its peak, Piedmont activated its DSM programs and reduced the load by 5 MW. The Public Staff believes that the forecasts by Piedmont are reasonable for planning purposes.

H. Rutherford

Rutherford's 15-year forecast predicts that its system peak will grow at an average annual rate of 3.7%. Its energy sales are predicted to grow at an average annual rate of 1.0%. The average annual growth of Rutherford's system peak is 5 MW over the 15-year period. Rutherford's annual peak of 342 MW occurred on Friday, January 14, 2011, at the hour ending 8:00 a.m. Rutherford did not activate any of its DSM programs at the time of its peak.

The 3.7% average annual growth rate forecasted for Rutherford's peak appears to be rather high. Based on discussions with the Company and its consultants, it appears that the models used to forecast the EMC's load may have given excessive weight to the recent large increases in the Company's peaks that may not be sustainable over the next fifteen years, and Rutherford will make a correction in its the 2012 IRP. As Duke is a full requirements provider to Rutherford, Duke relies on its own independent forecasts of Rutherford's capacity and energy requirements. The Public Staff believes that the forecasts used by Rutherford are reasonable for planning purposes.

I. Conclusions on 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.

2012- 2026 Growth Rates
(After New EE and DSM)

	Summer Peak	Winter Peak	Energy Sales	Annual MW Growth
PEC	1.6%	1.8%	1.3%	201
Duke	1.8%	1.7%	1.8%	351
DNCP	1.4%	1.6%	1.6%	274
NCEMC	1.6%	2.2%	1.5%	52
EU	0.7%	0.6%	1.0%	4
Haywood	1.8%	1.9%	2.0%	2
Piedmont	2.0%	1.9%	1.8%	3
Rutherford	3.8%	3.7%	1.0%	18

On October 7, 2011, NC WARN filed its Initial Comments on the 2011 IRPs and maintained that the growth projections by Duke and PEC are overly optimistic. However, the growth rates cited by NC WARN for Duke and PEC appear to relate only to the retail sales class and exclude any wholesale sales. Second, the issues that relate to generation planning for a utility's retail native load customers and its historically served wholesale customers have been litigated and resolved in Docket Nos. E-100, Sub 85A and E-7, Sub 858. The growth rates in the table above, with the exception of Rutherford's peak growth rates, are very similar to growth rates in recent IRPs approved by the Commission, and the Public Staff believes they are reasonable for planning in this proceeding.

III. GENERATING FACILITIES

Commission Rule R8-60(i)(2) specifies certain data each utility must provide in its biennial IRP, and revise as applicable in its annual update, regarding its existing and planned electric generating facilities. In its March 21, 2007, Order Granting Certificate Of Public Convenience and Necessity with Conditions in Docket No. E-7, Sub 790, for Cliffside Unit 6, the Commission ordered Duke to retire older coal units on a MW-for-MW basis to account for actual load reductions achieved by new EE and DSM programs, up to 800 MW, subject to consideration of the impact on system reliability. In the air permit issued by the North Carolina Department of Environmental and Natural Resources, Division of Air Quality (DAQ) for Cliffside Unit 6, Duke agreed to retire the 800 MW of additional coal capacity without regard to achieving a commensurate level of MW savings from new EE and DSM programs. Duke filed a Greenhouse Gas Reduction Plan with DAQ, which can be revised with DAQ's approval if the Commission determines that the scheduled retirement of any unit will have a material impact on the reliability of Duke's system. Duke has included as Appendix J a Carbon Neutrality Plan that projects retirements that would exceed its Greenhouse Gas Reduction Plan by close to 50%.

In its Application filed on July 1, 2011 in Docket No. E-7, Sub 989, Duke sought to accelerate the depreciation of certain plants slated for early retirement. In the Stipulation filed by Duke, Time-Warner, and the Public Staff on December 2, 2011, the depreciation schedule for these plants was left unchanged. The Public Staff recommends that the actual timing of the retirements and the accounting treatment Duke proposes to follow with respect to the unrecovered cost of generating units projected to be retired be addressed in one or more separate dockets.

Duke also requests approval from the NCUC of its proposed method of calculating the Emission Reduction Requirements and emissions offset values of certain "Qualifying Actions" as set out in Table J.3. The Public Staff proposes that this issue also be addressed in a separate docket.

The Public Staff further recommends that that Duke be required to continue to provide updates in future IRPs regarding its obligations related to this air permit to:(a) retire 800 MW of coal capacity in North Carolina in accordance with the schedule set forth in Table J.1, (b) accommodate to the extent practicable the installation and operations of future carbon control technology at Cliffside 6, and (c) take additional actions to make Cliffside 6 carbon neutral by 2018.

IV. RESERVE MARGINS AND RESERVE MARGIN ADEQUACY

Commission Rule R8-60(i)(1)(ii) requires that both the biennial and annual IRP reports contain forecasts for the planning period that include projected reserve margins. Commission Rule R8-60(i)(3) requires that utilities include an explanation when the reserve margin during a given year varies by plus or minus 3% from the target or planning reserve margin. PEC provided the explanation required by the Rule.

Duke's 2011 IRP incorporates a 17% planning reserve margin, while its projected reserve margins as set out in Table 8.A vary from 16.1% to 24.3% over the planning period. Duke's IRP did not include a specific explanation for the instances in 2021, 2023, and 2024 when the projected reserve margins vary from the planning reserve margins by plus or minus 3%, as required by Rule R8-60(i)(3). The Public Staff recommends that Duke include the information required by Rule R8-60(i)(3) in its reply comments in regard to its 2011 IRP and comply with this requirement in subsequent IRP reports.

DNCP is currently adding significant amounts of new capacity with its Bear Garden and Virginia City Hybrid Energy Center facilities in order to meet obligations imposed by the Commonwealth of Virginia 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).[11] PJM's 2009 assessment recommended using a reserve margin of 15.3%. DNCP uses the PJM reserve margin guidelines in conjunction with its own load forecast to determine its long-term need for capacity. Because DNCP is obligated under the RAA to only maintain a reserve margin for its portion of the PJM coincidental peak load, it determined that an effective reserve margin of 11% for 2014 through 2025 would be adequate (based a coincidence factor of 96.3%). Nevertheless, the reserve margins for two years of the planning period are 15.28% (2015), and 17.33% (2016). Like Duke, DNCP also offered no explanation for exceeding the planning reserve margin by greater than 3%. The Public Staff recommends that DNCP include the information required by Rule R8-60(i)(3) in its reply comments in regard to its 2011 IRP and comply with this requirement in subsequent IRP reports.

In its October 26, 2011 Order approving the 2010 IRPs and REPS Compliance Plans (2010 IRP Order), the Commission ordered Duke and PEC to prepare a comprehensive reserve margin requirements study to be included as part of their 2012 IRPs and keep the Public Staff updated as they develop the parameters of the studies. Duke and PEC have indicated to the Public Staff that they intend to issue a request for proposals for a Reserve Margin Study by February 2012 and award the contract by March 2012.

[11] The RAA obligates DNCP to own or acquire sufficient capacity to maintain overall reliability. PJM annually conducts a 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.

V. DSM AND EE

A. Changes in Forecasted EE Savings

The Public Staff's review of the 2011 IRPs indicates a continuing decrease in the forecasted EE savings from the IOUs' and EMCs' portfolios of DSM/EE programs. With the exception of DNCP and Haywood, the forecasted EE savings in the 2011 IRPs are 0.2% to 64% lower than those projected in the 2010 IRPs for the respective years of the planning horizon. While not required by Commission rule, the Public Staff believes that it would assist the Commission in its review of biennial and annual IRP reports if the IOUs and EMCs addressed in future IRPs the reasons for significant variances[12] from year to year in projections of EE savings. Thus, the Public Staff recommends that the Commission require the utilities to include a discussion of significant variances in projected EE savings in future IRPs.

B. DSM/EE Programs and Education Initiatives

No utility indicated that it had discontinued any DSM/EE program that it included in its 2010 IRP. Duke and PEC included new DSM/EE programs that had received Commission approval in 2011. Additionally, Rutherford included a new smart meter program that provides customers with usage information through a secure web-based portal, though it is unclear whether Rutherford considered the program to be an EE program. If Rutherford considers the program to be an EE program, it should file for Commission approval pursuant to Rule R8-68.

All IOUs and EMCs included a list of educational initiatives in their 2011 IRPs similar to those included in their 2010 IRPs.

C. Use of DSM to its Fullest Extent in Order to Maximize Fuel Savings

The Commission concluded in its 2010 IRP Order that while it did not find a correlation between DSM-related fuel savings and the spot market for purchased power, DSM resources could be activated during times of high system load to achieve low fuel costs in lieu of dispatching higher cost peaking generation resources. The Commission directed all IOUs and EMCs to specifically address this issue in their 2012 IRPs. Duke and PEC addressed this issue in their 2011 IRPs and indicated that they would include a more detailed evaluation of the possible fuel savings from DSM in their 2012 IRPs.

Each IOU, EU, Haywood, Piedmont, and Rutherford reported activating their DSM at the time of their 2011 system peaks. The IOUs provided additional information indicating use of DSM throughout their summer peak seasons during several high load hours. In response to a Public Staff data request NCEMC (including Halifax EMC as a member) indicated that its member EMCs did not use DSM at the time of their 2011

[12] The Public Staff proposes that a variance of 10% in projected EE savings from one IRP report to the next trigger the requirement that the utility address the reason for the variance.

system peaks. The Public Staff continues to study the use of DSM to offset fuel costs and will conduct further analysis in its review of the 2012 IRPs.

D. Market Potential Study for DSM/EE Resources

The 2010 IRP Order directed the IOUs, GreenCo/NCEMC, and the independent EMCs to maintain current DSM/EE market potential studies. PEC stated that it had updated its DSM/EE forecast of market potential in 2010, and provided the Public Staff with a list of possible DSM/EE measures that were under consideration. It also noted that it intends to file a new market potential study as part of its 2012 IRP. In its 2010 IRP, Duke indicated that it planned to provide an updated market potential study in its 2012 IRP. The Public Staff recommends that the utilities include a discussion of the status of market potential studies or updates in their 2012 IRPs.

E. Other Issues

In its 2010 IRP Order, the Commission directed Duke to file corrected calculations of the avoided cost benefits and costs, and related DSM/EE cost effectiveness test results for all of its DSM/EE programs that were impacted by the double-counting error acknowledged in the 2010 IRP. Duke filed corrected calculations and cost effectiveness test results on June 3, 2011 in Docket No. E-7, Subs 831 and 953, and Docket No. E-100, Subs 114, 118, 124, and 128. The Public Staff has reviewed these calculations and believes the data has been appropriately corrected.

In its 2010 IRP Order, the Commission ordered that if Piedmont considered its smart meter program to be an EE program, it should file for Commission approval of the program pursuant to Commission Rule R8-68. In response to a Public Staff data request, Piedmont indicated that the program is part of GreenCo's Power Cost Monitor program, which was approved August 23, 2010 in Docket No. EC-83, Sub 0. Thus, it does not appear that Piedmont's smart meter program would require additional approval by the Commission pursuant to Commission Rule R8-68.

The Public Staff notes that the original application for approval for the Power Cost Monitor program in Docket No. E-83, Sub 0 included several options for member EMCs to use the information available from an energy monitor, including a prepay billing option. The Public Staff understands that GreenCo members Brunswick, Piedmont, Pitt & Greene, and Central EMCs have some form of a prepay billing option and are participating in GreenCo's Power Cost Monitor program. GreenCo member Edgecombe-Martin EMC also has a prepay program, but does not participate in GreenCo's Power Cost Monitor program. Blue Ridge, which is not a member of GreenCo, also has a prepay billing option. A utility claiming EE savings for REPS compliance purposes from a program using a prepay billing option will be required to show through measurement and verification that less energy has been used to perform the same function pursuant to G.S. 62-133.8(a)(4). Thus, the Public Staff does not believe that energy saving resulting from self-rationing of electricity or disconnection would constitute EE for REPS compliance purposes.

On May 3, 2011, the Commission issued an Order in Docket No. EC-33, Sub 58 (Halifax Order) requiring, among other things, Halifax to file its Heat Pump Rebate EE (HPR) program for approval pursuant to GS 62-140 and Commission Rule R8-68. In that proceeding, Halifax claimed 11.3 renewable energy credits (RECs) from the HPR program. The Commission concluded that the HPR program was established prior to August 20, 2007 and therefore did not require Commission approval pursuant to GS 62-133.9(c). The Commission, however, found that the HPR program was subject to GS 62-140(c), as it was unclear whether participants in the HPR program were being paid incentives to either convert lower-efficiency electric or gas heating equipment to higher efficiency electric equipment, or to switch from propane or natural gas heating equipment to electric heating equipment.

On August 29, 2011, Halifax filed a response to the Halifax Order that provided information regarding the origin of the HPR program. Halifax stated that the HPR program did not require additional Commission approval as an EE program pursuant to GS 62-140(c) and Commission Rule R8-68 because the program was part of an EE program approved for NCEMC on October 25, 1989 in Docket No. EC-67, Sub 4. The NCEMC heat pump rebate program was one of three DSM-oriented programs approved pursuant to GS 62-140(c) that provided rebates to customers who converted less efficient electric or gas water heating equipment and electric heat pumps to more efficient electric water heating and heat pump equipment. Under this program, the rebate incentives were only available to participants installing a new electric heat pump or replacing an existing electric heat pump. The NCEMC heat pump rebate program was amended to increase the efficiency standards associated with heat pumps and to increase the levels of incentive paid to participants by Order dated July 29, 1992 in Docket No. EC-67, Sub 4.

Halifax has continued to offer the NCEMC heat pump rebate program and provide rebates to new and replacement electric heat pump installations each year. In the most recent report filed March 2011, Halifax indicated 84 new rebates were issued in calendar year 2010. Halifax's HPR program, as articulated by Board Policy No. 513 (included in Halifax's response), suggests the HPR program has been updated to incent electric heat pump equipment that is above the current high energy efficiency standards applicable to air-to-air and groundwater source electric heat pumps.

Based on this information, the Public Staff agrees with Halifax that the HPR program does not require further approval by the Commission pursuant to GS 62-140(c), GS 62-133.9(c), and Commission Rule R8-68. Halifax acknowledges in its Response that actual EE savings from the HPR program will need to be substantiated through appropriate measurement and verification.

VI. EVALUATION OF RESOURCE OPTIONS

Rule R8-60(i)(8) requires that the IOUs describe their analysis and evaluation of resource options. The IOUs indicate in their IRPs that they use accepted production cost simulation models that identify the least cost mix of resources required to meet the future energy and capacity needs in an efficient and reliable manner at the least cost. The models have the ability to perform optimization analyses to select among competing resources that could be added in various combinations to satisfy the utility's future load requirements. The least cost objective of these models is measured by the present value of revenue requirements (PVRR) for the various portfolios, while maintaining the target reserve margin. The models incorporate forecasts for the utilities' energy sales and peak load with planning assumptions on the operating characteristics of a utility's existing generating units (including, but not limited to net MW output, planned outages, forced outage rates, projected fuel prices, heat rates, start costs, emission costs, and variable operating and maintenance expenses) to calculate the projected dispatch cost of each generating unit. In addition, the models integrate assumptions regarding planned generation uprates and retirements, planned renewable energy generation, DSM and EE programs, environmental regulations, and the capital costs and operating characteristics for proposed traditional generation and alternative resources to arrive at a least cost plan. To consider the uncertainties, the utilities generally develop a base or preferred plan and alternative plans. These plans are analyzed using variations in projected loads, fuel prices, carbon dioxide (CO_2) emission credit prices, construction costs, and other sensitivities, allowing the utility to choose the optimal plan that provides a balanced mix of traditional generation, renewable energy, and DSM and EE to meet the utilities' baseload, intermediate, and peaking requirements.

Duke developed its plan after evaluating six generation portfolios that included the addition of the new pulverized coal unit at Cliffside Steam Station in 2012, along with resource mixes of new natural gas-fired generation, nuclear generation, renewable energy, and DSM and EE resources. PEC developed its plan after evaluating three generation portfolios with resource mixes of new natural gas-fired generation, nuclear generation, renewable energy, and DSM and EE resources. PEC's plan is generally similar to Duke's plan, except PEC does not include a new coal generation unit in its resource mix. DNCP developed its base plan after evaluating four generation portfolios that include the addition of the Virginia City Hybrid Energy Center coal and biomass unit in 2012, along with resource mixes of new natural gas-fired generation, nuclear generation, renewable energy, and DSM and EE resources.

Because of the increasing uncertainty associated with the timing, extent, and likelihood of federal carbon legislation, the Public Staff investigated the assumptions made with respect to carbon prices in the utilities' IRPs. Duke and PEC considered only scenarios that assumed the impacts of a carbon constrained world, each using different carbon emission prices and compliance timeframes. DNCP considered a no-carbon scenario in its 2011 IRP. DNCP acknowledges that one of the biggest uncertainties facing the electric utility industry is whether carbon legislation will be enacted, and, if it is passed, what the structure of the legislation and its potential impacts on the fuel markets would be. DNCP therefore noted that "[d]ue to the uncertainty surrounding potential future carbon legislation, the Company chose to examine a scenario where future carbon legislation would not come into effect during the Planning Period."

In response to a Public Staff data request for a scenario that assumed no future carbon legislation, Duke indicated that such an analysis would require repeating the IRP process with new load and fuel cost forecasts. Duke also noted that removing the assumption of future carbon legislation also would impact the economics associated with EE and renewable energy. In this response, Duke performed a model run without carbon legislation, but also without revising the load forecast, fuel price forecasts, and other factors that would be impacted by a no-carbon assumption. Duke pointed out that the results of this model run provide only a limited view of the PVRR impacts of CO_2 and related carbon legislation. Nevertheless, the model runs indicate that the absence of carbon legislation effectively **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

In its comments on the 2010 IRPs filed on February 10, 2011, the Public Staff recommended that each IOU, NCEMC, and EMC be required to include no carbon and low carbon price scenarios in their 2011 IRPs, as well as scenarios factoring in the impact of regulation of carbon emissions until such scenarios are no longer plausible. The Commission found in its 2010 IRP Order, issued October 26, 2011, that the scenarios relating to carbon emissions used by the utilities were appropriate for the purposes of the 2010 IRP proceeding.

As the uncertainty regarding carbon legislation continues, a scenario without carbon legislation during the planning period has become even more plausible than in the 2010 IRP proceeding. Assumptions about future carbon legislation clearly could affect the choice between a plan that relies on new nuclear generation units rather than a plan that relies heavily on new natural gas-fired generation units, and it is to the public's benefit for the utilities to evaluate all plausible scenarios in their IRPs. The Public Staff asks the Commission to require the IOUs to evaluate no-carbon alternative plans or scenarios in their 2012 IRPs and future IRPs until the status of future carbon legislation becomes clearer.

In its comments filed on October 7, 2011, NC WARN contends that Duke's and PEC's IRPs use unrealistically low construction costs for the planned nuclear plants The Public Staff has reviewed the inputs and forecasts in the models used for planning by the utilities and believes that these inputs and forecasts are reasonable for planning purposes.

VII. 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. Alternatively, a supplier may comply with the REPS requirements by reducing energy consumption through implementation of EE measures or by electricity demand reduction (and, in the case of EMCs and municipalities, through DSM measures). Electric public utilities can use EE measures to meet up to 25% of the general requirements of G.S. 62-133.8(b). EMCs and municipalities can use DSM and EE to meet the requirements of G.S. 62-133.8(b) without any limits. They may also use energy from a hydroelectric power facility and allocations from the Southeastern Power Administration (SEPA) to meet up to 30% of the general requirements. All electric power suppliers may obtain Renewable Energy Certificates (RECs) from out-of-state sources to meet up to 25% of the requirements of G.S. 62-133.8(b) and (c) with the exception of DNCP, which can use out-of-state RECs to meet 100% of its requirements. In N.C. Sess. L. 2001-55, enacted on April 28, 2011, the General Assembly added electricity demand reduction as a method to comply with REPS requirements.

Electric power suppliers must file their REPS Compliance Plans on or before September 1 of each year and explain 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 2011, 2012, and 2013 (the Planning Period). An electric power supplier can have its REPS requirements met by a utility compliance aggregator as defined in Commission Rule R8-67(a)(5). In 2011, all electric power suppliers filed plans as required or were properly included in a plan filed by a utility compliance aggregator.

Docket No. E-100, Sub 128 includes the plans filed by Duke, PEC, DNCP, GreenCo Solutions, Inc. (GreenCo), EnergyUnited (EU), and Halifax EMC. Docket No. E-100, Sub 131 includes the plans filed by North Carolina Eastern Municipal Power Agency (NCEMPA), North Carolina Municipal Power Agency 1 (NCMPA1), the Tennessee Valley Authority (TVA), the Fayetteville Public Works Commission (Fayetteville), the Town of Winterville, the Town of Oak City, and the Town of Fountain. The Public Staff's comments on the plans of each electric power supplier can be found in Sections A through E below. The tables in Section F allow a comparison of the data on retail sales, incremental costs, and annual cost caps required by Commission Rule R8-67(b)(1)(iv)-(vii).

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

A. Duke

Duke has contracted for or procured sufficient resources to meet the REPS requirements of G.S. 62-133.8(b), (c), and (d) for the Planning Period. Duke has made these efforts for its own compliance and the compliance of the electric power suppliers for which it is providing REPS compliance services. Duke is contractually obligated to secure resources to meet all the REPS requirements of the following electric power suppliers: Rutherford EMC, Blue Ridge EMC, the City of Dallas, the Town of Forest City, the City of Concord, the Town of Highlands, and the City of Kings Mountain (collectively, Duke's Wholesale Customers).

A portion of the general requirement of Duke and Duke's Wholesale Customers will be met by co-firing biomass with coal or re-powering existing coal stations with biomass fuel. Duke has executed purchased power agreements and REC-only purchases from other biomass power providers. However, Duke stated that uncertainty with air permit requirements has caused it to reduce its reliance on biomass for future REPS compliance. This uncertainty has caused Duke to consider the possibility of using wind energy delivered directly to its customers in North Carolina to meet the in-state general requirements. This anticipated shift is a change from last year's plan. In addition, out-of-state wind RECs have proven very cost effective, and Duke anticipates using them to help it meet up to 25% of the general REPS requirements of G.S. 62-133.8 (b) and (c). Duke also plans to use EE programs to meet 25% of these requirements. Hydroelectric facilities and energy allocations from SEPA will be used to meet up to 30% of the general requirements of Duke's Wholesale Customers. If the cost of solar energy continues to decrease as it has in the past, Duke could possibly use it to meet the general requirements. To meet the general requirement of 3% of sales for 2012 and 2013, Duke anticipates using 1,598,958 and 1,383,221 general RECs respectively, including EE and SEPA allocations.[13]

Duke is implementing the following projects to meet the solar set-aside: (1) self-owned distributed solar photovoltaic (PV) facilities, (2) solar purchased power agreements, (3) in-state solar thermal and PV REC purchases, and (4) out-of-state solar REC purchases for up to 25% of the requirement.[14] Even with the disconnection of its self-owned assets, Duke anticipates that it will meet the solar set-aside requirements for the Planning Period. For Duke and Duke's Wholesale Customers, the

[13] The sharp decrease in the number of general RECs required from 2012 to 2013 is attributable to an increase in the poultry waste set-aside. Under G.S. 62-133.8(d), the statewide poultry waste set-aside amounts to 170,000 RECs for 2012 and 700,000 for 2013. Duke's proportional share of the set-aside is 76,819 RECs in 2012 and 316,312 RECs in 2013. The increase in the set-aside leads to a reduction in the general requirement.

[14] In April 2011, a fire occurred on the roof of the host manufacturing facility for one of Duke's distributed solar PV installations. Duke subsequently disconnected the electrical wiring of the solar panels for this facility, as well as the wiring for all of its other commercial rooftop solar distributed generation facilities. Duke is currently testing and implementing additional safety measures for these facilities and has placed approximately half of its solar distributed generation back in operation.

0.02% of sales requirement for the solar set-aside equates to 12,190 MWH in 2011. The 0.07% of sales requirement for the solar set-aside equates to 41,015 MWH in 2012 and 41,597 MWH in 2013.

Duke anticipates that its REPS compliance costs will be well below the cost caps in G.S. 62-133.8(h)(4) for the Planning Period.

B. PEC

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

PEC's primary method of meeting the REPS requirements for itself and PEC's Wholesale Costumers is the purchase of RECs and electricity from renewable energy generators. PEC maintains an open request for proposals for non-solar generation of less than 10 MW and has purchased out-of-state wind and solar RECs, which have proven to be very cost effective. To meet the general requirement of 3% of sales for 2012 and 2013, PEC anticipates using 1,026,617 and 883,170 general RECs respectively, including EE and SEPA allocations.[15]

PEC has implemented its Commercial and Residential SunSense programs to help it 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. This program aims to add 5 MW or equivalent capacity per year. The Residential SunSense program incentivizes solar PV systems up to 10 kW. This program aims to add 1 MW of capacity per year. In June 2011, PEC issued a request for proposals for solar PV energy and RECs from facilities ranging from 1 to 3 MW.

For PEC and the Wholesale Customers, the 0.02% of sales requirement for the solar set-aside equates to 7,848 MWH in 2011. The 0.07% of sales requirement equates to 26,326 MWH in 2012 and 26,560 MWH in 2013.

C. DNCP

DNCP plans to purchase RECs and use approved EE programs to meet the general REPS requirements of G.S. 62-133.8(b) and (c) for itself and the Town of Windsor (Windsor), for which it is providing REPS compliance services for the Planning

[15] As in Duke's case (see note 14 above), the reason for the sharp decrease in PEC's general REC requirement from 2012 to 2013 is the corresponding increase in the poultry waste set-aside during these years.

Period. DNCP will rely on out-of-state RECs to meet most of its compliance requirements but will obtain in-state RECs to meet Windsor's 75% in-state requirement.

DNCP intends to purchase unbundled solar RECs to meet the set-aside requirements for the Planning Period. For DNCP, the 0.02% of sales requirement for the solar set-aside equates to 866 MWH in 2011. The 0.07% of sales requirement equates to 2,798 MWH in 2012 and 2,895 MWH in 2013.

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.[16] 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 EMCs filed plans independently.

1. GreenCo

GreenCo submitted a REPS compliance plan that explains how its 24 EMCs expect to meet the REPS requirements of G.S. 62-133.8(c) and (d). To comply with subsection (c), GreenCo plans to rely on RECs from 11 EE programs, SEPA allocations, out-of-state wind facilities, and one in-state biomass facility. Mecklenburg and Broad River are headquartered in other states but serve a small number of customers in North Carolina. They are not officially members of GreenCo, and will not be using GreenCo's EE programs to meet the REPS requirements.

GreenCo intends to meet the solar energy requirements of G.S. 62-133.8(d) by purchasing RECs from several privately owned solar facilities with capacities of 3 kW to 1 MW and one facility with a capacity of 5 MW. GreenCo is also planning to purchase out-of-state solar RECs.

It appears that Mecklenburg may reach the cost caps in 2012 and 2013 before meeting the requirements of G.S. 62-133.8(c), (d), (e), and (f). This EMC has over 25,000 members in Virginia but only 123 members in North Carolina. Its retail sales in North Carolina will be 1,642, 1,658, and 1,675 MWH for 2011, 2012, and 2013 respectively. These sales are much lower than those of any other electric power supplier in North Carolina.

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[16] GreenCo filed a consolidated 2011 REPS Compliance Plan on behalf of Albemarle EMC, Broad River, Brunswick EMC, Cape Hatteras EMC, Craven-Carteret EMC, Central EMC, Edgecombe-Martin County EMC, Four County EMC, French Broad, Haywood, Jones-Onslow EMC, Lumbee River EMC, Mecklenburg, 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. Broad River and Mecklenburg are not officially members of GreenCo but use GreenCo to meet their REPS compliance requirements.

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(c) by purchasing in-state and out-of-state RECs. TVA also plans to use RECs from the SEPA allocations of the Distributors and earn RECs from several DSM and EE measures.

To meet the solar set-aside, TVA intends to purchase solar RECs, generate electricity at its own solar facilities, and produce RECs through its TVA Generation Partners program, which provides incentives for residential and business users of TVA power to install and operate renewable energy facilities, including solar PV facilities.

TVA will meet the REPS compliance requirements of the Distributors at no cost to them.

3. EU

To comply with the REPS requirements, EU plans to use two EE programs, purchase renewable energy from a landfill gas project, and purchase out-of-state wind and biomass RECs. EU also plans to obtain hydroelectric RECs from its SEPA allocation and from small hydroelectric facilities in North Carolina. To meet the solar set-aside, EU plans to purchase RECs from two in-state solar PV facilities. EU is evaluating its customer base for locating additional solar facilities.

4. Halifax

Halifax plans to meet the general REPS requirements for itself and the Town of Enfield through its EE programs, SEPA allocations, and out-of-state wind RECs. To meet its solar set-aside requirements, Halifax has constructed a 98.56-kW solar PV facility and has developed a rate rider to purchase solar RECs from its members.

E. Municipalities

REPS compliance for most of the municipalities in the State is managed by either NCEMPA or NCMPA1. NCEMPA filed a plan on behalf of its 32 municipalities[17] and NCMPA1 filed a plan on behalf of its 19 municipalities.[18]

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[17] 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. Wilson will meet the REPS compliance requirements of Pinetops, Macclesfield, and Walstonburg. .

[18] 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.

1. NCEMPA

NCEMPA plans to use both in-state and out-of-state unbundled RECs to comply with most of the REPS requirements. NCEMPA's member municipalities have no plans to generate electricity at a renewable energy facility at least until 2018 because it is prohibited by their full requirements contract with PEC. Energy purchases from SEPA are authorized by the contract with PEC, however, and serve to meet some of NCEMPA's REPS requirements. Up to 10% of NCEMPA's REPS requirements will be met with DSM and EE programs. NCEMPA has implemented or is expected to implement the following DSM programs: water heater control, heat pump heat strip control, air conditioning control, and residential and commercial time of use rate programs. Its EE programs include energy audits, appliance recommendation and metering, efficient building practices, water heater replacement, heat pump replacement, and insulation replacement. NCEMPA anticipates meeting the general requirement in G.S. 62-133.8(c) for the Planning Period and does not anticipate reaching the cost caps in G.S. 62-133.8(h)(4).

For the solar set-aside, NCEMPA is pursuing contracts for in-state and out-of-state unbundled solar RECs and has contracted for sufficient solar RECs to meet the statutory requirements in the Planning Period. NCEMPA will also use solar thermal facilities to produce solar RECs.

2. NCMPA1

NCMPA1 has executed contracts for the purchase of RECs from various renewable resources to meet its REPS requirements. It has not built any renewable generation facilities but continues to investigate and seek proposals for these types of facilities. Its members intend to use energy purchases from SEPA to satisfy 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, and has purchased solar RECs. In July 2011, NCMPA1 issued a request for proposals for in-state solar RECs to begin delivery in 2013. For future compliance, it is 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'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 issuing a request for proposals for commercial and industrial customers to design their own EE improvements. Up to 20% of NCMPA1's REPS requirement should be met with these programs by 2018. 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.

3. Fayetteville

Fayetteville plans to meet up to 30% of its general REPS requirements through the use of its SEPA allocation. It is considering a combined heat and power system to begin operating at its Cross Creek Water Reclamation Facility Digester Complex. Fayetteville plans to earn RECs from the following DSM/EE programs:

- Energy efficiency improvements at its customer service center
- Energy conservation in the Cumberland County School System
- Distribution voltage control
- $martWorks, a DSM program that allows customers real-time monitoring and control of their energy usage

For its municipal buildings, the City of Fayetteville is planning the following EE programs:

- Light emitting diode (LED) street lighting
- Additional lighting retrofits
- Cool roof replacement
- Heating, ventilation, and air conditioning (HVAC) replacement
- Insulation addition
- Thermal film installation

Fayetteville plans to purchase solar RECs to meet the requirements for 2011 and 2012. For 2013, it plans to purchase solar RECs and participate in the development of a rooftop solar PV system.

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 EMC. 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 Winterville, Oak City, and Fountain submitted their REPS Compliance Plans independent from any other entity. The Town of Winterville will depend mostly on REC purchases to meet the compliance requirements and has implemented several EE programs. It is also pursuing solar PV and solar thermal facilities, but none have been constructed. Winterville stated that it may reach the cost cap before meeting the REPS requirements. However, the Public Staff believes that

Winterville's projected costs for administrative and outside services are excessive; if some of these costs are reduced or disallowed, Winterville's total compliance costs may be within the cap. The Town of Oak City plans to purchase RECs to meet its REPS compliance requirements and is considering a CFL program to help meet future compliance requirements. The Town of Fountain plans to purchase RECs to meet its REPS compliance requirements.

F. REPS Compliance Comparison Tables

The tables on the following pages are drawn from data submitted in the electric suppliers' compliance plans. Table 1 on the following page shows the larger electric power suppliers' projected annual MWH sales, on which their REPS obligations are based. It is important to note that the figures shown for each year are the suppliers' MWH sales for the preceding year; for instance, the sales in the 2012 column are projected sales for the calendar year 2011. The sales totals are presented in this manner because each supplier's REPS obligation is determined as a percentage of its MWH sales for the preceding year.

Table 2 presents a comparison of the larger electric power suppliers' projected annual incremental REPS compliance costs with their annual cost caps. It indicates that of the larger suppliers, only Fayetteville projects that its incremental costs may exceed the cost cap.

TABLE 1: MWH Sales for preceding year

Electric Power Supplier	**2011**	**2012**	**2013**
Duke[1]	60,950,335	58,593,552	59,424,222
PEC[1]	39,239,000	37,609,000	37,943,000
DNCP	4,329,303	3,996,743	4,135,654
GreenCo	13,179,297	12,808,357	13,016,133
TVA	629,549	635,844	642,202
EU	2,439,808	2,344,756	2,381,430
Halifax[1]	207,893	199,525	201,520
NCEMPA	7,310,376	7,378,243	7,400,008
NCMPA1	5,020,653	5,129,893	5,151,068
Fayetteville	2,214,346	2,214,386	2,236,530

[1] Includes retail sales of wholesale customers for which the electric power supplier is providing REPS compliance reporting and services.

TABLE 2: Projected REPS incremental costs and annual cost caps

Supplier	2011 Incremental Cost	2011 Annual Cost Cap	2012 Incremental Cost	2012 Annual Cost Cap	2013 Incremental Cost	2013 Annual Cost Cap
Duke[1]	10,168,830	31,560,390	12,874,382	61,528,700	22,175,118	62,335,166
PEC[1]	21,100,000	21,100,000	26,700,000	42,800,000	36,100,000	43,300,000
DNCP	29,526	1,970,600	689,980	4,073,292	1,695,167	4,131,072
GreenCo	2,669,815	9,242,478	3,884,968	15,830,223	6,774,269	16,074,269
TVA	0	769,820	0	1,718,240	0	1,735,346
EU	1,231,489	1,879,250	723,649	3,747,416	938,149	3,762,950
Halifax[1]	105,815	185,930	89,662	352,018	209,052	355,522
NCEMPA	1,400,000	4,500,000	1,600,000	9,100,000	2,800,000	9,100,000
NCMPA1	1,000,000	2,900,000	900,000	6,000,000	2,300,000	6,000,000
Fayetteville	38,000	1,148,160	1,149,700	2,190,036	1,310,000	2,201,088

[1]Includes retail sales of wholesale customers for which the electric power supplier is providing REPS compliance reporting and services.

G. <u>Swine Waste Set-Aside in G.S. 62-133.8(e)</u>

Duke, PEC, DNCP, GreenCo, NCEMPA, NCMPA1, and Fayetteville 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 the swine waste set-aside in G.S. 62-133.8(e). This statute requires that the State's electric power suppliers must collectively procure energy or RECs from swine waste resources to meet 0.07% of sales in 2012 and 2013. Duke has taken a leadership role for the Swine Group and executed four long-term purchase agreements with swine waste REC suppliers on behalf of the group. These four contracts will result in as many as 25 swine waste-to-energy facilities in North Carolina. Despite these contracts, the Swine Group does not believe it can obtain enough swine waste resources to meet the 2012 requirements for the group. However, the group believes that it can meet the requirements for 2013 and beyond. Uncertainties remain in procuring swine RECs, such as the following: (1) providers of swine waste RECs are few, (2) the production of energy from swine waste at a commercial scale is unproven, and (3) swine waste-to-energy facilities are small and highly distributed compared to traditional generation and the set-aside requirement. DNCP did not mention problems with securing RECs from swine waste resources, but the Public Staff believes all electric power suppliers in North Carolina face similar problems in this area. As of this date, no electric power supplier has filed to modify or delay the swine waste set-aside under the "off-ramp" provision of the statute, G.S. 62-133.8(i)(2).

H. <u>Poultry Waste Set-Aside in G.S. 62-133.8(f)</u>

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). This statute requires that the State's electric power suppliers must collectively procure energy from poultry waste resources in the amount of 170,000 MWH or equivalent in 2012 and 700,000 MWH or equivalent in 2013. PEC has taken a leadership role for the Poultry Group. Meeting the poultry waste set-aside has presented challenges to the Poultry Group; some are similar to those of meeting the swine waste set-aside. However, several actions by the General Assembly and the Commission in 2010 and 2011 have made compliance with the poultry waste set aside easier to achieve than the Public Staff anticipated before 2010.

S.L. 2010-195 (Senate Bill 886) 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. On April 18, 2011, the Commission issued an order in Docket No. SP-100, Sub 28, which clarified Senate Bill 886. The order stated that all triple credits will provide one general REC and two poultry waste RECs. On June 23, 2011, the General Assembly enacted Session Law 2011-279, which limits the capacity eligible for poultry waste triple credit to 10 MW.

N.C. S. L. 2011-309 (Senate Bill 710) allows the thermal output of any combined heat and power system that uses poultry waste as fuel to earn RECs.

Duke indicated that the poultry waste-to-energy market is still new and indicated that it is optimistic but uncertain about compliance. PEC is more confident that it can meet the poultry waste requirement. In April 2011, PEC signed a contract to purchase energy and RECs from a 36-MW poultry waste-to-energy facility that should be able to deliver 200,000 poultry waste RECs per year. GreenCo also plans to obtain poultry waste RECs from this facility. However, the owners of the facility have not filed an application for a certificate of public convenience and necessity. NCEMPA has not secured enough poultry waste RECs to meet the 2012 requirement but is continuing to pursue them. NCMPA1 has secured enough poultry waste RECs to meet the 2012 requirement but is still pursuing resources to meet the requirement for 2013.

I. <u>Concerns Raised by NC WARN</u>

In its October 7, 2011, initial comments, NC WARN expressed concern that certain graphs in the IRPs of Duke and PEC indicate that these utilities do not in fact plan to meet their general REPS requirements. The graphs, which appear on page 90 of Duke's IRP and page 28 of PEC's IRP, are in the form of pie charts, showing the percentages of generation that will come from various sources in 2012 for each utility, in 2031 for Duke, and in 2026 for PEC. NC WARN pointed out that Duke's graphs do not show the 3% of renewable generation or EE required by the general REPS obligation in 2012 or the 12.5% required in 2031, and PEC's graphs do not show any renewable generation or EE at all.

The Public Staff has discussed these graphs with Duke and PEC. Duke advised the Public Staff that the graphs represent its total generation, including wholesale and South Carolina retail sales; the 3% of North Carolina retail sales required by the general REPS obligation equates to well under 3% of Duke's total system sales. Moreover, many of the RECs that Duke will use for REPS compliance are unbundled from the underlying electrical energy and thus are not accounted for in the graphs. Finally, some of the RECs Duke will use for REPS compliance appear in the sections of the pie chart marked "DSM/EE" and "Hydro."

PEC indicated to the Public Staff that the renewable energy it intends to use for general REPS compliance in 2012 is purchased from third parties. Thus, it is shown in the section of the pie chart marked "Purchases," and the graph indicates that purchases are expected to make up 4.1% of PEC's generation mix for 2012. Moreover, even though EE can be used for compliance with the REPS requirements, it is not a type of generation, and it is not included in the pie charts in PEC's IRP. Lastly, even though PEC fully expects to comply with the REPS requirements in 2026, it has entered into very few contracts that call for delivery of RECs or bundled renewable energy in that year; it intends to enter into such contracts closer to the time they will be needed. Since very few contracts for 2026 are currently in place, the "Purchases" section of the 2026 pie chart is quite small.

Based on these discussions with Duke and PEC, the Public Staff is satisfied that they do intend to comply with the general REPS requirements through 2026 (or in Duke's case 2031), and the pie charts in their IRPs should not be taken as an indication to the contrary.

J. 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 Planning Period.

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). The only electric power suppliers that might reach the cost cap during the Planning Period are the Town of Winterville and Mecklenburg. However, the Public Staff disagrees with some of Winterville's projected costs as discussed above.

XIV. PUBLIC STAFF'S RECOMMENDATIONS

In conclusion, the Public Staff makes the following recommendations:

1. That the Commission require Duke to continue to provide updates in future IRPs regarding its obligations related to this air permit to: (a) retire 800 MW of coal capacity in North Carolina in accordance with the schedule set forth in Table J.1, (b) accommodate to the extent practicable the installation and operations of future carbon control technology at Cliffside 6, and (c) take additional actions to make Cliffside 6 carbon neutral by 2018;

2. That Duke and DNCP include the information required by Rule R8-60(i)(3) in their reply comments in regard to their 2011 IRP and comply with this requirement in future IRPs;

3. That the Commission require the utilities to include a discussion of significant variances in projected EE savings in future IRPs;

4. That the Commission require the utilities to include a discussion of the status of market potential studies or updates in their 2012 IRPs; and

5. That the Commission require the IOUs to evaluate no-carbon alternative plans or scenarios in their 2012 IRPs and future IRPs.

Respectfully submitted, this the 13th day of January, 2012.

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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 13th day of January, 2012.

Lucy E. Edmondson

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