NORTH CAROLINA
PUBLIC STAFF
UTILITIES COMMISSION

April 11, 2014

Ms. Gail L. Mount
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4325

Re: Docket No. E-100, Sub 137

Dear Ms. Mount:

Enclosed for filing in the above-referenced docket are the Comments of the Public Staff on the 2013 IRPs.

By copy of this letter, I am forwarding a copy to all parties of record.

Sincerely,

Lucy E. Edmondson
Staff Attorney
lucy.edmondson@psncuc.nc.gov

Enclosure

LEE/cla

PUBLIC VERSION

Comments of the Public Staff

2013 Updated Integrated Resource Plans and Related 2013 REPS Compliance Plans

Docket No. E-100, Sub 137

April 11, 2014

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NOW COMES THE PUBLIC STAFF – North Carolina Utilities Commission, by and through its Executive Director, Christopher J. Ayers, and submits the following comments pursuant to Commission Rule R8-60(j). These comments address the 2013 updates to the biennial integrated resource planning documents (IRPs) filed by the investor-owned utilities (IOUs) operating in North Carolina: Duke Energy Progress, Inc. (DEP), Duke Energy Carolinas, LLC (DEC), and Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP).

INTRODUCTION

Several statutes and Commission rules guide the Commission's review of the electric utilities' resource planning. 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 requiring "energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable" and 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." 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 is required to 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.

S.L. 2007-397 AND COMMISSION RULES

S.L. 2007-397 (Senate Bill 3 or SB3) expanded the Commission's review of electric utilities' resource planning. The act amended G.S. 62-2(a) to provide 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 enacted G.S. 62-133.8, which establishes Renewable Energy and Energy Efficiency Portfolio

Standards (REPS) that are applicable to each electric power supplier (IOU, electric membership corporation or EMC, and municipality) in North Carolina.

SB3 further enacted G.S. 62-133.9, which provides in subsection (c) 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." G.S. 62-133.8(a)(2) defines demand-side management (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." G.S. 62-133.8(a)(4) defines 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" and specifically states that EE measures do not include DSM. The foregoing statutory definitions are used in these comments.

To meet the requirements of G.S. 62-2(3a), G.S. 62-110.1, and portions of 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 electric utility 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 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." As part of its IRP, each electric utility must provide forecasts and assessments for at least a 15-year period (planning period). In odd-numbered years, each electric utility 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, the Public Staff or any other intervenor may identify any issue that it believes should be the subject of an evidentiary hearing. In addition, Commission Rule R8-62(p) requires that the electric utilities incorporate information in their IRPs concerning the construction of transmission lines.

OTHER RELEVANT COMMISSION PROCEEDINGS

DOCKET NO. E-100, SUB 126 - SMART GRID TECHNOLOGY PLANS

On April 11, 2012, the Commission issued its *Order Amending Commission Rule R8-60 and Adopting Commission Rule R8-60.1* in Docket No. E-100, Sub 126 (*Smart Grid Order*). Commission Rule R8-60(i), as amended, includes a new subsection (10), which requires each utility, beginning in 2012, to include in its IRP information regarding the impacts of its smart grid deployment plan on its resource plan.[1]

For purposes of the amended Rule, the Commission defined the term "smart" to mean, but not be limited to, "a system having the ability to receive, process, and send information and/or data - essentially establishing a two-way communication protocol." Further, the Commission stated that:

> smart grid technologies that are implemented in a smart grid deployment plan may include those that: (1) utilize digital information and controls technology to improve the reliability, security and efficiency of an electric utility's distribution or transmission system; (2) optimize grid operations dynamically; (3) improve the operational integration of distributed and/or intermittent generation sources, energy storage, demand response, demand-side resources and energy efficiency; (4) provide utility operators with data concerning the operations and status of the distribution and/or transmission system, as well as automating some operations; and/or (5) provide customers with usage information.

Specifically, the Commission required the utilities to include in their IRPs the following information: (a) a description of the technology installed and for which installation is scheduled to begin in the next five years and the resulting and projected net impacts from installation of that technology, including, if applicable, the potential demand (megawatts) and energy (megawatt-hours) savings resulting from the described technology; (b) a comparison to "gross"

[1] Commission Rule R8-60.1 requires the electric power suppliers to file a biennial "Smart Grid Technology Plan" with specific information regarding future investments in Smart Grid technologies beginning on July 1, 2013. By Order issued on May 6, 2013, the Commission amended Rule R8-60.1 to change the due date for the initial biennial report on smart grid technologies from July 1, 2013, to October 1, 2014.

megawatts (MW) and megawatt-hours (MWh) without installation of the described smart grid technology; and (c) a description of MW and MWh impacts on a system, North Carolina retail jurisdictional, and North Carolina retail customer class basis, including proposed plans for measurement and verification of customer impacts or actual measurement and verification of customer impacts.

<u>DOCKET NOS. E-2, SUB 998 AND E-7, SUB 986 – MERGER OF DUKE ENERGY CORPORATION AND PROGRESS ENERGY, INC.</u>

On June 29, 2012, the Commission issued an *Order Approving Merger Subject to Regulatory Conditions and Code of Conduct* in Docket Nos. E-2, Sub 998, and E-7, Sub 986 (*Merger Order*), approving the business combination of Duke Energy Corporation and Progress Energy, Inc., pursuant to G.S. 62-111(a). The regulatory conditions in the Merger Order set forth commitments made by the merging entities and their North Carolina public utility subsidiaries, DEC and DEP (referred to as "PEC" in the regulatory conditions), as a precondition of approval of the merger. While a number of the conditions are relevant to this proceeding, of particular significance are Regulatory Conditions 3.5, 3.6, and 4.1. Regulatory Conditions 3.5 and 3.6 state as follows:

> 3.5 Least Cost Integrated Resource Planning and Resource Adequacy.
>
> DEC and PEC shall each retain the obligation to pursue least cost integrated resource planning for their respective Retail Native Load Customers and remain responsible for their own resource adequacy subject to Commission oversight in accordance with North Carolina law. DEC and PEC shall determine the appropriate self-built or purchased power resources to be used to provide future generating capacity and energy to their respective Retail Native Load Customers, including the siting considered appropriate for

such resources, on the basis of the benefits and costs of such siting and resources to those Retail Native Load Customers.

3.6 Priority of Service.

(a) The planning and joint dispatch of DEC's system generation and Purchased Power Resources shall ensure that DEC's Retail Native Load Customers receive the benefits of that generation and those resources, including priority of service, to meet their electricity needs consistent with the JDA [Joint Dispatch Agreement]. DEC shall continue to serve its Retail Native Load Customers with the lowest-cost power it can reasonably generate or obtain as Purchase Power Resources before making power available for sales to customers that are not entitled to the same level of priority as Retail Native Load Customers.

(b) The planning and joint dispatch of PEC's system generation and Purchase Power Resources shall ensure that PEC's Retail Native Load Customers receive the benefits of that generation and those resources, including priority of service, to meet their electricity needs consistent with the JDA. PEC shall continue to serve its Retail Native Load Customers with the lowest-cost power it can reasonably generate or obtain as Purchase Power Resources before making power available for sales to customers that are not entitled to the same level of priority as Retail Native Load Customers.

In addition, Regulatory Condition 4.1 provides that:

> DEC and PEC acknowledge that the Commission's approval of the merger and the transfer of dispatch control from PEC to DEC for purposes of implementing the JDA and any successor document is conditioned upon the JDA or successor document never being interpreted as providing for or requiring: (a) a single integrated electric system, (b) a single BAA [Balancing Authority Area], control area or transmission system, (c) joint planning or joint development of generation or transmission, (d) DEC or PEC to construct generation or transmission facilities for the benefit of the other, (e) the transfer of any rights to generation or transmission facilities from DEC or PEC to the other, or (f) any equalization of DEC's and PEC's production costs or rates. If, at any time, DEC, PEC or any other Affiliate learns that any of the foregoing interpretations are being considered, in whatever forum, they shall promptly notify and consult with the Commission and the Public Staff regarding appropriate action.

Pursuant to these Regulatory Conditions, DEP and DEC each must pursue least cost integrated resource planning and file separate IRPs until required or allowed to do otherwise by Commission order or until a combination of the utilities is approved by the Commission.

DOCKET NO. E-100, SUB 133 – PETITION FOR RULEMAKING

On October 30, 2012, the Commission issued an *Order Denying a Rulemaking Petition* in Docket No. E-100, Sub 133, denying a request by the North Carolina Waste Awareness and Reduction Network (NC WARN) that the Commission amend Commission Rules R1-17 and R8-60, which govern the information and analysis filed by electric utilities in rate case proceedings and IRPs, to include consideration of various cost allocation methods, and in particular, consideration of the cost of meeting new demand. In that Order, the Commission: (i) strongly encouraged the electric utilities "to take reasonable measures to inform all customers of the forecasted summer peak to allow all customers to engage in voluntary demand response and peak shaving," and (ii) required all electric utilities to include in future IRPs a full discussion of the drivers of each class's load forecast, including new or changed demand of a particular sector or sub-group.

DOCKET NO. E-100, SUB 137 – 2012 IRPS AND REPS COMPLIANCE PLANS

On October 14, 2013, the Commission issued its *Order Approving Integrated Resource Plans and REPS Compliance Plans*. The Order required utilities to include certain information in future IRP filings, including the following:

> 8. That each IOU shall continue to include a discussion of a variance of 10% or more in projected EE savings from one IRP report to the next.
>
> 9. That each IOU shall continue to include a discussion of the status of EE market potential studies or updates in their future IRPs.
>
> . . .
>
> 11. That, pursuant to the Regulatory Conditions imposed in the Merger Order, DEC and DEP shall continue to pursue least-cost integrated resource planning and file separate IRPs until otherwise required or allowed to do so by Commission order or until a combination of the utilities is approved by the Commission.
>
> 12. That DEC shall continue to provide updates in future IRPs regarding its obligations related to the Cliffside Unit 6 air permit.
>
> . . .
>
> 16. That, to the extent an IOU selects a preferred resource scenario based on fuel diversity, the IOU should provide additional support for its decision based on the costs and benefits of alternatives to achieve the same goals.

CURRENT PROCEEDING

On August 22, 2013, DEP and DEC moved for an extension of time to file their 2013 IRPs to October 1, 2013. The Commission granted this motion by Order issued August 28, 2013. On August 30, 2013, DNCP filed its 2013 IRP.

On September 23, 2013, DEP and DEC filed a motion for a further extension of the date by which to file their IRPs until October 15, 2013. This motion was granted by the Commission on September 24, 2013.

On October 4, 2013, the Public Staff filed a Motion in Docket No. E-100, Subs 137 and 139, requesting that the Commission designate February 4, 2014, as the date for the Public Staff and other intervenors to file comments on the IRPs. On October 11, 2013, the Commission issued an Order that, among other things, established February 4, 2014, as the date by which interested persons may file petitions to intervene in the docket, and the Public Staff and other intervenors may file initial comments on the electric public utilities' IRPs. Further, the Order set February 18, 2014, as the date by which all parties may file reply comments.

On October 15, 2013, DEP and DEC filed their IRPs.

On January 6, 2014, the Commission scheduled a public hearing on the 2013 IRP annual update reports and the 2013 REPS compliance plans for March 3, 2014, in Raleigh.

On January 16, 2014, the Public Staff filed a motion requesting an extension of the date for petitions to intervene and initial comments to March 14, 2014, and the date for reply comments to March 28, 2014. The Commission granted this motion on the same day.

On March 3, 2014, the Commission canceled the public hearing scheduled to be held in Raleigh due to adverse weather. On March 6, 2014, the Commission rescheduled the public hearing for April 28, 2014.

On March 7, 2014, DEP and DEC filed updated information on multiple portions of their IRPs.

On March 10, 2014, NC WARN filed a Motion to Review Costs of Proposed Plant in South Carolina in the above-captioned docket. By its motion, NC WARN requested that the Commission conduct a review of the costs and need for a 750-MW combined cycle (CC) natural gas generating plant (Lee CC Plant) that DEC is proposing to build in South Carolina. On March 21, 2014, the Commission issued an Order denying NC WARN's motion.

On March 12, 2014, the Southern Alliance for Clean Energy (SACE) and the Sierra Club filed a motion requesting that the dates for comments and reply comments on the IRPs be extended to April 11, 2014, and April 25, 2014, respectively. The Commission granted this motion on March 13, 2014.

In addition to the Public Staff, the following parties have intervened in Docket No. E-100, Sub 137: the Blue Ridge Environmental Defense League, the Carolina Industrial Group for Fair Utility Rates I, II, and III, Carolina Utility Customers Association, Inc., Greenpeace, Inc., the Mid-Atlantic Renewable Energy Coalition, the North Carolina Sustainable Energy Association, NC WARN, SACE, the Sierra Club, Nucor Steel-Hertford, and Invenergy Wind Development LLC and Invenergy Solar Development LLC.

PEAK AND ENERGY FORECASTS

The Public Staff has reviewed the 15-year peak and energy forecasts (2014–2028) of DEP, DEC, and DNCP. The compound annual growth rates (CAGRs) for the forecasts are within the range of 1.2% to 1.4%.

All of the utilities used 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.

In assessing the reasonableness of the forecasts, the Public Staff first compared the most recent weather-normalized peak loads to the utilities' forecasts in the 2012 IRPs. Second, the Public Staff analyzed the accuracy of the utilities' peak demand and energy sales predictions in their 2008 IRPs in comparison to their actual peak demands and energy sales. A review of past forecast errors can identify trends in the IOUs' forecasting and assist in assessing the reasonableness of the utilities' current and future forecasts. Finally, the Public Staff reviewed several of the assumptions that underlie the forecasts of other adjoining utilities and the SERC Reliability Corporation (SERC).

DEP

DEP's 15-year forecast predicts that its adjusted[2] summer peaks will grow at a CAGR of 1.2%, as compared to a 0.9% growth rate in the 2012 IRP. Without the reduction in peak demand resulting from the implementation of its EE programs, DEP expects its summer peaks to grow at a rate of 1.7%. The

[2] Adjusted for firm sales as reported in Tables 8-C and 8-D, pp. 29-30 of DEP's 2013 IRP.

increase in the growth rate in peaks is partially due to DEP's adoption of DEC's methods of forecasting load and calculating reserve margins, which considers DSM as a resource rather than as a decrement to the load forecast. In prior IRPs, DEP deducted the DSM load reductions from its forecasted peak loads. The average annual growth of its summer peak, which is considered its system peak, is forecasted to be 171 MW for the next 15 years, in comparison to the 130 MW forecast in last year's IRP. DEP predicts that in 15 years, the load reductions from its DSM programs will reduce its peak load by approximately 4%, as compared to a 9% reduction forecast in the 2012 IRP.

DEP's energy sales, including the impacts from its EE programs, are predicted to grow at a CAGR of 1.4% as compared to 1.0% in the 2012 IRP. DEP predicts that in 15 years, the MWh reductions from its EE programs will reduce its energy sales by approximately 4%, which is similar to its projection in its 2012 IRP.

The Public Staff's review of DEP's weather adjusted peak load forecasting accuracy for one year shows that the predictions in the 2012 IRP had a forecast error of 2%, caused in part by the relatively mild summer temperatures in 2013.[3] The Public Staff's review of DEP's actual peak load over five years (2009-2013), as compared to its forecasts, shows a forecast error of 3%. This 3% forecast error results in an average annual overestimation of 407 MW. A comparison of

[3] The Mean Absolute Error is used to calculate the forecast error. The one-year review incorporates weather normalized peak demands while the five-year review incorporates actual unadjusted peak demands.

DEP's actual energy sales over the same five years with those predicted in its 2008 IRP reflects a 5% forecast error.

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

DEC

DEC's 15-year forecast predicts that its adjusted[4] summer peaks will grow at a CAGR of 1.4%, as compared to the 1.7% growth rate projected in the 2012 IRP. Without the reduction in peak demand resulting from the implementation of its EE programs, DEC expects its summer peaks to grow at 1.9%. The average annual growth of its summer peak, which is considered its system peak, is forecasted to be 283 MW for the next 15 years, in comparison to the 321 MW forecast in last year's IRP. DEC predicts that load reductions from the activation of its DSM programs will reduce its peak load by approximately 6% in 2028.

DEC's energy sales, including the effects of its EE programs, are expected to grow at a CAGR of 1.4%. This growth rate in energy sales is less than the 1.7% predicted in the 2012 IRP. DEC predicts that the MWh savings from its EE programs will reduce its energy sales by approximately 7% in 2028.

[4] Adjusted for firm sales as reported in Tables 8-C and 8-D, pp. 29-30 of DEC's 2013 IRP.

The Public Staff's review of DEC's weather adjusted peak load forecasting accuracy for one year shows that its 2012 IRP forecast had a 1% forecast error. However, a review of DEC's actual peak loads for five years (2009-2013), as compared to its forecasts, indicates a forecast error of 11%. This 11% forecast error indicates an average annual overestimation of 1,884 MW of capacity, 1,680 MW of capacity when adjusted for weather. In regard to DEC's energy sales forecasts, a comparison of its actual energy sales over the same five years with those predicted in 2008 prediction indicates an 8% forecast error.

The Public Staff's review indicates that DEC's forecasts for both peak demand and energy sales have been consistently higher than actual loads and sales since 2008.

The Public Staff believes that the economic, weather-related, and demographic assumptions underlying DEC's 2013 peak and energy forecasts are reasonable, and that DEC has employed accepted statistical and econometric forecasting practices. However, the Public Staff is concerned with DEC's pattern of over-forecasting more often than under-forecasting its load. DEP's IRP indicates that DEP has adopted DEC's forecasting methods, even though DEP's forecasting of its energy sales and its peak demands has generally been more accurate than DEC's forecasting. For its energy sales forecasts, DEP has typically relied on the monthly-based econometric model with end-use data over a span of ten or more years of historical data. This model has been used for over 30 years, and during these years, DEP has relied on the load factor method to forecast its peak demands. While DEC has also used econometric models, it has made various modifications to the general econometric equations used for its energy sales and peak demand forecasts over the last 30 years. In response to inquiries from the Public Staff, DEC indicated that it is currently preparing to incorporate statistically adjusted end-use data in its models to improve the accuracy of its forecasts in future IRPs. While the Public Staff believes that DEC's 2013 forecasts are reasonable for planning purposes, the Public Staff recommends that DEC carefully review and incorporate the best forecasting practices of DEP and DEC.

DNCP

DNCP's 15-year forecast predicts that its adjusted[5] summer peaks will grow at a CAGR of 1.2%, a decrease from the projected 1.5% growth rate in its 2012 IRP. Without the reduction in peak demand resulting from the implementation of its EE programs, DNCP expects its summer peaks to grow at 1.6%. The average annual growth of its summer peak is forecasted to be 239 MW for the next 15 years, in comparison to the 285 MW forecast in the 2012 IRP. DNCP predicts that load reductions from its DSM programs will reduce its 2028 peak load by approximately 1%.

DNCP's energy sales are predicted to grow at an average annual rate of 1.4%; which is a decrease from the projected 1.6% growth rate in the 2012 IRP.

[5] Adjusted for new and existing DSM programs and load reductions associated with new EE programs as reported in Appendix 2H, p. AP-9, 2013 DNCP IRP.

DNCP predicts that the MWh savings from its EE programs will reduce its energy sales by approximately 3% in 2028.

The Public Staff's review of DNCP's weather adjusted peak load forecasting accuracy for one year shows that the predictions in its 2012 IRP had a forecast error of 3%. The Public Staff's review of DNCP's actual peak loads over the last five years (2009-2013), as compared to its 2008 predictions, indicates a forecast error of 5%. This 5% forecast error results in an average annual overestimation of 787 MW. In regard to DNCP's energy sales forecasts, an annual comparison of its actual sales with its predicted sales in its 2008 IRP indicates a forecast error of 3%.

The Public Staff believes that the economic, weather-related, and demographic assumptions underlying 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.

SUMMARY OF GROWTH RATES

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

2014- 2028 Growth Rates

(After New EE and DSM)

	Summer Peak	Winter Peak	Energy Sales	Annual MW Growth
DEP	1.2%	1.4%	1.4%	171
DEC	1.4%	1.5%	1.5%	283
DNCP	1.2%	1.1%	1.4%	239

SYSTEM PEAKS AND USE OF DSM RESOURCES

DEP's 2013 annual system peak was 12,166 MW, as compared to 12,770 MW in 2012. At the time of the peak, which occurred on August 12, 2013, at the hour ending 4:00 p.m., DEP activated its EnergyWise Home and Commercial, Industrial, and Government Demand Response programs, which reduced peak load by 87 MW and 15 MW, respectively. DEP activated its DSM programs on five of its ten highest summer loads in 2013 for an average load reduction of 96 MW. DEP's 2012 IRP projected that it would have 828 MW available from its DSM, EE, and voltage control programs, of which 728 MW could be activated to reduce its 2013 summer peak.

DEC's system peaked at 16,482 MW on August 16, 2013, at the hour ending 5:00 p.m. The 2012 system peak was 17,740 MW. DEC did not activate its DSM or load curtailment programs at the time of its 2013 system peak; rather, DEC activated its DSM at only two of its top ten highest summer loads for an average load reduction of 111 MW. DEC's 2012 IRP projected the availability of 872 MW from its DSM programs to reduce its summer peak.

DNCP's 2013 annual system peak of 16,366 MW occurred on July 19, 2013, at the hour ending 4:00 p.m. Its 2012 system peak was 16,787 MW. At the time of the summer peak, DNCP called on its Distributed Generation Pilot[6] for a load reduction of 14 MW and its Air Conditioning Cycling Program for a reduction of 50 MW. DNCP activated these two DSM programs on seven of its ten highest summer loads in 2013 for an average reduction of 63 MW. DNCP's 2012 IRP projected the availability of 83 MW from its DSM programs to reduce its 2013 summer peak.

DNCP and DEP generally appear to have maximized their available DSM resources to reduce their peak demands. While the temperatures during the summer of 2013 were relatively mild and may have reduced the need for use of DSM, all three utilities should maximize these DSM resources in the future.

GENERATING FACILITIES

EXISTING GENERATION

CLIFFSIDE UNIT 6 AIR PERMIT

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 DEC to retire, in addition to Cliffside Units 1-4, "older coal-fired

[6] The Distributed Generation Pilot operates only in Dominion's Virginia jurisdiction.

generating units . . . on a MW-for-MW basis, considering the impact on the reliability of the entire system, to account for actual load reductions realized from [new EE and DSM] programs, up to the MW level added by" Cliffside Unit 6, i.e., 825 MW. In the air permit issued by the North Carolina Department of Environmental and Natural Resources, Division of Air Quality (DAQ) for Cliffside Unit 6, DAQ required DEC to implement a Greenhouse Gas Reduction Plan and to retire 800 MW of additional coal capacity without regard to achieving a commensurate level of MW savings from new EE and DSM programs. DEC's Greenhouse Gas Reduction Plan 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 DEC's system.

In its 2012 IRP, DEC included as Appendix J a Cliffside Unit 6 Carbon Neutrality Plan. This Plan incorporated actions required under the Greenhouse Gas Reduction Plan, as well as those required under DEC's additional obligations related to its Cliffside Unit 6 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 operation of future carbon control technology at Cliffside Unit 6, and (c) take additional actions as necessary to make Cliffside Unit 6 carbon neutral by 2018. DEC did not file a Carbon Neutrality Plan with its 2013 IRP.

In its October 14, 2013, *Order Approving Integrated Resource Plans and REPS Compliance Plans* issued in this docket regarding the 2012 IRPs, the

Commission ordered DEC to continue to provide updates in future IRPs regarding its obligations related to the Cliffside Unit 6 air permit. The Public Staff recommends that DEC file a Carbon Neutrality Plan with its reply comments and continue to provide updates in future IRPs regarding its obligations related to the Cliffside Unit 6 air permit.

Relicensing of Existing Nuclear Plants

One of the significant issues faced by the IOUs is the pending expiration of operating licenses for substantial nuclear energy resources in the next 20 to 30 years. The following table summarizes the current license expiration dates for the nuclear facilities owned by DEP, DEC, and DNCP.

Potential Nuclear Retirements

Name	Utility	Summer Capacity (MW)	License Expiration Date
Robinson Unit 2	DEP	741	July 2030
Surry Unit 1	DNCP	838	May 2032
Surry Unit 2	DNCP	838	January 2033
Oconee Unit 1	DEC	846	February 2033
Oconee Unit 2	DEC	846	October 2033
Oconee Unit 3	DEC	846	July 2034
Brunswick Unit 2	DEP	938	December 2034
Brunswick Unit 1	DEP	932	September 2036
North Anna Unit 1	DNCP	838	April 2038
North Anna Unit 2	DNCP	835	August 2040
McGuire Unit 1	DEC	1129	June 2041
McGuire Unit 2	DEC	1129	March 2043
Catawba Unit 1	DEC	1129	December 2043
Catawba Unit 2	DEC	1129	December 2043
Harris Unit 1	DEP	928	October 2046

The Public Staff notes that recent draft revisions to technical guidance and regulation by the Nuclear Regulatory Commission (NRC) and others[7] may

[7] *See* NRC Policy Issue Notation Vote, January 31, 2014 SECY-14-0016, http://www.nrc.gov/reading-rm/doc-collections/commission/secys/2014/2014-0016scy.pdf, *Renewing Licenses for the Nation's Nuclear Power Plants,* APS Panel on Public Affairs, December, 2013, http://www.aps.org/policy/reports/popa-reports/upload/nuclear-power.pdf.

ultimately provide an option to operators of commercial nuclear power facilities for extension past the current 60-year licenses. Potential extension of licenses would be evaluated based on the specific risks and costs associated with individual units. The NRC has stated that it expects the first extensions beyond 60 years to be filed in the 2018 to 2019 time frame. Relicensing could mitigate the currently expected combined (DNCP, DEP, and DEC) loss of nuclear baseload generation of 7,013 MW in the 2030 to 2034 time frame and the loss of an additional 7,162 MW in the 2038 to 2046 time frame. The Public Staff recommends that the IOUs consider the potential for relicensing of their existing nuclear units and reflect such potential relicensing, as appropriate, in their 2014 IRPs.

PLANNED GENERATION

DEP

Subsequent to DEP's filing of its IRP, uprates totaling 49 MW were implemented at Robinson Unit 2 (5 MW), Harris (4 MW), Smith CT9 (20 MW), and Smith CT10 (20 MW). Additionally, the L.V. Sutton facility, a 625-MW natural gas-fired CC facility, began commercial operation in November 2013. DEP's planned generation listed in its short-term action plan consists of additional nuclear uprates of 24 MW in 2015, a 137 MW CC uprate in 2018, and a 126 MW fast-start combustion turbine (CT) in December 2017.

DEP's 2013 plan also includes 46 MW of partial ownership in the V.C. Summer Nuclear Station (Summer) in 2018 being developed by South Carolina

Public Service Authority and South Carolina Electric & Gas, and an additional 46 MW in 2020. However, on January 27, 2014, Duke Energy Corporation disclosed in a filing with the Securities and Exchange Commission that it is no longer engaged in discussions regarding the potential acquisition of partial ownership of Summer by DEP and DEC.

In response to Public Staff data requests, DEP indicated that removing the proposed ownership portion of 5% of Summer does not significantly impact its 2013 IRP from an installed capacity perspective. DEP is also investigating the potential for regional ownership of a portion of other nuclear facilities under development, including a 20% share in DEC's proposed Lee nuclear units in Cherokee County, South Carolina. At this time, however, no contractual agreements have been signed.

DEP's short-term action plan through 2018 also includes the cumulative addition of 22 MW of solar, nine MW of biomass/hydro, and 246 MW of DSM/EE. The Public Staff notes that the projected 22 MW of solar seems low when compared with the significant number of Qualified Facilities (QFs) that have received certificates of public convenience and necessity (CPCNs) from the Commission and are currently in DEP's interconnection queue. In response to Public Staff data requests, DEP indicated that its interconnection queue contained 1,495 MW of solar as of September 1, 2013. DEP indicated that it has historically seen approximately one-quarter of the capacity in the queue come to fruition, but noted that the current levels exceed historic experience, so there is uncertainty as to whether the historical fruition rates are indicative of future fruition rates. DEP also noted that not all solar QFs in the interconnection queue sell renewable energy credits (RECs) to the utilities, and without the RECs, the utility does not recognize the electricity purchased from a QF as a renewable resource, but as general purchased power contracts.

The Public Staff agrees with DEP that currently unprecedented levels of interest in solar photovoltaic (PV) generation in North Carolina exist and that it is unlikely that all of the generation will be constructed. However, the Public Staff finds DEP's assumption that only an additional 22 MW of solar generation will be added between 2014 and 2018 (approximately 1.5% of DEP's queue as of September 1, 2013) to be extremely low. As of March 15, 2014, DEP had 218.5 MW of customer-owned solar generation operating on its system. In addition, the Public Staff notes that on February 13, 2014, DEP and DEC issued a combined request for proposals (RFP) seeking 300 MW of large solar PV generation, including the RECs, to be in service before the end of 2015. In a news release issued April 4, 2014, Duke Energy Corporation announced that its RFP had garnered substantial participation and it had received bids for nearly three times the capacity being sought. The Public Staff recommends that, in future IRP filings, DEP factor in reasonable estimates of solar generation based on issued RFPs and a percentage of the proposed facilities in the interconnection queue coming to fruition.

DEC

DEC's 2012 IRP showed a need for 700 MW in 2016. In comparison, its 2013 IRP shows a need of 680 MW in 2017. It plans to meet this need by converting the Lee Steam Station Unit 3 from coal to natural gas fuel (170 MW) and constructing the 750 MW Lee CC Plant, of which DEC would own 650 MW and the North Carolina Electric Membership Corporation (NCEMC) 100 MW. On April 9, 2014, in Docket No. 2013-392-E, the Public Service Commission of South Carolina issued a directive finding that DEC and NCEMC had satisfied the statutory criteria necessary for the grant of a Certificate of Environmental Compatibility and Public Convenience and Necessity for this plant.[8] The short-term action plan through 2018 also includes the addition of 77 MW of nuclear uprates, 436 MW of solar, 56 MW of biomass/hydro, and 637 MW of DSM/EE.

Similar to DEP, DEC included 66 MW of partial ownership in Summer in 2018 and an additional 66 MW in 2020. However, as indicated above, such partial ownership is no longer being considered as of January 27, 2014. Like DEP, DEC indicated that loss of the Summer baseload energy contributions to the DEP and DEC systems will be reflected in the 2014 IRP planning assumptions, and that all other things being equal, the removal of Summer will tend to favor slightly the addition of more baseload-oriented units to replace the baseload energy assumed with Summer.

[8] *See* http://dms.psc.sc.gov/pdf/matters/D02EE03C-155D-141F-23B1B9833C74315E.pdf.

DEC is continuing its evaluation of the potential need for two 1,100 MW nuclear units at the Lee facility.

While not as significant as DEP's potential underestimation of solar resources, DEC's projected 436 MW of solar resources through 2018 also may underestimate the potential for QF solar facilities when compared to the number of solar QFs with interconnection requests pending in DEC's service area (700 MW as of September 1, 2013), and the RFP issued by DEP and DEC seeking a combined 300 MW of solar generation to be in service before the end of 2015. As of March 15, 2014, DEC had 140.2 MW of customer-owned solar generation operating in its system. The Public Staff recommends that DEP and DEC in their reply comments and future IRPs provide both information on the number and resource type of the facilities currently within the respective utility's interconnection queue and a discussion of how the potential QF purchases would affect the utility's long-range energy and capacity needs.

DNCP

DNCP's IRP indicates that conversion of the Hopewell, Altavista, and Southampton Coal Stations to biomass-fueled facilities was scheduled to be implemented before the end of 2013. The Company completed the conversion of the Altavista plant in July of 2013, but did not provide an update regarding the Hopewell or Southampton Coal Stations. The Public Staff recommends that DNCP provide an update regarding the conversion of the Hopewell and Southampton Coal Stations in its reply comments.

The planned generation additions based on the short-term action plan also include the conversion of Bremo units 3 and 4 to natural gas-fueled generation in 2014, a 1,337 MW CC unit at the Warren County Power Station scheduled to be completed in the 2015 timeframe, the 24 MW Solar Partnership Program, a 1,375 MW CC at the Brunswick County Power Station scheduled to be completed in 2016, the addition of 34 MW of solar PV generation in 2017-2018, and a two MW offshore wind demonstration project in 2018. DNCP also indicates that it continues to evaluate the addition of another nuclear unit at its North Anna facility. In addition, DNCP's resource evaluation indicates that its existing blackstart generation capacity[9] is quickly reaching the end of its useful life and requires replacement for compliance with the PJM Generator Operational Requirements Manual in order to maintain adequate blackstart capability. PJM plans to issue RFPs every five years, with the first five-year selection resulting in a solution that will be effective by April 1, 2015.

NON-UTILITY GENERATION

Commission Rule R8-60(i)(2)(iii) requires each electric utility to provide a separate and updated list of all non-utility electric generating facilities in its service areas, including customer-owned and stand-by generating facilities, in its

[9] Blackstart generation is utilized to energize portions of a distribution system following a complete loss of generation and/or load. Larger generating units typically require the distribution grid to be energized prior to synchronizing the voltage and frequency output of the generator with the load of the distribution grid. Use of blackstart generation typically follows a catastrophic event involving widespread loss of load, which causes generating units to trip off line.

biennial IRP, updated as necessary in its annual update.[10] DEP, DEC, and DNCP each provided a list of non-utility generators (NUGs). This information is included as part of the IRP filings because the utilities rely upon this capacity to meet resource requirements.

DEP reported seven firm wholesale purchase contracts with a combined capacity of 2,257 MW. DEP also reported 523.9 MW of customer-owned generation in North Carolina and 141.4 MW of customer-owned generation in South Carolina. In addition, DEP receives approximately 95 MW from the Southeastern Power Administration (SEPA) for wholesale customers located within DEP's control area.

DEC reported two firm wholesale purchase contracts with a combined capacity of 94 MW. DEC also reported 430.54 MW of customer-owned generation in North Carolina and 135.9 MW of customer-owned generation in South Carolina as of July 2013.

DNCP reports seven NUGs in Virginia with a combined capacity of 1,422.8 MW and three NUGs in North Carolina with a combined capacity of 324.5 MW. These NUGs are included in DNCP's resource plan as firm capacity. DNCP also reports ten NUGs at various customer sites behind the meter in North Carolina totaling 33.8 MW that are non-firm and are not included in the plan. Other North Carolina customer-owned generators total 55.9 MW.

[10] Similar information is also required pursuant to an Order issued June 6, 1989, in Docket No. E-100, Sub 41B.

RESERVE MARGINS AND RESERVE MARGIN ADEQUACY

A reserve margin is generally defined as (Resources – Demand) / Demand. The "margin" is necessary to ensure that adequate capacity is available to meet system needs at peak load while allowing for scheduled and unscheduled maintenance, higher than expected load growth, limitations based on environmental constraints, variance in load due to extreme weather, transmission availability, and disruptions in power resulting from noncompliance with purchased power agreements.

In 2012, DEP and DEC contracted with Astrape Consulting to conduct a detailed resource adequacy assessment that included an evaluation of their resource margins. Astrape's study provided DEP and DEC each with a recommended system reserve margin based on the Loss of Load Expectation (LOLE) probabilistic assessment. The LOLE is a metric that targets the probability of the loss of load on one day in a ten-year period, or one firm load shed event resulting in unserved energy for a firm customer on one day in a ten-year period. A greater frequency of loss load probability is generally considered to be inadequate system reliability. Based on Astrape's analyses, the reserve margins that correlate with this LOLE are 14.5% for DEP and 14% for DEC. Additional analysis is planned by Astrape to verify the adequacy of the target reserve margins now that the JDA has been implemented.

DNCP utilizes the PJM capacity planning process for long- and short-term planning of capacity needs. The current (2012) study recommends use of a reserve margin of 15.6% to satisfy the reliability criteria required by the North American Electric Reliability Corporation (NERC), Reliability First Corporation, and PJM's Planned Reserve Sharing Group. DNCP utilizes a coincidence factor to account for the historically different peak periods between DNCP and PJM and therefore determine its ability to meet its PJM reserve requirements. This coincidence factor reduces DNCP's reserve margin requirement to 11.2%. DNCP also includes a 16.2% upper margin, which is commensurate with the upper bound that PJM's Reliability Pricing Model (RPM) market auction has historically cleared. The DNCP planning reserve margin remains at 11%.

For the planning period 2014 to 2028, the range of summer reserve margins reported by the electric utilities continues to be similar to those used in previous annual reports. For this time period, the planned reserves are:

Utility	Target Reserve Margin	Planned Reserve
DEP	14.5%	14.9% to 19.6%
DEC	14.5%	14.3% to 21.5%
DNCP	11%	11.2% to 17.6%

DEP's IRP indicates that DEP will meet its projected reserve margin targets for the planning period and will exceed the minimum planning target of 14.5% by 3% or more in 2014-2016 due to a decrease in the load forecast. The IRP also states that the reserves exceed the minimum target by an average of approximately 3% to 5% in 2019, 2022, and 2023 as a result of the addition of large CC facilities. The Public Staff considers the planned reserves adequate.

DEC's IRP indicates that its reserve margins will meet its target reserve margin percentages for the planning period and will exceed the minimum planning target of 14.5% by an average of approximately 3% to 7% after the additions of large base load facilities in 2024 and 2026. The Public Staff concludes that DEC's planned reserves are adequate.

The Public Staff notes that differences in projected versus actual peak load growth can have a significant impact on the reserve margin. If the forecasted CAGR of DEC's peak loads grow at 1.0%, as opposed to the 1.4% rate projected in its 2013 IRP, the reserve margins will remain over 20% for most of the planning period.

As pointed out in the Planned Generation section of the Public Staff's comments, DEP and DEC do not appear to be fully considering the large number of solar QFs in the interconnection queue that could provide significant amounts of energy and capacity over the planning period, and the Public Staff has recommended that they include more realistic assumptions of potential solar energy and capacity. However, inclusion of these potential solar resources should not affect the short-term action plans.

DNCP participates in the PJM market and, through the RPM auction, has obtained a commitment for additional capacity purchases above the existing identified firm purchases to ensure that its reserve margins meet the target of 11% reserves in 2013 and thereafter.

Based on its review of the IRPs, the Public Staff believes the reserve margins filed by the IOUs are reasonable for planning purposes.

WHOLESALE CONTRACTS FOR PURCHASE AND SALE OF POWER

DEP and DEC provided a list of firm wholesale purchased power contracts, while DNCP stated that its contracts with NUGs are considered firm capacity resources that are included in its IRP. Each utility provided a discussion of recent and pending requests for proposals and a list of the wholesale power contracts for the planning horizon in compliance with Rule R8-60(i)(4).

TRANSMISSION FACILITIES

The electric utilities included a copy of their most recent FERC Form 715 and discussed with the Public Staff detailed information concerning their transmission line inter-tie capabilities, transmission line loading constraints, planned new construction and upgrades, and NERC compliance within their respective control areas for the planning period under consideration. Each electric utility appears to be in compliance with the Commission's filing requirements and NERC transmission reliability standards.

TRANSMISSION PLANNING

In 2004, the Commission instituted a collaborative process involving transmission stakeholders in order to obtain information on any specific transmission-related issues that currently existed or were likely to arise in the future. The result of this collaborative process was the development of the North Carolina Transmission Planning Collaborative (NCTPC) involving DEP, DEC, NCEMC, ElectriCities,[11] and others to address transmission issues facing North Carolina. The NCTPC provides stakeholders with opportunities to participate in the transmission planning process, preserves the integrity of the existing planning processes, expands the transmission planning process to include analyses of increasing access to supply resources inside and outside DEP's and DEC's control areas, and develops a single coordinated transmission plan for the participants. The NCTPC has an agreement with PJM to share planning data and PJM routinely participates in meetings of the NCTPC.

The aim of the NCTPC is to create an integrated long-term transmission expansion plan that will result in a reliable and cost effective transmission system. A Transmission Advisory Group (TAG) provides advice and recommendations to the load serving entities for incorporation into the coordinated transmission expansion plan for North Carolina. The TAG membership is open to all parties interested in the development of the NCTPC. DEP and DEC also participate in the Southeastern Inter-regional Participation Process and the Eastern Interconnection Planning Collaborative inter-regional efforts.

[11] ElectriCities is an organization representing cities, towns, and universities that own electric distribution systems.

A significant development related to transmission planning was the FERC's issuance of its Order No. 1000 in 2011 amending prior transmission planning requirements and requiring each public utility transmission provider to: (1) participate in a regional transmission planning process that produces a regional transmission plan; (2) amend its OATT (Open Access Transmission Tariff) to describe procedures for the consideration of transmission needs driven by public policy requirements established by local, state, or federal laws or regulations in the local and regional transmission planning processes; and (3) remove federal rights of first refusal from Commission-jurisdictional tariffs and agreements for certain new transmission facilities.

On October 11, 2012, DEP, DEC and Alcoa Power Generating, Inc. (d/b/a as Yadkin), submitted to the FERC revisions to their respective OATTs in order to comply with the directives in Order No. 1000. DEP and DEC contended that, despite their recent merger, they were still separate transmission providers and, with the addition of Yadkin, the NCTPC was an Order No. 1000-compliant transmission planning region. By Order dated February 21, 2013, the FERC rejected DEP and DEC's arguments, finding that, post-merger, DEP and DEC were no longer separate transmission providers for Order No. 1000 transmission planning purposes and, because Yadkin owns and operates so few transmission facilities, including it in the NCTPC region did not cure this deficiency. The FERC directed DEP and DEC to make a further compliance filing that, at a minimum, included another transmission provider of sufficient scope to create a transmission planning region sufficient to meet the Order No. 1000 requirements or that indicates DEP, DEC and Yadkin have joined an Order No. 1000-compliant transmission planning region.

DEP and DEC requested rehearing but agreed under protest to join the Southeastern Regional Transmission Planning (SERTP) process. On May 22, 2013, DEP and DEC submitted revisions to Attachment N-1 of their joint OATT to comply with the directives of the FERC. DEP and DEC stated that they had revised their joint OATT to distinguish between the NCTPC process, which they would use for local transmission planning, and the SERTP process, which they would use for regional transmission planning. On December 19, 2013, the FERC denied rehearing of its February Order rejecting DEC, DEP, and Yadkin's compliance filing. The FERC has not yet acted on DEP and DEC's revisions.

DSM AND EE

FORECAST OF DSM/EE

DEP

DEP's portfolio of DSM and EE programs is largely the same as in its 2012 IRP, with the addition of two new programs (Residential New Construction and Small Business Energy Saver). DEP also modified its Residential EE Lighting and Residential Home Energy Improvement programs to include additional measures. These changes are represented in the projections of capacity and energy savings included in the tables in Appendix D of DEP's 2013 IRP. DEP uses its DSM and EE portfolio-related energy and capacity savings as reductions to its load forecast before determining the need to build new supply side resources. DSM resources are considered capacity resources, while EE resources are direct reductions to the load forecasts.

A comparison of the projected energy and capacity savings attributable to DSM and EE programs in DEP's 2012 and 2013 IRPs indicates some significant changes in the methodology for quantifying DSM and EE savings, which lead to significant differences in the projections. In its 2012 IRP, DEP represented DSM and EE program savings on a net basis, after making net-to-gross (NTG) adjustments such as free ridership and spillover. In the 2013 IRP, these program savings are represented on a gross basis, with no NTG adjustments. Secondly, unlike its 2012 IRP, DEP's 2013 IRP assumes a beginning point of 2013 for the portfolio of programs and does not include program savings from measures installed prior to 2013. DEP based its DSM and EE program savings on its 2012 market potential study, which presumed no measures were installed prior to 2013. These two differences make it very difficult to analyze changes in the portfolio savings from 2012 to 2013, including changes in individual DSM and EE programs.

There are several points the Commission should consider in its review of DEP's EE savings impacts:

DEP forecasts a 4.95%[12] increase in the annual energy savings from 2013 through 2028.[13]

- The CIG (commercial, industrial, and governmental) portion of the EE Lighting Program will provide 20% of its portfolio energy savings by 2028.
- The Residential EE Products Program[14] will provide 50% of the portfolio energy savings by 2028.
- By 2028, the amount of energy savings provided by the Residential EE Lighting Program will significantly decrease.

DEC

DEC included energy and capacity savings in its load forecast from its recently approved portfolio of DSM and EE programs in Docket No. E-7, Sub 1032. Several of these programs are the same programs included in previous years under DEC's Save-A-Watt DSM and EE portfolio. Like DEP, DEC uses its DSM and EE portfolio-related energy and capacity savings as reductions to its load forecast before determining the need to build new supply side resources. DEC considers DSM resources as capacity resources, while EE resources are direct reductions to the load forecasts.

[12] 4.95% calculated using data from Annual MWh Energy Savings for Post SB-3 DSM/EE (at generator) Table, p. 79, 2013 DEP IRP.

[13] It appears that the EE savings do not include pre-2013 program savings.

[14] While DEP referred to this program as "Res EE Products" in its data response, it appears that this reference is to the Residential Home Energy Improvement program.

A review of the projected energy and capacity savings in DEC's 2013 IRP reflect a significant change in methodology since the 2012 IRP. DEC's calculations include only the impacts associated with measures added in 2013 and future years. In prior IRPs, however, DEC included these pre-2013 program impacts. In response to Public Staff inquiry, DEC stated that EE savings for the first five years were based only on the market potential study, which assumed a starting point of 2013 (i.e., no EE savings prior to 2013), thereby lowering the initial EE savings potential. For the next 15 years of the planning horizon, DEC looked at the achievable potential at the portfolio level.[15]

The Public Staff's review indicates a significant increase in the projected amount of capacity and energy savings provided by DSM and EE programs between the 2012 and 2013 IRPs, average increases of 27% and 24%[16] in the projected capacity and cumulative energy savings, respectively.[17] Using DEC's

[15] DEC indicated that under this methodology, EE savings for each measure are converted into hourly savings and summed up at the portfolio level, and then the impacts are evaluated over 8,760 hours of the year.

[16] To evaluate the changes between the 2012 and 2013 IRPs related to DSM and EE, the Public Staff included the pre-2013 program savings in its calculations because these measures are producing impacts that are incorporated into the load forecasts and thus should be included in the EE savings identified in the IRP. The Public Staff recognizes that its approach does not adequately consider the impacts of measures that reach the end of their useful lives and cease to produce EE savings impacts. The Public Staff also recognizes that program adoption rates, implementation, efficiency standards, and the experience of operating a DSM/EE program will also influence the short-term program savings obtained from the DSM/EE portfolio. However, in the first five to ten years, this approach reasonably accounts for the EE savings impacts associated with new and existing measures.

[17] The Public Staff reviewed the energy and capacity savings from DSM and EE programs by comparing Table 4.A, p. 39, 2012 DEC IRP, and the Base Case Load Impacts of EE and DSM Programs table, p. 90, 2013 DEC IRP. As noted at p. 89, 2013 DEC IRP, the data in the Base Case Load Impacts of EE and DSM Programs table do not include 257 MW and 1,828 GWh of pre-2013 (SB3) program savings that were part of the DSM and EE programs implemented pursuant to G.S. 62-133.9 and installed prior to 2013.

method of calculating the impacts, the change between the 2012 and 2013 IRPs is an initial decrease of 75% in energy savings and 4.9% in capacity savings over the planning horizon. However, by 2028, the 2013 IRP projects an increase of 2.2% in energy savings and 19.5% in capacity savings over the projections in the 2012 IRP.

In Appendix D of its 2013 IRP, DEC discusses its forecast of DSM/EE savings and the variances in those savings since the last IRP. DEC stated its forecast of EE savings was the result of blending the achievable potential of EE savings as identified in an updated market potential study, with its forecast for the first five years of the planning horizon. For years six through 20 of the planning horizon, DEC employed the straight line method used by DEP in its 2012 IRP.

There are several points the Commission should consider in its review of DEC's EE savings impacts:

- DEC expects a large increase in potential EE savings in the first five years of the forecast, with the cumulative EE savings increasing from 436 GWh in 2013 to 2,436 GWh in 2017, a 460% increase.[18] Both figures are lower than the EE savings projected for the respective years in the 2012 IRP.
- Incremental new EE savings for each of the first five years averages 487 GWh per year.

[18] Base Case Load Impacts of EE and DSM Programs table, p. 90, 2013 DEC IRP.

- 70% of the EE savings are projected to come from the My Home Energy Report, Non-Residential Smart Saver, and Non-Residential Smart Saver Custom programs.

DNCP

Consistent with previous IRPs, DNCP included existing, proposed, and anticipated DSM and EE programs in its load forecast.[19] As a member of PJM, DNCP bids all of its capacity resources, including DSM resources, into the PJM capacity market. In Section 5.5.7 of its IRP, DNCP provides a general discussion of the differences in the projections of the energy and capacity savings derived from DSM and EE between its 2012 and 2013 IRPs. The Company projects a decrease in energy and capacity savings of approximately 7% and 34%, respectively from its projections in its 2012 IRP. DNCP identified the changes in the participation levels associated with the Residential Air Conditioner Cycling Program as the major driver of the decrease in capacity savings. DNCP also indicated that these projections are affected by implementation issues, regulatory changes and delays, and the rate of growth in participation.

In response to Public Staff's data requests, DNCP provided a breakdown by DSM/EE program of the changes in projected energy and capacity savings between the 2012 and 2013 IRPs. For example in year 2028, most of the

[19] Several of the proposed programs discussed in DNCP's IRP have now been approved by the Commission: Non-Residential Energy Audit Program in Docket No. E-22, Sub 495, Non-Residential Duct Testing and Sealing Program in Docket No. E-22, Sub 496, Residential Duct Testing and Seal Program in Docket No. E-22, Sub 497, Residential Home Energy Check Up Program in Docket No. E-22, Sub 498, Residential Heat Pump Tune Up Program in Docket No. E-22, Sub 499, and Residential Heat Pump Upgrade Program in Docket No. E-22, Sub 500.

Company's DSM/EE programs are projected to have lower energy savings across the planning horizon. However, the Residential Heat Pump Tune Up, Commercial Energy Audit, Commercial HVAC Upgrade, and Non-Residential Distributed Generation[20] Programs and the future Non-Residential Custom Incentive Program are projected to provide greater energy savings. With the exception of the Non-Residential Distributed Generation Program, these same programs are also projected to provide greater capacity savings. The Commercial Lighting Program is projected to provide greater capacity savings but lower energy savings by 2028. However, these increases in projected savings are not sufficient to overcome the overall decrease in projected energy and capacity savings associated with the remaining DSM and EE programs in 2028.

DNCP indicated in response to Public Staff data requests that the differences in energy and capacity savings related to the Residential Air Conditioning and Low Income programs were attributable to changes in the methods of cost recovery in its Virginia jurisdiction, which impacted the participation in these programs.[21] Data provided by DNCP indicated that the decreased energy and capacity savings from these two programs were 3% and 82%, respectively. The significant decrease in capacity savings shows the large

[20] Approved only in the Virginia jurisdiction.

[21] The Virginia State Corporation Commission (VSCC) has capped the amount of expenditures for DSM and EE programs in the Virginia jurisdiction. Once a program reaches its spending cap, Dominion ceases offering the program to new participants.

contribution that the Residential Air Conditioning Program makes to DNCP's overall capacity savings.

Notwithstanding the impacts of changes in the methods of cost recovery for its DSM/EE programs in Virginia, the magnitude of the changes in the projections of the energy savings, and to a larger extent the capacity savings, from the 2012 IRP to the 2013 IRP is significant. These issues create a level of uncertainty in the load forecast. While the levels of energy and capacity savings are small in comparison to supply-side resources, the importance of properly forecasting DSM and EE program savings will increase as the contributions from DSM and EE to the overall resource portfolio grow.

The Public Staff recommends that DNCP continue to monitor and report any changes of more than 10% in the energy and capacity savings derived from DSM and EE between successive IRPs, and evaluate and discuss any changes on a program-specific basis. The Public Staff also recommends that any issues impacting program deployment be thoroughly explained and quantified in future IRPs.

RECOMMENDATIONS REGARDING PROJECTIONS OF DSM/EE SAVINGS

The Public Staff recommends that the IOUs, and in particular DEP and DEC, develop a consistent method of evaluating their DSM and EE portfolios and incorporate the savings in a manner that would provide a clearer understanding of the year-by-year changes occurring in the portfolios and their impact on the load forecast and resource plan in future IRPs. The Public Staff believes DEC's methodology appropriately applies market potential to the initial planning horizon, and that later years are much more difficult to forecast given the other influences that can impact EE measures. The Public Staff also recommends that the savings impacts be represented on a net basis, taking into account any NTG impacts DEP and DEC have derived through their respective evaluation, measurement, and verification (EM&V) processes.

The Public Staff recommends that DEP and DEC specifically identify the values of DSM and EE portfolio capacity and energy savings separately in their load forecast tables and not embed these values in the system peak load or energy. Additionally, DEP, DEC, and DNCP should account for all of their DSM and EE program savings from programs approved pursuant to G.S. 62-133.9 and Commission Rule R8-68, regardless of when those measures were installed. The Public Staff does not dispute that savings related to EE measures installed prior to the filing of the IRP result in reduced load and energy requirements. However, by embedding these savings into the overall system load forecasts, it is difficult to know how these DSM and EE programs are performing, or how they will contribute to future reductions in capacity and energy requirements.

Finally, the Public Staff's evaluation of the impacts related to the DSM/EE portfolio in the IRP relies heavily on an analysis of the changes to the year-by-year portfolio and program impacts and their influence on the resource plan in general. Changing the methods of evaluation and presentation of data complicates the evaluation of DSM and EE and their impacts on the resource plan from year to year. The Public Staff recommends that DEP and DEC adopt one methodology of evaluating the DSM and EE components of the IRP and remain consistent year-to-year. Given the variability of DSM and EE savings and the influence of factors such as program design changes, adoption rates, efficiency standards, and program costs, all IOUs should strive to maintain consistent methods in their evaluations of the DSM and EE portfolio impacts that are incorporated into their IRPs. If an IOU determines that a change in methodology is required or appropriate, these changes should be thoroughly explained, justified, and reconciled to the savings projected in the previous IRP.

CURRENT PORTFOLIO OF DSM AND EE PROGRAMS

DEP's portfolio of DSM and EE programs remains largely unchanged from the portfolio presented in its 2012 IRP. However, in 2013, DEP received approval and began implementing its new Residential New Construction and Small Business Energy Saver programs and its expanded EE Lighting Program. The Residential New Construction Program replaced the Residential Home Advantage Program and addressed changes in the building energy codes, which impact the cost effectiveness of the programs and potential for capacity and energy savings.

DEC recently received Commission approval of a new DSM/EE portfolio of programs in Docket No. E-7, Sub 1032, including re-approval of several existing programs that were approved under the Save-A-Watt mechanism. However, unlike the Save-A-Watt portfolio of programs, which had a four-year duration, the new portfolio of programs has no specific term.

DNCP recently received Commission approval to implement six new EE programs in North Carolina, including two programs (Commercial HVAC and Commercial Lighting) targeted only to its North Carolina retail jurisdiction. In additional to these programs, DNCP continues to include its Residential AC Cycling and Residential Low Income programs in its portfolio.

PROPOSED AND REJECTED DSM AND EE PROGRAMS

DEP discussed proposed modifications to its CIG Demand Response Automation Program to provide additional options for DSM; these modifications were approved by the Commission in late 2013. DEP also indicated that it was currently evaluating opportunities related to the small business and low income sectors, some of which could be incorporated into its existing Small Business Energy Saver and Residential Neighborhood Energy Saver programs.

DEC did not identify any proposed programs it is considering. However, the DEC Collaborative is discussing potential EE programs that would be targeted to multi-family residential developments, low income customers, and large commercial customers, including the combined heat and power market.

DNCP included three programs recently approved by the VSCC: the Non-Residential Solar Window Film, Non-Residential Lighting Systems & Controls, and Non-Residential Heating & Cooling Efficiency programs. Projected energy and capacity savings from these programs and three other programs yet to be submitted to the VSCC or Commission are included in the Company's forecast.

None of the IOUs reported that it had rejected any new DSM/EE programs in the planning period.

OTHER DSM/EE ISSUES

TIME OF USE (TOU) AND CURTAILABLE RATE SCHEDULES

For many years, DNCP, DEP, and DEC have included TOU and curtailable rates in their IRPs. In recent general rate cases for DEP and DEC,[22] both utilities agreed to develop additional TOU rate schedules and update their curtailable rate schedules. Recent cold weather conditions have prompted the utilities to implement various load control programs and increase rates on real-time pricing rate schedules. Responses to Public Staff data requests suggest customers are responsive to relatively high prices available to them on a day-ahead basis and have acted to reduce load during times of peak demand. The Public Staff recommends that each utility continue its efforts to inform customers of these rate schedules and educate customers regarding their benefits.

[22] Docket Nos. E-2, Sub 1023 and E-7, Sub 1026, respectively.

CONSUMER EDUCATION PROGRAMS

The consumer education programs identified by each IOU remain consistent with those reported in DEP and DNCP's respective 2012 IRPs and in DEC's reply comments filed March 5, 2013, in this docket.

DNCP's MARKET POTENTIAL STUDY

In its 2012 IRP, DNCP indicated that it was updating its market potential study and would incorporate the new study in its 2013 IRP. In its 2013 IRP, DNCP stated that this new study has been delayed and would not be incorporated until the 2014 IRP.

DEC'S GRID MODERNIZATION

DEC included a brief discussion of its "grid modernization" program similar to the discussion included in the 2012 IRP. DEC is planning to implement its grid modernization program over the next five years, and anticipates demand reductions of 1.0% by 2019. DEC's program would be similar to DEP's Distribution System Demand Response Program. DEC indicated in response to the Public Staff data requests that it had developed a foundation for its grid modernization strategy, and would provide greater details of its efforts once they were more firmly established. The Public Staff also notes that DEC indicated that it expects to recover the costs it has incurred to date related to its grid modernization through base rates.

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 must also provide general information on any changes to the methods and assumptions used in the assessment since its most recent biennial or annual report.

For the currently operational or potential future alternative supply-side energy resources included in each utility's plan, the utility must provide information on the capacity and energy actually available or projected to be available, as applicable, from the resource. The utility must also provide this information for any actual or potential alternative supply-side energy resources that have been discontinued from its plan since its last biennial report and the reasons for that discontinuance. For alternative supply-side energy resources evaluated but rejected, the utility must provide the following information for each resource considered: a description of the resource; the potential capacity and energy associated with the resource; and the reasons for the rejection of the resource. Each utility provided the information required by Commission Rule R8-60(i)(7).

EVALUATION OF RESOURCE OPTIONS

Commission Rule R8-60(i)(8) requires each utility to include in its IRP a description and summary of the results and analyses of potential resource options and combinations of options. The IOUs indicate in their IRPs that they use accepted 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. DEP and DEC utilize System Optimizer and Planning and Risk models to determine the dispatch and production costs for their system and DNCP utilizes the Strategist model.

These models have the ability to perform optimization analyses to select among resources that could be added in various combinations to satisfy the utility's future load requirements. They are designed to compare various generation portfolios to determine which has the lowest present value revenue requirement (PVRR) while maintaining the target reserve margin. The models incorporate forecasts of energy sales and peak load with assumptions on the operating characteristics of existing and future generating units (including 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 order to arrive at a least-cost plan, 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 consider uncertainties, the utilities generally develop a base or preferred plan and alternative plans. As the 2013 IRP updated the 2012 biennial IRP, DEP and DEC evaluated a limited number of alternative plans under two scenarios. DNCP's 2013 IRP is a full biennial IRP to comply with IRP filing requirements in Virginia (full IRPs in odd years, updates in even years). As a result, DNCP's IRP was more robust than that of DEP and DEC as it contained several alternative plans that were evaluated under various scenarios.

The IOUs use modeling assumptions that, in some cases, vary substantially. The tables that follow compare certain modeling assumptions used by DEP, DEC and DNCP, consisting of operational data and the projected capital cost estimates per kW, without AFUDC, of certain supply side resources. While the variations may be justified due to the specific resource modeled by each IOU, these variations significantly influence the plans.

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DEP and DEC	CTs 7FA-4 turbines	Combined Cycle 2x1	Combined Cycle 3x1	Nuclear[1,4]	Solar
Capacity (MW)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Heat Rate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Investment ($/kW)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Book Life	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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DNCP	CTs 7 FA turbines[2]	Combined Cycle 2x1	Combined Cycle 3x1	Nuclear[3,4]	Solar
Capacity (MW)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Heat Rate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Investment ($/kW)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Book Life	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes: [1] DEP and DEC use the AP1000 design.
[2] Based on use of a Siemens 500F CT without backup fuel on a brownfield site.
[3] DNCP uses the General Electric-Hitachi ESBWR design.
[4] AFUDC can add approximately $100 to the cost per kW of a CC and over $1,000 to the cost per kW of a nuclear unit.

DEP AND DEC

DEP's Stand-Alone Plans

DEP's evaluation of resource options is discussed in the quantitative analysis section of its IRP. DEP's Base Plan included new natural gas-fired CTs, new CC generation, new nuclear generation, and the mandated level of renewable resources associated with SB3.

DEP also considered an Environmental Focus Scenario, which doubled the amount of renewable resources, increased the amount of EE, and included CO_2 prices higher than those in its Base Case. This scenario resulted in a delay in the need for two 843 MW CC resources: one from 2019 to 2020, and a second from 2021 to 2026. It also eliminated the need for 403 MW of CT generation during the planning period.

In DEP's initial filing, it indicated that the Environmental Focus Scenario PVRR through 2028 was $0.5 billion higher than the PVRR under the Base Case. However, in its March 7, 2014, filing, the Company noted that based on a recalculation of the production cost benefits using the appropriate capacity values for wind and solar energy, the PVRR difference between the Base Case and the Environmental Focus Scenario decreased from $0.5 billion to $0.1 billion over the planning period.

After completing the above analyses, DEP concluded that its preferred plan should include the following capacity additions: the 625 MW Sutton CC (which went into commercial operation in 2014), partial ownership of Summer (88 MW), two 201 MW CTs (403 MW), three 843 MW CCs (2,529 MW), and 240 MW of renewable capacity.

DEC's Stand-Alone Plans

DEC's evaluation of resource options is discussed in the quantitative analysis section of its IRP. Its Base Plan contains new CTs, new CCs, new nuclear generation, and the mandated level of renewable resources associated with SB3. DEC also considered an Environmental Focus Scenario using the same assumptions as used by DEP regarding renewables and EE and the prices of fossil fuel and CO_2. Under the Environmental Focus Scenario, DEC would delay the need for an 843 MW CC resource and eliminate the need for 403 MW of CT generation during the planning period.

DEC noted in its initial filing that the Environmental Focus Scenario PVRR through 2028 was $2 billion higher than the PVRR under the Base Case. In its March 7, 2014, revision to its 2013 IRP, however, the Company noted that based on a recalculation of the production cost benefits using the appropriate capacity values for wind and solar energy, the PVRR difference between the Base Case and the Environmental Focus Scenario decreased from $2 billion to $1.3 billion over the planning period.

After completing the above analyses, DEC concluded that its preferred plan should include the following capacity additions: the 2015 Lee Steam plant conversion to natural gas (170 MW), nuclear uprates (97 MW), partial ownership of Summer (132 MW), full ownership of two nuclear units going into service in 2024 and 2026 (1,117 MW per unit), two 201 MW CTs (403 MW), a 680 MW and a 840 MW CC[23] (1,523 MW), and 735 MW of renewable capacity.

DEP AND DEC JOINT PLANNING SCENARIO

DEP and DEC included a Joint Planning Scenario that examines the potential for them to share capacity.[24] They indicated that the Joint Planning Scenario produces a total PVRR savings of $400 million over the planning horizon by eliminating the need for a 843 MW CC, deferring one CT and two CCs

[23] Including the planned Lee CC unit.

[24] Regulatory Conditions imposed in the *Merger Order* require DEP and DEC each to pursue least-cost integrated resource planning and file separate IRPs until required or allowed to do otherwise by Commission order or until a combination of the utilities is approved by the Commission. The 2013 IRPs filed by DEP and DEC, and specifically the Joint Planning Scenario, appear to comply with this requirement.

for a year, and sharing the capacity of DEC's two proposed Lee nuclear units. The Joint Planning Scenario makes the following changes relative to DEP and DEC's Combined Base Case: delays until 2018 (one year) the need for a 680 MW CC; replaces a 2019 843 MW CC resource with 403 MW of CT generation in 2021; and defers a 403 MW CT by one year to 2023.

Discussion and Recommendations Regarding DEP and DEC's Plans

Optimization of Renewable Resources

A review of the inputs utilized by DEP and DEC individually and in the Joint Planning Scenario indicates that DEP and DEC did not allow the level of renewable resources to be optimized based on their installed costs and operating costs; rather, they set the level of renewable generation at the mandated level embodied in SB3 for their Base Cases and double the SB3 level in the Environmental Focus Scenario. As such, the PVRR of each generation portfolio may not fully incorporate the economic use of renewables. While the level of renewable generation required by SB3 is reasonable for use in a particular scenario, the Public Staff finds using an amount of renewable generation at twice the SB3 level for the Environmental Focus Scenario to be somewhat arbitrary. The Public Staff recommends that in their 2014 IRPs, DEP and DEC allow their models to select the optimum level of renewable energy generation based on the current and projected cost of solar generation, system integration costs, and other resource data, resulting in a more optimal level of solar generation. DEP and DEC also considered only a 25 MW solar unit as a potential supply side resource. The Public Staff also recommends that in their 2014 IRPs, DEP and

DEC allow their integration models to consider various sizes and types of solar generators from relatively small customer-owned rooftop systems to large solar farms, as well as their integration costs.

Addition of New Nuclear Resources

DEC's contention that the portfolios including new nuclear generation are competitive is largely dependent on the assumption of a carbon constrained economy with the pricing of carbon under various cap and trade proposals or the enactment of clean energy legislation and on DEC's desire to lower its carbon footprint. The Public Staff has noted in past IRP proceedings that new nuclear generation is the least cost resource option only under a scenario projecting future carbon prices. If carbon legislation is not enacted, then the base plan identified by DEC will result in **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** more in PVRR than a portfolio that includes only new natural gas and renewables.[25] Similarly, the joint planning scenario results in a cost to ratepayers of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** more in PVRR than the natural gas and renewable portfolio in the absence of carbon legislation.

The impact of carbon emission prices is advantageous to the economics of nuclear generation given that coal and natural gas generation emit CO_2 and nuclear generation does not. As such, DEC asserts that the fuel cost savings

[25] DEC's PVRR results were based on a 15-year planning horizon, but the economics supporting new nuclear were extended to 2052 to capture the long-term benefits of the low production cost and carbon-free generation.

and emissions reductions associated with nuclear outweigh its high capital costs relative to coal and natural gas generation. In order to capture these benefits fully within the IRP, DEC extended the model evaluation to 2052 in order to reduce potential bias against commissioning capital-intensive facilities, such as nuclear plants, in the latter years of the planning period.[26]

DEC has maintained that new nuclear units are necessary, in large part, because of the future retirements of its nuclear plants, beginning with the three 846 MW Oconee nuclear units in 2033 and 2034. The current 15-year planning horizon, however, ends in 2028, and there is limited discussion concerning the impact of these anticipated retirements in the IRP. The Public Staff notes that the Load, Capacity and Reserve Margin tables[27] in DEC's 2012 IRP extended 20 years in the future, while these same tables in DEC's 2013 IRP extend only 15 years.[28] Given the time required to secure an engineering, procurement, and construction contract (EPC) and the approximately ten years needed to build a new nuclear unit, the Public Staff recommends that the planning period for future IRPs that foresee substantial nuclear retirements be extended to at least 20 years.

[26] DNCP's use of the Strategist model provides a similar calculation of the end-effects of the generation portfolio.

[27] Table 8.A, pp. 93-94, 2012 DEC IRP.

[28] Tables 8-C and 8-D, pp. 29-30, 2013 DEC IRP.

In previous IRP proceedings, the Public Staff has identified the additional cost to ratepayers of the generation plans that include new nuclear plants. The Public Staff continues to believe that the benefit of additional nuclear generation from a fuel diversity perspective requires further evaluation. The economics of fuel diversity are difficult to quantify. In addition, the potential risks of construction cost increases and other uncertainties associated with nuclear power raise additional questions on the merits of DEC's preferred plan under both its stand-alone and Joint Planning scenarios. While the Public Staff has supported the Company's efforts to maintain the Lee nuclear site as a viable generation alternative, it is important to note the cost of maintaining this option. As of December 31, 2013, the accrued incremental expenditures for this alternative are $382 million, including AFUDC. The Public Staff recommends that detailed support be included in future IRPs if a utility prefers a resource plan that is based on unquantified benefits of fuel diversity as opposed to a plan that is otherwise lower in cost.

DNCP

DNCP's Plans

DNCP evaluated six generation portfolios that it determined were plausible resource plans:

- Plan A, its Base Plan, consisting of new natural gas-fired CTs and CCs;

- Plan B, the Fuel Diversity Plan, consisting of a combination of a new nuclear unit at the North Anna site, new natural gas-fired generation, offshore wind generation, and solar generation;
- Plan C, its Renewable Plan, consisting of renewable generation from biomass, onshore wind, offshore wind, solar, and a combination of new natural gas-fired CTs and CCs;
- Plan D, its Coal Plan, consisting of coal-fired facilities equipped with carbon capture and sequestration technology, along with a combination of new natural gas-fired CTs and CCs;
- Plan E, its Climate Action Plan, consisting of a combination of a new nuclear unit at the North Anna site, new natural gas-fired generation, onshore and offshore wind generation, and solar generation; and
- Plan F, its Offshore Wind Plan, consisting of a combination of offshore wind generation and new natural gas-fired generation.

To evaluate the selected plans, DNCP subjected them to various scenarios related to carbon costs, fuel and emissions allowance prices, load growth, construction costs, transmission and distribution costs, net metering, electric vehicle market penetration, renewable energy certificate (REC) sales, high and low cost combinations, and various residential rate designs. Figure 6.7.1 of DNCP's IRP provides a clear summary and comparison of the plans and scenarios considered, as well as the relative costs of each alternative relative to Plan A, its Base Plan under the base assumptions. It appears that Plan A is the least cost plan in all scenarios shown in Dominion's Alternative Plan Comparison, Figure 6.7.1.

Following this evaluation, DNCP selected Plan A, designed using least-cost planning methods as its Base Plan. This is a change from the 2012 IRP when the Company selected its Fuel Diversity Plan as its preferred plan. In its discussion of the 2013 plan, DNCP indicated that it plans to "concurrently continue forward with reasonable development efforts of the additional resources" identified in the Fuel Diversity Plan. DNCP then discussed at length the benefits of the fuel diversity plan, including fuel price stability, avoidance of "low probability, high impact" events, and avoiding overreliance on any one fuel source or generation technology.[29] Relative to all other plans considered except the Base Plan, the Fuel Diversity Plan has the lowest PVRR over the planning period. However, the Fuel Diversity Plan, under current planning assumptions, results in a significantly higher cost than DNCP's Base Plan. Since the 2012 IRP, DNCP issued an RFP for an EPC that provided the Company with more specific data, causing it to revise its cost estimate. DNCP indicated in response to Public Staff data requests that the PVRR of the Fuel Diversity Plan is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** than its Plan A with new natural gas generation.[30] This change was due in part to the **[BEGIN**

[29] DNCP's discussion sufficiently addresses the recommendation of the Public Staff contained in its comments filed in the 2012 IRP proceeding that electric utilities selecting a preferred plan based on fuel diversity should elaborate and provide additional support for their decision.

[30] DNCP's PVRR includes the end-effects of the generation portfolio.

CONFIDENTIAL] [redacted] [END CONFIDENTIAL] in DNCP's projected installed costs for the North Anna unit , lower projected costs of natural gas, and other factors. In DNCP's 2012 IRP, the PVRR of the nuclear portfolio was [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] higher than the portfolio with only new natural gas. The cost of the Fuel Diversity Plan with new nuclear generation has escalated compared to the natural gas plan by over [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] from the 2012 IRP.

<u>DISCUSSION AND RECOMMENDATIONS REGARDING DNCP'S PLANS</u>

The concerns expressed by the Public Staff in its discussion of DEP and DEC's preferred plans about the added costs of new nuclear generation also apply to DNCP. These costs have become clearer as DNCP's RFP provided more realistic cost projections. While the Public Staff generally supports the Company's efforts to maintain the North Anna 3 units as a viable generation alternative, projected incremental capital expenditures of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] through December 2013 are required to maintain this option.

As noted previously, the Public Staff recommends that detailed support be included in future IRPs if a utility selects a preferred resource plan that is based on fuel diversity as opposed to a plan that is otherwise least-cost. Further, as the licenses for DNCP's Surry and North Anna units expire after the end of the 15-year planning period, the Public Staff recommends for DNCP, as it did for DEP and DEC, that the planning period for future IRPs that foresee substantial nuclear retirements be at least 20 years.

For its Fuel Diversity Plan, DNCP forced the model to select the North Anna 3 unit in 2025 rather than allowing the optimization algorithms in the model to select the next resource and the date that it goes online. This modeling decision, in the Public Staff's view, calls into question the economic rationale for the Fuel Diversity Plan. Based on responses to Public Staff data requests, it appears that portfolios with starting dates for the North Anna 3 unit in 2030 and 2035, rather than 2025, reveal significantly lower PVRR relative to the Fuel Diversity Plan. The only plan considered by DNCP in which North Anna 3 was economically selected is Plan E, the Climate Action Plan, which imposed a 67% cap on the amount of the Company's generation that could come from natural gas generation.

FURTHER OBSERVATIONS REGARDING ALTERNATIVE RESOURCE PLANS

IMPACT OF CERTAIN KEY VARIABLES

The significantly higher revenue requirements for DEC's and DNCP's plans that include new nuclear generation are driven by three key variables: future carbon prices, future natural gas prices, and projected installed costs to build the nuclear units. The following graphs help to illustrate the significance of these three variables used in the 2012 and 2013 IRPs for DEP, DEC, and DNCP. Holding all else constant, lower forecasted natural gas prices improve the competitive advantage of natural gas-fired units relative to nuclear and renewable energy generation, higher projected carbon prices give competitive advantage to nuclear and renewable energy generation, and higher installed costs of nuclear generation tend to increase the competitive advantage of nuclear generation relative to other types of generation. Each of the graphs highlights plausible forecasts, but has a different influence on the economics of the resource expansion plans.

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Chart of 2012 and 2013 Natural Gas Forecasts of DEC and DNCP

[redacted]

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Chart of DEC and DNCP's 2012 and 2013 Carbon Prices

[redacted]

Note: DEC's 2013 Environmental Focus portfolio utilizes a different carbon price ($20/ton carbon in 2020, rising to $45/ton by 2028).

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Chart of 2011-2013 Nuclear Installed Cost per kW for DEC and DNCP

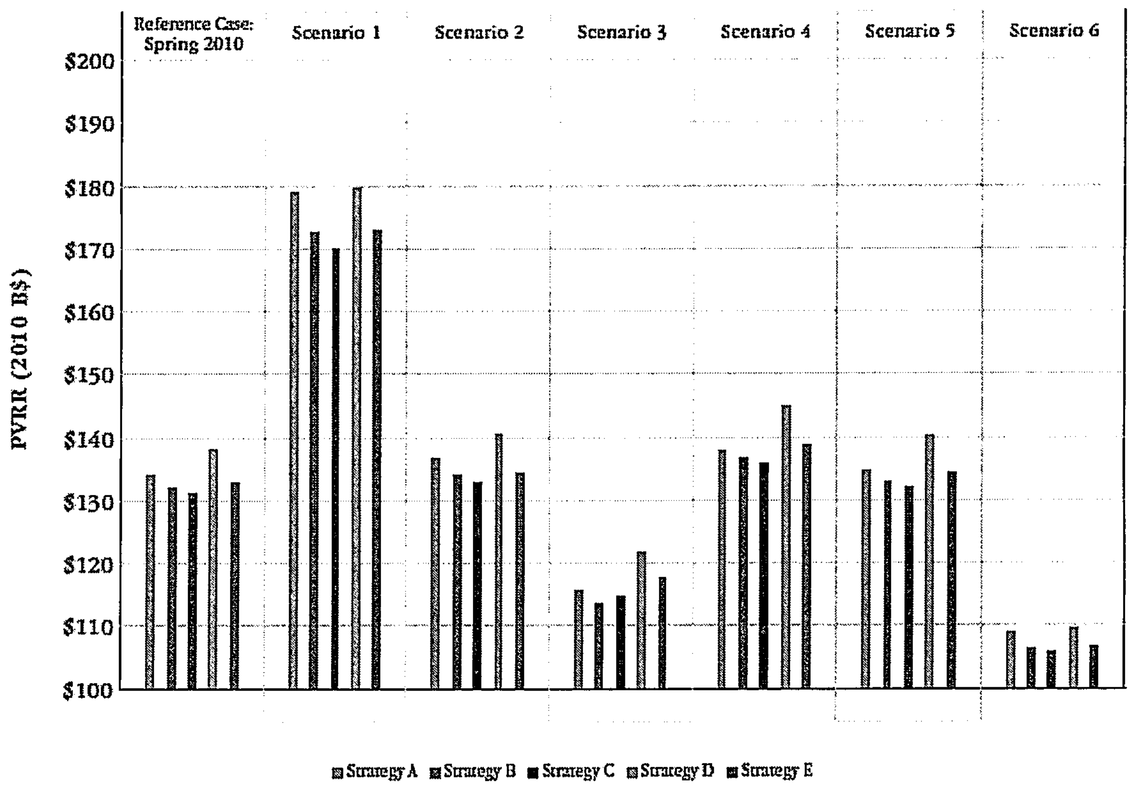
[redacted]

Quantification of the Value of Fuel Diversity and Reduced Risk

The evaluation of resource options in the IRP is an ongoing process. Waiting or deferring decisions may provide more certainty in resource planning and reduce the likelihood of selecting a resource mix that is not least-cost. A more diverse generation portfolio may mitigate future cost variability and the risk of relatively high energy prices in the future. However, the benefits of avoiding potentially high prices must be weighed against the known costs of building new generation, particularly nuclear.

In recent IRPs, the IOUs have stressed the value of generation diversity, but generally have not provided a metric to quantify the value of diverse generation portfolios that they have selected as their preferred plan. Diverse generation portfolios should provide a reduction in future cost variability and risk of high cost futures due to uncertainty. This reduced risk and variability can be used to justify investments in higher cost alternatives, relative to a least-cost option under a base case scenario. Given the utilities' stated desire to build diverse generation portfolios, demonstration and quantification of risk benefits and reduced variability would allow a more systematic comparison of investment options and portfolios that maintain or increase generation diversity relative to least cost options under a base case. This approach could be incorporated through different modeling approaches to risk and uncertainty, including consideration of alternative approaches such as consideration of least-risk or "no-regrets" analysis, real options analysis, expected value analysis using probabilities, and other stochastic optimization methods.

There is no clear preferred method to quantify the benefits of a diverse generation portfolio. One possible method of illustrating the value of diversity is by graphing the PVRR for the resource portfolios by various scenarios as the Tennessee Valley Authority (TVA) did in its March 2011 IRP.



Source: TVA Integrated Resource Plan, March 2011, Figure 7-9, p. 128.

The Public Staff recommends that the utilities continue to develop methods of quantifying the benefits of fuel diversity. The Public Staff further recommends that the utilities provide not only the PVRR for the possible resource expansion plans, but also an estimate of the annual rate impacts of such plans levelized over the life of the resource additions. A calculated rate impact on a levelized per kWh basis would provide a clearer understanding of the ratepayer impacts of future portfolios comprising varying combinations of new nuclear units, more natural gas units, and more renewable resources.

ENVIRONMENTAL CONSIDERATIONS

Impact of Pending Regulations

An additional issue impacting the alternative resource plans is how the costs associated with pending or potential environmental regulations should be considered. The following information excerpted from Figure 3.1.3.1 of DNCP's 2013 IRP provides an illustration of the environmental regulations considered by the utilities.[31]

[31] See also Appendix G, 2013 DEP and DEC IRPs.

Figure 3.1.3.1 EPA REGULATIONS AS OF AUGUST 30, 2013

Constituent		Key Regulation	Final Rule
AIR	Hg/HAPS	Mercury & Air Toxics Standards (MATS)	2011
	SO_2	2010 CAIR	2005
		2015 CAIR	2005
		SO_2 NAAQS	2010
	NOx	Ozone Std Rev (75 ppb)	2008
		Ozone Standard Rev (60-70 ppb)	2014
		2009 CAIR	2005
		2015 CAIR	2005
	CO_2	GHG Tailoring Rule	2010
		EGU NSPS (New)	2014
		Federal CO_2 Program &/or EGU NSPS (Existing)/CAP	June 2015
WASTE	Ash	CCB's	Late 2013
WATER	Water 316(b)	316(b) Impingement	2013
		316(b) Entrainment	
	Water Effluent	Effluent Discharges	2014

Key: Constituent: Hg: Mercury; HAPS: Hazardous Air Pollutants; SO_2: Sulfur Dioxide; NO_x: Nitrogen Oxide; CO_2: Carbon Dioxide; GHG: Greenhouse Gas; Water 316b: Clean Water Act § 316(b) Cooling Water Intake Structures;
Regulation: MATS: Mercury & Air Toxics Standards; CAIR: Clean Air Interstate Rule; CAP: President's Climate Action Plan; SO_2 NAAQS: Sulfur Dioxide National Ambient Air Quality Standards; Ozone Std Rev PPB: Parts Per Billion; EGU NSPS: Electric Generating Units New Source Performance Standard; CCB: Coal Combustion Byproducts.

The utilities appropriately noted that several of these regulations are still under development or may be the subject of litigation. DNCP also indicated that its base case assumes that carbon legislation/regulation will be enacted by 2023, and DEP and DEC include an assumption that a carbon tax will take effect in 2020.

All of the IRPs discuss pending environmental regulations, but make no explicit assumptions about the potential cost of compliance, with the exception of a carbon price for federal greenhouse gas regulation. Of the proposed rules modeled, carbon prices may have the potential for the most significant impact on future resource alternatives, but the scope, cost, and timeframe for carbon regulation are no less speculative than for any other environmental regulation. In fact, several of the pending regulations, including the Mercury and Air Toxics Standard and the Coal Combustion Byproducts regulations, are likely to have more immediate impacts on utility operations than carbon regulation. SACE identified this issue in its comments on DEP and DEC's 2012 IRP by noting that TVA included a more robust evaluation of the environmental impacts of each alternative resource portfolio in terms of air emissions, water impacts, and waste disposal costs. The Public Staff recommends that in the 2014 and future IRPs, the utilities include an economic analysis of the costs of compliance with pending environmental regulations, both individually and in combinations, and an environmental compliance scenario that includes reasonable assumptions regarding the costs of compliance.

Inclusion of Decommissioning Costs

The Public Staff believes that it may be appropriate for fuller consideration of the decommissioning costs associated with each resource type within the IRP process. Not including these costs in the models at the time future resource options are being considered may introduce a bias in favor of generation resources with relatively high decommissioning costs that must be borne by future generations of ratepayers. In light of this concern, the Public Staff recommends that the Commission require the utilities in their 2014 IRPs to include the decommissioning costs associated with each resource type, including coal, nuclear, natural gas, and renewable resources in one or more of the scenarios evaluated.

GENERAL COMMENTS ABOUT THE IRP PROCESS

Since the Commission's July 11, 2007, *Order Revising Integrated Resource Planning Rules* in Docket No. E-100, Sub 111, the utilities and intervenors have strived to follow the IRP timeline in a meaningful and productive way in order to provide the Commission with better, more comprehensive information to consider when implementing G.S. 62-110.1(c) and G.S. 62-2(3a), and when considering CPCNs in North Carolina. Despite the Commission's efforts to keep the IRP process within the established schedules, the annual IRP process has typically taken more than a year to complete. For example, in Docket No. E-100, Sub 128, the Commission's Order approving the 2010 IRPs was not issued until October 26, 2011, almost 14 months after 2010 IRPs were filed, and over a month after the 2011 IRP updates were filed. Similarly, in 2012, the Commission's order approving the 2012 IRPs in Docket E-100, Sub 137, was not issued until October 14, 2013, six weeks after the September 1 date for filing updates. The utilities have indicated that their internal IRP planning processes are ongoing, but in order for Commission directives to be fully considered in their next IRPs, they need to receive the inputs from the Commission in late spring or early summer prior to the filing deadline. In addition to the time required for preparation of plans and reports, the complexity of issues and sheer volume of information to be considered have resulted in a process that is sometimes disjointed and reactive, rather than constructive and deliberate.

The Public Staff believes it may be appropriate to consider some changes to the IRP process to make it more robust and meaningful. Some of the options that the Public Staff has considered include a biennial process with a more limited annual update, but with more stakeholder involvement in the development of the inputs and scenarios to be used. To allow for more timely consideration of the IRP, the information required to be filed in the odd-year updates could be less extensive than the biennial reports, but still contain an updated forecast, as well as a discussion of any significant amendments or revisions to the previous biennial report. Comments and public hearings on the odd-year updates could be required only at the discretion of the Commission.

Given the current IRP process and modeling used in North Carolina, the selection of appropriate scenarios by the utilities is critical. If the scenarios analyzed and presented in the filed IRPs do not cover most or all of the major sources of risks, the IRPs will not provide sufficient information to enable the Commission to consider the prudence of major capacity additions or portfolios of resources. One method to improve this process would be to provide an opportunity for stakeholders to have input prior to the development of the plans. Some utilities, such as TVA, include a stakeholder review process that allows opportunities for additional input. In addition, the Commission may wish to consider requiring the utilities to include certain common scenarios and sensitivities that will be of interest to all participants and allow for better comparison of alternatives. In order to do so, the Commission may wish to consider issuing expedited rulings on key inputs and assumptions in order to ensure that these items are received in time to be fully incorporated by the utilities in their modeling processes.[32]

The Public Staff recommends that the Commission request comments from the IOUs and other parties on the potential changes to the IRP process discussed above, as well as other alternatives that may assist in making the process more robust and effective for all of the parties involved.

PUBLIC STAFF'S RECOMMENDATIONS REGARDING IRPS

The Public Staff makes the following recommendations:

1. DEC should carefully review and incorporate the best forecasting practices of DEP and DEC.

2. DEP, DEC, and DNCP should maximize their DSM resources in the future.

3. DEC should file a Carbon Neutrality Plan with its reply comments and continue to provide updates in future IRPs regarding its obligations related to the Cliffside Unit 6 air permit.

4. The IOUs should consider the potential for relicensing of their existing nuclear units and reflect such potential relicensing, as appropriate, in their 2014 IRPs.

[32] See Public Staff IRP Recommendations Nos. 4, 5, 15, 16, 19, and 20.

5. In future IRP filings, DEP should factor in reasonable estimates of solar generation based on issued RFPs and a percentage of the proposed facilities in the interconnection queue coming to fruition.

6. DEP and DEC in their reply comments and future IRPs should provide both information on the number and resource type of the facilities currently within the respective utility's interconnection queue and a discussion of how the potential QF purchases would affect the utility's long-range energy and capacity needs.

7. DNCP should provide an update regarding the conversion of the Hopewell and Southampton Coal Stations in its reply comments.

8. The IOUs should maintain their proposed reserve margins as filed for purposes of this proceeding.

9. The IOUs should continue to monitor and report any changes of more than 10% in the energy and capacity savings derived from DSM and EE between successive IRPs, and evaluate and discuss any changes on a program-specific basis. Any issues impacting program deployment should be thoroughly explained and quantified in future IRPs.

10. The IOUs should develop a consistent method of evaluating their DSM and EE portfolios and incorporate the savings in a manner that provides a clearer understanding of the year-by-year changes occurring in the portfolios and their impact on the load forecast and resource plan in future IRPs. The savings

impacts should be represented on a net basis, taking into account any NTG impacts derived through EM&V processes.

11. DEP and DEC should specifically identify the values of DSM and EE portfolio capacity and energy savings separately in their load forecast tables and not embed these values in the system peak load or energy.

12. The IOUs should account for all of their DSM and EE program savings from programs approved pursuant to G.S. 62-133.9 and Commission Rule R8-68, regardless of when those measures were installed.

13. DEP and DEC should each adopt one methodology of evaluating the DSM and EE components of the IRP and remain consistent year-to-year. If an IOU determines that a change in methodology is required or appropriate, these changes should be thoroughly explained, justified, and reconciled to the savings projected in the previous IRP.

14. Each utility should continue its efforts to inform customers of its TOU rate schedules and educate customers regarding their benefits.

15. In their 2014 IRPs, the IOUs should allow their integration models to (a) select the optimum level of renewable energy generation based on the current and projected cost of solar generation, system integration costs, and other resource data, resulting in a more optimal level of solar generation; and (b) consider various sizes and types of solar generators from relatively small

customer-owned rooftop systems to large solar farms, as well as their integration costs.

16. The planning period for future IRPs that foresee substantial nuclear retirements should be extended to at least 20 years.

17. The IOUs should continue to develop methods of quantifying the benefits of fuel diversity. Detailed support should be included in future IRPs if a utility prefers a resource plan that is based on unquantified benefits of fuel diversity as opposed to a plan that is otherwise lower in cost.

18. The utilities should provide not only the PVRR for the possible resource expansion plans, but also an estimate of the annual rate impacts of such plans levelized over the life of the resource additions.

19. In the 2014 and future IRPs, the utilities should include an economic analysis of the costs of compliance with pending environmental regulations, both individually and in combinations, and an environmental compliance scenario that includes reasonable assumptions regarding the costs of compliance.

20. The utilities in their 2014 IRPs should include the decommissioning costs associated with each resource type, including coal, nuclear, natural gas, and renewable resources in one or more of the scenarios evaluated.

21. The Commission should consider issuing expedited rulings on key inputs and assumptions to be included in the next IRP process in order to ensure that these items are received in time to be fully incorporated by the utilities in their modeling processes. In particular, the Commission should consider issuing an expedited ruling on Public Staff Recommendations Regarding IRPs Nos. 4, 5, 15, 16, 19, and 20 above.

22. The Commission should request comments from the IOUs and other parties on potential changes to the IRP process, as well as other alternatives that may assist in making the process more robust and effective for all of the parties involved.

23. The Commission should approve the IRPs filed by the IOUs in 2013, subject to the recommendations contained herein.

REPS COMPLIANCE PLAN REVIEW

G.S. 62-133.8 requires all electric power suppliers in North Carolina to meet specified percentages of their retail sales using renewable energy and EE through the REPS. One MWh of renewable energy, or its thermal equivalent, equates to one REC, which is used to demonstrate compliance. An electric power supplier may comply with the REPS by generating renewable energy at its own facilities, by purchasing bundled renewable energy from a renewable energy facility, or by buying RECs. Alternatively, a supplier may comply by reducing energy consumption through implementation of EE measures or electricity demand reduction[33] (or through DSM measures, in the case of EMCs and municipalities). Electric public utilities can use EE measures to meet up to 25% of the general requirements in G.S. 62-133.8(b). One MWh of savings from DSM, EE, or demand reduction creates one energy efficiency certificate (EEC), which is similar to a REC and is used to demonstrate compliance with the REPS. EMCs and municipalities may use DSM and EE to meet the requirements in G.S. 62-133.8(c) without any limits. They may also use energy from a hydroelectric power facility and allocations from SEPA to meet up to 30% of the general requirements. All electric power suppliers may obtain RECs from out-of-state sources to satisfy 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 the requirements. The total amount of renewable energy or EECs that must be provided by an electric power supplier for 2013 and 2014 is equal to 3% of its North Carolina retail sales for the preceding year. For 2015, this amount increases to 6%.

Commission Rule R8-67(b) provides the requirements for REPS Compliance Plans (Plans). Electric power suppliers must file their 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 2013, 2014, and 2015 (the planning period). An electric power supplier may have its REPS

[33] "Electricity demand reduction," as used here, is a technical term defined in G.S. 62-133.8(a)(3a).

requirements met by a utility compliance aggregator as defined in R8-67(a)(5). The instant docket includes the plans filed by DEP, DEC, and DNCP, and their wholesale customers in North Carolina for which they are contracted to provide REPS compliance services.

DEP

DEP filed its 2013 Plan along with its IRP on October 15, 2013. DEP 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. DEP is contractually obligated to secure resources to meet all the REPS requirements of the City of Waynesville and the Towns of Sharpsburg, Stantonsburg, Black Creek, and Lucama (collectively, DEP's Wholesale Customers). After filing its Plan, DEP contracted to provide REPS compliance services to the Town of Winterville for 2013 and beyond.

DEP intends to use EE programs to meet 25% of its REPS requirements. Energy allocations from SEPA will be used to meet up to 30% of the general requirement of the City of Waynesville, the only DEP Wholesale Customer that receives energy from SEPA. Hydroelectric qualifying facilities will also provide RECs for DEP's other Wholesale Customers and its retail customers. DEP will continue to pursue wind energy, either through REC-only purchases or through energy delivered to its customers in North Carolina, to meet the general requirement. A portion of the general requirement of DEP and its Wholesale

Customers will be met by executed purchased power agreements and REC-only purchases from landfill gas and biomass power providers, some of which are combined heat and power facilities. DEP plans to use the increased availability of solar energy to help it meet the general requirement.

DEP will use the following methods to meet the solar set-aside: (1) its residential solar PV program, (2) in-state solar PV and thermal REC purchases, and (3) out-of-state solar REC purchases.

DEP anticipates that its REPS compliance costs will be well below the cost caps in G.S. 62-133.8(h)(3) and (4) for the planning period.

DEP files its measurement and verification plan for each EE program as part of its request for Commission approval of the program.

DEC

DEC filed its 2013 Plan along with its IRP on October 15, 2013. DEC 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, both for itself and for the electric power suppliers for which it is providing REPS compliance services. DEC 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, DEC's Wholesale Customers).

DEC intends to use EE programs to meet 25% of its REPS requirements. Hydroelectric facilities and energy allocations from SEPA will be used to meet up to 30% of the general requirement of DEC's Wholesale Customers. Hydroelectric qualifying facilities and the increased capacity of DEC's Bridgewater hydroelectric facility, following its modification in 2012, will provide RECs for DEC's retail customers. DEC will continue to pursue wind energy, either through REC-only purchases or through energy delivered to its customers in North Carolina, to meet the general requirement. A portion of the general requirement of DEC and its Wholesale Customers will be met by executed purchased power agreements and REC-only purchases from landfill gas and biomass power providers, some of which are combined heat and power facilities. However, DEC has reduced its reliance on biomass for future REPS compliance because of the increased availability of solar energy and other renewable resources. DEC also expects to make some use of solar resources to satisfy the general requirement.

DEC will use the following methods to meet the solar set-aside: (1) self-owned distributed solar PV facilities, (2) in-state solar PV and thermal REC purchases, and (3) out-of-state solar REC purchases.

DEC anticipates that its REPS compliance costs will be well below the cost caps in G.S. 62-133.8(h)(3) and (4) for the planning period.

DEC filed an update to its EM&V plan in its 2013 application for cost recovery of DSM and EE programs in Docket No. E-7, Sub 1032.

DNCP

DNCP's 2013 Plan was filed on August 31, 2013, as an addendum to its IRP. DNCP 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 Town of Windsor (Windsor), for which it is providing REPS compliance services. DNCP plans to use EE, purchased RECs, and new self-generated renewable energy to meet the general REPS requirements of G.S. 62-133.8(b) and (c) for itself and Windsor. DNCP will rely on out-of-state RECs to meet most of its compliance requirements, as allowed by G.S. 62-133.8(b)(2)(e), but will obtain in-state RECs to meet Windsor's 75% in-state requirement. DNCP intends to purchase unbundled solar RECs to meet the solar set-aside requirements during the planning period for itself and Windsor. Its 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.

DNCP anticipates that the REPS compliance costs for itself and Windsor will be well below the cost caps in G.S. 62-133.8(h)(3) and (4) for the planning period.

DNCP filed an update to its measurement and verification plan in its 2013 application for cost recovery of DSM and EE programs in Docket No. E-22, Sub 494.

REPS COMPLIANCE COMPARISON TABLES

The tables in this section are drawn from data submitted in the DEP, DEC, and DNCP Plans. Table 1 shows the projected annual MWh sales on which the utilities' REPS obligations are based. It is important to note that the figures shown for each year are the utilities' MWh sales for the preceding year; for instance, the sales in the 2013 column are projected sales for the calendar year 2012. The totals are presented in this manner because each utility's REPS obligation is determined as a percentage of its MWh sales for the preceding year. The sales amounts include retail sales of wholesale customers for which the utility is providing REPS compliance reporting and services. Table 2 presents a comparison of the projected annual incremental REPS compliance costs with the utilities' annual cost caps.

TABLE 1: MWh Sales for preceding year

	Compliance Year		
Electric Power Supplier	**2013**	**2014**	**2015**
DEC	58,562,512	59,161,845	59,743,779
DEP	36,737,450	37,217,015	37,722,745
DNCP	4,161,815	4,223,188	4,080,270
TOTAL	99,461,777	100,602,048	101,546,794

TABLE 2: Comparison of Incremental Costs to the Cost Cap

		DEC	DEP	DNCP
2013	Incremental Costs	8,575,016	21,026,450	557,326
	Cost Cap	63,600,083	42,520,860	3,947,064
	Percent of Cap	13%	49%	14%
2014	Incremental Costs	12,563,910	24,846,641	1,453,756
	Cost Cap	64,543,124	42,825,158	4,191,726
	Percent of Cap	19%	58%	35%
2015	Incremental Costs	15,104,036	22,550,528	1,487,743
	Cost Cap	106,425,364	68,889,101	6,660,020
	Percent of Cap	14%	33%	22%

SWINE WASTE AND POULTRY WASTE SET-ASIDES

Some electric power suppliers indicated in the Plans filed in 2011 that they had difficulty in obtaining RECs to comply with the swine and poultry waste set-asides in G.S. 62-133.8(e) and (f), which require them to meet a portion of their REPS obligations with energy derived from swine waste and poultry waste beginning in 2012.

In May 2012, the Commission issued an order in Docket No. E-100, Sub 113, requiring the electric power suppliers to file an update on their efforts to meet these compliance requirements. Most electric power suppliers responded and filed a joint motion seeking to delay the swine and poultry waste set-asides as allowed in G.S. 62-133.8(i)(2). The joint movants claimed that they had had difficulty acquiring RECs to meet the swine and poultry waste set-asides because the technology for waste-to-energy facilities was still in its infancy and would need more time to reach maturity.

In November 2012, the Commission issued an order that eliminated the swine waste set-aside for 2012 and delayed the poultry waste set-aside until 2013. This order required DEP and DEC to file tri-annual reports describing the state of their compliance with the set-asides and reporting on their negotiations with the developers of swine and poultry waste-to-energy projects. The order further required them to provide internet-available information to assist the developers of swine and poultry waste-to-energy projects in getting contract approval and interconnecting facilities.

On September 16, 2013, many of the electric power suppliers filed another joint motion to delay the swine and poultry waste set-asides, similar to the request they filed in 2012. In the proceedings on this motion, DEC indicated that it would not be able to comply with the poultry waste set-aside in 2013. DEP indicated that it expected to be able to comply with the poultry waste requirement in 2013, but in its Plan, it states that compliance in 2014 or 2015 is unlikely. DNCP indicated that it has been able to secure enough out-of-state poultry waste RECs to meet its requirements for 2013 and 2014, but has not secured enough in-state poultry RECs for Windsor. All the utilities stated that they would be unable to comply with the swine waste set-aside in 2013.

On December 20, 2013, the Commission issued a notice of decision and order in Docket No. E-100, Sub 113, which delayed the swine and poultry waste set-asides until 2014. The order extended the tri-annual reporting to DNCP and most other EMCs and municipal electric systems. It also requested that the Public Staff hold stakeholder meetings in 2014 and 2015 to facilitate compliance with the swine and poultry waste set-asides.

The Public Staff believes the electric power suppliers will likely continue to have difficulty meeting the swine and poultry waste set-asides for at least the next one to two years. The swine waste-to-energy industry remains largely undeveloped, particularly relative to the need for approximately 92,000 MWh of swine waste energy each year in 2014 and 2015 to meet the Commission's Order of December 20, 2013. The poultry waste-to-energy industry has somewhat more potential to produce the 170,000 MWh of energy necessary in 2014 to comply with the same Order, but the currently operating biomass power plants that have successfully utilized poultry waste fuel do not have enough combined capacity to fulfill the entire requirement. Even if these plants reach their full operational potential in 2014, they will not have enough capacity to produce the 700,000 MWh of poultry waste energy necessary to meet the 2015 requirement. The lack of swine and poultry waste-to-energy facilities is the result of: (1) limited technology development and expertise because currently North Carolina is the only state with swine and poultry set-aside requirements; (2) the utilities' reluctance to commit to expensive purchase contracts for speculative technologies; and (3) the current uncertainty as to whether the General Assembly will alter the REPS requirements in ways that could leave the owners of these facilities with stranded costs.

CONCLUSIONS ON REPS COMPLIANCE PLANS

In summary, the Public Staff's conclusions regarding the REPS compliance plans of DEP, DEC, and DNCP are as follows:

1. The compliance plans of DEP, DEC, and DNCP indicate that they should be able to meet their REPS obligations, with the exception of the swine and poultry waste set-asides, during the planning period without nearing or exceeding their cost caps.

2. The utilities will have difficulty meeting the Commission's revised swine waste requirements in 2014 and 2015, and DEP and DEC will have

difficulty meeting the poultry waste requirements, but they are actively seeking energy and RECs to meet these requirements.

3. The Commission should approve the REPS Compliance Plans filed by DEP, DEC, and DNCP in 2013.

This the 11th day of April, 2014.

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CERTIFICATE OF SERVICE

I do hereby certify that 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 by electronic delivery.

This the 11th day of April, 2014.

Electronically submitted
s/ Lucy E. Edmondson