

E-100, Sub 141

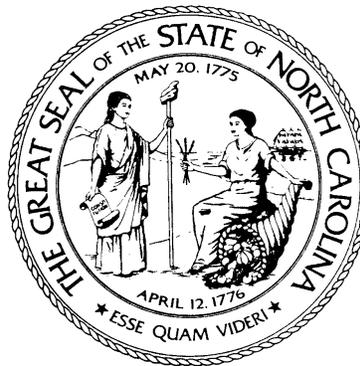
**ANNUAL REPORT REGARDING
LONG RANGE NEEDS FOR EXPANSION OF
ELECTRIC GENERATION FACILITIES FOR SERVICE
IN NORTH CAROLINA**

REQUIRED PURSUANT TO G.S. 62-110.1(c)

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**RECEIVED BY
THE GOVERNOR OF NORTH CAROLINA
AND
THE JOINT LEGISLATIVE COMMISSION ON
GOVERNMENTAL OPERATIONS**



**SUBMITTED BY
THE NORTH CAROLINA UTILITIES COMMISSION**

ABBREVIATIONS AND ACRONYMS

CC combined-cycle

CEPCN Certificate of Environmental Compatibility and Public Convenience and Necessity

CIGFUR Carolina Industrial Group for Fair Utility Rates

COL combined construction and operating license

CPCN Certificate of Public Convenience and Necessity

CPP EPA's Clean Power Plan

CT combustion turbine/s

CUCA Carolina Utility Customers Association, Inc.

DOE U.S. Department of Energy

DSM demand-side management

Duke Duke Energy Carolinas, LLC

EDF Environmental Defense Fund

EE energy efficiency

EMC electric membership corporation

EnergyUnited EnergyUnited EMC

EPA U.S. Environmental Protection Agency

EPAct 2005 Energy Policy Act of 2005

FERC Federal Energy Regulatory Commission

GreenCo GreenCo Solutions, Inc.

GridSouth GridSouth Transco, LLC

G.S. General Statute

GWh gigawatt-hour/s

Halifax Halifax EMC

IOU investor-owned electric utility

IRP integrated resource planning/integrated resource plans

kWh kilowatt-hour/s

LEE CC Lee combined-cycle plant in SC

Lee Nuclear William States Lee III nuclear station in SC

MAREC Mid-Atlantic Renewable Energy Coalition

MW megawatt/s

MWh megawatt-hour/s

NCDEQ North Carolina Department of Environmental Quality

NCEMC North Carolina Electric Membership Corporation

ABBREVIATIONS AND ACRONYMS (continued)

NCEMPA North Carolina Eastern Municipal Power Agency
NCMPA1 North Carolina Municipal Power Agency No. 1
NC Power Dominion North Carolina Power
NC-RETS North Carolina Renewable Energy Tracking System
NCSEA North Carolina Sustainable Energy Association
NCTPC North Carolina Transmission Planning Collaborative
NC WARN North Carolina Waste Awareness and Reduction Network
NERC North American Electric Reliability Corporation
NRC Nuclear Regulatory Commission
OASIS Open Access Same-time Information System
OATT open access transmission tariff
OPSI Organization of PJM States, Inc.
PJM PJM Interconnection, LLC
PPA purchase power agreement/s
Progress Duke Energy Progress, LLC
PURPA Public Utility Regulatory Policies Act of 1978
PV photovoltaic
REC renewable energy certificate/s
REPS Renewable Energy and Energy Efficiency Portfolio Standard
RFP request for proposals
ROE return on equity
RTO regional transmission organization
SACE Southern Alliance for Clean Energy
SCC State Corporation Commission of Virginia
SCE&G South Carolina Electric & Gas
Senate Bill 3 Session Law 2007-397
SEPA Southeastern Power Administration
SERC Southeastern Electric Reliability Corporation
SERTP Southeastern Regional Transmission Planning
TOU time-of-use
TRANSCO Transcontinental Gas Pipe Line Company, LLC
TVA Tennessee Valley Authority
VEPCO Virginia Electric and Power Company
WPSA Wholesale Power Supply Agreement

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1. EXECUTIVE SUMMARY

This annual report to the Governor and the General Assembly is submitted pursuant to General Statute (G.S.) 62-110.1(c), which specifies that each year the North Carolina Utilities Commission shall submit to the Governor and appropriate committees of the General Assembly a report of its analysis of the long-range needs for the expansion of facilities for the generation of electricity in North Carolina and a report on its plan for meeting those needs. Much of the information contained in this report is based on reports to the Commission by the electric utilities regarding their analyses and plans for meeting the demand for electricity in their respective service areas. It also reflects information from other records and files of the Commission.

There are three regulated investor-owned electric utilities (IOUs) operating under the laws of the State of North Carolina and subject to the jurisdiction of the Commission. All three of the IOUs own generating facilities. They are Duke Energy Progress, LLC (Progress), whose corporate office is in Raleigh; Duke Energy Carolinas, LLC (Duke), whose corporate office is in Charlotte; and Virginia Electric and Power Company (VEPCO), whose corporate office is in Richmond, Virginia, and which does business in North Carolina under the name Dominion North Carolina Power (NC Power).

Duke and Progress, the two largest electric IOUs in North Carolina, together supply about 95% of the utility-generated electricity consumed in the state. Approximately 21% of the IOUs' 2014 electric sales in North Carolina were to the wholesale market, consisting primarily of electric membership corporations and municipally-owned electric systems.

Table ES-1 shows the gigawatt-hour (GWh) sales of the regulated electric utilities in North Carolina.

Table ES-1: Electricity Sales of Regulated Utilities in North Carolina

	NC Retail GWh*		NC Wholesale GWh*		Total GWh Sales* (NC Plus Other States)	
	2014	2013	2014	2013	2014	2013
Progress	37,506	36,887	16,650	16,485	62,871	60,204
Duke	56,738	55,282	7,826	8,787	87,646	85,790
NC Power	4,447	4,310	1,220	996	83,938	82,852

*GWh = 1 Million kWh (kilowatt hours)

During the 2015 to 2029 timeframe, the average annual growth rate in summer peak demand for electricity in North Carolina is forecasted to be in the range of 1.0% to 1.4%. Table ES-2 illustrates the systemwide average annual growth rates forecast by the IOUs that operate in North Carolina. Each uses generally accepted forecasting methods and, although their forecasting models are different, the econometric techniques employed by each are widely used for projecting future trends.

Table ES-2: Forecast Annual Growth Rates for Progress, Duke, and NC Power (After Energy Efficiency (EE) and Demand-Side Management (DSM) are Included) (2015 – 2029)

	Summer Peak	Winter Peak	Energy Sales
Progress	1.3%	1.2%	1.0%
Duke	1.4%	1.5%	1.0%
NC Power	1.0%	1.1%	1.1%

North Carolina's IOUs depend on coal-fired and nuclear-fueled steam generation to produce the overwhelming majority of their electric output, as illustrated in Table ES-3.

Table ES-3: Total Energy Resources by Fuel Type for 2014

	Progress	Duke	NC Power
Coal	24%	34%	30%
Nuclear	39%	46%	34%
Net Hydroelectric*	1%	1%	1%
Natural Gas and Oil	27%	9%	15%
Non-Hydro Renewable	0%	0%	1%
Purchased Power	9%	10%	19%

* See discussion of pumped storage in Section 6.

On August 20, 2007, with the signing of Session Law 2007-397 (Senate Bill 3), North Carolina became the first state in the Southeast to adopt a Renewable Energy and Energy Efficiency Portfolio Standard (REPS). Under this new law, investor-owned utilities in North Carolina will be required to meet up to 12.5% of their energy needs through renewable energy resources or energy efficiency measures by 2021. Rural electric cooperatives and municipal electric suppliers are subject to a 10% REPS requirement. In general, electric power suppliers may comply with the REPS requirement in a number of ways, including the use of renewable fuels in existing electric generating facilities, the generation of power at new renewable energy facilities, the purchase of power from renewable energy facilities, the purchase of renewable energy certificates (RECs), or the implementation of energy efficiency measures. This issue is discussed further in Section 8.

A map showing the service areas of the North Carolina IOUs can be found at the back of this report.

2. INTRODUCTION

The General Statutes of North Carolina require that the Utilities Commission analyze the probable growth in the use of electricity and the long-range need for future generating capacity in North Carolina. The General Statutes also require the Commission to submit an annual report to the Governor and to the General Assembly regarding future electricity needs. G.S. 62-110.1(c) provides, in part, as follows:

The Commission shall develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina, including its estimate of the probable future growth of the use of electricity, the probable needed generating reserves, the extent, size, mix and general location of generating plants and arrangements for pooling power to the extent not regulated by the Federal Energy Regulatory Commission (FERC) and other arrangements with other utilities and energy suppliers to achieve maximum efficiencies for the benefit of the people of North Carolina, and shall consider such analysis in acting upon any petition by any utility for construction . . . Each year, the Commission shall submit to the Governor and to the appropriate committees of the General Assembly a report of its analysis and plan, the progress to date in carrying out such plan, and the program of the Commission for the ensuing year in connection with such plan.

Some of the information necessary to conduct the analysis of the long-range need for future electric generating capacity required by G.S. 62-110.1(c) is filed by each regulated utility as a part of the Least Cost Integrated Resource Planning process. Commission Rule R8-60 defines an overall framework within which least cost integrated resource planning takes place. Commonly called integrated resource planning (IRP), it is a process that takes into account conservation, energy efficiency, load management, and other demand-side options along with new utility-owned generating plants, non-utility generation, renewable energy, and other supply-side options in order to identify the resource plan that will be most cost-effective for ratepayers consistent with the provision of adequate, reliable service.

Prior to July 1, 2013, Commission Rule R8-60(b) specified that the IRP process was applicable to the North Carolina Electric Membership Corporation (NCEMC) and any individual electric membership corporation (EMC) to the extent that it is responsible for procurement of any or all of its individual power supply resources. However, with the ratification of Session Law 2013-187 on June 26, 2013, EMCs and NCEMC have been exempted from filing IRPs with the Commission, effective July 1, 2013.

This report is an update of the Commission's December 11, 2014 Annual Report. It is based primarily on reports to the Commission by the regulated electric utilities serving North Carolina, but also includes information from other records and Commission files.

3. OVERVIEW OF THE ELECTRIC UTILITY INDUSTRY IN NORTH CAROLINA

There are three regulated investor-owned electric utilities (IOUs) operating in North Carolina subject to the jurisdiction of the Commission. All three of the IOUs own generating facilities. They are Duke Energy Progress, LLC (Progress), whose corporate office is in Raleigh; Duke Energy Carolinas, LLC (Duke), whose corporate office is in Charlotte; and Virginia Electric and Power Company (VEPCO), whose corporate office is in Richmond, Virginia, and which does business in North Carolina under the name Dominion North Carolina Power (NC Power). A map outlining the areas served by the IOUs can be found at the back of this report.

Duke and Progress, the two largest IOUs, together supply about 95% of the utility-generated electricity consumed in the state. As of December 31, 2014, Duke had 1,896,000 customers located in North Carolina, and Progress had 1,319,000. Each also has customers in South Carolina. NC Power supplies approximately 5% of the state's utility-generated electricity. It has 119,000 customers in North Carolina. The large majority of its corporate operations are in Virginia, where it does business under the name of Virginia Electric and Power Company. About 21% of the IOUs' North Carolina electric sales were to the wholesale market, consisting primarily of EMCs and municipally-owned electric systems.

Based on annual reports submitted to the Commission for the 2014 reporting period, the gigawatt-hour (GWh) sales for the electric utilities in North Carolina are summarized in Table 1.

Table 1: Electricity Sales of Regulated Utilities in North Carolina

	NC Retail GWh*		NC Wholesale GWh*		Total GWh Sales* (NC Plus Other States)	
	2014	2013	2014	2013	2014	2013
Progress	37,506	36,887	16,650	16,485	62,871	60,204
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NC Power	4,447	4,310	1,220	996	83,938	82,852

*GWh = 1 Million kWh (kilowatt hours)

The Commission does not regulate the retail rates of municipally-owned electric systems or EMCs. However, the Commission does have oversight over EMC and municipal construction of generation and transmission facilities, through its jurisdiction over

the licensing of all new electric generating plants and large-scale transmission facilities built in North Carolina.

EMCs are independent, not-for-profit corporations. There are 31 EMCs serving 1,054,000 customers in North Carolina, including 26 that are headquartered in the state. The other five are headquartered in adjacent states and provide service in limited areas across the border into North Carolina. EMCs serve customers in 95 of the state's 100 counties. Twenty-five EMCs are members of NCEMC, a generation and transmission services cooperative that provides its member EMCs with wholesale power and other services. All 25 NCEMC members are headquartered and incorporated in North Carolina.

Since 1980, NCEMC has been a part owner in the Catawba Nuclear Station located in York County, South Carolina. Duke operates and maintains the station, which has been operational since 1985. NCEMC's ownership interests consist of 61.51% of Unit 1, approximately 700 megawatts (MW), and 30.754% in the common support facilities of the station. NCEMC's ownership entitlement is bolstered by a reliability exchange between the Catawba Nuclear Station and Duke's McGuire Nuclear Station located in Mecklenburg County, NC.

NCEMC owns and operates about 680 MW of combustion turbine (CT) generation at sites in Anson and Richmond Counties. These peaking resources operate on natural gas as primary fuel, with diesel storage on-site as a secondary fuel. NCEMC also owns and operates two diesel-powered generating stations on the Outer Banks of North Carolina (located on Ocracoke Island and in Buxton), with a combined capacity of 18 MW, which are used primarily for peak shaving and voltage support. Finally, most EMCs receive an allocation of hydroelectric power from the Southeastern Power Administration (SEPA).

There are five NCEMC members that have assumed responsibility for their own future power supply resources. These "Independent Members" include Blue Ridge EMC, EnergyUnited EMC, Piedmont EMC, Rutherford EMC, and Haywood EMC. Under a Wholesale Power Supply Agreement (WPSA), NCEMC supplies Independent Members with electric power and energy from existing contract and generation resources. To the extent that the electric power and energy supplied under the WPSA is not sufficient to meet the electric energy requirements of its customers, the Independent Members must independently arrange for purchases of additional electric power.

The service territories of NCEMC's member EMCs are located within the control areas of Duke, Progress, and NC Power. The NC Power control area is situated within the footprint of PJM Interconnection, the regional transmission organization (RTO) serving a portion of North Carolina. Six of NCEMC's members fall within that footprint, thus NCEMC is also a PJM member. Though NCEMC's system is spread across these three distinct control areas, NCEMC continues to serve all its members as a single integrated system using a combination of its owned resources and purchases of wholesale electricity.

In addition to the EMCs, there are about 75 municipal and university-owned electric distribution systems serving approximately 580,000 customers in North Carolina. Most of these systems are members of ElectriCities, an umbrella service organization. ElectriCities is a non-profit organization that provides many of the technical, administrative, and management services needed by its municipally-owned electric utility members in North Carolina, South Carolina, and Virginia.

New River Light and Power, located in Boone, and Western Carolina University, located in Cullowhee, are both university-owned members of ElectriCities. Unlike other members of ElectriCities, the rates charged to customers by these two small distribution companies require Commission approval.

ElectriCities is a service organization for its members, not a power supplier. Fifty-one of the North Carolina municipals are participants in one of two municipal power agencies which provide wholesale power to their membership. ElectriCities' largest activity is the management of these two power agencies. The remaining members buy their own power at wholesale.

One agency, the North Carolina Eastern Municipal Power Agency (NCEMPA), is the wholesale supplier to 32 cities and towns in eastern North Carolina. Since April 1982, NCEMPA had jointly owned portions of five Progress generating units (about 700 MW of coal and nuclear capacity). On July 28, 2014, Progress filed notice with the Commission of its intent to file with the FERC a request for approval to purchase NCEMPA's ownership in these generating facilities together with associated assets pursuant to a proposed Asset Purchase Agreement. As provided in the Agreement, the final purchase and sale was subject to approval by the FERC, approval by the Commission, and enactment of legislation by the North Carolina General Assembly.

On May 12, 2015, in Docket Nos. E-2, Sub 1067 and E-48, Sub 8, the Commission issued an Order Approving Transfer of Certificate and Ownership Interests In Generating Facilities. The transaction between Progress and NCEMPA closed on July 31, 2015. On August 13, 2015, the Commission issued an Order Transferring Certificate of Public Convenience and Necessity.

NCEMPA has Load Agreements with Progress to meet the energy needs of its 32 member cities and towns. In addition, NCEMPA has installed 20 MW of distributed generation.

The other power agency is North Carolina Municipal Power Agency No. 1 (NCMPA1), which is the wholesale supplier to 19 cities and towns in the western portion of the state. NCMPA1 has a 75% ownership interest (832 MW) in Catawba Nuclear Unit 2, which is operated by Duke. It also has an exchange agreement with Duke that gives NCMPA1 access to power from the McGuire Nuclear Station and Catawba Unit 1.

NCMPA1 purchases power through bilateral agreements with other generators to obtain its requirements above its Catawba entitlement. To meet its supplemental power

requirements, NCMPA1 has purchase power agreements with Duke, Southern Power, and SEPA. NCMPA1 also owns 65 MW of diesel-fueled distributed generation located at certain city delivery points, and it has contracts for an additional 91 MW of generation owned by municipalities and retail customers which is available during times of high demand and spiking wholesale prices. NCMPA1 also owns two natural gas-fired turbine generators located in Monroe that provide an additional 24 MW of peaking and reserve capacity.

The Tennessee Valley Authority (TVA), which generates electricity from coal, nuclear, and hydroelectric plants, sells energy directly to the Murphy, North Carolina, Power Board, and to three out-of-state cooperatives that supply power to portions of North Carolina: Blue Ridge Mountain EMC, Tri-State EMC, and Mountain Electric Cooperative. These distributors of TVA power are located in six North Carolina counties and serve over 33,000 households and 8,400 commercial and industrial customers. The North Carolina counties served by distributors of TVA power are Avery, Burke, Cherokee, Clay, McDowell, and Watauga.

TVA owns and operates four hydroelectric dams in North Carolina with a combined generation capacity of 523 MW. The dams are Apalachia and Hiwassee in Cherokee County, Chatuge in Clay County, and Fontana in Swain and Graham counties. TVA owns and/or maintains 11 substations and switchyards and nearly 119 miles of transmission line in North Carolina.

4. THE HISTORY OF INTEGRATED RESOURCE PLANNING IN NORTH CAROLINA

Integrated resource planning is an overall planning strategy which examines conservation, energy efficiency, load management, and other demand-side measures in addition to utility-owned generating plants, non-utility generation, renewable energy, and other supply-side resources in order to determine the least cost way of providing electric service. The primary purpose of integrated resource planning is to integrate both demand-side and supply-side resource planning into one comprehensive procedure that weighs the costs and benefits of all reasonably available options in order to identify those options which are most cost-effective for ratepayers consistent with the obligation to provide adequate, reliable service.

Initial IRP Rules

By Commission Order dated December 8, 1988, in Docket No. E-100, Sub 54, Commission Rules R8-56 through R8-61 were adopted to define the framework within which integrated resource planning takes place. Those rules incorporated the analysis of probable electric load growth with the development of a long-range plan for ensuring the availability of adequate electric generating capacity in North Carolina as required by G.S. 62-110.1(c).

The initial IRPs were filed with the Commission in April 1989. In May of 1990, the Commission issued an Order in which it found that the initial IRPs of Progress, Duke, and NC Power were reasonable for purposes of that proceeding and that NCEMC should be required to participate in all future IRP proceedings. By an Order issued in December 1992, Rule R8-62 was added. It covers the construction of electric transmission lines.

The Commission subsequently conducted a second and third full analysis and investigation of utility IRP matters, resulting in the issuance of Orders Adopting Least Cost Integrated Resource Plans on June 29, 1993, and February 20, 1996. A subsequent round of comments included general endorsement of a proposal that the two/three year IRP filing cycle, plus annual updates and short-term action plans, be replaced by a single annual filing. There was also general support for a shorter planning horizon than the fifteen years required at that time.

Streamlined IRP Rules (1998)

In April 1998, the Commission issued an Order in which it repealed Rules R8-56 through R8-59 and revised Rules R8-60 through R8-62. The new rules shortened the reported planning horizon from 15 to 10 years and streamlined the IRP review process while retaining the requirement that each utility file an annual plan in sufficient detail to allow the Commission to continue to meet its statutory responsibilities under G.S. 62-110.1(c) and G.S. 62-2(a)(3a).

These revised rules allowed the Public Staff and any other intervenor to file a report, evaluation, or comments concerning any utility's annual report within 90 days after the utility filing. The new rules further allowed for the filing of reply comments 14 days after any initial comments had been filed and required that one or more public hearings be held. An evidentiary hearing to address issues raised by the Public Staff or other intervenors could be scheduled at the discretion of the Commission.

In September 1998, the first IRP filings were made under the revised rules. The Commission concluded, as a part of its Order ruling on these filings, that the reserve margins forecast by Progress, Duke, and NC Power indicated a much greater reliance upon off-system purchases and interconnections with neighboring systems to meet unforeseen contingencies than had been the case in the past. The Commission stated that it would closely monitor this issue in future IRP reviews.

In June 2000, the Commission stated in response to the IOUs' 1999 IRP filings that it did not believe that it was appropriate to mandate the use of any particular reserve margin for any jurisdictional electric utility at that time. The Commission concluded that it would be more prudent to monitor the situation closely, to allow all parties the opportunity to address this issue in future filings with the Commission, and to consider this matter further in subsequent integrated resource planning proceedings. The Commission did, however, want the record to clearly indicate its belief that providing adequate service is a fundamental obligation imposed upon all jurisdictional electric utilities, that it would be

actively monitoring the adequacy of existing electric utility reserve margins, and that it would take appropriate action in the event that any reliability problems developed.

Further orders required that IRP filings include a discussion of the adequacy of the respective utility's transmission system and information concerning leveled costs for various conventional, demonstrated, and emerging generation technologies.

Order Revising Integrated Resource Planning Rules – July 11, 2007

A Commission Order issued on October 19, 2006, in Docket No. E-100, Sub 111, opened a rulemaking proceeding to consider revisions to the IRP process as provided for in Commission Rule R8-60. On May 24, 2007, the Public Staff filed a Motion for Adoption of Proposed Revised Integrated Resource Planning Rules setting forth a proposed Rule R8-60 as agreed to by the various parties in that docket. The Public Staff asserted that the proposed rule addressed many of the concerns about the IRP process that were raised in the 2005 IRP proceeding and balanced the interests of the utilities, the environmental intervenors, the industrial intervenors, and the ratepayers. Without detailing all of the changes recommended in its filing, the Public Staff noted that the proposed rule expressly required the utilities to assess on an ongoing basis both the potential benefits of reasonably available supply-side energy resource options, as well as programs to promote demand-side management. The proposed rule also substantially increased both the level of detail and the amount of information required from the utilities regarding those assessments. Additionally, the proposed rule extended the planning horizon from 10 to 15 years, so the need for additional generation would be identified sooner. The information required by the proposed rule would also indicate the projected effects of demand response and energy efficiency programs and activities on forecasted annual energy and peak loads for the 15-year period. The Public Staff also noted that the proposed rule provided for a biennial, as opposed to annual or triennial, filing of IRP reports with an annual update of forecasts, revisions, and amendments to the biennial report. The Public Staff further noted that adoption of the proposed Rule R8-60 would necessitate revisions to Rule R8-61(b) to reflect the change in the frequency of the filing of the IRP reports.

With the addition of certain other provisions and understandings, the Commission ordered that revised Rules R8-60 and R8-61(b), attached to its Order as Appendix A, should become effective as of the date of its Order, which was entered on July 11, 2007. However, since the utilities might not have been able to comply with the new requirements set out in revised Rule R8-60 in their 2007 IRP filings, revised Rule R8-60 was ordered to be applied for the first time to the 2008 IRP proceedings in Docket No. E-100, Sub 118. These new rules were further refined in Docket No. E-100, Sub 113 to address the implementation of Senate Bill 3 requirements.

2014 Biennial Integrated Resource Plans (Docket No. E-100, Sub 141)

2014 Biennial Integrated Resource Plans were filed by Progress, Duke, and NC Power. In addition, each of the three IOUs filed 2014 REPS compliance plans.

The following parties intervened in this proceeding: Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR); Carolina Utility Customers Association, Inc. (CUCA); Environmental Defense Fund (EDF); Mid-Atlantic Renewable Energy Coalition (MAREC); North Carolina Sustainable Energy Association (NCSEA); North Carolina Waste Awareness and Reduction Network (NC WARN); North Carolina Electric Membership Corporation (NCEMC); Sierra Club; and Southern Alliance for Clean Energy (SACE). The Public Staff's intervention is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

A Public Hearing was held in Raleigh on March 9, 2015. The Commission's June 26, 2015 Order Approving Integrated Resource Plans and REPS Compliance Plans, which includes the procedural history of this proceeding, can be found in the back of this report as Appendix 1.

5. LOAD FORECASTS AND PEAK DEMAND

Forecasting electric load growth into the future is, at best, an imprecise undertaking. Virtually all forecasting tools commonly used today assume that certain historical trends or relationships will continue into the future and that historical correlations give meaningful clues to future usage patterns. As a result, any shift in such correlations or relationships can introduce significant error into the forecast. Progress, Duke, and NC Power each utilize generally accepted forecasting methods. Although their respective forecasting models are different, the econometric techniques employed by each utility are widely used for projecting future trends. Each of the models requires analysis of large amounts of data, the selection of a broad range of demographic and economic variables, and the use of advanced statistical techniques.

With the inception of integrated resource planning, North Carolina's electric utilities have attempted to enhance forecasting accuracy by performing limited end-use forecasts. While this approach also relies on historical information, it focuses on information relating to specific electrical usage and consumption patterns in addition to general economic relationships.

Table 2 illustrates the systemwide average annual growth rates in energy sales and peak loads anticipated by Progress, Duke, and NC Power. These growth rates are based on the utilities' system peak load requirements. Detailed load projections for the respective utilities are shown in Appendices 2, 3, and 4.

Table 2: Forecast Annual Growth Rates for Progress, Duke, and NC Power (After Energy Efficiency (EE) and Demand-Side Management (DSM) are Included) (2015 – 2029)

	Summer Peak	Winter Peak	Energy Sales
Progress	1.3%	1.2%	1.0%
Duke	1.4%	1.5%	1.0%
NC Power	1.0%	1.1%	1.1%

North Carolina utility forecasts of future peak demand growth rates are in the range of forecasts for the nation as a whole. The 2015-2024 Long-Term Reliability Assessment by the North American Electric Reliability Corporation (NERC) indicates that the national forecast of average annual growth in summer peak demand for that period is 1.05%.

Table 3 provides historical peak load information for Progress, Duke, and NC Power.

Table 3: Summer and Winter Systemwide Peak Loads for Progress, Duke, and NC Power Since 2010 (in MW)

	Progress		Duke		NC Power	
	Summer	Winter*	Summer	Winter*	Summer	Winter*
2010	12,074	12,230	17,358	17,570	19,140	17,689
2011	12,094	11,338	17,651	16,002	20,061	16,881
2012	12,770	12,376	17,610	15,307	19,249	17,623
2013	12,248	14,159	18,239	18,859	18,763	19,785
2014	12,219	15,151	18,993	21,101	18,692	21,651

*Winter peak following summer peak

6. GENERATION RESOURCES

Traditionally, the regulated electric utilities operating in North Carolina have met most of their customer demand by installing their own generating capacity. These generating plants are usually classified by fuel type (nuclear, coal, gas/oil, hydro, etc.) and placed into three categories based on operational characteristics:

- (1) Baseload – operates nearly full cycle;
- (2) Intermediate (also referred to as load following) – cycles with load increases and decreases; and
- (3) Peaking – operates infrequently to meet system peak demand.

Nuclear and large coal facilities, as well as combined-cycle natural gas units, serve as baseload plants and typically operate more than 5,000 hours annually. Smaller and older coal and oil/gas plants are used as intermediate load plants and typically operate between 1,000 and 5,000 hours per year. Finally, combustion turbines and other peaking plants usually operate less than 1,000 hours per year.

All of the nuclear generation units operated by the utilities serving North Carolina have been relicensed so as to extend their operational lives. Duke has three nuclear facilities with a combined total of seven individual units. The McGuire Nuclear Station located near Huntersville is the only one located in North Carolina, and it has two generating units. The other Duke nuclear facilities are located in South Carolina. All of Duke's nuclear units have been granted extensions of their original operating licenses by the Nuclear Regulatory Commission (NRC). The new license expiration dates fall between 2033 and 2043.

Progress has four nuclear units divided among three locations. Two of the locations are in North Carolina. The Brunswick facility, near Southport, has two units, and the Harris Plant, near New Hill, has one unit. The Robinson facility, which also has one unit, is located in South Carolina. The NRC has renewed the operating licenses for all of Progress's nuclear units. The new renewal dates run from 2030 to 2046.

NC Power operates two nuclear power stations with two units each. Both stations are located in Virginia. All four units have been issued license extensions by the NRC. The new license expiration dates range from 2032 to 2040.

Hydroelectric generation facilities are of two basic types: conventional and pumped storage. With a conventional hydroelectric facility, which may be either an impoundment or run-of-river facility, flowing water is directed through a turbine to generate electricity. An impoundment facility uses a dam to create a barrier across a waterway to raise the level of the water and control the water flow; a run-of-river facility simply diverts a portion of a river's flow without the use of a dam.

Pumped storage is similar to a conventional impoundment facility and is used by Duke and NC Power for the large-scale storage of electricity. Excess electricity produced at times of low demand is used to pump water from a lower elevation reservoir into a higher elevation reservoir. When demand is high, this water is released and used to operate hydroelectric generators that produce supplemental electricity. Pumped storage produces only two-thirds to three-fourths of the electricity used to pump the water up to the higher reservoir, but it costs less than an equivalent amount of additional generating capacity. This overall loss of energy is also the reason why the total "net" hydroelectric

generation reported by a utility with pumped storage can be significantly less than that utility's actual percentage of hydroelectric generating capacity.

Some of the electricity produced in North Carolina comes from non-utility generation. In 1978, Congress passed the Public Utility Regulatory Policies Act (PURPA), which established a national policy of encouraging the efficient use of renewable fuel sources and cogeneration (production of electricity as well as another useful energy byproduct – generally steam – from a given fuel source). North Carolina electric utilities regularly utilize non-utility, PURPA-qualified, purchased power as a supply resource.

Another type of non-utility generation is power generated by merchant plants. A merchant plant is an electric generating facility that sells energy on the open market. It is often constructed without a native load obligation, a firm long-term contract, or any other assurance that it will have a market for its power. These generating plants are generally sited in areas where the owners see a future need for an electric generating facility, often near a natural gas pipeline, and are owned by developers willing to assume the economic risk associated with the facility's construction.

The current capacity mix generated by each IOU is shown in Table 4.

**Table 4: Installed Utility-Owned Generating Capacity by Fuel Type
(Summer Ratings) for 2014**

	Progress	Duke	NC Power
Coal	27%	33%	28%
Nuclear	27%	33%	19%
Hydroelectric	2%	15%	12%
Natural Gas and Oil	44%	19%	40%
Non-Hydro Renewable	0%	0%	1%

The actual generation usage mix, based on the megawatt-hours (MWh) generated by each utility, reflects the operation of the capacity shown above, plus non-utility purchases, and the operating efficiencies achieved by attempting to operate each source of power as close to the optimum economic level as possible.

Generally, actual plant use is determined by the application of economic dispatch principles, meaning that the start-up, shutdown, and level of operation of individual generating units is tied to the incremental cost incurred to serve specific loads in order to attain the most cost effective production of electricity. The actual generation produced and power purchased for each utility, based on monthly fuel reports filed with the Commission for 2014, is provided in Table 5.

Table 5: Total Energy Resources by Fuel Type for 2014

	Progress	Duke	NC Power
Coal	24%	34%	30%
Nuclear	39%	46%	34%
Net Hydroelectric*	1%	1%	1%
Natural Gas and Oil	27%	9%	15%
Non-Hydro Renewable	0%	0%	1%
Purchased Power	9%	10%	19%

* See the paragraph on pumped storage in this section.

The Commission recognizes the need for a mix of baseload, intermediate, and peaking facilities and believes that conservation, energy efficiency, peak-load management, and renewable energy resources must all play a significant role in meeting the capacity and energy needs of each utility.

Progress Generation

As of September 2015, Progress had 12,923 MW of installed generating capacity (summer rating). This does not include purchases and non-utility owned capacity.

NCEMPA previously owned partial interest in several Progress plants, including Brunswick Nuclear Plant Units 1 and 2, Mayo Plant, Roxboro Plant Unit 4 and the Harris Nuclear Plant. The Power Agency's ownership interest in these plants represented approximately 700 MW of generating capacity. The boards of directors of Duke Energy and the NCEMPA approved an agreement for Progress to purchase the Power Agency's ownership in these generating assets. All required regulatory approvals were completed and the agreement closed on July 31, 2015. Progress is now 100% owner of these previously jointly owned assets. Under the agreement, Progress will continue meeting the needs of NCEMPA customers previously served by the Power Agency's interest in the Progress plants.

As part of the Western Carolinas Modernization Project (WCMP), the combined 376 MW Asheville 1 and 2 coal units are planned to be retired by 2020. The retired units are expected to be replaced with two 280 MW natural gas combined-cycle (CC) units. Additionally, an undetermined amount of solar generation is planned for installation at the same site. The Certificate of Public Convenience and Necessity (CPCN) for the new combined-cycle units is expected to be filed with the Commission in January 2016.

Other capacity additions include:

- Planned nuclear uprates totaling 29 MW in the 2017-2018 timeframe.
- Planned combined-cycle uprates totaling 135 MW in 2019.

- Addition of 84 MW Sutton Blackstart combustion turbines in Wilmington in 2017.
- Addition of 895 MW of combined-cycle capacity in 2021, 2022 and 2030.
- Addition of 828 MW of combustion turbine capacity in 2021 and 2027.

Other planned retirements include:

- Sutton combustion turbine units 1, 2A and 2B in 2017 (61 MW).
- Darlington, SC combustion turbine units 1-3, 5, and 7-10 by 2020 (406 MW).
- Blewett combustion turbine units 1-4 and Weatherspoon combustion turbine units 1-4 in 2027 (180 MW).

These retirement assumptions are for planning purposes only. The dates are based on useful life expectations of the units.

Duke Generation

As of September 2015, Duke had 21,434 MW of installed generating capacity (summer rating), excluding purchases and non-utility owned capacity. That total includes generation jointly-owned with NCMPA1, NCEMC, and Piedmont Municipal Power Agency produced at Duke's Catawba Nuclear Facility in South Carolina.

As shown in recent Duke IRP plans, a capacity need has been identified in 2017/2018. In an order dated May 2, 2014, the Company received a Certificate of Environmental Compatibility and Public Convenience and Necessity (CEPCPN) from the Public Service Commission of South Carolina to build the Lee combined-cycle plant (Lee CC) at the Lee Steam Station site located in Anderson, S.C. The Lee CC facility is projected to be available in November of 2017 at a capacity of 670 MW. This is the Duke capacity net of 100 MW to be owned by NCEMC.

Existing Lee Steam Station Unit 3 (170 MW) was successfully converted from a coal unit to a natural gas-fired boiler facility. The conversion was completed in April of 2015 and the unit was available for the summer peak of 2015.

Duke continues the work necessary to obtain a combined construction and operating license (COL) for the William States Lee III Nuclear Station (Lee Nuclear). The Lee Nuclear COL application references and incorporates the Westinghouse AP1000 NRC certified design. As that design is refined and modified through Westinghouse's design finalization activities and construction of AP1000 units in China and the United States, a handful of issues have arisen that must be resolved by the NRC prior to issuance of the Lee Nuclear COL. Assuming no new significant issues are identified, issuance of the COL is expected by late 2016.

Given the long cycle times to license and build a new nuclear electric generation station, Duke believes that it is essential to continue the licensing work on Lee Nuclear as a hedge against extensive carbon dioxide regulation, uncertain load growth, volatile fuel prices, and the possibility of not relicensing the existing operating nuclear stations. Duke currently projects the possible addition of 1,117 MW for Lee Nuclear units in both 2024 and 2026.

Other capacity additions include:

- Addition of 895 MW of combined-cycle capacity in 2022, 2028 and 2030.
- Addition of 65 MW due to nuclear uprates at Catawba, McGuire and Oconee in 2016-2017.

Retirements:

- In its 2015 Integrated Resource Plan filed with the Commission on September 1, 2015, Duke listed an expected retirement date of June 2028 for Allen coal units 1-5 located in Belmont, North Carolina. Pursuant to a settlement to end the remaining component of a civil lawsuit filed against Duke in 2000 by the U.S. Justice Department on behalf of the U.S. Environmental Protection Agency (EPA) and approved by the United States District Court for the Middle District of North Carolina, Duke will retire Allen units 1-3 by December 31, 2024.

NC Power / VEPCO Generation

As of July 2015, NC Power had 18,470 MW of existing Company owned generating capacity (summer rating). This excludes purchases and non-utility capacity. Of this total, only 480 MW is located in North Carolina.

NC Power issued a Request for Proposals (RFP) on November 3, 2014, for up to approximately 1,600 MW of new or existing intermediate or baseload dispatchable generation. The RFP requested purchase power agreements (PPA) with a term of 10 to 20 years, commencing in the 2019/2020 timeframe. Multiple proposals were received and evaluated. The Company's self-build 1,585 MW CC in Greensville County, Virginia provided superior customer benefits compared to all other options. The Greensville County certificate of public convenience and necessity (CPCN) was filed with the State Corporation Commission of Virginia (SCC) on July 1, 2015. It is forecasted to be completed in 2019.

NC Power's Brunswick County Power Station (1,368 MW CC unit) is currently under construction, and is expected to be online by May 2016.

The Company is in the process of developing a new nuclear unit, North Anna 3, at its existing North Anna Power Station located in Louisa County in central Virginia, subject to obtaining all required approvals. Based on the expected schedule for obtaining the

COL, the SCC certification and approval process, and the construction timeline for the facility, the earliest possible in-service date for North Anna 3 is September 2027, with capacity being available to meet the Company's 2028 summer peak. This in-service date has not changed from the 2014 Plan. Currently, the Company has not committed to build North Anna 3 and will not make a final decision until after the issuance of the COL. However, the Company continues to develop the project, given the proven operational, economic, and environmental benefits of nuclear power, and to assure that this supply-side resource option remains available to its customers for fuel diversity and as an option to comply with the EPA's Clean Power Plan (CPP).

The technology selection for North Anna 3 is the General Electric-Hatachi Economic Simplified Boiling Water Reactor (ESBWR). In July 2013, the Company submitted a revised COL application to the NRC to reflect the change in technology from the Mitsubishi Heavy Industries Advanced Pressurized Water Reactor that was identified in the 2012 Plan. This decision was based on a continuation of the competitive procurement process that began in 2009 to find the best solution to meet its need for future baseload generation. In October 2014, a major milestone was achieved when the NRC certified the ESBWR design for use in the United States.

NC Power expects to receive the COL in 2016 and intends to maintain the development option of North Anna 3 for several key reasons. First, North Anna 3 will provide much needed baseload capacity to the region in the latter portion of the Planning Period while enhancing system reliability. Second, nuclear units provide emission-free generation, which is particularly important as the Company plans for effective and anticipated EPA regulations. Third, North Anna 3 will enhance fuel diversity within the Company's generation portfolio, which in turn, promotes fuel price stability for customers.

Possum Point Unit 6 is a CC unit that went into commercial operation in July 2003. A turbine uprate was completed in the spring of 2015, which increased summer capacity from 559 MW to 587 MW.

Bear Garden Power Station is a CC that was completed in the summer of 2011. A turbine uprate is planned to be completed in the spring of 2017, which will increase summer capacity from 590 MW to 616 MW.

Based on the effective and anticipated environmental regulations along with current market conditions, NC Power's 2015 Plan includes the following impacts to the Company's existing generating resources in terms of retirements. Chesapeake Energy Center Units 1 (111 MW), 2 (111 MW), 3 (149 MW), and 4 (207 MW) were retired December 23, 2014. Yorktown Units 1 (159 MW) and 2 (164 MW) are scheduled for retirement in 2016, unless an EPA Administrative Order is sought and received.

Currently under evaluation is the potential retirement of Yorktown Unit 3, 790 MW of oil-fired generation, to be retired in 2020. Also under evaluation are the potential retirements of Chesterfield Units 3 (98 MW) and 4 (163 MW), and Mecklenburg Units 1 (69 MW) and 2 (69 MW), all modeled for retirement in 2020.

7. RELIABILITY AND RESERVE MARGINS

An electric system's reliability is its ability to continuously supply all of the demands of its consumers with a minimum interruption of service. It is also the ability of an electric system to withstand sudden disturbances, such as short circuits or sudden loss of system components due to scheduled or unscheduled outages. The reliability of an electric system is a function of the number, size, fuel type, and age of the utility's power plants; the different types and numbers of interconnections the utility has with neighboring electric utilities; and the environment to which its distribution and transmission systems are exposed.

There are several measurements of reliability utilized in the electric utility industry. Generally, they are divided between probabilistic measures (loss of load probability and the frequency and duration of outages) and non-probabilistic measures (reserve margin and capacity margin). One of the most widely used measures is the reserve margin.

The reserve margin is the ratio of reserve capacity to actual needed capacity (i.e., peak load). It is an indicator of the ability of an electric utility system to continue to operate despite the loss of a large block of capacity (generating unit outage and/or loss of a transmission line), deratings of generating units in operation, or actual load exceeding forecast load. A similar indicator is capacity margin, which is the ratio of reserve capacity to total overall capacity (i.e., reserve capacity plus actual needed capacity). Although reserve margin was the exclusive industry standard term for many years, capacity margin has also been widely used in recent years. This report continues to utilize reserve margin terminology.

It is difficult, if not impossible, to plan for major generating capacity additions in such a manner that constant reserve margins are maintained. Reserve margins will generally be lower just prior to placing new generating units into service and greater just after new generating units come online.

Previously, a 20% reserve margin was considered appropriate for long-range planning purposes. In recent years, the Commission has approved IRPs containing reserve margins lower than 20%. Adequate reliability can be preserved despite these lower reserve margins because of the increased availability of emergency power supplies from the interconnection of electric power systems across the country, the increasing efficiency with which existing generating units have been operated, and the relative size of utility generating units compared to overall load. Forecasted yearly reserve margins for Progress, Duke, and NC Power are shown in Appendices 2, 3, and 4. The summer reserve margins currently projected by each IOU are shown in Table 6.

Table 6: Projected Summer Reserve Margins for Progress, Duke, and NC Power (2015-2029, after DSM)

	Reserve Margins
Progress	15.2% –21.1%
Duke	15.0% – 22.7%
NC Power	11.2% – 17.4%

While coal and nuclear continue to remain the most widely used fuels in our area, most of the generation facilities constructed in recent years use natural gas as their primary fuel. With relatively low fuel costs and short construction lead times, natural gas generating units are efficient and produce relatively low emissions. Fuel deliverability, however, is a concern because of the nature of the infrastructure that delivers natural gas to the generating stations. Some regions of North America are served only by a few, or even a single, pipeline system. North Carolina, in fact, is almost entirely dependent on Transcontinental Gas Pipe Line Company, LLC (Transco) for its natural gas requirements.

Transco is expanding its system to bring shale gas to the State from the north. And Dominion is now working to build a large new pipeline into North Carolina to serve both gas and electric generation customers. That project, the Atlantic Coast Pipeline, is due to be ready for service in late 2018.

8. RENEWABLE ENERGY AND ENERGY EFFICIENCY

Renewable Energy and Energy Efficiency Portfolio Standard (REPS)

On August 20, 2007, with the signing of Senate Bill 3, North Carolina became the first state in the Southeast to adopt a REPS. Under this law, investor-owned electric utilities are required to increase their use of renewable energy resources and/or energy efficiency such that those sources meet 12.5% of their needs in 2021. EMCs and municipal electric suppliers are subject to a 10% REPS requirement. The requirements under the law phase in over time. In 2010, electric power suppliers were required to ensure that 0.02% of their retail electric sales in North Carolina came from solar energy resources. In 2012, electric power suppliers were required to meet 3% of their sales via renewable energy and energy efficiency, and the solar energy requirement increased to 0.07%. Also in 2012, requirements related to swine waste and poultry waste took effect, although those requirements were delayed by the Commission as discussed below.

On October 1, 2015, the Commission submitted its sixth annual report to the Governor, the Environmental Review Commission, and the Joint Legislative Commission on Governmental Operations regarding Commission implementation of, and electric power supplier compliance with, the REPS. The report is available on the Commission's web site, www.ncuc.net.

Senate Bill 3 requires the Commission to monitor compliance with REPS and to develop procedures for tracking and accounting for renewable energy certificates (RECs). In 2008 the Commission opened Docket No. E-100, Sub 121 and established a stakeholder process to propose requirements for a North Carolina Renewable Energy Tracking System (NC-RETS). On October 19, 2009, the Commission issued a request for proposals (RFP) via which it selected a vendor, APX, Inc., to design, build, and operate the tracking system. NC-RETS began operating July 1, 2010, consistent with the requirements of Session Law 2009-475.

Members of the public can access the NC-RETS web site at www.ncrets.org. The site's "resources" tab provides public reports regarding REPS compliance and NC-RETS account holders. NC-RETS also provides an electronic bulletin board where RECs can be offered for purchase.

As of October 28, 2015, NC-RETS had issued 26,944,781 RECs and 7,598,087 energy efficiency certificates. In addition, 11,472,678 RECs had been imported into NC-RETS accounts. (These certificates were issued by registries located outside of North Carolina.) About 412 organizations, including electric power suppliers and owners of renewable energy facilities, have established accounts in NC-RETS. About 887 renewable energy facilities and utility energy efficiency programs participate as "projects" in NC-RETS, which means that NC-RETS issues RECs or energy efficiency certificates to the project owners based on the facilities' energy output, or the savings achieved by the energy efficiency program.

Renewable Energy and Energy Efficiency Portfolio Standard (REPS) Compliance

For 2010 and 2011, each electric power supplier was subject to a solar obligation of 0.02% of retail sales. At the end of 2010 and 2011, each electric power supplier was required to have placed solar RECs that they acquired to meet their 2010 and 2011 REPS solar set-aside obligation into a compliance account within NC-RETS. When the Commission concluded its review of each electric power supplier's REPS compliance report, the associated RECs were permanently retired.

Starting in 2012, North Carolina's electric power suppliers were subject to an increased solar obligation of 0.07% of retail sales, and this requirement increased to 0.14% in 2015. In addition, starting in 2012 they were subject to: 1) a general REPS obligation of 3% of retail sales; 2) a swine waste resource obligation of 0.07% of retail sales, and 3) their pro-rata share of a 170,000 MWh statewide aggregated poultry waste resource obligation. With the exception of the swine and poultry waste requirements (discussed below), all of the electric power suppliers have complied with their 2010-2013 REPS obligations. The Commission approved the 2014 REPS compliance of Duke on July 30, 2015.¹ The 2014 REPS compliance of Progress,² NC Power,³ and the municipal and cooperative utilities⁴ remain pending before the Commission.

¹ Docket No. E-7, Sub 1074.

² Docket No. E-2, Sub 1071.

For all electric power suppliers, the general REPS obligation increased to 6 percent of retail sales in 2015.

In 2012, the electric power suppliers requested that their 2012 and 2013 swine and poultry waste obligations be delayed by two years. On November 29, 2012, the Commission issued an Order eliminating the 2012 requirement for swine waste resources and delaying for one year the requirement for poultry waste resources.

In 2013, the electric power suppliers requested an additional one-year delay to both the swine and poultry waste obligations, which was granted by the Commission on March 26, 2014.

In 2014, the electric power suppliers requested an additional delay to the swine waste requirement, but not the poultry waste requirement. On November 13, 2014, the Commission issued an Order Modifying the Swine Waste Set-Aside Requirement and Providing Other Relief in Docket No. E-100, Sub 113. This Order delayed the swine waste requirement until 2015; requested the Public Staff to facilitate two stakeholder meetings in 2015; and required electric power suppliers to file tri-annual reports detailing their efforts to secure swine waste resources.

In 2015, the electric power suppliers requested another one-year delay (until 2016) in the need to comply with the swine waste and poultry waste requirements. This request remains pending before the Commission in Docket No. E-100, Sub 113. (As of this writing it appears that all electric power suppliers have complied with the 2014 poultry waste requirement of an aggregated obligation of 170,000 MWh, although three 2014 REPS compliance dockets remain pending.)

Energy Efficiency

Electric power suppliers in North Carolina are required to implement demand-side management (DSM) and energy efficiency (EE) measures and use supply-side resources to establish the least cost mix of demand reduction and generation measures that meet the electricity needs of their customers. Energy reductions through the implementation of DSM and EE measures may also be used by the electric power suppliers to comply with REPS. Duke, Progress, NC Power, EnergyUnited, Halifax, and GreenCo have filed for and received approval for EE and DSM programs.

NC GreenPower

In October 2003, NC GreenPower was launched as a voluntary program to supplement the State's existing power supply with electricity generated from renewable energy sources like the sun, wind, water, and organic matter. NC GreenPower's first

³ Docket No. E-22, Sub 525.

⁴ Docket No. E-100 Sub 145.

project came online in 2004; two years later, the organization cut the ribbon for its first landfill generator and wind turbine. In 2008, the program added a carbon offset product, giving citizens the opportunity to offset emissions caused by driving and other activities by mitigating greenhouse gases via landfill or hog lagoon methane capture projects.

NC GreenPower projects have generated nearly 567 billion kilowatt-hours of energy, and donors have helped provide about \$7 million in incentive payments to the owners of more than 900 renewable energy projects located in almost every county across NC. That's the equivalent of providing 39,400 houses with energy for a year. Carbon offset projects have mitigated 31,100 tons of greenhouse gases, the equivalent of planting 5.2 million trees.

On April 1, 2015, NC GreenPower announced a new pilot program to provide matching grants for the installation of solar photovoltaic generation at schools. NC GreenPower's pilot will likely award four schools with 3.5-kW arrays, monitoring equipment, and curriculum for educators.

9. TRANSMISSION AND GENERATION INTERCONNECTION ISSUES

Transmission Planning

The North Carolina Transmission Planning Collaborative (NCTPC) was established in 2005. Participants (transmission-owning utilities, such as Duke and Progress, and transmission-dependent utilities, such as municipal electric systems and EMCs) identify the electric transmission projects that are needed to be built for reliability and estimate the costs of those upgrades. The NCTPC's January 15, 2015 report stated that 8 major (greater than \$10 million each) transmission projects are needed in North Carolina by the end of 2024 at an estimated cost of \$209 million. For more information, visit the NCTPC's website at www.nctpc.net/nctpc.

On July 21, 2011, the FERC issued Order No. 1000, entitled "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities."⁵ This Order requires transmission owners to participate in new regional and inter-regional transmission planning efforts. Duke and Progress have complied with Order No. 1000 by participating in the Southeastern Regional Transmission Planning (SERTP)⁶ process.

⁵ FERC issued Order No. 1000 on July 21, 2011, in its Docket No. RM10-23-000.

⁶ For more information about the Southeastern Regional Transmission Planning process, see <http://southeasternrtp.com/>. Other members of the SERTP are: Southern Company, Dalton Utilities, Georgia Transmission Corporation, the Municipal Electric Authority of Georgia, PowerSouth, Louisville Gas & Electric Company, Kentucky Utilities Company, the Ohio Valley Electric Corporation, Indiana-Kentucky Electric Corporation, Associated Electric Cooperative, Inc., and the Tennessee Valley Authority.

On July 3, 2013, Session Law 2013-232 was enacted. This law states that only a public utility may obtain a certificate to build a new transmission line (except a line for the sole purpose of interconnecting an electric power plant). In this context, a public utility includes IOUs, EMCs, joint municipal power agencies, and cities and counties that operate electric utilities.

State Generator Interconnection Standards

On June 4, 2004, in Docket No. E-100, Sub 101, Progress, Duke, and NC Power jointly filed a proposed model small generator interconnection standard, application, and agreement to be applicable in North Carolina. In 2005, the Commission approved small generator interconnection standards for North Carolina.

In Session Law 2007-397, the General Assembly, among other things, directed the Commission to “[e]stablish standards for interconnection of renewable energy facilities and other nonutility-owned generation with a generation capacity of 10 megawatts or less to an electric public utility’s distribution system; provided, however, that the Commission shall adopt, if appropriate, federal interconnection standards.”

On June 9, 2008, the Commission issued an Order revising North Carolina’s Interconnection Standard. The Commission used the federal standard as the starting point for all state-jurisdictional interconnections (regardless of the size of the generator), and made modifications to retain and improve upon the policy decisions made in 2005. The Commission’s Order required regulated utilities to update any affected rate schedules, tariffs, riders, and service regulations to conform with the revised standard.

On July 9, 2008, Duke filed a motion for reconsideration regarding whether an external disconnect switch should be required for certified inverter-based generators up to 10 kW. On December 16, 2008, the Commission issued an Order in which it granted Duke’s motion for reconsideration and gave electric utilities the discretion to require external disconnect switches for all interconnecting generators. However, if a utility requires such a switch for a certified, inverter-based generator under 10 kW, the utility shall reimburse the generator for all costs related to that installation.

On April 8, 2014, the North Carolina Sustainable Energy Association (NCSEA) requested that the Commission revise its small generator interconnection standards in light of changes that had been made to similar procedures at the federal level and in other states. The Commission asked the Public Staff to facilitate a meeting of interested parties to discuss potential changes to North Carolina’s interconnection standards, and established a schedule for parties to file comments and reply comments. After several stakeholder meetings, and several requests for time extensions, the parties filed a proposal to revise the State’s interconnection standards that was largely, but not entirely, supported by the stakeholders.

The Commission issued an Order Approving Revised Interconnection Standard on May 15, 2015.⁷ That Order made substantial changes to the procedures for requesting to interconnect a generator to the electric grid. Most of these changes were recommended by the stakeholders with the intent of addressing a back-log of interconnection requests. Parties filed comments explaining these changes were needed so that owners of proposed generation projects would be incented to either move ahead with their projects, or withdraw them from the utilities' interconnection queues. The more significant changes in the State's interconnection standards were: 1) a project's ability to be expedited is now based not only on the project's size, but also on the size of the line it would connect to, and its distance from a substation; 2) a new process for addressing "interdependent" projects was added, where one generator needs to decide whether it is going to move ahead in order for the utility to determine that capacity exists to interconnect a second generator; 3) developers must provide a deposit of at least \$20,000; 4) developers must demonstrate that they have site control; and 5) developers must pay for upgrades before the utility begins construction. The utilities are required to file a quarterly report to the Commission reporting on their progress in addressing the interconnection queue backlog. The Public Staff is to convene a workgroup of interested parties within two years to discuss whether the State's small generator interconnection standards require additional revisions.

Net Metering

"Net metering" refers to a billing arrangement whereby a customer that owns and operates an electric generating facility is billed according to the difference over a billing period between the amount of energy the customer consumes and the amount of energy it generates. In Senate Bill 3, codified at G.S. 62.133.8(i)(6), the General Assembly required the Commission to consider whether it is in the public interest to adopt rules for electric public utilities for net metering of renewable energy facilities with a generation capacity of one megawatt or less.

On March 31, 2009, following hearings on its then-current net metering rule, the Commission issued an Order requiring Duke, Progress, and NC Power to file revised riders or tariffs that allow net metering for any customer that owns and operates a renewable energy facility that generates electricity with a capacity of up to one megawatt. The customer shall be required to interconnect pursuant to the approved generator interconnection standard, which includes provisions regarding the study and implementation of any improvements to the utility's electric system required to accommodate the customer's generation, and to operate in parallel with the utility's electric distribution system. The customer may elect to take retail electric service pursuant to any rate schedule available to other customers in the same rate class and may not be assessed any standby, capacity, metering, or other fees other than those approved for all customers on the same rate schedule. Standby charges shall be waived, however, for any net-metered residential customer with electric generating capacity up to 20 kW and any net-metered non-residential customer up to 100 kW. Credit for excess electricity generated during a monthly billing period shall be carried

⁷ For more information, see Docket No. E-100, Sub 101.

forward to the following monthly billing period, but shall be granted to the utility at no charge and the credit balance reset to zero at the beginning of each summer billing season. If the customer elects to take retail electric service pursuant to any time-of-use (TOU) rate schedule, excess on-peak generation shall first be applied to offset on-peak consumption and excess off-peak generation to offset off-peak consumption; any remaining on-peak generation shall then be applied against any remaining off-peak consumption. If the customer chooses to take retail electric service pursuant to a TOU-demand rate schedule, it shall retain ownership of all RECs associated with its electric generation. If the customer chooses to take retail electric service pursuant to any other rate schedule, RECs associated with all electric generation by the facility shall be assigned to the utility as part of the net-metering arrangement.

On February 24, 2014, NCSEA filed a Motion for Disclosure and Equitable Relief requesting that the Commission direct Duke and Progress to: (1) guarantee, at a minimum, the continued availability of the current net-metering terms and conditions for 10 years for each residential and commercial customer who installs a net-metered rooftop solar system prior to issuance of a final order in any net-metering proceeding initiated in the coming year; and (2) disclose the analysis upon which Duke was basing its messaging that net metering in North Carolina is unfair. The Commission requested comments on NCSEA's motion.

On May 28, 2014, the Commission issued an Order Denying Motion stating that there is no petition before the Commission to change the current net-metering policy, and that NCSEA's request for disclosure had become moot because Duke's analysis had become public.

10. FEDERAL ENERGY INITIATIVES

Open Access Transmission Tariff

In April 1996, the FERC issued Order Nos. 888 and 889, which established rules governing open access to electric transmission systems for wholesale customers and required the construction and use of an Open Access Same-time Information System (OASIS) for reserving transmission service. In Order No. 888, the FERC also required utilities to file standard, non-discriminatory OATTs under which service is provided to wholesale customers such as electric cooperatives and municipal electric providers. As part of this decision, the FERC asserted federal jurisdiction over the rates, terms, and conditions of the transmission service provided to retail customers receiving unbundled service while leaving the transmission component of bundled retail service subject to state control. In Order No. 889, the FERC required utilities to separate their transmission and wholesale power marketing functions and to obtain information about their own transmission system for their own wholesale transactions through the use of an OASIS system on the Internet, just like their competitors. The purpose of this rule was to ensure that transmission owners do not have an unfair advantage in wholesale generation markets.

Regional Transmission Organizations (RTOs)

In December 1999, the FERC issued Order No. 2000 encouraging the formation of RTOs, independent entities created to operate the interconnected transmission assets of multiple electric utilities on a regional basis. In compliance with Order No. 2000, Duke, Progress, and SCE&G filed a proposal to form GridSouth Transco, LLC (GridSouth), a Carolinas-based RTO. The utilities put their GridSouth-related efforts on hold in June 2002, citing regulatory uncertainty at the federal level. The GridSouth organization was formally dissolved in April 2005.

Dominion, NC Power's parent, filed an application with the Commission on April 2, 2004, in Docket No. E-22, Sub 418, seeking authority to transfer operational control of its transmission facilities located in North Carolina to PJM Interconnection, an RTO headquartered in Pennsylvania. The Commission approved the transfer subject to conditions on April 19, 2005.

The Commission has continued to provide oversight over NC Power and PJM by using its own regulatory authority, through regional cooperation with other State commissions, and by participating in proceedings before the FERC. Together with the other State commissions with jurisdiction over utilities in the PJM area, the Commission is involved in the activities of the Organization of PJM States, Inc. (OPSI).

Transmission Rate Filings

In 2010, the Commission and the Public Staff jointly intervened in an NC Power transmission rate case before the FERC, arguing that some transmission costs should not be passed on to all transmission customers. Specifically, the Commission and the Public Staff argued that North Carolina citizens should not be required to pay the incremental cost of undergrounding several electric transmission lines located in Virginia when viable, less-costly overhead options were available. On September 17, 2012, the Commission joined with NCEMC, Old Dominion Electric Cooperative, and the Virginia Municipal Electric Association No. 1 to file a reply brief in this case. A FERC-appointed administrative law judge convened settlement negotiations, but the parties were not able to reach a settlement. On December 2, 2014, FERC assigned the dispute to an administrative law judge and a hearing was held October 8, 2015.⁸ After the administrative law judge issues its recommendation, FERC will make a final decision in the matter.

Cyber Security

Federal and State regulators are increasingly concerned about cyber security and physical threats to the nation's bulk power system. Cyber security threats may be posed by foreign nations or others intent on undermining the United States' electric grid. North Carolina's utilities are working to comply with federal standards that require them

⁸ For more information, see www.ferc.gov, Docket No. EL10-49-003.

to identify critical components of their infrastructure and install additional protections from cyberattacks. The NC Utilities Commission meets with utility officials periodically to understand the cyber threats the utilities are facing and the actions they are taking to address these threats.

Physical Security

In April of 2013 a substation near San Jose, California, sustained a well-planned attack during which firearms were used to severely damage electric equipment. In response to this and other incidents, the FERC on March 7, 2014, required NERC to quickly develop new reliability standards that would require each owner and operator of the bulk electric system to perform a risk assessment of its systems to identify critical facilities; evaluate potential threats to, and vulnerabilities of those facilities; and develop and implement a security plan to protect against attacks on those facilities. NERC developed the physical security standards and filed them with FERC on May 23, 2014. On July 17, 2014, FERC proposed modifications to the draft standards, including the ability for governmental authorities to add or subtract facilities from the list of critical facilities for which physical security measures would be required. After receiving comments, on November 20, 2014, FERC issued Order No. 802. That order requires NERC to remove wording that FERC believes could reduce the number of “critical facilities” that would be subject to the rule. The order did not adopt FERC’s earlier proposal that would have allowed governmental authorities to add or remove facilities from the list of critical facilities. The rules became effective June 1, 2015.⁹

EPA’s Proposal to Regulate Carbon Emissions From Existing Power Plants

On August 3, 2015, the U.S. Environmental Protection Agency (EPA) finalized regulations for reducing CO₂ emissions from existing power plants, relying on authority from the Clean Air Act. These regulations establish CO₂ emission levels for existing power plants in each State based upon three “building blocks”: 1) altering coal-fired power plants to increase their efficiency, 2) substituting natural gas combined cycle generation for generation from coal; and 3) substituting generation from low or zero-carbon energy generation, such as wind and solar, for generation from fossil fuels.

In North Carolina the Department of Environmental Quality (NCDEQ) is the lead agency for compliance with the Clean Air Act. On October 23, 2015, NCDEQ joined with 24 other States to petition the US Court of Appeals for a stay of the regulations, as well as expedited consideration of a petition for review of those regulations. These States argue that EPA over-stepped its authority in promulgating the rules, that EPA lacks expertise and authority to regulate the energy grid, and that the States will experience irreparable harm if they must begin to comply with the regulations pending the outcome of legal challenges. The outcome of this litigation, and the ultimate disposition of federal CO₂ controls, could have a major impact on the electric generation fleet, reliability of service, and electricity prices in North Carolina.

⁹ For more information, go to <http://www.ferc.gov/>, Docket No. RM14-15.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 141

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
2014 Biennial Integrated Resource Plans
and Related 2014 REPS Compliance
Plans) ORDER APPROVING
) INTEGRATED RESOURCE
) PLANS AND REPS COMPLIANCE
) PLANS

HEARD: Monday, March 9, 2015, at 7:00 p.m. in Commission Hearing Room 2115,
Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Bryan E. Beatty, Presiding; Chairman Edward S. Finley,
Jr., and Commissioners Susan W. Rabon, ToNola D. Brown-Bland, Don
M. Bailey, Jerry C. Dockham, and James G. Patterson

APPEARANCES:

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BY THE COMMISSION: Integrated Resource Planning (IRP) is intended to identify those electric resource options that can be obtained at least cost to the utility and its ratepayers consistent with the provision of adequate, reliable electric service. IRP considers demand-side alternatives, including conservation, efficiency, and load management, as well as supply-side alternatives in the selection of resource options. Commission Rule R8-60 defines an overall framework within which the IRP process takes place in North Carolina. Analysis of the long-range need for future electric generating capacity pursuant to G.S. 62-110.1 is included in the Rule as a part of the IRP process.

General Statute (G.S.) 62-110.1(c) requires the Commission to “develop, publicize, and keep current an analysis of the long-range needs” for electricity in this State. The Commission's analysis should include: (1) its estimate of the probable future growth of the use of electricity; (2) the probable needed generating reserves; (3) the extent, size, mix, and general location of generating plants; and (4) arrangements for pooling power to the extent not regulated by the Federal Energy Regulatory Commission (FERC). Further, G.S. 62-110.1 requires the Commission to consider this analysis in acting upon any petition for the issuance of a certificate for public convenience and necessity for construction of a generating facility. 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 a report of its: (1) analysis and plan; (2) progress to date in carrying out such plan; and (3) program for the ensuing year in connection with such plan. G.S. 62-15(d) requires the Public Staff to assist the Commission in making its analysis and plan pursuant to G.S. 62-110.1.

G.S. 62-2(a)(3a) declares it a policy of the State to:

assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to require 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, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills

Session Law (S.L.) 2007-397 (Senate Bill 3), signed into law on August 20, 2007, amended G.S. 62-2(a) to add subsection (a)(10) that provides that it is the policy of North Carolina “to promote the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard (REPS)” 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, and (4) provide improved air quality and other benefits to the citizens of North Carolina. To that end, Senate Bill 3 further provides that “[e]ach electric power supplier to which G.S. 62-110.1 applies shall include an assessment of demand-side management and energy efficiency in its resource plans submitted to the Commission and shall submit cost-effective demand-side management and energy efficiency options that require incentives to the Commission for approval.”¹

Senate Bill 3 also 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” and defines an energy efficiency (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.”² EE measures do not include DSM.

To meet the requirements of G.S. 62-110.1 and G.S. 62-2(a)(3a), the Commission conducts an annual investigation into the electric utilities’ IRPs. Commission Rule R8-60 requires that each utility, to the extent that it is responsible for procurement of any or all of its individual power supply resources (collectively, the utilities),³ furnish the Commission with a biennial report in even-numbered years that contains the specific information set out in Rule R8-60. In odd-numbered years, each of the electric utilities must file an annual report updating its most recently filed biennial report.

Further, Commission Rule R8-67(b) requires any electric power supplier subject to Rule R8-60 to file a REPS compliance plan as part of each biennial and annual report. In addition, each biennial and annual report should (1) be accompanied by a

¹ G.S. 62-133.9(c).

² G.S. 62-133.8(a)(2) and (4).

³ During the 2013 Session, the General Assembly enacted S.L. 2013-187 (House Bill 223), which exempted the EMCs from the requirements of G.S. 62-110.1(c) and G.S. 62-42, effective July 1, 2013. As a result, EMCs are no longer subject to the requirements of Rule R8-60 and are no longer required to submit IRPs to the Commission for review.

short-term action plan that discusses those specific actions currently being taken by the utility to implement the activities chosen as appropriate per the applicable biennial and annual reports and (2) incorporate information concerning the construction of transmission lines pursuant to Commission Rule R8-62(p).

Within 150 days after the filing of each utility's biennial report and within 60 days after the filing of each utility's annual report, the Public Staff or any other intervenor may file its own plan or an evaluation of, or comments on, the utilities' biennial and annual reports. Furthermore, the Public Staff or any other intervenor may identify any issue that it believes should be the subject of an evidentiary hearing. The Commission must schedule one or more hearings to receive public testimony.

2014 BIENNEIAL REPORTS

This Order addresses the 2014 biennial reports (2014 IRPs) filed in Docket No. E-100, Sub 141, by Duke Energy Progress, Inc. (DEP); Duke Energy Carolinas, LLC (DEC); and Dominion North Carolina Power (DNCP) (collectively, the investor-owned utilities, utilities or IOUs). In addition, this Order also addresses the REPS compliance plans filed by the IOUs.

The following parties have been allowed to intervene in this docket: Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR); Carolina Utility Customers Association, Inc. (CUCA); Environmental Defense Fund (EDF); Mid-Atlantic Renewable Energy Coalition (MAREC); North Carolina Sustainable Energy Association (NCSEA); North Carolina Waste Awareness and Reduction Network (NC WARN); North Carolina Electric Membership Corporation (NCEMC); Sierra Club; and Southern Alliance for Clean Energy (SACE). The Public Staff's intervention is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

PROCEDURAL HISTORY

On August 29, 2014, DNCP filed its 2014 biennial IRP report and REPS compliance plan. On September 2, 2014, DEC and DEP filed their 2014 biennial IRP reports and REPS compliance plans.

On September 29, 2014, the Commission issued an Order Establishing Dates for Comments on Integrated Resource Plans and REPS Compliance Plans. That Order set January 30, 2015, as the date for filing petitions to intervene and for filing initial comments. Reply comments were due on February 13, 2015.

On January 20, 2015, the Commission issued an Order Scheduling Public Hearing on 2014 Biennial IRP Reports And Related 2014 REPS Compliance Plans. That Order set the public witness hearing for 7:00 p.m. on March 9, 2015, in Raleigh.

On January 21, 2015, DEP filed a corrected page 174 to its IRP report due to errors discovered in the calculation of the projected cost amounts contained in Table 5.

On January 28, 2015, the Public Staff filed a motion for extension of time for the filing for petitions to intervene and initial comments to February 23, 2015, and the date for reply comments to March 12, 2015. The Commission granted this motion on January 29, 2015.

On February 20, 2015, the Public Staff filed a second motion for extension of time for the filing for petitions to intervene and initial comments to March 2, 2015 and the date for reply comments to March 19, 2015. This motion was granted by the Commission on the same day.

Also on February 20, 2015, NC WARN filed its initial comments and a request for an evidentiary hearing.

On February 27, 2015, initial comments were filed by MAREC.

On March 2, 2015, initial comments were filed by NCSEA, the Public Staff and jointly by SACE and the Sierra Club.

On March 9, 2015, the public witness hearing was held in Raleigh, as scheduled.

On March 10, 2015, DEC, DEP and DNCP filed a joint motion for extension of time to file reply comments to April 9, 2015. This motion was granted on March 11, 2015.

On March 20, 2015, NC WARN filed a correction to paragraph 45 on page 27 of its initial comments filed on February 20, 2015.

On April 7, 2015, DEC, DEP and DNCP filed a joint motion for a second extension of time to file reply comments to April 20, 2015. This motion was granted by the Commission on April 8, 2015.

On April 20, 2015, reply comments were filed by DNCP, and jointly by DEC and DEP.

Public Hearing

Pursuant to G.S. 62-110.1(c) the Commission held a public hearing in Raleigh on Monday, March 9, 2015, at 7:00 p.m., where 13 public witnesses spoke. The witnesses discussed the damage that fossil fuels do to the environment versus the benefits of generating electricity with renewable sources of energy, especially solar. It was noted

that we are all stewards of the planet with a responsibility for building a healthy place for people and wildlife to flourish together.

The witnesses offered support for the EPA Clean Power Plan and an overall increase in the use of renewables and energy efficiency programs, including offering incentives to electricity consumers to invest in energy efficiency measures. There was also discussion of various issues related to coal ash cleanup.

Request for Evidentiary Hearing

In NC WARN's comments and request for an evidentiary hearing, filed on February 20, 2015, NC WARN first discusses the purpose of the IRPs and NC WARN's overriding criticism that DEC's and DEP's (collectively, Duke's) IRPs maintain the status quo of heavy reliance on fossil fuel generation. In summary, NC WARN makes four main points: (1) that Duke's growth forecasts are unrealistic; (2) that Duke's IRPs include its continued reliance on expensive and unnecessary new natural gas and nuclear plants; (3) that Duke fails to plan to use strategic purchases and transmission cooperation with other utilities and merchant plants even though Duke and other southeastern electricity providers have significant excess capacity; and (4) that Duke fails to plan for the use of cost-effective and readily available renewable energy, energy efficiency measures, and combined heat and power (CHP) resources.

NC WARN's Comments

NC WARN asserts that both DEC and DEP base their 15-year IRPs on a 1.4% annual growth in peak demand for electricity, even though actual growth in electricity demand has been flat for more than a decade. NC WARN further notes that these projections include the impact of Duke's energy efficiency programs, and estimates that the actual growth in demand projected by Duke is almost 1.9%. NC WARN submits that these projections are unrealistic because they are based on a full economic recovery and a booming growth in population. In contrast, NC WARN forecasts zero growth, which it submits is in line with the most recent growth projections by the United States Energy Information Administration (EIA), and the American Council for an Energy-Efficient Economy (ACEEE), as well as actual growth for the past decade. NC WARN states that projected demand growth is a crucial component in determining the costs for new generation facilities and that the Duke forecast, resulting in a need for 7,282 MW of capacity, will cost ratepayers over \$25 billion, potentially doubling electric rates over the IRP planning period. On the other hand, NC WARN's analysis shows that a zero growth scenario allows for the phase out of all coal plants, eliminates the need to construct new nuclear plants and reduces the need for some existing natural gas generation. According to NC WARN, this can be achieved with strengthened energy efficiency measures, a more rapid development of renewable energy, continued reliance on pumped storage, and the fostering of distributed generation, backed up with purchases from other utilities and merchant plants.

In addition, NC WARN notes that Duke's reserve margins over the IRP planning period are in excess of Duke's goal of 14.5%, with DEC's reserve margins ranging from 15% to 22.7% for summer peak (and 19.4% to 25.7% for winter peak), and DEP's ranging from 15.2% to 21.1% for summer peak (and 22.1 to 31.7% for winter peak). NC WARN opines that all utilities in the southeast region have excess capacity that should be used among the utilities to supplement each other's generation requirements, rather than building unneeded or underutilized generation. NC WARN cites and discusses the North American Electric Reliability Corporation's (NERC's) 2014 Summer Reliability Assessment. NC WARN contends that there are no compelling reasons why Duke and the other southeast utilities should continue to construct new generation without looking at mutual purchasing agreements. According to NC WARN, using average monthly peaks taken from EIA Form-714 for the shoulder months of April, May, October and November, DEC's average reserve capacity during its monthly peak is 40.6%, while DEP's is 36% and for several of these shoulder months, more than 50% of the available capacity was not needed. In addition, the excess capacity would be even more extreme assuming a flat growth rate. NC WARN discusses studies by FERC and the Lawrence Berkeley National Laboratory, and suggests that North Carolina could optimize energy efficiency and reliable distribution by implementation of a regional transmission organization (RTO), or other similar regional strategy.

NC WARN also discusses Duke's plan to build new nuclear plants. It asserts that these projects will be extremely expensive and risky, citing the cost of projects in other states. Further, NC WARN laments the drawbacks of Duke's increased reliance on natural gas plants as a baseload resource, including greenhouse gases and externalized costs of fracking and conventional drilling, refining, transportation and combustion. Further, NC WARN submits that the utilities should include an assessment of the amount of carbon emissions and other pollution as a part of their IRPs, asserting that the externalized costs from fossil fuels, such as the estimated 17 - 27 cents/kWh in health and environmental damages from coal-fired electricity, add tremendously to the cost of generating electricity with fossil fuels. NC WARN states that Duke is expected to emit approximately 34.5 million tons of carbon dioxide annually, and that the coal plants being closed by Duke are old, small coal units rarely used in the years preceding their scheduled closures, noting that the average capacity of the units that Duke has closed or projects to close is 110 MW and the age of the units at the time of retirement ranges from 50 to 89 years.

NC WARN contends that its plan for North Carolina's energy future is competition driven, its primary goal being to maximize efficiencies and thus minimize costs to ratepayers. To do this, NC WARN would increase energy efficiency and renewable energy, and encourage distributed generation to place energy sources near where they are needed. According to NC WARN, this would allow for closure of all coal-fired power plants, eliminate the need for new centralized generating plants and, as a result, decrease electric rates and pollution. NC WARN's Appendix A contains a set of pie

charts comparing Duke's forecasts with those in NC WARN's energy proposal -- a zero growth scenario. NC WARN states that the most significant difference between NC WARN's plan and Duke's is NC WARN's proposed increase of energy efficiency and demand-side management (DSM) programs to 19% of capacity and 24% of energy over the planning horizon, far greater than the 5% of capacity and 5.1% of energy in Duke's IRPs. Likewise, CHP and microgrids are increased to 8% of capacity and 10% of energy in the NC WARN plan, while neither is included in Duke's forecasts. Similarly, wind and solar is increased to 18% of capacity and 7% of energy in the NC WARN proposal, far greater than the 4% of capacity and 4% of energy in Duke's plan. Wholesale purchases in the NC WARN plan are 6% capacity and 6% in sales compared to 0.8% capacity and 0.2% in Duke's plan.

Moreover, NC WARN submits that some utility companies, including Florida Power and Light (FPL), argue that energy efficiency has run its course and is no longer the best option. Nevertheless, NC WARN states that a recent report by ACEEE shows that utility energy efficiency programs appear to be holding steady as the least-cost resource. Similarly, in recent long-term predictions the EIA addresses the implications of low electricity demand growth and examines various scenarios to show the effects of future savings. The EIA low electricity demand growth report discusses how variations in the amount of energy efficiency done now can affect the demand in the coming years. In the reference case, which assumes no new efficiency standards beyond those already in place, total electricity use grows by an average of less than 1% per year from 2012-2040. In addition, NC WARN discusses the energy efficiency gains made in lighting, commercial air conditioners, refrigeration units and "smart appliances."

NC WARN further states that ACEEE's 2014 State Energy Efficiency Scorecard ranks North Carolina number 24 among the states, with no change from the previous year. NC WARN contends that North Carolina's utilities should take more initiative to implement energy efficiency programs, as efficiency continues to be the most cost effective option available.

In addition, NC WARN submits that the second main component of a responsible energy future is a renewable energy build-up to account for 7% of total electricity sales and 18% of total capacity in North Carolina over the planning horizon, including both retail and wholesale sales. Within this expansion, NC WARN sees solar photovoltaic (PV) systems as a tremendous resource that can provide reliable electricity, with costs continuing to fall steadily. It discusses several initiatives that are contributing to the growth of solar resources in North Carolina, and studies showing that solar has reached grid parity in ten states, and would reach grid parity in 36 of 50 states by 2016. NC WARN further contends that solar facilities are a positive asset to utility grids, providing resilience, diversity, and a hedge against increased fuel costs. In addition, NC WARN states that further development of storage technology is poised to bolster the rapid growth of distributed renewable energy such as wind and solar and provide additional grid support.

NC WARN states that it also continues to recommend the development of substantial CHP systems for commercial and industrial customers who use both heat and electricity in their facilities, and microgrid technologies putting electricity generation as close as possible to where it is needed. It states that conventional methods of producing heat and power separately have a typical combined efficiency of 45%, while CHP systems often have a total efficiency of 70 – 80%, and are versatile and flexible. Noting that currently in North Carolina there are 167 CHP facilities in operation, with a capacity of 1,541 MW, NC WARN notes that in the United States CHP represents nearly 10% of total generating capacity.

NC WARN submits that at a minimum Duke's business model will in all likelihood cause rates to double from 2009 to 2029, with additional increases in the subsequent decade depending on when new large-scale generation is added. In contrast, NC WARN asserts that its approach can provide billions of dollars in annual savings for North Carolina electricity customers, and is a responsible energy future, one that promotes job creation, a good economy, and a healthier place to live, while also doing North Carolina's share in finding solutions to climate change.

NC WARN concludes its comments with a request for an evidentiary hearing on (1) Duke's 1.5% growth rate forecast; (2) Duke's continued reliance on new natural gas and nuclear plants; (3) Duke's refusal to plan on strategic purchases and transmission cooperation with other utilities and merchant plants; and (4) Duke's failure to plan for cost-effective and readily available renewable energy, energy efficiency measures, and CHP.

Duke's Reply Comments

In its reply comments, Duke states that NC WARN essentially restated the same arguments that NC WARN made in the 2013 IRP docket and notes that those arguments were rejected by the Commission. In summary, Duke asserts that NC WARN advances unsupported positions regarding the resource plans filed by DEC and DEP. In particular, Duke asserts that NC WARN's proposed alternative resource plan is not supported by legitimate data or substantive analysis. Duke states that when it sought information from NC WARN it was informed that NC WARN did not prepare a true load forecast, but simply assumed "zero growth." Duke states that such an assumption is entirely inconsistent with the actual data utilized to prepare the load forecasts for Duke's 2014 IRPs, and that Duke stands by the reasonableness of the load forecasts contained in its 2014 IRPs. Duke also notes that its load forecasts are supported by the Public Staff.

With regard to NC WARN's comments on Duke's proposed coal retirement and replacement plan, Duke states that NC WARN's responses to data requests indicated that NC WARN did not prepare production cost simulation models and screening

models of its plan or model, nor develop any of the inputs listed in the data request, except the cost of coal and natural gas price forecasts. In addition, Duke states that according to NC WARN's data request responses, the pie charts contained in Appendix A to NC WARN's report were prepared by NC WARN's researcher/paralegal. Further, in response to a data request seeking the detailed data assumptions utilized to determine the economic value of the analysis reflected in NC WARN's comments, NC WARN responded, "NC WARN has not conducted PVRR calculations, nor made assumptions associated with those calculations." (NC WARN Response to Duke Energy's First Data Request No. 21, March 18, 2015)

Moreover, Duke notes that NC WARN also alleges that, "If the Commission approves the Duke Energy plan, it approves a status quo threatening to bankrupt North Carolina's economy" (NC WARN Comments, at p. 3). However, Duke states that in response to a data request asking for all workpapers, studies or other documents that were relied upon in forming this statement, NC WARN responded that it did not have any such workpapers or studies, but that its statement is explained in its comments, and based on 0% load growth and the potential that Duke's rate will double in order to pay for new generating plants. Duke maintains that NC WARN has no credible support for its allegation that Commission approval of Duke's 2014 IRP would threaten to bankrupt North Carolina's economy.

With regard to NC WARN's assertion that Duke can retire all existing coal units and some existing natural gas units, and meet its customers' needs exclusively through a mix of new EE, renewable energy, pumped storage, distributed generation, and purchases from other utilities and merchant plants, Duke states that NC WARN has no legitimate economic analysis to support its proposed resource plan. As an example, Duke cites NC WARN's response to a data request in which NC WARN acknowledges that it has not documented the capital costs, on-going capital streams, fixed and variable O&M costs, life of asset, assumptions of federal/state tax incentives, load profiles, and capacity factors beyond the statements and footnotes in the comments. Further, in response to a data request seeking the EE and demand response costs, program participation and participation studies used to support the NC WARN comments, NC WARN stated that it had not prepared that data beyond NC WARN's proposal for a Community Enhanced Income Qualified Energy Efficiency and Weatherization Program, as contained in NC WARN's testimony in Docket No. E-7, Sub 1032. Duke also states that NC WARN has conducted no revenue requirements analysis for its proposed resource portfolio and, therefore, has no legitimate basis to assert that its proposal will be cost effective for Duke's customers. In addition, Duke states that WARN's alternative resource plan was apparently developed without regard to system reliability concerns. In support of this observation, Duke notes that NC WARN's data request responses reveal that it conducted no loss of load study. Further, when asked to explain in detail how its proposed plan will provide adequate reliability for Duke's customers, NC WARN responded simply as follows:

As stated in the Comments, paragraph 6 and accompanying footnotes, the inclusion of a balanced mix of distributed generation and energy efficiency is more reliable than the current generation – transmission – distribution system, and especially if backed up by batteries. Electricity is placed where it is most needed both on the grid and at peak periods, and at the same time, distributed generation provides grid support services. As noted in the Comments, paragraphs 15-16, a wide variety of these sources do not require as high a reserve margin as does a system relying on a limited number of large coal and nuclear plants. In addition, NC WARN recently looked at the value of solar, including reliability, as part of the preparation of [testimony filed by NC WARN in Docket No. E-100, Sub 140].

NC WARN Response to Duke Energy's First Data Request No. 11, March 18, 2015.

Duke asserts that NC WARN's responses to its data requests create significant concern with the analysis presented by NC WARN that serves as the basis for NC WARN's comments.

With respect to NC WARN's contention that Duke's reserve margins are "consistently above average for the industry" and that Duke and "all of the utilities in the Southeast region have excess capacity," Duke notes that in the last two winters frigid temperatures pushed utility systems throughout the country to their limits. Duke states that its ability to serve its retail customers under these challenging conditions proves that NC WARN's position is wrong and misguided. According to Duke, if it had not been able to access its full portfolio of resources at the current planning reserve margins, the outcome easily could have been rolling blackouts or much higher electricity prices. In addition, NC WARN's assertion that Duke could simply rely on excess capacity throughout the region also was proven to be incorrect during this period, as Duke's neighboring utilities confronted the same frigid temperatures and peak demands, and had little or no capacity to share with other utilities.

In conclusion, Duke submits that NC WARN's alternative resource plan would not enable North Carolina to ensure that reliable and affordable electricity is available to all customers over the IRP planning horizon. Duke acknowledges that renewable resources, EE and DSM are important and increasingly significant components of its IRPs, but states that they cannot realistically be relied upon in the almost exclusive nature that NC WARN has proposed. In contrast, Duke maintains that its IRPs present robust and balanced portfolios of diverse supply and demand side resources that will cost-effectively and reliably serve customers' needs across a range of many possible future scenarios. Accordingly, Duke requests that NC WARN's comments be disregarded and its request for an evidentiary hearing be denied.

DNCP's Reply Comments

In its reply comments, DNCP notes that NC WARN's concerns are not focused on DNCP's 2014 IRP. In addition, DNCP opines that NC WARN has not presented any compelling issues or reasoning in support of its request for an evidentiary hearing. Finally, DNCP states that if a hearing is held it should be limited to issues regarding Duke's 2014 IRPs.

Discussion

General Statute 62-110.1(c), in pertinent part, requires the Commission to “develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina, including its estimate of the probable future growth of the use of electricity.” In State ex rel. Utils. Comm'n v. North Carolina Electric Membership Corporation, 105 N.C. App 136, 141, 412 S.E.2d 166, 170 (1992), the Court of Appeals discussed the nature and scope of the Commission's IRP proceedings. The Court affirmed the Commission's conclusion that

[t]he Duke and CP&L plans were “reasonable for the purposes of [the] proceeding” before it. That is to say, the plans submitted by Duke and CP&L were reasonable for the purpose of “analy[zing]...the long-range needs for expansion of facilities for the generation of electricity in North Carolina...” See N.C. Gen. Stat. § 62-110.1(c).

The Court further explained that the IRP proceeding is akin to a legislative hearing in which the Commission gathers facts and opinions that will assist the Commission and the utilities to make informed decisions on specific projects at a later time. On the other hand, it is not an appropriate proceeding for the Commission to use in issuing “directives which fundamentally alter a given utility's operations.” With regard to the Commission's authority to issue specific directives, the Court cited the availability of the Commission's certificate of public convenience and necessity (CPCN) proceedings and complaint proceedings. Id., at 144, 412 S.E.2d at 173.

In the context of considering whether the utilities' IRPs are reasonable for planning purposes, the Commission gives substantial weight to the underlying data, modeling and analyses presented by the utilities, the Public Staff and the intervenors. With respect to the credibility of Duke's load forecasts, as more fully discussed later in this Order, the Public Staff reviewed Duke's load forecasts and concluded that Duke employed accepted statistical and econometric forecasting practices. Therefore, the Public Staff supports the reasonableness of Duke's load forecasts for planning purposes. Comments of the Public Staff, at 12-18.

Likewise, the Public Staff reviewed Duke's reserve margins and found them to be reasonable for planning purposes. The Public Staff describes the Loss of Load Expectation (LOLE) probabilistic assessment employed by Duke in estimating its reserve margins. The Public Staff also discusses the tight reserve margins experienced by Duke during the unusually cold temperatures in 2014 and 2015, and notes that neighboring utilities were experiencing the same tight supplies. Comments of the Public Staff, at 37-41.

In contrast, it does not appear that NC WARN employed specific data or modeling techniques to support its load forecast of 0% growth and its criticisms of Duke's reserve margins. The Commission appreciates and is interested in the statistics and analyses of EIA, NERC ACEEE and other national organizations. On the other hand, the Commission's charge in this proceeding is to determine whether the utilities' IRPs are reasonable planning tools for North Carolina's electric needs. Regional and national forecasts simply do not carry the weight of the specific, data-based analyses employed by Duke and verified by the Public Staff.

Similarly, in the context of considering whether the utilities' IRPs are reasonable for planning purposes, the Commission gives substantial weight to the goal of adequate and reliable electric service. Planning for adequacy and reliability requires careful analysis that gives due consideration to a myriad of factors, not just cost. NC WARN's proposals rely heavily on renewable resources and energy efficiency programs. However, it does not appear that NC WARN has given due consideration to factors such as load profiles, the future of tax incentives for renewable resources, capacity factors of renewable resources, transmission availability and energy efficiency program participation rates. On the other hand, the Public Staff discusses its review of Duke's extensive resource modeling techniques, including Duke's use of the System Optimizer and Planning and Risks models, and finds Duke's analyses to be reasonable for planning purposes. Comments of the Public Staff, at 46-59. In addition, the Commission notes that in a CPCN proceeding for an electric generating plant G.S. 62-110.1(d) requires the Commission to consider the applicant's arrangements for purchased power, power pooling and other such interchanges. Further, in CPCN proceedings for coal or nuclear plants G.S. 62-110.1(e) requires the applicant to demonstrate that energy efficiency measures, DSM, renewable resources and CHP, or any combination thereof, would not be as reliable or cost-effective as the proposed generating plant. Therefore, NC WARN's proposals can be addressed directly and appropriately at the time that Duke applies for a CPCN to build additional generating facilities in North Carolina.

Pursuant to Commission Rule R8-60(j), an intervenor may file an IRP of its own with respect to any utility. If it chooses to propose an alternative IRP, the intervenor's IRP should conform to the information and analytic requirements of Rule R8-60(c) – (i). To the extent that NC WARN intended for its comments to be construed as an alternative IRP for Duke, the Commission finds and concludes that NC WARN's proposal was inadequate with respect to data, modeling and analysis.

On March 9, 2015, the Commission held a public hearing in Raleigh for the purpose of receiving testimony from Duke's and DNCP's ratepayers. Thirteen witnesses testified regarding their views and concerns on a wide range of topics, including renewable energy, energy efficiency, coal ash disposal, coal plant retirements and CHP. The Commission has fully considered the testimony of these public witnesses, along with numerous statements of position from ratepayers on these and other matters, in arriving at its conclusions in this Order. This information, plus the IRPs and the parties' comments and reply comments, provide the Commission with an extensive record in this docket. Having reviewed the record and considered the parties' arguments, the Commission concludes that the issues raised by ratepayers at the hearing and in their statements of position, as well as those raised by NC WARN in its comments and request for an evidentiary hearing, have been adequately addressed by Duke.

The Commission finds and concludes that the record in this proceeding includes sufficient detail to allow the Commission to decide all contested issues without the necessity of a further evidentiary hearing. As a result, the Commission is not persuaded that there is good cause to grant NC WARN's motion that the Commission hold an evidentiary hearing in this docket. Therefore, the motion should be and is denied.

FINDINGS OF FACT

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission makes the following findings of fact:

1. The IOUs' 15-year forecasts of native load requirements and other system capacity or firm energy obligations, supply-side and demand-side resources expected to satisfy those loads, and reserve margins are reasonable and should be approved.
2. The IOUs included a full discussion of their DSM programs and their use of these resources as required by Rule R8-60(i)(6).
3. The Cliffside Unit 6 Carbon Neutrality Plan filed by DEC is a reasonable path for DEC's compliance with the carbon emission reduction standards of its air quality permit.
4. DEP, DEC and DNCP have adequately addressed the Public Staff's specific recommendations regarding the 2014 IRPs.
5. The IOUs included a full discussion of REPS compliance and their plans should be approved.
6. DEP, DEC and DNCP have adequately addressed the issues raised by the intervenors.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-3

PEAK AND ENERGY FORECASTS

The Public Staff has reviewed the 15-year peak and energy forecasts (2015–29) of DEP, DEC, and DNCP. The compound annual growth rates (CAGR) for the forecasts are within the range of 1.0% 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 that uses computer modeling, 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 utilities' most recent weather-normalized peak loads to those forecasted in their 2013 IRPs. The Public Staff then analyzed the accuracy of the utilities' peak demand and energy sales predictions in their 2009 IRPs by comparing them 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 the forecasts of other adjoining utilities and the SERC Reliability Corporation.

In their 2013 IRPs, all three utilities predicted that their 2014 system peaks would occur in the summer. However, during January 2014, the IOUs reported several hourly peak loads that were greater than the summer peak loads that occurred later that year. Additionally, in February 2015, both DEC and DEP experienced all time system peaks.

DEP

DEP's 15-year forecast predicts that its summer peaks will grow at a CAGR of 1.3%, as compared to growth rates of 1.2% and 0.9% in its 2013 and 2012 IRPs, respectively. Without the reduction in peak demand resulting from the implementation of its energy efficiency (EE) programs, DEP would expect its summer peaks to grow at a rate of 1.6%. The average annual growth of its summer peak, which DEP considers its system peak, is forecasted to be 190 megawatts (MW) for the next 15 years according to the 2014 IRP, in comparison to a predicted growth of 171 MW in DEP's 2013 IRP. DEP predicts that in 15 years, the load reductions from its new EE programs will reduce its annual peak load by approximately 4%, which is similar to its projection in its 2013 IRP. DEP assumes that it can actively reduce 7% of its peak load by using its demand-side management (DSM) resources, which it considers a capacity resource.

The Public Staff observed that DEP's forecast of its winter peak loads reflects a slightly lower CAGR of 1.2% than that of its summer peaks, with winter peaks

approximately 600 MW less than the forecasted summer peaks on average. DEP's energy sales, including the impacts of its EE programs, are predicted to grow at a CAGR of 1.0%, as compared to 1.4% and 1.0% in its 2013 and 2012 IRPs, respectively. DEP predicts that over the next 15 years, the megawatt-hour (MWh) reductions from its EE programs will cause a reduction in annual energy sales of 1% in 2015, increasing to approximately 4% in 2029. This is similar to the projection in DEP's 2013 IRP.

The Public Staff's review of DEP's actual and weather adjusted peak load forecasting accuracy for one year shows that the forecasts in DEP's 2013 IRP overpredicted the 2014 summer peak load by 12% and underpredicted the 2014 winter peak forecast by 12%. However, the forecast errors are reduced to 5% and below when the two peaks are adjusted to remove the impacts of an unusually mild summer peak-day temperature and an abnormally cold peak-day winter temperature.

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. Accordingly, the Public Staff asserted that DEP's peak load and energy sales forecasts are reasonable for planning purposes.

DEC

Regarding DEC, the Public Staff responded that DEC's 15-year forecast predicts that its summer peaks will grow at a CAGR of 1.4%, identical to the 1.4% forecast in its 2013 IRP and similar to the 1.7% growth rate projected in its 2012 IRP. Without the reduction in peak demand resulting from the implementation of its EE programs, DEC would expect its summer peaks to grow at an average of 1.7% each year for the next 15 years. The average annual growth of its summer peak, which DEC considers its system peak, is forecasted to be 286 MW for the next 15 years, as opposed to the 283 MW and 321 MW forecast in its 2013 and 2012 IRPs, respectively. DEC predicts that in the next 15 years, the load reductions from its new EE programs will reduce its annual peak load by approximately 5%, similar to its projection in its 2013 IRP. The plan also assumes that the Company can reduce 5% of its load by 2029 by using its DSM resources, considered a capacity resource. DEC's forecast of its winter peak loads reflects a slightly higher CAGR of 1.5%; however, on average, the winter peaks are approximately 1,180 MW lower than the forecasted summer peaks.

The Public Staff stated that DEC's energy sales, including the effects of its EE programs, are expected to grow at a CAGR of 1.0%. This growth rate is less than the 1.5% and 1.7% predicted in its 2013 and 2012 IRPs, respectively. DEC predicts that its EE programs will reduce its energy sales by approximately 6% by 2029.

The Public Staff's review of DEC's actual and weather adjusted peak load forecasting accuracy for one year shows that the forecasts in its 2013 IRP overpredicted

its summer peak load by 9% and underpredicted its 2014 winter peak load by 8%. However, the forecast errors are reduced to 3% and below if the two peaks are adjusted to remove an unusually mild summer peak-day temperature and an abnormally cold winter peak-day temperature.

The Public Staff pointed out that, for several years, DEC's forecasts for both peak demand and energy sales have consistently been higher than the actual peak demands and sales. In contrast, DEP's and DNCP's forecasts generally have generated at least one annual peak prediction that was less than the actual peak. The five-year trend of overpredicting DEC's loads is still apparent even when the abnormally high winter peak load in 2014 is used instead of the summer peak load of 2014. Using this calculation, DEC's peak load was overpredicted by an annual average of 435 MW.

According to the Public Staff, the importance of load forecast accuracy cannot be overstated given that the resource expansion plan is designed to serve the forecasted load at the least cost. The adoption of a forecast with a lower growth rate of 1.0%, as opposed to DEC's forecasted 1.4%, would result in the elimination of the need for at least one or more of the planned large baseload units, while maintaining a reasonable reserve margin over the 15-year plan. A 1% growth rate is hypothetical; however, this lower growth rate, in comparison with DEC's estimate of 1.4%, is closer to DEC's recent peak demand growth rate.

Nonetheless, the Public Staff believes that the economic, weather-related, and demographic assumptions underlying DEC's peak and energy forecasts are reasonable and that DEC has employed accepted statistical and econometric forecasting practices. The Public Staff continues to be concerned with DEC's pattern of overforecasting more often than underforecasting its load. As noted in the Public Staff's comments on the 2013 IRPs, after the merger of DEP and DEC, DEP adopted DEC's forecasting methods, even though DEP's forecasting of its energy sales and peak demands before the merger had been more accurate than DEC's forecasting. Before the merger, DEP typically relied on a monthly-based econometric model with end-use data over a span of ten or more years of historical data for its energy sales forecasts. This model was used for over 30 years, and during these years, DEP used the load factor method to forecast its peak demands. 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, but is now planning to replace its current model with a monthly peak model. While DEC's 2014 forecasts are reasonable for planning purposes, the Public Staff recommends that DEC continue to review its forecasting models carefully, including planned changes to identify further improvements.

DNCP

The Public Staff observed that DNCP's 15-year forecast predicts that its adjusted summer peaks will grow at a CAGR of 1.0%, a decrease from the 1.2% and 1.5% growth rates projected in its 2013 and 2012 IRPs, respectively. Without the reduction in peak demand resulting from the implementation of its EE programs, DNCP would expect its summer peaks to grow at 1.4%. The average annual growth of its summer peak is forecasted to be 198 MW for the next 15 years, in comparison to the 239 MW forecast in the 2013 IRP. DNCP predicts that in the next 15 years, the load reductions from its EE programs will reduce its annual peak load by approximately 2%, an increase from the 1% forecast in its 2013 IRP. DNCP predicts that load reductions from the activation of its DSM programs will reduce its peak load by approximately 1% by 2029. While DNCP's forecast of its winter peak loads reflects a slightly higher CAGR of 1.1% relative to the 1.0% CAGR for its summer peaks, the winter peaks are approximately 3,382 MW less than the forecasted summer peaks on average.

The Public Staff indicated that DNCP's energy sales are predicted to grow at an average annual rate of 1.1%, a decrease from the 1.4% and 1.6% growth rates predicted in its 2013 and 2012 IRPs, respectively. DNCP predicts that the MWh savings from its EE programs will reduce its energy sales by approximately 3% by 2029.

The Public Staff's review of DNCP's actual peak load forecasting accuracy for one year shows that its 2013 IRP overpredicted the Company's summer peak load by 6% and underpredicted its 2014 winter peak load by 11%. As with DEC and DEP, the forecast errors are somewhat attributable to the mild summer peak-day temperatures and abnormally cold peak-day winter temperatures for 2014.

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; therefore, the Public Staff concludes that DNCP's peak load and energy sales forecasts are reasonable for planning purposes.

PUBLIC STAFF'S CONCLUSIONS ON PEAK LOAD FORECASTS

The five-year forecast errors based on the summer peak forecasts filed in the 2009 IRP have improved from those calculated based on the 2008 IRPs, especially for DEC. Nevertheless, the Public Staff remains concerned with DEC's tendency to overforecast its summer peaks. However, the Public Staff believes that DEC's move to a monthly model may correct this tendency.

A second concern involves the unexpectedly large increases in the demand for electricity at the 2014 system peaks for all three IOUs that occurred in January at abnormally low temperatures. Identifying and properly forecasting the shape of

customers' response to abnormally cold conditions can be challenging due to its non-linear nature that may not be fully captured in the current equations in the IOUs' peak forecast models. As such, the Public Staff recommends that the companies review their winter peak equations in order to better quantify the response of customers to abnormally low temperatures.

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.

2015- 29 Growth Rates

(After New EE and DSM)

	<u>Summer Peak</u>	<u>Winter Peak</u>	<u>Energy Sales</u>	<u>Annual MW Growth</u>
<u>DEP</u>	<u>1.3%</u>	<u>1.2%</u>	<u>1.0%</u>	<u>190</u>
<u>DEC</u>	<u>1.4%</u>	<u>1.5%</u>	<u>1.0%</u>	<u>286</u>
<u>DNCP</u>	<u>1.0%</u>	<u>1.1%</u>	<u>1.1%</u>	<u>198</u>

SYSTEM PEAKS AND USE OF DSM RESOURCES

DEP's 2014 annual system peak of 14,159 MW occurred on January 7, 2014, at the hour ending 8:00 a.m., at a system-wide temperature of 11 degrees. The 11 degrees is significantly colder than the 18 degrees assumed in the winter peak load forecast. DEP's 2013 and 2012 peaks were 12,166 MW in August 2013 and 12,770 MW in July 2012. The 2014 peak occurred after several days of abnormally cold temperatures. The Company projected its day-ahead operating reserves at 5.8%. In addition to the abnormal temperatures, several of the Company's generating units were down with forced outages, resulting in available operating reserves of only 0.19% at the time of its actual peak. Due to its low operating reserves, DEP activated all of its DSM resources and reduced its peak demand by 383 MW as follows: EnergyWise Home for 9 MW, Commercial, Industrial, and Government (CIG) Demand Response Automation for 6 MW, Distribution Service Demand Response (DSDR)⁴ for 157 MW, and Curtailable Rate programs for 211 MW.

⁴ The Commission has classified DSDR as an EE program, but DEP generally uses it as it would a DSM program.

DEC's system peaked at 19,151 MW on January 30, 2014, at the hour ending 8:00 a.m. at a system-wide temperature of 12 degrees. The 12 degrees is significantly colder than the 18 degrees assumed in the winter peak load forecast. Given the forecasted weather conditions and unit availability, DEC had anticipated that its day-ahead operating reserves would be approximately 18%. However, at the actual time of system peak, its operating reserves fell to 2.4%. At this time, the Company did not activate any of its DSM programs. However, during its second highest peak, which occurred on January 7, 2014, the Company did activate its DSM programs, reducing load by 478 MW. At hour ending 8:00 a.m. that day, DEC anticipated having 10% available operating reserve; however, its actual level of operating reserves fell to 0.24%, similar to DEP's 0.19% operating reserves. The Public Staff notes that the extended unusually cold temperatures resulted in higher than projected energy use and that coincident forced outages (also related to the extended abnormally cold temperatures) also contributed to the low reserves available for both DEC and DEP. During the morning hours on January 7, DEC activated its Interruptible Service for 124 MW, Standby Generation Service for 31 MW, PowerShare Mandatory for 310 MW, and Power Share Generators for 13 MW. On the next day, DEC activated the same four programs with similar load reductions. In regard to DSM activations during the Company's highest 15 peak loads, DEC used DSM on three occasions, with its third and final DSM activation on September 2, 2014, obtaining a 202 MW load reduction from its PowerShare Mandatory program. DEC's 2013 IRP projected 561 MW of available DSM capacity, while in actuality only 478 MW, or 85%, of the 2013 projection was available.

DEC has indicated to the Public Staff that its DSM resources are used in near emergency situations to maintain reliability and has pointed to its higher level of available operating reserves at the time of the peak and other near peak events that forestalled the need to use DSM. DEC also stressed two additional important considerations with regard to DSM activations. First, each DSM program has different timing considerations regarding advance notice to participating customers and customer response times that may affect the ability of the utility to call on a particular customer. Second, over-utilization of DSM programs could reduce the willingness of customers to participate in the programs, negatively impacting the long-term availability of those programs for reliability purposes.

The Public Staff recognizes these important considerations and agrees the utilities must take them into account in deciding when and to what extent to activate their DSM programs. Nonetheless, the Public Staff believes that DEC could take greater advantage of its DSM programs by activating them on a more frequent basis, both for reliability and for reduction in fuel costs.

DNCP's 2014 annual system peak of 16,840 MW occurred on January 30, 2014, at the hour ending 8:00 a.m., unlike its 2013 and 2012 system peak loads of 16,366 MW and 16,787 MW, respectively, both of which occurred in the

summer. At the time of the 2014 peak, DNCP called on its Distributed Generation Pilot⁵ (DG) for a load reduction of 10 MW, which is less than the 34 MW of DSM identified as being available in DNCP's 2013 IRP.

THE PUBLIC STAFF'S COMMENTS ON DSM ACTIVATIONS

One area of concern for the Public Staff in its review of the DSM activations at the time of the 15 highest hourly peaks for each utility is the actual DSM load reductions that are realized when system operations call on DSM as a resource. There is a substantial difference between the DSM load reduction actually realized on the 15 days when peak demand was highest for all three utilities and the amount of DSM load reduction forecasted.

As noted previously, despite complete activations of its DSM programs, DEP had only 76% of its projected DSM capacity actually available at the system peak on January 7, 2014. Likewise, DEP's use of Energy Wise in the summer resulted in 107 MW of capacity reduction out of the 230 MW forecasted to be available.

During DEC's two uses of its Power Manager Program during the summer, the program produced a load reduction of 61% of the reduction forecast in the IRP for planning purposes. For DEC's Power Share-Mandatory program and Schedule SG customers, the load reduction realized from both programs was approximately 85% of the reduction forecast in the IRP. However, Schedules IS achieved a load reduction of 95% of the total reduction DEC had indicated to be available.

DNCP's DSM capacity reductions were also below the amount forecast in its IRP, with the Residential Air Conditioning Cycling program achieving 74% of its forecasted amount of capacity reductions, and the Customer Distributed Generation program achieving 65% and 71% of its forecasted winter and summer season capacity reductions, respectively.

A second area of concern for the Public Staff involves differences in DSM resources available in the winter as opposed to the summer because winter season DSM has typically not been found to be cost effective. Each North Carolina utility has a summer air conditioning load control program, customer-owned standby generation, and load curtailment programs. Standby generation and load curtailment resources are available to each utility in the winter season. However, DEP is the only utility that has any dispatchable DSM for use during the winter season (the Heat Strips and Water Heater measures in the EnergyWise program). While DSDR has been classified by the Commission as an EE program, it was used by DEP several times in both the winter and summer seasons to reduce peak demand.

⁵ The Distributed Generation Pilot is approved only in Dominion's Virginia jurisdiction.

The Public Staff has two recommendations to address these concerns regarding DSM. First, the DSM resources identified in the IRP should represent the reasonably expected load reductions that are available at the time the resource is called upon as capacity. Through evaluation, measurement, and verification (EM&V) of these DSM programs, utilities should identify the enrolled DSM capacity and the reasonably expected level of load reduction that can be reliably called on during a DSM event, winter and summer. Second, the recent rise in winter peak demands suggests that the IOUs should pursue a renewed emphasis on designing new DSM programs to meet winter peak demands, as well as summer peak demands.

RESERVE MARGINS AND RESERVE MARGIN ADEQUACY

In its comments, the Public Staff noted that DEP and DEC use 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. The reserve margins that correlate with this LOLE are approximately 14.5% for DEP and DEC. Because generating capacity is added in block amounts, DEP and DEC target as an acceptable reserve margin a range of approximately 14.5% – 17.0%. Additional analysis was performed to verify the adequacy of these target reserve margins following the implementation of the Joint Dispatch Agreement (JDA) between DEP and DEC. Based on this subsequent review, DEC and DEP utilize a 14.5% target planning reserve margin.

DNCP utilizes the PJM capacity planning process for long- and short-term planning of capacity needs. PJM's 2013 Reserve Requirement Study recommends use of a reserve margin of 15.7% 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 its ability to meet its PJM reserve requirements. This coincidence factor reduces the Company's reserve margin requirement to 11.2%. DNCP also includes a 16.2% upper margin that is commensurate with the upper bound where the Reliability Pricing Model (RPM) market auction has historically cleared. The DNCP planning reserve margin remains at 11.2%.

According to the Public Staff, for the planning period 2015 to 2029, 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:

Electric Utility	Planned Reserve 2015-2029	Target Reserve Margin
DEP	15.2% to 21.1%	14.5%
DEC	15.0% to 21.2%	14.5%
DNCP	11.2% to 17.4%	11.2%

The Public Staff explained that DEP's IRP indicates that DEP will meet its projected reserve margin targets for the planning period and will exceed the minimum 14.5% by three percent or more in 2015-17 due to a decrease in the load forecast. The IRP also states that the reserves exceed the minimum target by three percentage points or more in 2022 and 2023 as a result of the addition of large combined-cycle (CC) facilities.

DEC's IRP indicates that its reserve margins will meet its projected reserve margin targets for the planning period and will exceed the minimum 14.5% by three percent due to a decrease in the load forecast in 2015, and in subsequent years (2020, 2021, 2024, and 2025-2028) coincident with large unit additions.

DNCP participates in the PJM market and, through the RPM auction, has obtained a commitment for additional capacity purchases above and beyond the existing identified firm purchases to ensure that its reserve margins meet the target of 11.2% reserves in 2014 and thereafter.

Based on its review of the annual plans, the Public Staff believes that the reserves listed are reasonable, and recommends that DEP, DEC and DNCP maintain their proposed reserve margins as filed.

The Public Staff does note that these projected reserve margins are based on the load growth estimates and the projected peaks forecast by the Companies. Actual winter peaks for 2014 and this year have exceeded the estimates by a significant amount due, in part, to abnormally cold weather. Forced outages coincident with the winter peaks resulted in very low available reserves at the time of DEP's system peak on January 7, DEC's peak on January 30, and the most recent peak of DEC and DEP, which occurred on February 20, 2015.⁶ This abnormal weather also stressed the available capacity for neighboring utilities. In particular, South Carolina Electric & Gas' shed 300 MW of its load during the polar vortex of 2014. Good system operation, firm and spot purchases, employment of DSM, appeals to the public to reduce load, and sharing of information, forecasts, and resources with neighboring

⁶ Forced outages did not occur at the time of DNCP's peak on January 30, 2014, but both before and after this peak.

utilities resulted in the utilities meeting their capacity needs to date. With two winters in a row in which the system operators have encountered some level of difficulty securing adequate winter capacity, the Public Staff recommends that DEC and DEP review their load forecasting methodology to ensure the assumptions and inputs remain current and that appropriate models quantifying customers' response to weather, especially abnormally cold winter weather, are employed.

As such, the purpose of the Public Staff's discussion is not to examine the precise reasons for the low operating margins of DEC and DEP on January 7, 2014, but rather to highlight for the Commission how far these operating margins fell. As noted in the previous section on load forecasts, the Public Staff recommends that DEC and DEP work to improve their forecasting accuracy, especially with regard to possible abnormally cold weather events. DEC and DEP have indicated in discussions with the Public Staff that rather than calculating an independent winter peak forecast, as they do for the summer peak, they derive the winter peak based on a ratio applied to the summer peak. The Public Staff believes that the use of a monthly peak model, as used by DNCP, may lead to better summer and winter peak forecasts. Secondly, the Public Staff recommends that DEC and DEP assess why their actual DSM capacity was significantly less than expected. Third, the Public Staff recommends that DEC and DEP continue to evaluate modifications to or maintenance of their systems to improve their operations during periods of extreme cold temperatures, so the expected capacity will be available and reserve margins maintained.

Based on its review of the annual plans, the Public Staff believes that the reserves listed are reasonable, and recommends that DEP, DEC and DNCP maintain their proposed reserve margins as filed.

DEC'S CARBON NEUTRALITY PLAN

DEC included as Appendix K to its 2014 IRP a Cliffside Unit 6 Carbon Neutrality Plan. This Plan incorporated actions required under the Greenhouse Gas Reduction Plan, as well as 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 K.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.

The Carbon Neutrality Plan submitted by DEC in its 2014 IRP is very similar to the one approved in the 2014 IRP Order, and incorporates the same implementation schedule, with updated values for the estimates of conservation, renewable energy, and nuclear uprates. The Public Staff considers this plan update

to represent a reasonable path for DEC's compliance with the carbon emission reduction standards of its air quality permit.

RELICENSING OF EXISTING NUCLEAR PLANTS

As discussed in the Public Staff's comments on the 2013 IRPs, one of the significant issues faced by the IOUs is the pending expiration of operating licenses for significant 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 may 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 recommended in its comments filed in response to the 2013 IRPs that in their 2014 IRPs, the IOUs consider the potential for relicensing of their existing nuclear units and reflect such potential relicensing in their IRPs. No scenarios were included in the 2014 IRPs that discussed this issue.

While it acknowledges the uncertainty of this potential, the Public Staff notes reports that DEC's Oconee and DNCP's Surry nuclear plants have been identified as leading candidates for license extension beyond 60 years.⁷ Extensions of the licenses for the existing units would dramatically change the utilities' energy needs and therefore the forecasted construction schedule of new generation. The Public Staff repeats its recommendations that the IOUs consider the potential for relicensing of their existing nuclear units and reflect such potential relicensing in their IRPs.

NON-UTILITY GENERATION (NUG)

Commission Rule R8-60(i)(2)(iii) requires each electric utility to provide in its biennial IRP report a list of all non-utility electric generating facilities in its service areas, including customer-owned and stand-by generating facilities. DEC, DEP, and DNCP each provided a list of NUGs in compliance with this requirement.

DEP reported 11 firm wholesale purchase contracts with a combined capacity of 1,749 MW. DEP also reported 856.1 MW of customer-owned generation in North Carolina and 156.4 MW of customer-owned generation in South Carolina. In addition, DEP receives approximately 95 MW from Southeastern Power Administration (SEPA) for wholesale customers located within DEP's control area.

DEC reported 20 firm wholesale purchase contracts with a combined capacity of 231 MW. DEC also reported 316.8 MW of customer-owned generation in North Carolina and 40.6 MW of customer-owned generation in South Carolina as of June 2014.

DNCP reported nine NUGs with a combined capacity of 1,747.4 MW, which it included in its IRP as firm capacity. DNCP also reported ten "behind the meter" (BTM)

⁷ <http://www.nytimes.com/2014/10/20/business/power-plants-seek-to-extend-life-of-nuclear-reactors.html?emc=eta1&r=0>

NUGs in North Carolina with a combined capacity of 30.8 MW, and 19 BTM NUGs in Virginia with a combined capacity of 217.3 MW. These BTM NUGs are considered non-firm and were not included in DNCP's IRP as firm capacity. DNCP also reported other customer-owned generators of 53.4 MW in North Carolina and 2,795.9 MW in Virginia, which also were not included in its IRP as firm capacity.

WHOLESALE CONTRACTS FOR PURCHASE AND SALE OF POWER

Each utility, with the exception of DNCP, provided a list of firm wholesale purchased power contracts; DNCP stated that its contracts with NUGs are considered firm capacity resources and are included in its IRP. In addition, each utility provided a discussion of recent and pending RFPs and a list of firm wholesale power contracts during the planning horizon in compliance with Rule R8-60(i)(4).

TRANSMISSION FACILITIES

Pursuant to the 2014 IRP Order, the electric utilities included a copy of their most recent FERC Form No. 715 (Annual Transmission Planning and Evaluation Report) 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.

DSM AND EE

The Public Staff's review of the DSM/EE forecasts and programs indicated that each IOU complied with the requirements of Commission Rule R8-60 and previous Commission orders regarding the forecasting of DSM and EE program savings, as well as the presentation of data related to those savings. Each IOU included information about its respective DSM and EE portfolios⁸ that is largely the same as reported in the 2013 IRPs. Each IOU's forecast of DSM and EE resources and the forecast of peak demand and energy savings from those programs was slightly different from the forecast in the last IRP, but none changed by more than 10%, so no explanation of the drivers behind those changes was required. Unlike last year, DEP and DEC presented their DSM/EE forecast data in the same manner, allowing a clearer understanding of each utility's DSM/EE projections. Finally, as recommended by the Public Staff in its comments on the 2013 IRPs, all three utilities separately delineated the existing EE savings that were incorporated in the load forecasts.

⁸ For purposes of these comments, the Public Staff includes time-of-use (TOU) rate schedules in its discussion of DSM and EE.

According to the Public Staff, the IOUs included a discussion of new initiatives to expand their DSM/EE portfolios. DNCP currently has three new programs before the Virginia State Corporation Commission, which it intends to file in North Carolina later this year. DEP discussed five programs being considered for implementation (three were approved for implementation in December 2014). DEC did not offer any specific programs being considered for future implementation.

The Public Staff also notes that DNCP completed a new market potential study in late 2014, but indicated to the Public Staff that the findings of the study were still being reviewed at this time before being released. Both DEP and DEC updated their studies in 2013.

With respect to TOU and other curtailable service rates, DEC and DEP are both conducting pilot TOU studies to determine the feasibility of new TOU and curtailable rate schedules. Those studies are ongoing and are expected to produce results in the next two years. The Public Staff continues to recommend that the IOUs implement all cost effective DSM and EE, and also TOU rate schedules. As discussed earlier in these comments, greater emphasis on meeting the wintertime peak demands may warrant reevaluation of DSM and TOU resources.

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 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. DEP and DEC utilize the System Optimizer and Planning and Risk models to determine the dispatch and production costs for their system; DNCP utilizes the Strategist model.

DEP' S AND DEC' S JOINT PLANNING SCENARIO

The Public Staff noted that DEP and DEC included in their IRPs a Joint Planning Scenario that examines the potential for them to share capacity,⁹ as compared to the JDA, which allows non-firm energy transactions. A shared capacity arrangement between DEC and DEP would require approvals from the FERC, as well as the North Carolina and South Carolina utility regulatory commissions. If allowed, the Joint Planning Scenario produces a total present value revenue requirement (PVRR) savings of approximately \$300 million over the 2029 planning horizon by delaying the need for two 866 MW combined-cycle units (CC) by one year and eliminating the need for 396 MW from two combustion turbine units (CT). As noted, this portfolio spans a fifty-year period and includes three new nuclear units shared by DEP and DEC, which would help to maintain current nuclear capacity and fleet generation diversity as the existing nuclear units are retired.

QUANTIFICATION OF THE VALUE OF FUEL DIVERSITY AND REDUCED RISK

The Public Staff observed that the evaluation of resource options in the IRP is an ongoing process. 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 and the potential for unknown costs of building new generation, particularly nuclear.

The Public Staff recommends that the utilities continue to develop methods of quantifying the benefits of fuel diversity. The Public Staff also 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

⁹ 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 2014 IRPs filed by DEP and DEC, and specifically the Joint Planning Scenario, appear to comply with this requirement.

resource additions. A calculated rate impact on a levelized per kilowatt-hour (kWh) basis would provide a clearer understanding of the ratepayer impacts of future portfolios. If it would make the rate impact study for each portfolio less complicated and burdensome to perform, the utilities could calculate only the impact of the annual revenue requirement on the Company's average overall rates for the last year of the 15-year plan.

NATURAL GAS ISSUES

Ordering Paragraph No. 15 of the 2014 IRP Order, required:

That, consistent with the Commission's May 7, 2013 Order in Docket No. M-100, Sub 135, the IOUs shall include with their 2014 IRP submittals verified testimony addressing natural gas issues, as detailed in the body of that Order.

In the Commission's May 7, 2013, Order Approving Rules, Requesting Comments, and Establishing Requirements for Electric Integrated Resource Plans to be Filed in 2014 in Docket No. M-100, Sub 135 (*Sub 135 Order*), the Commission detailed these natural gas issues:

- The potential risks inherent in their [the electric utilities'] increasing reliance on natural gas as a generation fuel and the long-term adequacy of North Carolina's gas infrastructure.
- The electric utilities' plans for procuring the additional gas supplies that would be required by the generation proposed in their IRPs.
- The electric utilities' plans to ensure long-term gas supply reliability and adequacy.
- The electric utilities' understanding of how much additional pipeline infrastructure will be needed, and when, due to the combined needs of gas distribution companies and existing and proposed gas-fueled electric generation.
- The advantages and disadvantages of a second major pipeline being built through North Carolina, and the electric utilities' understanding of the steps that would need to occur to effectuate such construction.

In its comments, the Public Staff concluded that DNCP, DEC, and DEP have made a reasonable assessment of their needs for natural gas infrastructure in order to meet their growing dependence on natural gas to provide electric generation. They also have demonstrated their understanding of how an interstate pipeline is planned, approved, and built, including the open season period to determine the

market for the pipeline and associated costs. Additionally, the IOUs are knowledgeable about the natural gas supply market, as well as the pipeline planning and build-out in order to move the natural gas supply to their electric generation facilities. It appears that the Atlantic Coast Pipeline (ACP) will be the second major natural gas pipeline into the State of North Carolina. The utilities have adequately set out the benefits of this additional pipeline. The Public Staff recommends that the electric utilities and the natural gas distribution companies continue to work together in planning for adequate pipeline capacity to meet electric generation needs. The Public Staff also recommends that the electric utilities consider natural gas electric generation facilities that also can operate on an alternate fuel.

The Commission finds and concludes that DEC, DEP and DNCP have complied with all Rule R8-60 requirements in their respective 2014 IRPs. Each has provided acceptable 15-year peak and energy forecasts of native load and other firm load requirements and obligations, as well as supply-side and demand-side resources expected to satisfy these loads. The reserve margins provided by the IOUs are reasonable for planning purposes and are approved.

Each IRP includes a full discussion of the utility's DSM programs and their use as required by Rule R8-60. DEC's Cliffside Unit 6 Carbon Neutrality Plan continues to show a reasonable path for DEC's compliance with the carbon emission reduction standards of its air quality permit.

The Public Staff, in its comments submitted on March 2, 2015, provided 11 specific recommendations regarding the utilities' IRPs. They are discussed in the following section of this Order. Several additional issues, raised by various other intervenors, along with responses by the utilities, appear later in this Order.

DISCUSSION AND CONCLUSION FOR FINDING OF FACT NO. 4

UTILITY RESPONSES TO SPECIFIC PUBLIC STAFF RECOMMENDATIONS REGARDING IRPS

- 1. In future IRPs, the utilities should include a discussion of the potential implications of the EPA Clean Power Plan, scenarios for possible compliance, and the costs of compliance.**

DEC/DEP

Because the Clean Power Plan (CPP) Rule has not been finalized, and the rule is likely to undergo significant changes and clarifications considering the extent of comments filed with the EPA regarding the rule, it is difficult for the Companies to model what the exact impacts of the rule will have on the DEC and DEP IRPs. Answers

to questions such as, "will the limits be rate or mass based?" and "which units will be included under the plan?" can have significant impacts on the IRP. For example, there is significant debate over the inclusion of carbon emissions from new natural gas combined cycle units. Given these uncertainties, the five scenarios presented in the DEC and DEP 2014 IRPs were evaluated with and without a carbon tax that coincided with the proposed onset of the CPP in 2020. A discussion of the impacts of the carbon tax on the initial resource needs, new nuclear selection, renewable generation, gas firing technology options, and energy efficiency was included in Appendix A of the IRP.

It must be noted that EPA's proposed CCP Rule is not a rule specific to a utility, but rather a state level rule requiring some form of CO₂ limits at the state level rather than the unit-specific or utility-specific level. Section III(d) outlines the process by which a State Implementation Plan (SIP) would be developed by each of the states. Ultimately, the SIP will dictate the rules and procedures the state will mandate for each of the effected organizations that emit CO₂. The Companies respectfully submit that it is simply premature to include a proposed CPP compliance plan along with associated costs at this point in time.

DNCP

The Public Staff recognizes DNCP's inclusion of Plan F: EPA GHG Plan for illustrative purposes in the 2014 Plan. Plan F was designed to illustrate a potential compliance scenario of how the Company could meet the proposed 2030 targets under the proposed Section 111(d) rule. The Public Staff commended DNCP for beginning to evaluate its CPP-compliance options, and recommends that the utilities' future IRPs "include discussion of the potential implications of the [Section 111(d)] Rule, scenarios for possible compliance, and costs of compliance."

The Company included the Plan F scenario in its 2014 Plan because it views planning for implementation of a final Section 111(d) rule as a prudent step given the proposed CPP rule's complexities and timelines for compliance. The Company agrees with Public Staff that its future IRPs should continue to plan for CPP compliance. During its 2015 Regular Session, the General Assembly of Virginia enacted Senate Bill 1349, which was signed into law by Governor McAuliffe on February 24, 2015. Senate Bill 1349 adjusts the Virginia resource planning process by 1) moving the 2015 IRP filing date to July 1 and requiring IRPs to be filed annually by May 1 beginning in 2016; 2) requiring future Virginia IRPs to address the effect of current and pending state and federal environmental regulations on existing generation facilities and new generation options; and 3) requiring future Virginia IRPs to evaluate the most cost-effective means of complying with state and federal environmental regulations, including options to minimize effects on customer rates. In recognition of the new resource planning obligations imposed by recently-enacted Senate Bill 1349, DNCP expects its future system-wide Plans to respond to the Public Staff's recommendation that future integrated resource planning address CPP compliance and the costs of compliance.

- 2. DEC should continue to review its forecasting models carefully, including planned changes to identify further improvements.**

DEC/DEP

The Public Staff concluded that both DEC and DEP's load forecasts and methodologies were reasonable for planning purposes. The Public Staff nonetheless commented that its review of DEC's five-year peak load forecasting accuracy based upon the DEC forecasts for 2010-2014 filed in DEC's 2009 IRP indicates a forecast error of 5%. The Public Staff recommended that DEC continue to review its forecasting models carefully, including planned changes to identify further improvements. As it has discussed in recent previous IRP reply comments, and in discussions with the Public Staff, DEC's forecasting error rate in the 2008-2009 timeframe mostly resulted from the severe economic downturn that occurred in 2009 and which no one reasonably foresaw. DEC suffered more than DEP and most utilities in the 2009 recession due to its large amount of industrial load, particularly from textiles. In contrast, the DEC peak forecast developed in 2010 projected a 2013 value that was only 131 MW different than the actual weather adjusted value for the year 2013. Thus, DEC acknowledges the anomaly in the load forecast caused by the severe economic downturn, but appreciates the Public Staff's conclusion that the load forecast included in the 2014 IRP is reasonable. The Companies note that their forecasting methodology is always evolving in an effort to further improve the process, as a result of post-merger best practices and otherwise.

- 3. The companies should review their winter peak equations in order to better quantify the response of customers to abnormally low temperatures.**

DEC/DEP

DEC stated that it certainly understands the importance of the long-term peak forecast's impact on future expansion plans. As such, DEC regularly reviews its peak forecasting methodology to ensure adherence to the latest industry standards. Given the increasing importance of efficiency trends on energy usage, DEC now incorporates Statistically Adjusted End Use Models (SAE) in its peak forecasting process. SAE models attempt to incorporate the effects of naturally occurring energy efficiency trends into the forecast as well as the expected impacts of government mandates. This approach also has the advantage of generating a forecast for each month rather than simply a seasonal forecast. In the Spring 2015 Forecast, the SAE methodology appeared to produce a slightly lower summer peak forecast, but a slightly higher winter peak forecast, which matches recent trends.

- 4. The companies should ensure that DSM resources identified in the IRP represent the reasonably expected load reductions available at the time the resource is called upon as capacity.**

DEC/DEP

The Companies include expected summer DSM resources and reasonable corresponding load reductions in the IRP for planning purposes. Furthermore, DEC and DEP calculate expected DSM load reductions on a daily basis, known as the Load Reduction Capability (LRC), and are based on a rolling twelve weeks' worth of historical load data. These daily LRC calculations are utilized by the Companies' system operators in planning and operating the DEC and DEP systems. DEC and DEP utilize DSM programs in conjunction with system planning, not only for economic reasons. Daily system dynamics, including but not limited to weather, customer operational adjustments and interests, day of the week, and time of day, impact the load curtailment actually achieved and therefore will always vary from the summer DSM capacity contained in the IRP for planning purposes. It is important to note that DEC and DEP have contracts in place with customers to curtail their load pursuant to Commission-approved DSM programs, but beyond the monetary penalties that are provided for in the contracts, the Companies cannot control an individual customer's behavior in response to a request to curtail load.

DNCP

Specific to DNCP, the Public Staff asserted that DNCP's realized DSM capacity reductions were below the amount forecast in its 2014 Plan, with the Residential Air Conditioning Cycling program achieving 74% of its forecasted amount of capacity reductions, and the Customer Distributed Generation program achieving 65% and 71% of its forecasted winter and summer season capacity reductions, respectively. The Public Staff recommends that DSM resources identified in the IRP should "represent the reasonably expected load reductions that are available at the time the resource is called upon as capacity" based upon enrolled DSM capacity and evaluation, measurement, and verification (EM&V) data. The Company is generally not opposed to this suggestion and incorporates actual performance and/or EM&V data into its planning process when appropriate and when the Company has sufficient program experience.

- 5. The Companies should put a renewed emphasis on designing new DSM programs to meet winter peak demands, as well as summer peak demands.**

DEC/DEP

The Companies continually review potential new DSM programs and seek input on such programs as part of the EE stakeholder collaborative groups in place for both DEC and DEP.

DNCP

The Public Staff's comments highlight the recent winter system peak demands experienced by DNCP and the other utilities, and recommends the Company employ a "renewed emphasis on designing new DSM programs to meet winter peak demands, as well as summer peak demands." DNCP agrees with the Public Staff that its most recent experience during 2014 and 2015 suggests that renewed planning focus on peak demands experienced during the winter months may be warranted. During the "polar vortex" periods of January and February 2014, the PJM DOM LSE zone experienced a 16,834 MW system peak demand on January 7, 2014. Most recently, on February 21, 2015, at 8:00 a.m., DNCP experienced its all-time system peak of 18,687 MW, which is up from the 16,834 MW prior system peak experienced in 2014. Recognizing this recent winter peaking experience (and that the recent surge of proposed solar photovoltaic generation is of extremely limited capacity value during winter morning peaks), DNCP will evaluate DSM program options that provide reliable capacity to meet peak demands during both the winter and summer periods in future IRPs. Specifically, the Company continues to evaluate options for cost effective DSM programs that provide benefits during peak periods. The Company also notes that its Virginia commercial distributed generation program provides DSM capacity during both summer and winter periods, but was not approved for deployment in North Carolina.

- 6. The IOUs should consider the potential for relicensing of their existing nuclear units and reflect such potential relicensing in their IRPs.**

DEC/DEP

The Companies plan to diligently review the business case for relicensing existing nuclear units, and if relicensing is in the best interest of their customers they will pursue second license renewal (SLR) for our plants. At this point, no license extension for the operation of nuclear plants beyond 60 years has been issued.

The NRC has indicated that it plans to use the same process for SLR as it used during the initial license renewal; however, this only addresses the process to review the renewal application and not any additional requirements that the NRC may impose to extend the license from 60 years to 80 years. As for timing, the NRC does not plan to issue its guidance for requirements to extend the license from 60 years to 80 years until the 2017 to 2018 timeframe. The Companies do not anticipate the first SLR applications to be submitted until later this decade, with decisions on SLR not expected until approximately 2022 or 2023.

There is a significant amount of uncertainty regarding the ability to get a license extension as well as the uncertainty of the costs to satisfy NRC requirements should they extend the license. In addition to the uncertainty regarding SLR, there is also

uncertainty regarding carbon regulations, environmental regulations, and fuel prices. DEC and DEP believe that the uncertainty combined with the new nuclear long development cycle (10 - 15 years to license and construct) makes it imperative that the Companies plan for these assets as if they will not be available, then adjust the plans as more information becomes available.

DNCP

As described in the 2014 Plan, the Company's customers today benefit substantially from the Company's prior investments in the four nuclear units, at North Anna and Surry, and the Company is mindful of the scheduled license expirations of these units between 2032 and 2040. The feasibility and cost of extending the lives and operating licenses of DNCP's existing nuclear units was similarly an issue of interest in the Company's recent Virginia IRP review proceeding. The State Corporation Commission of Virginia (VSCC) specifically directed DNCP to investigate the relicensing option for DNCP's existing nuclear units in its 2015 IRP filing, including comparing the cost of constructing North Anna 3 to the cost of renewing the licenses of the four existing nuclear units, as well as comparing the cost of retiring the four existing nuclear units to the cost of renewing the licenses for those units.

Accordingly, as the Company plans on a system-wide basis, the Company will provide an analysis of the potential for relicensing its existing nuclear units in its North Carolina IRP update to be filed by September 1, 2015.

7. Each utility should carefully review its projections of solar capacity.

DEC/DEP

In their 2014 IRPs, DEC and DEP assumed full NC REPS compliance, as well as compliance with a placeholder for a potential South Carolina renewable energy portfolio standard. The Companies include all currently signed solar, biomass and hydro contracts and any additional amounts required for full compliance in the later years. Solar providers are rushing to take advantage of the Federal and State tax incentives before their current expiration dates, and as such continue to submit their projects to the interconnection queue. DEC and DEP recently filed their Small Generator Interconnection Consolidated Annual Reports in Docket No. E-100, Sub 113B, which indicate that the projects currently in the interconnection queues for DEC and DEP total over 4,000 MW (nameplate) in both service territories. The vast majority of these projects are solar. Even though there is such a large amount of solar in the queue, the likelihood of these projects coming to fruition is unknown. Typically, only a fraction of these projects actually begin operation. As projects come online, the Companies will continue to sign contracts to ensure full compliance with NC REPS as well as those projects without associated RECs that will not be used for NC REPS compliance, but

are qualifying facilities (QFs) under PURPA. The Companies also include the non-compliance renewable projects in the IRP as part of the purchase contracts.

The Companies will continue to monitor the interconnection queue and sign contracts as the facilities actually begin operation.

DNCP

The Company is not opposed to reviewing its solar PV QF projections, similar to all other projections, in developing future Plans. However, as discussed at length in the Commission's recent avoided cost proceeding, Docket No. E-100, Sub 140, the Company's current experience does not support relying on the Company's interconnection queue to determine the solar QF resource capacity that may become commercially operational.

The Company's experience during the recent solar PV QF development surge has been that numerous projects in its interconnection queue are "speculative" and have a low probability of development and commercial operation as a resource that DNCP can rely upon to serve customers. Even where a QF has applied for interconnection, has filed for and obtained a CPCN, and executed a power purchase agreement (PPA), the Company still has little assurance of when or if the facility will be made operational. There are numerous aspects of a typical solar PV development project that will dictate whether it is ultimately constructed, including interconnection costs and constraints, qualification for and monetization of tax credits, securing financing, cost of equipment and construction, and, potentially, finding a buyer for the project. Because the Company has little to no visibility into these variables and little meaningful historical data to assess the percentage of solar QF capacity likely to be deployed, DNCP does not believe it prudent to rely upon the level of solar QF capacity pending in its interconnection queue as a reliable metric for future solar QF deployment in its service territory. In summary, so long as QF developers are not required to make any construction commitments when filing a CPCN or executing a PPA, the Company has very little ability to make meaningful estimates on the volume or timing of such QF development. Therefore, for planning purposes, the Company is limited to using its best estimate about the volume and timing of the QF projects that will ultimately be constructed. As in previous IRPs, the Company will continue to review CPCN filings and PPA status each year at the time of the IRP development and incorporate its best estimate of future QF development.

- 8. DEP, DEC, and DNCP should maintain their proposed reserve margins as filed.**

DEC/DEP

The Companies plan to review their reserve margins in 2015, in response to the recent winter peak loads experienced and the interconnection of increasing amounts of intermittent renewable resources to the DEC and DEP systems. Pending the results of that study, the Companies may seek to update their required minimum planning reserve margin target.

DNCP

DNCP agrees with the Public Staff's recommendation.

9. **For future IRPs that foresee substantial nuclear retirements, the planning period, and in particular, the period covered by the Load, Capacity, and Reserve Tables should be extended to 20 years.**

DEC/DEP

The Companies believe that the current 15-year planning horizon provides the most reasonable outlook for new generation requirements. Extending the required reported planning horizon to twenty years would add an additional level of uncertainty to the IRP reports, as the further out generation is evaluated, the inherently more uncertain the basis for those additions becomes. Additionally, 10 to 15 years matches the time required for licensing and constructing the longest lead time generation the Companies evaluate. Extending the planning period beyond 15 years would add an unnecessary administrative burden to the planning process, particularly in light of the fact that successive plans will certainly change over that additional timeframe. As such, DEC and DEP respectfully submit that having extensive stakeholder debate over planned resources projected for years 16 through 20 would only serve to complicate the annual IRP process while adding little tangible value to the process.

DNCP

DNCP believes that the Public Staff's specific recommendation "for future IRPs that foresee substantial nuclear retirements, the planning period, and in particular, the period covered by the Load, Capacity, and Reserve Tables should be extended to 20 years" is unnecessary. In the 2013 IRP proceeding, the Company opposed extending its planning period beyond the 15-year period required by Commission Rule R8-60(c) and (h), as well as Va. Code 56-592 *et seq.* and the VSCC's Integrated Resource Planning Guidelines. The 2013 IRP Order stated that the Commission is "satisfied with [the Utilities'] current 15-year planning periods," but that the Utilities "should always supply additional forward looking comments in their IRPs when warranted to provide adequate background concerning critical infrastructure decision-making." Accordingly, DNCP requests the Commission find that its proposal to provide

an analysis of the potential for relicensing its existing nuclear units in its 2015 IRP update is adequate and that there is no need to extend the 15-year planning period at this time.

10. The utilities should continue to develop methods of quantifying the benefits of fuel diversity.

DEC/DEP

As discussed in the Companies' 2013 IRP Update Reply Comments, the Companies believe that this recommendation is already captured as part of the existing IRP process commensurate with Commission Rule R8-60. The Companies' current IRP practices include modeling multiple sensitivities around fuel prices. Furthermore, the Companies show how different resource portfolios perform under these varying fuel prices. Both the quantitative impacts and the qualitative benefits of fuel diversity are fully presented in the IRPs. The Public Staff does not provide a specific recommendation as to what other quantitative metric or method they are recommending and as such it is difficult to ascertain the merits of such additional analysis. The Companies believe that the current approach both quantitatively and qualitatively addresses fuel diversity and is fully adequate.

DNCP

At the outset, the Company would note that its 2014 Plan does not select its Fuel Diversity Plan over the least-cost Base Plan. Instead, the Company recommends a path forward based upon the least-cost Base Plan, while concurrently continuing forward with reasonable development efforts of the additional resources identified in the Fuel Diversity Plan. As with any strategic plan, the Company will update its future Plans to incorporate new information as it becomes known.

In response to the Public Staff's Recommendation in the 2013 IRP proceeding, E-100, Sub 137, to establish metrics to quantify the benefits of fuel diversity, the Company's 2014 Plan provides the Section 6.6 "Portfolio Evaluation Scorecard" framework. The Scorecard is designed to evaluate the Base Plan relative to other alternative Plan scenarios based upon the following criteria: Strategist NPV cost results to reflect the least cost option; Rate Stability; fuel and construction cost risk, GHG Emissions, and Fuel Supply Concentration. Figure 6.6.1.1 in the 2014 Plan presents the analysis and criteria scoring under the Scorecard framework, while Figure 6.6.1.2 shows the Scorecard rankings for each planning scenario. The Fuel Diversity and EPA GHG Plans received the most favorable scores on the Scorecard. The results of the 2014 Plan's Scorecard framework supports the Company's planning recommendation to continue following the least-cost Base Plan, while also continuing reasonable development of the Company's Fuel Diversity Plan.

Further, the VSCC's 2013 Virginia IRP Order also requires the Company to "include an analysis of the trade-off between operating cost risk and project development cost risk associated with the Base Plan and the Fuel Diversity Plan" starting in the 2015 Virginia IRP filing. The Company plans to include a probabilistic analysis in the 2015 IRP which will provide a comparative assessment of operating cost risk and project development cost risk for both the Base Plan and the Fuel Diversity Plan. This analysis will further address the value of fuel diversity.

11. 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.

DEC/DEP

The Companies do not believe that providing an estimate of annual rate impacts of proposed resource plans in future IRPs is warranted. First, the Public Staff's recommendation is not part of the statutory requirement of the IRP filing to assist the Commission in fulfilling its responsibility pursuant to G.S. 62-110.1(c) to "develop, publicize, and keep current an analysis of the long-range needs" for electricity in the State. The Commission has repeatedly held that its approval of an IRP does not constitute approval of any of the individual generation resources contained therein, but that such individual generation resources are considered separately as part of the Certificate of Public Convenience and Necessity (CPCN) process established by G.S. 62-110.1 and Commission Rule R8-61. The Companies respectfully submit that consideration of rate impacts would be beneficial only after a utility has actually decided to construct a given generation plant. It is in a specific CPCN docket, or in a subsequent cost recovery proceeding, therefore, and not in an IRP docket, where rate impacts are appropriately considered. Indeed, Commission Rule R8-61(b)(3)(viii), which became effective January 1, 2015, now requires the filing of "the anticipated impact the facility will have on customer rates" as part of a utility's CPCN application.

Second, each IRP filing represents a "snapshot in time" view of the Companies' preferred resource plans over the 15-year planning horizon. The myriad inputs to the IRP planning process, including but not limited to cost assumptions, load forecasts, expected plant retirements, wholesale contracts, and evolving regulatory requirements necessarily change annually (if not multiple times within a year), as do the selected resource plans and the timing, size and nature of individual supply and demand side resources included within the resource plans. As a result, even if developed for the IRP filing, such annual rate impacts would be of limited value. Third, calculating such annual rate impacts would be an extremely burdensome and time-consuming effort for the Companies. The Companies' IRP planning process is already a year-round endeavor, and adding the annual rate impact estimation as part of the IRP would only add complexity and burden to the process, for limited, if any, benefit.

DNCP

While an estimate of annual rate impacts of resource additions on a levelized per kWh basis may provide some understanding of ratepayer impacts, the Company believes this value would be limited in comparison to the way bill impacts are provided in base rate, fuel, DSM and other ratemaking proceedings. In addition, the Company is concerned that such an additional requirement may be a source of confusion for customers since the Company is not asking for actual cost recovery in the IRP proceeding. Finally, DNCP notes that the Commission did not agree to this recommendation in the 2013 IRP Order.

In sum, while the Company disagrees with the Public Staff's specific recommendations to present PVRP and annual rate impacts of each planning scenario in analyzing its future Plans, the Company through its Portfolio Evaluation Scorecard framework provides a reasonable approach to quantifying the benefits of fuel diversity in its 2014 Plan and will continue to present the results of this analysis in future Plans.

The Commission has reviewed the responses that were provided by DEC, DEP and DNCP to the eleven specific issues raised by the Public Staff. Those responses appear appropriate and adequate to the issues raised. Based on those answers provided in the IOUs' reply comments, the Commission does not find it necessary to require DEC, DEP and DNCP to make any additional changes to their future IRP filings at the present time, other than those discussed in their individual reply comments.

DISCUSSION AND CONCLUSION FOR FINDING OF FACT NO. 5

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 renewable energy certificate (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 (or through DSM measures, in the case of electric membership corporations (EMCs) and municipalities). The electric public utilities (DEP, DEC, and DNCP) may 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 purchase electric energy from a hydroelectric power facility and use allocations from SEPA to meet up to 30% of the overall 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 the year 2014 is equal to 3% of its North Carolina retail sales for the preceding year. For 2015 and 2016, this amount is 6%.

Commission Rule R8-67(b) provides the requirements for REPS compliance plans (Plans). Electric public utilities must file their Plans on or before September 1 of each year, as part of their IRPs, 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 2014, 2015, and 2016 (the planning period). An electric power supplier may have its REPS 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, which includes plans for their wholesale customers in North Carolina for which they have contracted to provide REPS compliance services.

All three IOUs filed their 2014 Plans as part of their IRP. Immediately below are the Public Staff's comments on DEP, DEC, and DNCP's plans to comply with G.S. 62-133.8(b), (c), and (d), the general and solar energy requirements, followed by consolidated comments on plans to comply with G.S. 62-133.8(e) and (f), the swine waste and poultry waste resource requirements.

DEP

According to the Public Staff, DEP has contracted for and banked sufficient resources to meet the REPS requirements of G.S. 62-133.8(b), (c), and (d) for itself and the electric power suppliers for which it is providing REPS compliance services. 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, Lucama, and Winterville (collectively, DEP's Wholesale Customers).

DEP 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 the City of Waynesville, the only DEP Wholesale Customer that receives energy from SEPA. Hydroelectric QFs with a capacity of 10 MW or less will also provide RECs for DEP's 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 also plans to use the increased availability of solar energy to help it meet the general requirement.

To meet the solar requirement, DEP will obtain RECs from its residential solar PV program and from other solar PV and solar thermal facilities.

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 EM&V plan for each EE program as part of its request for Commission approval of the program.

DEC

The Public Staff noted that 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 of 10 MW or less, together with the increased capacity of DEC's Bridgewater hydroelectric facility following its modification in 2012, will provide RECs toward DEC's REPS obligation. 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 expects to use solar resources to satisfy some of its REPS requirement.

To meet the solar requirement, DEC will obtain RECs from its self-owned distributed solar PV facilities and from other solar PV and solar thermal facilities.

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 2014 application for cost recovery of DSM and EE programs in Docket No. E-7, Sub 1050.

DNCP

The Public Staff stated that DNCP has contracted for and banked sufficient RECs to meet the REPS requirements of G.S. 62-133.8(b), (c), and (d) for the planning period for itself and the Town of Windsor (Windsor), for which it is providing REPS compliance services. DNCP plans to use EE, purchased out-of-state wind RECs, and new self-generated renewable energy to meet the general REPS requirements of G.S. 62-133.8(b) and (c) for itself. For Windsor's general REPS requirement, DNCP plans to use out-of-state wind RECs, in-state biomass and solar RECs, and Windsor's SEPA allocation. For the solar requirements, DNCP plans to purchase in-state and out-of-state solar RECs 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 anticipates that it will incur relatively high research and development costs in 2014 and 2015 for its Microgrid Project, but these costs should be minimal in 2016. The Microgrid Project consists of wind and solar energy generation and storage at DNCP's Kitty Hawk District Office with fuel cells possibly added in 2015. The high costs in 2014 and 2015 are due to construction costs. 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 EM&V plan in its 2014 application for cost recovery of DSM and EE programs in Docket No. E-22, Sub 513.

REPS COMPLIANCE COMPARISON TABLES

The Public Staff prepared the tables in this section 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 2014 column are projected sales for calendar year 2013. 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 1: MWh Sales for preceding year

Electric Power Supplier	Compliance Year		
	2014	2015	2016
DEP	36,091,870	38,431,441	38,894,821
DEC	58,813,405	60,013,663	60,658,787
DNCP	4,358,551	4,186,914	4,256,454
TOTAL	99,263,826	102,632,018	103,809,062

Table 2 presents a comparison of the projected annual incremental REPS compliance costs with the utilities' annual cost caps, which increase significantly in 2015 due to the residential cost cap increasing from \$12 per year to \$34 per year.

TABLE 2: Comparison of Incremental Costs to the Cost Cap

		DEP	DEC	DNCP
2014	Incremental Costs	23,630,618	17,768,556	1,103,132
	Cost Cap	43,915,738	63,070,639	4,017,364
	Percent of Cap	54%	28%	27%
2015	Incremental Costs	22,106,981	20,805,290	1,432,489
	Cost Cap	71,350,928	103,084,760	6,246,082
	Percent of Cap	31%	20%	23%
2016	Incremental Costs	28,043,011	24,822,911	1,484,093
	Cost Cap	72,044,678	104,218,833	6,239,114
	Percent of Cap	39%	24%	24%

SWINE WASTE AND POULTRY WASTE REQUIREMENTS
IN G.S. 62-133.8(E) AND (F)

In its comments, the Public Staff stated that some electric power suppliers indicated in their Plans filed in 2011 that they were having difficulty in obtaining RECs to comply with the swine and poultry waste requirements in G.S. 62-133.8(e) and (f), which required them, beginning in 2012, to meet a portion of their REPS obligations with energy derived from swine waste and poultry waste.

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 by filing a joint motion seeking to delay the swine and poultry waste requirements 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 requirements because the technology for animal 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 this proceeding, the Commission issued a Notice of Decision and Order on December 20, 2013, that 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 requirements. The Commission issued a final Order on March 26, 2014.

On August 28, 2014, many of the electric power suppliers filed a joint request to delay the swine waste requirement for one more year, and the Commission granted the request in an Order dated November 13, 2014. The electric power suppliers did not request to delay the poultry waste requirement, and the Public Staff believes that 2014 will be the first year that the electric power suppliers will be able to comply with this requirement as modified by the Commission. One reason that the electric power suppliers did not request a delay in the poultry waste

requirement is the relatively low requirement of 170,000 MWh or equivalent energy in 2014 and the utilities' ability to bank RECs from earlier years. In addition, the availability of poultry waste RECs in the marketplace has been increased due to advances in the technology of power generation from poultry waste, and by the use of thermal energy to meet the requirement as authorized by N.C. Session Law 2011-309, and by the availability of poultry waste RECs from "cleanfields renewable energy demonstration parks," as authorized by N.C. Session Law 2010-195.

On June 23 and December 3, 2014, the Public Staff held stakeholder meetings as requested by the Commission. The attendees included farmers, the North Carolina Pork Council, the North Carolina Poultry Federation, waste-to-energy developers, state environmental regulators, and the electric power suppliers. The Public Staff believes that the meetings were made productive by allowing the stakeholders to network and voice their concerns to the other parties. The Public Staff intends to hold two more meetings in 2015 as requested and believes that they will be useful. However, the Public Staff believes the electric power suppliers will likely continue to have difficulty meeting the swine and poultry waste requirements for at least the next two years. The poultry waste requirement will more than quadruple from 170,000 to 700,000 MWh in 2015 and rise to 900,000 MWh in 2016. No electric power supplier requested a delay in the poultry waste set-aside for 2014, but both DEP and DEC have stated that they are "uncertain" that they can meet the poultry waste requirement in 2015 and beyond. The Public Staff agrees that the capacity of poultry waste-to-energy facilities may not be sufficient to generate enough RECs for 2015, and possibly not 2016. DNCP is in a better position because it can obtain all of its RECs from out of state.

The swine waste-to-energy industry has a few facilities operating in North Carolina, but its generation is very small relative to the need for approximately 70,000 MWh of in-state swine waste energy per year to meet the Commission's Order of November 13, 2014. Swine waste-to-energy facilities cannot earn RECs from thermal energy as poultry facilities can; however, they would probably be limited in thermal capacity even if thermal energy were allowed to earn RECs for several reasons, including differences in the energy content of each fuel on a volumetric basis and technological differences between the waste-to-energy facilities utilizing each fuel type.

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 waste requirements; (2) the utilities' reluctance to commit to expensive purchase contracts for speculative technologies; (3) limited availability of financing; and (4) uncertainty over REC prices.

PUBLIC STAFF'S 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 during the planning period, with the exception of the swine and poultry waste requirements, without nearing or exceeding their cost caps.

2. DEP, DEC, and DNCP will have difficulty meeting the Commission's revised swine waste requirements in 2015 and 2016, and DEP and DEC will have difficulty meeting the poultry waste requirements. However, 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 2014.

The preceding pages provide the Public Staff's utility-by-utility review of the REPS compliance plans submitted by the IOUs. Based on the Public Staff's review, it provided its conclusions on these plans as shown above and recommends that the Commission approve the REPS compliance plans filed by DEP, DEC and DNCP in 2014. The Commission concurs with this recommendation and therefore approves the REPS compliance plans submitted by the utilities with their 2014 IRPs.

DISCUSSION AND CONCLUSION FOR FINDING OF FACT NO. 6

ADDITIONAL ISSUES RAISED IN INTERVENOR COMMENTS

NCSEA

Energy Storage

In its initial comments, NCSEA requested that the Commission amend Rule R8-60(e) to include utility-scale energy storage as an alternative supply-side energy resource. NCSEA further requested that the Commission amend Rule R8-60(i)(10) to focus on smaller-scale energy storage. NCSEA proposed the following amendment to Rule R8-60(e):

Alternative Supply-Side Energy Resources. — As part of its integrated resource planning process, each utility shall assess on an on-going basis the potential benefits of reasonably available alternative supply-side energy resource options. Alternative supply-side energy resources include, but are not limited to, hydro, wind, geothermal, solar thermal, solar

photovoltaic, municipal solid waste, fuel cells, and biomass.
biomass, and utility-scale energy storage.

NCSEA likewise proposed the following amendment to Rule R8-60(i)(10):

Smart Grid Impacts. -Each utility shall provide information regarding the impacts of its smart grid deployment plan on the overall IRP.

For purposes of this requirement, the term "smart" in smart grid shall be understood to mean, but is not limited to, a system having the ability to receive, process, and send information and/or data -essentially establishing a two-way communication protocol.

For purposes of this requirement, 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, small-scale 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.

The information provided shall include:

(a) A description of the technology installed and for which installation is scheduled to begin in the next five years and the resulting and projected net impacts from installation of that technology, including, if applicable, the potential demand (MW) and energy (MWh) savings resulting from the described technology.

(b) A comparison to "gross" MW and MWh without installation of the described smart grid technology.

(c) A description of MW and MWh impacts on a system, North Carolina retail jurisdictional and North Carolina retail customer class basis, including proposed plans for measurement and verification of customer impacts or actual measurement and verification of customer impacts.

NCSEA requested that the Commission direct the utilities to use the best available model to consider energy storage during the IRP process. Because of the current lack of models that best integrate energy storage, at this time the directive would mean that the utilities use their current best practices and existing models.

When more appropriate models become available, they should be used by the utilities for future IRPs.

In their joint reply comments, DEC and DEP responded that NCSEA does not appear to have any criticism of the DEC and DEP IRPs, but instead asks the Commission to amend Rule RS-60(e) to include utility-scale energy storage as an alternative supply-side energy resource and amend Rule R8-60(i)(10) to list small-scale energy storage as a smart grid technology.¹⁰ While the benefits of advanced energy storage are obvious, the costs and practical applications of energy storage on a macro-level are less known. As the costs of this technology decline and impacts of energy storage on the grid come into clearer focus in the coming years, it may be a beneficial addition to the Companies' IRPs, but until then, it would not be prudent to include these systems. The Companies continue to monitor advanced energy storage technologies and evaluate potential uses in the Carolinas. However, at this time these technologies are neither economical, nor viable on a macro level for use in the IRP. The Companies will include Li-ion battery storage technology in the economic supply-side screening process as part of the 2015 IRP.

In its reply comments, DNCP explained that it does, in fact, evaluate energy storage in its 2014 Plan (as recognized by NCSEA's comments), finding that while "batteries have gained considerable attention due to their ability to integrate intermittent generation sources, such as wind and solar on the grid the primary challenge facing battery systems is the cost."¹¹ The Company plans to continue to evaluating energy storage options in future IRPs. However, DNCP does not view NCSEA's anecdotal support for the expected maturation of energy storage to a least-cost resource as trumping reality. Further, as NCSEA concedes, models do not currently exist today to fully evaluate the costs and benefits of energy storage. Therefore, DNCP questions the utility of recommending that the utilities be required to "take their best shot" at modeling energy storage. Instead, energy storage should continue to be evaluated under R8-60(i)(10), as a smart grid resource that can be integrated – if cost effective – to "improve the operational integration of distributed and/or intermittent generation sources." Finally, DNCP objects to NCSEA's procedural approach, which it characterizes as "lobbing its proposed revision to Rule R8-60(e) into this IRP review proceeding." DNCP states that NCSEA's request blurs the purpose of this proceeding, as established by the Commission's September 29, 2014, Order Establishing Dates for Comments on Integrated Resource Plans, REPS Compliance Plans and REPS Compliance Reports. According to DCNP, in past proceedings, both the Company and NCSEA have taken the procedurally-more-appropriate tact of foreshadowing a future request to modify a rule in a separate proceeding or requesting the Commission to initiate a rulemaking and

¹⁰ NCSEA spends approximately half of its Initial Comments field March 2, 2015, summarizing the DEC and DEP IRPs. The Companies note that NCSEA's Figures 2 and 3 at pp. 15-16 of its Comments omit the Companies' generation facilities located in South Carolina, which also serve the Companies' North Carolina customers.

¹¹ 2014 Plan, at 62-63.

NCSEA should have taken that tact here also. In sum, while DNCP submits there is little merit to NCSEA's recommendation to modify Rule R8-60(e), it argues the more appropriate place to consider such a request (if the Commission is inclined to do so) would be a separate rulemaking proceeding.

The Commission agrees with DEC, DEP and DNCP that these technologies are not economical or viable at this time for mandatory inclusion in the utilities' IRPs. Further, as models do not currently exist for a proper evaluation of energy storage, the Commission does not see a benefit in simply asking the IOUs to take their best shot at a modeling approach at this time.

MAREC

Wind Energy

According to MAREC in its comments, wind energy costs have fallen by 58% over the past five years, and wind energy represents an increasingly competitive form of energy. However, DEC's and DEP's IRPs project very little use of wind energy throughout the planning period.

MAREC recommends that the Commission direct DEP and DEC to revise their IRPs to include additional consideration of cost-effective wind resources in order to provide additional resource diversity both for meeting REPS requirements and in preparation for EPA's Clean Power Plan compliance. MAREC pointed out that, in its order approving DEC's and DEP's 2012 IRPs, the Commission held that the two companies "should continue to assess alternative-supply side resources such as wind energy on an ongoing basis." The Commission further ordered that the utilities "should consider additional resource scenarios that include larger amounts of renewable energy resources and to the extent those scenarios are not selected, discuss why the scenario was not selected."

MAREC concluded its comments with the following recommendations:

- The Commission should direct DEC and DEP to continue to evaluate the market price of all renewable energy resources for REPS compliance, including seeking additional renewable energy diversity when prices of various resources are comparable.
- Given the downward trend in wind energy costs, the Commission should direct DEC and DEP to continually seek feedback from the market on current wind energy prices and evaluate wind energy competitiveness not just for REPS compliance, but for competition with conventional generation resources.
- The Commission should direct DEC and DEP to include wind energy pricing in future cost sensitivity analyses.

- In light of DEC's and DEP's expectation for carbon dioxide legislation and the pending finalization of the Clean Power Plan, the Commission should direct that DEC's and DEP's generation screening alternatives continually evaluate whether renewable energy, energy efficiency and renewable energy/gas hybrid scenarios are a cost effective means to meet CPP goals.

In their joint reply comments, DEC and DEP responded that DEC's 2014 IRP base case includes 860 MW of renewable resources by 2019 and 2,155 MW by 2029, which includes 150 MW of wind. DEP's 2014 IRP base case includes 907 MW of renewable resources by 2019 and 1,187 MW by 2029, which includes 100 MW of wind. DEC and DEP explained that MAREC does not appear to appreciate, however, that both Companies' 2014 IRPs also included a High EE and High Renewables portfolio, which evaluated an assumed requirement to serve approximately 10% of each Company's combined retail load with new renewable resources by 2029—which represents over twice the amount of renewable energy as compared to the base case. The DEC High EE/Renewables portfolio included 427 MW of nameplate wind and the DEP High EE/Renewables included 289 MW of nameplate wind. The purpose of the scenario is to show how the Companies' resource plans would be affected in the event that additional cost-effective renewable and energy efficiency resources are identified or mandated. A key takeaway is that, in such an event, some traditional resources can be eliminated or deferred but significant levels of traditional resources such as new nuclear and natural-gas combined cycle are still needed.

According to DEC and DEP, the main locations for wind energy generation in the Carolinas are the North Carolina mountains and on-shore coastal regions. With ridge laws prohibiting wind turbine construction in the North Carolina mountains and siting issues along the coast, there are real physical limitations to the amount of wind power that could be built in the Carolinas currently. DEC and DEP, collectively, only have one wind project in the interconnection queue: a very small project of only approximately 2.5 kW. While the National Renewable Energy Laboratory study cited by MAREC may have determined a large potential for North Carolina wind projects, the prohibitive laws and siting issues continue to hinder wind facility construction in the North Carolina mountains or coast.

DEC and DEP believe that they have adequately considered wind and all other potential renewable energy resources in preparing their 2014 IRPs. They state that Duke Energy Corporation, the parent company of DEC and DEP, is one of the largest wind energy developers in the United States and recognizes the valuable potential that new wind energy resource development can provide. In their IRPs, however, DEC and DEP analyzed wind and other generation technologies and selected the resource plans that best met the Companies' needs to provide the reliable, least-cost resource mix as required by North Carolina's integrated resource planning and REPS laws. DEC and DEP noted that, it is for these reasons, that they Companies maintain a reasonable total of 250 MW of wind resources in their plans.

The Commission finds that DEC and DEP have adequately responded to the issues raised by MAREC related to wind energy. No further action is necessary at this time.

SACE and Sierra Club

Renewables, Energy Efficiency and Environmental Compliance Costs

The initial comments of SACE and the Sierra Club stated that the 2014 IRPs of DEC and DEP contain limited improvements upon the Companies' previous IRPs, but unfortunately, retain most of the flaws of earlier IRPs. In addition, new assumptions and methods compound the flaws carried over from previous plans, resulting in resource plans that are more costly, more risky, and more polluting than necessary. Key flaws in the 2014 IRPs include the following:

- The Companies are planning to build too much capacity, while underinvesting in resources that would reduce system costs for all customers.
- The Companies do not appear to have evaluated the full range of costs to achieve and maintain compliance with environmental regulations at their coal-fired power plants. For some units, accelerated retirement may be the most economic option.
 - As in prior IRPs, the Companies are not planning to capture all cost-effective energy efficiency, the cheapest, cleanest resource. This means system costs for ratepayers will be significantly higher than they need to be.
 - The Companies do not plan to maximize cost-effective renewable energy opportunities that reduce risks to customers from rising fuel costs and anticipated regulatory requirements.

SACE and the Sierra Club asserted that, as discussed in comments on previous IRPs, the Companies use inconsistent criteria to evaluate the risks associated with each resource, using criteria that provide support for favored resources while applying different criteria or analytic methods to undervalue energy efficiency and renewable energy. The concerns raised in prior comments with respect to the Companies' inconsistent consideration of risk are only magnified in the 2014 IRPs. The ever-changing criteria for evaluation seem to track the changing economics of DEC's proposed Lee nuclear plant.

SACE and the Sierra Club maintained that the DEC and DEP 2014 IRPs resulted in the selection of preferred resource portfolios that, if implemented by the Companies, would be unnecessarily costly, risky, and polluting. To correct these flaws and minimize costs and risks to ratepayers and the environment, they recommended that the Commission issue an order directing the Companies to implement the following

improvements, which are set forth in greater detail in the various sections of SACE and the Sierra Club's initial comments.

- Evaluate the costs to ratepayers of various resources over both the short- and long term, to accurately assess their risks and benefits;
- Clearly disclose the results of any analyses of changes to coal unit operations necessary to comply with forthcoming air, water and waste regulations;
- Plan to achieve the energy efficiency savings targets agreed to in connection with the Duke Energy-Progress Energy merger, and evaluate energy efficiency as a resource that competes on its own merits with supply-side resources and can grow over the planning horizon;
- Explicitly recognize and incorporate the benefits that renewable energy resources provide in addition to capacity and energy, including hedging against fuel cost and environmental compliance cost risks; and
- Study best practices for modeling utility-scale and distributed solar technologies and integrating such analysis into resource plans, and incorporate those practices into development of future IRPs.

In their joint reply comments, DEC and DEP observed that SACE and Sierra Club note that DEC "led the Southeast in energy savings from efficiency," in both 2011 and 2012, and that DEC ranked 2nd in the Southeast in 2013 and DEP ranked 3rd in the Southeast in 2013 in efficiency savings as a percentage of retail sales. Yet, despite these accolades, as in previous IRP comments, SACE and Sierra Club allege that DEC and DEP are not planning to capture all cost-effective EE and maximize renewable energy opportunities. DEC and DEP maintain that they have, however, included significant levels of EE and renewable resources in their 2014 IRPs, as detailed in Appendix D to the DEC and DEP 2014 IRPs.

DEC and DEP stated that on page 6 of the SACE Comments, SACE and Sierra Club state that "DEC's projection of EE impacts peaks in 2025 . . ." and that "DEP's projection of EE impacts peaks around 2021 ...;" however, these statements are incorrect. The Companies' EE forecasts do not peak as claimed, but continue to grow on a cumulative basis until reaching the full achievable market potential as estimated in the Forefront Economics market potential studies previously provided in this and other IRP dockets.

DEC and DEP argued that, contrary to SACE and Sierra Club's arguments, it would be imprudent for the Companies to include projected impacts from EE beyond the levels estimated in the market potential studies. Furthermore, SACE and Sierra Club leave the false impression that the Companies have excluded consideration of EE from its planning process for half of the PVRP study period. This is not correct because the cumulative projected impacts that capture the estimated market potential have been incorporated into the IRP analysis. The EE savings impacts have not been

"terminat[ed]" ... "halfway through the planning horizon" as alleged by SACE and Sierra Club; rather, all EE impacts that are reasonably expected to be achievable have been captured in the overall IRP process.

DEC and DEP further argued that SACE and Sierra Club also ignore the fact that both DEC and DEP evaluated two portfolios with High EE targets in their 2014 IRPs. These aspirational EE portfolios averaged \$5 billion higher cost than the base portfolio on a PVRR basis. Thus, while the Companies appropriately accounted for EE up to the market potential studies in the base case for the 2014 IRPs, increasing beyond the market potential EE levels would have resulted in a significantly higher-cost resource plan.

The Companies have included in their 2014 IRPs the level of EE they believe is reasonably achievable and economic. In response to a data request seeking the feasibility assumptions of the increased EE levels asserted in their comments, SACE and Sierra Club admitted that they did not conduct a market potential study or make assumptions regarding participation (penetration) rates, or technology to achieve penetration rates, for purposes of preparing their comments, but that their comments were "informed" by their review of market potential studies performed for DEC and other southeastern electric utilities. DEC and DEP asserted that SACE and Sierra Club do not appear to realize that potential does not equal cost-effective or achievable. In their comments criticizing DEC's EE cost assumptions, SACE and Sierra Club again rely upon the LBNL study by Barbose. While this study does make an attempt to adjust cost projections for size of first year impacts, it does not adjust for cumulative market penetration (i.e., the more that has been achieved on a cumulative basis, the higher must be the costs per kWh achieved). Furthermore, the study essentially relies on past spending and impacts to make its projection, which DEC and DEP assert is a very unreliable methodology.

DEC and DEP submitted that, as they did in their 2013 IRP comments, SACE and Sierra Club complain that the EE costs assumed by the Companies in their 2014 IRPs are too high. On pages 8-11 of their comments, SACE and Sierra Club restate four alleged flaws with DEC's EE cost assumptions and methods. As to SACE and Sierra Club's allegation that DEC's long-term EE cost projection included costs incurred by program participants instead of limiting the costs to those paid by DEC. DEC and DEP reply that this allegation is simply false. As to the use of the 60% market saturation, this is based upon the market potential study prepared for DEC and is consistent with reasonable adoption curves for typical measures. As to the criticism that there is no provision for introduction of new EE technology or for reduction in costs of future EE technology, SACE and Sierra Club's comments ignore that generation technology is treated exactly the same way in the IRP (no assumptions are made that generation technology costs will decrease over time). As to their assertion that economies of scale serve to reduce EE program costs as more customers participate, this ignores the

reality of EE program implementation: as less expensive EE measures are depleted (the "low hanging fruit"), more expensive measures must be offered.

In addition, DEC and DEP observed that, in part, SACE and the Sierra Club criticize the Companies for not discussing their solar resource capacity value methodology or why the estimates change over time. The Companies have utilized a methodology to determine the peak contribution of solar resources that has been utilized in the current and past IRPs. This methodology simply overlays the solar load profile with the peak hours to determine how much of a solar facility's output can be counted on during the peak hours. The peak hours are those defined in Option B of the avoided cost filing. The load shape in the peak hours determines the amount of capacity that can be counted on during each peak hour in both summer and winter periods. These values are summed to determine the overall contribution to peak percentages. A similar methodology is utilized for wind resources. As for these values changing over the years, the Companies continue to review processes and best practices for all methodologies in the IRP. The solar capacity values in the 2014 IRP actually increased as compared to previous years due to the process improvement, thus giving the solar facilities higher value in peak hours.

DEC and DEP also noted that, in their comments, SACE and Sierra Club also allege that DEC and DEP may not have considered current and future environmental regulations, including specifically EPA's Clean Power Plan. Appendix G to both the DEC and DEP 2014 IRPs contain extensive discussion of potential future environmental requirements that will impact the Companies' operations in the coming years, including those related to the Cross-State Air Pollution Rule (CSAPR) and the Clean Air Interstate Rule, the Mercury and Air Toxics Standards (MATS), National Ambient Air Quality Standards, SO₂ Standards, Particulate Matter Standard, Greenhouse Gas Regulation, Cooling Water Intake Structures (Clean Water Act 316(b)), Steam Electric Effluent Guidelines, and Coal Combustion Residuals. The Companies' maintained that their IRP models build in all known capital and O&M costs for environmental compliance.

DEC and DEP further observed that SACE and Sierra Club focus on the impacts of the Clean Power Plan and their own opinion of which coal plants should be considered for accelerated retirement. At the time of the development of the 2014 IRPs, not enough information was available about the Clean Power Plan and the compliance targets for the Companies to include compliance costs in the analysis. As noted previously, the Clean Power Plan Rule has not been finalized, and the rule is likely to undergo significant changes and clarifications considering the extent of comments filed with the EPA regarding the rule. In addition, the plants in question do have planning retirement dates included in the IRP, based reasonably on the current book value of the plants. As the Clean Power Plan, or any other regulation or legislation becomes more certain, the Companies will perform detailed analysis to determine the impacts to the DEC and DEP systems and to each individual generation plant. The Companies

evaluate the retirement dates for all generation units based upon changing circumstances, and update retirement dates accordingly.

DEC and DEP stated that, in response to several data requests, SACE and Sierra Club noted that they "do not purport to offer 'proposed resource additions and mix of resources' in their comments. According to DEC and DEP, "if these parties don't have a proposed alternate resource mix and associated costs to analyze and compare, then it belies the validity of the purported cost-effectiveness of their proposals and frustrates any meaningful consideration of their comments. In conclusion, the Companies assert that their IRPs and REPS compliance plans meet all applicable requirements and any SACE and Sierra Club arguments to the contrary should be dismissed."

The Commission finds that DEC and DEP have satisfactorily addressed the issues raised by SACE and the Sierra Club in their initial comments and that no further action is required.

IT IS, THEREFORE, ORDERED, as follows:

1. That this Order shall be, and is hereby, adopted as part of the Commission's current analysis and plan for the expansion of facilities to meet future requirements for electricity for North Carolina pursuant to G.S. 62-110.1(c).

2. That the IOUs' 15-year forecasts of native load requirements and other system capacity or firm energy obligations, supply-side and demand-side resources expected to satisfy those loads, and reserve margins are reasonable for planning purposes and are hereby approved.

3. That the 2014 REPS compliance plans filed in this proceeding by the IOUs are hereby approved.

4. That future IRP filings by all IOUs shall continue to include a detailed explanation of the basis and justification for the appropriateness of the level of the respective utility's projected reserve margins.

5. That future IRP filings by all IOUs shall continue to include a copy of the most recently completed FERC Form 715, including all attachments and exhibits.

6. That future IRP filings by all IOUs shall continue to: (1) provide the amount of load and projected load growth for each wholesale customer under contract on a year-by-year basis through the terms of the current contract, segregate actual and projected growth rates of retail and wholesale loads, and explain any difference in actual and projected growth rates between retail and wholesale loads, and (2) for any amount of undesignated load, detail each potential customer's current supply

arrangements and explain the basis for the utility's reasonable expectation for serving each such customer.

7. That 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.

8. That each IOU shall continue to include a discussion of the status of EE market potential studies or updates in their future IRPs.

9. That all IOUs shall continue to include in future IRPs a full discussion of the drivers of each customer class' load forecast, including new or changed demand of a particular sector or sub-group.

10. 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.

11. That DEC shall continue to provide updates in future IRPs regarding its obligations related to the Cliffside Unit 6 air permit.

12. That the Cliffside Unit 6 Carbon Neutrality Plan filed by DEC is approved as a reasonable path for DEC's compliance with the carbon emission reduction standards of the air quality permit; provided, however, this approval does not constitute Commission approval of individual specific activities or expenditures for any activities shown in the Plan.

13. 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.

14. That future IRP filings by DEP and DEC shall continue to provide information on the number, resource type and total capacity of the facilities currently within the respective utility's interconnection queue as well as a discussion of how the potential QF purchases would affect the utility's long-range energy and capacity needs.

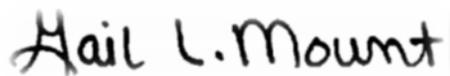
15. That, consistent with the Commission's May 7, 2013 Order in Docket No. M-100, Sub 135, the IOUs shall continue to include with their future IRP submittals verified testimony addressing natural gas issues, as detailed in the body of that Order.

16. That NC WARN's motion for an evidentiary hearing shall be, and is hereby, denied.

ISSUED BY ORDER OF THE COMMISSION.

This the 26th day of June, 2015.

NORTH CAROLINA UTILITIES COMMISSION

A handwritten signature in black ink that reads "Gail L. Mount". The signature is written in a cursive, slightly slanted style.

Gail L. Mount, Chief Clerk

Table 8-B Load, Capacity and Reserves Table - Summer

Summer Projections of Load, Capacity, and Reserves
for Duke Energy Progress 2014 Annual Plan

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Load Forecast															
1 Duke System Peak	12,983	13,198	13,406	13,626	13,856	14,075	14,303	14,539	14,786	15,041	15,284	15,517	15,793	16,046	16,298
2 Firm Sale	150	150	150	150	150	150	150	150	150	150	0	0	0	0	0
3 Cumulative New EE Programs	(60)	(101)	(139)	(173)	(210)	(252)	(297)	(342)	(386)	(428)	(467)	(499)	(527)	(549)	(571)
4 Adjusted Duke System Peak	13,074	13,247	13,417	13,603	13,796	13,974	14,157	14,347	14,550	14,763	14,817	15,018	15,266	15,496	15,726
Existing and Designated Resources															
5 Generating Capacity	12,779	12,799	12,799	12,836	12,973	12,973	12,567	12,567	12,567	12,567	12,567	12,567	12,567	12,387	12,387
6 Designated Additions / Upgrades	20	0	98	137	0	0	0	0	0	0	0	0	0	0	0
7 Retirements / Derates	0	0	(61)	0	0	(406)	0	0	0	0	0	0	(180)	0	0
8 Cumulative Generating Capacity	12,799	12,799	12,836	12,973	12,973	12,567	12,567	12,567	12,567	12,567	12,567	12,567	12,387	12,387	12,387
Purchase Contracts															
9 Cumulative Purchase Contracts	1,865	1,876	1,875	1,655	1,487	1,342	772	441	441	441	441	441	439	406	373
Non-Compliance Renewable Purchases	173	185	184	183	183	183	93	91	91	91	91	91	89	56	23
Non-Renewables Purchases	1,692	1,692	1,692	1,472	1,304	1,159	679	350	350	350	350	350	350	350	350
Undesignated Future Resources															
10 Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 Combined Cycle	0	0	0	0	0	866	0	866	0	0	0	0	866	0	0
12 Combustion Turbine	0	0	0	0	126	0	792	0	0	0	0	0	0	0	396
Renewables															
13 Cumulative Renewables Capacity	276	319	337	315	368	426	408	441	473	496	529	554	577	590	579
14 Cumulative Production Capacity	14,940	14,994	15,048	14,943	14,954	15,326	15,531	16,099	16,131	16,154	16,187	16,212	16,919	16,900	17,251
Demand Side Management (DSM)															
15 Cumulative DSM Capacity	885	925	966	1,002	1,036	1,046	1,053	1,060	1,066	1,073	1,079	1,086	1,092	1,098	1,098
16 Cumulative Capacity w/ DSM	15,826	15,920	16,014	15,945	15,990	16,372	16,584	17,159	17,197	17,227	17,266	17,298	18,011	17,998	18,350
Reserves w/ DSM															
17 Generating Reserves	2,752	2,672	2,598	2,342	2,194	2,399	2,427	2,812	2,647	2,463	2,449	2,279	2,745	2,502	2,623
18 % Reserve Margin	21.1%	20.2%	19.4%	17.2%	15.9%	17.2%	17.1%	19.6%	18.2%	16.7%	16.5%	15.2%	18.0%	16.1%	16.7%

Table 8-C Load, Capacity and Reserves Table - Winter

		Winter Projections of Load, Capacity, and Reserves for Duke Energy Progress 2014 Annual Plan														
		14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29
Load Forecast																
1	Duke System Peak	12,458	12,720	12,840	13,051	13,287	13,481	13,766	13,980	14,135	14,303	14,493	14,693	14,935	15,158	15,285
2	Firm Sale	150	150	150	150	150	150	150	150	150	150	0	0	0	0	0
3	Cumulative New EE Programs	(39)	(70)	(98)	(123)	(162)	(194)	(229)	(263)	(297)	(330)	(360)	(385)	(407)	(424)	(441)
4	Adjusted Duke System Peak	12,579	12,809	12,901	13,079	13,275	13,437	13,687	13,867	13,987	14,124	14,133	14,308	14,528	14,734	14,844
Existing and Designated Resources																
5	Generating Capacity	14,057	13,866	13,886	13,000	13,008	14,045	14,045	13,513	13,513	13,513	13,513	13,513	13,513	13,513	13,281
6	Designated Additions / Upgrades	4	20	14	84	137	0	0	0	0	0	0	0	0	0	0
7	Retirements / Derates	(195)	0	0	(76)	0	0	(532)	0	0	0	0	0	0	(232)	0
8	Cumulative Generating Capacity	13,866	13,886	13,900	13,908	14,045	14,045	13,513	13,281	13,281						
Purchase Contracts																
9	Cumulative Purchase Contracts	1,954	1,945	1,957	1,956	1,695	1,627	1,382	791	409	409	409	409	409	408	399
	Non-Compliance Renewable Purchases	124	115	127	126	125	125	125	35	34	34	34	34	34	33	24
	Non-Renewables Purchases	1,830	1,830	1,830	1,830	1,570	1,402	1,257	756	375	375	375	375	375	375	375
Undesignated Future Resources																
10	Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Combined Cycle	0	0	0	0	0	0	0	907	0	907	0	0	0	907	0
12	Combustion Turbine	0	0	0	0	147	0	0	872	0	0	0	0	0	0	0
Renewables																
13	Cumulative Renewables Capacity	176	165	190	199	168	204	274	240	256	272	278	294	302	310	314
14	Cumulative Production Capacity	15,998	15,998	16,046	16,063	16,055	15,923	16,223	16,470	17,011	17,026	17,033	17,049	17,057	17,739	17,733
Demand Side Management (DSM)																
15	Cumulative DSM Capacity	573	575	586	602	616	629	642	649	657	664	671	679	686	692	698
16	Cumulative Capacity w/ DSM	16,569	16,571	16,633	16,665	16,672	16,552	16,865	17,120	17,668	17,690	17,704	17,727	17,743	18,431	18,432
Reserves w/ DSM																
17	Generating Reserves	3,960	3,762	3,732	3,586	3,397	3,115	3,179	3,253	3,681	3,566	3,571	3,419	3,214	3,697	3,588
18	% Reserve Margin	31.7%	29.4%	28.9%	27.4%	25.6%	23.2%	23.2%	23.5%	26.3%	25.2%	25.3%	23.9%	22.1%	25.1%	24.2%

DEP - Assumptions of Load, Capacity, and Reserves Table

The following notes are numbered to match the line numbers on the Summer Projections of Load, Capacity, and Reserves table. All values are MW except where shown as a Percent.

1. Planning is done for the peak demand for the Duke Energy Progress System.
2. Firm sale of 150 MW through 2024.
3. Cumulative energy efficiency and conservation programs (does not include demand response programs).
4. Peak load adjusted for FERC mitigation sale, firm sales, and cumulative energy efficiency .
5. Existing generating capacity reflecting designated additions, planned uprates, retirements and derates as of April, 2014.

Includes total unit capacity of jointly owned units.

6. Capacity Additions include:

Planned nuclear uprates totalling 38 MW in the 2014-2017 timeframe.

Planned combined cycle uprates totalling 137 MW in 2018.

Expected replacement of Sutton CT units 1, 2A and 2B with an 84 MW combustion turbine in 2017.

7. Planned Retirements include:
Sutton CT Units 1, 2A and 2B in 2017 (61 MW)
Darlington CT Units 1-11 by 2020 (553 MW)
Blewett CT Units 1-4 and Weatherspoon CT units 1-4 in 2027 (180 MW)

8. Sum of lines 5 through 7.

9. Cumulative Purchase Contracts have several components:

Purchased capacity from PURPA Qualifying Facilities, Anson and Hamlet CT tolling,

Butler Warner purchase, Southern CC purchase, and Broad River CT purchase.

Additional line items are shown under the total line item to show the amounts of renewable and traditional resource purchases. Renewables in these line items are not used for NC REPS compliance.

DEP - Assumptions of Load, Capacity, and Reserves Table Cont.

10. New nuclear resources economically selected to meet load and minimum planning reserve margin Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of that year.

No new nuclear resources were selected in the Base Case in the 15 year study period.

11. New combined cycle resources economically selected to meet load and minimum planning reserve margin.

Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of that year.

Addition of 866 MW of combined cycle capacity in 2020, 2022 and 2027.

12. New combustion turbine resources economically selected to meet load and minimum planning reserve margin.

Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of that year.

Addition of 126 MW of combustion turbine capacity in 2019.

Addition of 792 MW of combustion turbine capacity in 2021.

Addition of 396 MW of combustion turbine capacity in 2029.

13. Cumulative solar, biomass, hydro and wind resources to meet NC REPS compliance.

Also include compliance resources for South Carolina (discussed in Chapter 5).

14. Sum of lines 8 through 13.

15. Cumulative Demand Side Management programs including load control and DSDR.

16. Sum of lines 14 and 15.

17. The difference between lines 4 and 16.

18. Reserve Margin = (Cumulative Capacity-System Peak Demand)/System Peak Demand

Minimum target planning reserve margin is 14.5%.

Table 8-B Load, Capacity and Reserves Table - Summer

Summer Projections of Load, Capacity, and Reserves
for Duke Energy Carolinas 2014 Annual Plan

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Load Forecast															
1 Duke System Peak	18,636	19,033	19,407	19,792	20,219	20,593	20,815	21,146	21,492	21,896	22,232	22,597	22,987	23,425	23,748
2 Firm Sale	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(101)	(164)	(230)	(297)	(366)	(440)	(524)	(617)	(718)	(811)	(912)	(1,002)	(1,091)	(1,149)	(1,211)
4 Adjusted Duke System Peak	18,533	18,869	19,177	19,495	19,853	20,123	20,291	20,629	20,777	21,086	21,320	21,696	21,906	22,276	22,637
Existing and Designated Resources															
5 Generating Capacity	20,449	20,311	20,311	20,358	21,026	21,036	21,042	21,042	21,042	21,042	21,042	21,042	21,042	21,042	19,915
6 Designated Additions / Upgrades	232	0	45	670	10	6	0	0	0	0	0	0	0	0	0
7 Retirements / Derates	(370)	0	0	0	0	0	0	0	0	0	0	0	0	(1,127)	0
8 Cumulative Generating Capacity	20,311	20,311	20,366	21,026	21,036	21,042	19,915	19,916							
Purchase Contracts															
9 Cumulative Purchase Contracts	243	237	233	230	189	186	100	81	79	79	79	79	78	66	6
Non-Compliance Renewable Purchases	73	68	84	80	58	58	58	58	56	55	55	55	55	43	5
Non-Renewables Purchases	169	169	199	160	131	128	42	24	24	24	24	24	24	14	0
Undesignated Future Resources															
10 Nuclear	0	0	0	0	0	0	0	0	0	1,117	0	1,117	0	0	0
11 Combined Cycle	0	0	0	0	0	866	0	0	0	0	0	0	0	0	0
12 Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0	0	792	0
Renewables															
13 Cumulative Renewables Capacity	274	316	324	321	414	533	626	710	799	892	953	1,018	1,071	1,111	1,112
14 Cumulative Production Capacity	20,828	20,864	20,912	21,676	21,639	22,826	22,633	22,698	22,786	23,986	24,067	26,238	26,291	24,974	24,924
Demand Side Management (DSM)															
15 Cumulative DSM Capacity	1,072	1,095	1,142	1,180	1,213	1,264	1,264	1,264	1,264	1,264	1,264	1,264	1,264	1,264	1,264
16 Cumulative Capacity w/ DSM	21,900	21,959	22,064	22,766	22,862	23,891	23,898	23,963	24,051	26,260	26,321	26,593	26,666	26,238	26,188
Reserves w/ DSM															
17 Generating Reserves	3,367	3,090	2,677	3,261	2,999	3,768	3,606	3,434	3,273	4,165	4,001	4,908	4,650	3,962	3,651
18 % Reserve Margin	18.17%	16.38%	15.00%	16.73%	16.11%	18.73%	17.77%	16.73%	16.76%	19.78%	18.77%	22.73%	21.23%	17.79%	16.20%

Table 8-C Load, Capacity and Reserves Table – Winter

	16/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29
Winter Projections of Load, Capacity, and Reserves for Duke Energy Carolinas 2014 Annual Plan														
Load Forecast														
1 Duke System Peak	17,784	18,175	18,556	18,934	19,246	19,485	19,771	20,092	20,478	20,829	21,160	21,520	21,933	22,243
2 Firm Sale	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(100)	(145)	(192)	(252)	(317)	(379)	(449)	(523)	(595)	(671)	(740)	(799)	(850)	(896)
4 Adjusted Duke System Peak	17,684	18,029	18,364	18,672	18,929	19,106	19,322	19,570	19,883	20,158	20,440	20,721	21,083	21,346
Existing and Designated Resources														
5 Generating Capacity	21,227	21,087	21,132	21,077	21,812	21,822	21,828	21,828	21,828	21,828	21,828	21,828	21,828	21,828
6 Designated Additions / Uprates	232	45	745	0	10	6	0	0	0	0	0	0	0	0
7 Retirements / Derates	(372)	0	0	(65)	0	0	0	0	0	0	0	0	0	(1,161)
8 Cumulative Generating Capacity	21,087	21,132	21,877	21,812	21,822	21,828	20,667							
Purchase Contracts														
9 Cumulative Purchase Contracts	205	199	198	195	155	152	60	41	39	39	39	39	39	18
Non-Compliance Renewable Purchases	29	24	22	19	18	18	18	18	16	15	15	15	15	5
Non-Renewables Purchases	175	175	175	175	137	134	42	24	24	24	24	24	24	14
Undesignated Future Resources														
10 Nuclear	0	0	0	0	0	0	0	0	0	1,117	0	1,117	0	0
11 Combined Cycle	0	0	0	0	0	907	0	0	0	0	0	0	0	0
12 Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0	0	872
Renewables														
13 Cumulative Renewables Capacity	121	132	130	117	160	262	297	328	366	401	424	444	458	475
14 Cumulative Production Capacity	21,413	21,463	22,205	22,123	22,136	23,146	23,091	23,103	23,139	24,292	24,314	25,452	25,465	25,172
Demand Side Management (DSM)														
15 Cumulative DSM Capacity	570	577	588	594	597	601	601	601	601	601	601	601	601	601
16 Cumulative Capacity w/ DSM	21,983	22,040	22,792	22,718	22,733	23,748	23,692	23,704	23,740	24,892	24,915	26,053	26,066	25,773
Reserves w/ DSM														
17 Generating Reserves	4,299	4,010	4,428	4,048	3,804	4,643	4,369	4,134	3,857	4,734	4,475	5,331	4,963	4,427
18 % Reserve Margin	24.3%	22.2%	24.1%	21.7%	20.1%	24.3%	22.8%	21.1%	19.4%	23.5%	21.9%	25.7%	23.6%	20.7%

DEC - Assumptions of Load, Capacity, and Reserves Table

The following notes are numbered to match the line numbers on the Summer Projections of Load, Capacity, and Reserves tables. All values are MW except where shown as a Percent.

1. Planning is done for the peak demand for the Duke System including Nantahala. Nantahala became a division of Duke Energy Carolinas in 1998.

A firm wholesale backstand agreement for 47 MW between Duke Energy Carolinas and PMPA starts on 1/1/2014 and continues through the end of 2020. This backstand is included in Line 1.

2. A 150 MW firm sale is included in 2014. The sale ends in 2014.
3. Cumulative energy efficiency and conservation programs (does not include demand response programs).
4. Peak load adjusted for firm sales and cumulative energy efficiency.
5. Existing generating capacity reflecting designated additions, planned uprates, retirements and derates as of April, 2014.

Includes 101 MW Nantahala hydro capacity, and total capacity for Catawba Nuclear Station less 832 MW to account for NCMAPA1 firm capacity sale.

6. Capacity Additions include the conversion of Lee Steam Station unit 3 from coal to natural gas in 2015 (170 MW).

Lee Combined Cycle is reflected in 2028 (670 MW). This is the DEC capacity net of 100 MW to be owned by NCEMC.

Capacity Additions include Duke Energy Carolinas hydro units scheduled to be repaired and returned to service. The units are returned to service in the 2014-2020 timeframe and total 18 MW.

Also included is a 105 MW capacity increase due to nuclear uprates at Catawba, McGuire, and Oconee. Timing of these uprates is shown from 2015-2017.

7. The 370 MW capacity retirement in summer 2015 represents the projected retirement date for Lee Steam Station.

A planning assumption for coal retirements has been included in the 2014 IRP.

Allen Steam Station (1127 MW) is assumed to retire in 2028.

Nuclear Stations are assumed to retire at the end of their current license extension.

DEC - Assumptions of Load, Capacity, and Reserves Table cont.

No nuclear facilities are assumed to retire in the 15 year study period.

The Hydro facilities for which Duke has submitted an application to FERC for license renewal are assumed to continue operation through the planning horizon.

All retirement dates are subject to review on an ongoing basis.

DEC - Assumptions of Load, Capacity, and Reserves Table Cont.

8. Sum of lines 5 through 7.
9. Cumulative Purchase Contracts including purchased capacity from PURPA Qualifying Facilities, an 88 MW Cherokee County Cogeneration Partners contract which began in June 1998 and expires June 2020 and miscellaneous other QF projects.

Additional line items are shown under the total line item to show the amounts of renewable and traditional QF purchases. Renewables in these line items are not used for NC REPS compliance.
10. New nuclear resources economically selected to meet load and minimum planning reserve margin.

Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of that year.

Addition of 1,117 MW Lee Nuclear Unit additions in 2024 and 2026.
11. New combined cycle resources economically selected to meet load and minimum planning reserve margin.

Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of that year.

Addition of 866 MW of combined cycle capacity in 2020.
12. New combustion turbine resources economically selected to meet load and minimum planning reserve margin.

Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of that year.

Addition of 792 MW of combustion turbine capacity in 2028.
13. Cumulative solar, biomass, hydro and wind resources to meet NC REPS compliance

Also includes compliance resources for South Carolina (discussions in Chapter 5).
14. Sum of lines 8 through 13.
15. Cumulative Demand Response programs including load control and DSDR.
16. Sum of lines 14 and 15.
17. The difference between lines 4 and 16.
18. Reserve Margin = $(\text{Cumulative Capacity} - \text{System Peak Demand}) / \text{System Peak Demand}$
Minimum target planning reserve margin is 14.5%.

Appendix 2H – Projected Summer & Winter Peak Load & Energy Forecast

Company Name:	Virginia Electric and Power Company																	Schedule 1		
I. PEAK LOAD AND ENERGY FORECAST																				
	(ACTUAL) ⁽¹⁾				(PROJECTED)															
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
1. Utility Peak Load (MW)																				
A. Summer																				
1a. Base Forecast	17,521	16,787	16,366	17,271	17,670	17,999	18,347	18,635	18,895	19,114	19,369	19,615	19,863	20,099	20,356	20,576	20,838	21,085	21,331	
1b. Additional Forecast																				
NCEMC	150	150	150	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Conservation, Efficiency ⁽⁴⁾	-36	-40	-47	-65	-107	-172	-232	-289	-336	-388	-451	-441	-339	-342	-344	-346	-349	-351	-354	
3. Demand Response ⁽²⁾⁽³⁾	-81	-83	-83	-123	-136	-182	-171	-190	-210	-219	-219	-218	-218	-219	-221	-223	-225	-228	-230	
4. Demand Response-Existing ⁽²⁾⁽³⁾	-6	-7	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5
5. Peak Adjustment	-	-	-	294	585	907	951	-85	-65	-65	-65	-65	-65	-65	-65	-65	-65	-65	-65	-65
6. Adjusted Load	17,635	16,897	16,469	17,650	18,148	18,734	19,065	18,291	18,507	18,702	18,963	19,219	19,469	19,702	19,937	20,177	20,434	20,679	20,922	
7. % Increase in Adjusted Load (from previous year)	4.3%	-4.2%	-2.8%	7.2%	2.8%	3.2%	1.8%	-4.1%	1.2%	1.1%	1.4%	1.4%	1.3%	1.2%	1.2%	1.2%	1.3%	1.2%	1.2%	
B. Winter																				
1a. Base Forecast	15,244	14,544	15,106	14,742	14,931	15,166	15,407	15,658	15,808	15,955	16,096	16,263	16,435	16,620	16,795	16,977	17,160	17,364	17,568	
1b. Additional Forecast																				
NCEMC	150	150	150	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Conservation, Efficiency ⁽⁴⁾	-36	-40	-47	-64	-99	-156	-219	-259	-303	-327	-322	-308	-298	-300	-302	-304	-305	-307	-308	
3. Demand Response ⁽²⁾⁽³⁾	-10	-16	-15	-21	-17	-15	-17	-19	-21	-23	-24	-25	-26	-27	-28	-29	-30	-31	-32	
4. Demand Response-Existing ⁽²⁾⁽³⁾	-8	-6	-6	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5
5. Adjusted Load	15,358	14,654	15,209	14,828	14,832	15,010	15,189	15,399	15,505	15,628	15,774	15,954	16,137	16,319	16,493	16,673	16,858	17,057	17,260	
6. % Increase in Adjusted Load	0.3%	-4.6%	3.8%	-2.5%	0.0%	1.2%	1.2%	1.4%	0.7%	0.8%	0.9%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.2%	1.2%	
2. Energy (GWh)																				
A. Base Forecast	83,393	81,498	83,311	85,777	86,176	90,297	91,760	93,043	93,946	95,208	95,976	97,146	98,331	99,496	100,644	101,816	103,022	104,258	105,467	
B. Additional Forecast																				
NCEMC	-	-	-	676	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Future BTM ⁽⁶⁾	-	-	-	-410	-410	-410	-410	-410	-410	-410	-410	-410	-410	-410	-410	-410	-410	-410	-410	-410
C. Conservation & Demand Response ⁽⁴⁾	-294	-338	-351	-529	-676	-885	-1,126	-1,552	-1,988	-2,334	-2,560	-2,762	-3,025	-3,179	-3,037	-3,042	-3,048	-3,055	-3,063	
D. Demand Response-Existing ⁽²⁾⁽³⁾	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E. Adjusted Energy	83,099	81,160	82,960	85,515	87,089	89,003	90,225	91,081	91,548	92,465	93,007	93,975	94,897	95,908	97,197	98,364	99,564	100,794	101,994	
F. % Increase in Adjusted Energy	-0.9%	-2.3%	2.2%	3.1%	1.8%	2.2%	1.4%	0.9%	0.5%	1.0%	0.6%	1.0%	1.0%	1.1%	1.3%	1.2%	1.2%	1.2%	1.2%	

- (1) Actual metered data.
- (2) Demand response programs are classified as capacity resources and are not included in adjusted load.
- (3) Existing DSM programs are included in the load forecast.
- (4) Actual historical data based upon measured and verified EM&V results.
- (5) Actual historical data based upon measured and verified EM&V results. Projected values represent modeled DSM firm capacity.
- (6) Future BTM, which is not included in the Base forecast.

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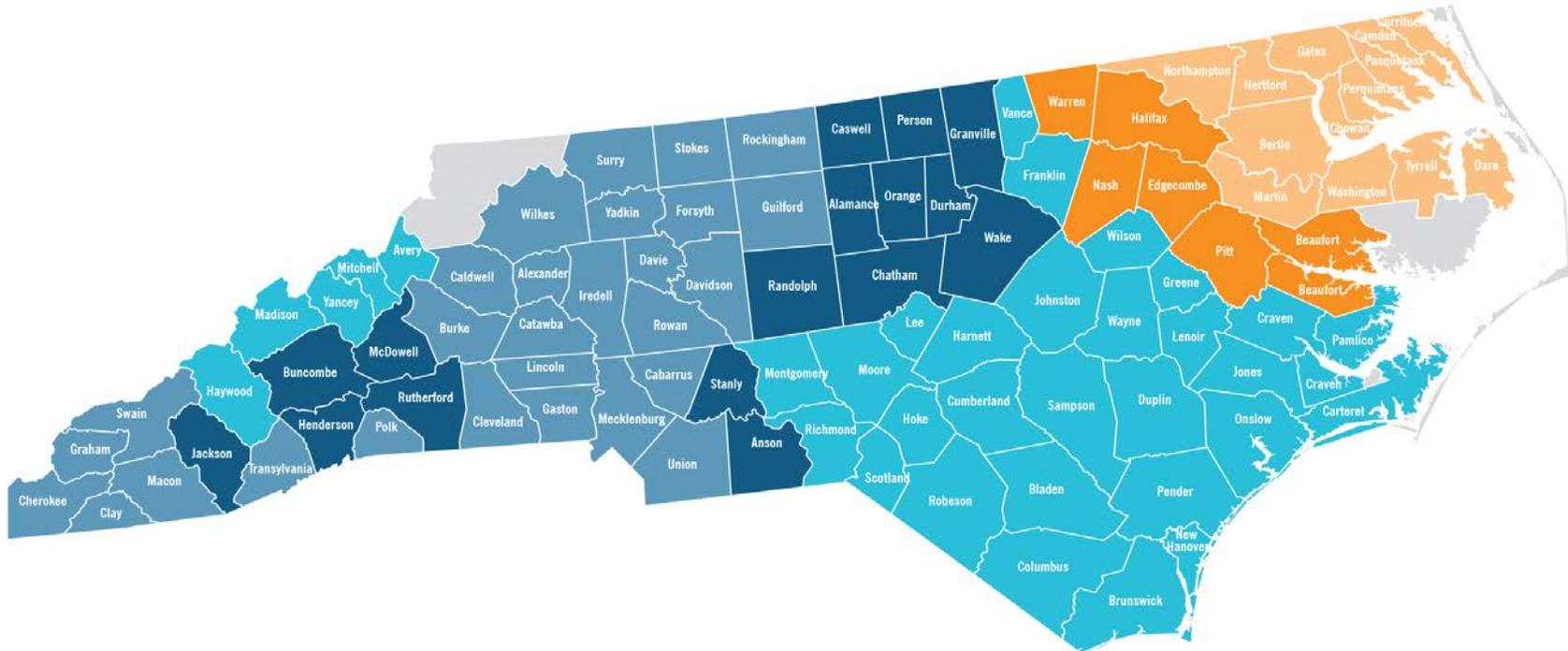
Appendix 2I – Required Reserve Margin

Company Name: Virginia Electric and Power Company
POWER SUPPLY DATA (continued)

Schedule 6

	(ACTUAL)				(PROJECTED)														
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
I. Reserve Margin⁽¹⁾																			
(Including Cold Reserve Capability)																			
1. Summer Reserve Margin																			
a. MW ⁽¹⁾	1,201	2,473	3,026	2,616	2,855	3,263	2,850	2,049	2,073	2,095	2,343	2,325	2,530	2,298	2,233	2,260	2,289	2,316	2,617
b. Percent of Load	6.8%	14.6%	18.4%	14.8%	15.7%	17.4%	15.0%	11.2%	11.2%	11.2%	12.4%	12.1%	13.0%	11.7%	11.2%	11.2%	11.2%	11.2%	12.5%
c. Actual Reserve Margin ⁽³⁾	N/A	N/A	N/A	13.2%	15.6%	17.1%	11.8%	9.4%	15.3%	14.0%	12.4%	12.1%	13.0%	11.7%	10.4%	9.1%	7.7%	6.4%	12.5%
2. Winter Reserve Margin																			
a. MW ⁽¹⁾	N/A	N/A	N/A	5,497	6,263	5,561	6,501	5,304	7,658	7,263	7,073	7,134	7,416	7,235	7,062	6,883	6,702	6,501	7,936
b. Percent of Load	N/A	N/A	N/A	37.1%	42.2%	37.0%	42.8%	34.4%	49.4%	46.5%	44.8%	44.7%	46.0%	44.3%	42.8%	41.3%	39.8%	38.1%	46.0%
c. Actual Reserve Margin ⁽³⁾	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I. Reserve Margin⁽¹⁾⁽²⁾																			
(Excluding Cold Reserve Capability)																			
1. Summer Reserve Margin																			
a. MW ⁽¹⁾	1,096	2,473	3,026	2,616	2,855	3,263	2,850	2,049	2,073	2,095	2,343	2,325	2,530	2,298	2,233	2,260	2,289	2,316	2,617
b. Percent of Load	6.2%	14.6%	18.4%	14.8%	15.7%	17.4%	15.0%	11.2%	11.2%	11.2%	12.4%	12.1%	13.0%	11.7%	11.2%	11.2%	11.2%	11.2%	12.5%
c. Actual Reserve Margin ⁽³⁾	N/A	N/A	N/A	13.2%	15.6%	17.1%	11.8%	9.4%	15.3%	14.0%	12.4%	12.1%	13.0%	11.7%	10.4%	9.1%	7.7%	6.4%	12.5%
2. Winter Reserve Margin																			
a. MW ⁽¹⁾	N/A	N/A	N/A	5,497	6,263	5,561	6,501	5,304	7,658	7,263	7,073	7,134	7,416	7,235	7,062	6,883	6,702	6,501	7,936
b. Percent of Load	N/A	N/A	N/A	37.1%	42.2%	37.0%	42.8%	34.4%	49.4%	46.5%	44.8%	44.7%	46.0%	44.3%	42.8%	41.3%	39.8%	38.1%	46.0%
c. Actual Reserve Margin ⁽³⁾	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
III. Annual Loss-of-Load Hours⁽⁴⁾	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

- (1) To be calculated based on Total Net Capability for summer and winter.
- (2) The Company and PJM forecasts a summer peak throughout the Planning Period.
- (3) Does not include spot purchases of capacity.
- (4) The Company follows PJM reserve requirements which are based on LOLE.



SERVICE TERRITORIES
(counties served)

-  Duke Energy Carolinas
-  Duke Energy Progress
-  Duke Energy Carolinas/
Duke Energy Progress overlapping counties
-  Dominion North Carolina Power
-  Dominion North Carolina Power/
Duke Energy Progress overlapping counties