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
CECPCN 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 SERC 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

TABLE OF CONTENTS

APPENDICES

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 provide about 95% of the utility-supplied electricity consumed in the state. Approximately 20% of the IOUs' 2015 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)	
	2015	2014	2015	2014	2015	2014
Progress	37,217	37,506	18,787	16,650	64,881	62,871
Duke	57,685	56,738	6,025	7,826	87,376	87,646
NC Power	4,378	4,447	1,355	1,220	85,179	83,938

*GWh = 1 Million kWh (kilowatt-hours)

During the 2016 to 2030 timeframe, the average annual growth rate in summer peak demand for electricity in North Carolina is forecasted to be in the range of 1.3% to 1.5%. Table ES-2 illustrates the system wide 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) (2016 – 2030)

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

As illustrated in Table ES-3, North Carolina's IOUs rely on a balanced mix of generating resources to ensure reliable energy to their customers.

Table ES-3: Total Energy Resources by Fuel Type for 2015

	Progress	Duke	NC Power
Coal	19%	28%	26%
Nuclear	39%	49%	30%
Net Hydroelectric*	1%	1%	1%
Natural Gas and Oil	33%	12%	25%
Non-Hydro Renewable	3%	1%	1%
Purchased Power	5%	9%	17%

* See discussion of pumped storage in Section 6.

Pursuant to G.S. 62-133.8 the Renewable Energy and Energy Efficiency Portfolio Standard (REPS), 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), and 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, the individual 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 November 19, 2015 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 provide about 95% of the utility-supplied electricity consumed in the state. As of December 31, 2015, Duke had 1,921,000 customers located in North Carolina, and Progress had 1,339,000. Each also has customers in South Carolina. NC Power supplies approximately 5% of the State's utility-generated electricity. It has 120,000 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 20% 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 2015 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)	
	2015	2014	2015	2014	2015	2014
Progress	37,217	37,506	18,787	16,650	64,881	62,871
Duke	57,685	56,738	6,025	7,826	87,376	87,646
NC Power	4,378	4,447	1,355	1,220	85,179	83,938

*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 1,071,000 metered customers in North Carolina. EMCs serve approximately 25% of the

State's population. Twenty-six EMCs are headquartered in the State. The other five EMCs 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 North Carolina Electric Membership Corporation (NCEMC), a generation and transmission services cooperative, centrally located in Raleigh, 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 from existing contract and generation resources. To the extent that the power supplied under the WPSA is not sufficient to meet the requirements of its customers, the Independent Members must independently arrange for additional purchases.

The service territories of NCEMC's member EMCs are located within the balancing authority 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 587,000 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) 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 8,800 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 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 15 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 levelized 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 requirements imposed by the 2007 REPS legislation.

2015 Update Reports
(Docket No. E-100, Sub 141)

2015 IRP Update Reports and REPS compliance plans filed by Progress, Duke and NC Power provided updates to their current Biennial Reports (Docket No. E-100, Sub 141). A public hearing in this docket was held in Raleigh on February 8, 2016. Public witnesses addressed a broad range of IRP related issues but especially the role of renewable energy alternatives in North Carolina.

Based upon the record in the proceeding, and the comments of the Public Staff regarding the IRP Update Reports and REPs compliance plans submitted, the Commission accepted the Update Reports filed by the utilities as complete and fulfilling the requirements set out in Commission Rule R8-60. In addition, the Commission approved the REPS compliance plans submitted by the utilities as recommended by the Public Staff. The Commission's March 22, 2016 Order can be found in the back of this report as Appendix 1.

New biennial reports were filed with the Commission in 2016 including current integrated resource and REPS compliance plans. These IRPs will be examined in Docket No. E-100, Sub 147.

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) (2016 – 2030)

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

North Carolina utility forecasts of future peak demand growth rates are in the range of forecasts for the southeast as a whole. The 2015 Long-Term Reliability Assessment by the North American Electric Reliability Corporation (NERC) indicates a forecast of average annual growth in peak demand of approximately 1.2% through 2025.

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 2011 (in MW)

	Progress		Duke		NC Power	
	Summer	Winter*	Summer	Winter*	Summer	Winter*
2011	13,315	12,692	19,644	17,506	20,061	16,881
2012	13,193	12,523	19,473	16,698	19,249	17,623
2013	12,404	14,215	18,239	20,799	18,763	19,785
2014	12,364	15,569	18,993	21,101	18,692	21,651
2015	12,849	13,298	20,003	19,377	18,980	18,948

**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 2015

	Progress	Duke	NC Power
Coal	27%	32%	24%
Nuclear	27%	33%	18%
Hydroelectric	2%	15%	12%
Natural Gas and Oil	44%	20%	45%
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 2015, is provided in Table 5.

Table 5: Total Energy Resources by Fuel Type for 2015

	Progress	Duke	NC Power
Coal	19%	28%	26%
Nuclear	39%	49%	30%
Net Hydroelectric*	1%	1%	1%
Natural Gas and Oil	33%	12%	25%
Non-Hydro Renewable	3%	1%	1%
Purchased Power	5%	9%	17%

* 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. In addition, the EPA's Clean Power Plan (CPP) continues to influence the development of the resource plans. While the CPP was stayed by the U.S. Supreme Court in 2016, each company continues to plan for a range of carbon dioxide (CO2) legislative outcomes assuming some level of carbon emission restrictions consistent with the CPP. The following highlights from utility generation planning exercises reflect information contained in 2016 Integrated Resource Plans the Commission will examine in Docket E-100, Sub 147.

Progress Generation

As of September 2016, Progress had 14,016 MW of installed generating capacity (winter 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 384 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 was filed with the Commission in January 2016 and subsequently approved in March 2016.

Other capacity additions include:

- Planned nuclear uprates totaling 34 MW in the 2017-2020 timeframe.
- Addition of 100 MW Sutton Blackstart combustion turbines in Wilmington in 2017.
- Addition of 1,221 MW of combined-cycle capacity in 2022.
- Addition of 3,276 MW of combustion turbine capacity in 2023 through 2031.

Other planned retirements include:

- Sutton combustion turbine units 1, 2A and 2B by 2017 (76 MW).
- Darlington, SC combustion turbine units 1-10 by 2020 (645 MW).
- Blewett combustion turbine units 1-4 and Weatherspoon combustion turbine units 1-4 by 2027 (232 MW).
- Planning assumptions for nuclear stations assume retirement at the end of their current license extension including Robinson 2 in 2030 (797 MW).

The ultimate timing of unit retirements can be influenced by factors that impact the economics of continued unit operations. Such factors include changes in relative fuel prices, operations and maintenance costs and the costs associated with compliance of evolving environmental regulations. As such, unit retirement schedules are expected to change over time as market conditions change.

Duke Generation

As of September 2016, Duke had 22,066 MW of installed generating capacity (winter 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 (CECPCN) 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 by the end of 2017 at a capacity of 683 MW. This is the Duke capacity net of 100 MW to be owned by NCEMC.

Duke continues to evaluate utility-owned solar additions to support its compliance targets and operational flexibility. Duke has two new utility-scale solar projects under construction which will be available for the summer peak of 2017. These are Monroe Solar Facility (60 MW in Union County) and Mocksville Solar Facility (15 MW in Davie County).

Duke expects to receive the Combined Construction and Operating License (COL) for the W.S. Lee Nuclear Station (Lee Nuclear) by the end of 2016. The integrated resource plan continues to support new nuclear generation as a carbon-free, cost effective, reliable option within the Company's resource portfolio. Historically low natural gas prices, ambiguity regarding the timing and impact of environmental regulations and uncertainty regarding the potential to extend the licenses of existing nuclear units affects the timing of the need for new nuclear generation. Duke currently projects the possible addition of 1,117 MW for Lee Nuclear units in both 2026 and 2028.

Other capacity additions include:

- Addition of 85 MW due to nuclear uprates at Catawba and Oconee in 2017-2020.
- Addition of 1,221 MW of combined-cycle capacity in 2023.
- Addition of 468 MW of combustion turbine resources in 2025.

Retirements:

- Allen coal units 1-3 (604 MW) and units 4-5 (557 MW) in 2024 and 2028, respectively.

NC Power / VEPCO Generation

As of April 2016, NC Power had 21,045 MW of installed generating capacity (winter rating). This excludes purchases and non-utility capacity. Of this total, only 501 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 and approved March 2016. The combined cycle plant is expected to be online by 2019.

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 from the NRC, 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 2028. Based on the timing of the evaluation and implementation of the EPA's Clean Power Plan (CPP), the Company has determined it is prudent to focus its near-term efforts for North Anna 3 on the activities needed to secure the COL, currently expected to be issued by the NRC in 2017. For integrated resource planning purposes, the North Anna 3 available capacity year is 2029 which will allow time for the CPP and COL processes to evolve.

Based on the current and anticipated environmental regulations along with current market conditions, NC Power's 2016 Plan includes the following impacts to the Company's existing generating resources in terms of retirements. Yorktown Units 1 (159 MW) and 2 (164 MW) are scheduled for retirement in 2017.

Currently under evaluation is the potential retirement of Yorktown Unit 3 in 2022 (790 MW of oil-fired generation). Also under evaluation are the 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 by 2022.

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 based on their 2015 IRP Update Reports 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 (2016-2030, after DSM)

	Reserve Margins
Progress	17.0% –21.9%
Duke	17.0% – 25.6%
NC Power	11.5% – 22.3%

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. North Carolina has historically been heavily dependent on one interstate pipeline, Transcontinental Gas Pipe Line Company, LLC (Transco) for its natural gas requirements. While two other interstate pipelines provide limited volumes, only Transco crosses the State generally along the I-85 corridor, which means that long intrastate lines must be built to serve generating plants in other parts of the State.

Transco historically delivered gas up from the Gulf Coast. Transco is expanding its system to bring shale gas to the State from the north. In addition, four major U.S. energy companies (Dominion, Duke Energy, Piedmont Natural Gas and AGL Resources) formed a joint venture – Atlantic Coast Pipeline (ACP) - to build and own a new large pipeline into North Carolina to serve both gas and electric generation customers. ACP will come down along the I-95 corridor and will bring shale gas from the north and provide a better interstate pipeline footprint in the State. ACP was scheduled to come on line in November 2018, but has been delayed until early 2019.

8. RENEWABLE ENERGY AND ENERGY EFFICIENCY

Renewable Energy and Energy Efficiency Portfolio Standard (REPS)

In 2007, North Carolina became the first state in the Southeast to adopt a Renewable Energy and Energy Efficiency Portfolio Standard. Under the REPS Statute, codified at G.S. 62 133.8, 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 NC retail sales in 2021. EMCs and municipal electric suppliers are required to meet a similar requirement of 10% of their NC retail sales in 2018 and thereafter. The requirements under the law phase in over time, with the most recent increase in 2015, requiring investor-owned utilities to meet 6% of their NC retail sales renewable and EE sources. Electric power suppliers must meet a specified portion of their total REPS requirements by producing or purchasing electricity produced from solar, swine waste, and poultry waste resources. As detailed in the following section, these specified source requirements also increase over time, however the Commission has modified and delayed the swine and poultry waste requirements several times.

The REPS Statute requires the Commission to monitor compliance with REPS and to develop procedures for tracking and accounting for renewable energy certificates (RECs), which represent units of electricity or energy produced or saved by a renewable energy facility or an implemented EE measure. 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 website 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.

On October 1, 2016, the Commission submitted its ninth 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 details Commission implementation of the REPS Statute since its enactment in 2007. As described in more detail below, the report concluded that all of the electric power suppliers have met the 2012-2015 general REPS requirements and the solar resource requirements, and appear on track to meet those requirements in 2016. Although the electric power suppliers also met the modified poultry waste resource requirements in 2015, most electric suppliers could not meet the swine waste resource requirements despite making reasonable efforts to do so. Again, that prompted the Commission in 2016 to delay the swine waste resource requirements and to modify the poultry waste requirements. The report is available on the Commission's web site, www.ncuc.net.

Renewable Energy and Energy Efficiency Portfolio Standard (REPS) Compliance

As described above, each electric power supplier serving retail customers in the State is subject to the REPS requirements, including the specific requirements for producing or purchasing electricity from solar, swine, and poultry waste resources. In 2015, the general REPS requirement increased to 6% of 2014 NC retail sales, the solar resource requirement increased to 0.07% of NC retail sales, the modified statewide aggregate poultry waste resource requirement was set by the Commission at 170,000 MWh, and the swine waste resource requirement was again delayed.

The Commission monitors compliance with the REPS requirements through each electric power supplier's annual filing of a compliance report and compliance plan. The compliance report looks back at the previous year and provides details on the electric power supplier's compliance efforts. The compliance plan is a forward-looking forecast of an electric power supplier's REPS requirements and its plan for meeting those requirements. When the Commission concludes its review of each electric power supplier's REPS compliance report, the associated RECs are permanently retired. In addition, the Commission holds annual proceedings to consider approval of a REPS rider for each electric public utility, allowing for recovery of REPS compliance costs subject to the annual per account limits in G.S. 62-133.8(h) (cost caps).

As described in the Commission's October 1, 2016 report, the electric power suppliers met the 2012-2015 general REPS requirements and the solar resource requirements, and appear on track to meet those requirements in 2016. Although the electric power suppliers also met the modified poultry waste resource requirements in 2015, most electric suppliers could not meet the swine waste resource requirements despite making reasonable efforts to do so. On August 16, 2016, in Docket No. E-7, Sub 1106, the Commission issued an Order approving Duke's 2015 compliance report and retiring the RECs in Duke's 2015 compliance sub-account. On December 20, 2016, in Docket No. E-22, Sub 535, the Commission issued an order approving NC Power's 2015 compliance report and retiring the RECs in NC Power's compliance sub-account. In these Orders, the Commission concluded that the Utilities met their REPS requirements and costs were within the limits of G.S. 62-133.8(h). Approval of the other electric power suppliers' compliance reports are pending before the Commission. Of note, Progress states in its REPS Rider application that its REPS compliance costs would have exceeded the cost limits of G.S. 62-133.8(h), and the expenses over that limit were re-allocated to other customer classes. Consideration of approval of that re-allocation method is pending before the Commission as part of Progress's REPS Rider proceeding. The other electric power suppliers appear on track to meet the REPS requirements within the cost limits.

On October 17, 2016, in Docket No. E-100, Sub 113, the Commission issued an Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief, delaying the swine waste resource requirements by one year and modifying the poultry waste resource requirement by maintaining the current requirement that the electric power suppliers, in the aggregate, produce 170,000 MWh from poultry waste resources and delaying scheduled increases in that requirement. That Order represents the fifth time that the Commission has taken similar action since enactment of the REPS statute. In that Order, the Commission found that the electric power suppliers made a reasonable effort to comply with the 2016 swine and poultry waste requirements but will not be able to do so. The inability to meet these requirements is largely due to the fact that the technology of power production from animal waste, particularly, swine waste continues to be in its early stages of development. The Commission's Order continued to require electric power suppliers to participate in semiannual reporting and stakeholder meetings, and noted encouraging developments that could allow compliance in future years.

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 filed and received approval for EE and DSM programs.

NC GreenPower

Founded in 2003, NC GreenPower was launched as a voluntary program to supplement the State's existing power supply with more green energy - electricity generated from renewable energy sources like the sun, wind, water, and organic matter. NC GreenPower is a 501(c)(3) nonprofit organization improving our state's environment not only by supporting renewable energy, but also carbon offset projects and by providing grants for solar installations at North Carolina K-12 schools.

Following a two-year strategic planning process, NC GreenPower announced on April 1, 2015 a new pilot program to provide matching grants for the installation of solar photovoltaic (PV) arrays at schools, providing them with clean, green renewable energy. NC GreenPower will divert a portion of its current donations to help North Carolina K-12 schools acquire a solar PV system. The NC GreenPower Solar Schools pilot will give teachers valuable tools to educate students about renewable energy. Currently in its second year, the pilot program expects to award five schools in 2016 with a 3 kW solar PV array, monitoring equipment and curriculum for educators. In addition, the State Employees' Credit Union (SECU) members via the SECU Foundation will provide a total investment of up to $140,000, awarding a $10,000 matching challenge grant to 14 K-12 public schools that meet NC GreenPower's program requirements for the installation of a pole-mounted solar PV system on school campuses. The Foundation's matching challenge grant will increase each school to a 5 kW solar array system. Year one of the pilot successfully funded four schools with grants to install 5 kW solar PV systems.

On September 20, 2016, Duke Energy Carolinas announced that it will provide $300,000 to NC GreenPower for "Schools Going Solar," which aims to provide 100% of the cost of solar installations for up to 10 schools in its North Carolina service territory. NC GreenPower will administer the program in conjunction with and in addition to its own statewide Solar Schools pilot program.

Contributions to NC GreenPower continue to help support the generation of green energy and reduction of greenhouse gases but also help to provide solar PV systems at schools across North Carolina. Statewide efforts of NC GreenPower also include community outreach and awareness. Voluntary donations to the program can be made by individuals or businesses through their utility bill or directly to NC GreenPower on its website. All current projects are located within North Carolina.

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 14, 2016 report stated that 8 major (greater than $10 million each) transmission projects are needed in North Carolina by the end of 2025 at an estimated cost of $156 million. In July 2016, the NCTPC issued a report updating the 2015 Collaborative Plan indicating that the total cost estimate of the 2015 Reliability Projects has changed from $156 million to $144 million due to the removal of one project and reduced project costs for five other projects. Two new projects were added to the 2016 Plan to accommodate two open access transmission tariff (OATT) generator interconnections requests. 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." [1] 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)[2] process.

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.

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

[2] 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.

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 2007 as part of REPS legislation codified at G.S. 62-133.8(i), the General Assembly provided that the Commission shall "[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."

In compliance, 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.

The Commission issued an Order Approving Revised Interconnection Standard on May 15, 2015. 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. 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 on or before May 2017 to discuss whether the State's small generator interconnection standards require additional revisions.

On July 26, 2016, Governor McCrory signed SB 770, a bill allowing certain renewable energy facilities fueled by swine and poultry waste to be moved to the front of the interconnection study queue.

On August 16, 2016, the Commission issued an Order allowing four animal waste projects to move to the front of the interconnection study queue and requiring the Public Staff to convene a stakeholder process by the end of October 2016, to discuss future interconnections of animal waste projects. As of September 30, 2016, more than a combined total of 7,300 MW are in DEC and DEP's interconnection queues and more than 6,600 MW are solar.

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. As part of REPS legislation, 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, in Docket No. E-100, Sub 83, 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 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.

Since the Commission's March 31, 2009 Order, the Commission has not altered the substantive net-metering policy for the State's electric public utilities. However, on April 13, 2016, in Docket Nos. E-2, Sub 1106 and E-7, Sub 1113, Duke and Progress requested that the Commission waive certain provisions of Commission Rules R8-66 and R8-67 with regard to the reporting requirements for participants receiving service under their respective net metering tariffs under a schedule other than a time-of-use schedule with demand rates. That matter is pending before the Commission.

10. FEDERAL ENERGY INITIATIVES

Open Access Transmission Tariff (OATT)

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. On March 31, 2016, Dominion filed a rate increase request with the North Carolina Utilities Commission (Docket No. E-22, Sub 532) in which it requested relief from all of the conditions that had been imposed upon the Company (and that it had agreed to) pursuant to its joining PJM. That request remains pending before the Commission.

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. FERC agreed that it was unjust and unreasonable for wholesale transmission customers with loads outside Virginia to be allocated the incremental costs of undergrounding these projects and ordered a hearing and settlement judge procedures to establish the specific dollar values that should be excluded from wholesale transmission rates. Subsequently an administrative law judge issued his initial decision on February 16, 2016, determining the amount of the incremental costs of undergrounding certain projects and requiring Dominion to refund certain Virginia customers and North Carolina customers this incremental cost that has been paid. The parties are awaiting FERC approval of this decision.

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 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.[3]

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 CO_2 emissions from existing power plants, relying on authority from the Clean Air Act. These regulations establish CO_2 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 like 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 these 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 CO_2 controls, could have a major impact on the electric generation fleet, reliability of service, and electricity prices in North Carolina. On February 9, 2016, the U.S. Supreme Court placed a "stay" on EPA's implementation of the rule, until an appeals court can consider its legality. The case was argued before the D.C. Circuit Court of Appeals on September 27, 2016, and remains pending.

[3] 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 2015 Integrated Resource Plan Update Reports and Related 2015 REPS Compliance Plans	))))	ORDER ACCEPTING FILING OF 2015 UPDATE REPORTS AND APPROVING 2015 REPS COMPLIANCE PLANS

HEARD: Monday, February 8, 2016, 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 ToNola D. Brown-Bland, Don M. Bailey, Jerry C. Dockham, and James G. Patterson

APPEARANCES:

For Virginia Electric and Power Company, d/b/a Dominion North Carolina Power:

E. Brett Breitschwerdt, McGuireWoods LLP, 434 S. Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

For Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC:

Lawrence B. Somers, Deputy General Counsel, Duke Energy Corporation, P.O. Box 1551, Raleigh, North Carolina 27602

For North Carolina Waste Awareness and Reduction Network:

John D. Runkle, 2121 Damascus Church Road, Chapel Hill, North Carolina 27516

For Southern Alliance for Clean Energy and Sierra Club:

Gudrun Thompson, Senior Attorney, Southern Environmental Law Center, 601 West Rosemary Street, Suite 220, Chapel Hill, North Carolina 27516

For North Carolina Sustainable Energy Association:

Peter Ledford, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For the Using and Consuming Public:

Robert S. Gillam, Staff Attorney, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

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), in pertinent part, 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 Update 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 Update Report. In addition, each Biennial and Update Report should (1) be accompanied by a short-term action plan that discusses those specific actions currently being taken by the utility to implement the activities chosen as appropriate per the applicable biennial and annual reports and (2) incorporate information concerning the construction of transmission lines pursuant to Commission Rule R8-62(p).

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[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.

Within 150 days after the later of either September 1 or the filing of each utility's Biennial Report, the Public Staff or any other intervenor may file an integrated resource plan or report of its own as to any utility or may file an evaluation of or comments on the reports filed by the utilities, or both. The Public Staff or any intervenor may identify any issue that it believes should be the subject of an evidentiary hearing. Within 60 days after the filing of initial comments, the parties may file reply comments addressing any substantive or procedural issue raised by any other party. A hearing to address issues raised by the Public Staff or other intervenors may be scheduled at the discretion of the Commission. The scope of any such hearing shall be limited to such issues as identified by the Commission. One or more hearings to receive testimony from the public, as required by law, shall be set at a time and place designated by the Commission.

Within 60 days after the filing of each utility's Update Report required by section (j) of Rule R8-60, the Public Staff or any other intervenor may file an update report of its own as to any utility. Further, within the same time period the Public Staff shall report to the Commission whether each utility's Update Report meets the requirements of this rule. Intervenors may request leave from the Commission to file comments. Comments will be received or expert witness hearings held on the Update Reports only if the Commission deems it necessary. The scope of any comments or expert witness hearing shall be limited to issues identified by the Commission. One or more hearings to receive testimony from the public, as required by law, shall be set at a time and place designated by the Commission.

By November 30 of each year, each utility individually or jointly shall hold a meeting to review its Biennial or Update Report with interested parties.

2015 Update Reports

This Order addresses the 2015 Update Reports (2015 IRPs) filed in Docket No. E-100, Sub 141, by Duke Energy Progress, LLC (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 July 1, 2015, DNCP filed its 2015 IRP Update Report and 2015 REPS compliance plan. On July 31, 2015, DNCP filed an Errata to page 124 of its Update Report.

On August 27, 2015, the Public Staff filed a Motion for Extension of Time to file a report on whether the IRP of DNCP meets Commission requirements and for parties to file comments on DNCP's July 1 filing. Also on August 27, the Presiding Commissioner granted an extension of time to allow the Public Staff until September 21, 2015, to complete its compliance review, and to allow any party until September 21, 2015, to seek leave to file comments on DNCP's IRP Update Report.

On September 1, 2015, DEC and DEP filed 2015 IRP Update Reports and related REPS compliance plans. On September 9, 2015, DEP filed a revised page 22 to its Update Report to correct a typographical error.

On September 17, 2015, the Public Staff filed a Motion to Authorize Combined Comments on REPS Compliance Plans, asking that the Commission designate October 22, 2015, as the deadline for filing the combined comments on the REPS compliance plans of DEC, DEP and DNCP. This motion was approved on September 18, 2015, by the Presiding Commissioner. The order also noted that November 2, 2015, shall continue to be the deadline for parties to seek leave to file comments on DEC's and DEP's IRPs.

On September 21, 2015, the Public Staff filed its report regarding whether DNCP's Update Report meets the requirements of Commission Rule R8-60(j). Based on its review, the Public Staff determined that DNCP's Update Report met the requirements of the rule.

On September 28, 2015, Duke Energy filed notice that, after communicating with the parties, the stakeholder meeting to review the 2015 DEP and DEC IRPs has been scheduled for November 6, 2015, in Raleigh.

On October 22, 2015, the Public Staff filed its Comments on REPS Compliance Plans submitted by DEP, DEC and DNCP as part of their 2015 Update Reports. In its conclusions, the Public Staff stated that:

> 1. DEP, DEC, and DNCP should be able to meet their REPS obligations during the planning period, with the exception of the swine and poultry waste set-asides, without nearing or exceeding their cost caps.
>
> 2. DEP and DEC do not expect to meet the swine and poultry waste requirements in 2015 and are uncertain about meeting the requirements in 2016 and 2017. DNCP will have difficulty meeting the

swine waste requirements for itself during the reporting period, and the poultry waste requirements for Windsor in 2015; but it expects to meet the poultry waste requirements for itself throughout the reporting period, the swine waste requirements for Windsor throughout the period, and the poultry waste requirements for Windsor in 2016 and 2017. DEP, DEC, and DNCP are actively seeking energy and RECs to meet the set-aside requirements for the years in which they expect to fall short of compliance.

3. The Commission should approve the 2015 REPS Compliance Plans filed by DEP, DEC, and DNCP.

On October 27, 2015, DEC filed a Revision to Allen Units 1-3 Expected Retirement Date. In the filing, DEC stated that "pursuant to a settlement agreement to end the remaining component of a civil lawsuit filed in 2000 against Duke Energy Corporation by the U.S. Justice Department on behalf of the Environmental Protection Agency, DEC agreed to retire Allen Units 1, 2 and 3 by December 31, 2024. The U.S. District Court for the Middle District of North Carolina approved that settlement on October 20, 2015."

On November 2, 2015, the Public Staff submitted its report regarding whether DEC's and DEP's Update Reports met the requirements of Commission Rule R8-60(j). Based on its review, the Public Staff determined that DEC's and DEP's Update Reports did meet the requirements of the rule.

Also on November 2, 2015, NC WARN filed a Motion to Seek Leave to File Comments. Attached to its motion were NC WARN's proposed comments. In its proposed comments, NC WARN made four main assertions: (1) that Duke's forecasts for growth in demand for electricity are exaggerated; (2) that Duke fails to plan to use strategic purchases and cooperation with other utilities; (3) that Duke's IRPs include its continued reliance on expensive and unnecessary new natural gas and nuclear plants; 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. In addition, NC WARN incorporated by reference its updated report entitled "A Responsible Energy Future for North Carolina."

On November 9, 2015, DEC and DEP filed an Objection to NC WARN's Motion to Seek Leave to File Comments. In summary, DEC and DEP submitted that NC WARN's proposed comments restate the same opinions and allegations that NC WARN has filed and that the Commission has rejected in previous IRP dockets. Duke requested that the Commission deny NC WARN's motion and decline to accept NC WARN's proposed comments.

On November 23, 2015, the Commission issued an Order Scheduling Public Hearing on 2015 IRP Update Reports and Related 2015 REPS Compliance Plans. The order set the required Public Hearing for the night of February 8, 2016.

Also on November 23, 2015, the Commission issued an Order Denying Leave to File Comments and Declining to Accept Comments. In the Discussion and Conclusion section of that order the Commission stated the following:

> 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." The purpose of the IRP process is to gather facts and opinions that assist the Commission and the utilities to plan now in order to be in a position to make informed decisions at a later time. On the other hand, the IRP process is not designed to result in Commission "directives which fundamentally alter a given utility's operations." Instead, those directives are appropriate in other types of Commission proceedings, such as certificate of public convenience and necessity and complaint proceedings. <u>See State ex rel. Utils. Comm'n v. North Carolina Electric Membership Corporation</u>, 105 N.C. App. 136, 144, 412 S.E.2d 166, 170, 173 (1992).
>
> As noted earlier, the Commission amended Rule R8-60 to establish guidelines for the Commission's review of the IRP updates filed by the electric utilities in odd-numbered years. As fully discussed in the IRP Procedure Order, one purpose of the amendments is to streamline the process for the Public Staff's review and the Commission's decision on the IRP updates. The IRP update process had become cumbersome and time consuming, due in large part to repetitive filings addressing the same or substantially similar facts. In an effort to alleviate unneeded repetition, the Commission adopted Rule R8-60(l), requiring that intervenors request leave from the Commission to file comments on the update reports, and providing that such comments will be limited to issues identified by the Commission.
>
> The proposed comments filed by NC WARN are essentially the same as the comments filed by NC WARN in the 2014 IRP biennial proceeding. The Commission carefully considered NC WARN's comments in the 2014 IRP proceeding. However, the Commission is not convinced that these same comments are helpful in the present IRP update proceeding. As a result, the Commission is not persuaded that there is good cause to grant NC WARN's motion for leave to file comments. Therefore, the Commission concludes that the motion should be denied and the comments should not be accepted.
>
> In addition, the Commission emphasizes that Rule R8-60(l) limits intervenor comments, when permitted by leave of the Commission, to those issues identified by the Commission. Thus, it is intended and will be

helpful if parties will file their motion for leave to file comments and identify the issues that they seek to address.

Public Hearing

Pursuant to G.S. 62-110.1(c), the Commission held a required public hearing in Raleigh on February 8, 2016, as scheduled. Thirteen public witnesses spoke. Eight of the 13 discussed various issues related to smart meters, which are part of a separate proceeding in this docket.

The five public witnesses that addressed IRP related issues were all customers of Duke Energy. Most of their testimony expressed their views that Duke is not paying enough attention to solar and other forms of renewable energy such as biomass, geothermal, hydro and wind generation as potential alternatives. In addition, they opined that the cost of solar and wind generation is plummeting and that battery storage has arrived in the market.

Various issues related to coal generation and coal ash were also discussed, as well as the view that energy efficiency is already the least-cost resource available.

Conclusion

Based upon the record in this proceeding, and the comments of the Public Staff regarding the IRP Update Reports and REPS compliance plans submitted by DEC, DEP and DNCP, the Commission hereby accepts the Update Reports filed by the utilities as complete and fulfilling the requirements set out in Commission Rule R8-60. The Commission further approves the REPS compliance plans submitted by DEC, DEP and DNCP as recommended by the Public Staff.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.

This the 22nd day of March, 2016.

NORTH CAROLINA UTILITIES COMMISSION

Paige J. Morris

Paige J. Morris, Deputy Clerk

Commissioner Lyons Gray did not participate.

Table 6-A **Load, Capacity and Reserves Table - Summer**

Summer Projections of Load, Capacity, and Reserves
for Duke Energy Carolinas 2015 Annual Plan

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load Forecast															
1 Duke System Peak	18,811	19,176	19,613	19,706	20,039	20,296	20,607	20,908	21,217	21,524	21,810	22,131	22,462	22,770	23,125
Catawba Owner Backstand	47	47	47	47	47	0	0	0	0	0	0	0	0	0	0
2 Firm Sale	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(140)	(202)	(263)	(325)	(381)	(438)	(486)	(531)	(568)	(590)	(601)	(604)	(603)	(606)	(608)
4 Adjusted Duke System Peak	**18,672**	**18,974**	**19,350**	**19,381**	**19,658**	**19,859**	**20,121**	**20,377**	**20,649**	**20,934**	**21,209**	**21,527**	**21,859**	**22,164**	**22,517**
Existing and Designated Resources															
5 Generating Capacity	20,368	20,389	20,734	21,104	21,114	21,120	21,120	21,120	21,120	21,120	21,120	21,120	21,120	19,993	19,993
6 Designated Additions / Uprates	21	345	670	10	6	0	0	0	0	0	0	0	0	0	0
7 Retirements / Derates	0	0	(300)	0	0	0	0	0	0	0	0	0	(1,127)	0	0
8 Cumulative Generating Capacity	**20,389**	**20,734**	**21,104**	**21,114**	**21,120**	**21,120**	**21,120**	**21,120**	**21,120**	**21,120**	**21,120**	**21,120**	**19,993**	**19,993**	**19,993**
Purchase Contracts															
9 Cumulative Purchase Contracts	**228**	**223**	**217**	**177**	**172**	**86**	**68**	**66**	**46**	**46**	**37**	**37**	**35**	**10**	**2**
Non-Compliance Renewable Purchases	69	64	58	56	54	54	54	42	33	33	23	23	21	10	2
Non-Renewables Purchases	159	159	159	121	118	32	14	14	14	14	14	14	14	0	0
Undesignated Future Resources															
10 Nuclear	0	0	0	0	0	0	0	0	1,117	0	1,117	0	0	0	0
11 Combined Cycle	0	0	0	0	0	0	895	0	0	0	0	0	895	0	895
12 Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13 CHP	0	0	20	0	20	0	0	0	0	0	0	0	0	0	0
Renewables															
14 Cumulative Renewables Capacity	212	200	202	459	708	961	1,044	1,057	1,079	1,093	1,110	1,122	1,140	1,160	1,171
15 Cumulative Production Capacity	**20,829**	**21,167**	**21,642**	**21,769**	**22,040**	**22,207**	**23,167**	**23,168**	**24,297**	**24,311**	**26,436**	**26,448**	**26,232**	**26,227**	**26,124**
Demand Side Management (DSM)															
16 Cumulative DSM Capacity	**1,066**	**1,064**	**1,097**	**1,127**	**1,161**	**1,202**	**1,202**	**1,202**	**1,202**	**1,202**	**1,202**	**1,202**	**1,202**	**1,202**	**1,202**
17 Cumulative Capacity w/ DSM	**21,886**	**22,221**	**22,639**	**22,897**	**23,191**	**23,409**	**24,369**	**24,370**	**25,499**	**25,513**	**26,637**	**26,650**	**26,434**	**26,429**	**27,326**
Reserves w/ DSM															
18 Generating Reserves	3,214	3,247	3,289	3,515	3,533	3,550	4,248	3,993	4,850	4,580	5,428	5,122	4,575	4,266	4,809
19 % Reserve Margin	**17.2%**	**17.1%**	**17.0%**	**18.1%**	**18.0%**	**17.9%**	**21.1%**	**19.6%**	**23.6%**	**21.9%**	**25.6%**	**23.8%**	**20.9%**	**19.2%**	**21.4%**

Table 6-B Load, Capacity and Reserves Table – Winter

Winter Projections of Load, Capacity, and Reserves for Duke Energy Carolinas 2015 Annual Plan

	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	29/30
Load Forecast														
1 Duke System Peak	18,019	18,377	18,782	18,846	19,180	19,449	19,687	19,959	20,259	20,543	20,851	21,134	21,476	21,797
2 Firm Sale	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(75)	(117)	(157)	(195)	(255)	(293)	(326)	(357)	(382)	(398)	(406)	(408)	(409)	(411)
4 Adjusted Duke System Peak	**17,943**	**18,260**	**18,626**	**18,651**	**18,925**	**19,156**	**19,360**	**19,602**	**19,877**	**20,145**	**20,445**	**20,726**	**21,067**	**21,386**
Existing and Designated Resources														
5 Generating Capacity	21,155	21,200	21,970	21,970	21,980	21,986	21,986	21,986	21,986	21,986	21,986	21,986	21,986	20,825
6 Designated Additions / Uprates	45	1,070	0	10	6	0	0	0	0	0	0	0	0	0
7 Retirements / Derates	0	(300)	0	0	0	0	0	0	0	0	0	0	(1,161)	0
8 Cumulative Generating Capacity	**21,200**	**21,970**	**21,970**	**21,980**	**21,986**	**21,986**	**21,986**	**21,986**	**21,986**	**21,986**	**21,986**	**21,986**	**20,825**	**20,825**
Purchase Contracts														
9 Cumulative Purchase Contracts	**193**	**191**	**185**	**146**	**141**	**49**	**31**	**19**	**18**	**18**	**17**	**17**	**16**	**1**
Non-Compliance Renewable Purchases	28	26	20	19	17	17	17	5	4	4	3	3	2	1
Non-Renewables Purchases	165	165	165	127	124	32	14	14	14	14	14	14	14	0
Undesignated Future Resources														
10 Nuclear	0	0	0	0	0	0	0	0	1,117	0	1,117	0	0	0
11 Combined Cycle	0	0	0	0	0	0	935	0	0	0	0	0	935	0
12 Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13 CHP	0	0	20	0	20	0	0	0	0	0	0	0	0	0
Renewables														
14 Cumulative Renewables Capacity	114	94	89	113	145	179	194	195	203	206	206	204	206	208
15 Cumulative Production Capacity	**21,507**	**22,255**	**22,264**	**22,259**	**22,312**	**22,254**	**23,185**	**23,174**	**24,298**	**24,302**	**25,417**	**25,415**	**25,191**	**25,178**
Demand Side Management (DSM)														
16 Cumulative DSM Capacity	**554**	**551**	**553**	**556**	**558**	**553**	**553**	**553**	**553**	**553**	**553**	**553**	**553**	**553**
17 Cumulative Capacity w/ DSM	**22,061**	**22,806**	**22,817**	**22,814**	**22,870**	**22,807**	**23,738**	**23,727**	**24,851**	**24,855**	**25,970**	**25,968**	**25,744**	**25,731**
Reserves w/ DSM														
18 Generating Reserves	4,118	4,546	4,191	4,163	3,946	3,651	4,378	4,125	4,974	4,710	5,525	5,242	4,677	4,345
19 % Reserve Margin	**22.9%**	**24.9%**	**22.5%**	**22.3%**	**20.8%**	**19.1%**	**22.6%**	**21.0%**	**25.0%**	**23.4%**	**27.0%**	**25.3%**	**22.2%**	**20.3%**

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.

   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. No additional firm sales are included.

3. Cumulative new 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 January 2015.

   Includes 101 MW Nantahala hydro capacity, and total capacity for Catawba Nuclear Station less 832 MW to account for NCMPA1 firm capacity sale.

6. A short-term 300 MW PPA is included in 2017, and removed in the fall of 2017.

   This PPA is a placeholder to ensure compliance with the minimum planning reserve margin and will be re-evaluated in the coming months.

   Lee Combined Cycle is reflected in 2018 (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 2016-2020 timeframe and total 17 MW.

   Also included is a 65 MW capacity increase due to nuclear uprates at Catawba, McGuire, and Oconee. Timing of these uprates is shown from 2016-2017.

7. The short-term 300 MW PPA is removed in the fall of 2017.

   A planning assumption for coal retirements has been included in the 2015 IRP.

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

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

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

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.

8. Sum of lines 5 through 7.

9. Cumulative Purchase Contracts including purchased capacity from PURPA Qualifying Facilities, an 86 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 895 MW of combined cycle capacity in 2022, 2028 and 2030.

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

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

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 combustion turbine resources were selected in the Base Case.

13. New 20 MW combined heat and power units included in 2018 and 2020. The 2015 IRP represents the first time that CHP resources have been included in the IRP.

14. Cumulative solar, biomass, hydro and wind resources to meet NC REPS and SC DERP compliance.

    Also includes Green Source solar projects.

15. Sum of lines 8 through 14.

16. Cumulative Demand Response programs including load control and DSDR.

17. Sum of lines 15 and 16.

18. The difference between lines 17 and 4.

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

    Line 18 divided by Line 4.

    Minimum target planning reserve margin is 17%.

Table 6-A Load, Capacity and Reserves Table – Summer

Summer Projections of Load, Capacity, and Reserves for Duke Energy Progress 2015 Annual Plan

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load Forecast															
1 Duke System Peak	13,048	13,224	13,402	13,595	13,949	14,208	14,444	14,709	14,901	15,082	15,264	15,440	15,636	15,814	15,981
2 Firm Sale	150	150	150	150	150	150	150	150	150	0	0	0	0	0	0
3 Cumulative New EE Programs	(67)	(96)	(125)	(155)	(183)	(212)	(239)	(265)	(290)	(313)	(330)	(342)	(344)	(349)	(352)
4 Adjusted Duke System Peak	**13,131**	**13,277**	**13,427**	**13,590**	**13,916**	**14,146**	**14,355**	**14,595**	**14,761**	**14,770**	**14,934**	**15,098**	**15,292**	**15,465**	**15,629**
Existing and Designated Resources															
5 Generating Capacity	12,776	12,776	12,813	12,828	12,963	13,194	12,844	12,844	12,844	12,844	12,844	12,844	12,664	12,664	12,664
6 Designated Additions / Uprates	0	98	15	135	1,013	0	0	0	0	0	0	0	0	0	0
7 Retirements / Derates	0	(61)	0	0	(782)	(350)	0	0	0	0	0	(180)	0	0	(741)
8 Cumulative Generating Capacity	**12,776**	**12,813**	**12,828**	**12,963**	**13,194**	**12,844**	**12,844**	**12,844**	**12,844**	**12,844**	**12,844**	**12,664**	**12,664**	**12,664**	**11,923**
Purchase Contracts															
9 Cumulative Purchase Contracts	**1,919**	**1,930**	**1,930**	**1,761**	**1,616**	**861**	**528**	**528**	**528**	**528**	**478**	**477**	**452**	**419**	**407**
Non-Compliance Renewable Purchases	177	188	188	188	188	132	131	130	130	130	80	80	58	25	12
Non-Renewables Purchases	1,742	1,742	1,742	1,574	1,429	729	397	397	397	397	397	397	394	394	394
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	895	895	0	0	0	0	0	0	0	895
12 Combustion Turbine	0	0	0	0	0	828	0	0	0	0	0	828	0	0	0
13 CHP	0	0	0	20	0	20	0	0	0	0	0	0	0	0	0
Renewables															
14 Cumulative Renewables Capacity	437	473	433	434	437	348	347	619	637	645	639	653	667	677	666
15 Cumulative Production Capacity	**15,132**	**15,217**	**15,191**	**15,179**	**15,268**	**15,816**	**16,378**	**16,648**	**16,666**	**16,674**	**16,618**	**17,280**	**17,269**	**17,246**	**17,377**
Demand Side Management (DSM)															
16 Cumulative DSM Capacity	**871**	**923**	**967**	**1,004**	**1,021**	**1,029**	**1,032**	**1,034**	**1,037**	**1,040**	**1,043**	**1,046**	**1,049**	**1,052**	**1,055**
17 Cumulative Capacity w/ DSM	**16,003**	**16,140**	**16,159**	**16,183**	**16,288**	**16,845**	**17,409**	**17,683**	**17,703**	**17,715**	**17,662**	**18,326**	**18,319**	**18,298**	**18,432**
Reserves w/ DSM															
18 Generating Reserves	2,872	2,862	2,732	2,593	2,372	2,698	3,054	3,088	2,942	2,945	2,728	3,228	3,027	2,832	2,803
19 % Reserve Margin	**21.9%**	**21.6%**	**20.3%**	**19.1%**	**17.0%**	**19.1%**	**21.3%**	**21.2%**	**19.9%**	**19.9%**	**18.3%**	**21.4%**	**19.8%**	**18.3%**	**17.9%**

Table 6-B Load, Capacity and Reserves Table – Winter

Winter Projections of Load, Capacity, and Reserves
for Duke Energy Progress 2015 Annual Plan

	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	29/30
Load Forecast														
1 Duke System Peak	12,767	12,938	13,133	13,342	13,531	13,703	13,882	14,062	14,278	14,437	14,621	14,797	15,022	15,183
2 Firm Sale	150	150	150	150	150	150	150	150	150	0	0	0	0	0
3 Cumulative New EE Programs	(40)	(62)	(84)	(105)	(129)	(151)	(171)	(190)	(209)	(226)	(240)	(249)	(250)	(253)
4 Adjusted Duke System Peak	**12,877**	**13,027**	**13,200**	**13,386**	**13,553**	**13,702**	**13,861**	**14,022**	**14,220**	**14,211**	**14,381**	**14,548**	**14,772**	**14,930**
Existing and Designated Resources														
5 Generating Capacity	13,895	13,899	13,917	13,935	14,289	13,772	13,772	13,772	13,772	13,772	13,772	13,772	13,540	13,540
6 Designated Additions / Uprates	4	94	18	733	350	0	0	0	0	0	0	0	0	0
7 Retirements / Derates	0	(76)	0	(379)	(867)	0	0	0	0	0	0	(232)	0	0
8 Cumulative Generating Capacity	**13,899**	**13,917**	**13,935**	**14,289**	**13,772**	**13,772**	**13,772**	**13,772**	**13,772**	**13,772**	**13,772**	**13,540**	**13,540**	**13,540**
Purchase Contracts														
9 Cumulative Purchase Contracts	**2,006**	**2,017**	**2,017**	**2,017**	**1,704**	**1,148**	**502**	**502**	**502**	**502**	**452**	**452**	**441**	**434**
Non-Compliance Renewable Purchas	126	137	137	137	137	81	80	80	80	80	30	30	22	15
Non-Renewables Purchases	1,880	1,880	1,880	1,880	1,567	1,066	422	422	422	422	422	422	419	419
Undesignated Future Resources														
10 Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 Combined Cycle	0	0	0	0	0	935	935	0	0	0	0	0	0	0
12 Combustion Turbine	0	0	0	0	0	878	0	0	0	0	0	878	0	0
13 CHP	0	0	0	20	0	20	0	0	0	0	0	0	0	0
Renewables														
13 Cumulative Renewables Capacity	222	257	216	216	218	129	129	178	174	177	176	179	178	183
14 Cumulative Production Capacity	**16,127**	**16,191**	**16,168**	**16,542**	**15,714**	**16,901**	**17,191**	**17,240**	**17,236**	**17,239**	**17,188**	**17,837**	**17,826**	**17,823**
Demand Side Management (DSM)														
15 Cumulative DSM Capacity	**531**	**552**	**569**	**583**	**595**	**606**	**610**	**613**	**617**	**621**	**624**	**628**	**631**	**634**
16 Cumulative Capacity w/ DSM	**16,658**	**16,743**	**16,737**	**17,125**	**16,310**	**17,508**	**17,800**	**17,853**	**17,853**	**17,860**	**17,813**	**18,464**	**18,456**	**18,457**
Reserves w/ DSM														
17 Generating Reserves	3,781	3,716	3,537	3,739	2,757	3,806	3,940	3,831	3,633	3,648	3,432	3,916	3,684	3,527
18 % Reserve Margin	**29.4%**	**28.5%**	**26.8%**	**27.9%**	**20.3%**	**27.8%**	**28.4%**	**27.3%**	**25.6%**	**25.7%**	**23.9%**	**26.9%**	**24.9%**	**23.6%**

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 firm sales and cumulative energy efficiency.

5. Existing generating capacity reflecting designated additions, planned uprates, retirements and derates as of January 1, 2015.

   Includes total unit capacity of jointly owned units.

6. Capacity Additions include:

   Planned nuclear uprates totaling 29 MW in the 2017-2018 timeframe.

   Planned combined cycle uprates totaling 135 MW in 2019.

   84 MW Sutton Blackstart combustion turbine addition in 2017.

   A short-term 350 MW PPA is included in 2017, and removed in the fall of 2017.

   This PPA is a placeholder to ensure compliance with the minimum planning reserve margin and will be re-evaluated in the coming months.

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).

   Robinson 2 in 2030 (741 MW).

8. Sum of lines 5 through 7.

DEP - Assumptions of Load, Capacity, and Reserves Table (cont.)

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.

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 895 MW of combined cycle capacity in 2021, 2022 and 2030.

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 828 MW of combustion turbine capacity in 2021 and 2027.

13. New CHP resources. 20 MW in 2019 and 20 MW in 2021.

14. Cumulative solar, biomass, hydro and wind resources to meet NC REPS and SC DERP compliance.

    Also includes utility-owned solar.

DEP - Assumptions of Load, Capacity, and Reserves Table (cont.)

15. Sum of lines 8 through 14.

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

17. Sum of lines 15 and 16.

18. The difference between lines 17 and 4.

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

    Line 18 divided by Line 4.

    Minimum target planning reserve margin is 17%.

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

Company Name: Virginia Electric and Power Company

Schedule 1

I. PEAKLOAD AND ENERGY FORECAST

	(ACTUAL)[1]				(PROJECTED)														
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1. Utility Peak Load (MW)																			
A. Summer																			
1a. Base Forecast	16,787	16,366	16,249	17,475	17,925	18,179	18,563	19,031	19,388	19,582	19,799	20,024	20,437	20,710	20,977	21,156	21,305	21,574	21,938
1b. Additional Forecast																			
NCEMC	150	150	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Conservation, Efficiency[4]	-40	-47	-51	-75	-115	-148	-176	-197	-210	-200	-194	-194	-196	-196	-198	-200	-201	202	-204
3. Demand Response[2][5]	-83	-83	-117	-127	-149	-180	-220	-266	-321	-380	-383	-387	-390	-394	-397	-399	-401	-404	-407
4. Demand Response-Existing[2][3]	-7	-5	-3	-3	-3	-3	-3	-3	-3	-3	3	-3	-3	-3	-3	-3	-3	-3	-3
5. Peak Adjustment	-	-	-	42	116	270	215	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55
6. Adjusted Load	16,897	16,469	16,348	17,442	17,926	18,302	18,601	18,779	19,123	19,327	19,550	19,775	20,186	20,459	20,724	20,901	21,049	21,317	21,679
7. % Increase in Adjusted Load (from previous year)	-4.2%	-2.5%	-0.7%	6.7%	2.8%	2.1%	1.6%	1.0%	1.8%	1.1%	1.2%	1.2%	2.1%	1.3%	1.3%	0.9%	0.7%	1.3%	1.7%
B. Winter																			
1a. Base Forecast	14,544	15,106	16,840	14,969	15,230	15,441	15,569	15,778	16,020	16,251	16,545	16,659	16,771	17,057	17,250	17,524	17,847	17,863	18,084
1b. Additional Forecast																			
NCEMC	150	150	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Conservation, Efficiency[4]	-40	-47	-51	-0.1	-2	-6	-10	-14	-14	-15	-15	-15	-15	-15	-15	-16	-16	-16	-16
3. Demand Response[2][4]	-16	-15	-14	-20	-20	-21	-24	-26	-28	-29	-30	-31	-32	-34	-35	-36	-37	-38	-39
4. Demand Response-Existing[2][3]	-6	-5	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2
5. Adjusted Load	14,654	15.209	16,939	14,969	15,227	15,435	15,559	15,764	16,006	16,236	16,530	16,644	16,756	17,042	17,235	17,508	17,831	17,847	18,068
6. % Increase in Adjusted Load	-4.6%	3.8%	11.4%	-11.6%	1.7%	1.4%	0.8%	1.3%	1.5%	1.4%	1.8%	0.7%	0.7%	1.7%	1.1%	1.6%	1.8%	0.1%	1.2%
2. Energy (GWh)																			
A. Base Forecast	81,498	83,311	84,401	86,386	89,027	90,369	91,831	93,059	94,644	95,596	96,896	98,184	99,707	100,765	101,968	103,254	104,834	105,879	107,076
B. Additional Forecast																			
NCEMC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Future BTM[6]	-	-	-	-410	-410	-410	-410	-410	-410	-410	-410	-410	-410	-410	-410	-410	-410	-410	-410
C. Conservation & Demand Response[5]	-338	-351	-558	-623	-811	-969	-1,144	-1,416	-1,749	-1,993	-2,260	-2,576	-2,833	-2,944	-2,953	-2,986	-2,992	-3,000	-3,008
D. Demand Response-Existing[2][3]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E. Adjusted Energy	81,160	82,960	83,843	85,353	87,806	88,990	90,277	91,233	92,486	93,193	94,226	95,198	96,464	97,352	98,606	99,859	101,432	102,470	103,658
F. % Increase in Adjusted Energy	-2.3%	2.2%	1.1%	1.8%	2.9%	1.3%	1.4%	1.1%	1.4%	0.8%	1.1%	1.0%	1.3%	0.9%	1.3%	1.3%	1.6%	1.0%	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.

Appendix 2I – Required Reserve Margin

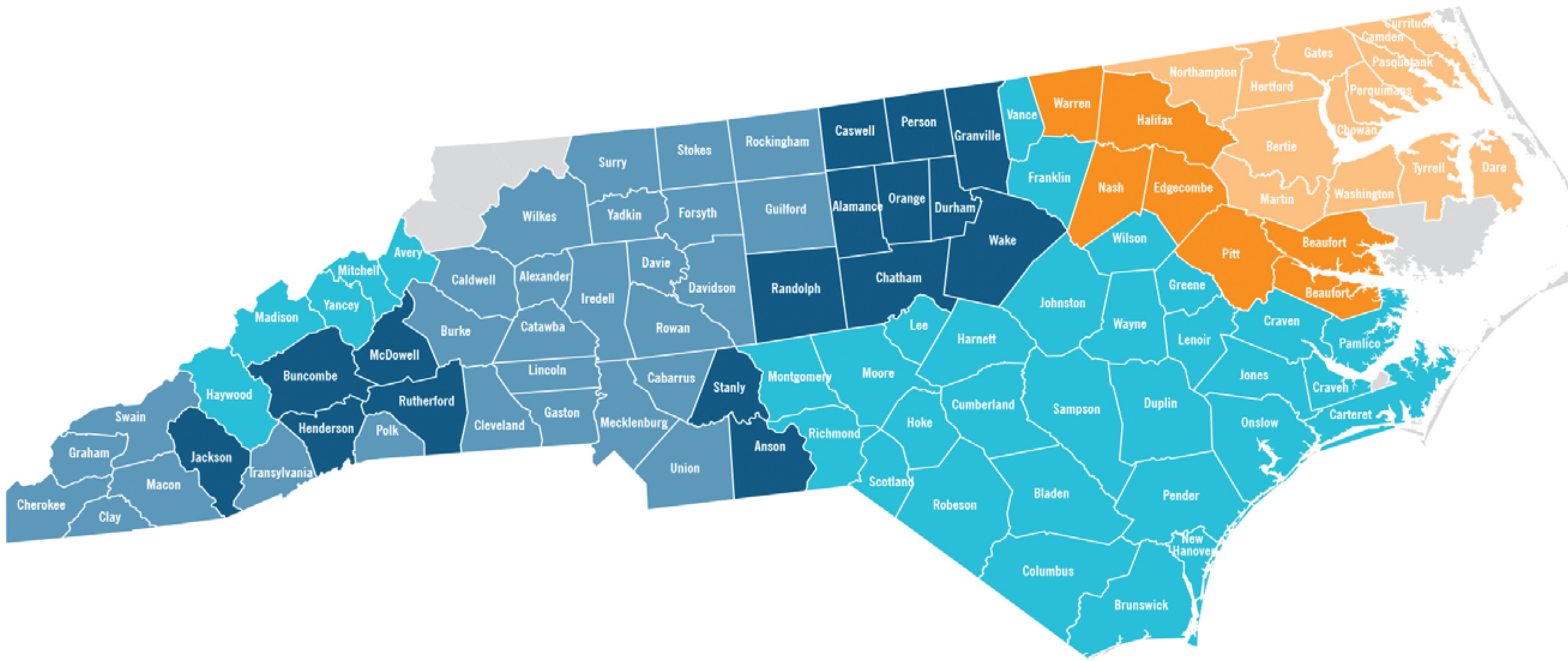
Company Name: Virginia Electric and Power Company

Schedule 6

POWER SUPPLY DATA (continued)

	(ACTUAL)			(PROJECTED)															
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
I. Reserve Margin[1]																			
(Including Cold Reserve Capability)																			
1. Summer Reserve Margin																			
a. MW[1]	2,580	3,026	3,955	3,623	4,000	2,741	2,391	2,681	2,202	2,226	2,781	2,593	2,325	2,356	2,387	2,407	2,424	2,455	2,918
b. Percent of Load	15.3%	18.4%	24.2%	20.8%	22.3%	15.0%	12.9%	14.3%	11.5%	11.5%	14.2%	13.1%	11.5%	11.5%	11.5%	11.5%	11.5%	11.5%	13.5%
c. Actual Reserve Margin[3]	N/A	N/A	N/A	16.9%	17.0%	12.2%	9.2%	14.3%	9.0%	8.2%	14.3%	13.1%	11.1%	9.8%	9.0%	8.7%	8.6%	7.9%	13.5%
2. Winter Reserve Margin																			
a. MW[1]	N/A	N/A	N/A	6,514	6,698	6,492	5,141	5,959	5,396	5,167	6,362	6,444	6,139	5,854	5,858	5,391	5,265	5,251	6,741
b. Percent of Load	N/A	N/A	N/A	43.5%	44.0%	42.1%	33.0%	37.8%	33.7%	31.8%	38.5%	38.7%	36.6%	34.4%	34.0%	30.8%	29.5%	29.4%	37.3%
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]	2,475	3,026	3,955	3,623	4,000	2,741	2,391	2,681	2,202	2,226	2,781	2,593	2,325	2,356	2,387	2,407	2,424	2,455	2,918
b. Percent of Load	14.6%	18.4%	24.2%	20.8%	22.3%	15.0%	12.9%	14.3%	11.5%	11.5%	14.2%	13.1%	11.5%	11.5%	11.5%	11.5%	11.5%	11.5%	13.5%
c. Actual Reserve Margin[3]	N/A	N/A	N/A	16.9%	17.0%	12.2%	9.2%	14.3%	9.0%	8.2%	14.3%	13.1%	11.1%	9.8%	9.0%	8.7%	8.6%	7.9%	13.5%
2. Winter Reserve Margin																			
a. MW[1]	N/A	N/A	N/A	6,514	6,698	6,492	5,141	5,959	5,396	5,167	6,362	6,444	6,139	5,854	5,858	5,391	5,265	5,251	6,741
b. Percent of Load	N/A	N/A	N/A	43.5%	44.0%	42.1%	33.0%	37.8%	33.7%	31.8%	38.5%	38.7%	36.6%	34.4%	34.0%	30.8%	29.5%	29.4%	37.3%
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 forecast 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