

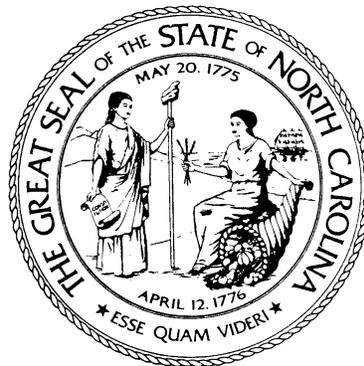
**ANNUAL REPORT REGARDING  
LONG RANGE NEEDS FOR EXPANSION OF  
ELECTRIC GENERATION FACILITIES FOR SERVICE  
IN NORTH CAROLINA**

**REQUIRED PURSUANT TO N.C. Gen. Stat. § 62-110.1(c)**

**DATE DUE: DECEMBER 31, 2018**

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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

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**ACE** EPA's Affordable Clean Energy Rule

**CC** combined-cycle

**CEPCN** Certificate of Environmental Compatibility and Public Convenience and Necessity

**CIGFUR** Carolina Industrial Group for Fair Utility Rates

**COL** combined construction and operating license

**CPCN** Certificate of Public Convenience and Necessity

**CPP** EPA's Clean Power Plan

**CT** combustion turbine/s

**CUCA** Carolina Utility Customers Association, Inc.

**DOE** U.S. Department of Energy

**DSM** demand-side management

**Duke** Duke Energy Carolinas, LLC

**Dominion** Dominion Energy North Carolina

**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-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  
**VOWTAP** Virginia Offshore Wind Technology Advancement Project  
**WPSA** Wholesale Power Supply Agreement

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## APPENDICES

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<i>Appendix 1</i>	<i>Order accepting filing of 2017 Integrated Resource Plan Update Reports and accepting 2017 REPS Compliance Plans (Docket No. E-100, Sub 147)</i>
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# 1. EXECUTIVE SUMMARY

This annual report to the Governor and the General Assembly is submitted pursuant to N.C. Gen. Stat. § 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 Energy North Carolina (Dominion).

Duke and Progress, the two largest electric IOUs in North Carolina, together provide approximately 96% of the utility-supplied electricity consumed in the state. Approximately 22% of the IOUs' 2017 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)	
	2017	2016	2017	2016	2017	2016
Progress	37,023	37,500	21,051	22,493	66,823	69,052
Duke	56,283	57,803	6,256	6,083	87,307	88,545
VEPCO	4,167	4,294	1,172	1,301	84,970	87,875

\*GWh = 1 Million kWh (kilowatt-hours)

During the 2018 to 2032 timeframe, the average annual growth rate in summer peak demand for electricity in North Carolina is forecasted to be approximately 0.5% compared to 0.8% for winter peak load growth. 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 VEPCO  
(With Energy Efficiency (EE) Included)  
(2018 – 2032)**

	Summer Peak	Winter Peak	Energy Sales
Progress	0.7%	0.7%	0.6%
Duke	0.4%	0.9%	0.4%
VEPCO	1.3%	1.2%	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 2017**

	Progress	Duke	VEPCO
Coal	12%	28%	20%
Nuclear	43%	49%	37%
Net Hydroelectric*	1%	1%	1%
Natural Gas and Oil	32%	12%	37%
Non-Hydro Renewable	7%	1%	2%
Other Purchased Power	5%	9%	3%

\* See discussion of pumped storage in Section 6.

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 N.C. Gen. Stat. § 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 2018, requiring investor-owned utilities to meet 10% of their prior year's NC retail sales through renewable energy and EE sources. This issue is discussed further in Section 8.

The electric utilities are subject to federal, state and local laws and regulations with regard to air and water quality, hazardous and solid waste disposal and other environmental laws and regulations. Environmental compliance directly impacts existing generation portfolios and choices for new generation resources. For example, the utilities evaluate how robust their plans are relative to potential greenhouse gas regulations as well as their own sustainability goals.

In addition, the Governor of North Carolina issued an Executive Order on October 29, 2018, which stated in part, that the State of North Carolina will strive to reduce statewide greenhouse gas emissions to 40% below 2005 levels by 2025. The utilities' existing plans, as reflected in their IRPs, already account for significant CO<sub>2</sub> reductions consistent with this goal. The IRPs, however, may also be influenced by activities in response to the Executive Order such as the development of a North Carolina Clean Energy Plan.

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

## 2. INTRODUCTION

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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. N.C.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 N.C.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 21, 2017 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 Energy North Carolina (Dominion). 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 approximately 96% of the utility-supplied electricity consumed in the state. As of December 31, 2017, Duke had 1,976,000 customers located in North Carolina, and Progress had 1,379,000. Each also has customers in South Carolina. Dominion supplies approximately 4% of the State's utility-generated electricity. It has 121,000 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 23% 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 2017 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)	
	2017	2016	2017	2016	2017	2016
Progress	37,023	37,500	21,051	22,493	66,823	69,052
Duke	56,283	57,803	6,256	6,083	87,307	88,545
VEPCO	4,167	4,294	1,172	1,301	84,970	87,875

\*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 metered customers in North Carolina. EMCs serve approximately 25% of the State's population. Twenty-six EMCs are headquartered in the State, and these twenty-six EMCs

served 1,052,750 metered customers in 2017. 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, which 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 is also a part owner in the 750 MW Lee Combined Cycle Plant located in Anderson, South Carolina. Duke owns approximately 650 MWs of the plant and NCEMC owns approximately 100 MWs. Duke is responsible for project operation.

Additionally, 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. Most EMCs also receive an allocation of hydroelectric power from the Southeastern Power Administration (SEPA).

Finally, NCEMC has facilitated the development of 18 community solar facilities, operates microgrids located on Ocracoke Island and at Butler Farm in Harnett County, and partners with its members to (a) implement DSM/EE programs such as a demand response programs for Wi-Fi enabled thermostats that currently has over 2,000 member-owner thermostats enrolled, and (b) deploy emerging technology such as 350 smart controllers on existing electric resistance water heaters and electric vehicle charging infrastructure.

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 Dominion. The Dominion 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 595,000 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.

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.

Both agencies purchase supplemental power as needed above their own generating resources, usually from investor-owned utilities and federally owned hydro-electric systems.

The Tennessee Valley Authority (TVA) sells energy directly to the Murphy Power Board and to three out-of-state cooperatives that supply power to portions of North Carolina: Blue Ridge Mountain EMC, Tri-State Membership Corporation, and Mountain Electric

Cooperative. These distributors of TVA power are located in six North Carolina counties and serve over 33,000 households and 9,000 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.

## **4. THE HISTORY OF INTEGRATED RESOURCE PLANNING IN NORTH CAROLINA**

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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 N.C.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 N.C.G.S. § 62-110.1(c) and N.C. Gen. Stat. § 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.

<p style="text-align: center;"><b>2017 IRP Update Reports and Related 2017 REPS Compliance Plans (Docket No. E-100, Sub 147)</b></p>
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2017 IRP Update Reports and REPS compliance plans filed by Progress, Duke and Dominion provided updates to their current Biennial Reports (Docket E-100, Sub 147). A public hearing in this docket was held in Raleigh on February 5, 2018 for the purpose of receiving non-expert public testimony. No public witnesses attended the hearing.

Based upon the record in the proceeding, and the comments of the Public Staff regarding the IRP Update Reports and REPS compliance plans submitted by DEC, DEP and DENC, the Commission accepted the 2017 IRPs filed by the utilities as complete and fulfilling the requirements set out in Commission Rule R8-60. The Commission further accepted the REPS compliance plans submitted by DEC, DEP and DENC, as recommended by the Public Staff. The Commission's April 16, 2018 Order can be found in the back of this report as Appendix 1.

Updated biennial reports were filed with the Commission in 2018 including current integrated resource plans and REPS compliance plans (Docket E-100, Sub 157).

## 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 VEPCO 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 VEPCO. These growth rates are based on the utilities' system peak load requirements.

**Table 2: Forecast Annual Growth Rates for Progress, Duke, and VEPCO  
(With Energy Efficiency (EE) Included)  
(2018– 2032)**

	Summer Peak	Winter Peak	Energy Sales
Progress	0.7%	0.7%	0.6%
Duke	0.4%	0.9%	0.4%
VEPCO	1.3%	1.2%	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 2017 Long-Term Reliability Assessment by the North American Electric Reliability Corporation (NERC) indicates a forecast of average annual growth in peak demand of approximately 1.0% through 2027.

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

**Table 3: Summer and Winter Systemwide Peak Loads for Progress, Duke, and VEPCO Since 2013 (in MW)**

	Progress		Duke		VEPCO	
	Summer	Winter*	Summer	Winter*	Summer	Winter*
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
2016	13,130	14,534	20,671	19,183	19,538	19,661
2017	12,784	15,519	20,120	21,620	18,902	21,232

\*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. However, purchases including renewables now make up a significant percentage of summer load resources. Generating plants are usually classified by fuel type (nuclear, coal, gas/oil, hydro, renewable, 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, combined-cycle natural gas units, and some large coal facilities, 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.

VEPCO 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. On October 16, 2018 Dominion Energy Virginia filed an application with the U.S. Nuclear Regulatory Commission to renew its operating licenses for the Surry nuclear plant for an additional 20 years which would keep the plant on line beyond 2050.

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 VEPCO for large-scale storage. 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 2017**

	Progress	Duke	VEPCO
Coal	28%	32%	21%
Nuclear	27%	34%	17%
Hydroelectric	2%	15%	11%
Natural Gas and Oil	42%	19%	50%
Non-Hydro Renewable	1%	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 2017, is provided in Table 5.

**Table 5: Total Energy Resources by Fuel Type for 2017**

	Progress	Duke	VEPCO
Coal	12%	28%	20%
Nuclear	43%	49%	37%
Net Hydroelectric*	1%	1%	1%
Natural Gas and Oil	32%	12%	37%
Non-Hydro Renewable	7%	1%	2%
Other Purchased Power	5%	9%	3%

\* 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 utilities continue to address all aspects of environmental compliance, including greenhouse gas regulation, in their resource planning. The following highlights from utility generation planning exercises reflect information contained in the 2018 Integrated Resource Plans filed with the Commission.

## Progress Generation

As of July 2018, Progress had 13,919 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 in November 2019. 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 application for a Certificate of Public Convenience and Necessity (CPCN) for the new CC units was filed with the Commission in January 2016 and subsequently approved in March 2016.

Other capacity additions include:

- Planned nuclear uprates totaling 56 MW in 2019 through 2028.
- Addition of 113 MW of storage capacity in 2019 through 2026.
- Addition of 2,676 MW of combined-cycle capacity in 2025 through 2027.
- Addition of 22 MW of cogeneration in 2021.
- Addition of 2,760 MW of combustion turbine capacity in 2028 through 2032.

Other planned retirements include:

- Darlington combustion turbine units by December 2020 (514 MW).
- Blewett combustion turbine units and Weatherspoon combustion turbine units in December 2024 (232 MW).
- Roxboro coal units 1-2 in December 2028 (1,053 MW).

Planning assumptions for nuclear stations assume subsequent license renewal 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 July 2018, Duke had 23,131 MW of installed generating capacity (winter rating), excluding purchases and non-utility owned capacity. That total includes generation jointly-owned with NCPMA1, NCEMC, and Piedmont Municipal Power Agency produced at Duke's Catawba Nuclear Facility in South Carolina.

Duke received the Combined Construction and Operating License (COL) for the W.S. Lee Nuclear Station (Lee Nuclear) on December 19, 2016. On August 25, 2017, Duke filed a request to cancel the Lee Nuclear Project as that project was originally envisioned and included in prior IRPs. That request was approved by the North Carolina Utilities Commission in its Order dated June 22, 2018.

Other capacity additions include:

- Addition of 44 MW of cogeneration in 2020 through 2021.
- Addition of 260 MW Bad Creek pumped storage uprates in 2020 through 2023.
- Addition of 120 MW of energy storage in 2020 through 2026.
- Addition of 402 MW of combustion turbine capacity in 2024 at Lincoln County.
- Addition of 2,676 MW of combined-cycle capacity in 2027 through 2030.
- Addition of 460 MW of combustion turbine capacity in 2032.

Retirements include:

- Allen coal units 1-3 (604 MW) and units 4-5 (526 MW) in 2024 and 2028, respectively.
- Lee Unit 3 natural gas (173 MW) in 2030.
- Cliffside unit 5 (546 MW) in 2032.

Planning assumptions for nuclear stations assume subsequent license renewal at the end of their current license extension including Oconee in 2033 and 2034 (2,618 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.

### VEPCO Generation

As of May 2018, VEPCO had 19,440 MW of installed generating capacity (winter rating). This excludes purchases and non-utility capacity. Of this total, only 480 MW is located in North Carolina.

VEPCO 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. According to VEPCO, the Company's self-build 1,585 MW CC in Greensville County, Virginia provided superior customer benefits compared to all other options. The application for 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 in 2019.

The Company obtained a Combined Operating License (COL) from the NRC in June 2017 to support a new nuclear unit, North Anna 3, at its existing North Anna Power Station located in Louisa County in central Virginia. However, based on the uncertainties of future carbon regulation, the Company determined it prudent to pause material development activities for North Anna 3. Going forward, the Company will continue to maintain the COL, which provides a valuable option in the future for a base load carbon-free generation resource.

The Company will continue to support the transition to a lower carbon future. For example, VEPCO plans to place over 1,200 MW of fossil-fueled generation into cold reserve by the end of the year. The Company is also moving aggressively to expand its use of renewable resources, with its investment in solar projects in Virginia and North Carolina approaching \$1 billion with a total of 1,350 MW of capacity in service, under construction, or under development. Additionally, VEPCO is one of the largest generators in the nation using renewable biomass and is developing an offshore wind demonstration project to be located off the coast of Virginia Beach. Further, the Company is in the process of evaluating a hydroelectric pumped storage facility in southwestern Virginia that could be supported by generators using renewable energy.

Other capacity additions include:

- Addition of 142 MW utility-scale solar (US-3 Solar 1) by 2020.
- Addition of 12 MW offshore wind (Coastal Virginia Offshore Wind) by 2021.
- Addition of 98 MW utility-scale solar (US-3 Solar 2) by 2021.
- Addition of 3,664 MW combustion turbines by 2033.

Retirements include:

- Yorktown coal units 1 and 2 in 2017 (584 MW).
- Bellemeade combined cycle by 2021 (267 MW).\*
- Bremo natural gas units 3 and 4 by 2021 (227 MW).\*
- Chesterfield coal units 3 and 4 by 2021 (261 MW).\*
- Mecklenburg coal units 1 and 2 by 2021 (138 MW).\*
- Pittsylvania biomass by 2021 (83 MW).\*
- Possum Point natural gas units 3 and 4 by 2021 (316 MW).\*
- Possum Point 5 heavy fuel oil by 2021 (786 MW).
- Yorktown 3 heavy fuel oil by 2022 (790 MW).
- Combustion turbines between 2019 and 2021 (257 MW)

\* Units will be placed into cold reserve in 2018 and remain in cold reserve until 2021. Units could be reactivated in approximately six months if system needs and market conditions dictate.

The generating units listed should be considered as tentative for retirement only. The Company's final decisions regarding any unit retirement will be made at a future date.

Planning assumptions for nuclear stations assume subsequent license renewal at the end of their current license extension including Surry in 2032 and 2033 (1,750 MW).

## **7. RELIABILITY AND RESERVE MARGINS**

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Resource adequacy refers to the ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. Utilities require a margin of reserve generating capacity in order to provide reliable service. Periodic scheduled outages are required to perform maintenance, inspections of generating plant equipment, and to refuel nuclear plants. Unanticipated mechanical failures may occur at any given time, which may require shutdown of equipment to repair failed components. Adequate reserve capacity must be available to accommodate these unplanned outages and to compensate for higher than projected peak demand due to forecast uncertainty and weather extremes. The Companies utilize reserve margin targets in their IRP processes to help ensure resource adequacy. Reserve margin is defined as total resources minus peak demand, divided by peak demand. The reserve margin target for planning is established based on probabilistic assessments. The Commission continues to evaluate in the IRP proceedings the appropriate reserve margins for planning.

The reserve margins currently projected by each IOU are shown in Table 6.

**Table 6: Projected Winter Reserve Margins for Progress, Duke, and Summer for VEPCO (2018-2032, after DSM)**

	Reserve Margins
Progress	17.0% – 26.0%
Duke	17.0% – 22.0%
VEPCO	13.0% – 19.0% <sup>1</sup>

<sup>1</sup> VEPCO is a PJM member and signatory to PJM's Reliability Assurance Agreement. The Company is obligated to maintain a reserve margin (12.48%) for its portion of the PJM coincident peak load. Also, the Company participates in PJM's capacity auction which results in short-term reserves in excess of the target level.

The amount of energy provided by the three utilities utilizing gas technologies is greater than the energy provided by coal. This highlights the importance of the infrastructure that delivers natural gas to the generating stations. The State 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 have had to be built to serve generating plants in other parts of the State. North Carolina has a statute -- N.C. Gen. Stat. § 62-36.01 -- that authorized the Commission, under some circumstances, to order the State's natural gas local distribution companies (LDCs) to enter into agreements with other pipeline suppliers to increase competition.

Transco historically delivered gas up from the Gulf Coast. Transco is reversing the flow on its pipelines to bring shale gas to the State from the north. While this provides North Carolina with another source of interstate gas, it has one significant negative impact. Historically, North Carolina customers have been able to contract for gas to be delivered to Transco north of the State -- either from other interstate pipelines or from market-area storage facilities -- and have had that gas "backhauled" on Transco. That means that the gas delivered upstream on Transco on behalf of N.C. customers would be physically delivered to other customers to the north, and swapped for their gas out of Transco as it passes through North Carolina. Since Transco is physically reversing the flow on its pipelines, N.C. customers can no longer count on cheap backhaul service and must pay for expensive firm forward-haul service on Transco, or find other ways to get gas to the State.

The amount of firm capacity needed to replace backhaul is significant. North Carolina LDCs have been contracting with Transco to obtain some capacity to deliver supplies that were previously backhauled. They are also seeking capacity on new interstate pipeline projects into the State.

Two major new interstate pipeline projects into North Carolina are being built to serve both gas and electric generation customers. They are the Atlantic Coast Pipeline, LLC (ACP) and MVP Southgate, an extension of the Mountain Valley Pipeline LLC (MVP) project. ACP will come down along the I-95 corridor and will bring shale gas from the north to serve both gas and electric generation customers. It will provide a better interstate pipeline footprint in the State. ACP was scheduled to come on line in November 2018, but has been delayed until 2019 or later. MVP Southgate extends the MVP project from southern Pittsylvania County, Virginia down into Alamance County, North Carolina. The MVP pipeline, which terminates in Virginia, is scheduled to come on line in late 2019. The MVP Southgate pipeline down into North Carolina is scheduled to come on line in late 2020. Until these projects come on line, LDCs will have to contract for short-term capacity. This capacity will be expensive and cannot be depended upon to meet long-term needs. Further delays in ACP and MVP Southgate are a matter of serious concern.

Another major development is the announcement by Piedmont Natural Gas of a decision to build a liquefied natural gas storage facility in Robeson County. This facility is anticipated to be completed in the summer of 2021 and filled in time to provide peaking support in the winter of 2021-2022. This will help meet both gas and electric peak demand.

## **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 N.C.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 2018, requiring investor-owned utilities to meet 10% of their prior year's NC retail sales through renewable energy and EE sources. Within the overall percentage requirements, 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](http://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, 2018, the Commission submitted its 11th Annual Report Regarding Renewable Energy and Energy Efficiency Portfolio Standard in North Carolina required pursuant to N.C.G.S. § 62-133.8. 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, or appear to have met, the 2012-2017 general REPS requirements and the solar resource requirements, and appear on track to meet those requirements in 2018. Although the electric power suppliers also met the modified poultry-waste resource requirements in 2017, the Commission determined that the swine-waste set-aside requirements could not be met in 2017, and again delayed those requirements. However, for 2018, the Commission modified the swine-waste set-aside requirements to require that investor-owned utilities meet 0.02% of prior year sales through the use of swine-waste resources, marking the first time that the Commission has found that compliance with the swine-waste set-aside requirements was achievable through reasonable efforts. For electric membership corporations and municipalities, the Commission continued to delay the first swine-waste set-aside requirements because these smaller utilities demonstrated that compliance could not be achieved through reasonable efforts. For all electric power suppliers, the poultry-waste set-aside requirements were modified to require an aggregate 300,000 MWh through the use of poultry-waste resources, an increase from the 170,000 MWh required in 2017. The report is available on the Commission's web site, [www.ncuc.net](http://www.ncuc.net).

### **Competitive Procurement of Renewable Energy**

On July 27, 2017, the Governor signed into law House Bill 589 (S.L. 2017-192). Part II of S.L. 2017-192 enacted N.C.G.S. § 62-110.8, which requires DEC and DEP to file for Commission approval on or before November 27, 2017, a program for the competitive procurement of energy and capacity from renewable energy facilities with the purpose of adding renewable energy to the State's generation portfolio in a manner that allows the State's electric public utilities to continue to reliably and cost-effectively serve customers' future energy needs (CPRE Program). Under the CPRE Program, DEC and DEP will issue requests for proposals to procure energy and capacity from renewable energy facilities in the aggregate amount of 2,660 MW, over the course of the 45-month program. Since House Bill 589 was signed into law, the Commission has adopted rules implementing the requirements of the CPRE Program and approved, with modifications, the CPRE Program proposed by DEC and DEP. In addition, the Commission approved Accion Group, LLC, as the Independent Administrator of the CPRE Program. On July 10, 2018, the Independent Administrator opened the period for the submission of proposals for the first RFP Solicitation under the CPRE Program, seeking proposals for 600 MW in DEC's service territories and 80 MW in DEP's service territories. As of the date of this report, the evaluation of proposals was underway and the Commission is awaiting reports on the results for the RFP Solicitation.

## 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, Dominion, EnergyUnited, Halifax, and NCEMC (which has assumed compliance responsibility from the now-dissolved GreenCo for REPS compliance for its member cooperatives) all administer 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 nonprofit improving the 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.

In April 2015, NC GreenPower launched a new pilot program giving up to a \$10,000 grant to schools for the installation of solar photovoltaic (PV) arrays, providing them with clean, green renewable energy. NC GreenPower uses a portion of its current donations to help North Carolina K-12 schools acquire a solar PV system. The NC GreenPower Solar Schools pilot gives teachers valuable tools to educate students about renewable energy. Currently in its fourth year, the pilot program has recently awarded five schools in 2018 with grant funding. Each awardee must raise a portion of the total costs and will receive a 3 to 5 kilowatt (kW) pole-mounted solar PV array, a weather station, data monitoring equipment, curriculum and training for educators. In addition, the State Employees' Credit Union (SECU) members, via the SECU Foundation, increased their support for 2018-2019 schools and will now provide a \$15,000 challenge grant towards the fundraising campaigns for 10 K-12 public schools that meet NC GreenPower's program requirements. The SECU Foundation's challenge grant will increase each school's solar array to a 5 kW system. Year one of the pilot successfully funded four schools with grants to install solar PV systems, year two awarded five schools and the five schools awarded in year three will have their installations completed by late 2018/early 2019.

In 2016, Duke Energy Carolinas announced that it would partner with NC GreenPower for "Schools Going Solar," which provides 100% of the cost of solar installations for eight schools in its North Carolina service territory. NC GreenPower is administering the program in conjunction with and in addition to our own statewide Solar Schools pilot program. Installations are in progress and will be completed by the end of 2018 for the schools who have been awarded the projects.

Contributions to NC GreenPower continue to help support the local 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: [www.ncgreenpower.org](http://www.ncgreenpower.org). All current projects are located within North Carolina. NC GreenPower is a 501(c)(3) nonprofit organization. By the end of this year, NC GreenPower will have brought solar education to nearly 23,000 students statewide at 27 schools across 22 counties.

## 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](http://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."<sup>1</sup> 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)<sup>2</sup> 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.

### State Generator Interconnection Standards

On June 4, 2004, in Docket No. E-100, Sub 101, Progress, Duke, and

<sup>1</sup> FERC issued Order No. 1000 on July 21, 2011, in its Docket No. RM10-23-000.

<sup>2</sup> For more information about the Southeastern Regional Transmission Planning process, see <http://southernrtp.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.

Dominion 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 N.C.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.

The Public Staff convened an initial planning meeting for the stakeholder process on May 9, 2017, followed by larger stakeholder meetings on June 1, July 14, August 8, and September 6, 2017. On December 15, 2017, the Public Staff filed a letter in which it stated that even though the parties had significant discussion and identified numerous issues that merit revision, no consensus was reached regarding what revisions should be made to the Interconnection Standard. On December 20, 2017, the Commission issued an Order Requesting Comments regarding modifications to the North Carolina Interconnection Procedures, Forms, and Agreements (collectively referred to as the NC Interconnection Standard). On August 10, 2018, the Commission issued an Order Scheduling Hearing, Requesting Comments, and Extending Tranche 1 CPRE RFP Solicitation Response Deadline. The order established an evidentiary hearing to consider all of the modifications to the NC Interconnection Standard, which is now scheduled for January 28, 2019, and established an oral argument on September 17, 2018, regarding the establishment of interim modifications to the NC Interconnection Standard to

accommodate Tranche 1 of the CPRE program. On October 5, 2018, the Commission issued an Order approving interim modifications to the NC Interconnection Standard.

As of September 2018, a combined total of 7,798 MW of renewable generation resources was included in DEC and DEP's N.C. interconnection queues. Dominion had 266 MW of solar capacity in the N.C. interconnection queue as of October 2018.

### 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 N.C.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 Dominion 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. 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.

## **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 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 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. The Commission relieved Dominion of compliance with most of the PJM conditions in the Commission's order dated December 22, 2016.

The Commission has continued to provide oversight over Dominion 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).

## PURPA Reform

In May, 2018, FERC indicated that it is directing FERC staff to reinvigorate its review of the Public Utility Regulatory Policies Act (PURPA) to determine if there are steps FERC can take to improve the implementation of the law. PURPA is a federal law that requires electric public utilities to interconnect with qualifying facilities (QFs) and to purchase, at the utility's "avoided cost," the power produced by the QFs. One area of possible reform is the "one-mile rule" wherein reform will tighten the rules so that QFs in RTOs/ISOs are not allowed to split up a large project into smaller under 20 MW projects to take advantage of the mandatory purchase obligation. Another area of possible reform is to allow utilities outside of an RTO/ISO to apply to FERC for an exemption to the mandatory purchase obligation if the utility can show that it is using a competitive process of comparable competitive quality as markets.

## Physical and Cyber Security

Federal and State regulators are increasingly concerned about cyber security and physical threats to the nation's bulk power system. North Carolina's utilities are working on many fronts to help ensure security and resilience of transmission and other critical infrastructure against people engaging in physical or cyber attacks and natural disasters. This includes compliance with NERC mandatory standards. The NC Utilities Commission meets with utility officials periodically to understand the threats the utilities are facing and the actions they are taking to address these threats.

## Greenhouse Gas Regulation

On August 3, 2015, the U.S. Environmental Protection Agency (EPA) finalized regulations for reducing CO<sub>2</sub> emissions from existing power plants, relying on authority from the Clean Air Act. These regulations establish CO<sub>2</sub> 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. On October 23, 2015, the EPA published its final Clean Power Plan (CPP) rule to regulate emissions of greenhouse gases, specifically carbon dioxide from existing fossil fuel-fired power plants.

In North Carolina, the Department of Environmental Quality (NCDEQ) is the lead agency for compliance with the Clean Air Act. 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<sub>2</sub> 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.

On March, 28, 2017, President Trump issued an Executive Order establishing a national policy in favor of energy independence, economic growth, and the rule of law. The purpose of that Executive Order is to facilitate the development of U.S. energy resources and to reduce unnecessary regulatory burdens associated with the development of those resources. Pursuant to the Executive Order, EPA initiated its review of the CPP and on October 10, 2017, the EPA proposed to repeal the CPP. In August 2018, EPA issued the proposed Affordable Clean Energy (ACE) Rule, which would replace the CPP.

STATE OF NORTH CAROLINA  
UTILITIES COMMISSION  
RALEIGH

DOCKET NO. E-100, SUB 147

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of  
2017 Integrated Resource Update )  
Reports and Related 2017 REPS )  
Compliance Plans )  
ORDER ACCEPTING FILING OF  
2017 UPDATE REPORTS AND  
ACCEPTING 2017 REPS  
COMPLIANCE PLANS

HEARD: Monday, February 5, 2018, at 7:00 p.m. in Commission Hearing Room  
2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding, and Commissioners ToNola D.  
Brown-Bland, Jerry C. Dockham, James G. Patterson, Lyons Gray, and  
Daniel G. Clodfelter

APPEARANCES:

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

E. Brett Breitschwerdt, McGuireWoods LLP, 434 S. Fayetteville Street, Suite 2600,  
Raleigh, North Carolina 27603

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

Lawrence B. Somers, Deputy General Counsel, Duke Energy Corporation, 410  
South Wilmington Street, NCRH 20, Raleigh, North Carolina 27602

For the Using and Consuming Public:

Lucy E. Edmondson, Staff Attorney; Heather D. Fennell, Staff Attorney; and Robert  
B. Josey, Staff Attorney; Public Staff-North Carolina Utilities Commission, 4326  
Mail Service Center, Raleigh, North Carolina 27699-4300

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

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

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

assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills....

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

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

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<sup>1</sup> G.S. 62-133.9(c).

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.”<sup>2</sup> Energy Efficiency 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,<sup>3</sup> furnish the Commission with a biennial report in even-numbered years that contains the specific information set out in Rule R8-60. In odd-numbered years, each of the electric utilities must file an annual report updating its most recently filed biennial report.

Further, Commission Rule R8-67(b) requires any electric power supplier subject to Rule R8-60 to file a REPS compliance plan as part of each biennial and annual report. In addition, each biennial and annual report should (1) be accompanied by a short-term action plan that discusses those specific actions currently being taken by the utility to implement the activities chosen as appropriate per the applicable biennial and annual reports, and (2) incorporate information concerning the construction of transmission lines pursuant to Commission Rule R8-62(p).

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

### 2017 Update Reports

This Order addresses the 2017 Update Reports (2017 IRPs) filed in Docket No. E-100, Sub 147, by Duke Energy Progress, LLC (DEP); Duke Energy Carolinas, LLC (DEC); and Dominion Energy North Carolina (DENC) (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: Alevo USA, Inc. (Alevo); Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR); Carolina Utility Customers Association, Inc. (CUCA); Environmental Defense Fund (EDF); Grant

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<sup>2</sup> G.S. 62-133.8(a)(2) and (4).

<sup>3</sup> 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.

Millin; Mid-Atlantic Renewable Energy Coalition (MAREC); North Carolina Sustainable Energy Association (NCSEA); North Carolina Waste Awareness and Reduction Network (NC WARN); Nucor Steel-Hertford (Nucor); and jointly, Southern Alliance for Clean Energy, Sierra Club, and the Natural Resources Defense Council (SACE, NRDC, and the Sierra Club). The Public Staff's intervention is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e). The Attorney General's intervention is recognized pursuant to G.S. 62-20.

### Procedural History

On May 1, 2017, DENC filed its 2017 IRP Update Report and 2017 REPS compliance plan. On July 10, 2017, DENC filed an Errata to page 20 of its Update Report.

On August 10, 2017, the Public Staff filed a motion requesting that the Commission (1) allow the Public Staff to file its comments on the electric utilities' IRP updates and REPS compliance plans in a single combined filing (IRP/REPS compliance review), and (2) establish October 31, 2017, as the due date for the filing of the Public Staff's IRP/REPS compliance review. The motion was approved on August 10, 2017 by the Commission. The Commission's order also noted that October 31, 2017, would continue to be the deadline for parties to seek leave to file comments on DEC's and DEP's IRP updates.

On September 1, 2017, DEC and DEP filed 2017 IRP Update Reports and related REPS compliance plans.

On September 15, 2017, DEC and DEP (collectively Duke) filed notice that the stakeholder meeting to review their 2017 IRPs had been scheduled for October 27, 2017, in Raleigh.

On October 12, 2017, NC WARN filed initial comments, with an attachment entitled "North Carolina Clean Path 2025" (hereinafter, comments). In summary, NC WARN states that Duke's 2017 IRPs contain lower load forecasts than Duke's 2016 IRPs. In addition, NC WARN generally criticizes Duke as using the same resource additions as in past years, without giving full consideration to renewable resources and energy efficiency.

On October 18, 2017, Duke filed a Motion to Strike NC WARN's Comments. In summary, Duke notes that NC WARN failed to file a motion requesting leave to file comments, and submits that NC WARN's 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 decline to accept NC WARN's proposed comments.

On October 30, 2017, NC WARN filed a response to Duke's motion to strike. In summary, NC WARN cites Commission Rule R8-62(k), the provision that allows intervenors to file their own alternative IRP, and asserts that its Clean Path 2025 constitutes an alternative IRP. NC WARN requests that if the Commission does not

accept its filing as comments or an alternate IRP, that the Commission accept it as a statement of consumer position.

On October 31, 2017, the Public Staff filed its report regarding whether the utilities' 2017 IRPs meet the requirements of Commission Rule R8-60(j). Based on its review, the Public Staff determined that the 2017 IRPs met the requirements of the rule. The Public Staff noted that this review should not be construed to indicate that it endorses all of the inputs and assumptions utilized by the utilities in the development of their 2017 IRPs. However, according to the Public Staff, the information utilized by the utilities appears to be reasonable for planning purposes.

On October 31, 2017, the Public Staff filed its Comments on REPS Compliance Plans submitted by the utilities as part of their 2017 IRPs. On November 3, 2017, the Public Staff filed a few minor corrections to its comments. In its conclusions, the Public Staff stated that:

1. DEP, DEC, and DENC should be able to meet their REPS obligations during the planning period, with the exception of the swine and poultry waste set-asides. In 2019, DEP projects to be at 98% of the cost cap.
2. DEP and DEC would not have been able to meet the swine waste requirement in 2017 had it not been delayed by the Commission, and they met the poultry waste requirement only after the Commission reduced the aggregate statewide requirement to 170,000 MWh. They are uncertain about meeting the requirement in 2018 and 2019.
3. For the planning period, DENC is confident that it will meet the swine waste requirement for itself although it is dependent on the performance of a single supplier. For the Town of Windsor, DENC is confident that it will meet the requirement for the full planning period.
4. DEP, DEC, and DENC are actively seeking energy and RECs to meet the set-aside requirement for the years in which they expect to fall short of compliance. DEP is no longer purchasing solar and general RECs to meet its general obligation or solar set-aside obligation because it has sufficient solar RECs to comply with both obligations during the planning period.
5. The Commission should approve the 2017 REPS Compliance Plans.

On November 15, 2017, the Commission issued an Order striking NC WARN's filing as comments and accepting the filing as a statement of position. The Commission concluded that NC WARN's Clean Path 2025 is not an alternative IRP under Rule R8-60(k), and further, that NC WARN did not follow the Rule R8-60(l) requirement

that intervenors request leave from the Commission to file comments on IRP update reports.

On November 21, 2017, the Commission issued an Order Scheduling Public Hearing on 2017 IRP Update Reports and Related 2017 REPS Compliance Plans. The order set the required public hearing for the night of February 5, 2018.

On January 24, 2018, DEC filed Affidavits of Publication for the Notice of Public Hearing on the 2017 IRPs. DEP filed similar affidavits on February 5, 2018. On January 31, 2018, DENC notified the Commission that due to an inadvertent oversight the Company did not publish a Notice of Public Hearing (Notice) in newspapers and it would not be capable of doing so prior to the scheduled public hearing. According to DENC, the Company did, however, post the Notice on its DENC website.

On January 30, 2018, the Public Staff requested an extension of time for DEC, DEP, and the Public Staff to submit the joint report addressing the utilities' target reserve margins called for in the Commission's June 27, 2017 IRP Order. The extension request was granted by the Commission on February 1, 2018, with a revised due date for the report of February 16, 2018. On February 16, 2018, the Public Staff requested a second extension to March 30, 2018 which was approved by the Commission on that same date.

On April 2, 2018, the Public Staff filed the Joint Report of the Public Staff, DEC, and DEP addressing target reserve margins pursuant to the Commission's June 27, 2017 IRP Order.

On April 3, 2018, NC WARN filed a Second Statement of Position regarding Integrated Resource Plans and stated that Duke Energy progressively relies on fossil fuel plants without first seeking opportunities to use energy storage or other renewable energy sources to meet its needs.

#### Public Hearing

Pursuant to G.S. 62-110.1(c), the Commission held a required public hearing in Raleigh on February 5, 2018, as scheduled. No public witnesses attended the hearing.

#### DSM Resources

In its 2016 IRP Order, the Commission noted that it "agrees with the Public Staff that additional emphasis should be placed on defining and implementing cost-effective demand-side management (DSM) programs that will be available to respond to winter peak demands" especially given the increased sensitivity in planning for winter loads and resources.

The Commission notes that DEP's 2017 IRP includes additional winter DSM resources of approximately 30 MW compared to DEP's 2016 IRP. DEP's increased emphasis on DSM as reflected in the 2017 IRP is consistent with the Commission's expectations. The Commission applauds the efforts of DEP, and in particular the work of

the Energy Innovation Task Force (EITF)<sup>4</sup> in the Western Region. DEP explained in its Western Carolinas Modernization Project Annual Report<sup>5</sup> that the focus and efforts associated with existing and new programs offered by the convening partners of the EITF continued in 2017, with increased participation in DEP's EnergyWise Home program being among the accomplishments:

Early on, the EnergyWise Home program was identified as a priority to drive peak demand reductions in the region. In 2017 efforts to increase participation in the program continued. Total new enrollments in EnergyWise Home for the DEP-W service area were 4,418 for the year. New enrollments in the winter program increased the curtailable winter load by 1.4 MW for a total of 13.75 MW of winter load being controlled. The focus on EnergyWise home in the region has clearly made a difference. Program participation grew by 17% in 2017. By comparison, program participation grew by 11% in the rest of the DEP service territory.

Western Carolinas Modernization Project Annual Report, pp. 4-5.

In contrast with the success of DEP's DSM efforts, the Commission notes that DEC's 2017 IRP includes winter DSM resources that are approximately 80 MW less than included in its 2016 IRP Report. The Commission is concerned with this development. The Commission expects DEC to place at least as much emphasis on DSM and energy efficiency in its integrated resource planning as that given DSM and EE by DEP. As a result, the Commission directs that DEC include in its 2018 IRP a detailed discussion of its decline in winter DSM during 2017, and its plans for re-emphasizing DSM.

#### Reserve Margins Joint Report

The Commission's 2016 IRP Order stated that "the analyses regarding reserve margin targets is extremely technical and complicated, made even more so by the advent of winter peaking on DEP and DEC's system. The Commission relies heavily on the Public Staff's review and analysis to make its decisions on this subject. Therefore, the Commission determines that DEC and DEP should work with the Public Staff to address the Public Staff's and Mr. Wilson's reserve margin concerns and to implement changes as necessary to help ensure that the reserve margin target(s) are fully supported in future IRPs."<sup>6</sup>

As stated in the Joint Report, since the issuance of the 2016 IRP Order, Duke and the Public Staff had further discussions to identify and address the areas of concern regarding the reserve margin targets. Duke and the Public Staff held conference calls to discuss the issues and identify actions needed to resolve outstanding items. Duke

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<sup>4</sup> The advisory and innovation group of community leaders co-convened by the City of Asheville, Buncombe County, and Duke Energy.

<sup>5</sup> Duke Energy Progress, LLC Western Carolinas Modernization Project Annual Progress Report, Docket E-2, Sub 1089 (March 28, 2018).

<sup>6</sup> Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans, Docket E-100, Sub 147 (June 27, 2017), p. 22.

responded to multiple requests for information and evaluated multiple inputs and scenarios that were suggested by the Public Staff. In addition, Duke and Astrapé met with the Public Staff to present results of the additional analyses and to work toward a consensus. As noted in the Joint Report, the discussions were helpful, however, the Public Staff and Duke did not reach consensus on all of the issues. The Public Staff recommends that DEC and DEP utilize a 16% reserve margin for planning purposes in their 2018 IRPs and until such time that a new resource adequacy study is conducted. Duke recommends that DEC and DEP utilize a minimum 17% winter reserve margin for planning purposes until such time that a new resource adequacy study is conducted. The Public Staff and Duke jointly recommend that DEC and DEP update their reserve margins no later than the 2020 biennial IRP filings to reflect updated peak load and forecast data, weather, and other relevant inputs.

The Commission appreciates the work of the parties to thoroughly investigate the resource adequacy planning accomplished by Duke. The Commission accepts the Joint Report of the Public Staff, DEC and DEP. Based on the analyses presented in the Joint Report, the Commission concludes that DEC and DEP may continue to utilize the minimum 17% winter reserve margin for planning purposes in their 2018 IRPs. In addition, the Commission will require DEC and DEP to present a sensitivity in its resource plan discussion that clearly illustrates the impact of a 16% winter reserve margin for planning. The sensitivity discussion should address, in specific terms, the risk impacts (including Loss of Load Expectations) of a 16% minimum reserve margin versus 17%.

The Public Staff and Duke do not dispute the appropriateness of modeling to include the economic load forecast uncertainty. Based on the Joint Report, Astrapé incorporated three years of economic load forecast uncertainty in the 2016 studies. The Public Staff agreed that it was appropriate to include the economic load forecast uncertainty; however, the Public Staff disagreed with the assumptions used to capture the uncertainty. The Public Staff believes that Astrapé's methodology for deriving the load forecast error (LFE) is problematic and will likely result in an incorrect calculation. The Public Staff provided LFE assumptions for Astrapé to simulate in lieu of the assumptions used in the 2016 study. The Public Staff's calculated LFEs are based directly on load forecasts rather than Astrapé's approach that starts with economic forecast uncertainty and then scales down 40% to proxy the uncertainty in load forecast. Astrapé ran the simulations which showed that the reserve margin could be reduced from 17% to about 16%. However, Duke and Astrapé do not agree with the Public Staff's assumptions and do not support the scenario results defined by the Public Staff.

The Commission concludes from the Joint Report that resource adequacy study results are impacted by the methodologies and assumptions employed in the models. The Public Staff and Duke did not reach consensus on how to model economic load forecast uncertainties. As a result, the Commission finds good cause to direct that Duke further address this issue in its 2018 IRP, including additional review and assessment of the Public Staff's proposed approach versus that employed by Astrapé in the 2016 study.

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 DENC, the Commission hereby accepts the 2017 IRPs filed by the utilities as complete and fulfilling the requirements set out in Commission Rule R8-60. The Commission further accepts the REPS compliance plans submitted by DEC, DEP and DENC, as recommended by the Public Staff.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.

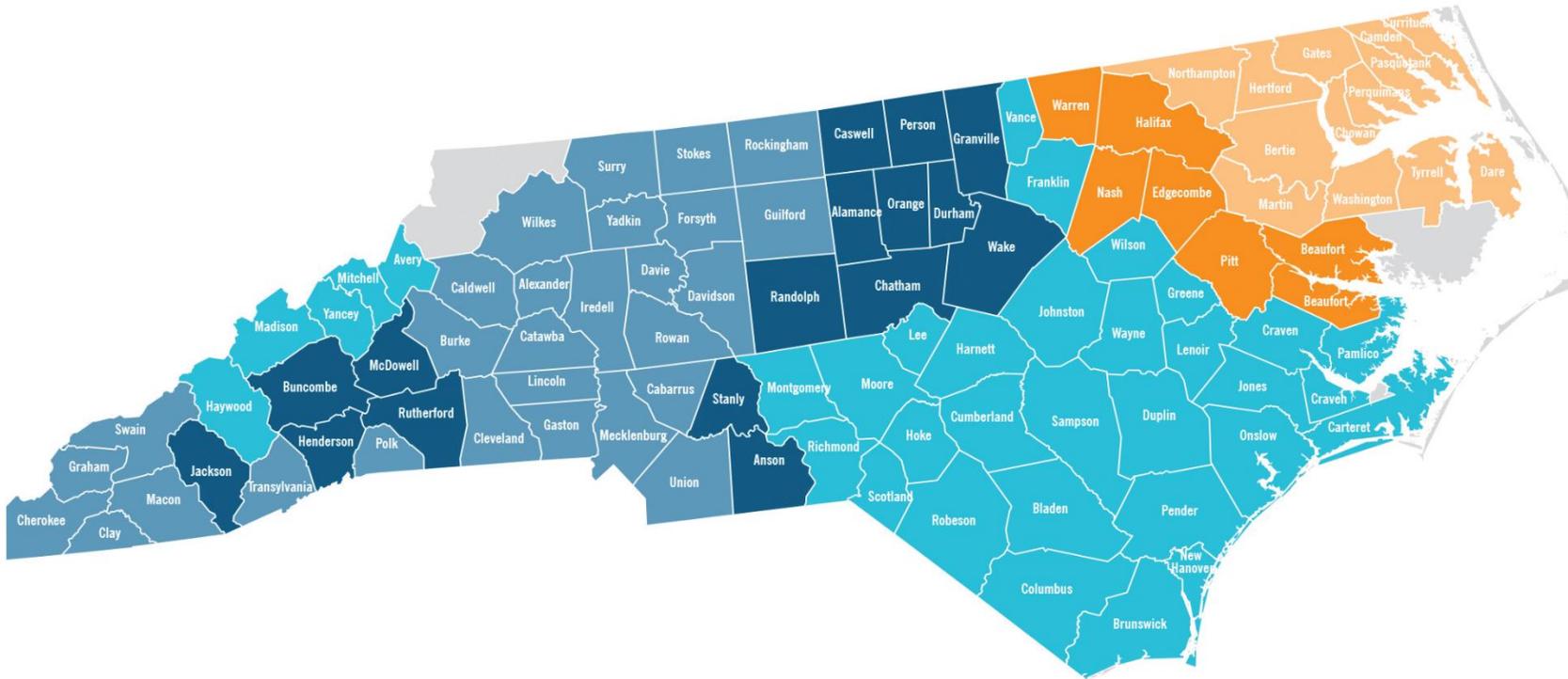
This the 16<sup>th</sup> day of April, 2018.

NORTH CAROLINA UTILITIES COMMISSION



Janice H. Fulmore, Deputy Clerk

Commissioners ToNola D. Brown-Bland and Charlotte A. Mitchell did not participate in this decision.



**SERVICE TERRITORIES**  
(counties served)

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