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, 2022
SUBMITTED: DECEMBER 30, 2022

RECEIVED BY
THE GOVERNOR OF NORTH CAROLINA;
THE JOINT LEGISLATIVE OVERSIGHT COMMITTEE ON AGRICULTURE AND NATURAL AND ECONOMIC RESOURCES; THE CHAIRS OF THE SENATE APPROPRIATIONS COMMITTEE ON AGRICULTURE, NATURAL, AND ECONOMIC RESOURCES; AND THE CHAIRS OF THE HOUSE OF REPRESENTATIVES APPROPRIATIONS COMMITTEE ON AGRICULTURE AND NATURAL AND ECONOMIC RESOURCES

SUBMITTED BY
THE NORTH CAROLINA UTILITIES COMMISSION

ABBREVIATIONS AND ACRONYMS

ACE EPA's Affordable Clean Energy Rule
BSER best system of emissions reduction
CC combined-cycle
CECPCN Certificate of Environmental Compatibility and Public Convenience and Necessity
CIGFUR Carolina Industrial Group for Fair Utility Rates
COL combined construction and operating license
CPCN Certificate of Public Convenience and Necessity
CPP EPA's Clean Power Plan
CPRE – Competitive Procurement of Renewable Energy
CT combustion turbine/s
CUCA Carolina Utility Customers Association, Inc.
DEC Duke Energy Carolinas, LLC
DENC Dominion Energy North Carolina
DEP Duke Energy Progress, LLC
DOE U.S. Department of Energy
DSM demand-side management
EDF Environmental Defense Fund
EE energy efficiency
EGU electric generating unit
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 plan
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

ABBREVIATIONS AND ACRONYMS (continued)

NCEMC North Carolina Electric Membership Corporation
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
NOPR Notice of Proposed Rulemaking
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
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
RPS renewable portfolio standard
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

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 (DEP), whose corporate office is in Raleigh; Duke Energy Carolinas, LLC (DEC), 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 (DENC).

DEC and DEP, 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' 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-1:2020-2021 Electricity Sales of Regulated Utilities in North Carolina

	NC Retail GWh*		NC Wholesale GWh*		Total GWh Sales* (NC Plus Other States) [1]	
	2021	2020	2021	2020	2021	2020
DEP	37,402	36,298	21,083	20,590	66,882	65,240
DEC	56,916	55,675	4,984	4,631	87,797	84,574
VEPCO	4,222	4,169	50	46	83,600	86,992

*GWh = 1 Million kWh (kilowatt-hours)

[1] DEC and DEP are also in South Carolina. VEPCO is also in Virginia.

During the 2022 to 2035 timeframe, the average annual growth rate in summer peak demand for electricity in North Carolina is forecasted to be approximately between 0.7% - 2.04% compared to 0.7% - 2.3% 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 DEP, DEC, and VEPCO (With Energy Efficiency (EE) Included) (2022 – 2035)

	Summer Peak	Winter Peak	Energy Sales
DEP	0.7%	0.7%	0.5%
DEC	0.8%	0.7%	0.7%
VEPCO	2.04%	2.31%	3.04%

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 2021

	DEP	DEC	VEPCO
Coal	10%	17%	10%
Nuclear	43%	49%	35%
Net Hydroelectric*	1%	2%	1%
Natural Gas and Oil	32%	21%	45%
Non-Hydro Renewable	9%	2%	2%
Other Purchased Power	5%	8%	7%

*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 (REPS). 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 2021, requiring investor-owned utilities to meet 12.5% of their prior year's NC retail sales through renewable energy and EE sources.

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.

North Carolina Governor Roy Cooper signed Executive Order No. 80 (EO80) on October 29, 2018, calling for a 40% reduction in statewide greenhouse gas emissions by 2030. The order tasked NCDEQ with developing a Clean Energy Plan (CEP) for North Carolina. After an extensive stakeholder engagement process, including meetings and public comment periods, the CEP was presented to Governor Cooper on September 27, 2019, and subsequently published in October 2019. The CEP includes Clean Energy Goals as follows:

- Reduce electric power sector greenhouse gas emissions by 70% below 2005 levels by 2030 and attain carbon neutrality by 2050;
- Foster long-term energy affordability and price stability for North Carolina's residents and businesses by modernizing regulatory and planning processes; and
- Accelerate clean energy innovation, development, and deployment to create economic opportunities for both rural and urban areas of the state.

NCDEQ established stakeholder groups tasked with providing policy designs to align with EO80 goals. Final reports from these efforts were published in early 2021.

In 2019, Duke Energy announced a corporate commitment to reduce carbon dioxide (CO_2) emissions by at least 50% from 2005 levels by 2030 and to achieve net-zero carbon emissions by 2050. According to Duke Energy, this is a shared goal important to the Company's customers and communities, many of whom have also developed their own clean energy initiatives. As one of the largest investor-owned utilities in the U.S., the goal to attain a net-zero carbon future represents one of the most significant reductions in CO_2 emissions in the U.S. power sector.

In February 2020, Dominion Energy announced its commitment to net zero CO_2 and methane emissions across its nationwide electric generation and natural gas infrastructure operations by 2050. The goal covers CO_2 and methane emissions, the dominant greenhouse gases, from electricity generation and gas infrastructure operations. According to Dominion Energy, the strengthened commitment builds on Dominion Energy's strong history of environmental stewardship, while acknowledging the need to further reduce emissions. According to the Dominion Climate Report, as Dominion works toward Net Zero emissions by 2050, Dominion Energy will focus on near-term progress. Under Dominion Energy's Net Zero strategy, Dominion is committed to reducing carbon emissions 55% by 2030 from their power generation business (compared to 2005 levels). Dominion Energy likewise expects to reduce methane emissions from their natural gas business by 65% by 2030 and 80% by 2040 (from 2010 levels).

The Virginia Clean Economy Act (VCEA) was signed into law on April 11, 2020. The VCEA includes provisions that institute a mandatory renewable portfolio standard, enhance renewable generation and energy storage development, require the retirement of certain generation units, establish energy efficiency targets, and expand net metering. The VCEA formalizes the administrative policy goals set by Virginia Governor Northam in September 2019 through Executive Order 43: Expanding Access to Clean Energy and Growing the Clean Energy Jobs of the Future (EO43). EO43 established statewide goals and targets for reducing carbon emissions. Specifically, EO43 included a goal that by 2030, 30% of the Commonwealth's electric system would be powered by renewable energy sources. By 2050, the goal is for 100% of Virginia's electricity to be produced from carbon-free sources such as wind, solar, and nuclear. In establishing a mandatory RPS, the VCEA sets forth a framework to meet the goals of EO43.

On October 13, 2021, Governor Cooper signed into law House Bill 951, also known as S.L. 2021-165 and later codified in pertinent part as N.C.G.S. § 62-110.9, directing the Commission to take all reasonable steps to reduce CO_2 emissions in this State resulting from electric generating facilities owned or operated by Duke Energy. The Commission is directed to achieve a reduction of 70% from 2005 levels by the year 2030, subject to certain discretionary extensions, and carbon neutrality by the year 2050. The Commission is directed to develop by December 31, 2022, a plan (the Carbon Plan) to achieve these emission reductions and to review the plan every two years thereafter. In addition to mandating carbon reduction, N.C.G.S. § 62-110.9 also authorizes the Commission to direct additional procurement of solar energy facilities in 2022 if needed to achieve the statutory carbon reduction goals. Finally, N.C.G.S. § 62-110.9 requires that the carbon emission reductions be met consistent with "current law and practice with respect to the least cost planning for generation[,]" and "maintain or improve upon the adequacy and reliability of the existing grid."

On November 19, 2021, the Commission opened Docket No. E-100, Sub 179, for the purpose of developing a Carbon Plan consistent with the provisions of N.C.G.S. § 62-110.9.

Consistent with N.C.G.S. § 62-110.9(1) and Commission directive, Duke Energy conducted three stakeholder engagement sessions between January 20, 2022, and February 25, 2022. The Commission also held three public sessions to receive updates on the sufficiency of the Duke Energy-led stakeholder process. Further the Commission held five public hearings to receive testimony from public witnesses across the State on the Carbon Plan.

On May 16, 2022, Duke Energy filed its proposed Carbon Plan as required by the Commission, which included four portfolios targeted at achieving the carbon emission reductions required by N.C.G.S. § 62-110.9 while balancing least cost and reliability considerations. An unprecedented number of parties have intervened and participated in the Carbon Plan proceeding, including the North Carolina Utilities Commission Public Staff, the Attorney General's office, and advocates for more discreet interest groups including large retail customers, renewable energy developers, low-income customers, wholesale

customers of Duke Energy, environmental advocates, and local governmental entities. Intervenors were afforded an opportunity to file extensive comments, testimony, and alternative Carbon Plans.

The Commission commenced an expert witness hearing on September 13, 2022, for the purpose of hearing testimony from experts, including Duke Energy and the intervening parties. The hearing lasted the better part of three weeks, finally concluding on September 29, 2022. The Commission will issue a final order encompassing its initial Carbon Plan on or before December 30, 2022.

2. INTRODUCTION

The North Carolina General Statutes 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. North Carolina General Statute § 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 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 Joint Legislative Oversight Committee on Agriculture and Natural and Economic Resources, the chairs of the Senate Appropriations Committee on Agriculture, Natural, and Economic Resources, and the chairs of the House of Representatives Appropriations Committee on Agriculture and Natural and Economic Resources 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.

N.C.GS. § 62-110.1(c).

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 IRP process. Commission Rule R8-60 defines an overall framework for IRPs. Commonly called integrated resource planning, 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 NCEMC and any individual 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 December 31, 2021 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 (DEP), whose corporate office is in Raleigh; Duke Energy Carolinas, LLC (DEC), 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 (DENC). A map outlining the areas served by the IOUs can be found at the end of this report.

DEC and DEP, the two largest IOUs in North Carolina, together provide 96% of the utility-supplied electricity consumed in the state. Approximately 22% 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 2020 reporting period, the gigawatt-hour (GWh) sales for the electric utilities in North Carolina are summarized in Table 1.

Table 1: 2021 Electricity Sales of Regulated Utilities in North Carolina

	NC Retail GWh*		NC Wholesale GWh*		Total GWh Sales* (NC Plus Other States)[1]	
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[1] DEC and DEP are also in South Carolina. VEPCO is also in Virginia.

EMCs are independent, not-for-profit corporations that operate distribution grids. 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 26 EMCs served 1,115,274 metered customers as of December 31, 2021. 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 Energy Carolinas (DEC) 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 30.75% in the common support facilities of the station. NCEMC's ownership entitlement is bolstered by a reliability exchange between the Catawba Nuclear Station and DEC's McGuire Nuclear Station located in Mecklenburg County, NC.

NCEMC is also a part owner in the Lee combined cycle (CC) plant located in Anderson, South Carolina. NCEMC's ownership interests consist of approximately 100 MW. DEC operates and maintains the plant, and NCEMC's ownership entitlement is bolstered by a reliability exchange between Lee CC and DEC's Dan River and Buck CC plants.

Additionally, NCEMC owns and operates approximately 680 MW of combustion turbine (CT) generation at sites in Anson and Richmond Counties, NC. 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).

NCEMC and the EMCs are deploying (or facilitating the deployment of) distributed energy resources/technologies (DER) on their grids as well as edge-of-the-grid programs to promote reliability, affordability, sustainability, and resiliency for the benefit of the communities they serve. These technologies and programs include but are not limited to the following:

1. Ten solar + energy storage sites totaling 18.5 MW/45.1 MWh in operation or under development;
2. Ten substation-based battery energy storage systems (BESS) totaling 40 MW/80 MWh in operation or under development;
3. Nineteen community solar facilities totaling 2,150 kW;
4. Energy efficiency (EE) programs that, in 2021, collectively produced 273,072 EE credits (the equivalent of 273,072 MWHs, or 2.0% of the prior year's retail sales, in reduced consumption by member-owners);
5. Approximately 49 MW of conservation voltage reduction capability with the feasibility of additional capability being actively studied; and
6. Ongoing development and operation of a Distributed Energy Resource Management System (DERMS) for the aggregated forecasting, notification, execution, analysis, and reporting of DR and DER programs.

NCEMC and its member distribution cooperatives have developed and implemented the NCEMC Distribution Operator (DO), a single entity that monitors, aggregates, and centrally coordinates distributed energy and demand response resources, bringing operational benefits to the distribution system, optimization to the market interface, and positive system impacts on the transmission systems upstream, including DEC, DEP, and DENC. The DO provides access to over half a gigawatt of distributed energy and demand resources, including solar, storage, microgrids, consumer devices, and behind-the-meter generation, and will continue to grow as additional resources are integrated into the DO system and processes become more automated. NCEMC continues to discuss the DO Platform with DENC, and with DEC and DEP to further evaluate how the DO Platform will interact with their Integrated System & Operations Planning (ISOP) process.

There are five NCEMC members that have assumed responsibility for their own future power supply resources. These "Independent Members" include Blue Ridge Energy, EnergyUnited, 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 DEC, DEP, and DENC. The DENC 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, controlled resources, and purchases of wholesale electricity.

In addition to the EMCs, there are 73 municipal and university-owned electric distribution systems serving approximately 616,000 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. 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 DEP generating units (about 700 MW of coal and nuclear capacity). On July 28, 2014, DEP filed notice with the Commission of its intent to file with 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 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 DEP 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 DEC. It also has an exchange agreement with DEC 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 35,000 households and about 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 492 MW. The dams are Appalachia 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

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).

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 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.G.S. § 62-2(a)(3a).

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

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

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

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

Order Revising Integrated Resource Planning Rules – July 11, 2007

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

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

2019 IRP Update Reports and Related 2019 REPS Compliance Plans (Docket No. E-100, Sub 157)

In the 2019 IRP Update Reports and REPS compliance plans filed by DEP, DEC, and DENC; the IOU's provided their current IRPs (Docket No. E-100, Sub 157). The Commission held an Oral Argument on January 8, 2020, to discuss load forecast and reserve margin issues for DEC and DEP. A public hearing in this docket was held in Raleigh on March 9, 2020, for the purpose of receiving non-expert public witness testimony. Six public witnesses testified at the hearing.

In its review and evaluation of the 2019 Update Reports the Commission gave particular attention to four topics: (1) carbon dioxide emissions; (2) resource adequacy, expressed in terms of reserve margins for DEC and DEP; (3) the integrated systems and operations planning (ISOP) effort underway for DEC and DEP; and (4) utility statement of need.

Based upon the full record in the proceeding, the Commission issued an Order on April 6, 2020, accepting 2019 IRP Update Reports and REPS compliance plans.

2020 Biennial Integrated Resource Plan Reports and Related 2020 REPS Compliance Plans
(Docket No. E-100, Sub 165)

The 2020 Biennial IRP Reports and REPS compliance plans were filed by DEP, DEC, and DENC in 2020. Public Hearings were held in April and May 2020 concerning the 2020 Biennial IRP Reports and REPS compliance plans.

On March 9, 2021, the Commission held a technical conference on Duke's initiative to develop and implement an Integrated Systems and Operations Planning (ISOP) project, and related ISOP topics (First Technical Conference). This technical conference was a follow-up to an ISOP technical conference held by the Commission in 2019 as part of the previous IRP process in Docket No. E-100, Sub 157.

Beginning on April 14, 2021, and continuing through May 26, 2021, the Commission held six public witness hearings in which it received testimony from 129 public witnesses. In addition to the witnesses who appeared at the public hearings, during the course of this docket, the Commission has received several hundred written consumer statements of position from interested persons.

On September 30 and October 1, 2021, the Commission held a technical conference (Second Technical Conference) to hear further presentations from the two Duke Utilities on the following three topics: (1) the proper methodology for evaluating economic retirement of coal-fired generating units, (2) potential use of an all-source procurement process, and (3) grid impacts of different resource portfolios.

Based upon the full record in the proceeding, the Commission issued an Order on November 19, 2021, that stated that the 2020 biennial IRP filed by DENC is reasonable for planning purposes, and the Commission hereby accepts DENC’s IRP, subject to adjustments based on its 2021 IRP Update; that DEC’s and DEP’s 2020 biennial IRPs are adequate to be used for short-term planning purposes as discussed in the Companies’ Short-Term Action Plans (STAPs); that the 2020 REPS Program Plans filed by DENC, DEC and DEP are hereby accepted; and that the 2020 CPRE Plan Updates filed by DEC and DEP are accepted.

2021 Biennial Integrated Resource Plan Reports and Related 2021 REPS Compliance Plans
(Docket No. E-100, Sub 165)

On June 29, 2021, the Commission issued an Order Waiving in Part Rule R8-60(h)(2) and Giving Notice of Additional Proceedings (the Additional Proceedings Order), suspending certain IRP filing requirements and stating the Commission's intention to address additional issues in further proceedings in the docket. In summary, the Additional Proceedings Order (1) relieved DEC and DEP of the obligation to file updated 2021 IRPs under Rule R8-60; (2) required DEC and DEP to file on or before September 1, 2021, their REPS Compliance Plans as required by Rule R8-60(h)(4) and Rule R8-67(b), their CPRE Program Plan update as required by Rule R8-71(g)(1), and any material modifications to the short-term action plans identified in their 2020 biennial IRPs as would be required by Rule R8-60(h)(3); (3) denied pending motions for further evidentiary hearings; and (4) required DENC to comply with all requirements for filing an updated 2021 IRP under Rule R8-60.

On September 1, 2021, DENC filed its 2021 IRP Update report. In addition, DEC and DEP each filed their 2021 Update to 2020 Short-Term Action Plan, REPS Compliance Plan, and CPRE Plan Update.

On February 23, 2022, the Commission issued an Order Accepting Filing of 2021 Update Reports and Accepting 2021 REPS Compliance Plans, which found DENC's 2021 IRP Update complete and in accordance with the requirements set out in Commission Rule R8-60. The Commission also accepted the REPS compliance plans submitted by DEC, DEP, and DENC. Finally, the Commission accepted DEC's, and DEP's CPRE Program Plan updates pursuant to Rule R8-71(g)(1) and modifications to the short-term action plans identified in their 2020 biennial IRPs.

2022 Integrated Resource Plan of Dominion Energy North Carolina
(Docket No. E-100, Sub 182)

On February 11, 2022, DENC filed a motion requesting that the Commission delay requiring a full IRP pursuant to Commission Rule R8-60(i) until 2023, and in the interim, allow it to file an IRP Update in accordance with Commission Rule R8-60(j) by September 1, 2022. On February 28, 2022, the Commission issued an Order Granting Motion of Dominion Energy North Carolina to Revise Integrated Resource Plan Filing Schedule. Accordingly, DENC filed its 2022 IRP Update and REPS Compliance Plan on September 1, 2022.

On October 31, 2022, the Public Staff filed a report detailing its review of DENC's 2022 IRP Update and comments on DENC's REPS Compliance Plan, stating that DENC's IRP Update meets the requirements of R8-60(k), further that DENC should be able to meet its REPS obligations during the Planning Period without exceeding its cost caps and recommending that the Commission approve DENC's 2022 REPS Compliance Plan.

2022 Duke REPS Compliance Plan & 2022 CPRE Program Plan Update (Docket No. E-100, Sub 186)

On September 1, 2022, DEP and DEC each individually filed 2022 NC REPS Compliance Plans, and jointly filed a CPRE Program Plan Update.

On October 31, 2022, the Public Staff filed comments on DEP and DEC's REPS Compliance Plans opining that DEC and DEP should be able to meet their general and solar energy set-aside requirements during the planning period, and their poultry waste set-aside requirement in 2022, without exceeding respective cost caps. Further, the Public Staff notes that DEC and DEP's swine waste set-aside requirements will be difficult to meet during the planning period, and that meeting the poultry waste set-aside requirements for 2023 and 2024 will be dependent on the performance of waste-to-energy developers under current contracts. Finally, the Public Staff recommends that the Commission approve DEP and DEC's 2022 REPS Compliance Plans.

On November 8, 2022, the Public Staff filed comments on DEP and DEC's joint CPRE Program Plan Update stating that DEP and DEC's joint CPRE Program Plan meets the requirements of Commission Rule R8-71(g) and should be accepted by the Commission. CPRE Program procurements are slated to conclude following completion of the ongoing 2022 Solar Procurement. S*ee* Commission Docket Nos. E-2, Subs 1159 and 1297 and E-7, Subs 1156 and 1268.

Carbon Plan (Docket No. E-100, Sub 179)

On November 19, 2021, the Commission opened Docket No. E-100, Sub 179, for the purpose of developing a Carbon Plan consistent with the provisions of N.C.G.S. § 62-110.9. The Commission's Order Requiring Filing of Carbon Plan and Establishing Procedural Deadlines notes in pertinent part that "the carbon reduction framework established by [N.C.G.S. § 62-110.9] and the analyses underlying Duke's IRPs overlap," and indicating the Commission's intent to eventually synchronize Carbon Plan and IRP proceedings, including undertaking a rulemaking proceeding to revise Commission Rule R8-60 to reflect the approach of syncing the Carbon Plan with the IRP proceedings. The Commission's initial Carbon Plan order, which will issue on or before December 30, 2022, will address consolidation of Duke Energy's traditional integrated resource planning process with ongoing Carbon Plan development and execution.

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. DEP, DEC, 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 system wide average annual growth rates in energy sales and peak loads anticipated by DEP, DEC, and VEPCO. These growth rates are based on the utilities' system peak load requirements.

Table 2: Forecast Annual Growth Rates for DEP, DEC, and VEPCO
(With Energy Efficiency (EE) Included)
(2021– 2035)

	Summer Peak	Winter Peak	Energy Sales
DEP	0.7%	0.7%	0.5%
DEC	0.8%	0.7%	0.7%
VEPCO	2.04%	2.31%	3.04%

North Carolina utility forecasts of future peak demand growth rates are in the range of forecasts for the southeast as a whole if not slightly higher. The 2021 Long-Term Reliability Assessment by the North American Electric Reliability Corporation (NERC) indicates a forecast of average annual growth in peak demand of approximately 0.65% through 2031.

Table 3 provides historical peak load information for DEP, DEC, and VEPCO.

Table 3: Summer and Winter Systemwide Peak Loads for DEP, DEC, and VEPCO Since 2016 (in MW)

	DEP		DEC		VEPCO	
	Summer	Winter*	Summer	Winter*	Summer	Winter*
2017	12,784	15,519	20,120	21,620	18,902	21,232
2018	13,090	13,669	20,379	19,286	19,244	19,930
2019	12,908	12,243	20,597	18,413	19,607	17,544
2020	13,233	12,258	20,398	17,830	20,087	17,867
2021	13,046	13,490	20,310	18,731	19,781	20,229

**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. DEC 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 DEC nuclear facilities are located in South Carolina. All of DEC'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.

DEP 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 DEP's nuclear units. The new renewal dates run from 2030 to 2046.

VEPCO operates two nuclear power stations, Surry and North Anna, with two units each. Both stations are located in Virginia. All four units have been issued license extensions by the NRC. For Surry, the licenses for Units 1 and 2 were renewed on May 4, 2021, permitting continued operation for Units 1 and 2 through 2052 and 2053, respectively, but approval by the Virginia State Corporation Commission will also be required for extending the licenses for Surry Units 1 and 2. North Anna's second license renewal was submitted to the NRC on August 24, 2020, and was accepted for review in October 2020. The issuance of the renewed license was expected by April 2022, but on February 24, 2022, the NRC Commission issued three orders (CLI-22-02, CLI-22-03, and CLI-22-04) and Staff Requirements Memorandum, SECY-21-0066, "Rulemaking Plan for Renewing Nuclear Power Plant Operating Licenses – Environmental Review," that impact the subsequent license renewal of various nuclear power plants including North Anna. As of now, the estimated date for the renewal has not been released. The renewal will preserve the option to continue operation of North Anna units 1 and 2 until 2058 and 2060, respectively.

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 DEC 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; sometimes these are gas-fired plants but the majority have been solar photovoltaic plants in recent years.

The 2020 capacity mix for each IOU is shown in Table 4.

Table 4: Installed Utility-Owned Generating Capacity by Fuel Type (Summer Ratings) for 2020[1]

	DEP	DEC	VEPCO
Coal	24%	33%	19%
Nuclear	28%	26%	17%
Hydroelectric	2%	16%	11%
Natural Gas and Oil	45%	24%	52%
Non-Hydro Renewable	1%	<1%	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 2021, is provided in Table 5.

[1] The Commission's Order in Docket No. E-100, Sub 165 issued on June 29, 2021, waived DEC and DEP's obligation to file 2021 updated IRPs therefore, 2021 data is not available for DEC and DEP for Table 5. While VEPCO filed its updated IRP for 2021, the data in Table 5 would be skewed if only it included updated information solely from VEPCO.

Table 5: Total Energy Resources by Fuel Type for 2021

	DEP	DEC	VEPCO
Coal	10%	17%	10%
Nuclear	43%	49%	35%
Net Hydroelectric*	1%	2%	1%
Natural Gas and Oil	32%	21%	45%
Non-Hydro Renewable	9%	2%	2%
Other Purchased Power	5%	8%	7%

*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 Commission is actively supporting efforts to expand the role of Distribution Planning into traditional IRP processes.

In 2020, DEP and DEC jointly initiated a multi-year Integrated Systems and Operations Planning Project (ISOP). This effort is an important and necessary evolution in electric utility planning processes to address the trends in technology development, declining cost projections for energy storage and renewable resources, and customer adoption of electric demand modifying resources such as roof-top solar and electric vehicles. The anticipated growth of Distributed Energy Resources necessitates moving beyond the traditional distribution and transmission planning assumption of on-way power flows on the distribution system and analysis based on limited snapshots of peak or minimum system conditions. As the grid becomes more dynamic, analysis of the distribution and transmission systems will need to account for increasing variability of generation and two-way power flows on the distribution system, which requires significant changes to modeling inputs and tools.

Merchant Generating Facilities

North Carolina General Statute § 62-110.1(a) requires that in addition to regulated public utilities themselves, all other persons who wish to construct or operate electric generating facilities in North Carolina obtain a CPCN in order to do so. When the Public Utilities Act was originally enacted, electricity generating facilities in North Carolina not owned or operated by public utilities predominantly consisted of two types – small scale hydroelectric facilities or facilities owned by large industrial companies or by universities or other governmental entities who generated electricity for their own use. After enactment of PURPA in 1978, North Carolina began to experience growth in the number of commercial, third-party developed, owned, and operated generating facilities, most of which sold their capacity and energy to regulated public utilities under the provisions of PURPA. Because of PURPA's "must purchase" requirements for qualifying facilities, the CPCN review process for these new "merchant" generating facilities was somewhat

limited in scope. As the costs for development of new solar generating facilities continued to fall over the course of the first two decades of this century, the number of these qualifying facilities seeking to obtain CPCNs multiplied rapidly. After the enactment of HB 589 in 2017, this trend was amplified and reinforced by the new renewable energy competitive solicitation and procurement program codified in N.C. Gen. Stat. § 62-110.8.

Beginning in 2020, the Commission began to experience an increase in applications for CPCNs from merchant generating facilities not seeking to sell capacity and energy as qualifying facilities under PURPA and not participating in the competitive procurement process under N.C.G.S. § 62-110.8. These new merchant facilities are instead seeking to sell their capacity and energy output either by negotiated bilateral contracts with regulated public utilities or by selling into an organized RTO market such as PJM. Often this new type of merchant facility although located in North Carolina will be selling to buyers and consumers located outside North Carolina.

In 2022, the Commission approved an on-shore wind facility with a capacity of 189 MW. This facility would interconnect to the transmission grid owned by DENC. The Commission also conducted multiple hearings on a CPCN application for a solar facility with a capacity of 275 MW that would interconnect to the transmission grid owned by DEP. However, that facility withdrew its application. Applications for CPCNs for seven additional solar facilities, with a combined capacity of 1278 MW, are pending before the Commission. These solar facilities would also interconnect with DENC. From their applications, it appears that all of them would bid their power into the PJM market pursuant to contracts with corporate counterparties.

The increase in applications for merchant generating facilities seeking to sell their output outside of North Carolina may continue. As this was likely not anticipated when the Public Utilities Act was originally adopted, the provisions of Chapter 62 of the General Statutes do not directly address how the Commission should consider these CPCN applications. Prior to 2001 the Commission had no rule specifically addressing procedures for processing CPCN applications filed by merchant generating plants. To address this situation the Commission adopted Rule R8-63 by Order dated May 21, 2001 (Docket No. E-100, Sub 85). The Rule provides for a fact-specific, case-by-case consideration of the circumstances relating to each merchant plant CPCN application, comparable to the process the Commission follows in other types of CPCN applications. In its Order the Commission stated, “It is the Commission’s intent to facilitate, and not frustrate, merchant plant development. Given the present statutory framework, the Commission is not in a position to abandon any showing of need or to create a presumption of need. However, the Commission believes that a flexible standard for the showing of need is appropriate.” In the absence of different guidance, the Commission is continuing to apply the existing criteria, including those relative to such matters as the demonstration of need for the facility, the appropriateness of the proposed facility siting, and the effective management and containment of total project costs, that it uses for reviewing other CPCN applications under N.C.G.S. § 62-110.1(a).

7. RELIABILITY AND RESERVE MARGINS

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.

DEP and DEC each utilize a minimum winter planning reserve margin of 17%. VEPCO is a PJM member and signatory to PJM's Reliability Assurance Agreement. The Company is obligated to maintain a reserve margin (11.7%) for its portion of the PJM coincident peak load. The PJM reserve requirement for years 2021-2032 for its adjusted load forecast is approximately 15%. 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, Transco for its natural gas requirements. While two other interstate pipelines (Columbia and Patriot) 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. Pursuant to N.C. Gen. Stat. § 62-36.01, the Commission may, under some circumstances, order the State's natural gas local distribution companies (LDCs) to enter into natural gas service agreements (including "backhaul" 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. 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, North Carolina

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.

One major new interstate pipeline project into North Carolina is being built to serve both gas and electric generation customers. On October 13, 2017, FERC issued an order granting a Certificate of Public Convenience and Necessity to Mountain Valley Pipeline, LLC for the construction and operation of the Mountain Valley Pipeline Project (MVP). MVP includes approximately 303 miles of 42-inch-diameter greenfield natural gas pipeline, three new compressor stations, interconnections with new meter and regulator stations, taps, and other appurtenant facilities. FERC approved a Certificate of Public Convenience and Necessity for the MVP Southgate project on June 18, 2020. MVP Southgate is an extension of the MVP project. The proposed 75-mile long, 16 and 24-inch diameter natural gas pipeline would tie into Mountain Valley Pipeline (MVP) near Chatham, Virginia, and transport natural gas to delivery points in Rockingham and Alamance counties in North Carolina. In the Southgate Certificate Order, FERC directed the Office of Energy Projects to not issue any notice to proceed with construction of the Southgate Project until Mountain Valley receives the necessary federal permits for the Mainline System. MVP is currently 94% complete and is projected to be operational by late 2023. However, it is also facing long-running lawsuits. Until MVP Southgate can 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 MVP and MVP Southgate are a matter of serious concern.

Piedmont Natural Gas completed construction of the Robeson LNG plant during the fall of 2021. The Robeson LNG plant 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 and thereafter. 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 2021, requiring investor-owned utilities to meet 12.5% 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. 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, 2021, the Commission submitted its Annual Report Regarding Renewable Energy and Energy Efficiency Portfolio Standard in North Carolina, which was required pursuant to N.C.G.S. § 62-133.8. The report detailed Commission implementation of the REPS statute since its enactment in 2007. The report is available on the Commission's web site at www.ncuc.gov. Pursuant to House Bill 217 (Session Law 2021-23), N.C.G.S. § 62-133.8(j) was repealed eliminating the requirement for this report.

Competitive Procurement of Renewable Energy (CPRE)

Pursuant to N.C.G.S. § 62-110.8 the Commission is tasked with oversight of the CPRE Program designed and implemented by Duke Energy for the competitive procurement and development of an aggregate amount of 2,660 MW of renewable energy facilities in North Carolina over a period of 45 months, which commenced on February 21, 2018, and concluded on November 21, 2021 (CPRE Program Procurement Period).

During the CPRE Program Procurement Period, Duke Energy was required to solicit a total of 6,160 MW of renewable energy through a combination of (1) CPRE Program procurement solicitations (CPRE MW) and (2) the execution of power purchase agreements (PPAs) for renewable energy capacity within the DEC and DEP balancing authority areas that are not subject to economic dispatch or curtailment and were not procured pursuant to the Green Source Advantage program authorized under N.C. Gen. Stat. § 62-159.2 (Transition MW). Under N.C.G.S. § 62-110.8(a) and (b)(1), 2,660 MW of this 6,160 MW total was targeted to be procured through the CPRE Program, and the remaining 3,500 MW was targeted to be Transition MW.

Section 62-110.8(b)(1) provides that, if during the CPRE Program Procurement Period, Duke contracts for Transition MW in excess of 3,500 MW, the Commission shall reduce the CPRE MW by the amount of such exceedance. Further, N.C.G.S. § 62-110.8(a) states that "[t]he Commission shall require the additional competitive procurement of renewable energy capacity by the electric public utilities in an amount that includes all of the following: (a) any unawarded portion of the initial competitive procurement required by this subsection . . . ."

During the CPRE Program Procurement Period, DEC and DEP collectively procured 1,185 MW via the CPRE Program. Further, during the CPRE Program Procurement Period, Duke procured a total of 4,378 Transition MW, an excess of 878 MW. Therefore, pursuant to N.C.G.S. § 62-110.8(b)(1), the Commission determined that it was appropriate to reduce the CPRE Program procurement target to 1,782 MW. As a result, the Commission concluded that Duke was 596 MW short of the adjusted CPRE Program procurement target at the end of the CPRE Program Procurement Period and on December 20, 2021, ordered DEC to initiate a third procurement solicitation (Tranche 3) of the CPRE Program to procure 596 MW.

On January 5, 2022, DEC issued the CPRE Tranche 3 request for proposals (RFP) seeking to procure 596 MW. The bid window for CPRE Tranche 3 closed on February 3, 2022. Only eight projects totaling 520 MW bid into CPRE Tranche 3. Following closure of the bid window, 365 MW withdrew from Tranche 3, citing market uncertainty and the rising costs of solar development as the cause of their withdrawal. Ultimately, only two projects totaling 155 MW completed the Tranche 3 bid evaluation process and have signed CPRE Program PPAs with DEC.

On September 1, 2022, Duke Energy filed a petition notifying the Commission that the CPRE Program was 441 MW short of meeting the target established by N.C.G.S. § 62-110.8 and requesting the Commission's approval to procure the shortage through the 2022 Solar Procurement, which was approved by the Commission on May 26, 2022, pursuant to Section 2(c) of S.L. 2021-165. By order dated November 1, 2022, the Commission authorized Duke Energy to seek the CPRE Program shortfall through the 2022 Solar Procurement.

The Commission's November 1, 2022 Order Permitting Additional CPRE Program Procurement And Establishing Target Procurement Volume For The 2022 Solar Procurement notes that, while the Commission has no ongoing obligation to target the CPRE Program shortfall "it is reasonable and consistent with the plain language of N.C.G.S. § 62-110.8(a) and the whole of the act to procced on a discretionary basis with regard to further conducting additional procurements aimed at the CPRE MW shortfall." The Commission further concluded that "regardless of whether the CPRE MW shortfall is procured in total through the 2022 Solar Procurement, the CPRE Program will be closed out upon the conclusion of the 2022 Solar Procurement."

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. DEC, DEP, DENC, EnergyUnited, Fayetteville Public Works Commission, 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

NC GreenPower's mission is to expand public knowledge and acceptance of cleaner energy technologies to all North Carolinians through local, community-based initiatives. Founded in 2003 as a subsidiary of Advanced Energy Corporation, the nonprofit was launched by the NC Utilities Commission as a voluntary program to supplement the state's existing power supply with more green energy. NC GreenPower works to improve the state's environment by supporting renewable energy and carbon offset projects and by providing grants for solar installations at North Carolina K-12 schools.

Introduced on April 1, 2015, NC GreenPower Solar+ Schools uses donations to provide grants for educational solar PV packages at North Carolina schools. All K-12 schools are eligible, though preference may be given to those in economically distressed counties as defined by the NC Department of Commerce. Following a five-year pilot, the program was made official by the NC Utilities Commission in 2019 and offers top-of-pole mounted systems, roof-mounted systems, solar awnings, and other designs as needed to accommodate various structures.

The NC GreenPower Solar+ Schools program gives teachers valuable tools to educate students about renewable energy. NC GreenPower's grant pays for all of the project's construction costs requiring selected schools to raise only a small portion of the costs, approximately $3,500, to cover any operations and maintenance costs. NC GreenPower's partner, the State Employees' Credit Union (SECU) Foundation, will provide an additional grant of up to $600,000 over the next three years to assist with the installation costs for then selected public schools per year.

In 2022, NC GreenPower awarded 20 North Carolina schools a solar education package valued at $42,000. In addition to a 5-kW solar array, each school will receive donated SunPower solar modules, a weather station, data monitoring equipment, STEM curricula and training for educators.

By the end of 2022, the NC GreenPower Solar+ Schools program will have reached a total of 76 North Carolina schools in 46 counties, bringing solar energy and STEM

education to nearly 57,000 students. To date, the schools have collectively produced an estimated 720,939 kilowatt hours of green energy, a savings of about $68,400.

Additionally, as part of the American Rescue Plan Act, NC GreenPower was awarded $798,436 in funding from NCDEQ's State Energy Office allowing NC GreenPower to purchase and install high-efficiency light-emitting diode (LED) fixtures in 60 qualifying North Carolina K-8 public school gymnasiums at no cost to the schools thereby reducing the schools' energy burden.

Contributions to NC GreenPower continue to help support the local generation of green energy and reduction of greenhouse gases but also help to install 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 electric bill or directly to NC GreenPower on their website: www.ncgreenpower.org. NC GreenPower is a 501(c)(3) nonprofit organization, and all current projects are located within North Carolina.

9. TRANSMISSION AND GENERATION INTERCONNECTION ISSUES

Transmission Planning

The North Carolina Transmission Planning Collaborative (NCTPC) was established in 2005. Its processes are intended to comply with the local transmission planning requirements imposed by FERC in Order Nos. 890 and 1000. The NCTPC participants consist of DEC and DEP which own transmission, and NCEMC and ElectriCities which represent transmission-dependent utilities. Through the NCTPC processes, the participants, create a local transmission plan that (a) identifies the electric transmission projects needed to maintain reliability, to integrate new generation resources or loads, for economic needs (i.e., to increase transmission access to potential supply resources inside and outside of the territories of DEC and DEP), and for public policy needs and (b) provides estimates of costs. The NCTPC's January 24, 2022 report (the "2021 Study") stated that 16 major transmission projects (greater than $10 million each) are needed in North Carolina by the end of 2031 at an estimated cost of $694 million. This compares to the original 2020 Study Plan estimate of $804 million for 17 reliability projects. In a mid-year update to the 2021 Plan, the NCTPC updated the costs of existing reliability projects from $694 million to $748 million. In addition, the mid-year update proposed adding 18 new projects with an estimated cost of $560.6 million "to integrate additional generation and to meet the public policy requirements of the Carbon Plan." After receiving input from stakeholders and after issuance of an order from the Commission, the NCTPC decided not to pursue to postpone approval of the new projects in the 2021 plan; although it expects many or most of them will be included in a future plan. For more information, visit the NCTPC's website at www.nctpc.org.

On July 21, 2011, FERC issued Order No. 1000, entitled "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities."[2] This Order requires transmission owners to participate in regional and inter-regional transmission planning efforts. DEC and DEP have complied with Order No. 1000 by participating in the Southeastern Regional Transmission Planning (SERTP)[3] 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 Energy Carolinas, Duke Power, and Virginia Electric and Power Company 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 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 backlog of interconnection requests. The more significant changes in the State's interconnection standards were the following:

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

[3] For more information about the Southeastern Regional Transmission Planning process, see http://southeasternrtp.com/. Other sponsors 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, Associated Electric Cooperative, Inc., and the Tennessee Valley Authority.

(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.

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

On June 14, 2019, the Commission issued an order further modifying the NC Interconnection Standard that made fairly minor changes while establishing deadlines for considering more substantial changes. These include the following:

1. The utilities were required to file additional information explaining their need for generators' production profiles. The Commission subsequently approved this new requirement on September 23, 2019.
2. Duke was required to file a proposal for an expedited study process for battery storage being added to an existing solar generator. Duke made the required filing and on August 17, 2021, the Commission resolved several issues relative to adding storage at an existing solar site and required Duke to (1) provide a list of interconnection procedure waivers that would be needed to implement expedited storage retrofits at solar sites, and (2) propose a process whereby an existing QF that seeks to add storage could establish eligibility for a bifurcated avoided cost rate. Duke filed the required information September 29, 2021.Other parties have since filed comments on these issues, which remain pending.
3. Duke was required to consult with the Electric Power Research Institute as to ways to improve the fast track / supplemental review processes and file a report with the Commission. Duke filed that report on October 23, 2019.
4. The utilities were required to host stakeholder meetings about the adoption of Interconnection Standard IEEE-1547 and file a report with the Commission. This report was filed April 1, 2020. On March 2, 2021, the Commission issued an order requiring Duke and DENC to file by March 15 each year a report on the status of their implementation efforts.
5. Duke was required to establish a stakeholder process to discuss transitioning the interconnection process from a first-come first-served process to a grouping study process. Duke subsequently filed a queue reform proposal. In October of 2020, the Commission approved a queue reform proposal that had been developed by Duke with input from stakeholders. In 2021, the reforms were also approved by the

South Carolina Public Service Commission and FERC, and in August of 2021, the Commission ordered Duke to move ahead with implementation. In 2022, the utility conducted a Transitional Cluster Study as part of the transition to the new process, and is currently performing the 2022 DISIS (Definitive Interconnection System Impact Study) process.

FERC Transmission Planning and Cost Allocation Proceedings

In June 2021, the Federal Energy Regulatory Commission (FERC) established a Joint Federal-State Task Force on Electric Transmission and solicited nominations for state utility commission representation on the Task Force. (FERC Docket No. AD21-15) NC Commissioner Kimberly Duffley was appointed to the Task Force on August 30, 2021, and was renominated for a second one-year term on July 15, 2022. Commissioner Duffley has presented her views during the first five Task Force meetings. The Task Force will focus on topics related to efficiently and fairly planning and paying for electric transmission, including transmission to facilitate generator interconnection, and exploring opportunities for states to voluntarily coordinate to identify, plan, and develop regional transmission. The Task Force will expire in three years, but its term may be extended by agreement between FERC and state regulators.

In July 2021, FERC issued an advance notice of proposed rulemaking in which it sought comments on a wide range of proposals relating to planning and paying for regional transmission and facilitating generator interconnections. (FERC Docket No. RM21-17) The NCUC filed comments in that proceeding. A major focus of the Commission's comments was transmission cost allocation inequities that result in DEP customers paying for transmission upgrades that are needed due to electric generators interconnecting with DENC in order to export their power to the PJM Regional Transmission Operator that operates the power grid north and west of North Carolina. The NCUC also argued for the retention of "participant funding," wherein the generator that causes the need for a transmission upgrade should bear the full cost.

In April 2022, FERC issued a notice of proposed rulemaking in which it sought comments on proposals relating to long-term regional transmission planning, use of advanced technologies in regional transmission planning, seeking agreement of state entities within transmission planning regions related to cost allocation, and transparency requirements for local and regional transmission planning processes. (FERC Docket No. RM21-17) The NCUC filed joint comments in that proceeding with the North Carolina Public Staff. These comments expressed support for FERC's proposal to give states a greater role in transmission planning and cost allocation decisions.

In June 2022, FERC issued a notice of proposed rulemaking in which it sought comments on proposals relating to reforms to FERC's pro forma Large Generator Interconnection Procedures and Agreement and pro forma Small Generator Interconnection Agreement, to address interconnection queue backlogs, improve certainty, and prevent undue discrimination for new technologies. (FERC Docket No. RM22-14) The NCUC filed joint comments in that proceeding with the North Carolina

Public Staff. These comments gave the Commission another opportunity to describe to FERC how some of its policies tend to burden North Carolina ratepayers and violate the fundamental ratemaking principle that those who cause costs should pay for them. The Commission reported to FERC that many of its proposed reforms with respect to interconnecting new energy generation had already been implemented in North Carolina.

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)

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, and 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 by using its own regulatory authority. Additionally, the Commission engages with PJM and monitors its activities, including, through regional cooperation with other State commissions, and by participating in proceedings before 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). Commission Chair Charlotte Mitchell is currently the President of OPSI.

Southeast Energy Exchange Market (SEEM)

On December 11, 2020, DEC and DEP filed an advance notice with the Commission stating their intention to file with the Federal Energy Regulatory Commission revisions to their Open Access Transmission Tariff in order to establish an energy-only electricity market in the Southeast, known as the Southeast Energy Exchange Market (SEEM). Membership in the SEEM is not limited to investor-owned utilities, and NCEMC is also a member of SEEM. The market is designed to facilitate short-term, bi-lateral, automated energy sales across the region. The SEEM members have received clearance from FERC to enter into the SEEM agreements and modify their respective federal tariffs. Cost savings will flow to retail customers via the fuel rider, which the Commission adjusts annually. The SEEM initiated operations on November 9, 2022.

PURPA Reform

In July 2020, FERC issued a final rule which is the first major change to PURPA regulations since 1980. (Order No. 872, FERC Docket Nos. RM19-15 and AD16-16) In general terms, PURPA provides rights to certain non-utility power generators known as qualifying facilities or “QFs” to require electric utilities to purchase the QF’s output at the utility’s avoided cost. FERC is charged with ensuring that QF rates are just and reasonable to consumers and that the rates do not discriminate against QFs. Among its key revisions, the final rule grants additional flexibility to state regulatory authorities in establishing avoided cost rates for QF sales inside and outside of the organized electric markets. The rule also grants states the ability to require energy rates (but not capacity rates) to vary during the life of a QF contract.

FERC also changed the rules that determine whether facilities are located at the same site, replacing the “one-mile rule” with a “ten-mile rule.” Further FERC reduced the rebuttable presumption for “nondiscriminatory access” to power markets - from 20 MW to 5 MW - for small power production but not cogeneration facilities. Finally, in order for a QF to establish a legally enforceable obligation, the final rule requires that the QFs must demonstrate commercial viability and financial commitment to build under objective and reasonable state-determined criteria.

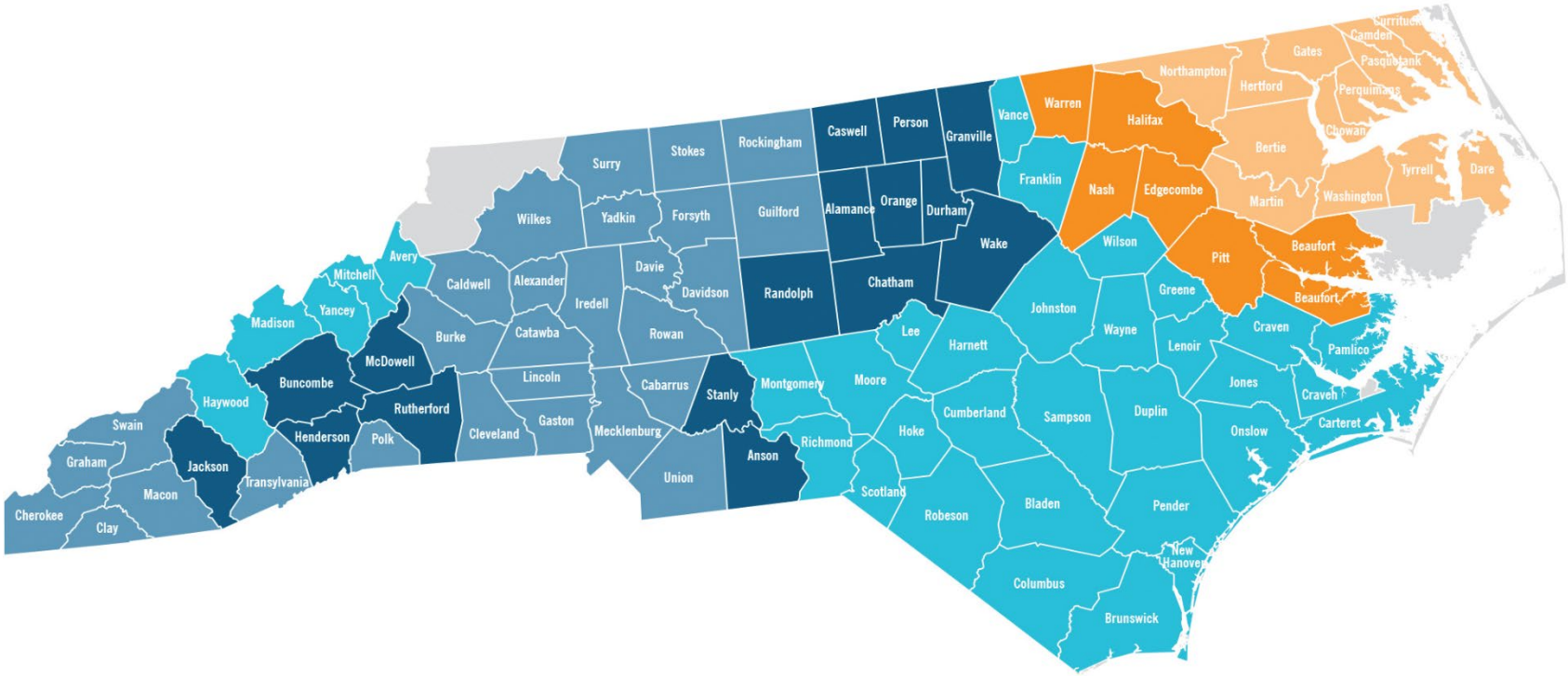
The final rule does not change other elements of the existing PURPA regulations that encourage QF development. These include regulations “requiring electric utilities to provide backup electric energy to QFs on a non-discriminatory basis and at just and reasonable rates; requiring electric utilities to interconnect with QFs; and providing exemptions to QFs from many provisions of the Federal Power Act and state laws governing utility rates and financial organization.”

Affordable Clean Energy Rule (ACE Rule)

Citing its authority under Section 1111 of the Clean Air Act, the Environmental Protection Agency (EPA) released the final version of the Affordable Clean Energy Rule (ACE Rule) on June 19, 2019, which replaced and repealed the Clean Power Plan. The

ACE Rule, which applied to existing coal-fired power plants greater than or equal to 25 MW, was a mechanism intended to provide achievable and realistic standards for reducing greenhouse gas emissions using heat rate improvement technologies. Appeals from this action eventually came before the United States Supreme Court, which applied the major questions doctrine and held that the EPA had exceeded its statutory authority in promulgating the ACE Rule. *West Virginia v. EPA*, 142 S. Ct. 2587 (2022). The Supreme Court's decision was issued on June 30, 2022.

APPENDIX 1



SERVICE TERRITORIES
(counties served)

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

APPENDIX 2