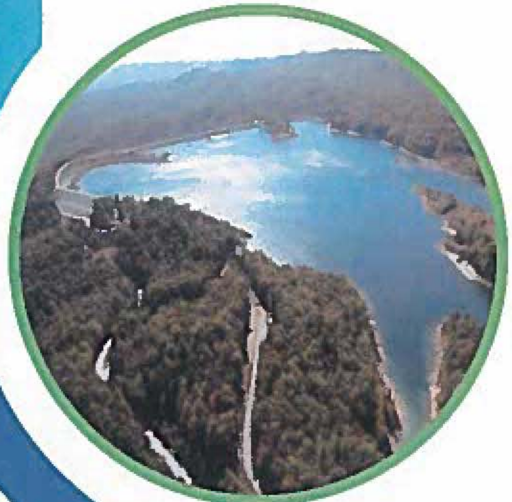
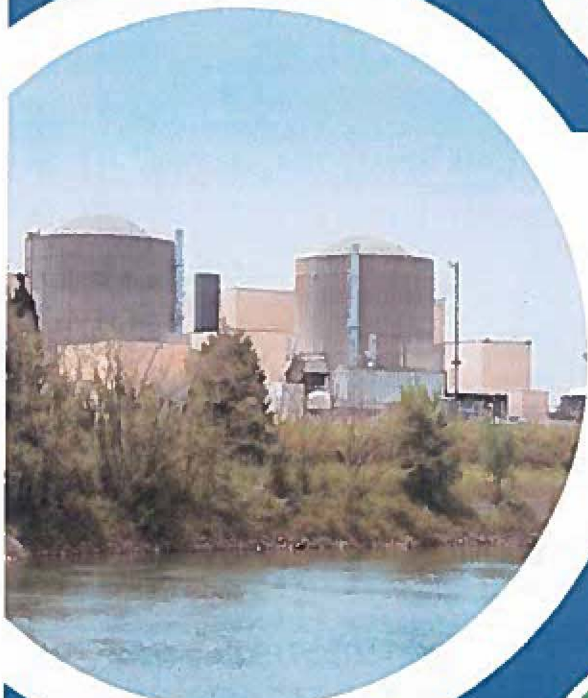


DUKE ENERGY CAROLINAS



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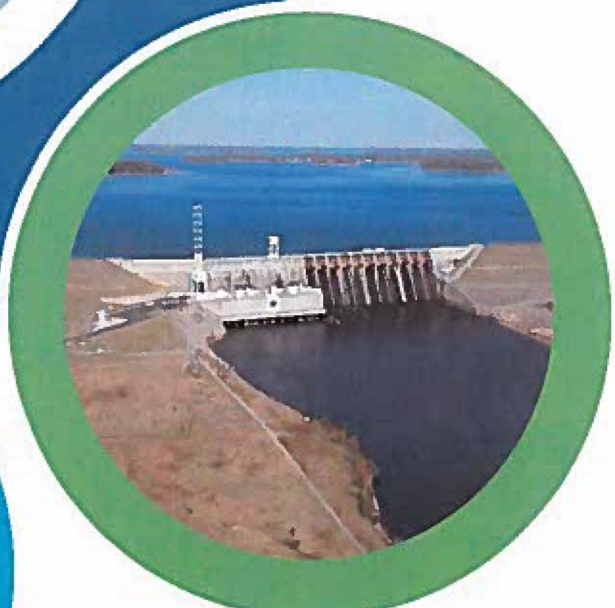
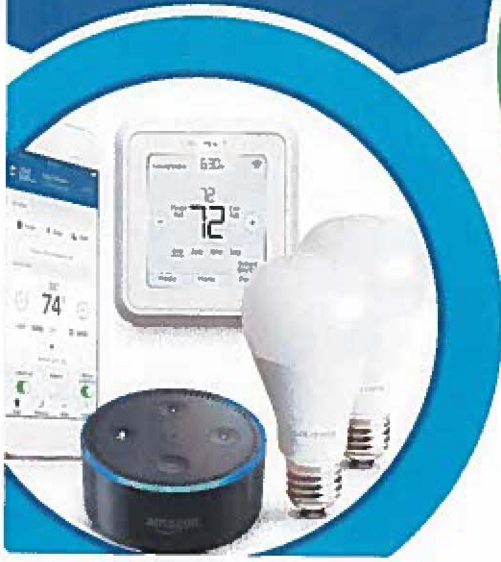
DUKE ENERGY CAROLINAS

INTEGRATED RESOURCE PLAN UPDATE REPORT

2019





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ABBREVIATIONS:	
AC	Alternating Current
ACE	Affordable Clean Energy
ADP	Advanced Distribution Planning
AEO	Annual Energy Outlook
BCFD	Billion Cubic Feet Per Day
CAIR	Clean Air Interstate Rule
CAMA	North Carolina Coal Ash Management Act of 2014
CAMR	Clean Air Mercury Rule
CAPP	Central Appalachian Coal
CC	Combined Cycle
CCR	Coal Combustion Residuals Rule
CCS	Carbon Capture and Sequestration
CECPCN	Certificate of Environmental Compatibility and Public Convenience and Necessity (SC)
CEP	Comprehensive Energy Planning
CFL	Compact Fluorescent Light bulbs
CO_2	Carbon Dioxide
COD	Commercial Operation Date
COL	Combined Construction and Operating License
COWICS	Carolinas Offshore Wind Integration Case Study
CPCN	Certificate of Public Convenience and Necessity (NC)
CPRE	Competitive Procurement of Renewable Energy
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbine
DC	Direct Current
DCA	Design Certification Application
DEC	Duke Energy Carolinas
DEF	Duke Energy Florida
DEI	Duke Energy Indiana
DEK	Duke Energy Kentucky
DEP	Duke Energy Progress
DER	Distributed Energy Resource
DESC	Dominion Energy South Carolina, Inc.
DIY	Do It Yourself
DOE	Department of Energy
DOJ	Department of Justice
DSM	Demand-Side Management
EE	Energy Efficiency
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPC	Engineering, Procurement, and Construction Contractors
EPRI	Electric Power Research Institute
EVs	Electric Vehicles
FERC	Federal Energy Regulatory Commission

ABBREVIATIONS:	
FGD	Flue Gas Desulfurization
FLG	Federal Loan Guarantee
FPS	Feet Per Second
GALL-SLR	Generic Aging Lessons Learned for Subsequent License Renewal
GHG	Greenhouse Gas
GWh	Gigawatt-hour
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation and Air Conditioning
IA	Interconnection Agreement
IGCC	Integrated Gasification Combined Cycle
ILB	Illinois Basin
ILR	Inverter Load Ratios
IRP	Integrated Resource Plan
IS	Interruptible Service
ISOP	Integrated Systems and Operations Planning
IT	Information Technologies
ITC	Federal Investment Tax Credit
IVVC	Integrated Volt-Var Control
JDA	Joint Dispatch Agreement
kW	Kilowatt
kWh	Kilowatt-hour
LCR Table	Load, Capacity, and Reserves Table
LED	Light Emitting Diodes
LEED	Leadership in Energy and Environmental Design
LEO	Legally Enforceable Obligation
LFE	Load Forecast Error
LNG	Liquified Natural Gas
LOLE	Loss of Load Expectation
M&V	Measurement and Verification
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standard
MGD	Million Gallons Per Day
MW	Megawatt
MWh	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NAP	Northern Appalachian Coal
NAPP	Northern Appalachian Coal
NC	North Carolina
NC HB 589	North Carolina House Bill 589
NC REPS	North Carolina Renewable Energy and Energy Efficiency Portfolio Standard
NCCSA	North Carolina Clean Smokestacks Act
NCDAQ	North Carolina Division of Air Quality
NCEMC	North Carolina Electric Membership Corporation

ABBREVIATIONS:	
NCMPA1	North Carolina Municipal Power Agency #1
NCTPC	NC Transmission Planning Collaborative
NCUC	North Carolina Utilities Commission
NEMS	National Energy Modeling Systems
NERC	North American Electric Reliability Corporation
NES	Neighborhood Energy Saver
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_x	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standard
NUG	Non-Utility Generator
NUREG	Nuclear Regulatory Commission Regulation
NYMEX	New York Mercantile Exchange
O&M	Operating and Maintenance
OATT	Open Access Transmission Tariff
PD	Power Delivery
PEV	Plug-In Electric Vehicles
PJM	PMJ Interconnection, LLC
PMPA	Piedmont Municipal Power Agency
PPA	Purchase Power Agreement
PPB	Parts Per Billion
PROSYM	Production Cost Model
PSCSC	Public Service Commission of South Carolina
PSD	Prevention of Significant Deterioration
PURPA	Public Utility Regulatory Policies Act
PV	Photovoltaic
PVDG	Solar Photovoltaic Distributed Generation Program
PVRR	Present Value Revenue Requirement
QF	Qualifying Facility
RCRA	Resource Conservation Recovery Act
REC	Renewable Energy Certificate
REPS	Renewable Energy and Energy Efficiency Portfolio Standard
RFP	Request for Proposal
RICE	Reciprocating Internal Combustion Engines
RIM	Rate Impact Measure
RPS	Renewable Portfolio Standard
RRP	Refrigerator Replacement Program
SAE	Statistical Adjusted End-Use Model
SAT	Single-Axis Tracking
SC	South Carolina
SC Act 62	South Carolina Energy Freedom Act of 2018

ABBREVIATIONS:	
SC DER or SC ACT 236	South Carolina Distributed Energy Resource Program
SCR	Selective Catalytic Reduction
SEPA	Southeastern Power Administration
SERC	Southeastern Electric Reliability Corporation
SERVM	Strategic Energy Risk Valuation Model
SG	Standby Generation
SIP	State Implementation Plan
SISC	Solar Integration Services Charge
SLR	Subsequent License Renewal
SMR	Small Modular Reactor
SO	System Optimizer
SO_2	Sulfur Dioxide
SRP – SLR	Standard Review Plan for the Review of Subsequent License Renewal
STAP	Short-Term Action Plan
T&D	Transmission & Distribution
TAG	Technology Assessment Guide
The Company	Duke Energy Progress
The Plan	Duke Energy Progress Annual Plan
TRC	Total Resource Cost
TVA	Tennessee Valley Authority
UCT	Utility Cost Test
UEE	Utility Energy Efficiency
VACAR	Virginia/Carolinas
VAR	Volt Ampere Reactive
WERP	Weatherization and Equipment Replacement Program
ZELFRS	Zero – Emitting Load Following Resources

1. INTRODUCTION

For more than a century, North and South Carolinians have received affordable and reliable electricity from Duke Energy Carolinas (DEC) who now serves more than 2.6 million customers. Working with businesses and communities, Duke Energy helped shape the Carolinas of today, building important infrastructure like our power plants, transmission grid and other facilities that power our homes and businesses. Duke Energy is committed to securing a sustainable energy future for its growing number of customers by planning for resource needs in the most reliable and economic way possible while using increasingly clean forms of energy. DEC works across the Carolinas to support a cleaner environment and mitigate climate change by being an industry leader in carbon-free nuclear, hydro-electric and solar generation. DEC is also a driving force of innovation in a region well-known for research and scientific exploration, helping to engineer new technologies that move the Carolinas forward. Through its Joint Dispatch Agreement (JDA) with Duke Energy Progress (DEP), the two companies collectively provide approximately 55% of all energy delivered on the combined Carolinas system with carbon-free resources.

Each year, as required by the North Carolina Utilities Commission (NCUC) and the Public Service Commission of South Carolina (PSCSC), DEC submits a long-range planning document called the Integrated Resource Plan (IRP). The IRP details projections of infrastructure needed to match the forecasted electricity needs of our customers plus an adequate reserve margin, to maintain a reliable electric system for customers over the next 15 years.

The Company files a comprehensive Biennial IRP in even numbered years. This document is an update to the comprehensive DEC 2018 IRP.

In recent years, the Company has filed separate IRP updates to the comprehensive plan for NC and SC, which has created some confusion. The IRP is truly a single plan, for a single system that happens to span both NC and SC. As result, the Company is filing one IRP update for both states to ensure each Commission and all stakeholders have a clear and comprehensive view of the Company's integrated resource plan. The IRP update analyzes the DEC system in total across both states including customer demand, energy efficiency (EE), demand side management (DSM), renewable resources and traditional supply-side resources.

2. 2019 IRP SUMMARY

Each year, as required by the NCUC and the PSCSC, DEC submits an IRP update detailing projected infrastructure needed to meet the forecasted electricity requirements for its customers over the next 15 years. The 2019 IRP is the best projection of how the Company's capacity and energy portfolio is expected to evolve over the next 15 years, based on current data assumptions. This projection may change over time as variables such as the projected load forecasts, fuel price forecasts, environmental regulations, technology performance characteristics and other outside factors change.

The proposed plan will meet the following objectives:

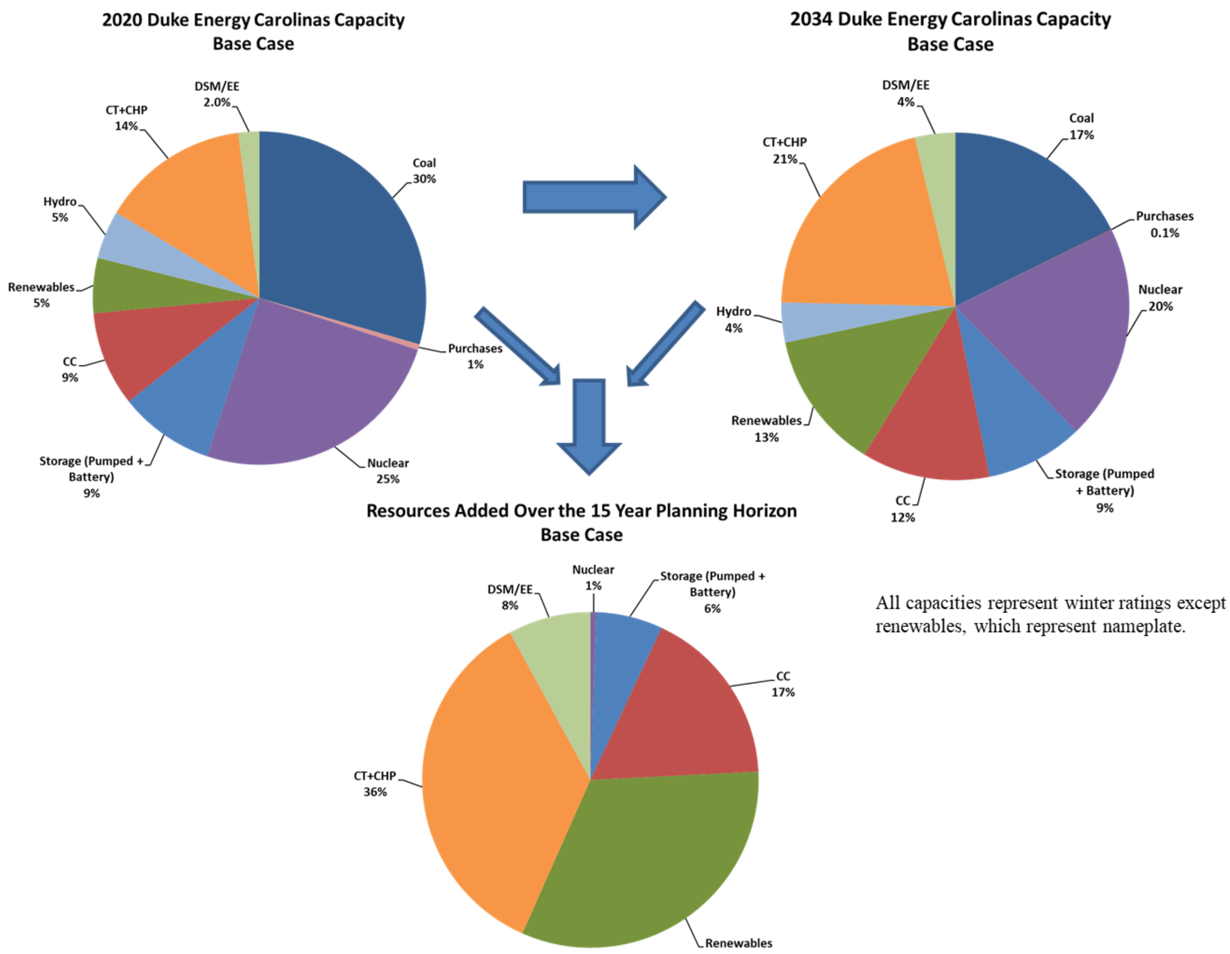
- Provide reliable electricity throughout the year, especially during periods of high peak demand such as cold winter mornings by maintaining adequate planning reserve margins. Peak demand refers to the highest amount of electricity being consumed for any given hour across DEC's entire system.
- Select new resources at the lowest reasonable cost to customers. These resources include a balance of EE, DSM, renewable resources, pumped storage, battery storage and natural gas generation.
- Improve the environmental footprint of the portfolio by meeting or exceeding all federal, state and local environmental regulations. Furthermore, Duke Energy Corporation is committed to reducing its carbon emissions. Over the next decade, we are on track in the Carolinas to reduce carbon emissions by over 50 percent relative to a 2005 baseline level. Beyond 2030 even further reductions are attainable with continued technology development in the areas of carbon free generation and energy storage.

As 2019 is an update year, DEC developed two cases which reflect updates to the 2018 IRP Base Case. The first case, or the "Base Case," is an update to the presented base case in the 2018 IRP, which includes the expectation of future carbon legislation. Additionally, a "No Carbon Case" was developed in which no carbon legislation is considered. All results presented in this IRP represent the Base Case, unless otherwise noted. DEC has updated several key planning assumptions such as technology cost assumptions, fuel prices, renewable generation projections and the DEC load forecast.

As shown in the 2019 IRP Base Case, projected incremental needs are driven by load growth and the retirement of aging generation resources. Of note, DEC has an increased load forecast and an increased projection of renewable resources relative to its 2018 IRP. This IRP update reflects the impacts of these increases to the DEC system. A more detailed discussion of the load forecast and the forecast of renewable resources can be found in Chapter 5 and Chapter 6, respectively.

The 2019 IRP seeks to achieve a reliable, economic long-term power supply through a balance of incremental renewable resources, EE, DSM, and traditional supply-side resources planned over the coming years which allows the Company to maintain a diversified resource mix while also providing increasingly clean energy. Chart 2-A represents the incremental investments required to meet future needs.

Chart 2-A 2020 and 2034 Base Case Winter Capacity Mix and Sources of Incremental Capacity



3. IRP PROCESS OVERVIEW

To meet the future needs of DEC's customers, it is necessary for the Company to adequately understand the load and resource balance. For each year of the planning horizon, the Company develops a load forecast of cumulative energy sales and hourly peak demands. To determine total resources needed, the Company considers the peak demand load obligation plus a 17% minimum planning reserve margin.

The projected capability of existing resources, including generating units, EE and DSM, renewable resources and purchase power contracts, is measured against the total resource need. Any deficit in future years will be met with a mix of additional resources that reliably and cost-effectively meet the load obligation and planning reserve margin while complying with all environmental and regulatory requirements.

Growth in Peak Demand and Energy Consumption	+	Resource Retirements	=	New Resource Needs

It should be noted that DEC considers the non-firm energy purchases and sales associated with the JDA with DEP in the development of its independent Base Case. To accomplish this, DEC and DEP plans are determined simultaneously to minimize revenue requirements of the combined jointly dispatched system while maintaining independent reserve margins for each company.

DEC's IRP includes new resource additions driven by winter peak demand projections inclusive of winter reserve requirements. The completion of a comprehensive reliability study in 2016 demonstrated the need to include winter peak planning in the IRP process. The study recognized the growing volatility associated with winter morning peak demand conditions such as those observed during recent polar vortex events. The study also incorporated the expected significant growth in solar facilities that provide valuable assistance in meeting summer afternoon peak demands on the system but do little to assist in meeting demand for power on cold winter mornings. Based on results of the reliability study, DEC is utilizing a winter planning reserve margin of 17% in its planning process.

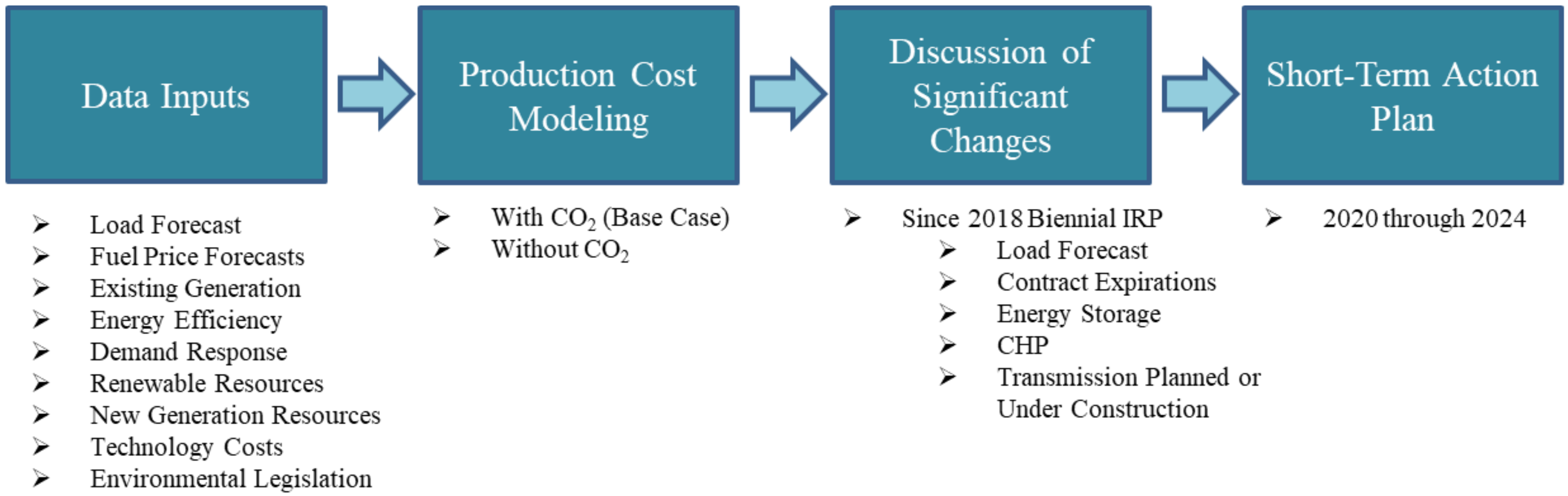
For the 2019 Update IRP, the Company presents a Base Case with a carbon tax beginning in 2025. However, remaining consistent with the Commission's Order to both include and exclude costs associated with carbon regulation, the current assumption of a carbon tax is intended to serve as a placeholder for some form of potential future carbon regulation. [1] An additional case assuming no carbon legislation was also developed.

While future carbon legislation is unknown, the Company feels that it is prudent to continue to plan for this scenario, as well as other potential future scenarios. Furthermore, a primary focus of this update IRP is the Short-Term Action Plan (STAP), which covers the period 2020 to 2024. It was determined that the inclusion of the carbon tax did not have a significant impact on the STAP, and therefore the majority of the data presented in this report represents the Base Case.

Figure 3-A represents a simplified overview of the resource planning process in the update years (odd years) of the IRP cycle.

[1] "Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans"; NCUC Docket No. E-100, Sub 147; p. 35

Figure 3-A Simplified IRP Process



4. SIGNIFICANT CHANGES FROM THE 2018 IRP

As an initial step in the IRP process, all production cost modeling data is updated to include the most current data. Throughout the year, best practices are implemented to ensure the IRP best represents the Company's planning assumptions including load forecast, generation system, conservation programs, renewable energy and fuel costs. The data and methodologies are regularly updated and reviewed to determine if adjustments can be made to further improve the IRP process and results.

As part of the review process, certain data elements with varying impacts on the IRP, inevitably change. A discussion of new or updated data elements that have the most substantial impact on the 2019 IRP is provided below.

a) Load Forecast

The Duke Energy Carolinas Spring 2019 forecast provides projections of the energy and peak demand needs for its service area. The forecast covers the time period of 2020 – 2034 and represents the needs of the following customer classes:

- Residential
- Commercial
- Industrial
- Other Retail
- Wholesale

The Retail forecast consists of the three major classes: Residential, Commercial and Industrial.

The Residential class sales forecast is comprised of two projections. The first is the number of residential customers, which is driven by population. The second is energy usage per customer, which is driven by weather, regional economic and demographic trends, electricity prices and appliance efficiencies.

The average annual growth rate of residential energy sales in the Spring 2019 forecast, including the impacts of Utility Energy Efficiency programs (UEE), rooftop solar and electric vehicles from 2020 – 2034 is 1.1%.

The three largest sectors in the Commercial class are offices, education and retail. Commercial energy sales are expected to grow 1.1% per year over the forecast horizon.

The Industrial class is forecasted by a standard econometric model, with drivers such as total manufacturing output, textile output, and the price of electricity. Overall, Industrial sales are expected to grow 0.4% per year over the forecast horizon.

The Company continues to look at ways to improve the load forecasting methodology in order to develop the most accurate and reasonable demand forecasts for DEC. The load forecast has increased in the 2019 Update as compared to the 2018 IRP, primarily driven by adding 2018 peaks to the history used in the forecast. The key economic drivers and forecast changes are shown below in Tables 4-A and 4-B. A more detailed discussion of the load forecast can be found in Chapter 5.

Table 4-A Key Drivers

	2020-2034
Real Income	2.7%
Manufacturing Industrial Production Index (IPI)	1.1%
Population	1.6%

Table 4-B reflects a comparison between the 2018 and 2019 growth rates of the load forecast with and without impacts of EE.

Table 4-B 2019 Load Forecast Growth Rates vs. 2018 Load Forecast Growth Rates (Inclusive of Retail and Wholesale Load)

	2019 Forecast (2020 – 2034)			**2018 Forecast (2019 – 2033)**		
	Summer Peak Demand	**Winter Peak Demand**	**Energy**	**Summer Peak Demand**	**Winter Peak Demand**	**Energy**
Excludes impact of new EE programs	1.2%	1.0%	1.1%	1.4%	1.2%	1.1%
Includes impact of new EE programs	1.0%	0.8%	0.9%	1.0%	0.9%	0.8%

Peak Demand and Energy Forecast

The load forecast projection for energy and capacity, including the impacts of UEE, rooftop solar, and electric vehicles, that was utilized in the 2019 IRP is shown in Table 4-C.

Table 4-C Load Forecast Net of Energy Efficiency Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWh)
2020	18,153	18,460	92,742
2021	18,266	18,449	93,141
2022	18,338	18,530	93,458
2023	18,474	18,580	94,067
2024	18,625	18,737	94,865
2025	18,782	18,852	95,574
2026	18,965	19,031	96,352
2027	19,202	19,192	97,262
2028	19,471	19,442	98,411
2029	19,713	19,665	99,410
2030	19,969	19,884	100,436
2031	20,252	20,120	101,616
2032	20,521	20,432	102,810
2033	20,819	20,680	104,051
2034	21,160	20,944	105,472
Avg. Annual Growth Rate	1.0%	0.8%	0.9%

Note: Tables 8-A and 8-B differ from these values due to a 47 MW Piedmont Municipal Power Agency (PMPA) backstand contract through 2020 and an 82 MW backstand contract with North Carolina Electric Membership Corp. (NCEMC) throughout the study period.

b) Changes to the 2019 Build Plan

As a result of the increase in the load forecast, the total need for new generation in DEC has increased, and the timing of the first resource need has accelerated from 2028 to 2026. The first need is met with a 470 megawatt (MW) bank of CTs while, similar to the 2018 IRP, a 1,441 MW combined cycle meets the 2028 resource need.

c) Energy Storage

Building on the 2018 IRP which included placeholders for approximately 150 MW of usable alternating current (AC)[2] grid-tied battery storage, the 2019 Update IRP includes estimates for additional battery storage that is coupled with solar. The inclusion of nearly 200 MW of storage coupled with solar over the planning horizon is driven by two factors. First, the results of the first tranche of the Competitive Procurement of Renewable Energy (CPRE) plan in DEC included two solar plus storage winning projects which provide some guidance as to the types of projects being developed. Second, the most recent avoided cost rate structures proposed in both NC and SC provide strong price incentives for Qualifying Facilities (QFs) to shift energy from lower priced energy-only hours to hours that have higher energy and capacity prices. This new rate design provides appropriate incentives to encourage storage plus solar projects.[3] The amount of solar coupled with storage represented in the IRP will change over time as conditions evolve, but these initial assumptions represent a first-step towards including such installations.

Looking forward, advancements in modeling capabilities, and plans to further study the capacity value of storage in the Carolinas will help the Company ensure the reliability benefits of these technologies are appropriately captured in its planning process.

d) Combined Heat and Power

Combined Heat and Power (CHP) systems, also known as cogeneration, generate electricity and useful thermal energy in a single, integrated system. CHP is not a new technology, but an approach to applying existing technologies. Heat that is normally wasted in conventional power generation is recovered as useful energy, which avoids the losses that would otherwise be incurred from separate generation of heat and power. CHP incorporating a gas-fired combustion turbine (CT) and heat recovery steam generator (HRSG) is more efficient than the conventional method of producing power and usable heat separately with a CT/generator and a stand-alone steam boiler.

DEC is exploring and working with potential customers with good base thermal loads on a regulated Combined Heat and Power offer. The CHP asset is included as part of Duke Energy's IRP as a placeholder for future projects as described below. The steam sales are credited back to the revenue requirement of the projects to reduce the total cost of this resource. Along with the potential to be a

[2] Usable alternating current for battery storage refers to the portion of the battery's nameplate AC MW rating that is available to the grid after taking into account limitations in depth of charge and discharge.
[3] From North Carolina Avoided Cost Docket No. E-100, Sub 158 and South Carolina Avoided Cost Docket Nos. 2019-185-E and 2018-186-E.

cost-competitive generation resource, CHP can result in carbon dioxide (CO_2) emission reductions, and is a potential economic development opportunity for both NC and SC.

DEC has signed agreements and obtained regulatory approval for a 15 MW CHP at Clemson University, which is expected to be in service by 2020. No projects beyond the signed Clemson project have been included in the 2019 IRP Update.

Potential projects with industrial customers have been challenging due to credit requirements, contract length, estimated capital cost, and changes to natural gas price forecasts.

Projections for CHP have been included in the following quantities in this IRP:

2020: 15 MW (winter) / 15 MW (summer)

This is a difference from the 2018 IRP as the following was included:

2020: 22 MW (winter) / 20 MW (summer)
2021: 22 MW (winter) / 20 MW (summer)

As CHP development continues, future IRPs will incorporate CHP, as appropriate. Additional technologies evaluated as part of this IRP are discussed in Chapter 8.

e) <u>Transmission Planned or Under Construction</u>

This section contains the planned transmission line additions since the 2018 IRP. Only those projects that have changed since the 2018 IRP are included. Additionally, a discussion of the system adequacy of DEC's transmission system is included. Table 4-D lists the line projects that are planned to meet reliability needs. This section also provides information pursuant to the North Carolina Utilities Commission Rule R8-62.

Table 4-D: DEC Transmission Line Additions

	Location		Capacity	Voltage	
Year	**From**	**To**	**MVA**	**KV**	**Comments**
2022	Sadler Tie	Ernest Switching Station	N/A	230	Delayed by one year the project to install a switchable series reactor on the Sadler Tie – Ernest Switching Station 230 kV transmission line.

Rule R8-62: Certificates of environmental compatibility and public convenience and necessity for the construction of electric transmission lines in North Carolina.

(p) Plans for the construction of transmission lines in North Carolina 161 kilovolt (kV) and above) shall be incorporated in filings made pursuant to Commission Rule R8-60. In addition, each public utility or person covered by this rule shall provide the following information on an annual basis no later than September 1:

(1) For existing lines, the information required on FERC Form 1, pages 422, 423, 424, and 425, except that the information reported on pages 422 and 423 may be reported every five years.

Please refer to the Company's Federal Energy Regulatory Commission (FERC) Form No. 1 filed with NCUC in April 2019.

(p) Plans for the construction of transmission lines in North Carolina (161 kV and above) shall be incorporated in filings made pursuant to Commission Rule R8-60. In addition, each public utility or person covered by this rule shall provide the following information on an annual basis no later than September 1:

(2) *For lines under construction, the following:*

Two 230 kilovolt (kV) lines are under construction to support the development of a new 230/100 kV tie station in the existing line between the Lincoln Combustion Turbine site and Longview Tie.

a. Commission docket number;

DOCKET NO. E-7, SUB 1177

b. Location of end point(s);

Blackburn Line Location Description:
The tap will be located approximately 418 feet southwest of str. #134 on the Lincoln Combustion Turbine to Longview Tie– Blackburn 230 kV Transmission line. The transmission line will run in a transmission easement northeast for approximately 466 linear feet to the property boundary of a DEC owned parcel. The Blackburn 230 kV line will then run approximately 4,029 linear feet north/northeast to the new bank in the 230 kV tie station. The approximately 4,029 linear feet is entirely on DEC owned property. The total tap line is approximately 4,495 feet (0.85 miles).

Mercer Line Location Description:
The tap will be located approximately 538 feet southwest of str. #134 on the Lincoln Combustion Turbine to Longview Tie–Mercer 230 kV Transmission line. The transmission line will run in a transmission easement northeast for approximately 454 linear feet to the property boundary of a DEC owned parcel. The Mercer 230 kV line will then run approximately 2,988 linear feet north/northeast to the new bank in the 230 kV tie station. The approximately 2,988 linear feet is entirely on DEC owned property. The total tap line is approximately 3,442 feet (0.65 miles).

c. Length;

Blackburn Lines: 0.85 Miles
Mercer Lines: 0.65 Miles

d. Range of right-of-way width;
Right of way includes a 100kV line, so it is a total of 319 feet

e. Range of tower heights;
122 feet to 164 feet above ground

f. Number of circuits;
4 - 230 kV circuits

g. Operating voltage;
230 kV

h. Design capacity;
Summer Continuous: 766MVA
Winter Continuous: 1007MVA

i. Date construction started;
Fall 2018

j. Projected in-service date;
Fall 2019, the whole project is scheduled to be complete 12/1/2020

DEC Transmission System Adequacy

Duke Energy Carolinas monitors the adequacy and reliability of its transmission system and interconnections through internal analysis and participation in regional reliability groups. Internal transmission planning looks 10 years ahead at available generating resources and projected load to identify transmission system upgrade and expansion requirements. Corrective actions are planned and implemented in advance to ensure continued cost-effective and high-quality service. The DEC transmission model is incorporated into models used by regional reliability groups in developing plans to maintain interconnected transmission system reliability. DEC works with DEP, North Carolina Electric Membership Corporation (NCEMC) and ElectriCities to develop an annual NC Transmission Planning Collaborative (NCTPC) plan for the DEC and DEP systems in both North and South Carolina. In addition, transmission planning is coordinating with neighboring systems including Dominion Energy South Carolina Inc. (DESC; formerly SCE&G) and Santee Cooper under a number of mechanisms including legacy interchange agreements between DESC, Santee Cooper, DEP, and DEC.

The Company monitors transmission system reliability by evaluating changes in load, generating capacity, transactions and topography. A detailed annual screening ensures compliance with DEC's Transmission Planning Guidelines for voltage and thermal loading. The annual screening uses methods that comply with SERC Reliability Corporation (SERC) policy and North American Electric Reliability Corporation (NERC) Reliability Standards and the screening results identify the need for future transmission system expansion and upgrades.

Transmission planning and requests for transmission service and generator interconnection are interrelated to the resource planning process. DEC currently evaluates all transmission reservation requests for impact on transfer capability, as well as compliance with the Company's Transmission Planning Guidelines and the FERC Open Access Transmission Tariff (OATT). The Company performs studies to ensure transfer capability is acceptable to meet reliability needs and customers' expected use of the transmission system. Generator interconnection requests are studied in accordance with the FERC Large and Small Generator Interconnection Procedures in the OATT and related North Carolina and South Carolina state procedures.

SERC audits DEC every three years for compliance with NERC Reliability Standards. Specifically, the audit requires DEC to demonstrate that its transmission planning practices meet NERC standards and to provide data supporting the Company's annual compliance filing certifications. SERC conducted a NERC Reliability Standards compliance audit of DEC in June 2019. The scope of this audit included standards impacting the Transmission Planning area. DEC received "No Findings" from the audit team in the areas associated with Transmission Planning activities.

DEC participates in a number of regional reliability groups to coordinate analysis of regional, sub-regional and inter-balancing authority area transfer capability and interconnection reliability. The reliability groups' purpose is to:

- Assess the interconnected system's capability to handle large firm and non-firm transactions for purposes of economic access to resources and system reliability;

- Ensure that planned future transmission system improvements do not adversely affect neighboring systems; and

- Ensure interconnected system compliance with NERC Reliability Standards.

Regional reliability groups evaluate transfer capability and compliance with NERC Reliability Standards for the upcoming peak season and five- and ten-year periods. The groups also perform computer simulation tests for high transfer levels to verify satisfactory transfer capability. Application of the practices and procedures described above ensures that DEC's transmission system continues to provide reliable service to its native load and firm transmission customers.

5. LOAD FORECAST

Methodology

The Duke Energy Carolinas' Spring 2019 Forecast provides projections of the energy and peak demand needs for its service area. The forecast covers the time period of 2020 – 2034 and represent the needs of the following customer classes:

- Residential
- Commercial
- Industrial
- Other Retail
- Wholesale

Energy projections are developed with econometric models using key economic factors such as income, electricity prices, industrial production indices, along with weather, appliance efficiency trends, rooftop solar trends, and electric vehicle trends. Population is also used in the residential customer model.

The economic projections used in the Spring 2019 Forecast are obtained from Moody's Analytics, a nationally recognized economic forecasting firm, and include economic forecasts for the states of North and South Carolina. Moody's forecasts consist of economic and demographic projections, which are used in the energy and demand models.

The Retail forecast consists of the three major classes: Residential, Commercial and Industrial.

The Residential class sales forecast is comprised of two projections. The first is the number of residential customers, which is driven by population. The second is energy usage per customer, which is driven by weather, regional economic and demographic trends, electricity prices and appliance efficiencies.

The usage per customer forecast was derived using a Statistical Adjusted End-Use Model (SAE). This is a regression based framework that uses projected appliance saturation and efficiency trends developed by Itron using Energy Information Administration (EIA) data. It incorporates naturally occurring efficiency trends and government mandates more explicitly than other models. The outlook for usage per customer is essentially flat through much of the forecast horizon, so most of the growth is primarily due to customer increases. The average annual growth rate of residential in the Spring

2019 forecast, including the impacts of Utility Energy Efficiency programs (UEE), rooftop solar and electric vehicles from 2020-2034 is 1.1%.

The Commercial forecast also uses an SAE model in an effort to reflect naturally occurring as well as government mandated efficiency changes. The three largest sectors in the Commercial class are offices, education and retail. Commercial energy sales are expected to grow 1.1% per year over the forecast horizon.

The Industrial class is forecasted by a standard econometric model, with drivers such as total manufacturing output, textile output, and the price of electricity. Overall, Industrial sales are expected to grow 0.4% over the forecast horizon.

Weather impacts are incorporated into the models by using Heating Degree Days with a base temperature of 59 and Cooling Degree Days with a base temperature of 65. The forecast of degree days is based on a 30-year average, which is updated every year.

The appliance saturation and efficiency trends are developed by Itron using data from the EIA. Itron is a recognized firm providing forecasting services to the electric utility industry. These appliance trends are used in the residential and commercial sales models.

Peak demands were projected using the SAE approach. The peak forecast was developed using a monthly SAE model, similar to the sales SAE models, which includes monthly appliance saturations and efficiencies, interacted with weather and the fraction of each appliance type that is in use at the time of monthly peak.

Forecast Enhancements

In 2013, as referenced above, the Company began using the SAE model projections to forecast sales and peaks. The end use models provide a better platform to recognize trends in equipment /appliance saturation and changes to efficiencies, and how those trends interact with heating, cooling, and "other" or non-weather-related sales. These appliance trends are used in the residential and commercial sales models. In conjunction with peer utilities and ITRON, the company continually looks for refinements to its modeling procedures to make better use of the forecasting tools, and develop more reliable forecasts.

Each time the forecast is updated, the most currently available historical and projected data is used. The current 2019 forecast utilizes:

- Moody's Analytics January 2019 base and consensus economic projections.

- End use equipment and appliance indexes reflect the 2018 update of ITRON's end-use data, which is consistent with the Energy Information Administration's 2018 Annual Energy Outlook
- A calculation of normal weather using the period 1988-2017

The Company also researches weather sensitivity of summer and winter peaks, hourly shaping of sales, and load research data in a continuous effort to improve forecast accuracy.

Assumptions

Below are the projected average annual growth rates of several key drivers from DEC's Spring 2019 Forecast.

	2020-2034
Real Income	2.7%
Manufacturing Industrial Production Index (IPI)	1.1%
Population	1.6%

In addition to economic, demographic, and efficiency trends, the forecast also incorporates the expected impacts of UEE, as well as projected effects of electric vehicles and behind the meter solar technology.

Utility Energy Efficiency

UEE Programs continue to have a large impact in the acceleration of the adoption of energy efficiency. When including the energy and peak impacts of UEE, careful attention must be paid to avoid the double counting of UEE efficiencies with the naturally occurring efficiencies included in the SAE modeling approach. To ensure there is not a double counting of these efficiencies, the forecast "rolls off" the UEE savings at the conclusion of its measure life. For example, if the accelerated benefit of a residential UEE program is expected to have occurred 7 years before the energy reduction program would have been otherwise adopted, then the UEE effects after year 7 are subtracted ("rolled off") from the total cumulative UEE. With the SAE model's framework, the naturally occurring appliance efficiency trends replace the rolled off UEE benefits serving to continue to reduce the forecasted load resulting from energy efficiency adoption.

The table below illustrates this process on sales:

Table 5-A UEE Program Life Process (GWh)

	A	B	C	D	E	F	G
Year	Forecast Before UEE	Historical UEE Roll Off	Forecast With Historical Roll Off	Forecasted UEE Incremental Roll on	Forecasted UEE Incremental Roll Off	UEE to Subtract From Forecast	Forecast After UEE
2020	93,393	9	93,401	(971)	312	(660)	92,742
2021	94,154	26	94,180	(1,360)	321	(1,038)	93,141
2022	94,802	70	94,872	(1,746)	331	(1,415)	93,458
2023	95,703	161	95,864	(2,139)	342	(1,797)	94,067
2024	96,753	288	97,041	(2,530)	353	(2,177)	94,865
2025	97,660	461	98,121	(2,913)	366	(2,547)	95,574
2026	98,594	668	99,262	(3,293)	383	(2,910)	96,352
2027	99,647	872	100,519	(3,669)	412	(3,257)	97,262
2028	100,941	1,054	101,995	(4,043)	459	(3,584)	98,411
2029	102,066	1,206	103,271	(4,413)	553	(3,861)	99,410
2030	103,250	1,304	104,554	(4,791)	673	(4,118)	100,436
2031	104,595	1,360	105,955	(5,178)	839	(4,339)	101,616
2032	105,923	1,391	107,314	(5,573)	1,068	(4,505)	102,810
2033	107,307	1,399	108,706	(5,972)	1,317	(4,655)	104,051
2034	108,797	1,399	110,196	(6,377)	1,652	(4,725)	105,472

Customer Growth

Tables 5-B and 5-C show the history and projections for DEC customers

Table 5-B Retail Customers (annual average in thousands)

Year	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Retail Customers
2009	2,024	331	7	14	2,377
2010	2,034	333	7	14	2,389
2011	2,041	335	7	14	2,397
2012	2,053	337	7	14	2,411
2013	2,068	339	7	14	2,428
2014	2,089	342	7	15	2,452
2015	2,117	345	6	15	2,484
2016	2,148	349	6	15	2,519
2017	2,182	354	6	15	2,557
2018	2,215	358	6	17	2,596
Avg. Annual Growth Rate	1.0%	0.9%	-2.2%	2.2%	1.0%

Table 5-C Retail Customers (Thousands, Annual Average)

	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Retail Customers
2020	2,272	364	6	21	2,663
2021	2,298	365	6	21	2,690
2022	2,326	366	6	21	2,719
2023	2,355	366	6	22	2,748
2024	2,384	367	6	22	2,779
2025	2,414	369	6	22	2,811
2026	2,443	371	6	22	2,842
2027	2,471	373	6	22	2,872
2028	2,499	375	6	23	2,902
2029	2,526	377	6	23	2,932
2030	2,553	379	5	23	2,960
2031	2,578	381	5	24	2,988
2032	2,604	382	5	24	3,015
2033	2,628	384	5	24	3,042
2034	2,653	386	5	24	3,068
Avg. Annual Growth Rate	1.0%	0.4%	-1.0%	1.0%	0.9%

Electricity Sales

Table 5-D shows the actual historical gigawatt hour (GWh) sales. As a note, the values in Table 5-D are not weather adjusted Sales.

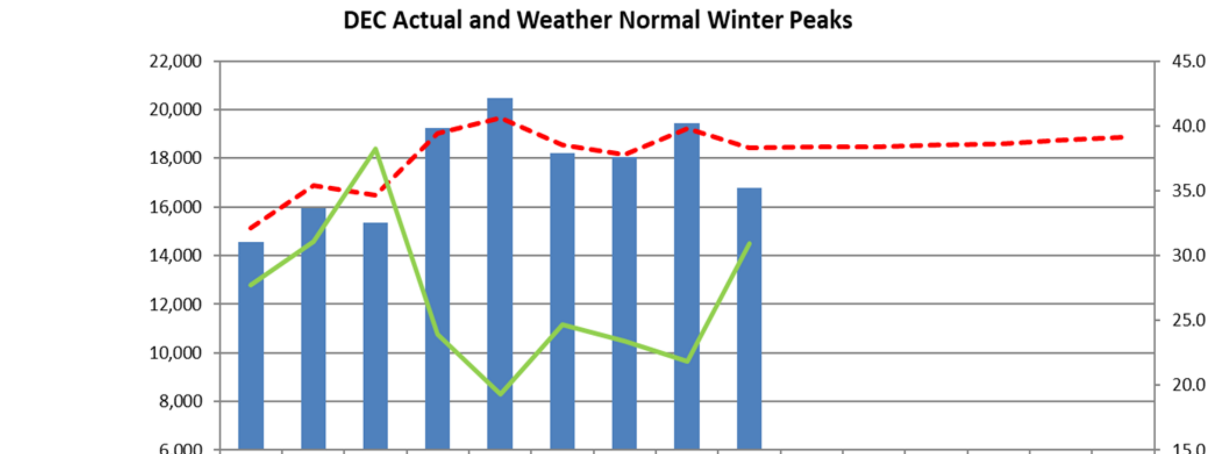
Table 5-D Electricity Sales (GWh)

Year	Residential GWh	Commercial GWh	Industrial GWh	Military & Other GWh	Retail GWh	Wholesale GWh	Total System GWh
2009	27,273	26,977	19,204	287	73,741	3,788	77,529
2010	30,049	27,968	20,618	287	78,922	5,166	84,088
2011	28,323	27,593	20,783	287	76,986	4,866	81,852
2012	26,279	27,476	20,978	290	75,023	5,176	80,199
2013	26,895	27,765	21,070	293	76,023	5,824	81,847
2014	27,976	28,421	21,577	303	78,277	6,559	84,836
2015	27,916	28,700	22,136	305	79,057	6,916	85,973
2016	27,939	28,906	21,942	304	79,091	7,614	86,705
2017	26,593	28,388	21,776	301	77,059	7,558	84,617
2018	28,417	29,083	21,525	305	79,330	8,889	88,219
Avg. Annual Growth Rate	0.5%	0.8%	1.3%	0.7%	0.8%	9.9%	1.4%

System Peaks

Charts 5-E and 5-F show the historical actual and weather normalized peaks for the system:

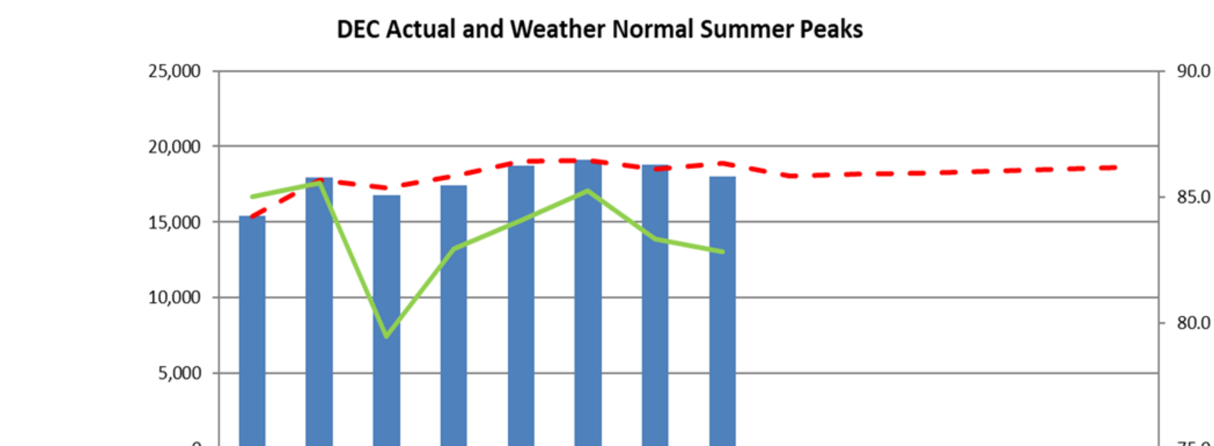
Chart 5-E Winter Peaks



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Actual	14,561	15,962	15,363	19,232	20,455	18,213	18,069	19,436	16,782						
WN Peak/Forecast	15,141	16,875	16,500	19,040	19,674	18,544	18,162	19,204	18,426	18,460	18,449	18,530	18,580	18,737	18,852
Temp	27.7	31.1	38.3	23.9	19.4	24.7	23.4	21.9	30.9						

Note: WN Peak/Forecast values in years 2020-2024 are forecasted peak values from the 2019 Spring Forecast. The Temperatures are the average daily temperature on the day of the peak.

Chart 5-F Summer Peaks



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Actual	15,420	17,933	16,757	17,397	18,742	19,119	18,811	18,008						
WN Peak/Forecast	15,410	17,803	17,269	18,063	19,051	19,086	18,495	18,899	18,028	18,153	18,266	18,338	18,474	18,625
Temp	85.0	85.5	79.5	82.9	84.1	85.3	83.3	82.8						

Note: WN Peak/Forecast values in years 2019-2024 are forecasted peak values from the 2019 Spring Forecast. The Temperatures are the average daily temperature on the day of the peak.

Forecast Results

A tabulation of the utility's sales and peak forecasts are shown as charts below:

- Table 5-G: Forecasted energy sales by class (Including the impacts of UEE, rooftop solar, and electric vehicles)
- Table 5-H: Summary of the load forecast without UEE programs and excluding any impacts from demand reduction programs
- Table 5-I: Summary of the load forecast with UEE programs and excluding any impacts from demand reduction programs

These projections include Wholesale, and all the loads and energy in the tables and charts below are at generation, except for the class sales forecast, which is at meter.

Load duration curves, with and without UEE programs are shown as Charts 5-A and 5-B.

The values in these tables reflect the loads that Duke Energy Carolinas is contractually obligated to provide and cover the period from 2020 to 2034.

Table 5-G Forecasted Energy Sales by Class

Year	Residential Gwh	Commercial Gwh	Industrial Gwh	Other Gwh	Retail Gwh
2020	28,888	29,687	21,723	319	80,618
2021	29,041	29,890	21,699	318	80,949
2022	29,337	30,200	21,592	317	81,446
2023	29,652	30,538	21,465	315	81,970
2024	29,956	30,827	21,561	313	82,657
2025	30,184	31,190	21,582	310	83,266
2026	30,478	31,568	21,585	308	83,939
2027	30,797	31,916	21,721	305	84,738
2028	31,171	32,372	21,917	303	85,762
2029	31,513	32,753	22,086	300	86,652
2030	31,902	33,127	22,237	297	87,563
2031	32,371	33,575	22,382	295	88,622
2032	32,897	33,951	22,553	292	89,693
2033	33,368	34,402	22,756	289	90,816
2034	33,940	34,849	23,030	286	92,105
Avg. Annual Growth Rate	1.1%	1.1%	0.4%	-0.7%	0.9%

Table 5-H Summary of the Load Forecast without UEE Programs and Excluding any Impacts from Demand Reduction Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2020	18,259	18,521	93,401
2021	18,431	18,564	94,180
2022	18,562	18,697	94,872
2023	18,759	18,800	95,864
2024	18,966	19,034	97,041
2025	19,184	19,194	98,121
2026	19,425	19,429	99,262
2027	19,718	19,636	100,519
2028	20,040	19,919	101,995
2029	20,331	20,179	103,271
2030	20,631	20,432	104,554
2031	20,954	20,698	105,955
2032	21,251	21,029	107,314
2033	21,578	21,297	108,706
2034	21,934	21,571	110,196
Avg. Annual Growth Rate	1.2%	1.0%	1.1%

Chart 5-A

Load Duration Curve without Energy Efficiency Programs and Before Demand Reduction Programs

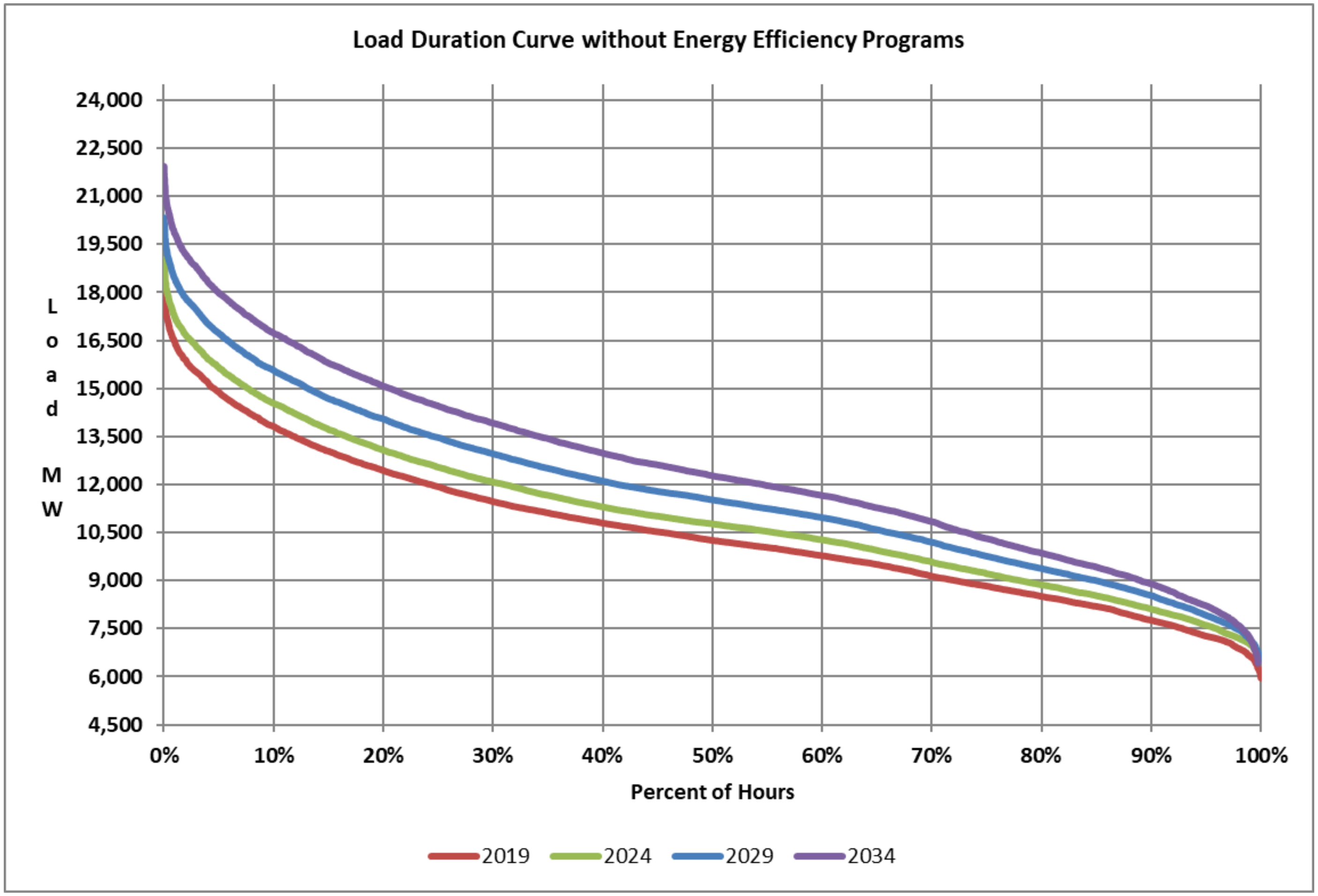
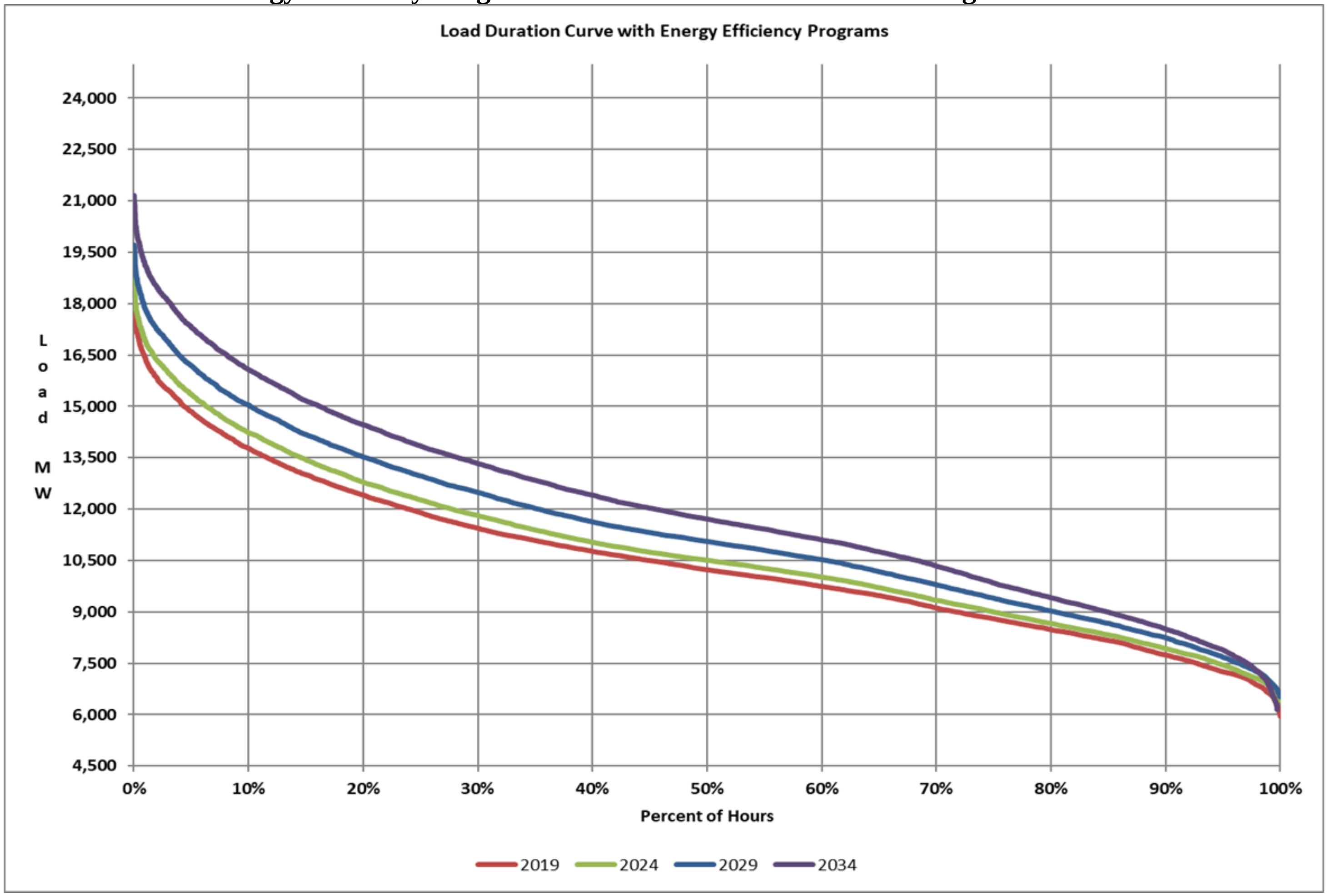


Table 5-I Summary of the Load Forecast with UEE Programs and Excluding any Impacts from Demand Reduction Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2020	18,153	18,460	92,742
2021	18,266	18,449	93,141
2022	18,338	18,530	93,458
2023	18,474	18,580	94,067
2024	18,625	18,737	94,865
2025	18,782	18,852	95,574
2026	18,965	19,031	96,352
2027	19,202	19,192	97,262
2028	19,471	19,442	98,411
2029	19,713	19,665	99,410
2030	19,969	19,884	100,436
2031	20,252	20,120	101,616
2032	20,521	20,432	102,810
2033	20,819	20,680	104,051
2034	21,160	20,944	105,472
Avg. Annual Growth Rate	1.0%	0.8%	0.9%

Tables 8-A and 8-B differ from these values due to a 47 MW Piedmont Municipal Power Agency (PMPA) backstand contract through 2020 and an 82 MW backstand contract with North Carolina Electric Municipal Co-op (NCEMC) throughout the study period.

Chart 5-B
Load Duration Curve with Energy Efficiency Programs & Before Demand Reduction Programs



6. RENEWABLE ENERGY AND ENERGY STORAGE

The growth of renewable generation in the United States continued in 2018. According to EIA, in 2018, 6.6 GW of wind and 4.9 GW of utility-scale solar capacity were installed nationwide. Green Tech Media, a subsidiary of Wood Mackenzie, estimates 4.5 GW of small scale solar was added as well. Meanwhile, 12.9 GW of coal was retired in 2018 with no new coal-fired generation installed.[4]

North Carolina ranked third in the country in solar capacity added in 2018, and remains second behind only California in total solar capacity online. According to Green Tech Media, South Carolina ranked twelfth in 2018. Duke Energy's compliance with the North Carolina Renewable Energy and Energy Efficiency Portfolio Standards (NC REPS), the South Carolina Distributed Energy Resource Program (SC DER or SC Act 236), the Public Utility Regulatory Policies Act (PURPA) as well as the availability of the Federal Investment Tax Credit (ITC) were key factors behind the high penetration of solar.

The interconnection queue has remained steady compared to 2018, with the DEP and DEC combined solar queue representing approximately 12 GW. Key drivers to queue growth have been North Carolina House Bill 589 (NC HB 589), the implementation of the SC DER Program and anticipated further growth in South Carolina via SC Act 62 (described below), and favorable avoided cost rates and 15-year contract terms for QFs under PURPA that previously existed in North Carolina pre- NC HB 589.

The implementation of NC HB 589, and the passage of SC Act 62 in SC are significant to the amount of solar projected to be operational during the planning horizon. Growing customer demand, the federal ITC, and declining installed solar costs make solar capacity the Company's primary renewable energy resource in the 2019 IRP. The following key assumptions regarding renewable energy were included in the 2019 IRP:

- Installed solar capacity increases in DEC from 1,137 MW in 2020 to 3,752 MW in 2034 with approximately 200 MW of usable AC storage coupled with solar included;
- Compliance with NC REPS continues to be met through a combination of solar, other renewables, EE, and Renewable Energy Certificate (REC) purchases;
- Achievement of the SC Act 236 goal of 120 MW of solar capacity located in DEC; and

[4] All renewable energy GW/MW represent GW/MW-AC (alternating current) unless otherwise noted.

- Implementation of NC HB 589 and continuing solar cost declines drive solar capacity growth above and beyond NC REPS requirements and SC Act 236 requirements, and in support of SC Act 62.

NC HB 589 Competitive Procurement of Renewable Energy (CPRE):

NC HB 589 established a competitive solicitation process, known as the Competitive Procurement of Renewable Energy (CPRE), which calls for the addition of 2,660 MW of competitively procured renewable resources across the Duke Energy Balancing Authority Areas over a 45-month period. On July 10, 2018, Duke issued a request for bids for the first tranche of CPRE, requesting 600 MW in DEC and 80 MW in DEP. On April 9, 2019 the independent administrator selected 12 projects totaling 515 MW in DEC and two projects totaling 83 MW in DEP. Eleven of the DEC projects signed PPA's (totaling 465 MW), and all DEC projects selected will be interconnected to the transmission system. Nine of the projects will be located in North Carolina (415 MW) and two will be in South Carolina (50 MW). Two of the solar only projects selected will be owned by Duke Energy Carolinas and three by Duke Energy Renewables. Two of the third-party projects selected include battery storage. See the annual CPRE Program Plan included as Attachment II for additional details.

The Companies expect to request the same amount of system capacity in the second tranche of CPRE as the first (600 MW in DEC and 80 MW in DEP). Given continued increases in capacity referred to in this document as the "Transition MW", the Companies will continue to monitor potential impacts on future tranche volumes. These "Transition MW" represent the total capacity of renewable generation projects in the combined Duke Balancing Authority area that are (1) already connected; or (2) have entered into purchase power agreements (PPAs) and interconnection agreements (IAs) as of the end of the 45-month competitive procurement period, and which are not subject to curtailment or economic dispatch. The total CPRE target of 2,660 MW will vary based on the amount of Transition MW at the end of the 45-month period, which NC HB 589 expected to total 3,500 MW. If the aggregate capacity in the Transition MW exceeds 3,500 MW, the competitive procurement volume of 2,660 MW will be reduced by the excess amount. As of August 2019, there are approximately 3,700 MW that currently meet NC HB 589's definition of "Transition MW", meaning CPRE will be reduced by a minimum of 200 MW. The company believes the Transition may exceed 3,500 MW by as much as 1,400 MW, and possibly more depending on the extent to which SC Act 62 drives new solar growth in SC by the end of the 45-month CPRE period.

NC and SC Interconnection Queues:

Through the end of 2018, DEC had more than 700 MW of utility scale solar on its system, with approximately 100 MW interconnecting in 2018. When renewable resources were evaluated for the 2019 IRP, DEC reported over 400 MW of third-party solar under construction and more than 5,000 MW in the interconnection queue. The renewable interconnection queue information below provides details on the number of pending projects and pending capacity by state.

Table 6-A: Renewable Interconnection Queue as of 7-31-19

Annual IRP Interconnection Queue

Report as of: 07-31-2019

Report Month End: 07-31-2019

OPCO: DEC

Facility State: NC,SC

Utility	Facility State	Energy Source Type	Number of Pending Projects	Pending Capacity (MW AC)
DEC	NC	Battery	1	2.8
		Biomass	1	4.0
		Hydroelectric	1	4.0
		Solar	118	2,388.1
	NC Total		**131**	**2,398.8**
	SC	Battery	1	5.0
		Hydroelectric	1	320.0
		Other	2	61.0
		Solar	163	3,068.3
	SC Total		**176**	**3,746.3**
DEC Total			**307**	**6,145.1**

Projecting future solar connections from the interconnection queue presents a significant challenge due to the large number of project cancellations, ownership transfers, interconnection studies required, and the unknown outcome of which projects will be selected through the CPRE program.

DEC's contribution to the Transition depends on many variables including connecting projects under construction, the expected number of renewable projects in the queue with a PPA and IA, SC Act 62, and SC DER Program Tier I. As of May 31, 2019, DEC had nearly 750 MW of solar capacity with a PPA and IA, and roughly 100 MW of non-solar renewable capacity with PPA's that extend through the 45-month CPRE period. A number of additional projects in the queue are expected to acquire both a PPA and IA prior to the expiration of the 45-month period defined in NC HB 589, potentially resulting in approximately an additional 500 MW contributing to the Transition. In total, DEC may contribute roughly one-quarter of the Transition MW with DEP accounting for the remaining three-quarters.

NC REPS Compliance:

DEC remains committed to meeting the requirements of NC REPS, including the poultry waste, swine waste, and solar set-asides, and the general requirement, which will be met with additional renewable and energy efficiency resources. DEC's long-term general compliance needs are expected to be met through a combination of renewable resources, including RECs obtained through the NC HB 589 competitive procurement process. For details of DEC's NC REPS compliance plan, please reference the NC REPS Compliance Plan, included as Attachment I to this IRP.

NC HB-589 Competitive Procurement and Utility-Owned Solar:

DEC continues to evaluate utility-owned solar additions to grow its renewables portfolio. For example, DEC owns and operates three utility-scale solar projects, totaling 81 MW-AC, as part of its efforts to encourage emission free generation resources and help meet its compliance targets:

- Monroe Solar Facility – 60 MW, located in Union County, North Carolina placed in service on March 29, 2017; and
- Mocksville Solar Facility – 15 MW, located in Davie County, North Carolina placed in service on December 16, 2016.
- Woodleaf Solar Facility – 6 MW, located in Rowan County, North Carolina placed in service on December 21, 2018

No more than 30% of the CPRE Program requirement may be satisfied through projects in which Duke Energy or its affiliates have an ownership interest at the time of bidding. DEC and Duke Energy Renewables were each awarded approximately 20% of the capacity selected in the first tranche of CPRE. DEC intends to bid into the second tranche of the CPRE and will also evaluate the potential for acquiring facilities where appropriate. NC HB 589 does not stipulate a limit for DEC's option to acquire projects from third parties that are specifically proposed in the CPRE Request for Proposals

(RFP) as acquisition projects, though any such project will not be procured unless determined to be among the most cost-effective projects submitted.

Additional Factors Impacting Future Solar Growth:

A number of factors impact the Company's forecasting of future solar growth in the Carolinas. First, potential changes in the Company's avoided cost in either NC or SC may impact the development of projects under PURPA, NC HB 589, and SC Act 62. Avoided cost forecasts are subject to variability due to changes in factors such as natural gas and coal commodity prices, system energy and demand requirements, the level and cost of generation ancillary service requirements and interconnection costs. PURPA requires utilities to purchase power from QFs at or below the utility's avoided cost rates. NC HB 589 requires that competitive bids are priced below utility's avoided cost rates, as approved by the NCUC, in order to be selected. Therefore, the cost of solar is a critical input for forecasting how much solar will materialize in the future.

Solar costs are also influenced by other variables. Panel prices have historically decreased at a significant rate and are expected to continue to decline. However, in January 2018, President Trump announced a tariff on solar modules and cells with a rate of 30% in year 1, declining 5% per year until the fourth and final year in which the tariff rate is 15%. Additional factors that could put upward pressure on solar costs include direct interconnection costs, as well as costs incurred to maintain the appropriate operational control of the facilities. Finally, as panel prices have decreased, there has been more interest in installing single-axis tracking (SAT) systems (as demonstrated in CPRE tranche 1) and/or systems with higher inverter load ratios (ILR) which change the hourly profile of solar output and increase expected capacity factors. DEC now models fixed tilt and SAT system hourly profiles with a range of ILRs as high as 1.6 (DC/AC ratio).

In summary, there is a great deal of uncertainty in both the future avoided costs applied to solar and the expected price of solar installations in the years to come. As a result, the Company will continue to closely monitor and report on these changing factors in future IRP and competitive procurement filings.

NC HB 589 Customer Programs:

In addition to the CPRE program, NC HB 589 offers direct renewable energy procurement for major military installations, public universities, and other large customers, as well as a community solar program. These programs will complement the existing SC Act 236 Programs and upcoming SC Act 62 programs.

As part of NC HB 589, the renewable energy procurement program for large customers such as military installations and universities enables large customers to procure renewable energy attributes from new renewable energy resources. The program allows for up to 600 MW of total capacity, with set asides for military installations (100 MW of the 600 MW) and the University of North Carolina (UNC) system (250 MW of the 600 MW). The 2019 IRP base case assumes all 600 MW of this program materialize, with the DEC/DEP split expected to be roughly 55/45. If all 600 MW are not utilized, the remainder will roll back to the competitive procurement, increasing its volume.

The community solar portion of NC HB 589 calls for up to 20 MW of shared solar in DEC. This program is similar to the SC Act 236 shared solar program, and allows customers who cannot or do not want to put solar on their property to take advantage of the economic and environmental benefits of solar by subscribing to the output of a centralized facility. The 2019 IRP Base Cases assume that all 20 MW of the NC HB 589 shared solar program materializes.

NC HB 589 also calls for a rebate program for rooftop solar. The rebate program opened in July 2018 and the program has spurred greater interest in solar installations and therefore, more net metered customers in NC. Residential and non-residential capacity limits were quickly fully subscribed in 2018 and 2019. In 2018, DEC NC installed approximately 13 MW of rooftop solar, more than triple the capacity installed in 2017. Through June of 2019, installed rooftop solar capacity is approximately 11 MW or only two MW short of 2018 totals.

SC Act 236 and SC Act 62:

Steady progress continues to be made with the first two tiers of the SC DER Program summarized below, completion of which would unlock the third tier:

- Tier I: 40 MW of solar capacity from facilities each >1 MW and ≤ 10 MW in size.
- Tier II: 40 MW of behind-the-meter solar facilities for residential, commercial and industrial customers, each ≤1 MW, 25% of which must be ≤ 20 kilowatts (kW). Since Tier II is behind the meter, the expected solar generation is embedded in the load forecast as a reduction to expected load.

- Tier III: Investment by the utility in 40 MW of solar capacity from facilities each >1 MW and ≤10 MW in size. Upon completion of Tiers I and II (to occur no later than 2021), the Company may directly invest in additional solar generation to complete Tier III.

DEC has executed twelve PPAs totaling approximately 31 MW and is working to complete Tier I. Tier II incentives have resulted in growth in rooftop solar in DEC, which now has over 70 MW of rooftop solar installed. The 2% net metering application cap of 80 MW established in Act 236 was reached in DEC SC but has since been eliminated by SC Act 62.

The Company launched its first Shared Solar program in DEC as part of Tier I in the first quarter of 2019. Duke Energy designed its initial SC shared solar program to have strong appeal to residential and commercial customers who rent or lease their premises, residential customers who reside in multifamily housing units or shaded housing or for whom the relatively high up-front costs of solar PV make net metering unattainable, and non-profits who cannot monetize the ITC. The program capacity is 3 MW including 400 kW set aside for customers earnings less than 200% of the federal poverty line. As of the end of June 2019, 10 kW was subscribed. The unreserved 2,600 kW of capacity sold out within 60 days due to the program's strong economic proposition.

SC Act 62 passed in South Carolina on May 16, 2019. SC Act 62 will likely drive additional PURPA solar as DEC must offer fixed price PPAs to certain small power producers at avoided cost for a contract term of 10 years. The 10-year rate is applicable for projects located in SC until DEC has executed IAs and PPAs with aggregated nameplate capacity equal to 20 percent of the previous 5-year average of DEC's SC retail peak load, or roughly 800 MW. After 800 MW have executed IAs and PPAs the Commission will determine conditions, rates, and terms of length for future contracts. Given there is roughly 3,000 MW of solar pending in DEC SC, the Company expects to easily meet 800 MW within the IRP planning period. The Company intends to closely monitor the capacity with executed IAs and PPAs, evaluate impacts on the NC HB 589 Transition MW and corresponding reduction in CPRE volume.

SC Act 62 also called for additional customer programs, requiring the utilities to file voluntary renewable energy programs within 120 days of SC Act 62 passing, and encouraging for additional community solar. The Company has a proposed voluntary renewable energy program pending before the Commission, which would create a 150 MW program for DEC and DEP SC combined (113 MW in DEC) offering up to 15-year PPAs. The Companies are considering whether additional community solar should be pursued.

Finally, SC Act 62 lifted the cap on net metering, requiring the Company to offer net metering through June 1, 2021. No later than January 1, 2020, the Commission will open a docket to establish a solar choice metering tariff to go into effect for customer applications received after May 31, 2021. The Company expects net metering adoption to pick up to at least the levels of adoption observed in DEC-SC in 2017/2018 through June 2021.

Wind:

DEC considers wind a potential energy resource in the long term to support increased renewable portfolio diversity, long-term general compliance needs, as well as potential resource for further carbon reduction. In August 2017, DEC issued an RFP for delivered energy, capacity, and associated RECs from wind projects up to 500 MW. While bids received were not economically valuable enough to pursue, the Company will continue to evaluate potential projects, especially those opportunities that may exist to transmit wind energy into the Carolinas from out-of-state regions where wind is more cost-effective.

Summary of Expected Renewable Resource Capacity Additions:

The 2019 IRP incorporates the Base Case renewable capacity forecast below. This case includes renewable capacity components of the Transition MW of NC HB 589, such as capacity required for compliance with NC REPS, PURPA purchases, the SC DER Program, legacy NC Green Source Rider program, and the additional three components of NC HB 589 (competitive procurement, renewable energy procurement for large customers, and community solar). The Base Case also includes additional projected solar growth beyond NC HB 589, and in support of expected growth from SC Act 62 and the Company's efforts to reduce carbon emissions. While certain regions of DEC may become saturated with solar, it is the Company's belief that continued declines in the installation cost of solar and storage will enable solar and coupled "solar plus storage" systems to contribute to growing energy needs. The Company also believes supportive policies for solar and solar plus storage will continue to exist in NC and SC, even beyond the NC HB 589 procurement horizon.

Given two projects in the first tranche of CPRE included storage, the Company is projecting a similar ratio of solar capacity coupled with storage in future tranches of CPRE. Additionally, the most recent avoided cost rate structures proposed in both NC and SC provide strong price incentives for QFs to shift energy from lower priced energy-only hours to hours that have higher energy and capacity prices. This new rate design provides appropriate incentives to encourage storage plus solar projects. The Company this year is also projecting that a significant amount of incremental solar beyond NC HB

589 will be coupled with storage. Additional scenarios will be included in the 2020 IRP, but for now the 2019 base case assumes storage is DC coupled with solar, has a four-hour duration, and the maximum capacity of the battery storage is 25% of the max capacity of the solar. In total, DEC expects nearly 200 MW of storage coupled with solar by the end of 2034.

The Company anticipates a diverse portfolio including solar, biomass, hydro, storage, and other resources. Actual results could vary substantially for the reasons discussed previously, as well as, other potential changes to legislative requirements, tax policies, technology costs, carbon prices, ancillary costs, interconnection costs, and other market forces. The details of the forecasted capacity additions, including both nameplate and contribution to winter and summer peaks are summarized in Table 6-B below.

While solar is not at its maximum output at the time of DEC's expected peak load in the summer, solar's contribution to summer peak load is large enough that it may push the time of summer peak to a later hour if solar penetration levels continue to increase. However, solar is unlikely to have a similar impact on the morning winter peak due to little solar output in the morning hours. Solar capacity contribution percentages to summer and winter peak demands are assumed to be the same as those used in the 2018 IRP. Note, however the solar contribution to peak values now also include additional contributions provided by storage coupled with solar, assumed to be 80% of the storage capacity installed.

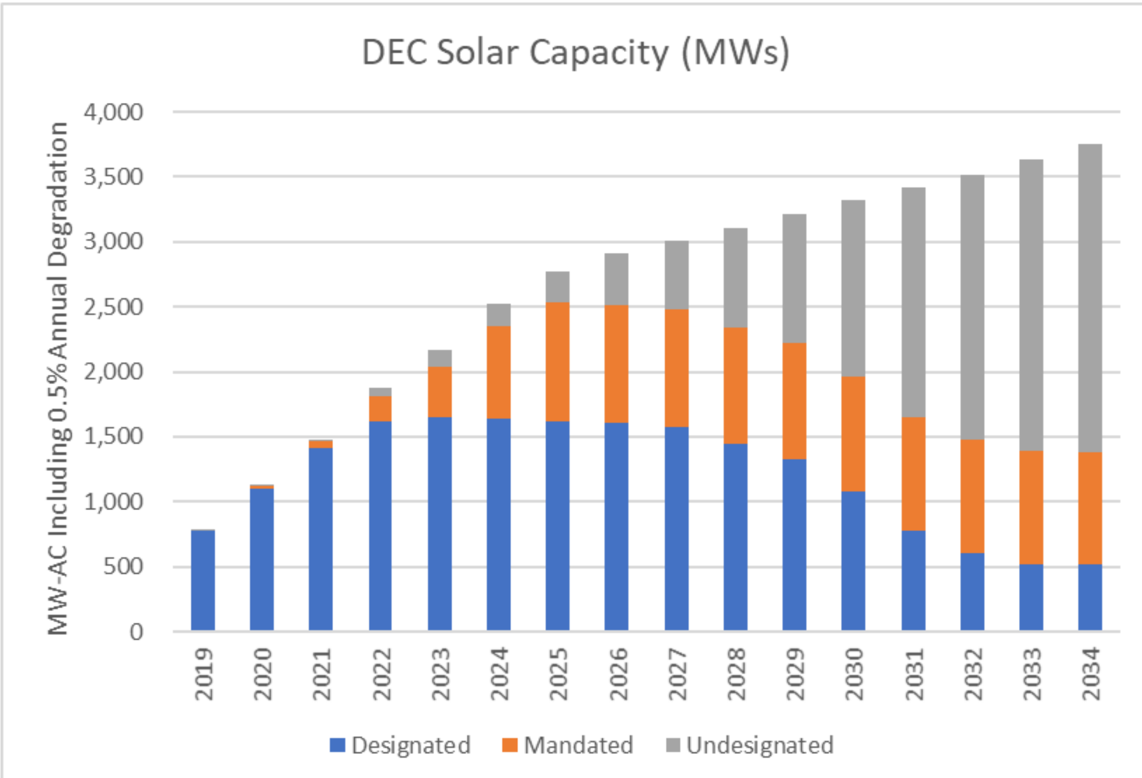
Table 6-B: DEC Base Case Total Renewables

DEC Base Renewables - Compliance + Non-Compliance										
	MW Nameplate				MW Contribution to Summer Peak				MW Contribution to Winter Peak		
	Solar	Biomass/ Hydro	Total		Solar	Biomass/ Hydro	Total		Solar	Biomass/ Hydro	Total
2020	1,137	97	1,234		384	97	481		11	97	108
2021	1,482	83	1,565		481	83	564		25	83	108
2022	1,873	61	1,934		592	61	653		43	61	104
2023	2,166	61	2,227		670	61	730		50	61	111
2024	2,528	57	2,586		769	57	826		62	57	119
2025	2,766	48	2,814		832	48	880		68	48	116
2026	2,915	46	2,960		886	46	931		86	46	132
2027	3,011	42	3,053		921	42	963		98	42	140
2028	3,105	42	3,147		955	42	997		110	42	152
2029	3,217	32	3,249		993	32	1,026		124	32	156
2030	3,316	19	3,335		1,014	19	1,032		136	19	155
2031	3,423	2	3,424		1,036	2	1,037		149	2	150
2032	3,515	0	3,515		1,055	0	1,055		160	0	160
2033	3,637	0	3,637		1,080	0	1,080		175	0	175
2034	3,752	0	3,752		1,103	0	1,103		189	0	189
Solar includes 0.5% per year degradation											
Capacity listed excludes REC Only Contracts											
Contribution to peak based on 2018 Astrape analysis plus 80% estimated capacity value for storage that is coupled with solar											

As a number of solar contracts are expected to expire over the IRP planning period, the Company is additionally breaking down its solar forecast into three buckets described below:

- **Designated**: Contracts that are already connected today or those who have yet to connect but have an executed PPA are assumed to be designated for the duration of the purchase power contract.
- **Mandated**: Capacity that is not yet under contract but is required through legislation (examples include future tranches of CPRE, the renewables energy procurement program for large customers, and community solar under NC HB 589 as well as SC Act 236)
- **Undesignated**: Additional capacity projected beyond what is already designated or mandated. Expiring solar contracts are assumed to be replaced in kind with undesignated solar additions. Such additions could include existing providers or new facilities that enter into contracts that have yet been executed.

The chart below shows DEC's breakdown of these three buckets through the planning period. Note for avoided cost purposes, the Company only includes the Designated and Mandated buckets in the base case. For pricing the second tranche of CPRE, the Company includes the Designated bucket only.



Energy Storage

The Company is assessing the integration of battery storage technology into its portfolio of assets. Battery storage costs are expected to continue to decline, which may make this resource a viable option for grid support services, including frequency regulation, solar smoothing during periods with high incidences of intermittency, as well as, the potential to provide overall energy and capacity value. Energy storage, in some circumstances, also can have the potential to provide value to the transmission and distribution (T&D) system by deferring or eliminating traditional upgrades and can be used to improve reliability and power quality to certain locations on the Company's distribution system. This approach results in stacked benefits which couples value streams from the Transmission, Distribution, and Generation systems. This unique evaluation process falls outside of the Company's traditional IRP process which focuses primarily on meeting future generation needs reliably and at the lowest possible cost. This new approach to evaluating technologies that have generation, transmission and distribution value is being addressed through the ISOP enhancements, discussed further in the following section.

The Company has begun investing in multiple grid-connected storage systems dispersed throughout its North and South Carolina service territories that will be located on property owned by the Company or leased from its customers. These deployments will allow for a more complete evaluation of potential benefits to the distribution, transmission and generation system while also providing actual operations and maintenance cost impacts of batteries deployed at a significant scale. This will allow the Company to explore the nature of new offerings desired by customers and fill knowledge gaps such as how the Company can best integrate battery storage into its daily operations. The Company will work with Generation, Transmission and Distribution organizations in this evaluation process, utilizing the ISOP framework. The goal is to optimize the location to couple localized T&D system benefits with bulk system benefits, and to minimize cost and maximize benefits for its customers. The Company believes such investments are consistent with the direction of state policy in both NC and SC under the NC HB 589 and SC DER Program, respectively, as well as the most recently filed avoided cost rates in both states. Additionally, the Company plans to further study the capacity value of storage in the Carolinas with any learnings to be included in the 2020 IRP.

7. INTEGRATED SYSTEM & OPERATIONS PLANNING (ISOP)

The concept of ISOP was introduced in the 2018 IRP filed in NC and SC. Duke continues to view this effort as a natural evolution in the planning process to address continued trends in technology development, declining cost projections for grid-tied technologies, and customer preferences for distributed energy resources such as roof-top solar and end-use electrification such as electric vehicles (EVs). The anticipated growth of energy resources on (or closer to) the grid edge, particularly energy storage, will require utilities to move beyond the traditional utility distribution and transmission planning practice of analysis that considers only a few snapshots of system conditions at discrete points in time. Moving forward, analysis of the distribution and transmission systems will need to account for increasing volatility of net demand (load less variable distributed resources), which will require significant changes to modeling inputs and tools.

Recognizing that development of new tools and analytical methods involve significant uncertainty of timing and outcomes, Duke's goal at this point is to implement the basic elements of ISOP in the 2022 IRPs for the Carolinas. This timeline is based on the Company's perspective that ISOP will provide additional analytic tools and planning processes to support future IRPs as the potential for distributed energy resources grows and as the electrification of the transportation sector and other end-uses begin to have more significant impacts on energy planning, as a whole. To be clear, the ISOP effort is not prejudging the analytical outcome of the effort, but rather is intended to enhance the planning methodology and tool sets to enable a fair and thorough evaluation of resources in an evolving energy marketplace. It should be noted that changes introduced by a stakeholder engagement process or potential rulemaking by NCUC or PSCSC could impact the ISOP timeline.

One of the first steps in this process is development of an hourly forecast of projected load and DER output for each distribution circuit that covers a sufficient time horizon. This granular forecast is required to determine potential operational issues and costs at the circuit level as well as to capture potential benefits of deferred capacity additions for DERs. Given the size of the Company's system, this effort involves a significant time and resource commitment to gather the necessary input data and build the forecasting models required to support this extensive level of granular forecasting. For example, Duke is developing models to enable derivation of hourly forecasts for 4500+ distribution circuits in the Carolinas covering a ten-year horizon.

Additionally, new modeling capabilities are necessary to perform hourly power flow analysis of the effects of DERs. Duke has been working with the Electric Power Research Institute (EPRI), as well as a 3rd party industry leader in distribution modeling, to develop an Advanced Distribution Planning

(ADP) tool capable of evaluating both traditional and non-traditional solutions on the distribution system, which requires analyzing distribution circuits for potential violations on an hourly basis. The development and testing effort for the basic ADP functionality is targeted to be rolled out progressively to DEC and DEP Distribution Planners during 2021. Subsequent development efforts will focus on adding more robust capability such as multi-circuit analysis of more complex switching, combinations of traditional and non-traditional solutions, etc.

Basic functionality of the ADP toolset will include the ability to evaluate DERs (including energy storage) as a potential solution, and determine the hourly pattern where the DER would be utilized to address local issues. In the case of energy storage, the unutilized hours of the resource can then be evaluated for additional value at the transmission and bulk generation levels, where feasible. This points out the need for coordination and data integration between the respective models across distribution, transmission, and generation planning disciplines to assess value across multiple use cases for DERs, which will add significant complexity. One practical implication is that the envisioned coordinated modeling processes will likely require more time than the current stand-alone generation planning processes, which could impact the development timeline for future IRPs.

Duke is also testing an established 3rd party DC transmission power flow model to develop an effective hourly power flow analysis process to complement the AC power flow model used for transmission planning today. The DC power flow analysis could be used for screening over much broader time periods to help identify hours and conditions that may warrant more detailed AC power flow analysis in conventional transmission planning processes. As it relates to ISOP modeling coordination, the hourly DC power flow model would be used to develop the need profile where there are opportunities to utilize energy storage as a non-traditional solution on the transmission system. The value of remaining hours of energy storage availability could then be evaluated at the bulk level.

Enhanced generation production cost models are expected to provide additional areas of improvement in the planning process. Duke continues to refine the quantification of ancillary requirements associated with intermittent resources, such as solar and while also working on the development of on-shore and off-shore wind ancillary requirements to evaluate benefits of a more diverse renewable resource mix in the Carolinas. Additionally, enhancements to hourly production cost models can help to better represent the sub-hourly impact of intermittent resources as well as the ability of energy storage to mitigate such costs. Duke is exploring the ability of sub-hourly models to address these challenges, as shown in the filing for the Solar Integration Services Charge (SISC) agreed to between Duke and the NC Public Staff and filed with the NCUC on May 21, 2019.

Finally, it should be noted that outreach has been and remains an important part of the ISOP effort. Over the last several years, the Company's ISOP development team has gathered input from other utilities, national labs, EPRI, consultants, and academic groups to inform our vision and work-scope to better address the challenges of modeling renewables and energy storage at both the distributed and bulk levels. We recognize that there is also interest in these ISOP development efforts from our regulators and customers, as well as environmental advocates, business interest groups and other stakeholders. Duke has initiated outreach to stakeholders in recent months, providing an overview of the ISOP process and inviting feedback regarding a potential stakeholder engagement process to continue the constructive dialog. It is important to note that DEC and DEP Balancing Areas include both NC and SC resources and load obligations, and both states have benefitted from the economies of scale from a large system with a combined planning process. As such, ISOP-related stakeholder engagement requires both NC and SC stakeholder representatives to ensure balanced outcomes for customers in both states. As part of the broader outreach effort, Duke will also support the NARUC-NASEO Task Force on Comprehensive Energy Planning (CEP). The Company views this as an important collaborative effort to support the building up and sharing of knowledge necessary to address the challenges and opportunities of incorporating non-traditional solutions across the respective planning disciplines within varying utility, regulatory, and market structures.

8. DEVELOPMENT OF THE RESOURCE PLAN

The following section details the Company's expansion plan and resource mix that is required to meet the needs of DEC's customers over the next 15 years. The section also includes a discussion of resource adequacy, the various technologies considered during the development of the IRP, as well as a summary of the resources required in the No Carbon Case.

Tables 8-A and 8-B represent the winter and summer Load, Capacity, and Reserves (LCR) tables for the Base Case.

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

Winter Projections of Load, Capacity, and Reserves
for Duke Energy Carolinas 2019 Annual Plan

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Load Forecast																
1	DEC System Winter Peak	18,568	18,564	18,697	18,800	19,034	19,194	19,429	19,636	19,924	20,179	20,432	20,697	21,029	21,297	21,571
	Catawba Owner Backstand	47	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Catawba Owner Backstand - NCEMC	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82
3	Cumulative New EE Programs	(61)	(115)	(167)	(220)	(297)	(342)	(398)	(444)	(481)	(515)	(548)	(577)	(597)	(617)	(626)
4	**Adjusted Duke System Peak**	**18,589**	**18,531**	**18,611**	**18,662**	**18,818**	**18,934**	**19,113**	**19,274**	**19,524**	**19,746**	**19,966**	**20,202**	**20,514**	**20,762**	**21,026**
Existing and Designated Resources																
5	Generating Capacity	21,454	21,454	21,519	21,599	21,679	21,759	21,557	21,557	21,557	21,557	21,031	21,031	20,858	20,858	20,311
6	Designated Additions / Uprates	-	65	80	80	80	402	-	-	-	-	-	-	-	-	-
7	Retirements / Derates	-	-	-	-	-	(604)	-	-	-	(526)	-	(173)	-	(547)	-
8	**Cumulative Generating Capacity**	**21,454**	**21,519**	**21,599**	**21,679**	**21,759**	**21,557**	**21,557**	**21,557**	**21,557**	**21,031**	**21,031**	**20,858**	**20,858**	**20,311**	**20,311**
Purchase Contracts																
9	**Cumulative Purchase Contracts**	**173**	**75**	**55**	**55**	**56**	**52**	**52**	**48**	**46**	**39**	**36**	**38**	**26**	**25**	**25**
	Non-Compliance Renewable Purchases	43	32	18	20	21	18	18	15	15	15	12	11	11	10	10
	Non-Renewables Purchases	130	43	37	35	35	34	34	34	32	24	24	27	15	15	15
Undesignated Future Resources																
10	Nuclear															
11	Combined Cycle									1,341						
12	Combustion Turbine							470					470	470	470	470
Renewables																
13	**Cumulative Renewables Capacity**	65	76	85	90	98	98	113	125	137	141	143	139	149	164	178
	Renewables w/o Storage	65	65	60	61	60	55	54	54	54	45	35	18	17	17	17
	Solar w/ Storage (Solar Component)	-	1	1	2	2	2	3	3	4	5	5	6	6	7	7
	Solar w/ Storage (Storage Component)	-	10	24	28	37	41	57	68	79	92	103	115	126	140	154
14	**Combined Heat & Power**	15	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	**Grid-connected Energy Storage**	4	16	20	20	20	20	20	-	-	-	-	-	-	-	-
16	**Cumulative Production Capacity**	**21,711**	**21,705**	**21,794**	**21,899**	**22,008**	**21,822**	**22,327**	**22,336**	**23,686**	**23,157**	**23,156**	**23,451**	**23,919**	**23,856**	**24,340**
Demand Side Management (DSM)																
17	**Cumulative DSM Capacity**	**469**	**468**	**468**	**468**	**469**	**465**	**465**	**465**	**465**	**465**	**465**	**465**	**465**	**465**	**465**
18	**Cumulative Capacity w/ DSM**	**22,180**	**22,173**	**22,263**	**22,367**	**22,477**	**22,286**	**22,792**	**22,800**	**24,151**	**23,622**	**23,620**	**23,916**	**24,384**	**24,321**	**24,805**
Reserves w/ DSM																
19	Generating Reserves	3,591	3,642	3,651	3,705	3,658	3,353	3,679	3,527	4,627	3,875	3,654	3,714	3,870	3,559	3,779
20	**% Reserve Margin**	**19.3%**	**19.7%**	**19.6%**	**19.9%**	**19.4%**	**17.7%**	**19.2%**	**18.3%**	**23.7%**	**19.6%**	**18.3%**	**18.4%**	**18.9%**	**17.1%**	**18.0%**

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

Summer Projections of Load, Capacity, and Reserves
for Duke Energy Carolinas 2019 Annual Plan

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Load Forecast																
1	DEC System Summer Peak	18,306	18,431	18,562	18,759	18,966	19,184	19,425	19,718	20,040	20,331	20,631	20,954	21,251	21,578	21,934
	Catawba Owner Backstand	47	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Catawba Owner Backstand - NCEMC	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82
3	Cumulative New EE Programs	(106)	(165)	(224)	(285)	(342)	(401)	(460)	(516)	(569)	(617)	(662)	(702)	(730)	(759)	(775)
4	**Adjusted Duke System Peak**	**18,282**	**18,347**	**18,420**	**18,556**	**18,706**	**18,864**	**19,047**	**19,284**	**19,553**	**19,795**	**20,051**	**20,334**	**20,603**	**20,901**	**21,242**
Existing and Designated Resources																
5	Generating Capacity	20,421	20,486	20,551	20,631	20,711	20,726	20,509	20,509	20,509	20,509	19,993	19,993	19,833	19,833	19,288
6	Designated Additions / Uprates	65	65	80	80	15	365	0	0	0	0	0	0	0	0	0
7	Retirements / Derates	0	0	0	0	0	(582)	0	0	0	(516)	0	(160)	0	(545)	0
8	**Cumulative Generating Capacity**	**20,486**	**20,551**	**20,631**	**20,711**	**20,726**	**20,509**	**20,509**	**20,509**	**20,509**	**19,993**	**19,993**	**19,833**	**19,833**	**19,288**	**19,288**
Purchase Contracts																
9	**Cumulative Purchase Contracts**	**310**	**242**	**274**	**320**	**359**	**390**	**386**	**380**	**375**	**363**	**352**	**313**	**294**	**286**	**279**
	Non-Compliance Renewable Purchases	180	200	237	286	325	357	353	346	343	339	328	301	294	286	279
	Non-Renewables Purchases	130	43	37	35	35	34	34	34	32	24	24	12	0	0	0
Undesignated Future Resources																
10	Nuclear															
11	Combined Cycle									1,241						
12	Combustion Turbine							426					470	470	940	
Renewables																
13	**Cumulative Renewables Capacity**	301	364	416	445	501	523	578	616	654	686	704	736	760	793	824
	Renewables w/o Storage	301	330	351	370	408	421	437	449	461	464	458	465	467	473	478
	Solar w/ Storage (Solar Component)	0	24	41	46	57	62	84	99	114	130	143	155	166	180	192
	Solar w/ Storage (Storage Component)	0	10	24	28	37	41	57	68	79	92	103	115	126	140	154
14	**Combined Heat & Power**	15	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	**Energy Storage**	4	16	20	20	20	20	20	0	0	0	0	0	0	0	0
16	**Cumulative Production Capacity**	**21,116**	**21,193**	**21,376**	**21,551**	**21,682**	**21,538**	**22,035**	**22,066**	**23,340**	**22,844**	**22,851**	**23,154**	**23,629**	**24,049**	**24,073**
Demand Side Management (DSM)																
17	**Cumulative DSM Capacity**	**1,108**	**1,124**	**1,140**	**1,153**	**1,157**	**1,155**	**1,155**	**1,155**	**1,155**	**1,155**	**1,155**	**1,155**	**1,155**	**1,155**	**1,155**
18	**Cumulative Capacity w/ DSM**	**22,224**	**22,317**	**22,515**	**22,704**	**22,839**	**22,693**	**23,190**	**23,221**	**24,495**	**23,999**	**24,006**	**24,309**	**24,784**	**25,204**	**25,228**
Reserves w/ DSM																
19	Generating Reserves	3,942	3,970	4,096	4,148	4,132	3,829	4,143	3,938	4,942	4,204	3,955	3,975	4,181	4,303	3,986
20	**% Reserve Margin**	**21.6%**	**21.6%**	**22.2%**	**22.4%**	**22.1%**	**20.3%**	**21.8%**	**20.4%**	**25.3%**	**21.2%**	**19.7%**	**19.5%**	**20.3%**	**20.6%**	**18.8%**

DEC - Assumptions of Load, Capacity, and Reserves Table

The following notes are numbered to match the line numbers on the Winter Projections of Load, Capacity, and Reserves tables. All values are MW (winter ratings) except where shown as a percent.

1. Planning is done for the peak demand for the Duke Energy Carolinas System including Nantahala.

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

2. Firm sale of Catawba backstand for NCEMC. (481 MW * 17% RM) = 82 MW

3. Cumulative new energy efficiency and conservation programs (does not include demand response programs).

4. Peak load adjusted for firm sales and cumulative energy efficiency.

5. Existing generating capacity reflecting designated additions, planned uprates, retirements and derates as of July 1, 2019.

   Includes 103 MW Nantahala hydro capacity. Only DEC portion of Catawba Nuclear Station capacity is included. Lee CC capacity of 683 MW (net of NCEMC ownership of 100 MW) is included.

6. Designated Capacity Additions include:

   Planned runner upgrades on each of the four Bad Creek pumped storage units. Each upgrade is expected to be 65 MW and are projected in the 2020 – 2023 timeframe.
   One unit will be upgraded per year.

   Nuclear upgrades of 15 MW for each Oconee unit between 2022 through 2024.

   402 MW Lincoln CT 17 included in 2025.

7. A planning assumption for coal retirements has been included in the 2018 IRP. Dates correspond to the depreciation study approved as part of the DEC rate case.

   Allen Steam Station Units 1-3 (604 MW) are assumed to retire in December 2024.

   Allen Steam Station Units 4-5 (526 MW) are assumed to retire in December 2028.

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

Lee 3 Natural Gas Boiler (173 MW) is assumed to retire in December 2030.

Cliffside Unit 5 (546 MW) is assumed to retire in December 2032.

Planning assumptions for nuclear stations assume subsequent license renewal at the end of the current license. 2,618 MW Oconee 1-3 are assumed to be relicensed in 2033 and 2034. Base case assumption is that nuclear stations will acquire an SLR.

The Hydro facilities for which Duke has submitted an application to Federal Energy Regulatory Commission (FERC) for license renewal are assumed to continue operation through the planning horizon.

All retirement dates are subject to review on an ongoing basis. Dates used in the 2019 IRP are for planning purposes only, unless unit is already planned for retirement.

8. Sum of lines 5 through 7.

9. Cumulative Purchase Contracts including purchase capacity from PURPA Qualifying Facilities.

   Additional line items shown under the total line item represent the amounts of renewable and traditional QF purchases.

   Renewable resources in these line items are not used for NC REPS compliance.

10. New nuclear resources economically selected to meet load and minimum planning reserve margin.

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

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

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

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

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

Addition of 1,341 MW of combined cycle capacity online December 2027.

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

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

    Addition of 470 MW of combustion turbine capacity online December 2025.

    Addition of 470 MW of combustion turbine capacity online December 2030 and December 2031.

    940 MW of combustion turbine capacity online December 2032.

13. Resources to comply with NC REPS, NC HB 589 and SC Act 236 along with solar customer product offerings such as Green Source and SC DER Program were input as existing resources. The contribution to peak is subdivided into resources that do not include energy storage, and resources (solar) that are coupled with energy storage. The contribution to peak for solar coupled with energy storage is further subdivided into the contribution from the solar component and contribution from the storage component.

14. New 15 MW of combined heat and power capacity included in 2020.

15. Addition of 120 MW (80% of usable AC capacity) of grid-tied energy storage over the years 2020 through 2026.

16. Sum of lines 8 through 16.

17. Cumulative demand response programs including wholesale demand response.

18. Sum of lines 17 and 18.

19. The difference between lines 19 and 4.

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

    Line 20 divided by Line 4.

Minimum winter target planning reserve margin is 17%.

Resource Adequacy

Background:

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. DEC utilizes a reserve margin target in its IRP process to ensure resource adequacy. Reserve margin is defined as total resources minus peak demand, divided by peak demand. The reserve margin target is established based on probabilistic assessments of resource adequacy.

2016 Resource Adequacy Study:

DEC retained Astrapé Consulting in 2016 to conduct an updated resource adequacy study.[5] The updated study was warranted to account for the extreme weather experienced in the service territory in recent winter periods, and the significant amount of solar capacity that has been added to the system and in the interconnection queue. Solar resources provide meaningful capacity benefits in the summer since peak demand typically occurs in afternoon hours when the sun is shining and solar resources are available. However, solar resources contribute very little capacity value to help meet winter peak demands that typically occur in early morning hours.

Based on results of the 2016 resource adequacy assessment, the Company adopted a 17% minimum winter reserve margin target for scheduling new resource additions and incorporated this planning criterion beginning with the 2016 IRP. The Company plans to update all inputs and assumptions and conduct a new resource adequacy study to support the development of its 2020 IRP.

Adequacy of Projected Reserves:

[5] Astrapé Consulting is an energy consulting firm with expertise in resource adequacy and integrated resource planning. Astrapé conducted resource adequacy studies for DEC and DEP in 2012 and 2016.

The IRP provides general guidance in the type and timing of resource additions. Projected reserve margins will often be somewhat higher than the minimum target in years immediately following new generation additions since capacity is generally added in large blocks to take advantage of economies of scale. Large resource additions are deemed economic only if they have a lower Present Value Revenue Requirement (PVRR) over the life of the asset as compared to smaller resources that better fit the short-term reserve margin need.

DEC's resource plan reflects winter reserve margins ranging from approximately 17.1% to 23.7%. Reserves projected in DEC's IRP meet the minimum planning reserve margin target and thus satisfy the one day in 10 years LOLE criterion. Projected reserve margins exceed the minimum 17% winter target by 3% or more in 2028 as a result of a large combined cycle addition. Reserves projected in the Company's IRP are appropriate for providing an economic and reliable power supply.

16% Winter Reserve Margin Sensitivity:

The NCUC's April 16, 2018 Order Accepting Filing of 2017 Update Reports and Accepting 2017 REPS Compliance Plans in Docket No. E-100, Sub 147, concluded that DEC and DEP may continue to utilize the minimum 17% winter reserve margin for planning purposes in their 2018 IRPs. The Commission also required the Companies to present a sensitivity analysis in their 2018 IRPs that illustrates the impact of a 16% winter reserve margin, including the specific risk impact (LOLE) of using a 16% minimum reserve margin versus a 17% minimum reserve margin. For information purposes, the Company has also included a 16% reserve margin scenario in its 2019 IRP.

Table 8-C below shows a comparison of DEC's base case resource additions using a 17% winter reserve margin compared to a scenario using a 16% winter reserve margin. As illustrated in the table, use of a 16% reserve margin would result in a one-year deferral of the 2026 CT addition and the 2028 CC addition. The 2031 CT addition could also be deferred to 2033. The reserve margins resulting from these changes are depicted in the table.

The 2016 resource adequacy study recommendation used a consensus of the DEC and DEP study results to establish a minimum 17% winter reserve margin target for the two companies. This minimum reserve margin target is needed to maintain an LOLE of one day in ten years (0.1 days/year). Based on results from the 2016 study, allowing the DEC reserve margin to decline to 16% for a given year would increase the loss of load expectation to approximately 0.116 days/year for DEC, which equates to one expected firm load shed event approximately every 8.6 years.

Table 8-C   16% Reserve Margin Sensitivity

**Winter Projections of Load, Capacity, and Reserves
for Duke Energy Carolinas 2019 Annual Plan**

(17% Reserve Margin Base Case)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Adjusted System Peak Load (MW)	18,589	18,531	18,611	18,662	18,818	18,934	19,113	19,274	19,524	19,746	19,966	20,202	20,514	20,762	21,026
Undesignated Future Resources (MW)															
Combined Cycle									1,341						
Combustion Turbine							470					470	470	470	470
Generating Reserves	3,591	3,642	3,651	3,705	3,658	3,353	3,679	3,527	4,627	3,875	3,654	3,714	3,870	3,559	3,779
% Reserve Margin	**19.3%**	**19.7%**	**19.6%**	**19.9%**	**19.4%**	**17.7%**	**19.2%**	**18.3%**	**23.7%**	**19.6%**	**18.3%**	**18.4%**	**18.9%**	**17.1%**	**18.0%**

(16% Reserve Margin Scenario)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Adjusted System Peak Load (MW)	18,589	18,531	18,611	18,662	18,818	18,934	19,113	19,274	19,524	19,746	19,966	20,202	20,514	20,762	21,026
Undesignated Future Resources (MW)															
Combined Cycle										1,341					
Combustion Turbine								470					470	940	470
Generating Reserves	3,591	3,642	3,651	3,705	3,658	3,353	3,209	3,527	3,286	3,875	3,654	3,244	3,400	3,559	3,779
% Reserve Margin	**19.3%**	**19.7%**	**19.6%**	**19.9%**	**19.4%**	**17.7%**	**16.8%**	**18.3%**	**16.8%**	**19.6%**	**18.3%**	**16.1%**	**16.6%**	**17.1%**	**18.0%**

Technologies Considered

Similar to the 2018 IRP, the Company considered a diverse range of technology choices utilizing a variety of different fuels in order to meet future generation needs in the 2019 IRP. The Company conducted an economic screening analysis of various technologies as part of the 2019 IRP, with changes from the 2018 IRP highlighted below.

Dispatchable (Winter Ratings)

- Base load – 782 MW Ultra-Supercritical Pulverized Coal with CCS
- Base load – 557 MW 2x1 IGCC with CCS
- Base load – 2 x 1,117 MW Nuclear Units (AP1000)
- Base load – **672 MW** – 1x1x1 Advanced Combined Cycle (No Inlet Chiller and Fired)
- Base load – **1,341 MW** – 2x2x1 Advanced Combined Cycle (No Inlet Chiller and Fired)
- Base load – 22 MW – Combined Heat & Power (Combustion Turbine)
- Base load – 9 MW – Combined Heat & Power (Reciprocating Engine)
- Base load – **720 MW** – Small Modular Reactor (SMR)
- **Peaking/Intermediate – 18 MW 2 x Reciprocating Engine Plant**
- Peaking/Intermediate – **197 MW** 4 x LM6000 Combustion Turbines (CTs)
- Peaking/Intermediate – **201 MW** 12 x Reciprocating Engine Plant
- Peaking/Intermediate – **756 MW** 2 x J-Class Combustion Turbines (CTs)
- Peaking/Intermediate – **940 MW** 4 x 7FA.05 Combustion Turbines (CTs)
- Storage – **10 MW / 10 MWh** Li-ion Battery
- **Storage – 10 MW / 20 MWh Li-ion Battery**
- **Storage – 10 MW / 40 MWh Li-ion Battery**
- Storage – **50 MW / 200 MWh** Li-ion Battery
- **Storage – 50 MW / 300 MWh Li-ion Battery**
- **Storage – 102 MW / 816 MWh Redox Flow Battery**
- Storage – 1,400 MW Pumped Storage Hydro (PSH)
- Renewable – 75 MW Wood Bubbling Fluidized Bed (BFB, biomass)
- Renewable – 5 MW Landfill Gas

Non-Dispatchable (Nameplate)

- Renewable – 150 MW Wind - On-Shore
- Renewable – **75 MW** Solar PV, Fixed-tilt (FT)
- Renewable – **75 MW** Solar PV, Single Axis Tracking (SAT)
- Renewable – **75 MW Solar PV plus 20 MW / 80 MWh** Li-ion Battery

Combined Cycle base capacities: Based on proprietary third-party engineering studies, the Advanced CC saw minor increases in base load output. The 1x1x1 Advanced CC increased 5 MW while the 2x2x1 Advanced CC increased 2 MW.

Small Modular Reactor base capacities: As described in Appendix F of the 2018 IRP, the leading SMR design increased from 600 MW to 720 MW due to a 20% upgrade in the design. The 2019 update reflects the new 720 MW output of the proposed design.

Combustion Turbine base capacities and technologies: Based on proprietary third-party engineering studies, the CT technologies saw a minor change in winter capacity. The most significant change was the F-Frame CT, which increased 21 MW. Additionally, a smaller Reciprocating Engine of 18 MW was considered in addition to the 201 MW design. The G/H-Frame CTs were not considered in the updated IRP. However, as the Company begins the process of evaluating particular technologies for future undesignated generation needs, these technologies, along with other new technologies, may be considered based on factors such as generation requirements, plot size, new environmental regulations, etc.

Energy Storage capacities and technologies: Energy storage solutions, in particular batteries, continue to be viewed as an increasing necessity for support of grid services, including frequency regulation, solar smoothing, and/or energy shifting from localized renewable energy sources with a high incidence of intermittency (i.e. solar and wind). These technologies are capable of providing resiliency benefits and economic value for the utility and its customers. Duke Energy is committed to supporting emerging technologies that can complement more conventional technologies and is in a prime position to optimize the investment in batteries by dispatching them in a manner that directly benefits customers.

The updated IRP includes additional battery options, reflecting the continued change in the industry, to allow for larger batteries with increasing durations. The additional sizes allow for greater flexibility in deployment, and the increased capacities take advantage of economies of scale. Additionally, a Redox Flow Battery is now considered in addition to the Lithium-Ion options. Although Redox Flow Batteries are still in an immature state compared to Lithium-Ion batteries, the high cycling ability of Redox Flow Batteries and longer duration of storage shows promise to meet future grid requirements.

Solar PV Capacity: Solar PV continues to evolve as the industry matures. The capacity of solar PV was increased from 50 MW to 75 MW to reflect typical industry deployments.

Solar PV Plus Storage Capacity and Usage: Hybrid solar and storage projects have been deployed more frequently in the last year and continue to be announced across the country. The energy storage component of such a system can be dispatched in a variety of ways depending on price signals and needs of the broader DEC system. For instance, during winter months, DEC's peak demand occurs during mornings when there is little to no solar energy being generated, but a solar facility coupled with energy storage can store solar energy from the previous day when that energy is less valued on the DEC system and dispatch it during those high-value, early winter morning hours. Additionally, there is value for the battery to supplement solar energy during times of cloud cover to "smooth" the output of the solar plus storage facility thereby reducing the effects of solar intermittency on the DEC system. The ability for a solar plus storage facility to both shift energy and smooth output may be limited based on the design of the hybrid facility, the terms of the battery warranty, and other constraints. For the purposes of the 2019 Update IRP, solar PV plus storage is modeled at 75 MW solar alongside a 20 MW battery with a 4-hour duration. This ratio of nameplate storage capacity to nameplate solar capacity is consistent with recent projects evaluated on the DEC and DEP systems.

Expansion Plan and Resource Mix

A tabular presentation of the 2019 Base Case resource plan represented in the above LCR table is shown below:

Table 8-D DEC Base Case Resources – Winter (with CO_2)

Duke Energy Carolinas Resource Plan [1]
Base Case - Winter

Year	Resource					MW				
2020	CHP		Solar		Energy Storage	15			348	5
2021	Solar + Storage		Bad Creek Uprates	Solar	Energy Storage	75 (13)		65	270	20
2022	Nuclear Uprates	Solar + Storage	Bad Creek Uprates	Solar	Energy Storage	15	60 (18)	65	330	25
2023	Nuclear Uprates	Solar + Storage	Bad Creek Uprates	Solar	Energy Storage	15	20 (5)	65	273	25
2024	Nuclear Uprates	Solar + Storage	Bad Creek Uprates	Solar	Energy Storage	15	41 (10)	65	322	25
2025	Solar + Storage		Solar		Energy Storage	20 (5)		218		25
2026	New CT	Solar + Storage	Solar		Energy Storage	470	80 (20)	68		25
2027	Solar + Storage		Solar			54 (14)		42		
2028	New CC	Solar + Storage	Solar			1,341	53 (14)	41		
2029	Solar + Storage		Solar			61 (16)		50		
2030	Solar + Storage		Solar			56 (14)		44		
2031	New CT	Solar + Storage	Solar			470	59 (15)	48		
2032	New CT	Solar + Storage	Solar			470	52 (14)	40		
2033	New CT	Solar + Storage	Solar			470	67 (18)	56		
2034	New CT	Solar + Storage	Solar			470	63 (17)	52		

Notes:
(1) Table includes both designated and undesignated capacity additions
(2) Incremental solar additions represent nameplate ratings and do not include solar coupled with storage
(3) Incremental Energy Storage additions represent useable AC MW capacity
(4) Solar + Storage values in ( ) represent useable AC MW storage behind solar inverter
(5) Future additions of other renewables, EE and DSM not included

Table 8-E DEC Base Case Resources (with CO_2) Cumulative Winter Totals

DEC Base Case Resources
Cumulative Winter Totals - 2020 - 2034

Nuclear	45
Solar	2,202
Solar + Storage	760 (192)
CC	1,341
CT	2,350
Pumped Storage	260
CHP	15
Energy Storage	150
Total	6,973

The following charts illustrate both the current and forecasted capacity by fuel type for the DEC system, as projected in the Base Case. As demonstrated in Chart 8-A, the capacity mix for the DEC system changes with the passage of time. In 2034, the Base Case projects that DEC will have a smaller reliance on coal, a continued reliance on nuclear and hydro but a higher reliance on renewables, energy storage, gas-fired generation and EE as compared to the current state.

Chart 8-A 2020 and 2034 Base Case Winter Capacity Mix [6]

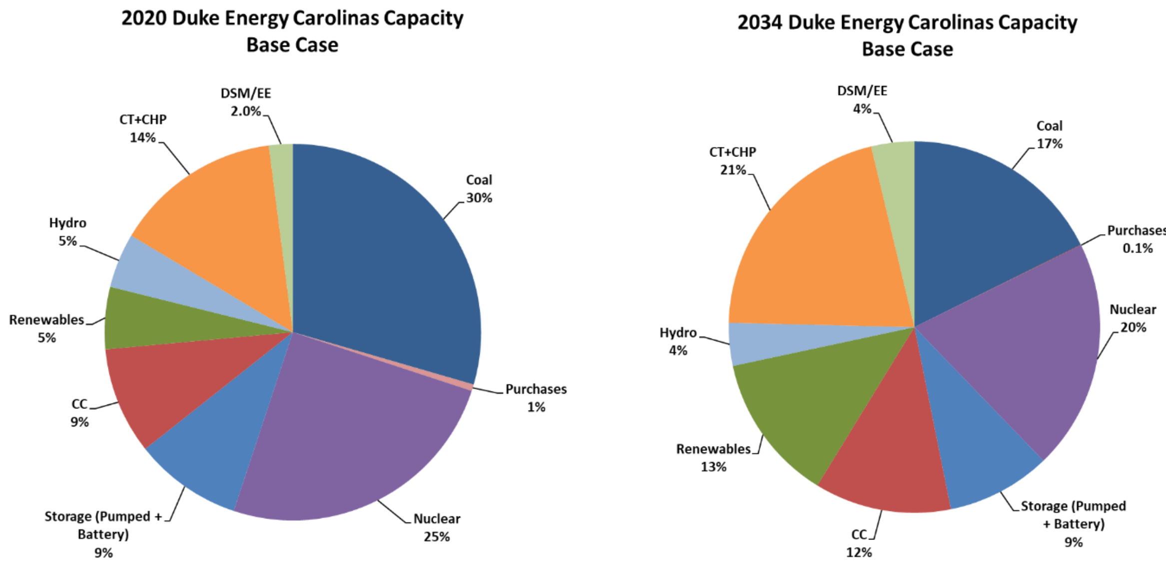
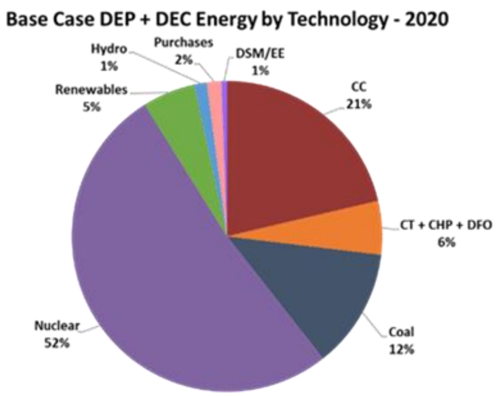
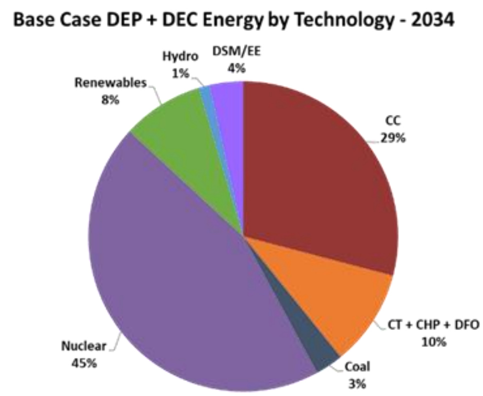


Chart 8-B represents the energy of both the DEC and DEP Base case over time. Due to the joint dispatch agreement (JDA), it is prudent to combine the energy of both utilities to develop a meaningful energy figure. From 2020 to 2034, the figure shows that nuclear resources will continue to serve almost half of DEC and DEP energy needs, a reduction in the energy served by coal, and an increase in the energy served by natural gas, renewables and EE.

[6] EE represents incremental EE and does not reflect impacts of historical efforts.

Chart 8-B 2020 & 2034 DEC and DEP Energy – Base Case





As discussed earlier, the Company developed one additional case which represents a variation of the Base Case which assumes no carbon regulations. The expansion plan for this case is shown below in Table 8-F.

Table 8-F No Carbon Case – Winter

Duke Energy Carolinas Resource Plan [1]
No CO_2 Case - Winter

Year	Resource					MW				
2020	CHP		Solar		Energy Storage	15			348	5
2021	Solar + Storage		Bad Creek Uprates	Solar	Energy Storage	75 (13)		65	270	20
2022	Nuclear Uprates	Solar + Storage	Bad Creek Uprates	Solar	Energy Storage	15	60 (18)	65	330	25
2023	Nuclear Uprates	Solar + Storage	Bad Creek Uprates	Solar	Energy Storage	15	20 (5)	65	273	25
2024	Nuclear Uprates	Solar + Storage	Bad Creek Uprates	Solar	Energy Storage	15	41 (10)	65	322	25
2025	Solar + Storage		Solar		Energy Storage	20 (5)		218		25
2026	New CT	Solar + Storage	Solar		Energy Storage	470	80 (20)	68		25
2027	Solar + Storage		Solar			54 (14)		42		
2028	New CT	Solar + Storage	Solar			470	53 (14)	41		
2029	New CT	Solar + Storage	Solar			940	61 (16)	50		
2030	Solar + Storage		Solar			56 (14)		44		
2031	New CT	Solar + Storage	Solar			470	59 (15)	48		
2032	Solar + Storage		Solar			52 (14)		40		
2033	New CT	Solar + Storage	Solar			940	67 (18)	56		
2034	New CT	Solar + Storage	Solar			470	63 (17)	52		

Notes: (1) Table includes both designated and undesignated capacity additions
(2) Incremental solar additions represent nameplate ratings and do not include solar coupled with storage
(3) Incremental Energy Storage additions represent useable AC MW capacity
(4) Solar + Storage values in ( ) represent useable AC MW storage behind solar inverter
(5) Future additions of other renewables, EE and DSM not included

9. DEC FIRST RESOURCE NEED

The IRP process provides a resource plan to most economically and reliably meet the projected load requirements and a reasonable reserve margin throughout the 15-year study period. In addition to load growth, planned unit retirements contribute to the need for new generation resources.

The resources used to meet the load requirements fall into two categories: Designated and Undesignated. Designated resources are those resources that are in service, projects that have been granted a Certificate of Public Convenience and Necessity (CPCN) or Certificate of Environmental Compatibility and Public Convenience and Necessity (CECPCN), smaller capacity additions that are a result of unit uprates that are in the Companies' planning budget, firm market purchases over the duration of the signed contract or DSM/EE programs.

Undesignated resources include purchase power contracts that have not yet been executed and projected resources in the IRP that do not have a CPCN or CECPCN granted.

Additionally, firm market purchases, which include wholesale contracts, including renewable contracts, are assumed to end at the end of the currently contracted period. There is no guarantee that the counterparty will choose to sell or the Company will agree to buy its capacity after the contracted timeframe. Beyond the contract period, the seller may elect to retire the resource or sell the output to an entity other than the Company. As such, contracted resources are deemed designated only for the duration of their legally enforceable contract.

Further, solar renewable contracts are broken down into three categories: Designated, Mandated and Undesignated. As discussed in Chapter 6, the definitions of each bucket are below:

- **Designated**: Contracts that are already connected today or those who have yet to connect but have an executed PPA are assumed to be designated for the duration of the purchase power contract.
- **Mandated**: Capacity that is not yet under contract but is required through legislation (examples include future tranches of CPRE, the renewables energy procurement program for large customers, and community solar under NC HB 589 as well as SC Act 236).
- **Undesignated**: Additional capacity projected beyond what is already designated or mandated. Expiring solar contracts are assumed to be replaced in kind with undesignated solar additions. Such additions could include existing providers or new facilities that enter into contracts that have yet been executed.

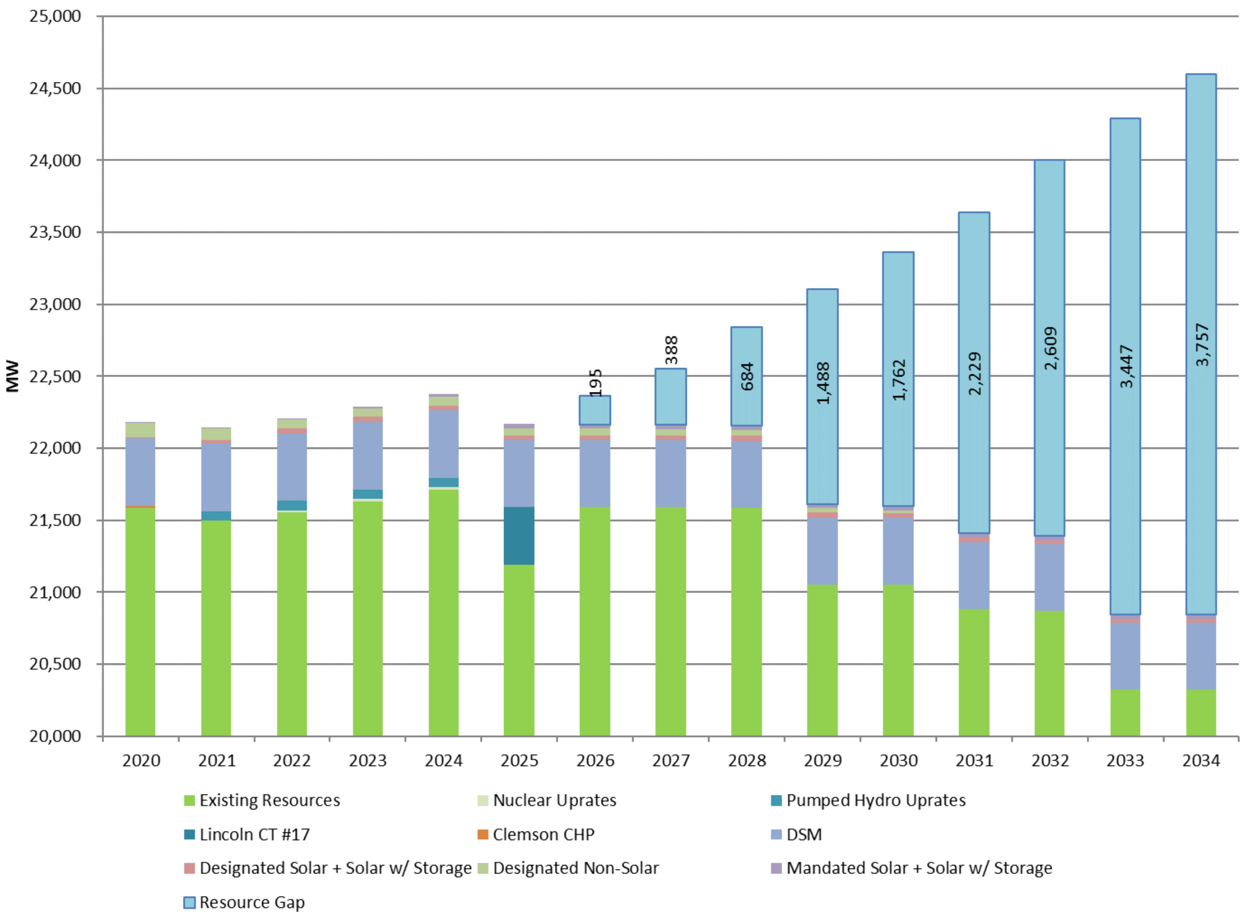
Only designated and mandated resources are considered when determining the first need for purposes of the determination of standard offer avoided capacity rates.

Designated resources have an impact on the determination of the first resource need in the IRP. A list of designated resources for DEC is below:

- Bad Creek Runner upgrades
- Lincoln CT Project
- Clemson CHP Project
- Designated and mandated renewable resources
- Nuclear Uprates
- Designated wholesale contracts
- DSM/EE programs

Including only the designated and mandated resources, Chart 9-A demonstrates the first need for DEC is in 2026. To the extent current contracts under negotiation become executed and moved from an undesignated to designated resource, the timing of the first need will change accordingly.

Chart 9-A Load Resource Balance for DEC First Need



10. SHORT-TERM ACTION PLAN

The Company's Short-Term Action Plan, which identifies accomplishments in the past year and actions to be taken over the next five years, is summarized below:

Continued Reliance on EE and DSM Resources

The Company is committed to continuing to grow the amount of EE and DSM resources utilized to meet customer growth. The following are the ways in which DEC will increase these resources:

- Continue to execute the Company's EE and DSM plan, which includes a diverse portfolio of EE and DSM programs spanning the residential, commercial and industrial classes.

- Continue on-going collaborative work to develop and implement additional cost-effective EE and DSM products and services.

- Continue to seek enhancements to the Company's EE/DSM portfolio by: (1) adding new or expanding existing programs to include additional measures, (2) program modifications to account for changing market conditions and new measurement and verification (M&V) results and (3) considering other EE research and development pilots.

- Continue to seek additional DSM programs that will specifically benefit during winter peak situations.

Continued Focus on Renewable Energy Resources

DEC is committed to the addition of significant renewable generation into its resource portfolio. Supporting policies such as SC Act 236, NC REPS, NC HB 589, and the newly signed SC Act 62 have all contributed to DEC's aggressive plans to grow its renewable resources. DEC is also committed to meeting its targets for the SC DER Program.

Under NC HB 589, DEC and DEP successfully procured approximately 550 MW of solar capacity through tranche one of CPRE and intends to request another 680 MW of solar capacity in the second tranche. The Companies also launched shared solar programs in SC and have proposed a voluntary renewable energy program totaling 150 MW pending before the SC Commission. These activities will be done in a manner that allows the Companies to continue to reliably and cost-effectively serve customers' future energy needs. For further details, refer to Chapter 6, as well as Attachments I and II.

DEC has signed agreements and obtained regulatory approval for a 15 MW CHP at Clemson University, which is expected to be in service by 2020. DEC continues to pursue CHP opportunities, as appropriate, and placeholders will be included in future IRPs.

Integration of Battery Storage on System:

The Company continues to identify locations to deploy energy storage on the DEC system that will allow for a more complete evaluation of potential benefits to the distribution, transmission and generation system while also providing actual operations and maintenance cost impacts of batteries deployed at a significant scale. The Company will work with Generation, Transmission and Distribution departments in this evaluation process, utilizing the ISOP framework. The goal is to optimize the location to couple localized T&D system benefits with bulk system benefits, and to minimize cost and maximize benefits for its customers.

DEC plans to construct on the distribution grid, a 5 MW battery energy storage system near Anderson, SC which will be hosted by the Anderson Civic Center. The battery will provide bulk grid benefits and will be capable of providing back-up power to the Anderson Civic Center in the event of an outage. The Anderson Civic Center is South Carolina's largest Special Medical Needs Evacuation Shelter. The Company also plans to further study the capacity value of storage in the Carolinas and will include any learnings in the 2020 IRP.

Continue to Find Opportunities to Enhance Existing Clean Resources:

DEC is committed to continually looking for opportunities to improve and enhance its existing resources. DEC has committed to the replacement of the runners on each of its four Bad Creek pumped storage units. Each replacement is expected to gain approximately 65 MW of capacity. The first replacement is projected to be in 2020, available for the 2021 winter peak. The remaining units will be replaced at the rate of one per year for availability in the winter peaks from 2022 to 2024.

Addition of Clean Natural Gas Resources

- A CPCN application was filed on June 12, 2017 for the construction of a new, state-of-the-art 402 MW combustion turbine at the existing Lincoln County CT site. While Duke Energy is not expected to take care, custody, and control of the CT until October 2024, DEC and its customers will benefit from the energy produced by the generating unit beginning in 3Q2020 as the unit begins an extended commissioning and testing period.

- As part of the Company's effort to modernize and increase unit flexibility, and in order to take advantage of continued low natural gas prices, DEC is moving forward with modifications to Belews Creek Coal Units 1 and 2 and Marshall Coal Units 1 – 4. The Belews Creek project will enable 50% natural gas co-firing on each unit. The Marshall Project will enable 50% co-firing on Units 3 & 4 and up to 40% co-firing on Units 1&2. Similar to the Cliffside DFO Project that was completed in 2018, co-firing at Belews Creek and Marshall is designed to maximize the value of these units, improve unit dispatch, and increase unit flexibility by lowering the delivered fuel cost to the complex through gas co-firing. Based on the current schedule, COD for Belews Creek Unit 1 is December 2019 and Belews Creek Unit 2 is December 2020. COD for Marshall Unit 3 is September 2020, Unit 4 is November 2020, and Units 1&2 are December 2021.

Subsequent License Renewal for Nuclear Power Plants

Duke Energy will continue to evaluate SLR for all its nuclear plants and is actively working on DEC's Oconee Nuclear Station SLR application to extend the licenses to 80 years. The remaining nuclear sites will do likewise where the cost/benefit balance proves acceptable.

Continued Focus on System Reliability and Resource Adequacy for DEC System

Based on results of the 2016 resource adequacy assessment, the Company adopted a 17% minimum winter reserve margin target for scheduling new resource additions and incorporated this planning criterion beginning with the 2016 IRP. The Company plans to work with the regulatory staffs to update all inputs and assumptions and conduct a new resource adequacy study to support the development of its 2020 IRP.

Continued Transition Toward Integrated System & Operations Planning

As introduced in the 2018 IRP and discussed in in Chapter 7 of this IRP Update, the traditional methods of utility resource planning are continuing to evolve. DEC is committed to moving toward an integrated planning process to meet the changing needs of planning in the future. The traditional methods of utility resource planning will be enhanced through an ISOP effort.

One key goal of ISOP is for the planning models to reasonably mimic the future operational realities to allow DEC to serve its customers with newer technologies. These enhancements in planning are expected being addressed and will be incorporated over the next several years, as soon as the modeling tools, processes and data development will allow.

Continued Focus on Evolving Regulations and Environmental Compliance

- As of April 2015, all of DEC's older, un-scrubbed coal units have been retired. In total, DEC has retired 1,700 MW of older vintage coal units since 2011.
- The 2019 IRP shows approximately 1,800 MW of additional retirements over the 15-year study period. The retirement of Allen coal units 1-3 are expected by year-end 2024. [7]
- Engage with state environmental agencies to determine the plan to implement the Affordable Clean Energy (ACE) Rule. The ACE Rule was published by the US EPA on July 8, 2019. The rule revokes and replaces the Clean Power Plan and establishes a requirement for states to develop carbon dioxide emissions standards for coal-fired electric utility generating units based on evaluation of certain heat rate improvement (efficiency) measures. ACE requires states to submit plans to the EPA by July 8, 2022, and facilities are required to demonstrate compliance within 2 years of that date (July 8, 2024). Various parties (including the State of North Carolina) have filed litigation opposing EPA's action to replace the Clean Power Plan. However, unless the federal courts take action to stay the rule pending judgment, states and affected industry will be obligated to meet the deadlines established by the ACE Rule. Duke Energy does not have sufficient information to determine the impact of the ACE Rule on its facilities.
- Continue to stay informed of changes and updates to existing and potential environmental regulations such as the Mercury and Air Toxics Standards (MATS), the Coal Combustion Residuals Rule (CCR), the Cross-State Air Pollution Rule (CSAPR), and the new Ozone National Ambient Air Quality Standard (NAAQS). The Company will comply with any regulatory requirements associated with these regulations.

[7] As required by a September 2015 settlement with the U.S. Department of Justice, Allen Units 1-3 are required to retire by the end of 2024. The ultimate timing of other unit retirements can be influenced by factors changing the economics of continued unit operations. Such factors include changes in relative fuel prices, operations and maintenance costs and the costs associated with compliance of evolving environmental regulations. As such, unit retirement schedules are expected change over time as market conditions change.

- Evaluate and monitor the draft NC Clean Energy Plan Issued on August 16, 2019, as it is finalized.

Regulatory:

- Continue to monitor energy-related statutory and regulatory activities.
- Continue to examine the benefits of joint capacity planning and pursue appropriate regulatory actions.
- Comply with all NCUC and PSCSC orders resulting from state-specific legislation and pending regulatory dockets.

A summarization of the capacity resources for the reference plan in the 2019 IRP is shown in Table 10-A below. Capacity retirements and additions are presented as incremental values in the year in which the change is projected to impact the winter peak. The values shown for renewable resources, EE and DSM represent cumulative totals.

Table 10-A DEC Short-Term Action Plan

2019 Duke Energy Carolinas Short-Term Action Plan (1) (2)							
			Renewable Resources (Cumulative Nameplate MW)				
Year	Retirements	Additions (3)	Solar (4)	Solar w/ Storage(5)	Biomass/ Hydro	Cumulative EE	DSM (6)
2020		15 MW Clemson CHP 5 MW Energy Storage	1,137	0	97	61	469
2021		20 MW Energy Storage 65 MW Bad Creek Upgrade	1,407	75 w/ 13 Storage	83	115	468
2022		25 MW Energy Storage 15 MW Nuc Uprate 65 MW Bad Creek Upgrade	1,738	135 w/ 30 Storage	61	167	468
2023		25 MW Energy Storage 15 MW Nuc Uprate 65 MW Bad Creek Upgrade	2,011	155 w/ 35 Storage	61	220	468
2024		25 MW Energy Storage 15 MW Nuc Uprate 65 MW Bad Creek Upgrade	2,332	196 w/ 46 Storage	57	297	469

Notes:

(1) Capacities shown in winter ratings unless otherwise noted.

(2) Dates represent when the project impacts the winter peak.

(3) Energy storage is grid-tied storage and represents total usable MW.

(4) Capacity is shown in nameplate ratings and does not include solar coupled with energy storage.

(5) Solar coupled with storage; storage only charged from solar.

(6) Includes impacts of grid modernization.

11. CONCLUSIONS

DEC continues to focus on the needs of customers by meeting the growing demand in the most economical and reliable manner possible while improving the environmental footprint of its resource portfolio. The Company continues to improve the IRP process by determining best practices and making changes to more accurately and realistically represent the DEC System in its planning practices. The 2019 IRP represents a 15-year projection of the Company's plan to balance future customer demand and supply resources to meet this demand plus a 17% minimum winter planning reserve margin. Over the 15-year planning horizon, DEC expects to add 6,973 MW of generating resources in addition to the incremental EE and DSM already in the resource plan.

The Company focuses on the needs of the short-term, while keeping a close watch on market trends and technology advancements to meet the demands of customers in the long-term. The Company's short-term and long-term plans are summarized below:

Short-Term

Over the next 5 years, DEC's 2019 IRP focuses on the following:

- Continue work on the Bad Creek unit upgrades.
- Pursue investment in a limited number of battery storage projects to gain additional operational and technical experience with evolving utility-scale storage technologies.
- Continue work on the new Lincoln CT that will begin providing low-cost energy benefits to DECs customers in 3Q2020, prior to taking care, custody, and control of the CT in 4Q2024.
- Continue work on the Belews Creek and Marshall dual fuel optimization projects to increase flexibility of the DEC system.
- Procure CHP resources as cost-effective and diverse generation sources, as appropriate.
- Continue to meet NC REPS, SC Act 236 and NC HB 589 compliance plans.
- Implement requirements of SC Act 62.
- Continue to invest in EE and DSM in the Carolinas region.
- Continue to seek additional DSM programs that will specifically benefit during winter peak situations.
- Continue work on the 15 MW CHP at Clemson University, which is expected to be in service in 2020.
- Continue to transition toward Integrated System & Operations Planning.
- Conduct new resource adequacy study to support the development of 2020 IRP.

- Continue to study energy storage and solar plus storage capacity value.
- Continue with plan for subsequent license renewal of existing nuclear units.

Long-Term

Beyond the next 5 years, DEC's 2019 IRP focuses on the following:

- Continue to seek the most cost-effective, reliable resources to meet the growing customer demand in the service territory. Currently these are combustion turbine and combined cycle units in the 15-year planning horizon.
- Continue evaluating and deploying storage and zero-emitting-load-following resources in order to better integrate increasing levels of intermittent renewable resources on the DEC system.
- Continue to reduce the carbon footprint of the Company's generation portfolio.
- Continue discussions with other potential steam hosts to pursue CHP opportunities, as appropriate.
- Continue to meet and NC REPS, SC Act 236 and NC HB 589 compliance plans and invest in additional cost-effective and diverse renewable resources.
- Continue implementing all portions of the NC HB 589 bill.
- Continue to grow and enhance cost-effective EE and DSM in the Carolinas region.
- Plan for the retirements of Allen 1 - 5 and Cliffside 5 coal units.

DEC's goal is to continue to diversify the DEC system by adding a variety of cost-effective, reliable, clean resources to meet customer demand. Over the next 15 years, the Company projects filling the increasing demand with investments in natural gas, nuclear, renewables, storage, EE and DSM.

12. DUKE ENERGY CAROLINAS OWNED GENERATION

Duke Energy Carolinas' generation portfolio includes a balanced mix of resources with different operating and fuel characteristics. This mix is designed to provide energy at the lowest reasonable cost to meet the Company's obligation to serve its customers. Duke Energy Carolinas-owned generation, as well as purchased power, is evaluated on a real-time basis in order to select and dispatch the lowest-cost resources to meet system load requirements.

The tables below list the Duke Energy Carolinas' plants in service in North Carolina and South Carolina with plant statistics, and the system's total generating capability.

Existing Generating Units and Ratings [a, b, c, d, e]
All Generating Unit Ratings are as of January 1, 2019

Coal						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
Allen	1	167	162	Belmont, N.C.	Coal	Peaking
Allen	2	167	162	Belmont, N.C.	Coal	Peaking
Allen	3	270	258	Belmont, N.C.	Coal	Peaking
Allen	4	267	257	Belmont, N.C.	Coal	Intermediate
Allen	5	259	259	Belmont, N.C.	Coal	Peaking
Belews Creek	1	1110	1110	Belews Creek, N.C.	Coal	Base
Belews Creek	2	1110	1110	Belews Creek, N.C.	Coal	Base
Cliffside	5	546	544	Cliffside, N.C.	Coal	Peaking
Cliffside	6	849	844	Cliffside, N.C.	Coal	Intermediate
Marshall	1	380	370	Terrell, N.C.	Coal	Intermediate
Marshall	2	380	370	Terrell, N.C.	Coal	Intermediate
Marshall	3	658	658	Terrell, N.C.	Coal	Base
Marshall	4	660	660	Terrell, N.C.	Coal	Base
Total Coal		6,823	6,764			

Combustion Turbines						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
Lee	7C	48	42	Pelzer, S.C.	Natural Gas/Oil-Fired	Peaking
Lee	8C	48	42	Pelzer, S.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	1	98	76	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	2	99	76	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	3	99	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	4	98	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	5	97	74	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	6	97	73	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	7	98	76	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	8	98	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	9	97	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	10	98	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	11	98	74	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	12	98	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	13	98	74	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	14	97	74	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	15	98	73	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	16	97	73	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	1	95	71	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	2	95	70	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	3	95	71	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	4	96	70	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	5	96	69	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	6	92	71	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	7	95	70	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	8	93	71	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	1	179	165	Reidsville, N.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	2	179	165	Reidsville, N.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	3	179	165	Reidsville, N.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	4	179	165	Reidsville, N.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	5	179	165	Reidsville, N.C.	Natural Gas/Oil-Fired	Peaking
Total NC		2,460	2,018			
Total SC		853	647			
Total CT		3,313	2,665			

Natural Gas Fired Boiler						
		Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Lee	3	173	160	Pelzer, S.C.	Natural Gas	Peaking
Total Nat. Gas		173	160			

Combined Cycle						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Buck	CT11	206	178	Salisbury, N.C.	Natural Gas	Base
Buck	CT12	206	178	Salisbury, N.C.	Natural Gas	Base
Buck	ST10	304	312	Salisbury, N.C.	Natural Gas	Base
Buck CTCC		716	668			
Dan River	CT8	199	171	Eden, N.C.	Natural Gas	Base
Dan River	CT9	199	171	Eden, N.C.	Natural Gas	Base
Dan River	ST7	320	320	Eden, N.C.	Natural Gas	Base
Dan River CTCC		718	662			
WS Lee	CT11	240	237	Pelzer, S.C.	Natural Gas	Base
WS Lee	CT12	239	236	Pelzer, S.C.	Natural Gas	Base
WS Lee	ST10	313	313	Pelzer, S.C.	Natural Gas	Base
WS Lee CTCC		792	786			
Total CTCC		2,226	2,116			

Pumped Storage						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
Jocassee	1	195	195	Salem, S.C.	Pumped Storage	Peaking
Jocassee	2	195	195	Salem, S.C.	Pumped Storage	Peaking
Jocassee	3	195	195	Salem, S.C.	Pumped Storage	Peaking
Jocassee	4	195	195	Salem, S.C.	Pumped Storage	Peaking
Bad Creek	1	340	340	Salem, S.C.	Pumped Storage	Peaking
Bad Creek	2	340	340	Salem, S.C.	Pumped Storage	Peaking
Bad Creek	3	340	340	Salem, S.C.	Pumped Storage	Peaking
Bad Creek	4	340	340	Salem, S.C.	Pumped Storage	Peaking
Total Pump. Storage		2,140	2,140			

Hydro						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
99 Islands	1	4.2	4.2	Blacksburg, S.C.	Hydro	Peaking
99 Islands	2	3.4	3.4	Blacksburg, S.C.	Hydro	Peaking
99 Islands	3	4.2	4.2	Blacksburg, S.C.	Hydro	Peaking
99 Islands	4	3.4	3.4	Blacksburg, S.C.	Hydro	Peaking
99 Islands	5	0	0	Blacksburg, S.C.	Hydro	Peaking
99 Islands	6	0	0	Blacksburg, S.C.	Hydro	Peaking
Bear Creek	1	9.5	9.5	Tuckasegee, N.C.	Hydro	Peaking
Bridgewater	1	15	15	Morganton, N.C.	Hydro	Peaking
Bridgewater	2	15	15	Morganton, N.C.	Hydro	Peaking
Bridgewater	3	1.5	1.5	Morganton, N.C.	Hydro	Peaking
Bryson City	1	0.5	0.5	Whittier, N.C.	Hydro	Peaking
Bryson City	2	0.4	0.4	Whittier, N.C.	Hydro	Peaking
Cedar Cliff	1	6.4	6.4	Tuckasegee, N.C.	Hydro	Peaking
Cedar Cliff	2	0.4	0.4	Tuckasegee, N.C.	Hydro	Peaking
Cedar Creek	1	15	15	Great Falls, S.C.	Hydro	Peaking
Cedar Creek	2	15	15	Great Falls, S.C.	Hydro	Peaking
Cedar Creek	3	15	15	Great Falls, S.C.	Hydro	Peaking
Cowans Ford	1	81	81	Stanley, N.C.	Hydro	Peaking
Cowans Ford	2	81	81	Stanley, N.C.	Hydro	Peaking
Cowans Ford	3	81	81	Stanley, N.C.	Hydro	Peaking
Cowans Ford	4	81	81	Stanley, N.C.	Hydro	Peaking
Dearborn	1	14	14	Great Falls, S.C.	Hydro	Peaking
Dearborn	2	14	14	Great Falls, S.C.	Hydro	Peaking
Dearborn	3	14	14	Great Falls, S.C.	Hydro	Peaking
Fishing Creek	1	11	11	Great Falls, S.C.	Hydro	Peaking
Fishing Creek	2	10	10	Great Falls, S.C.	Hydro	Peaking
Fishing Creek	3	10	10	Great Falls, S.C.	Hydro	Peaking
Fishing Creek	4	11	11	Great Falls, S.C.	Hydro	Peaking
Fishing Creek	5	8	8	Great Falls, S.C.	Hydro	Peaking
Franklin	1	0.5	0.5	Franklin, N.C.	Hydro	Peaking
Franklin	2	0.5	0.5	Franklin, N.C.	Hydro	Peaking
Gaston Shoals	3	0	0	Blacksburg, S.C.	Hydro	Peaking
Gaston Shoals	4	0	0	Blacksburg, S.C.	Hydro	Peaking
Gaston Shoals	5	2	2	Blacksburg, S.C.	Hydro	Peaking
Gaston Shoals	6	2.5	2.5	Blacksburg, S.C.	Hydro	Peaking

Hydro (Cont.)						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Great Falls	1	3	3	Great Falls, S.C.	Hydro	Peaking
Great Falls	2	3	3	Great Falls, S.C.	Hydro	Peaking
Great Falls	5	3	3	Great Falls, S.C.	Hydro	Peaking
Great Falls	6	3	3	Great Falls, S.C.	Hydro	Peaking
Keowee	1	76	76	Seneca, S.C.	Hydro	Peaking
Keowee	2	76	76	Seneca, S.C.	Hydro	Peaking
Lookout Shoals	1	9.0	9.0	Statesville, N.C.	Hydro	Peaking
Lookout Shoals	2	9.0	9.0	Statesville, N.C.	Hydro	Peaking
Lookout Shoals	3	9.0	9.0	Statesville, N.C.	Hydro	Peaking
Mission	1	0.6	0.6	Murphy, N.C.	Hydro	Peaking
Mission	2	0.6	0.6	Murphy, N.C.	Hydro	Peaking
Mission	3	0.6	0.6	Murphy, N.C.	Hydro	Peaking
Mountain Island	1	14	14	Mount Holly, N.C.	Hydro	Peaking
Mountain Island	2	14	14	Mount Holly, N.C.	Hydro	Peaking
Mountain Island	3	17	17	Mount Holly, N.C.	Hydro	Peaking
Mountain Island	4	17	17	Mount Holly, N.C.	Hydro	Peaking
Nantahala	1	50	50	Topton, N.C.	Hydro	Peaking
Oxford	1	20	20	Conover, N.C.	Hydro	Peaking
Oxford	2	20	20	Conover, N.C.	Hydro	Peaking
Queens Creek	1	1.4	1.4	Topton, N.C.	Hydro	Peaking
Rhodhiss	1	9.5	9.5	Rhodhiss, N.C.	Hydro	Peaking
Rhodhiss	2	11.5	11.5	Rhodhiss, N.C.	Hydro	Peaking
Rhodhiss	3	12.4	12.4	Rhodhiss, N.C.	Hydro	Peaking
Tuxedo	1	3.2	3.2	Flat Rock, N.C.	Hydro	Peaking
Tuxedo	2	3.2	3.2	Flat Rock, N.C.	Hydro	Peaking
Tennessee Creek	1	9.8	9.8	Tuckasegee, N.C.	Hydro	Peaking
Thorpe	1	19.7	19.7	Tuckasegee, N.C.	Hydro	Peaking
Tuckasegee	1	2.5	2.5	Tuckasegee, N.C.	Hydro	Peaking
Wateree	1	17	17	Ridgeway, S.C.	Hydro	Peaking
Wateree	2	17	17	Ridgeway, S.C.	Hydro	Peaking
Wateree	3	17	17	Ridgeway, S.C.	Hydro	Peaking
Wateree	4	17	17	Ridgeway, S.C.	Hydro	Peaking
Wateree	5	17	17	Ridgeway, S.C.	Hydro	Peaking

Hydro (cont.)						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Wylie	1	18	18	Fort Mill, S.C.	Hydro	Peaking
Wylie	2	18	18	Fort Mill, S.C.	Hydro	Peaking
Wylie	3	18	18	Fort Mill, S.C.	Hydro	Peaking
Wylie	4	18	18	Fort Mill, S.C.	Hydro	Peaking
Total NC		627.7	627.7			
Total SC		477.7	477.7			
Total Hydro		1,105.4	1,105.4			

Solar						
		Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
NC Solar		.9	31.4	N.C.	Solar	Intermediate
Total Solar		.9	31.4			

Nuclear						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
McGuire	1	1199.0	1158.0	Huntersville, N.C.	Nuclear	Base
McGuire	2	1187.2	1157.6	Huntersville, N.C.	Nuclear	Base
Catawba	1	1198.7	1160.1	York, S.C.	Nuclear	Base
Catawba	2	1179.8	1150.1	York, S.C.	Nuclear	Base
Oconee	1	865	847	Seneca, S.C.	Nuclear	Base
Oconee	2	872	848	Seneca, S.C.	Nuclear	Base
Oconee	3	881	859	Seneca, S.C.	Nuclear	Base
Total NC		2,386.2	2,315.6			
Total SC		4,996.5	4,864.2			
Total Nuclear		7,382.7	7,179.8			

Total Generation Capability		
	Winter Capacity (MW)	**Summer Capacity (MW)**
TOTAL DEC SYSTEM - N.C.	14,696.8	14,042.7
TOTAL DEC SYSTEM – S.C.	8,467.2	8,118.9
TOTAL DEC SYSTEM	23,164.0	22,161.6

Note a: Unit information is provided by State, but resources are dispatched on a system-wide basis.

Note b: Cliffside also called the Rogers Energy Center

Note c: Catawba Units 1 and 2 capacity reflects 100% of the station's capability.
Note d: The Catawba units' multiple owners and their effective ownership percentages are:

Note e: WS Lee Combined Cycle (CC) Units CT11, CT12 and ST10 reflects 100% of the CC's capability and does not factor in the 100 MW of capacity owned by NCEMC. The DEC – NCEMC Joint-Owner contract includes an energy buyback provision for DEC of the capacity owned by NCEMC in the WS Lee CC facility.

Note f: Solar capacity ratings reflect contribution to winter and summer peak values.

Catawba Owner	Percent of Ownership
Duke Energy Carolinas	19.246%
North Carolina Electric Membership Corporation (NCEMC)	30.754%
NCMPA#1	37.5%
PMPA	12.5%

Note a: The capacity represented in this table is the total operating capacity addition and is not adjusted for the Joint Exchange Agreement for Catawba and McGuire. The adjusted values are utilized in the resource plan.
Note b: Capacity not reflected in Existing Generating Units and Ratings section.

Planned Additions/Uprates			
Unit	**Date**	**Winter MW**	**Summer MW**
Bad Creek 1	June 2023	65.0	65.0
Bad Creek 2	June 2020	65.0	65.0
Bad Creek 3	June 2021	65.0	65.0
Bad Creek 4	June 2022	65.0	65.0
Oconee 1	Jan 2023	15.0	15.0
Oconee 2	Jan 2022	15.0	15.0
Oconee 3	Jan 2024	15.0	15.0
Clemson CHP	Nov 2020	15.0	15.0

Retirements				
Unit and Plant Name	**Location**	**Capacity (MW) Summer**	**Fuel Type**	**Retirement Date**
Buck 3[a]	Salisbury, N.C.	75	Coal	05/15/11
Buck 4[a]	Salisbury, N.C.	38	Coal	05/15/11
Cliffside 1[a]	Cliffside, N.C.	38	Coal	10/1/11
Cliffside 2[a]	Cliffside, N.C.	38	Coal	10/1/11
Cliffside 3[a]	Cliffside, N.C.	61	Coal	10/1/11
Cliffside 4[a]	Cliffside, N.C.	61	Coal	10/1/11
Dan River 1[a]	Eden, N.C.	67	Coal	04/1/12
Dan River 2[a]	Eden, N.C.	67	Coal	04/1/12
Dan River 3[a]	Eden, N.C.	142	Coal	04/1/12
Buzzard Roost 6C[b]	Chappels, S.C.	22	Combustion Turbine	10/1/12
Buzzard Roost 7C[b]	Chappels, S.C.	22	Combustion Turbine	10/1/12
Buzzard Roost 8C	Chappels, S.C.	22	Combustion Turbine	10/1/12
Buzzard Roost 9C[b]	Chappels, S.C.	22	Combustion Turbine	10/1/12
Buzzard Roost 10C[b]	Chappels, S.C.	18	Combustion Turbine	10/1/12
Buzzard Roost 11C[b]	Chappels, S.C.	18	Combustion Turbine	10/1/12
Buzzard Roost 12C[b]	Chappels, S.C.	18	Combustion Turbine	10/1/12
Buzzard Roost 13C[b]	Chappels, S.C.	18	Combustion Turbine	10/1/12
Buzzard Roost 14C[b]	Chappels, S.C.	18	Combustion Turbine	10/1/12
Buzzard Roost 15C[b]	Chappels, S.C.	18	Combustion Turbine	10/1/12
Riverbend 8C[b]	Mt. Holly, N.C.	0	Combustion Turbine	10/1/12
Riverbend 9C[b]	Mt. Holly, N.C.	22	Combustion Turbine	10/1/12
Riverbend 10C[b]	Mt. Holly, N.C.	22	Combustion Turbine	10/1/12
Riverbend 11C[b]	Mt. Holly, N.C.	20	Combustion Turbine	10/1/12

*converted to NG

Retirements (cont.)				
Buck 7C [b]	Spencer, N.C.	25	Combustion Turbine	10/1/12
Buck 8C [b]	Spencer, N.C.	25	Combustion Turbine	10/1/12
Buck 9C [b]	Spencer, N.C.	12	Combustion Turbine	10/1/12
Dan River 4C [b]	Eden, N.C.	0	Combustion Turbine	10/1/12
Dan River 5C [b]	Eden, N.C.	24	Combustion Turbine	10/1/12
Dan River 6C [b]	Eden, N.C.	24	Combustion Turbine	10/1/12
Riverbend 4 [a]	Mt. Holly, N.C.	94	Coal	04/1/13
Riverbend 5 [a]	Mt. Holly, N.C.	94	Coal	04/1/13
Riverbend 6 [c]	Mt. Holly, N.C.	133	Coal	04/1/13
Riverbend 7 [c]	Mt. Holly, N.C.	133	Coal	04/1/13
Buck 5 [c]	Spencer, N.C.	128	Coal	04/1/13
Buck 6 [c]	Spencer, N.C.	128	Coal	04/1/13
Lee 1 [d]	Pelzer, S.C.	100	Coal	11/6/14
Lee 2 [d]	Pelzer, S.C.	100	Coal	11/6/14
Lee 3 [e]	Pelzer, S.C.	170	Coal	05/12/15*
Great Falls 3	Great Falls, S.C.	0	Hydro	05/31/18
Great Falls 4	Great Falls, S.C.	0	Hydro	05/31/18
Great Falls 7	Great Falls, S.C.	0	Hydro	05/31/18
Great Falls 8	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 1	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 2	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 3	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 4	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 5	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 6	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 7	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 8	Great Falls, S.C.	0	Hydro	05/31/18
Ninety-Nine Islands 5	Blacksburg, S.C.	0	Hydro	12/31/18
Ninety-Nine Islands 6	Blacksburg, S.C.	0	Hydro	12/31/18
	Total	2,037 MW		

Note a: Retirement assumptions associated with the conditions in the NCUC Order in Docket No. E-7, Sub 790, granting a CPCN to build Cliffside Unit 6.
Note b: The old fleet combustion turbines retirement dates were accelerated in 2009 based on derates, availability of replacement parts and the general condition of the remaining units.
Note c: The decision was made to retire Buck 5 and 6 and Riverbend 6 and 7 early on April 1, 2013. The original expected retirement date was April 15, 2015.
Note d: Lee Steam Units 1 and 2 were retired November 6, 2014.
Note e: The conversion of the Lee 3 coal unit to a natural gas unit was effective March 12, 2015.

Planning Assumptions – Unit Retirements [a,b]					
Unit & Plant Name	**Location**	**Winter Capacity (MW)**	**Summer Capacity (MW)**	**Fuel Type**	**Expected Retirement**
Allen 1	Belmont, NC	167	162	Coal	12/2024
Allen 2	Belmont, NC	167	162	Coal	12/2024
Allen 3	Belmont, NC	270	261	Coal	12/2024
Allen 4	Belmont, NC	267	257	Coal	12/2028
Allen 5	Belmont, NC	259	259	Coal	12/2028
Belews Creek 1	Belews Creek, NC	1,110	1,110	Coal	12/2038
Belews Creek 2	Belews Creek, NC	1,110	1,110	Coal	12/2038
Cliffside 5	Cliffside, NC	546	544	Coal	12/2032
Cliffside 6	Cliffside, NC	849	844	Coal	12/2048
Marshall 1	Terrell, NC	380	370	Coal	12/2034
Marshall 2	Terrell, NC	380	370	Coal	12/2034
Marshall 3	Terrell, NC	658	658	Coal	12/2034
Marshall 4	Terrell, NC	660	660	Coal	12/2034
Lee 3	Pelzer, SC	173	160	NG	12/2030
Queens Creek	Topton, NC	1.4	1.4	Hydro	12/2032
Total		6,997.4	6,928.4		

Note a: Retirement assumptions are for planning purposes only; retirement dates based on the most recent depreciation study approved as part of the most recent DEC rate case.

Note b: For planning purposes, the 2019 IRP Base Case assumes subsequent license renewal for existing nuclear facilities beginning at end of current operating licenses. Total planning retirements exclude nuclear capacities.

Operating License Renewal:

Operating License Renewal - Nuclear				
Plant and Unit Name	**Location**	**Original Operating License Expiration**	**Date of Approval**	**Extended Operating License Expiration**
Catawba Unit 1	York, SC	12/6/2024	12/5/2003	12/5/2043
Catawba Unit 2	York, SC	2/24/2026	12/5/2003	12/5/2043
McGuire Unit 1	Huntersville, NC	6/12/2021	12/5/2003	6/12/2041
McGuire Unit 2	Huntersville, NC	3/3/2023	12/5/2003	3/3/2043
Oconee Unit 1	Seneca, SC	2/6/2013	5/23/2000	2/6/2033
Oconee Unit 2	Seneca, SC	10/6/2013	5/23/2000	10/6/2033
Oconee Unit 3	Seneca, SC	7/19/2014	5/23/2000	7/19/2034

Note a: Base assumption is that all nuclear units will receive a subsequent license renewal.
Note b: Nuclear retirements based on the expiration of current operating license only used in sensitivity case.

Planned Operating License Renewal - Hydro				
Bad Creek (PS)(1-4)	Salem, SC	N/A	8/1/1977	7//31/2027
Jocassee (PS) (1-4)	Salem, SC	N/A	9/1/1966	8/31/2016
Cowans Ford (1-4)	Stanley, NC	8/31/2008	Pending	8/31/2064 (Est)
Keowee (1&2)	Seneca, SC	N/A	9/1/1966	8/31/2016
Rhodhiss (1-3)	Rhodhiss, NC	8/31/2008	Pending	8/31/2064 (Est)
Bridge Water (1-3)	Morganton, NC	8/31/2008	Pending	8/31/2064 (Est)
Oxford (1&2)	Conover, NC	8/31/2008	Pending	8/31/2064 (Est)
Lookout Shoals (1-3)	Statesville, NC	8/31/2008	Pending	8/31/2064 (Est)
Mountain Island (1-4)	Mount Holly, NC	8/31/2008	Pending	8/31/2064 (Est)
Wylie (1-4)	Fort Mill, SC	8/31/2008	Pending	8/31/2064 (Est)
Fishing Creek (1-5)	Great Falls, SC	8/31/2008	Pending	8/31/2064 (Est)
Great Falls (1-8)	Great Falls, SC	8/31/2008	Pending	8/31/2064 (Est)
Dearborn (1-3)	Great Falls, SC	8/31/2008	Pending	8/31/2064 (Est)
Rocky Creek (1-8)	Great Falls, SC	8/31/2008	Pending	8/31/2064 (Est)
Cedar Creek (1-3)	Great Falls, SC	8/31/2008	Pending	8/31/2064 (Est)

Planned Operating License Renewal – Hydro (cont.)				
Wateree (1-5)	Ridgeway, SC	8/31/2008	Pending	8/31/2064 (Est)
Gaston Shoals (3-6)	Blacksburg, SC	12/31/1993	6/1/1996	5/31/2036
Tuxedo (1&2)	Flat Rock, NC	N/A	N/A	N/A
Ninety Nine (1-6)	Blacksburg, SC	12/31/1993	6/1/1996	5/31/2036
Cedar Cliff (1)	Tuckasegee, NC	1/31/2006	5/1/2011	4/30/2041
Bear Creek (1)	Tuckasegee, NC	1/31/2006	5/1/2011	4/30/2041
Tennessee Creek (1)	Tuckasegee, NC	1/31/2006	5/1/2011	4/30/2041
Nantahala (1)	Topton, NC	2/28/2006	2/1/2012	1/31/2042
Queens Creek (1)	Topton, NC	9/30/2001	3/1/2002	2/29/2032
Thorpe (1)	Tuckasegee, NC	1/31/2006	5/1/2011	4/30/2041
Tuckasegee (1)	Tuckasegee, NC	1/31/2006	5/1/2011	4/30/2041
Bryson City (1&2)	Whittier, NC	7/31/2005	7/1/2011	6/30/2041
Franklin (1&2)	Franklin, NC	7/31/2005	9/1/2011	8/31/2041
Mission (1-3)	Murphy, NC	7/31/2005	10/1/2011	9/30/2041

13. WHOLESALE

The following information describes the tables included in this chapter.

Wholesale Sales Contracts

This aggregated table includes wholesale sales contracts that are included in the Spring 2019 Load Forecast.

Wholesale Purchase Contracts

This aggregated table includes all wholesale purchase contracts that are included as resources in the 2019 IRP.

Table 13-A Wholesale Sales Contracts

DEC Aggregated Wholesale Sales Contracts									
Commitment (MW)									
2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
1,647	1,669	1,636	1,608	1,621	1,635	1,647	1,661	1,676	1,690

Notes:

- Backstand contract values represent the reserve margin amount. For example, for NCEMC Backstand of Catawba 17% *579 = 98 MWs
- For wholesale contracts, Duke Carolinas/Duke Progress assumes all wholesale sales contracts will renew unless there is an indication that the contract will not be renewed.

Table 13-B Firm Wholesale Purchase Power Contracts

Purchased Power Contract	Summer Capacity (MW)	Location	Volume of Purchases (MWh) Jun 18-May 19
Peaking / Fuel Oil	21	NC	21,334
Peaking / Gas	91	NC/SC	599,934
Peaking / Hydro	8	GA/AL/SC	24,621
Base / Nuclear	51	NC	446,496
Base / Solar	0.6	NC	453
System	7	NC	52,118

Notes:
Data represented above represents contractual agreements. These resources may be modeled differently in the IRP.

14. FUEL COMMODITY PRICES

The following table provides the fuel commodity prices used in the 2019 IRP for natural gas, coal and fuel oil.

DEC Annual Average Fuel Prices, $/MMBtu			
	Natural Gas Henry Hub	Coal DEC Average	Fuel Oil Average
2020	$2.50	$2.68	$14.48
2021	$2.57	$2.66	$14.15
2022	$2.61	$2.67	$13.97
2023	$2.68	$2.75	$14.13
2024	$2.78	$3.07	$14.55
2025	$2.90	$3.39	$14.99
2026	$3.01	$3.71	$15.44
2027	$3.12	$4.03	$15.90
2028	$3.25	$4.35	$16.38
2029	$3.39	$4.67	$16.87
2030	$3.68	$4.78	$17.53
2031	$4.07	$4.93	$18.20
2032	$4.50	$5.06	$18.86
2033	$5.04	$5.20	$19.52
2034	$5.30	$5.35	$20.18

TABLE 15-A CROSS-REFERENCE TABLE

This section contains a cross-reference table, Table 15-A, that provides the document location of information required by both NCUC and PSCSC in this 2019 IRP Update report.

	REQUIREMENT:	CHAPTER LOCATION:
1.	Summary of significant amendments or revisions to most recently filed biennial report (including amendments to type and size of resources identified	Chapters 2, 4
2.	The electric utility's annual update must describe the impact of the updated base planning assumptions on the selected resource plan.	Chapter 8
3.	Short-Term Action Plan	Chapter 10
4.	REPS Compliance Plan	Attachment 1
5.	Renewable Energy Forecast	Chapter 6
6.	Most recent 10-year history and forecast of: • Customers by each customer class • Energy sales (mwh) by each customer class • Utilities summer and winter peak load	Chapter 5
7.	15-year table (w/ and w/o projected supply or demand side resources) of: • Peak loads for summer and winter seasons of each year • Annual energy forecasts • Reserve margins • Load duration curves • Effects of DR and EE programs on forecasted annual energy and peak loads	Chapters 5, 8
8.	Description of future supply-side resources including type of capacity / resource (MW rating, fuel source, base, intermediate, or peaking)	Chapter 8
9.	List of existing units in service with: • Type of fuel(s) used • Type of unit (base, int, peak) • Location of existing unit • List of units to be retired with location and date • List of units for which there are specific plans for life extension, refurbishment, or upgrading • Other changes to existing generating units that are expected to impact gen capability by 10% or 10 mw	Chapter 12
10.	Planned Generation Additions with: • Type of fuel used • Type of unit (MW rating, base, int, peak) • Location if determined • Summaries of analyses supporting any new gen additions included in its 15-year forecast	Chapters 8, 9, 10

	REQUIREMENT:	CHAPTER LOCATION:
11.	List of all NUG facilities • Facility name • Location • Primary fuel type • Capacity (base, int, peak) • Which are included in its total supply of resources	External document
12.	Commodity Fuel Prices	Chapter 14
13.	Cumulative resource additions necessary to meet load obligation & reserve margins	Chapters 8, 9, 10, 11

ATTACHMENT I:

The Duke Energy Carolinas NC Renewable Energy & Energy Efficiency Portfolio Standard (NC REPS) Compliance Plan

DUKE ENERGY CAROLINAS NC REPS COMPLIANCE PLAN CONTENTS:

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I. INTRODUCTION

Duke Energy Carolinas, LLC ("DEC" or "the Company") submits its annual Renewable Energy and Energy Efficiency Portfolio Standard ("NC REPS" or "REPS") Compliance Plan ("Compliance Plan") in accordance with NC Gen. Stat. § 62-133.8 and North Carolina Utilities Commission ("the Commission") Rule R8-67(b). This Compliance Plan, set forth in detail in Section II and Section III, provides the required information and outlines the Company's projected plans to comply with NC REPS for the period 2019 to 2021 ("the Planning Period"). Section IV addresses the cost implications of the Company's REPS Compliance Plan.

In 2007, the North Carolina General Assembly enacted Session Law 2007-397 (Senate Bill 3), codified in relevant part as NC Gen. Stat. § 62-133.8, in order to:

- Diversify the resources used to reliably meet the energy needs of consumers in the State;
- Provide greater energy security through the use of indigenous energy resources available within the State;
- Encourage private investment in renewable energy and energy efficiency; and
- Provide improved air quality and other benefits to energy consumers and citizens of the State.

As part of the broad policy initiatives listed above, Senate Bill 3 established the NC REPS, which requires the investor-owned utilities, electric membership corporations or co-operatives, and municipalities to procure or produce renewable energy, or achieve energy efficiency savings, in amounts equivalent to specified percentages of their respective retail megawatt-hour (MWh) sales from the prior calendar year.

Duke Energy Carolinas seeks to advance these State policies and comply with its REPS obligations through a diverse portfolio of cost-effective renewable energy and energy efficiency resources. Specifically, the key components of Duke Energy Carolinas' 2019 Compliance Plan include: (1) purchases of renewable energy certificates ("RECs"); (2) purchases of renewable biogas to generate RECs; (3) constructing and operating Company-owned renewable facilities; (4) energy efficiency programs that will generate savings that can be counted towards the Company's REPS obligation; and (5) research studies to enhance the Company's ability to comply with its future REPS obligations. The Company believes that these actions yield a diverse portfolio of qualifying resources and allow a flexible mechanism for compliance with the requirements of NC Gen. Stat. § 62-133.8.

In addition, the Company has undertaken, and will continue to undertake, specific regulatory and operational initiatives to support REPS compliance, including: (1) submission of regulatory applications to pursue reasonable and appropriate renewable energy and energy efficiency initiatives in support of the

Company's REPS compliance needs; (2) solicitation, review, and analysis of proposals from renewable energy suppliers offering RECs and diligent pursuit of the most attractive opportunities, as appropriate; and (3) development and implementation of administrative processes to manage the Company's REPS compliance operations, such as procuring and managing renewable resource contracts, accounting for RECs, safely interconnecting renewable energy suppliers, reporting renewable generation to the North Carolina Renewable Energy Tracking System ("NC-RETS"), and forecasting renewable resource availability and cost in the future.

The Company believes these actions collectively constitute a thorough and prudent plan for compliance with NC REPS and demonstrate the Company's commitment to pursue its renewable energy and energy efficiency strategies for the benefit of its customers.

II. REPS COMPLIANCE OBLIGATION

Duke Energy Carolinas calculates its NC REPS Compliance Obligations[1] for 2019, 2020, and 2021 based on interpretation of the statute (NC Gen. Stat. § 62-133.8), the Commission's rules implementing Senate Bill 3 (Rule R8-67), and subsequent Commission orders, as applied to the Company's actual or forecasted retail sales in the Planning Period, as well as the actual and forecasted retail sales of those wholesale customers for whom the Company is supplying REPS compliance services. The Company's wholesale customers for whom it supplies REPS compliance services are Rutherford Electric Membership Corporation, Blue Ridge Electric Membership Corporation, Town of Dallas, Town of Forest City, and the Town of Highlands (collectively referred to as "Wholesale" or "Wholesale Customers")[2]. The contracts for the City of Concord and the City of Kings Mountain terminated on December 31, 2018. Table 1 below shows the Company's retail and Wholesale customers' REPS Compliance Obligation.

[1] For the purposes of this Compliance Plan, Compliance Obligation is more specifically defined as the sum of Duke Energy Carolinas' native load obligations for both the Company's retail sales and for wholesale native load priority customers' retail sales for whom the Company is supplying REPS compliance. All references to the respective Set-Aside requirements, the General Requirements, and REPS Compliance Obligation of the Company include the aggregate obligations of both Duke Energy Carolinas and the Wholesale Customers. Also, for purposes of this Compliance Plan, all references to the compliance activities and plans of the Company shall encompass such activities and plans being undertaken by Duke Energy Carolinas on behalf of the Wholesale Customers.

[2] For purposes of this Compliance Plan, Retail Sales is defined as the sum of Duke Energy Carolinas retail sales and the retail sales of the Wholesale Customers for whom the Company is supplying REPS compliance.

Table 1: Duke Energy Carolinas' NC REPS Compliance Obligation

Compliance Year	Previous Year DEC Retail Sales (MWhs) (1)	Previous Year Wholesale Sales (MWhs) (1) (2)	Total Retail sales for REPS Compliance (MWhs)	Solar Set-Aside (RECs)	Swine Set-Aside (RECs)	Poultry Set-Aside (RECs)	REPS Requirement (%) (3)	Total REPS Compliance Obligation (RECs)
2019	59,480,703	2,696,189	62,176,892	124,354	43,524	313,611	10.0%	6,217,689
2020	58,795,597	2,645,822	61,441,419	122,883	43,009	403,214	10.0%	6,144,142
2021	58,776,391	2,666,945	61,443,336	122,887	86,021	403,214	12.5%	7,613,743

(1) Annual compliance REC requirements are determined based on prior-year MWh sales. Retail sales figures shown for compliance years 2020 and 2021, are estimates of 2019 and 2020 retail sales, respectively.
(2) DEC's contractual obligation to serve as designated utility compliance aggregator for two of its seven wholesale customers (City of Concord and City of Kings Mountain) for which it provides REPS compliance services ended effective December 31, 2018.
(3) 2021 REPS requirement is 12.5% of prior-year Retail MWh sales and 10.0% of prior-year Wholesale MWh sales.

As shown in Table 1, the Company's requirements in the Planning Period include the solar energy resource requirement ("Solar Set-Aside"), swine waste resource requirement ("Swine Waste Set-Aside"), and poultry waste resource requirement ("Poultry Waste Set-Aside"). In addition, the Company must also ensure that, in total, the RECs that it produces or procures, combined with energy efficiency savings, are an amount equivalent to 10% of its prior-year retail sales in compliance years 2019 and 2020, and 12.5% of its prior-year retail sales in compliance year 2021, taking into account the 2021 requirement for wholesale customers remains at 10% of prior-year sales. The Company refers to this as its Total Obligation. For clarification, the Company refers to its Total Obligation, net of the Solar, Swine Waste, and Poultry Waste Set-Aside requirements, as its General Requirement.

III. REPS COMPLIANCE PLAN

In accordance with Commission Rule R8-67b(1)(i), the Company describes its planned actions to comply with the Solar, Swine Waste, and Poultry Waste Set-Asides, as well as the General Requirement below. The discussion first addresses the Company's efforts to meet the Set-Aside requirements and then outlines the Company's efforts to meet its General Requirement in the Planning Period.

A. SOLAR ENERGY RESOURCES

Pursuant to NC Gen. Stat. § 62-133.8(d), the Company must produce or procure solar RECs equal to a minimum of 0.20% of the prior year's total electric energy in megawatt-hours (MWh) sold to retail customers in North Carolina in 2019, 2020 and 2021.

Based on the Company's actual retail sales in 2018, the Solar Set-Aside is 124,354 RECs in 2019. Based on forecasted retail sales, the Solar Set-Aside is projected to be approximately 122,883 RECs in 2020 and 122,887 RECs in 2021. The Company has fully satisfied and exceeded the minimum Solar Set-Aside requirements in the Planning Period through a combination of Power Purchase Agreements and Company-owned solar facilities, including those listed below.

- Monroe Solar Facility – 60MW, located in Union County, placed in service on March 29, 2017; and
- Mocksville Solar Facility – 15MW, located in Davie County, placed in service on December 16, 2016; and
- Woodleaf Solar Facility – 6 MW, located in Rowan County, placed in service on December 21, 2018.

Additional details with respect to the REC purchase agreements are set forth in Exhibit A.

B. SWINE WASTE-TO-ENERGY RESOURCES

Pursuant to NC Gen. Stat. § 62-133.8(e), as amended by the North Carolina Utilities Commission ("NCUC") *Order Modifying the Swine and Poultry Waste Set-Aside Requirement and Providing Other Relief*, Docket No. E-100, Sub 113 (October 2018), for compliance years 2019 and 2020, at least 0.07%, and in 2021, at least 0.14%, of prior-year total retail electric energy sold in aggregate by utilities in North Carolina must be supplied by energy derived from swine waste. The Company's Swine Waste Set-Aside is estimated to be 43,524 RECs in 2019, 43,009 RECs in 2020, and 86,021 RECs in 2021.

Swine waste-to-energy compliance challenges have been numerous and varied. Three paths to the creation of swine waste-to-energy RECs have been identified, although each faces unique challenges.

1. On-farm generation

Projects consisting of digestion and generation on a single farm or tight cluster of farms often face gas production and feedstock agreement challenges, as well as interconnection difficulties. The Company understands that many farms in NC are contract growers and have only limited term agreements with the integrators. Accordingly, many contract growers are not in a position to provide a firm supply of waste sufficient to support project financing. On July 27, 2017 Governor Cooper signed into law the "Competitive Energy Solutions for North Carolina" bill or House Bill 589 ("HB 589") (SL 2017-92), which includes establishing an expedited interconnection review process for swine and poultry waste facilities that are two megawatts or less in size. This provision should help overcome some of the interconnection difficulties projects have experienced in the past.

2. Centralized digestion

This type of system would benefit farmers that cannot individually construct and operate an anaerobic digester manure handling system on their own due to the capital expense or just don't have the number of animals required to operate a digester successfully or cost effectively. Farms located close to each other could share the cost of the centrally located digester system. The centralized digester operated by an individual or private company would carry out the operation and maintenance of the digester and its mechanical systems. It would have the same advantages as on-farm digesters of odor reduction, pathogen and weed seed destruction, biogas production and a stable effluent ready to fertilize fields and crops. A downside with centralized digestion exists if the liquid swine waste has to be transported to the central site. One project has overcome this risk by co-locating the facility adjacent to a swine processing plant. The Company recognizes that NIMBY ("Not In My Back Yard") issues may scuttle some developers' plans for overcoming fuel supply and interconnection problems faced by more rural, on-farm projects.

3. Directed biogas

Directed biogas[3] reduces costs by piping isolated methane to a central area where it is cleaned up and injected into a natural gas pipeline and moved to large, efficient combined cycle plants in the place of smaller, less-efficient reciprocating engines typical of other projects. Technological advances in this field have helped drive pricing down to comparable levels of on-site generation for swine projects. The Company has worked diligently with Piedmont Natural Gas Company, Inc. ("Piedmont") and other market participants to help develop specifications for injection and contracts that developers can utilize. Continued challenges in this area include pipeline interconnection costs, gas clean-up requirements prior to injection and the general lack of physical proximity between clusters of farms and pipeline infrastructure.

The Company has entered into one contract to purchase swine waste-derived directed biogas from projects in the Midwest and three contracts to purchase swine waste-derived directed biogas from projects in North Carolina. The project in the Midwest is online and producing RECs, and the North Carolina projects are expected to come online in 2020 and 2021. The Company continues to explore opportunities for additional directed biogas in North Carolina through discussions with developers as well as participation in a collaborative group working to deploy renewable natural gas in Eastern North Carolina.

[3] "Directed Biogas" is defined as pipeline quality methane, injected into the pipeline system, and nominated to Duke Energy Carolinas generating facilities; this methane is biogenically derived from Swine Waste, Poultry Waste, and general Biomass sources.

On June 19, 2018, the NCUC issued an *Order Approving Appendix F and Establishing a Pilot Program* in Docket No. G-9, Sub 698. This Order introduces some uncertainty surrounding the future of swine and poultry waste-derived directed biogas projects, as it establishes a three-year pilot program where Piedmont will provide information to the NCUC regarding the impact of Alternative Gas[4] on its system operations and its customers. Piedmont and other Alternative Gas suppliers may apply to the Commission to participate in the pilot program; however, it must be demonstrated to the Commission that such additions will be useful in gathering the information and data sought by the Commission. At the end of the three-year period, the Commission will consider additional modifications to Appendix F, which sets forth the terms and conditions under which Piedmont will accept Alternative Gas into its system, based on the experience gained during the pilot period. Therefore, since NCUC approval is now required for any new swine or poultry-derived biogas project to be accepted into the pilot program, there's an additional level of uncertainty surrounding new swine and poultry-derived directed biogas projects coming online and the timing of these projects. These factors have presented challenges to timely project development of these resources as well as the relatively high cost that will likely be required to ultimately develop and deliver RECs from swine and poultry waste fuel.

In an effort to meet compliance with the Swine Waste Set Aside, the Company (1) continues direct negotiations for additional supplies of both in-state and out-of-state resources; (2) continues support of the Loyd Ray Farms research and development project; (3) works diligently to understand the technological, permitting, and operational risks associated with various methods of producing qualifying swine RECs and to aid developers in overcoming those risks; when those risks cannot be overcome, the Company works with developers via contract amendments to adjust for outcomes that the developers believe are achievable based on new experience; (4) explores modifications to current biomass and set-asides contracts by working with developers to add swine waste to their fuel mix; (5) continues pursuit of swine-derived directed biogas from North Carolina facilities and directing such biogas to combined cycle plants for combustion and generation; (6) utilizes the broker market for out-of-state swine RECs available in the market; (7) engages the North Carolina Pork Council ("NCPC") in a project evaluation collaboration effort that will allow the Company and the NCPC to discuss project viability, as appropriate with respect to the Company's obligations to keep certain sensitive commercial information confidential; and (8) participates in the North Carolina Energy Policy Council Biogas Working Group.

[4] "Alternative Gas" is defined in Appendix F as gas capable of combustion in customer appliances or facilities which is similar in heat content and chemical characteristics to natural gas produced from traditional underground well sources and which is intended to act as a substitute or replacement for Natural Gas (as that term is defined in Piedmont's North Carolina Service Regulations). Alternative Gas shall include but not be limited to biogas, biomethane, and landfill gas, as well as any other type of natural gas equivalent produced or manufactured from sources other than traditional underground well sources.

In addition, in December 2017, DEC, together with Duke Energy Progress (jointly, "The Companies"), issued a Request for Proposals soliciting proposals for swine waste fueled biogas, the supply of electric power fueled by swine waste, or swine RECs. This RFP solicited up to 750,000 MMBtu (million British thermal units), or the equivalent in MWh (megawatt hours) which is approximately 110,000 MWh from project developers. The Companies received seven responses to the RFP, have evaluated the proposals, and have executed contracts with two of the projects. Under these contracts, the Company will purchase the swine-derived biogas generated by the facilities, one being built in Union County, NC and the other in Wilson County, NC, and use it for generating power at the Companies' combined cycle facilities. The two projects are due online in 2021.

Duke Energy Carolinas is in a position to comply with its Swine Waste Set-Aside requirements in 2019, but the Company's ability to comply in 2020 and 2021 is dependent on the performance of swine waste-to-energy developers under current contracts, particularly achievement of projected delivery requirements and commercial operation milestones. The Company understands that swine waste-to-energy projects have encountered difficulties in achieving the full REC output of their contracts due to issues including local opposition to siting of the facilities, the inability to secure firm and reliable sources of swine waste feedstock from waste producers in North Carolina, difficulties securing project financing and technological challenges encountered when ramping up production. In addition, after terminating four contracts for swine waste RECs since 2017 due to failure to perform, force majeure events and project bankruptcy, the Company was notified by another project in January 2019 that the project will not be continuing due to failure to operate. Therefore, in order to not completely deplete its swine REC banks due to the uncertainty of future compliance, the Company will submit a motion to the Commission for approval of a request to reduce the 2019 Swine Waste Set-Aside compliance requirement and delay subsequent increases by one year.

The Company remains actively engaged in seeking additional resources and continues to make every reasonable effort to comply with the Swine Waste Set-Aside requirements. Additional details with respect to the Company's compliance efforts and REC purchase agreements are set forth in Exhibit A and the Company's semiannual progress reports, filed confidentially in Docket No. E-100, Sub 113A.

C. POULTRY WASTE-TO-ENERGY RESOURCES

Pursuant to NC Gen. Stat. § 62-133.8(f), as amended by NCUC *Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief*, Docket No. E-100, Sub 113 (October 2018), for calendar year 2019, at least 700,000 MWhs, and for 2020 and 2021, at least 900,000 MWhs, or an equivalent amount of energy, shall be produced or procured each year from poultry waste, as defined per the Statute and additional clarifying Orders. As the Company's retail sales share of the State's total retail megawatt-hour sales is approximately 45%, the Company's Poultry Waste Set-Aside is estimated to be 313,611 RECs in 2019, 403,214 RECs in 2020, and 403,214 in 2021.

In an effort to meet compliance with the Poultry Waste Set-Aside, the Company (1) continues direct negotiations for additional supplies of both in-state and out-of-state resources with multiple counterparties; (2) works diligently to understand the technological, permitting, and operational risks associated with various methods of producing qualifying poultry RECs and to aid developers in overcoming those risks; when those risks cannot be overcome, the Company works with developers via contract amendments to adjust for more realistic outcomes; (3) explores leveraging current biomass contracts by working with developers to add poultry waste to their fuel mix; (4) explores adding thermal capabilities to current poultry sites to bolster REC production; (5) explores poultry-derived directed biogas at facilities located in North Carolina and directing such biogas to combined cycle plants for combustion and electric generation; (6) utilizes the broker market for out-of-state poultry RECs available in the market; and (7) participates in the North Carolina Energy Policy Council Biogas Working Group.

Duke Energy Carolinas is in a position to comply with its Poultry Waste Set-Aside requirement in 2019, but the Company's ability to procure sufficient volumes of RECs to meet its pro-rata share of the increased Poultry Waste Set-Aside requirements in 2020 and 2021 is dependent on the performance of poultry waste-to-energy developers under current contracts, particularly achievement of projected delivery requirements and commercial operation milestones. One new poultry waste-to-energy project is scheduled to come online in the third quarter of 2019. Three poultry waste-to-energy facilities that were previously operational encountered operational issues and were shut down in 2018 to perform plant modifications. Two facilities are already back online, and the third is expected back online in late 2019, but 2019 production will be lower than originally expected. In addition, the Company had to terminate one contract for out-of-state poultry waste RECs due to failure to perform. DEC's ability to comply in 2020 and 2021 is dependent on facilities producing at their contracted levels, and historical experience indicates that facilities usually experience some start-up issues and take time to reach full expected production levels. Ramping up to meet the increased compliance targets for 2020 - 2021 has been problematic because suppliers have either delayed projects or lowered the volume of RECs to be produced. The Company is, nevertheless, encouraged by the growing use of thermal poultry RECs and the proposals that it has recently received from developers.

In order for all electric suppliers to be able to meet the state-wide poultry waste set-aside requirement, the Company, along with the other North Carolina electric suppliers, will submit a motion to the Commission for approval of a request to reduce the 2019 Poultry Waste Set-Aside requirement and delay subsequent increases by one year.

The Company remains actively engaged in seeking additional resources and continues to make every reasonable effort to comply with the Poultry Waste Set-Aside requirements. Additional details with respect to the Company's compliance efforts and REC purchase agreements are set forth in Exhibit A and the Company's semiannual progress reports, filed confidentially in Docket No. E-100, Sub 113A.

D. GENERAL REQUIREMENT RESOURCES

Pursuant to NC Gen. Stat. § 62-133.8, DEC is required to comply with its Total Obligation by submitting for retirement a total volume of RECs equivalent to 10% of its prior-year retail and wholesale sales in compliance years 2019 and 2020, and 12.5% of its prior-year retail sales in compliance year 2021, taking into account the 2021 requirement for wholesale customers remains at 10% of prior-year sales. Based on the Company's actual retail sales in 2018, the Total Requirement is 6,217,689 RECs in 2019. Based on forecasted retail sales, the Total Requirement is projected to be approximately 6,144,142 RECs in 2020, and 7,613,743 RECs in 2021. This requirement net of the Solar, Swine Waste, and Poultry Waste Set-Aside requirements, referred to as the General Requirement, is estimated to be 5,736,201 RECs in 2019, 5,575,036 RECs in 2020, and 7,001,622 RECs in 2021. The various resource options available to the Company to meet the General Requirement are discussed below, as well as the Company's plan to meet the General Requirement with these resources. The Company has contracted for, or has a plan to procure, sufficient resources to meet its General Requirement in the Planning Period. The Company submits that the actions and plans described herein represent a reasonable and prudent plan for meeting the General Requirement.

1. Use of Solar Resources for General Requirement

Duke Energy Carolinas plans to meet a portion of the General Requirement with RECs from solar facilities. Solar energy has emerged as a predominant renewable energy resource in the Southeast, and the Company views the downward trend in solar equipment and installation costs over the past several years as a positive development. As such, the Company expects solar resources to contribute to our compliance efforts beyond the Solar Set-Aside minimum threshold for NC REPS during the Planning Period.

i. Net Metering Facilities

Under the current Net Metering for Renewable Energy Facilities Rider offered by DEC (Rider NM), a customer receiving electric service under a schedule other than a time-of-use schedule with demand rates shall provide any RECs to DEC at no cost. Per the NCUC's June 2018 *Order Approving Rider and Granting Waiver Request*, filed in Docket No. E-7, Sub 1113, since net metering generators are not individually metered, DEC is permitted to estimate the RECs generated by these facilities using the PVWatts Solar Calculator developed by the National Renewable Energy Laboratory. Thus, DEC will follow the calculations approved by the NCUC to estimate the number of RECs generated from net metering facilities and will use these RECs for REPS compliance.

ii. North Carolina Solar Rebate Program

North Carolina HB 589 introduced a solar rebate program, which offers incentives to residential and nonresidential customers for the installation of small customer owned or leased solar energy facilities participating in the Company's net metering tariff. The incentive is limited to 10 kilowatts alternating current ("kW AC") for residential solar installations and 100 kW AC for nonresidential solar installations. The program incentive shall be limited to 10,000 kW of installed capacity annually starting January 1, 2018 and continuing until December 31, 2022. Since all customers participating in the Solar Rebate Program must be participating in DEC's net metering tariff, DEC retains the rights to the RECs from these facilities, as described in the net metering section above. In addition, under HB 589, DEC shall be authorized to recover all reasonable and prudent costs of incentives provided to customers and program administrative costs through the REPS Rider.

2. Energy Efficiency

During the Planning Period, the Company plans to meet up to 25% of the Total Obligation with Energy Efficiency ("EE") savings in 2019 and 2020, and up to 40% of the Total Obligation with EE savings in 2021, which is the maximum allowable amount under NC Gen. Stat. § 62-133.7(b)(2)c. The Company continues to develop and offer its customers new and innovative EE programs that will deliver savings and count towards its future NC REPS requirements. Pursuant to Commission Rule R8-67b(1)(iii), the Company has attached a list of those EE measures that it plans to use toward REPS compliance, including projected impacts and a description of the measure, as Exhibit B.

3. Biomass Resources

Duke Energy Carolinas plans to meet a portion of the General Requirement through a variety of biomass resources, including landfill gas to energy, combined heat and power, and direct combustion of biomass fuels. The Company is purchasing RECs from multiple biomass facilities in the Carolinas, including landfill gas to energy facilities and biomass-fueled combined heat and power facilities, all of which qualify as renewable energy facilities. Please see Exhibit A for more information on each of these contracts.

Duke Energy Carolinas notes, however, that reliance on direct-combustion biomass remains limited in long-term planning horizons, in part due to continued uncertainties around the developable potential of such resources in the Carolinas and the projected availability of more cost-effective forms of renewable resources.

4. Hydroelectric Power

Duke Energy Carolinas plans to use hydroelectric power from four sources to meet a portion of the General Requirement in the Planning Period: (1) Duke-owned hydroelectric stations that are approved as new renewable energy facilities; (2) Duke-owned hydroelectric stations that are approved as renewable energy facilities; (3) Wholesale Customers' Southeastern Power Administration ("SEPA") allocations; and (4) hydroelectric generation suppliers whose facilities have received Qualifying Facility (QF or QF Hydro) status.

(1) In 2012, the Company received Commission approval for a new, incremental capacity addition at one of its hydro facilities, Bridgewater. The Company applies RECs generated by this facility toward the General Requirements of Duke Energy Carolinas' retail customers.

(2) The Company has received Commission approval for ten of its hydroelectric stations as renewable energy facilities. The Company continues to use, as appropriate, the RECs generated by these facilities to meet the General Requirements of Duke Energy Carolinas' Wholesale Customers, pursuant to NC Gen. Stat. § 62-33.8(c)(2)d. The Company sold five of these facilities, with the sale closing in August 2019. If the facilities obtain approval from the NCUC to be considered new renewable energy facilities, the Company may purchase RECs generated by these facilities for use toward the General Requirements of DEC's retail customers.

(3) Wholesale Customers may also bank and utilize hydroelectric resources arising from their full allocations of SEPA. When supplying compliance for the Wholesale Customers, the Company will ensure that hydroelectric resources do not comprise more than 30% of each Wholesale Customers' respective compliance portfolio, pursuant to NC Gen. Stat. § 62-133.8(c)(2)c.

(4) In addition, the Company is purchasing RECs from multiple QF Hydro facilities in the Carolinas and will use RECs from these facilities toward the General Requirements of Duke Energy Carolinas' retail and wholesale customers. Please see Exhibit A for more information on these contracts.

5. Wind

Duke Energy Carolinas considers wind a potential viable option to support increased diversity of the renewables portfolio and plans to meet a portion of the General Requirement with RECs from wind facilities. While the Company may rely upon wind resources for future REPS compliance, the extent and timing will depend on deliverability, policy changes and market prices. Additional opportunities may exist to transmit wind energy from out of state regions where wind is more prevalent into the Carolinas.

6. Competitive Procurement of Renewable Energy ("CPRE")

North Carolina HB 589 introduced a competitive procurement process for adding 2,660 MW (subject to adjustment) of additional renewable energy and capacity in the Carolinas, with proposals issued over a 45-month period beginning on February 21, 2018, when the NCUC approved the CPRE Program. Renewable energy facilities eligible to participate in the CPRE solicitation(s) include those facilities that use renewable energy resources identified in G. S. § 62-133.8(a)(8), the REPS statute. DEC plans to use the RECs acquired through the CPRE RFP solicitations as needed for its future REPS compliance requirements and has therefore included the planned MW allocation and timeline in its REPS compliance planning process. Please see the CPRE Program Plan, which is included as Attachment II to this IRP, for additional information.

E. SUMMARY OF RENEWABLE RESOURCES

The Company has evaluated, procured, and/or developed a variety of types of renewable energy and energy efficiency resources to meet its NC REPS requirements within the compliance Planning Period. As noted above, several risks and uncertainties exist across the various types of resources and the associated parameters of the NC REPS requirements. The Company continues to carefully monitor opportunities and unexpected developments across all facets of its compliance requirements. Duke Energy Carolinas submits that it has crafted a prudent, reasonable plan with a diversified balance of renewable resources that will allow the Company to comply with its NC REPS obligation over the Planning Period.

IV. <u>COST IMPLICATIONS OF REPS COMPLIANCE PLAN</u>

A. CURRENT AND PROJECTED AVOIDED COST RATES

The Current Avoided Energy and Capacity costs included in the table below represent key data elements used to determine the PP (NC) tariff rates filed for DEC in Docket No. E-100, Sub 158.

The "Energy" columns reflect the cost of fuel and variable O&M per kwh embedded in the filed tariff energy rates. The "Capacity" column is based on the installed cost and capacity rating of a combustion turbine unit as reflected in the filed capacity rates.

The Projected Avoided Energy Costs included below reflect updated estimates of the same data elements provided with the current costs. The capacity cost shown is a placeholder based on the current avoided cost filing.

The avoided costs contained herein are subject to change, including (but not limited to) fuel price projections, variable O&M estimates, turbine costs and equipment capability.

Table 2: Current and Projected Avoided Cost Rates Table

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B. PROJECTED TOTAL NORTH CAROLINA RETAIL AND WHOLESALE SALES AND YEAR-END NUMBER OF CUSTOMER ACCOUNTS BY CLASS

Table 3: Retail Sales for Retail and Wholesale Customers

	2018 Actual	2019 Forecast	2020 Forecast	2021 Forecast
Retail MWh Sales	59,480,703	58,795,597	58,776,391	58,969,171
Wholesale MWh Sales (1)	2,696,189	2,645,822	2,666,945	2,688,235
Total MWh Sales	62,176,892	61,441,419	61,443,336	61,657,406

The MWh sales reported above are those applicable to REPS compliance years 2019-2022, and represent actual MWh sales for 2018, and projected MWh sales for 2019-2021.

(1) DEC's contractual obligation to serve as designated utility compliance aggregator for two of its seven wholesale customers for which it provides REPS compliance services ended effective December 31, 2018. Totals above exclude amounts for those two customers, as DEC's plan to meet its combined retail and wholesale compliance requirement will not include the two customers beginning with the current compliance year 2019.

Table 4: Retail and Wholesale Year-end Number of Customer Accounts

	2018 Actual	2019 Projected	2020 Projected	2021 Projected
Residential Accts	1,866,080	1,889,489	1,912,434	1,935,569
General Accts	262,147	263,294	264,320	265,682
Industrial Accts	4,957	4,926	4,889	4,849

The number of accounts reported above are those applicable to the cost caps for compliance years 2019–2022, and represent the actual number of accounts for year-end 2018, and the projected number of accounts for year-end 2019–2021.

(1) DEC's contractual obligation to serve as designated utility compliance aggregator for two of its seven wholesale customers for which it provides REPS compliance services ended effective December 31, 2018. Totals for 2018-2021 above exclude amounts for those two customers, as DEC's plan to meet it combined retail and wholesale compliance requirement will not include the two customers beginning with the current compliance year 2019.

C. PROJECTED ANNUAL COST CAP COMPARISON OF TOTAL AND INCREMENTAL COSTS, REPS RIDER AND FUEL COST IMPACT

Projected compliance costs for the Planning Period are presented in the cost tables below by calendar year. The cost cap data is based on the number of accounts as reported above.

Table 5: Projected Annual Cost Caps and Fuel Related Cost Impact

	2019	2020	2021
Total projected REPS compliance costs	$ 101,284,652	$ 120,615,158	$ 146,376,518
Recovered through the Fuel Rider	$ 68,665,833	$ 77,842,358	$ 92,102,915
Total incremental costs (REPS Rider)	$ 32,618,820	$ 42,772,800	$ 54,273,603
Total including Regulatory Fee	$ 32,664,550	$ 42,832,766	$ 54,349,692
Projected Annual Cost Caps (REPS Rider)	$ 94,663,210	$ 95,436,123	$ 96,172,929

EXHIBIT A

Duke Energy Carolinas, LLC's 2019 REPS Compliance Plan
Duke Energy Carolinas' Renewable Resource Procurement from 3rd Parties
(signed contracts as of June 30, 2019)

[BEGIN CONFIDENTIAL]

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[redacted]

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EXHIBIT B

Duke Energy Carolinas, LLC's 2019 REPS Compliance Plan
Duke Energy Carolinas, LLC's EE Programs and Projected REPS Impacts

Forecast of Annual Energy Efficiency Impacts for the REPS Compliance Planning Period 2019-2021 (kWh)			
Residential Programs	**2019**	**2020**	**2021**
Energy Efficient Appliances and Devices	175,270,318	74,547,838	63,119,128
Energy Efficiency Education Program	6,323,667	6,212,768	6,150,880
Income Qualified EE & Weatherization Assistance	3,479,083	2,765,220	2,765,220
Multi-Family Energy Efficiency	17,531,974	22,102,292	20,995,213
My Home Energy Report	222,672,194	230,657,812	231,234,397
Residential Energy Assessments	4,690,392	9,375,891	9,171,526
Residential Smart $aver® Energy Efficiency	6,052,820	5,487,620	5,714,412
Sub Total	**436,020,448**	**351,149,442**	**339,150,777**
Non-Residential Programs	**2019**	**2020**	**2021**
Non-Res Smart $aver® Custom	10,079,304	37,401,574	48,888,729
Non-Res Smart $aver® Custom Assessment	1,257,656	3,760,754	3,760,754
Non-Res Smart $aver® Prescriptive	142,939,785	153,730,211	156,804,158
Non-Res Smart $aver® Performance Incentive	0	9,861,679	13,715,680
Small Business Energy Saver	50,347,111	43,456,192	37,389,394
EnergyWise for Business	1,754,046	1,859,686	1,859,686
Sub Total	**206,377,902**	**250,070,096**	**262,418,401**
Total	**642,398,350**	**601,219,538**	**601,569,177**

DEC Energy Efficiency Programs

DEC uses the following Energy Efficiency ("EE") programs in its IRP to efficiently and cost-effectively alter customer demands and reduce the long-run supply costs for energy and peak demand.

Residential Customer Programs

- Energy Efficient Appliances and Devices
- Energy Efficiency Education
- Income-Qualified Energy Efficiency and Weatherization Assistance
- Multi-Family Energy Efficiency
- My Home Energy Report
- Residential Energy Assessments
- Smart $aver® Energy Efficiency

Non-Residential Customer Programs

- Non-Residential Smart $aver® Custom
- Non-Residential Smart $aver® Custom Assessment
- Non-Residential Smart $aver® Prescriptive
- Non-Residential Smart $aver® Performance Incentive
- Small Business Energy Saver
- EnergyWise for Business

Residential EE Programs

Energy Efficient Appliances and Devices Program provides incentives to residential customers for installing energy efficient appliances and devices to drive reductions in energy usage. The program includes the following measures:

- Energy Efficient Lighting: DEC customers can take advantage of several program options and delivery mechanisms to improve lighting efficiency, including:
    a. The Free LED program offers free 9-watt A19 Light Emitting Diodes ("LED") lamps to install in high-use fixtures. The LEDs are offered through multiple channels to eligible customers. The on-demand ordering platform enables eligible customers to request LEDs and have them shipped directly to their homes.
    b. The Duke Energy Savings Store is an extension of the on-demand ordering platform enabling eligible customers to purchase specialty bulbs and have them shipped directly to

their homes. The Store offers a variety LEDs including: Reflector, Globe, Candelabra, 3-Way, Dimmable and A-Line type bulbs.

c. The Retail Lighting program partners with retailers and manufacturers across North and South Carolina to provide price markdowns on customer purchases of efficient lighting. Product mix includes Energy Star rated standard, reflector, and specialty LEDs, and fixtures. Participating retailers include a variety of channel types, including Big Box, DIY, Club, and Discount stores.

- Energy Efficient Water Heating and Usage: This program component encourages the adoption of low flow showerheads and faucet aerators, water heater insulation, pipe wrap, and thermostatic valve shower start devices.
- Other Energy Efficiency Products and Services: Other energy efficient measures recently added to the program are WiFi enabled smart thermostats and smart strips.

Energy Efficiency Education Program is an energy efficiency program available to students in grades K-12 enrolled in public and private schools who reside in households served by Duke Energy Carolinas. The Program provides principals and teachers with an innovative curriculum that educates students about energy, resources, how energy and resources are related, ways energy is wasted and how to be more energy efficient. The centerpiece of the current curriculum is a live theatrical production focused on concepts such as energy, renewable fuels and energy efficiency performed by two professional actors.

Following the performance, students are encouraged to complete a home energy survey with their family to receive an Energy Efficiency Starter Kit. The kit contains specific energy efficiency measures to reduce home energy consumption and is available at no cost to student households at participating schools. Teachers receive supportive educational material for classroom and student take home assignments. The workbooks, assignments and activities meet state curriculum requirements.

Income-Qualified Energy Efficiency and Weatherization Assistance Program consists of three distinct components designed to provide EE to different segments of its low-income customers:

- Neighborhood Energy Saver (NES) is available only to individually-metered residences served by Duke Energy Carolinas in neighborhoods selected by the Company, which are considered low-income based on third party and census data, which includes income level and household size. Neighborhoods targeted for participation in this program will typically have approximately 50% or more of the households with income below 200% of the poverty level established by the U.S. Government. This approach allows the Company to reach a larger audience of low income customers than traditional government agency flow-through methods.

The program provides customers with the direct installation of measures into the home to increase the EE and comfort level of the home. Additionally, customers receive EE education to encourage behavioral changes for managing energy usage and costs.

- Weatherization and Equipment Replacement Program ("WERP") recognizes the existence of customers whose EE needs surpass the standard low cost measure offerings provided through NES. WERP is available to income-qualified customers in the Duke Energy Carolinas service territory for existing, individually metered, single-family, condominiums, and mobile homes. Funds are available for weatherization measures and/or heating system replacement with a 15 or greater SEER heat pump. A full energy audit of the residence is used to determine the measures eligible for funding. Customers are placed into a tier based on energy usage, where Tier 1 provides up to $600 for energy efficiency services; while Tier 2 provides up to $4,000 for energy efficiency services, including insulation, thus allowing high energy users to receive more extensive weatherization measures.
- The Refrigerator Replacement Program ("RRP") includes, but is not limited to, replacement of inefficient operable refrigerators in low income households. The program will be available to homeowners, renters, and landlords with income qualified tenants that own a qualified appliance. Income eligibility for RRP will mirror the income eligibility standards for the North Carolina Weatherization Assistance Program.

WERP and RRP are delivered in coordination with State agencies that administer the State's weatherization programs.

Multi-Family Energy Efficiency Program provides energy efficient lighting and water measures to reduce energy usage in eligible multi-family properties. The Program allows Duke Energy Carolinas to utilize an alternative delivery channel which targets multi-family apartment complexes. The measures are installed in permanent fixtures by the program administrator or the property management staff. The program offers LEDs including A-Line, Globes and Candelabra bulbs and energy efficient water measures such as bath and kitchen faucet aerators, water saving showerheads and pipe wrap.

My Home Energy Report Program provides residential customers with a comparative usage report that engages and motivates customers by comparing energy use to similar residences in the same geographical area based upon the age, size and heating source of the home. The report also empowers customers to become more efficient by providing them with specific energy saving recommendations to improve the efficiency of their homes. The actionable energy savings tips, as well as measure-specific coupons, rebates or other Company program offers that may be included in a customer's report are based on that specific customer's energy profile.

The program includes an interactive online portal that allows customers to further engage and learn more about their energy use and opportunities to reduce usage. Electronic versions of the My Home Energy Report are sent to customers enrolled on the portal. In addition, all MyHER customers with an email address on file with the Company receive an electronic version of their report monthly.

Residential Energy Assessments Program provides eligible customers with a free in-home energy assessment, performed by a Building Performance Institute ("BPI") certified energy specialist and designed to help customers reduce energy usage and save money. The BPI certified energy specialist completes a 60 to 90 minute walk-through assessment of a customer's home and analyzes energy usage to identify energy savings opportunities. The energy specialist discusses behavioral and equipment modifications that can save energy and money with the customer. The customer also receives a customized report that identifies actions the customer can take to increase their home's efficiency.

In addition to a customized report, customers receive an energy efficiency starter kit with a variety of measures that can be directly installed by the energy specialist. The kit includes measures such as energy efficiency lighting, low flow shower head, low flow faucet aerators, outlet/switch gaskets, weather stripping and an energy saving tips booklet.

Smart $aver® Energy Efficiency Program offers measures that allow eligible Duke Energy Carolinas customers to take action and reduce energy consumption in their home. The Program offering provides incentives for the purchase and installation of eligible central air conditioner or heat pump replacements in addition to Quality Installations and Wi-Fi enabled Smart Thermostats when installed and programmed at the time of installation of the heating, ventilation and air conditioning ("HVAC") system. Program participants may also receive an incentive for attic insulation/air sealing, duct sealing, variable speed pool pumps, and heat pump water heaters.

The prescriptive and a-la-carte design of the program allows customers to implement individual, high priority measures in their homes without having to commit to multiple measures and higher price tags. A referral channel provides free, trusted referrals to customers seeking reliable, qualified contractors for their energy saving home improvement needs.

Non-Residential EE Programs

Non-Residential Smart $aver® Custom Program offers financial assistance to qualifying commercial, industrial and institutional customers (that have not opted-out) to enhance their ability to adopt and install cost-effective electrical energy efficiency projects. The Program is designed to meet the needs of the Company's customers with electrical energy saving projects involving more complicated or alternative technologies, or those measures not covered by the Non-Residential Smart

$aver Prescriptive Program. The intent of the Program is to encourage the implementation of energy efficiency projects that would not otherwise be completed without the Company's technical or financial assistance. Unlike the Non-Residential Smart $aver Prescriptive Program, the Program requires pre-approval prior to the project initiation. Proposed energy efficiency measures may be eligible for customer incentives if they clearly reduce electrical consumption and/or demand.

Non-Residential Smart $aver® Custom Assessment Program offers financial assistance to qualifying commercial, industrial, and institutional customers to help fund an energy assessment, retro-commissioning design assistance in order to identify energy efficiency conservation measures of an existing or new building(s) or system. The goal of the Program is to encourage the implementation of energy efficiency projects that would not otherwise be completed without the Company's technical and financial assistance. The detailed study and subsequent list of suggested energy efficiency measures will reduce energy costs with the intent of also helping customers utilize the Non-Residential Smart $aver® Custom and/or Prescriptive Programs. The program also provides new construction design assistance to help enable new construction, major renovations and additions beyond the applicable state energy code.

Non-Residential Smart $aver® Prescriptive Program provides incentives to Duke Energy Carolinas commercial and industrial customers to install high efficiency equipment in applications involving new construction and retrofits and to replace failed equipment. The program also uses incentives to encourage maintenance of existing equipment in order to reduce energy usage. In addition, the program encourages dealers and distributors (or market providers) to stock and provide these high efficiency alternatives to meet increased demand for the products. Prescriptive incentives are offered for a large variety of technologies, which are summarized below by technology, but for the purpose of reporting historical performance, all of the impacts are combined into a single Non-Residential Smart $aver® Prescriptive Program total.

- **Non-Residential Smart $aver® Energy Efficient Food Service Products** provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of new high efficiency food service equipment in new and existing non-residential establishments and repairs to maintain or enhance efficiency levels in currently installed equipment. Measures include, but are not limited to, commercial refrigerators and freezers, steam cookers, pre-rinse sprayers, vending machine controllers, and anti-sweat heater controls.
- **Non-Residential Smart $aver® Energy Efficient HVAC Products** provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of new high efficient HVAC equipment in new and existing non-residential

establishments and efficiency-directed repairs to maintain or enhance efficiency levels in currently installed equipment. Measures include, but are not limited to, chillers, unitary and rooftop air conditioners, programmable thermostats, and guest room energy management systems.

- **Non-Residential Smart $aver® Energy Efficient Information Technologies ("IT") Products** provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of high efficiency new IT equipment in new and existing non-residential establishments and efficiency-directed repairs to maintain or enhance efficiency levels in currently-installed equipment. Measures include, but are not limited to, Energy Star-rated desktop computers and servers, PC power management from network, server virtualization, variable frequency drives ("VFD") for computer room air conditioners and VFD for chilled water pumps.
- **Non-Residential Smart $aver® Energy Efficient Lighting Products** provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of new high efficiency lighting equipment in new and existing non-residential establishments and the efficiency-directed repairs to maintain or enhance efficiency levels in currently installed equipment. Measures include, but are not limited to, interior and exterior LED lamps and fixtures, reduced wattage and high performance T8 systems, T8 and T5 high bay fixtures, and occupancy sensors.
- **Non-Residential Smart $aver® Energy Efficient Process Equipment Products** provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of new high efficiency equipment in new and existing non-residential establishments and efficiency-directed repairs to maintain or enhance high efficiency levels in currently installed equipment. Measures include, but are not limited to, VFD air compressors, barrel wraps, and pellet dryer insulation.
- **Non-Residential Smart $aver® Energy Efficient Pumps and Drives Products** provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of new high efficiency equipment in new and existing non-residential establishments and efficiency-directed repairs to maintain or enhance efficiency levels in currently installed equipment. Measures include, but are not limited to, pumps and VFD on HVAC pumps and fans.

Small Business Energy Saver Program is designed to reduce energy usage by improving energy efficiency through the direct installation of eligible energy efficiency measures. Program measures address major end-uses in lighting, refrigeration, and HVAC applications. Program participants receive a free, no-obligation energy assessment of their facility followed by a recommendation of energy efficiency measures that could be installed in their facility along with the projected energy savings, costs of all materials and installation, and the amount of the up-front incentive the Company. The customer makes the final determination of which measures will be installed after receiving the results of the energy assessment. The implementation vendor schedules the installation of the energy efficiency measure at a convenient time for the customer, and electrical subcontractors perform the installation. Program participants must have an average annual demand of 180 kW or less per active account and not opted-out of the Company's EE/DSM Rider. Participants may be owner-occupied or tenant facilities with owner permission.

Non-Residential Smart $aver® Performance Incentive encourages the installation of new high efficiency equipment in new and existing nonresidential establishments as well as efficiency-related repair activities designed to maintain or enhance efficiency levels in currently installed equipment. The intent of the Program is to broaden participation in non-residential efficiency programs by providing incentives for projects that clearly reduce electrical consumption and/or demand, but may have previously been deemed too unpredictable to calculate an acceptably accurate savings amount. The types of projects covered by the Program include projects with some combination of unknown building conditions or system constraints, or uncertain operating, occupancy, or production schedules. This Program provides a platform to understand new technologies better.

The key difference between this program and the custom component of the Non-Residential Smart $aver Energy® Efficient Products and Assessment program is that Performance Incentive participants get paid based on actual measure performance, and involves the following two-step process.

- Incentive #1: For the portion of savings that are expected to be achieved with a high degree of confidence, an initial incentive is paid once the installation is complete.
- Incentive #2: After actual performance is measured and verified, the performance-based part of the incentive is paid. The amount of the payout is tied directly to the savings achieved by the measures.

EnergyWise for Business is both an energy efficiency and demand response program for non-residential customers. Program participants can choose between a Wi-Fi thermostat or load control switch that will be professionally installed for free on each air conditioning or heat pump unit. The Wi-Fi thermostat option provides both EE and DR savings opportunities, while the load control switch option only offers DR savings capability. Only the EE component of the program is assumed to provide energy savings.

- ***EE Component***

  Participants choosing the thermostat will be given access to a portal that will allow them to set schedules, adjust the temperature set points, and receive energy conservation tips and communications from DEC. In addition to the portal access, participants will also receive conservation period notifications, so they can make adjustments to their schedules or notify their employees of the upcoming conservation periods.

- ***DR Component***

  The DR portion of the program allows DEC to reduce the operation of participants' air conditioning units to mitigate system capacity constraints and improve reliability of the power grid. In addition to equipment choice, participants can also select the cycling level they prefer (i.e., a 30%, 50% or 75% reduction of the normal on/off cycle of the unit). During a conservation period, DEC will send a signal to the thermostat or switch to reduce the on time of the unit by the cycling percentage selected by the participant. Participating customers will receive a $50 annual bill credit for each unit at the 30% cycling level, $85 for 50% cycling, or $135 for 75% cycling. Participants that have a heat pump unit with electric resistance emergency/backup heat and choose the thermostat can also participate in a winter option that allows control of the emergency/back up heat at 100% cycling for an additional $25 annual bill credit. Participants will also be allowed to override two conservation periods per year.

DUKE ENERGY CAROLINAS

ATTACHMENT II:

The Duke Energy Carolinas Competitive Procurement of Renewable Energy (CPRE) Plan

Duke Energy Carolinas, LLC's & Duke Energy Progress, LLC's Competitive Procurement of Renewable Energy (CPRE) Program Plan Update September 1, 2019

Introduction

In accordance with North Carolina Utilities Commission ("NCUC" or the "Commission") Rule R8-71(g), Duke Energy Carolinas, LLC ("DEC"), and Duke Energy Progress, LLC ("DEP" and together with DEC, "Duke Energy" or "the Companies") provide this update to the Program Plan for the Companies' Competitive Procurement of Renewable Energy ("CPRE") Program ("Program").

The CPRE Program is being implemented pursuant to N.C. Gen. Stat. § 62-110.8, as enacted by North Carolina Session Law 2017-192 ("HB 589"). This updated Program Plan presents the Companies' current plans for implementing the CPRE Program. The following provides a brief summary of significant events since the Program Plan was filed on September 1, 2018, in Docket Nos. E-2, Sub 1159 and E-7, Sub 1156, as part of the annual Integrated Resource Plan filing.

On January 9, 2018, the NCUC approved Accion, Inc. to act as the independent administrator ("IA") of the CPRE Program by its *Order Approving the Independent Administrator of the CPRE Program* in Docket No. E-100, Sub 151.

On February 21, 2018, the NCUC issued its *Order Modifying and Approving Joint CPRE Program*. The Order directed certain modifications to the initial Program Guidelines, which were incorporated into the CPRE Tranche 1 RFP documents that served as the Companies' Guidelines for purposes of the Tranche 1 RFP.[1] .

On June 25, 2018, the NCUC issued its *Order Denying Joint Motion, Approving Pro Forma PPA, and Providing Other Relief*, specifically approving Duke Energy's final Tranche 1 PPA. The Companies then issued the final RFP to the IA on July 5, 2018, as required by section (f)(1)(vi).

On July 10, 2018, the IA issued the final Tranche 1 RFP documents opening the RFP to bids. The Tranche 1 submission period closed on October 9, 2018 and winning bids were announced on April 9, 2019

On July 2, 2019, the NCUC issued its *Order Modifying and Accepting CPRE Program Plan* establishing a timeline for Tranche 2 without significant departure from the Tranche 1 framework

[1] As explained in the Companies' letter filed on May 11, 2018, the Tranche 1 RFP summary document constituted the updated CPRE Program Guidelines as required under Rule R8-71(f)(1)(ii) and conformed with the requirement of the Commission's Program Order to modify the initial CPRE Program Guidelines.

On July 8, 2019 the contracting period for Tranche 1 closed.

The acceptance of proposals for Tranche 2 shall open on October 15, 2019 and close on December 15, 2019 subject to adjustment depending on the timing of the issuance of a final order in the Sub 158 Proceeding.

1. CPRE Compliance Plan

1.1. Implementation of Aggregate CPRE Program requirements

Under N.C. Gen. Stat. § 62-110.8(a), the Companies are responsible for procuring renewable energy and capacity through a competitive procurement program in a manner that allows the Companies to continue to reliably and cost-effectively serve customers' future energy needs. The Companies are required to procure energy and capacity from renewable energy facilities in the aggregate amount of 2,660 MW ("Initial Targeted Amount") through requests for proposals ("RFPs"). The CPRE RFPs must be reasonably allocated over a term of 45 months beginning with the Commission approval of the CPRE Program on February 21, 2018.

Renewable energy facilities eligible to participate in the CPRE RFPs include those facilities that use renewable energy resources identified in N.C. Gen. Stat. § 62-133.8(a)(8) but are limited to a nameplate capacity rating of 80 MW or less that are placed in service after the date of the electric public utility's initial competitive procurement. The renewable energy facilities to be developed or acquired by the Companies or procured from a third party through a power purchase agreement under the CPRE Program must also deliver to the Companies all of the environmental and renewable attributes associated with the power.

The Companies can satisfy the CPRE Program requirements through any of the following:

(i) Renewable energy facilities to be acquired from third parties and subsequently owned and operated by the Companies;

(ii) Self-developed renewable energy facilities to be constructed, owned, and operated by the Companies up to a 30% cap identified in N.C. Gen. Stat. § 62-110.8(b)(4)[2]; or

(iii) The purchase of renewable energy, capacity, and environmental and renewable attributes from renewable energy facilities owned and operated by third parties that commit to allow the Companies rights to dispatch, operate, and control the solicited renewable energy facilities in the same manner as the Companies' own generating resources.

[2] The Companies voluntarily agree to recognize both Self-developed Proposals, as well as third-party PPA Proposals offered by any Duke Energy affiliate bid into the CPRE RFP Solicitation(s), as being subject to the 30% cap.

Per N.C. Gen. Stat. § 62-110.8(b), electric public utilities may jointly or individually implement these aggregate competitive procurement requirements. The Companies plan to continue to jointly implement the CPRE Program.

1.2. Projected Uncontrolled Renewable Energy Generating Capacity

N.C. Gen. Stat. § 62-110.8(b)(1) provides that if prior to the end of the initial 45-month competitive procurement period, the Companies have executed PPAs and interconnection agreements for renewable energy and capacity within their Balancing Authorities ("BAs") that are not subject to economic dispatch or curtailment and were not procured pursuant to N.C. Gen. Stat. § 62-159.2 ("Transition MW Projects") having an aggregate capacity in excess of 3,500 MW, the Commission shall reduce the competitive procurement aggregate amount by the amount of such exceedance. If the aggregate capacity of such Transition MW Projects is less than 3,500 MW at the end of the initial 45-month competitive procurement period, the Commission shall require the Companies to conduct an additional competitive procurement in the amount of such deficit.

As of the end of July 2019, approximately 3,665MW of Transition MW Projects are installed or under construction, creating an excess of approximately 165 MW. Note, at time the initial Program Plan was filed in November, 2017, approximately 2,900 MW of Transition MW Projects was installed or under construction.

Error! Reference source not found. specifies additional projects that may contribute to the Transition MWs but do not have both a signed IA and a signed PPA. The range was derived based on applying a materialization factor to the projects that have an established LEO to sell to the Companies. This includes many MW from certain settlement agreements that enabled certain projects to retain the rights to previously established LEO's from older avoided cost dockets. This increase in the number of MW that have reached settlement agreements is the primary cause of the significant increase in the projected total number of Transition MWs. As previously noted, a project must have executed a PPA and an Interconnection Agreement prior to the end of the CPRE Procurement Period in order to qualify as a Transition MW. Given the uncertainty about the number of projects that will satisfy the statutory criteria, the Companies are currently projecting a range for total Transition MW of 4,300 to 4,900. Note that some percentage of these potential Transition MW may not be counted as Transition MW due to delays in the Interconnection process, but may still be constructed after the CPRE Program has concluded.

Figure 1. Potential Transition MW's

Consolidated Transition Summary	DEC	DEP	Total
Solar Connected	676	2,407	**3,083**
Non-Solar Connected	83	96	**179**
Additional Solar with a PPA/IA	91	312	**403**
Sub-Total	**850**	**2,815**	**3,665**
Potential Additional MW's*	350 to 480	265 to 780	**615 to 1260**
Total	**~1,200 to 1,300**	**~3,100 to 3,600**	**~4,300 to 4,900**

*Includes projects with a signed PPA, but no IA as well as projects with a LEO but no PPA. The upper end of the range is based on Duke's estimates of materialization rates for these projects. Lower end of range is a more conservative view of materialization rates and intended to bound potential outcomes.

The updated estimate for the Transition MWs shows that the Companies procurement through CPRE will be less than the initial 2,660 MW target. Note that the Companies' projections have assumed that there will be no re-allocation of capacity to the CPRE program for unsubscribed MW under G.S. 62-159.2 (Renewable Energy Procurement for Major Military Installations, Public Universities and Other Large Customers).

1.3. Tranche 1 Results

On April 9, 2019 the Independent Administrator completed the selection process and delivered final status notifications to each Market Participant in Tranche 1 of the CPRE RFP. The contracting period for Tranche 1 concluded on July 8, 2019. Below is a summary of results for DEC and DEP:

<u>600 MW DEC Request</u>

- 58 proposals ranging from 7 to 80 MW-AC totaling 2,733 MW
  - Median proposal was 50 MW
- All proposals were solar, 3 included storage
- 1,416 MW proposed in NC, 1,317 MW in SC
- 11 projects were contracted totaling 465 MW
  - 9 in NC totaling 415 MW; 2 in SC totaling 50 MW
  - 2 projects included battery energy storage

   - 2 DEC utility-owned projects selected (94 MW) and 3 Duke affiliate (Duke Energy Renewables “DER”) projects selected (95 MW)
   - Average all in delivered price ~$37.75; estimated savings versus avoided cost of $247.8 million over 20 year term

80 MW DEP Request

- 20 proposals ranging from 7 to 80 MW-AC totaling 1,231 MW
   - Median proposal was 75 MW
- All proposals were solar, 1 included storage
- 617 MW proposed in NC, 614 MW in SC
- 2 projects were contracted totaling 87 MW
   - 1 in NC totaling 80 MW; 1 in SC totaling 7 MW
   - Average all in delivered price ~$38.31; estimated savings versus avoided cost of $33.17 million over 20-year term

1.4. Planned RFP Solicitations

1.5. Allocations of Resources

As prescribed by N.C. Gen. Stat. § 62-110.8(c), the Companies have the authority to determine the location and allocated amount of each CPRE RFP, as well as the CPRE Total Obligation to be procured within their respective service territories taking into consideration:

(i) the State's desire to foster diversification of siting of renewable energy resources throughout the State;
(ii) the efficiency and reliability impacts of siting of additional renewable energy facilities in each public utility's service territory; and
(iii) the potential for increased delivered cost to a public utility's customers as a result of siting additional renewable energy facilities in a public utility's service territory, including additional costs of ancillary services that may be imposed due to the operational or locational characteristics of a specific renewable energy resource technology, such as non-dispatchability, unreliability of availability, and creation or exacerbation of system congestion that may increase redispatch costs.

The Companies are currently planning to allocate and procure the CPRE Program Total Obligation through the Tranche 1-3 CPRE RFP Solicitations, discussed above, by soliciting the amounts of Renewable Energy Resource capacity shown in **Error! Reference source not found.**. The total solicitation is impacted by the amount of Transition MWs. The calculation of potential additional Transition MWs is dynamic and uncertain so Figure 2 shows a range of potential solicitations for Tranche 3.

Figure 2. Planned CPRE Solicitation Targets by Tranche

	DEC (Approximate MW)	**DEP (Approximate MW)**
Tranche 1 - Contracted	**465**	**86**
Tranche 2 - Issued	600	80
Tranche 3	0 to 570*	0 to 80*
Total	1,065 to 1635	166 to 246

*If all potential additional Transition MWs materialize then Tranche 3 may not be necessary. The upper end of the range represents a low materialization estimate for potential additional transition MWs

This allocation reflects the same consideration that informed the Companies' initial allocation of MW as described in the Companies' initial Program Plan. The Companies' system operational experience integrating additional renewable energy resource capacity into the DEC and DEP BAs and distribution and transmission system operations, will inform the manner in which future CPRE Program Plans propose to allocate the remaining CPRE Program Procurement between the DEC and DEP service territories. As a result, the planned CPRE solicitation targets for DEC and DEP shown in Figure 2 are subject to change.

The Companies took into consideration the following factors prescribed by N.C. Gen. Stat. § 62-110.8(c) when establishing the allocation of MWs to DEC an DEP:

(i) Fostering Diversification of Siting of Additional Renewable Energy Resources[3]
The Companies' primary objective is to procure cost-effective renewable energy resource facilities that allow DEC and DEP to reliably dispatch, operate, and control the facilities in the same manner as utility-owned generating resources, while diversifying the siting of renewable energy facilities across the Companies' BAs. The CPRE Program recognizes the State's desire to foster diversification of additional renewable energy facilities and to more effectively integrate additional

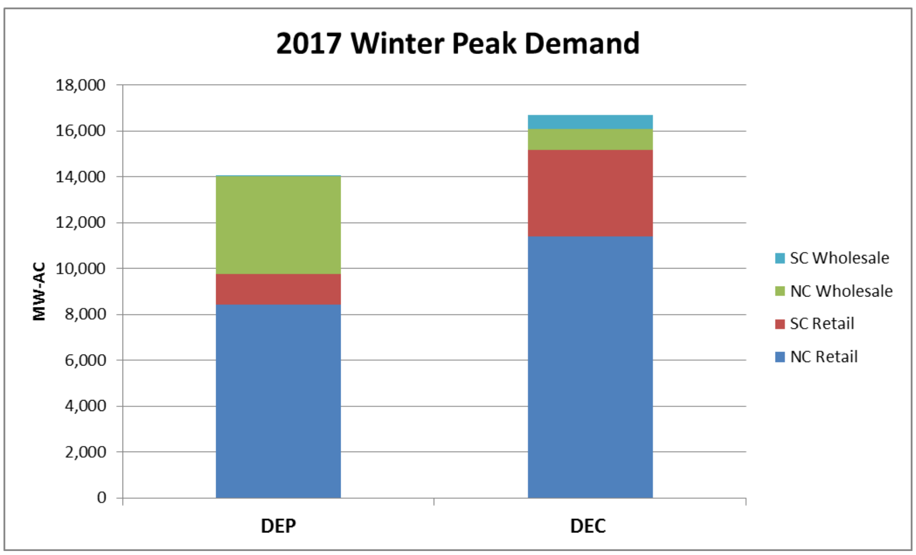
[3] All Proposals bid into the Tranche 1 CPRE RFP Solicitation were utility-scale solar generating facilities. The Companies have primarily analyzed the need for additional diversification of siting for utility-scale solar resources. The Companies may consider the need to analyze diversification of siting of other renewable energy resource technologies in future CPRE Program Plans, depending on interest from other technologies in the Tranche 2 CPRE RFP Solicitation.

utility-scale solar and other resources into the Companies' system operations. The Companies have developed the CPRE Program Plan allocations to meet the goals of diversifying the locations and avoiding inefficient or unreliable over-concentration of additional renewable energy facilities, and improving planning for the siting of additional facilities across the Companies' BAs and within their respective service territories throughout North Carolina and South Carolina.

Adding CPRE Utility-Scale Solar in DEC will Foster Improved Diversification as Existing Utility-Scale Solar is Concentrated in DEP

DEP is a smaller BA than DEC. In 2017, the DEC winter peak load was approximately 16,700 MW in comparison to the DEP winter peak load of approximately 14,200 MW, as seen in Figure 3.

Figure 3. 2017 Peak Load by BA[4]



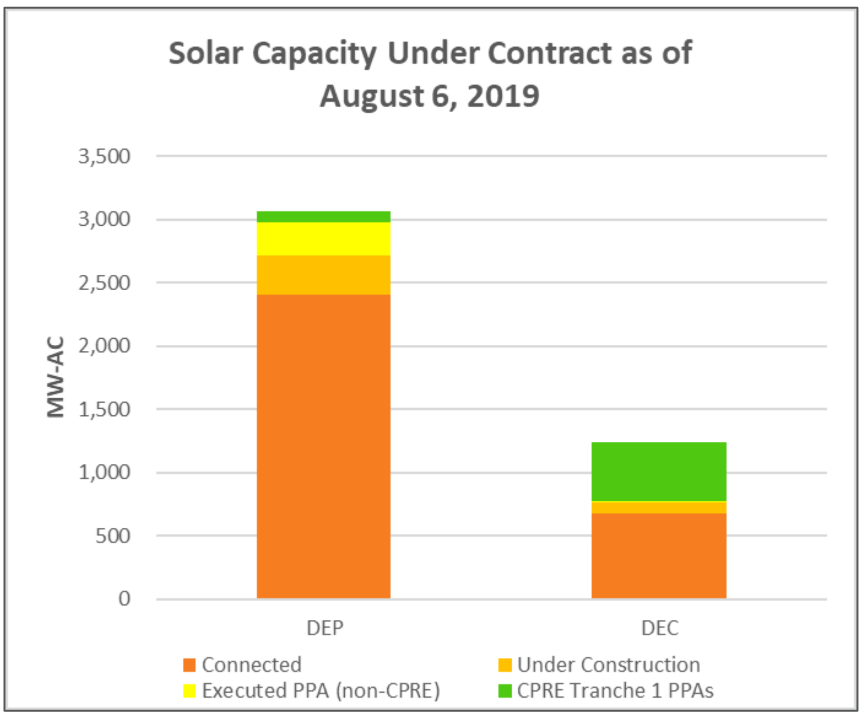
While DEP is a smaller BA, the Companies have experienced a significantly greater concentration of utility-scale solar development in DEP compared to DEC. As of August 6, 2019, the Companies are contractually obligated to purchase from third-party owners approximately 3,748 MW of solar under REPS and legacy PURPA contracts, in addition to 225 MW of utility-owned solar, and excluding CPRE Tranche 1 contracts. As shown in **Error! Reference source not found.**, this utility-scale solar growth has been especially significant in DEP, where approximately 80% of the total non-CPRE MWs under contract are located.

[4] Peak demand values shown in **Error! Reference source not found.** are for 2017 winter peak production demand allocators from the 2018 Cost of Service study.

If the total solar energy capacity in DEC and DEP were to be spread across the service territories based on their respective utilities' peak load, the DEC service territory should have approximately 60% of the solar energy capacity rather than its current ~20%.

To achieve the goals of diversifying the siting of renewable energy facilities throughout the Companies' service territories in a manner that promotes efficiency, reliability, and mitigates cost impact on the Companies' customers, the Companies' Tranche 1 RFP, as well as the planned total CPRE Program procurement allocation (provided in **Error! Reference source not found.**), seeks proposals primarily in the DEC service territory in North Carolina and South Carolina. If the Transition MW proceed as expected and the CPRE targets are met with primarily or all solar capacity, the resulting composition is a more balanced split of solar capacity between DEC and DEP.

Figure 4. Solar Capacity under Contract as of August 6, 2019



(ii) System Operations and Reliability Impacts

In developing the proposed allocation of CPRE Program resources between the DEP and DEC service territories, the Companies also considered the operational efficiency and reliability impacts of siting additional renewable energy facilities within the DEC and DEP BAs. The highly concentrated levels of uncontrolled legacy PURPA contract solar that are currently installed, under construction, and under contract to be installed in the DEP BA has caused the Companies to primarily allocate the planned CPRE Program procurement towards the larger DEC BA, where significantly less utility-scale solar is installed today. The Companies' planned CPRE Program allocation between the DEC and DEP BAs is also supported by the growing levels of operationally excess energy and increasingly steep ramping requirements in the DEP BA.

Independent BA System Operations Basics

DEP and DEC are each independent BAs responsible for maintaining compliance with North American Electric Reliability Corporation ("NERC") reliability standards to ensure reliable operations on their systems, as well as managing power flows between their systems and other utility systems. DEP and DEC must independently control their respective network resources to meet system loads and maintain compliance with reliability regulations within their separate BAs. Each BA must independently comply with NERC's mandatory Reliability Standards on a unified basis across the entire BA that encompasses territory in both North Carolina and South Carolina.

DEP's and DEC's system operators independently plan and operate each BA's generating resources to reliably meet increasing and decreasing intra-day and day-ahead system loads within reliability and generating unit availability and operating limits. These reliability requirements place the burden on the DEP and DEC BAs to balance generation resources (including new dispatchable CPRE renewable energy facilities), unscheduled energy injections (existing QF and renewable energy contracts), and load demand in real-time, all of which is essential to providing reliable firm native load service. To meet this objective, DEP and DEC must independently plan for and maintain a "Security Constrained Unit Commitment" of baseload and load-following assets, regulation resources, operating reserves, and spinning reserves, working together to ensure real-time frequency support and balancing.

The Companies' baseload[5] and must-run regulation units[6] represent the foundational resources necessary to meet load requirements, provide reliability, and meet mandatory NERC Reliability Standards. In the aggregate, the operationally constrained minimum reliable output of these generators represents the Lowest Reliability Operating Level ("LROL") of the BA's Security Constrained Unit Commitment. These essential generating resources cannot be de-committed in real time nor on an intra-day basis, because they must run within specified engineering levels and provide essential frequency and regulation support to the BA, and because they are needed to meet upcoming peak demands, such as the evening peak demands and next day peak demands. The

[5] The Companies' baseload units are firm native load generating resources such as nuclear, coal, and large natural gas combined cycle units that form the foundation of reliable service to meet the core system demand.
[6] Must-run regulation and regulation reserves resources are generating resources that must run to provide load balancing regulation and frequency regulation support to maintain reliability by supporting system frequency to the required target of 60 Hz in compliance with mandatory NERC Reliability Standards.

LROL represents the level on the BA at which continued energy injections into the BA above the BA's load causes the BA to have operationally excess energy.[7]

As has been discussed in recent avoided cost and IRP filings and in the initial CPRE plan filed in November, 2017, integration of additional solar is increasingly causing operationally excess energy and extreme ramping events in DEP. Further increases of solar generation in the DEP BA will continue to increase the risk of future potential NERC noncompliance and associated reliability risks, unless DEP has adequate dispatch control rights to proactively plan and dispatch generation resources on its system. Continued addition of solar generation in the DEP BA will exacerbate existing reliability challenges and increase the potential future risks of NERC noncompliance. The DEP BA's growing experience managing operationally excess energy and increasingly steep ramping requirements as additional unscheduled and uncontrolled solar generation comes online will also increase the likelihood of emergency curtailment in DEP. DEC currently is better positioned to accommodate additional solar resources without creating routine instances of operationally excess energy. However, DEC will also eventually face similar issues with operationally excess energy and ramping as additional solar generation is added to the system. This further strengthens the importance of the additional contractual curtailment rights available to DEC and DEP for the CPRE facilities.

(iii) Potential for Increased Delivered Cost; Ancillary Services

The Companies have evolved and will continue to evolve the modeling necessary to quantify the increased delivered costs and additional ancillary services needed to maintain NERC Balancing Authority compliance due to siting additional renewable energy facilities in DEC or DEP. Based on the prior two factors discussed, the vast majority of the MW's to be procured through CPRE have been allocated to DEC, however this third factor may influence future decisions to further adjust this allocation.

Allocation of Resources

In summary, the growing concentration of legacy PURPA solar facilities installed in the DEP BA, associated operational challenges and reliability risks on the DEP system and growing risks of uncompensated system emergency curtailments in DEP, and projections of DEP's and DEC's respective ability to reliably accommodate additional solar energy have informed the Companies' decision to allocate CPRE development primarily in the DEC service territory. The Companies anticipate that the designated allocation of CPRE Program capacity may evolve over the CPRE

[7] The Companies testified to the importance of managing system operations to maintain the LROL of the BA's Security Constrained Unit Commitment in the 2016 avoided cost proceeding. *See In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2016*, Pre-filed Direct Testimony of John S. Holeman, III, at 7-8, 12-13 Docket No E-100, Sub 148 (filed February 21, 2017).

Procurement Period, and the Companies intend to meet the CPRE Program requirements in a manner that ensures continued reliable electric service to customers while procuring cost-effective renewable energy resource capacity located within the DEC and DEP service territories. The Companies will update the planned allocation, if it is determined that changes are appropriate, through subsequent CPRE Program Plan filings.

1.6. Locational Designation

For purposes of the Tranche 1 CPRE RFP Solicitation, the Companies published Grid Locational Guidance information to the Independent Administrator's website on May 10, 2018 and also held a webinar open to all registrants to review and discuss these materials and answer questions from potential market participants and other interested parties. The Grid Locational Guidance was updated at conclusion of Tranche 1 and published to the Independent Administrator's website August 6, 2019 in advance of a webinar discussion on August 7, 2019. This guidance was intended to provide market participants with information on areas that have known transmission and distribution limitations as a result of the amount of existing or approved renewable energy facilities in the area. The goal of providing this grid locational guidance is to minimize the need for costly network upgrades to integrate CPRE renewable energy facilities and to provide information to market participants for use when planning development activities for the proposals to be submitted into the Tranche 2 CPRE RFP. The grid locational guidance information consists of a map and a table of circuits and substations that have known or increasing constraints.

The Companies continue to evaluate how to provide further updates to this guidance to provide potential participants in CPRE as much information as possible to enable the most cost effective proposals to be bid into the RFP.

2. CPRE Tranche 1 RFP Document and Pro forma PPA

The Tranche 1 RFP constitute the Companies' Program Guidelines for the completed solicitation.

<u>Comments on stakeholder engagement regarding the Pro forma PPA</u>

Consistent with the directive in the NCUC's order approving the CPRE Program in February 2018 in Docket Nos. E-2, Sub 1159 and E-7, Sub 1156, the Companies have substantially revised the PPA based on feedback received through two formal comment periods and continued to engage with stakeholders to determine if consensus can be reached on additional revisions to the PPA. More specifically, based on comments filed by stakeholders in Docket Nos. E-2, Sub 1159 and E-7, Sub 1156, the Companies made significant revisions to the November 2017 version of the Pro forma PPA before publishing this on May 11 as a pre-solicitation document for Tranche 1 of the RFP. Market Participants and other interested parties then had a second opportunity to review the

Pro Forma PPA (along with other draft solicitation documents). These comments were provided via the IA website. The Companies and the IA evaluated all of the comments received on the draft documents, including the Pro forma PPA and proceeded to make further, significant revisions to the Pro forma PPA before publishing the final PPA to be used in the Tranche 1 solicitation on June 8, 2018. The IA detailed the results of the comment period in their report which was completed on June 20, 2018 and posted to the website on June 21, 2018. In this report, the IA finds that the Companies gave full consideration to each observation and the IA agreed with the changes that the Companies elected to make to the PPA. On June 25, 2018 the Commission approved the final Pro forma PPA for use in Tranche 1 of the CPRE program.

The Companies held an additional stakeholder meeting regarding the PPA on August 7, 2018 via webinar. Approximately 50 participants called in to the webinar. The Companies presented a summary of the process that led to the Commission approval of the Tranche 1 PPA and summarized key changes made during the course of this process in response to comments and suggestions made by stakeholders. The Companies then opened the floor to questions from the webinar participants. Several of these questions were unrelated to the PPA and these individuals were directed to use the message board and Q&A process on the IA website. The comments on the PPA itself were very limited. The Companies provided responses to these comments on the call and reiterated the commitment to take these comments into consideration during the drafting of the Tranche 2 PPA document.

2. CPRE Tranche 2 RFP Document and Pro forma PPA

The Tranche 2 RFP document and pro-forma PPA are in review and subject to revisions during the Tranche 2 60-day pre-solicitation period which opened August 15, 2019. These documents will be posted to the Independent Administrators website when finalized: https://decprerfp2019.accionpower.com .

Comments on stakeholder engagement regarding the Pro forma PPA

Pursuant to the NCUC Order Modifying and Accepting CPRE Program Plan on July 2, 2019, the pre-solicitation process for Tranche 2 will allow for comment opportunity with stakeholders that will be supervised by the Independent Administrator. The Commission order requires monthly stakeholder meetings to address any issues not specifically addressed in the order and to reach consensus on Tranche 2 documents. The schedule for these meetings is provided as Figure 5.

Figure 5. Tranche 2 Stakeholder Meeting Schedule

Date	**Topic(s)**
August 7, 2019	Review of IA's final Tranche 1 Report Grid Locational Guidance Discussion concerning PPA Storage Protocols
September 12, 2019	PPA Terms and Conditions Grouping Study Base Case
October 10, 2019	General RFP Structure Asset Acquisition Discussion
November 13, 2019	Bidding Questions
December 12, 2019	To be determined

4. Other Program Plan Updates

Energy Storage

Recognizing the improving cost effectiveness of energy storage technologies and planned future adoption by the Companies and consideration by other utilities in recent competitive generation procurements, the Companies' made the determination that Renewable plus Storage Proposals—if thoughtfully integrated into the Companies' system operations—should be accepted for consideration in the CPRE RFP. For this reason, the Companies' Tranche 1 RFP and pro forma Tranche 1 PPA enabled market participants the option to offer Renewable plus Storage Proposals. Storage was included in 4 bids in Tranche 1 and 2 of these bids were ultimately awarded contracts.

To facilitate equitable consideration in the RFP, as well as to ensure effective integration of energy storage with the Companies' system operations under the CPRE Program framework, the Companies incorporated into the Pro Forma PPA a limited number of modifications, including a two-page "Energy Storage Protocol".

On May 23, 2019 the Companies participated in an NCUC CPRE Stakeholder Technical Conference to discuss modifications to the Energy Storage Protocol. The Companies provided an updated Energy Storage Protocol for Tranche 2 on August 7, 2019 for discussion in the initial Tranche 2 Stakeholder Meeting. The pre-solicitation feedback window is currently open.

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BUILDING A **SMARTER** ENERGY FUTURE℠

DEC NC and SC
<u>Front Cover Photos (Top to Bottom):</u>

Natural Gas: Dan River
Pump Storage: Bad Creek
Nuclear: McGuire
Hydro: Cowans Ford
Energy Efficiency

<u>Back Cover Photos (Top to Bottom):</u>

Uptown Greenville, SC
Duke Energy Transmission Line
Helping Our Customers
Duke Energy Lineman
Solar: McAlpine Creek Substation
Uptown Charlotte, NC