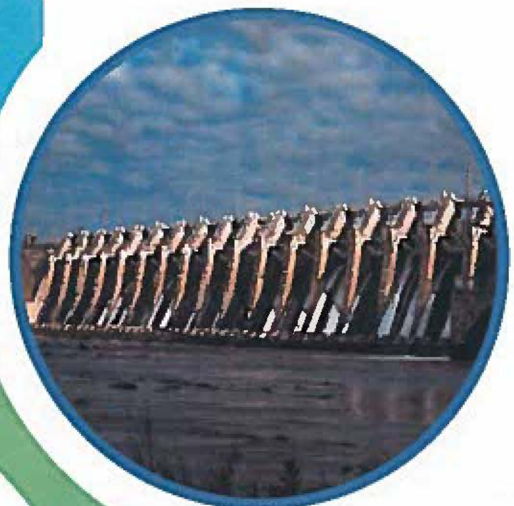
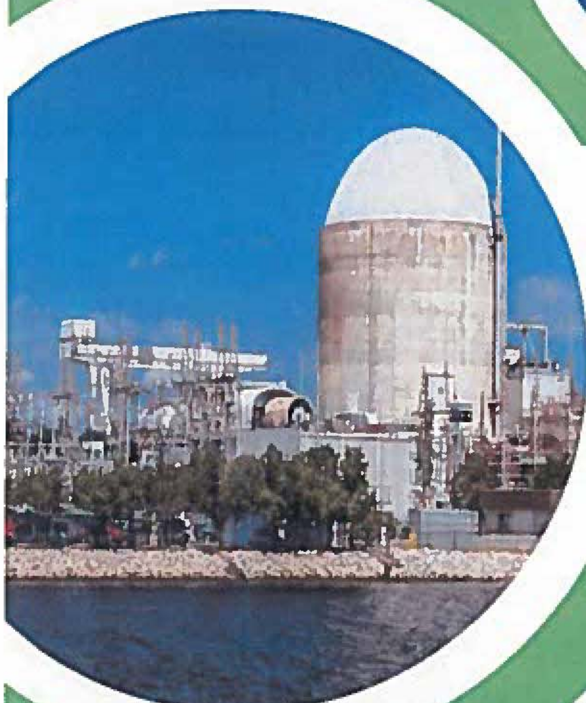


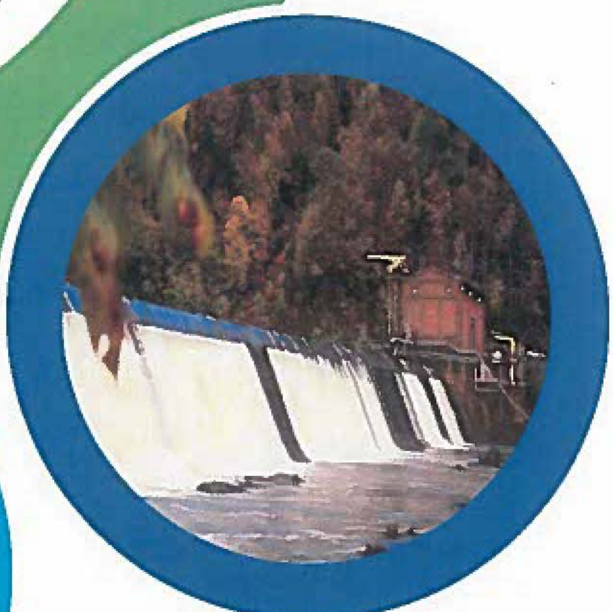
DUKE ENERGY PROGRESS



DOCKET NO. E-100, SUB 157

DUKE ENERGY PROGRESS

INTEGRATED RESOURCE PLAN UPDATE REPORT



2019

PUBLIC

DEP 2019 IRP CONTENTS:

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 Progress (DEP) who now serves more than 1.5 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. DEP 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. DEP 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 Carolinas (DEC), 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), DEP 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 DEP 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 a 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 DEP 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, DEP submits an IRP 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 cost and performance characteristics and other outside factors change.

The proposed plan will meet the following objectives:

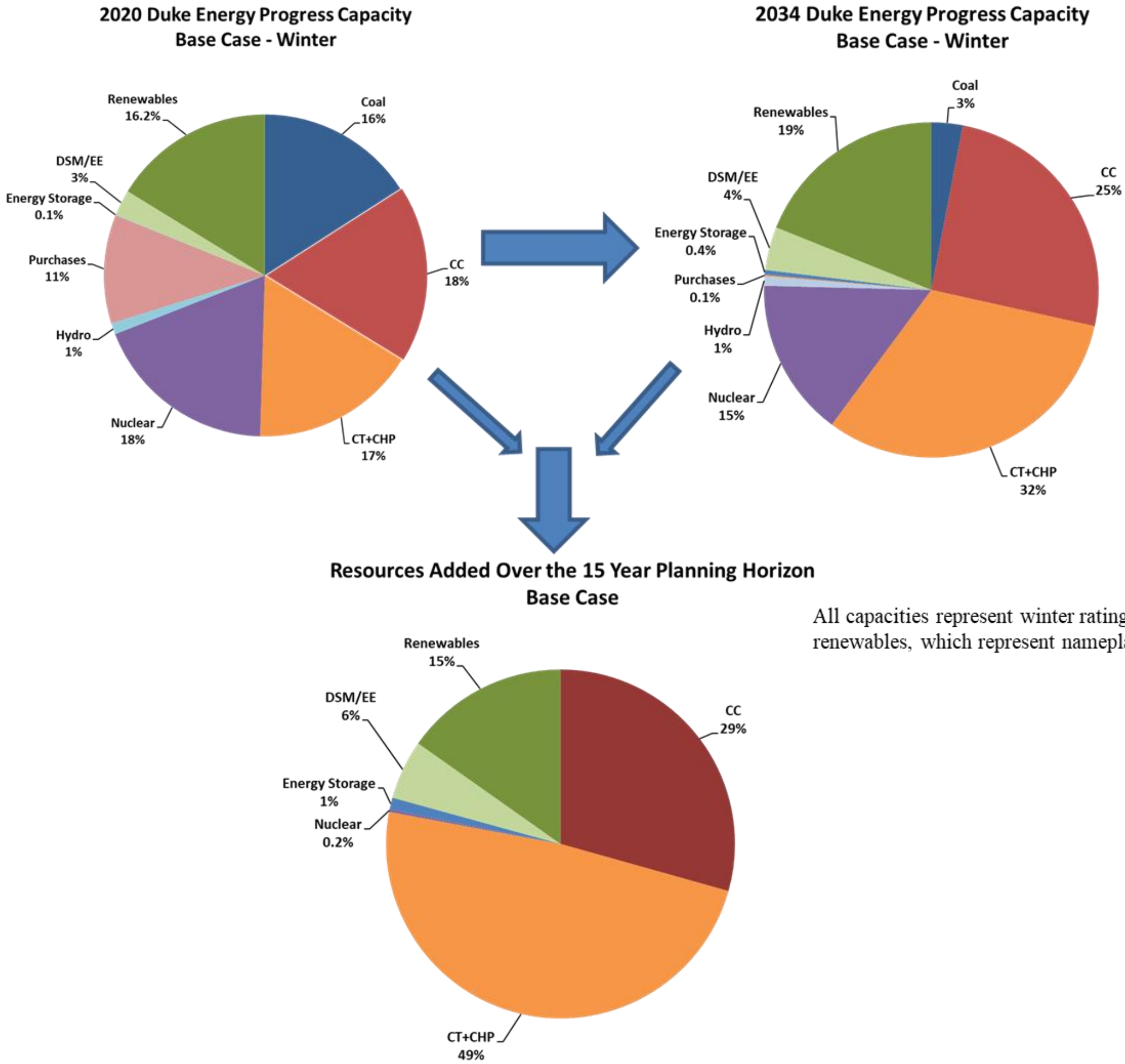
- Provide reliable electricity throughout the year, especially during periods of high peak demand such as cold winter mornings, by maintaining adequate planning reserve margins. Peak demand refers to the highest amount of electricity being consumed for any given hour across DEP's entire system.
- Select new resources at the lowest reasonable cost to customers. These resources include a balance of EE, DSM, renewable resources, 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, DEP 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. DEP has updated several key planning assumptions such as technology cost assumptions, fuel prices, renewable generation projections and the DEP load forecast.

As shown in the 2019 IRP Base Case, projected incremental needs are driven by load growth, contract expirations and the retirement of aging coal-fired and natural gas/oil resources. Of note, DEP has an increased load forecast relative to the prior IRP filing. A more detailed discussion of the load forecast can be found in Chapter 5. This increased forecast, coupled with contract expirations and retirement of aging natural gas/oil resources at DEP have left a short-term need for capacity in the mid-2020 timeframe. As mentioned in the Short-Term Action Plan, the Company has worked diligently to procure both renewable and traditional generation to meet this energy and capacity need in the near term. Those developments have been reflected in this year's IRP update.

The 2019 IRP seeks to achieve a reliable, economic long-term power supply through a balance of incremental renewable resources, EE, DSM, energy storage 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



All capacities represent winter ratings except renewables, which represent nameplate.

3. IRP PROCESS OVERVIEW

To meet the future needs of DEP'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 Contract Expirations**	=	**New Resource Needs**

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

DEP'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, DEP is utilizing a winter planning reserve margin of 17% in its planning process.

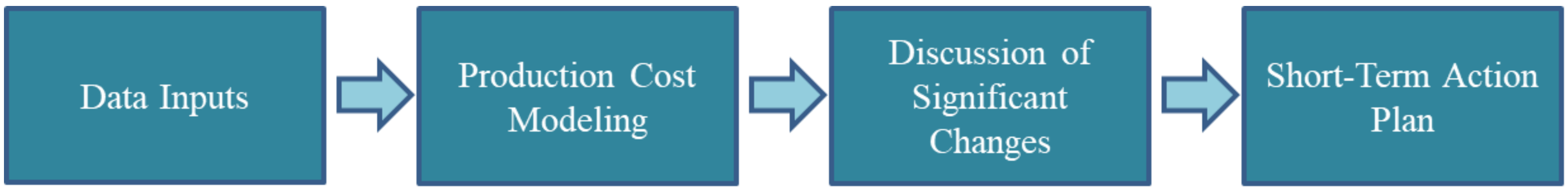
For the 2019 Update IRP, the Company presents a Base Case with a carbon tax beginning in 2025. However, remaining consistent with the Commission's Order to both include and exclude costs associated with carbon regulation, the current assumption of a carbon tax is intended to serve as a placeholder for 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



Data Inputs

- Load Forecast
- Fuel Price Forecasts
- Existing Generation
- Energy Efficiency
- Demand Response
- Renewable Resources
- New Generation Resources
- Technology Costs
- Environmental Legislation

Production Cost Modeling

- With CO_2 (Base Case)
- Without CO_2

Discussion of Significant Changes

- Since 2018 Biennial IRP
    - Load Forecast
    - Contract Expirations
    - Energy Storage
    - CHP
    - Transmission Planned or Under Construction

Short-Term Action Plan

- 2020 through 2024

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 Progress 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 1.3%.

The three largest sectors in the Commercial class are offices, education and retail. Commercial energy sales are expected to grow 0.8% 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 0.5% 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 DEP. 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%	1.1%	1.2%	1.0%	0.8%	0.7%
Includes impact of new EE programs	1.0%	0.9%	1.0%	0.8%	0.7%	0.5%

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	13,133	14,473	63,964
2021	13,182	14,434	64,040
2022	13,274	14,557	64,465
2023	13,404	14,649	65,043
2024	13,529	14,843	65,724
2025	13,663	14,965	66,330
2026	13,867	15,106	66,990
2027	13,995	15,326	67,718
2028	14,198	15,502	68,586
2029	14,359	15,690	69,295
2030	14,551	15,883	70,163
2031	14,735	16,073	71,241
2032	14,937	16,276	72,552
2033	15,136	16,461	73,374
2034	15,360	16,654	74,306
Avg. Annual Growth Rate	1.0%	0.9%	1.0%

Note: This table differs from Tables 9-A and 9-B due to a 150 MW firm sale in years 2020 – 2024.

b) Contract Expirations and Short-Term Need

The 2018 IRP reflected the impact of approximately 1,500 megawatts (MW) of purchase power contract expirations by 2025. The expiration of these contracts, along with the increase in the winter peak demand forecast and the planned retirement of nearly 500 MW of aging CT units at the Darlington CT Complex, created a significant short-term resource need. The Company has worked diligently to address this short-term need by issuing a Request for Proposals (RFP) resource solicitation in 2018. DEP received a significant response to the solicitation, and as a result, DEP is currently in the process of negotiating contracts with short-listed bidders to fulfill its near-term needs.

As discussed in Section 10, contracts that have been executed as part of this solicitation as of August 1, 2019 are included as firm designated resources in this year's IRP while others are still under negotiation. Contracts that have yet to be executed are not included as designated resources in the IRP and, as such, the IRP continues to reflect a resource need as early as the winter of 2020. The Company fully expects to fill this resource gap through future execution of these contracts.

c) Energy Storage

Building on the 2018 IRP which included placeholders for approximately 140 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 100 MW of storage coupled with solar over the planning horizon is driven by two factors. First, the results of the first tranche of CPRE 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.

[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.

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.

DEP is exploring and working with potential customers with good base thermal loads on a regulated Combined Heat and Power offer. 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 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. In DEP, discussions with potential steam hosts are currently underway.

Potential projects with industrial customers have been challenging due to credit requirements, contract length, estimated capital cost, and changes to natural gas price forecasts. As such, no projections for CHP have been included this DEP IRP update.

This is a difference from the 2018 IRP placeholders have been removed in the update::

2021: 22 MW (winter) / 20 MW (summer)
2022: 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 9.

e) Transmission Planned or Under Construction

This section lists the planned transmission line additions. A discussion of the adequacy of DEP's transmission system is also included. Table 4-D lists the transmission 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: DEP Transmission Line Additions

	Location		Capacity	Voltage	
Year	**From**	**To**	**MVA**	**KV**	**Comments**
2019	Roxboro Plant	Person (Hyco)	1084	230	Uprate
2020	Cleveland Matthews Rd. Tap	Cleveland Matthews Rd	621	230	New
2020	Sutton Plant	Wallace	580	230	Uprate
2020	Jacksonville	Grants Creek	1195	230	New
2020	Newport	Harlowe	681	230	New
2021	Vanderbilt	West Asheville	307	115	Upgrade
2021	Asheboro	Asheboro East North Line	307	115	Upgrade
2021	Sutton Plant	Castle Hayne North Line	239	115	Upgrade
2022	Baldwin Tap	Baldwin	209	115	New
2023	Chestnut Hills	Milburnie	202	115	Uprate

DEP has three transmission line projects, 161 kilovolt (kV) and above, currently under construction. These are the Cleveland Matthews Rd 230 kV Tap Line, the Jacksonville-Grants Creek 230 kV Line and the Newport-Harlowe 230 kV Line.

The remainder of this section provides information pursuant to the North Carolina Utility Commission Rule R8-62.

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 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 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:*

a. Commission docket number;
b. Location of end point(s);
c. Length;
d. Range of right-of-way width;
e. Range of tower heights;
f. Number of circuits;
g. Operating voltage;
h. Design capacity;

i. *Date construction started;*
j. *Projected in-service date;*

<u>Cleveland Matthews Road 230 kV Tap Line</u>

Project Description: Construct new 230 kV transmission line from the Erwin-Selma 230 kV Line in Johnston County to the Cleveland Matthews Road 230 kV Substation in Johnston County.

a. Docket number: E-2, Sub 1150
b. County location of end point(s); Johnston County
c. Approximate length; 11.5 miles
d. Typical right-of-way width for proposed type of line; 125 feet
e. Typical tower height for proposed type of line; 80 – 120 feet
f. Number of circuits; 1
g. Operating voltage; 230 kV
h. Design capacity; 621 MVA
i. Date construction started; March 2019
j. Projected in-service date; June 2020

<u>Jacksonville – Grants Creek 230 kV Line</u>

Project Description: Construct new 230 kV transmission line from the Jacksonville 230 kV Substation in Onslow County to the Grants Creek 230 kV Substation in Onslow County.

a. Docket number: E-2, Sub 1102
b. County location of end point(s); Onslow County
c. Approximate length; 15 miles
d. Typical right-of-way width for proposed type of line; 125 feet
e. Typical tower height for proposed type of line; 80 – 120 feet
f. Number of circuits; 1
g. Operating voltage; 230 kV
h. Design capacity; 1195 MVA
i. Date construction started; September 2018
j. Projected in-service date; June 2020

<u>Newport – Harlowe 230 kV Line</u>

Project Description: Construct new 230 kV transmission line from the Newport 230 kV Substation in Carteret County to the Harlowe 230 kV Substation in Carteret County.

a. Docket number: E-2, Sub 1113
b. County location of end point(s); Carteret County
c. Approximate length; 8 miles
d. Typical right-of-way width for proposed type of line; 125 feet
e. Typical tower height for proposed type of line; 80 – 120 feet
f. Number of circuits; 1
g. Operating voltage; 230 kV
h. Design capacity; 681 MVA
i. Date construction started; October 2018
j. Projected in-service date; June 2020

(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:

(3) For all other proposed lines, as the information becomes available, the following:

a. county location of end point(s);
b. approximate length;
c. typical right-of-way width for proposed type of line;
d. typical tower height for proposed type of line;
e. number of circuits;
f. operating voltage;
g. design capacity;
h. estimated date for starting construction (if more than 6 month delay from last report, explain); and
i. estimated in-service date (if more than 6-month delay from last report, explain). (NCUC Docket No. E-100, Sub 62, 12/4/92; NCUC Docket No. E-100, Sub 78A, 4/29/98.)

The following pages represent those projects in response to Rule R8-62 part (3).

Porters Neck 230 kV Tap Line

Project Description: Construct new 230 kV transmission line from the Castle Hayne-Folkstone 230 kV Line to the Porters Neck 230 kV Substation in New Hanover County.

a. County location of end point(s); New Hanover County
b. Approximate length; 4.5 miles
c. Typical right-of-way width for proposed type of line; 125 feet
d. Typical tower height for proposed type of line; 80 – 120 feet
e. Number of circuits; 1
f. Operating voltage; 230 kV
g. Design capacity; 442 MVA
h. Estimated date for starting construction; January 2022
i. Estimated in-service date; June 2023

DEP Transmission System Adequacy

DEP 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 DEP transmission model is incorporated into models used by regional reliability groups in developing plans to maintain interconnected transmission system reliability. DEP works with DEC, North Carolina Electric Membership Corporation (NCEMC) and ElectriCities to develop an annual NC Transmission Planning Collaborative (NCTPC) plan for the DEP and DEC systems in both North and South Carolina. In addition, transmission planning is coordinated with neighboring systems including Dominion Energy South Carolina (DESC) 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

DEP's Transmission Planning Summary 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. The transmission system is planned to ensure that no equipment overloads and adequate voltage is maintained to provide reliable service. The most stressful scenario is typically at projected peak load with certain equipment out of service. A thorough screening process is used to analyze the impact of potential equipment failures or other disturbances. As problems are identified, solutions are developed and evaluated.

Transmission planning and requests for transmission service and generator interconnection are interrelated to the resource planning process. DEP currently evaluates all transmission reservation requests for impact on transfer capability, as well as compliance with the Company's Transmission Planning Summary 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 Large and Small Generator Interconnection Procedures in the OATT and the North Carolina and South Carolina Interconnection Procedures.

SERC audits DEP every three years for compliance with NERC Reliability Standards. Specifically, the audit requires DEP 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 DEP in June 2019. DEP received "No Findings" from the audit team.

DEP 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. Each reliability group's 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 DEP's transmission system continues to provide reliable service to its native load and firm transmission customers.

5. LOAD FORECAST

Methodology

The Duke Energy Progress 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

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 1.3%.

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 0.8% 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 0.5% per year 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 Energy Information Administration (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 DEP'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 impacts of UEE on energy and peaks, 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	64,293	9	64,302	(454)	116	(338)	63,964
2021	64,556	32	64,587	(663)	116	(547)	64,040
2022	65,142	81	65,223	(875)	116	(759)	64,465
2023	65,852	164	66,016	(1,090)	117	(973)	65,043
2024	66,632	277	66,910	(1,303)	118	(1,186)	65,724
2025	67,312	409	67,722	(1,511)	119	(1,392)	66,330
2026	68,035	543	68,578	(1,710)	122	(1,588)	66,990
2027	68,833	658	69,491	(1,901)	128	(1,773)	67,718
2028	69,779	743	70,522	(2,084)	149	(1,936)	68,586
2029	70,554	798	71,352	(2,259)	202	(2,057)	69,295
2030	71,493	825	72,319	(2,430)	274	(2,156)	70,163
2031	72,652	837	73,488	(2,600)	353	(2,247)	71,241
2032	74,030	840	74,870	(2,772)	454	(2,318)	72,552
2033	74,907	840	75,747	(2,945)	573	(2,372)	73,374
2034	75,852	840	76,692	(3,120)	734	(2,386)	74,306

Customer Growth

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

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

Year	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Retail Customers
2009	1,207	215	5	2	1,429
2010	1,216	216	5	2	1,439
2011	1,221	217	4	2	1,445
2012	1,231	219	4	2	1,457
2013	1,242	222	4	2	1,470
2014	1,257	223	4	2	1,486
2015	1,275	226	4	2	1,507
2016	1,292	229	4	2	1,527
2017	1,310	232	4	1	1,547
2018	1,331	235	4	1	1,571
Avg. Annual Growth Rate	1.1%	1.0%	-1.3%	-8.1%	1.1%

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

Year	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Retail Customers
2020	1,358	240	4	1	1,603
2021	1,372	240	4	1	1,618
2022	1,388	240	4	1	1,633
2023	1,403	241	4	1	1,650
2024	1,420	242	4	1	1,667
2025	1,436	244	4	1	1,685
2026	1,451	245	4	1	1,702
2027	1,467	247	4	1	1,719
2028	1,482	248	4	1	1,735
2029	1,496	250	4	1	1,751
2030	1,511	251	4	1	1,767
2031	1,525	253	4	1	1,782
2032	1,538	254	4	1	1,797
2033	1,551	255	4	1	1,811
2034	1,565	256	4	1	1,826
Avg. Annual Growth Rate	1.0%	0.5%	-0.8%	0.0%	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)

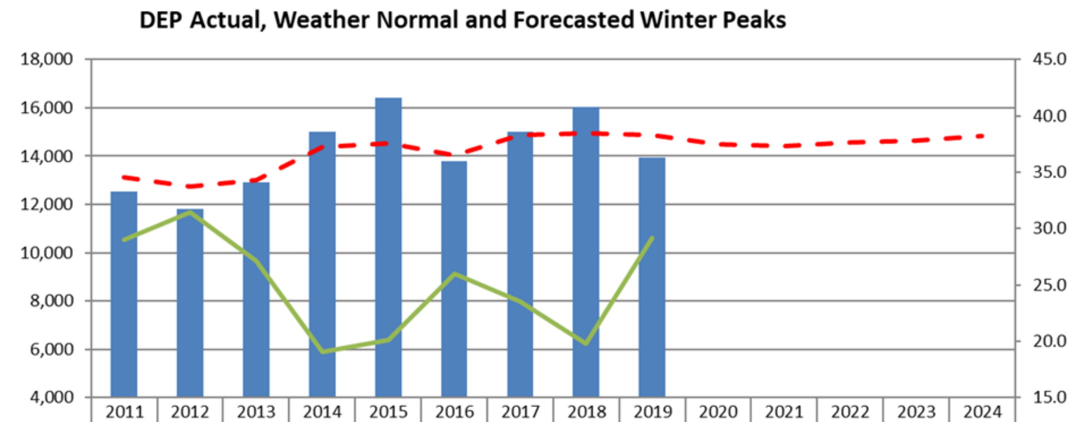
Year	Residential GWh	Commercial GWh	Industrial GWh	Military & Other GWh	Retail GWh	Wholesale GWh	Total System GWh
2009	17,000	13,940	11,216	1,467	43,622	12,868	56,489
2010	17,117	13,639	10,375	1,497	42,628	12,772	55,400
2011	19,108	14,184	10,677	1,574	45,544	12,772	58,316
2012	17,764	13,709	10,573	1,591	43,637	12,267	55,903
2013	16,663	13,581	10,508	1,602	42,355	12,676	55,031
2014	18,201	13,887	10,321	1,614	44,023	13,578	57,601
2015	17,954	14,039	10,288	1,597	43,876	15,782	59,658
2016	17,686	14,082	10,274	1,563	43,606	18,676	62,282
2017	17,228	13,903	10,391	1,531	43,053	18,242	61,295
2018	18,182	14,025	10,407	1,541	44,155	19,331	63,486
Avg. Annual Growth Rate	0.8%	0.1%	-0.8%	0.6%	0.1%	4.6%	1.3%

Note: The wholesale values in Table 5-D exclude NCEMPA sales for all years before 2015, and is only partially included in 2015.

System Peaks

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

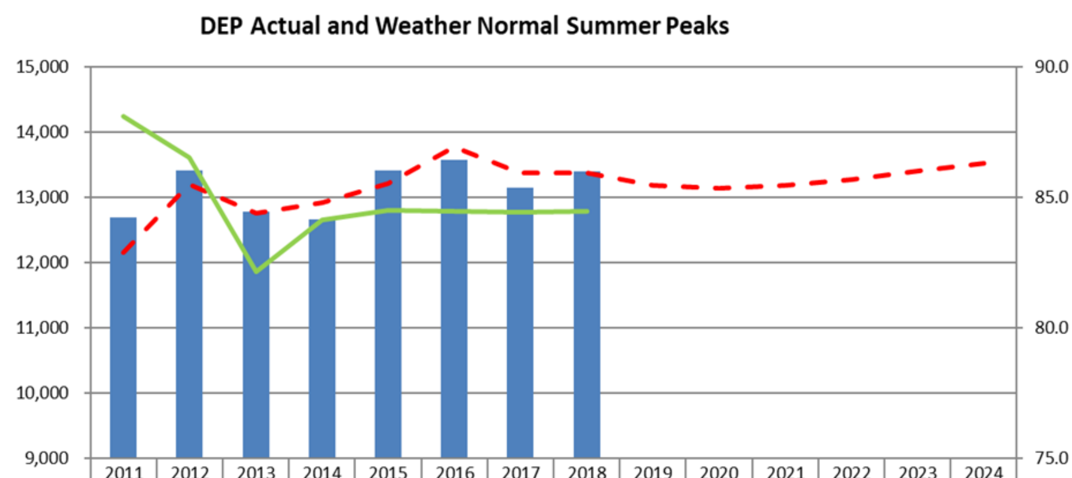
Chart 5-E Winter Peaks



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Actual	12,522	11,826	12,897	14,993	16,429	13,801	15,020	16,016	13,942					
WN Peak/Forecast	13,107	12,760	12,994	14,374	14,519	14,026	14,857	14,967	14,858	14,473	14,434	14,557	14,649	14,843
Temp	29.0	31.5	27.1	19.1	20.1	26.0	23.5	19.8	29.2					

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	12,686	13,405	12,785	12,663	13,415	13,578	13,143	13,403						
WN Peak/Forecast	12,146	13,198	12,757	12,922	13,206	13,777	13,375	13,381	13,181	13,133	13,182	13,274	13,404	13,529
Temp	88.1	86.5	82.2	84.1	84.5	84.5	84.4	84.5						

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 the 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 Progress 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	18,327	14,245	10,379	1,534	44,484
2021	18,395	14,306	10,424	1,525	44,650
2022	18,562	14,408	10,389	1,514	44,873
2023	18,789	14,538	10,390	1,505	45,222
2024	19,078	14,635	10,427	1,496	45,636
2025	19,353	14,751	10,427	1,486	46,016
2026	19,652	14,868	10,438	1,478	46,436
2027	19,950	14,984	10,516	1,471	46,921
2028	20,282	15,134	10,620	1,465	47,501
2029	20,566	15,265	10,714	1,460	48,004
2030	20,872	15,387	10,805	1,455	48,519
2031	21,189	15,544	10,896	1,450	49,078
2032	21,546	15,663	10,987	1,445	49,641
2033	21,869	15,813	11,094	1,440	50,215
2034	22,242	15,957	11,238	1,437	50,875
Avg. Annual Growth Rate	1.3%	0.8%	0.5%	-0.4%	0.9%

Note: Values are at meter

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	13,194	14,522	64,302
2021	13,281	14,523	64,587
2022	13,409	14,687	65,223
2023	13,574	14,819	66,016
2024	13,732	15,069	66,910
2025	13,902	15,237	67,722
2026	14,143	15,415	68,578
2027	14,304	15,670	69,491
2028	14,536	15,876	70,522
2029	14,723	16,084	71,352
2030	14,936	16,302	72,319
2031	15,138	16,512	73,488
2032	15,355	16,727	74,870
2033	15,569	16,921	75,747
2034	15,799	17,113	76,692
Avg. Annual Growth Rate	1.2%	1.1%	1.2%

Note: Values are at generation level

Chart 5-A

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

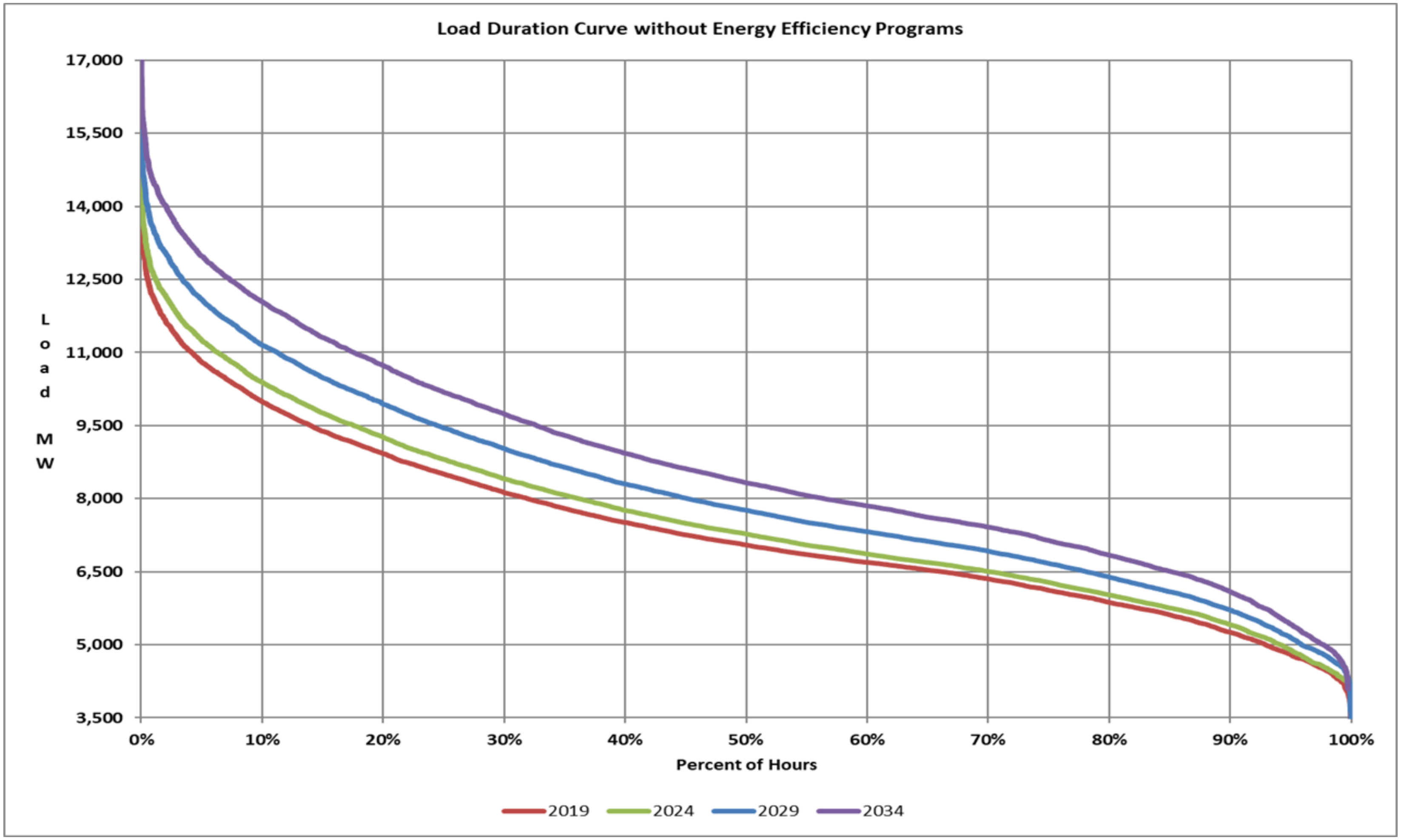


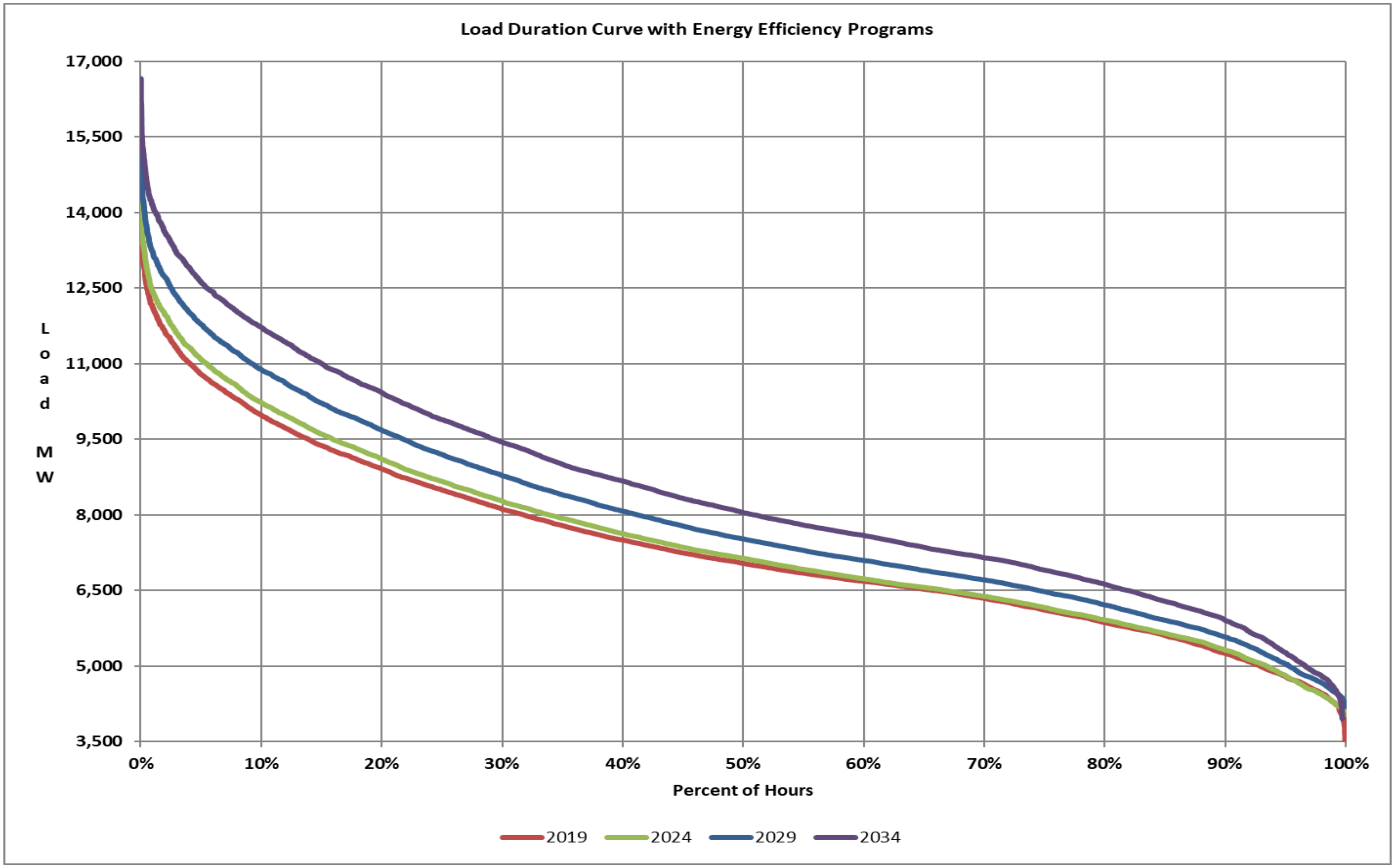
Table 5-I Summary of the Load Forecast with UEE Programs and Excluding any Impacts from Demand Reduction Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2020	13,133	14,473	63,964
2021	13,182	14,434	64,040
2022	13,274	14,557	64,465
2023	13,404	14,649	65,043
2024	13,529	14,843	65,724
2025	13,663	14,965	66,330
2026	13,867	15,106	66,990
2027	13,995	15,326	67,718
2028	14,198	15,502	68,586
2029	14,359	15,690	69,295
2030	14,551	15,883	70,163
2031	14,735	16,073	71,241
2032	14,937	16,276	72,552
2033	15,136	16,461	73,374
2034	15,360	16,654	74,306
Avg. Annual Growth Rate	1.0%	0.9%	1.0%

Note: Values are at generation level
Values differ from Tables 9-A and 9-B due to 150 MW firm sale in years 2020 – 2024.

Chart 5-B

Load Duration Curve with Energy Efficiency Programs & Before Demand Response 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 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 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 DEP from 3,005 MW in 2020 to 4,629 MW in 2034 with approximately 100 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 39 MW of solar capacity located in DEP; 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. Both DEP projects are third party owned although one of the DEP projects will be transmission tied in NC and the other will be distribution tied in SC. 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 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, DEP had approximately 2,500 MW of utility scale solar on its system, with over 450 MW interconnecting in 2018. When renewable resources were evaluated for the 2019 IRP, DEP reported another approximately 500 MW of third party solar under construction and more than 6,500 MW in the interconnection queue. Table 6-A contains interconnection queue information for renewable resources which 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: DEP

Facility State: NC,SC

Utility	Facility State	Energy Source Type	Number of Pending Projects	Pending Capacity (MW AC)
DEP	NC	Battery	4	864.8
		Biomass	1	4.2
		Other	1	14.0
		Solar	231	4,148.3
	NC Total		**248**	**5,031.3**
	SC	Solar	144	2,494.9
	SC Total		**144**	**2,494.9**
DEP Total			**392**	**7,526.2**

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.

DEP's contribution to the Transition depends on many variables including connecting projects under construction, the expected number of projects in the queue with a PPA and IA, SC Act 62, and SC DER Program Tier I. As of May 31, 2019, DEP had approximately 2,700 MW of solar capacity with a PPA and IA, and roughly 100 MW of non-solar renewable capacity with PPAs 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 800 MW contributing to the Transition. In total, DEP may contribute roughly three-quarters of the Transition MW with DEC accounting for the remaining quarter.

NC REPS Compliance:

DEP 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. DEP'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 DEP'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:

DEP continues to evaluate utility-owned solar additions to grow its renewables portfolio. DEP owns and operates four utility-scale solar projects, totaling 141 MW-AC, as part of its efforts to encourage emission free generation resources and help meet its compliance targets:

- Camp Lejeune Solar Facility – 13 MW, located in Onslow County, NC placed in service in November 2015;
- Warsaw Solar Facility – 65 MW, located in Duplin County, NC placed in service in December 2015;
- Fayetteville Solar Facility – 23 MW, located in Bladen County, NC placed in service in December 2015; and
- Elm City Solar Facility – 40 MW, located in Wilson County, NC placed in service in March 2016.

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. DEP 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 DEP's option to acquire projects from third parties that are specifically proposed in the CPRE 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. DEP now models fixed tilt and SAT system hourly profiles with a range of ILR's as high as 1.6 (DC/AC ratio).

In summary, there is a great deal of uncertainty in both the future avoided costs applicable 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 DEP/DEC split expected to be roughly 45/55. 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 DEP. 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, DEP NC installed approximately 11 MW of rooftop solar, more than triple the capacity installed in 2017. Through June of 2019, installed rooftop solar capacity is approximately 8 MW or only three 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: 13 MW of solar capacity from facilities each >1 MW and < 10 MW in size.
- Tier II: 13 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 13 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.

DEP has executed two PPAs to complete Tier I which will result in 15 MW, 5 MW of which are currently operational. Tier II incentives have resulted in growth in private solar in DEP, as nearly 16 MW of rooftop solar has been installed in DEP SC.

The Company launched its first Shared Solar program as part of Tier I. Duke Energy designed its initial SC Shared Solar program to have 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 1 MW including 200 kW set aside for customers earnings less than 200% of the federal poverty line. As of the end of June 2019, 52 kW was subscribed. The unreserved 800 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 DEP 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 DEP has executed IAs and PPAs with aggregated nameplate capacity equal to 20 percent of the previous 5-year average of DEP's SC retail peak load, or roughly 260 MW. After 260 MW have executed IAs and PPAs the Commission will determine conditions, rates, and terms of length for future contracts. Given there is roughly 2,500 MW of solar pending in DEP SC, the Company expects to easily meet 260 MW within the IRP planning period. The Company intends to closely monitor the capacity with executed IAs and PPAs, evaluate impacts on the 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 the Act passing, encouraging 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 (37 MW in DEP) offering up to 15-year PPA's. 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.

Wind:

DEP considers wind a potential energy resource in the long term to support increased renewables portfolio diversity, long-term general compliance needs, as well as a potential resource for further carbon reduction. However, investing in wind inside of DEP's footprint may be challenging in the short-term, primarily due to a lack of suitable sites, permitting challenges, and more modest capital cost declines relative to other renewable technologies like solar. Opportunities may exist to transmit wind energy into the Carolinas from out of state regions where wind is more cost-effective. The Company will continue to monitor the economic feasibility of offshore wind as well.

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, 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 DEP 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 DEC 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, DEP expects nearly 100 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 DEP'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.

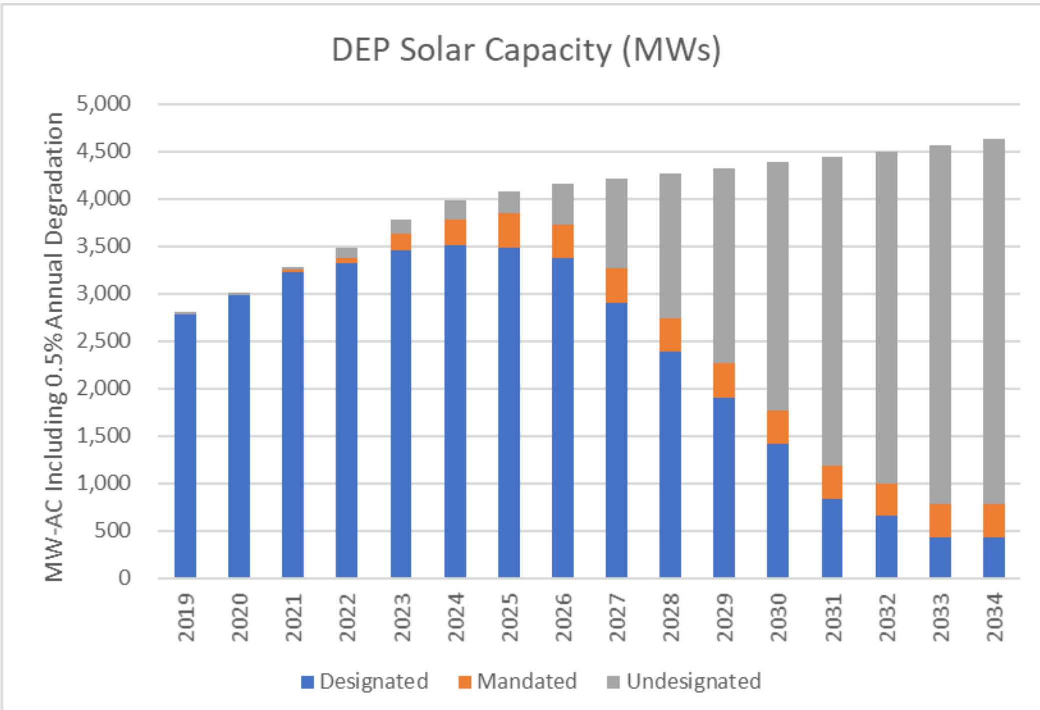
Table 6-B: DEP Base Case Total Renewables

DEP 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	3,005	264	3,269	1,052	264	1,316	30	264	294
2021	3,274	116	3,390	1,111	116	1,227	33	116	149
2022	3,477	116	3,593	1,142	116	1,257	35	116	151
2023	3,784	113	3,897	1,185	113	1,298	40	113	152
2024	3,987	112	4,099	1,206	112	1,318	42	112	154
2025	4,069	105	4,174	1,214	105	1,319	43	105	148
2026	4,157	105	4,262	1,234	105	1,338	54	105	159
2027	4,210	48	4,258	1,246	48	1,294	62	48	110
2028	4,262	44	4,306	1,259	44	1,303	70	44	114
2029	4,325	33	4,359	1,273	33	1,307	79	33	113
2030	4,381	32	4,413	1,287	32	1,319	87	32	120
2031	4,441	32	4,473	1,301	32	1,333	96	32	129
2032	4,491	31	4,522	1,313	31	1,344	104	31	135
2033	4,563	30	4,593	1,330	30	1,360	114	30	144
2034	4,629	30	4,659	1,345	30	1,376	124	30	154
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 to be executed.

The chart below shows DEP'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 can also 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 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 proposed 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 changed 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. WESTERN CAROLINAS MODERNIZATION PROGRAM (WCMP)

The WCMP has five primary components, all of which are moving forward on schedule:

- Complete construction of two 280 MW new combined cycle natural-gas fired units at the Asheville Plant to serve DEP's system in NC and SC.
- Retire the Asheville Coal Plant by Jan. 31, 2020.
- Improvements to the transmission and distribution system.
- Addition of at least 15 MW of solar in DEP-West.
- Addition of at least 5 MW of energy storage in DEP-West.

In 2016, the Energy Innovation Task Force (EITF), comprised of a diverse group of community leaders, was convened by Duke Energy Progress, City of Asheville and Buncombe County to:

1. Avoid or delay the construction of the planned contingent CT.
2. Transition DEP-West to a smarter, cleaner and affordable energy future.

As referenced in the 2018 Integrated Resource Plan, through community collaboration in DEP-West, specifically Buncombe County, the contingent CT has been pushed out beyond the horizon of this 15-year planning analysis.

The Energy Innovation Task Force, through its external-facing movement the Blue Horizons Project, had great success toward both goals during 2018/2019.

Energy Efficiency and Demand-side Management

The group continues to engage and leverage grassroots networks to increase demand-side management with both residential and non-residential customers; increase adoption and uptake in energy efficiency programs; and make purposeful and deliberate investments in renewables and storage.

The EnergyWise Home and Business programs continue to be priority areas to drive peak demand reductions in the region. As evidenced in the goal results, performance on this front has been strong. Following are some of the key drivers of this success:

1. Community advocacy: Several organizations, including those known for their advocacy of clean and sustainable energy solutions, have visibly and tangibly advocated for local home and business participation in EnergyWise. This grass roots support has had both direct and

indirect positive impacts on results that have been achieved. It has increased awareness that the benefits of the programs go far beyond the financial incentives that are offered and it has made Duke Energy's marketing and sales efforts more effective as a result.

2. Duke Energy Marketing/Sales: Aggressive efforts to encourage EnergyWise participation have continued. Co-branding with the Blue Horizons Project has helped make third-party advocacy more effective. A continuation of door-to-door campaigning has also proven to be effective.
3. Multi-Family/Rental Properties: A focused effort has been undertaken to pursue multi-family and rental properties, which has been a relatively underperforming segment for EnergyWise participation. Modifications to the load control switches have been made to enable installation of these applications, and work is underway to engage directly with landlords to encourage participation for their properties.

Additionally, in December 2018, the NCUC approved the Pay for Performance program to be piloted in the Asheville/Buncombe County area. This work is being completed by Community Action Opportunities and the Greenbuilt Alliance. There have been excellent results with the diversity of measures installed and the clear need in the community.

Distributed Energy Resources

Construction is complete on the Company's first DEP-West microgrid (solar and storage) in the Great Smoky Mountains National Park. Construction is underway for a battery storage project adjacent to a company-owned substation in south Asheville, near Rock Hill Road. The Company is starting construction on a large solar/storage microgrid project in Hot Springs, N.C.

In DEP's 2018 Integrated Resource Plan, the Company included a placeholder for 140 MW of battery storage, of which approximately 50 MW are planned to be deployed in the Western Carolinas. These grid-connected battery storage projects are intended to provide solutions for the transmission and distribution systems with the possibility of simultaneously providing benefits to DEP's generation resource portfolio. Since the utility is ultimately responsible for system reliability, DEP is the natural owner and operator of battery storage, which supports this critical objective for its customers.

What's Next

In late 2018, both Asheville (City) and Buncombe County (County) passed 100 percent clean/renewable energy goals, joining several other local governments in North Carolina that have set similar goals. The goals require both the City and County achieve the 100 percent targets for operations by 2030, and for all homes and businesses by 2042.

Considering the 100 percent goals set by the City and County, the EITF determined that its objectives should be updated to reflect achievement of the goals. The Energy Innovation Task Force has started its work to rename itself and redirect its goals toward helping the City of Asheville and Buncombe County meet their aggressive renewable energy goals.

The partnership between the City, County, and Duke Energy, through the EITF will be critical to enable achievement of the very ambitious goals that have been set.

9. DEVELOPMENT OF RESOURCE PLAN

The following section details the Company's expansion plan and resource mix that is required to meet the needs of DEP'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 9-A and 9-B represent the winter and summer Load, Capacity, and Reserves (LCR) tables for the Base Case.

Table 9-A Load, Capacity and Reserves Table – Winter

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

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Load Forecast															
1 DEP System Winter Peak	14,522	14,523	14,687	14,819	15,069	15,237	15,415	15,670	15,876	16,084	16,302	16,512	16,727	16,921	17,113
2 Firm Sale	150	150	150	150	150	0	0	0	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(48)	(90)	(131)	(170)	(226)	(271)	(309)	(344)	(375)	(394)	(419)	(439)	(451)	(460)	(459)
4 Adjusted Duke System Peak	**14,623**	**14,584**	**14,707**	**14,799**	**14,993**	**14,965**	**15,106**	**15,326**	**15,502**	**15,690**	**15,883**	**16,073**	**16,276**	**16,461**	**16,653**
Existing and Designated Resources															
5 Generating Capacity	13,941	14,123	13,626	13,626	13,626	13,626	13,398	13,398	13,398	13,404	12,351	12,361	12,361	12,361	12,361
6 Designated Additions / Uprates	566	0	0	0	0	4	0	0	6	0	10	0	0	0	0
7 Retirements / Derates	(384)	(497)	0	0	0	(232)	0	0	0	(1,053)	0	0	0	0	(1,409)
8 Cumulative Generating Capacity	**14,123**	**13,626**	**13,626**	**13,626**	**13,626**	**13,398**	**13,398**	**13,398**	**13,404**	**12,351**	**12,361**	**12,361**	**12,361**	**12,361**	**10,952**
Purchase Contracts															
9 Cumulative Purchase Contracts	**2,193**	**2,599**	**2,470**	**2,429**	**2,152**	**1,971**	**1,407**	**894**	**552**	**551**	**550**	**550**	**547**	**33**	**32**
Non-Compliance Renewable Purchases	103	35	37	39	41	42	42	39	37	36	35	35	33	33	32
Non-Renewables Purchases	2,090	2,565	2,433	2,389	2,110	1,929	1,365	855	515	515	515	515	514	0	0
Undesignated Future Resources															
10 Nuclear															
11 Combined Cycle						1,341		1,341							
12 Combustion Turbine									470	1,880		470		940	1,410
13 Short-Term Market Purchases	200	100	200	100	500	(200)	(100)	(200)	(100)	(500)					
Renewables															
14 Cumulative Renewables Capacity	**191**	**114**	**114**	**113**	**113**	**106**	**117**	**71**	**77**	**77**	**85**	**94**	**102**	**112**	**121**
Renewables w/o Storage	191	114	114	111	111	104	104	50	48	39	39	40	40	40	40
Solar w/ Storage (Solar Component)	0	0	0	0	0	0	1	1	1	2	2	3	3	3	4
Solar w/ Storage (Storage Component)	0	0	0	2	2	2	13	20	28	36	44	52	59	68	77
15 Combined Heat & Power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16 Grid-connected Energy Storage	12	12	12	14	14	16	16	16	0	0	0	0	0	0	0
17 Cumulative Production Capacity	**16,719**	**16,663**	**16,746**	**16,818**	**17,055**	**17,797**	**17,160**	**17,758**	**17,798**	**18,124**	**18,141**	**18,620**	**18,625**	**19,060**	**19,071**
Demand Side Management (DSM)															
18 Cumulative DSM Capacity	**478**	**487**	**495**	**505**	**514**	**520**	**525**	**530**	**536**	**541**	**547**	**553**	**558**	**564**	**571**
19 Cumulative Capacity w/ DSM	**17,197**	**17,150**	**17,241**	**17,323**	**17,569**	**18,317**	**17,685**	**18,288**	**18,334**	**18,665**	**18,688**	**19,172**	**19,183**	**19,625**	**19,642**
Reserves w/ DSM															
20 Generating Reserves	2,574	2,567	2,534	2,525	2,577	3,352	2,580	2,962	2,833	2,975	2,805	3,100	2,908	3,164	2,988
21 % Reserve Margin	**17.6%**	**17.6%**	**17.2%**	**17.1%**	**17.2%**	**22.4%**	**17.1%**	**19.3%**	**18.3%**	**19.0%**	**17.7%**	**19.3%**	**17.9%**	**19.2%**	**17.9%**

Table 9-B Load, Capacity and Reserves Table – Summer

**Summer Projections of Load, Capacity, and Reserves
for Duke Energy Progress 2098 Annual Plan**

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Load Forecast															
1 DEP System Summer Peak	13,194	13,281	13,409	13,574	13,732	13,902	14,143	14,304	14,536	14,723	14,936	15,138	15,355	15,569	15,799
2 Firm Sale	150	150	150	150	150	0	0	0	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(62)	(99)	(134)	(170)	(204)	(239)	(276)	(309)	(338)	(364)	(385)	(403)	(418)	(432)	(440)
4 Adjusted Duke System Peak	**13,283**	**13,332**	**13,424**	**13,554**	**13,679**	**13,663**	**13,867**	**13,995**	**14,198**	**14,359**	**14,551**	**14,735**	**14,937**	**15,136**	**15,360**
Existing and Designated Resources															
5 Generating Capacity	12,734	12,852	12,473	12,473	12,473	12,475	12,299	12,299	12,303	12,303	11,262	11,262	11,262	11,262	11,262
6 Designated Additions / Uprates	496	0	0	0	2	0	0	4	0	6	0	0	0	0	0
7 Retirements / Derates	(378)	(379)	0	0	0	(176)	0	0	0	(1,047)	0	0	0	0	(1,392)
8 Cumulative Generating Capacity	**12,852**	**12,473**	**12,473**	**12,473**	**12,475**	**12,299**	**12,299**	**12,303**	**12,303**	**11,262**	**11,262**	**11,262**	**11,262**	**11,262**	**9,870**
Purchase Contracts															
9 Cumulative Purchase Contracts	**2,688**	**3,190**	**3,100**	**3,128**	**2,925**	**2,759**	**1,668**	**1,315**	**1,302**	**1,290**	**1,278**	**1,267**	**1,255**	**759**	**749**
Non-Compliance Renewable Purchases	722	719	765	809	844	859	843	829	817	804	793	782	771	759	749
Non-Renewables Purchases	1,967	2,471	2,335	2,319	2,080	1,899	825	485	485	485	485	485	484	0	0
Undesignated Future Resources															
10 Nuclear															
11 Combined Cycle						1,241		1,241							
12 Combustion Turbine									426	1,278		426		852	1,278
13 Short Term Market Purchases	200	100	200	100	500	(200)	(100)	(200)	(100)	(500)					
Renewables															
14 Cumulative Renewables Capacity	594	507	492	492	477	462	514	493	525	553	587	623	654	693	730
Renewables w/o Storage	594	507	492	487	472	457	482	444	458	466	482	499	514	532	549
Solar w/ Storage (Solar Component)	0	0	0	3	3	3	19	29	39	51	61	72	81	93	104
Solar w/ Storage (Storage Component)	0	0	0	2	2	2	13	20	28	36	44	52	59	68	77
15 Combined Heat & Power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16 Grid-connected Energy Storage	12	12	12	14	14	16	16	16	0	0	0	0	0	0	0
17 Cumulative Production Capacity	**16,346**	**16,495**	**16,601**	**16,743**	**17,041**	**17,742**	**16,619**	**17,306**	**17,651**	**17,404**	**17,426**	**17,877**	**17,896**	**18,291**	**18,204**
Demand Side Management (DSM)															
18 Cumulative DSM Capacity	**917**	**941**	**960**	**974**	**982**	**986**	**990**	**995**	**1,000**	**1,005**	**1,009**	**1,015**	**1,020**	**1,025**	**1,031**
19 Cumulative Capacity w/ DSM	**17,263**	**17,436**	**17,561**	**17,717**	**18,022**	**18,728**	**17,609**	**18,301**	**18,651**	**18,408**	**18,435**	**18,891**	**18,915**	**19,316**	**19,235**
Reserves w/ DSM															
20 Generating Reserves	3,981	4,104	4,137	4,163	4,344	5,065	3,742	4,305	4,453	4,049	3,884	4,156	3,979	4,180	3,875
21 % Reserve Margin	**30.0%**	**30.8%**	**30.8%**	**30.7%**	**31.8%**	**37.1%**	**27.0%**	**30.8%**	**31.4%**	**28.2%**	**26.7%**	**28.2%**	**26.6%**	**27.6%**	**25.2%**

DEP - 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 table. All values are MW (winter ratings) except where shown as a percent.

1. Planning is done for the Winter peak demand for the Duke Energy Progress System.

2. Firm sale of 150 MW through 2024.

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

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

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

6. Designated Capacity Additions include:

   Planned nuclear uprates totaling 26 MW in the 2020 - 2030 timeframe.

   560 MW Asheville combined cycle addition in November 2019.

7. Planned Retirements include:

   384 MW Asheville Coal Units 1-2 in November 2019.

   497 MW Darlington CT Units 1-6, 8 and 10 by December 2020.

   232 MW Blewett CT Units 1-4 and Weatherspoon CT units 1-4 in December 2024.

   1,053 MW Roxboro Units 1-2 in December 2028

   1,409 MW Roxboro Units 3-4 in December 2033

   Planning assumptions for nuclear stations assume subsequent license renewal at the end of the current license. 797 MW Robinson 2 is assumed to be relicensed in 2030.

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

8. Sum of lines 5 through 7.

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

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

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

10. New nuclear resources 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 following year.

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

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

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

    Addition of 1,341 MW of combined cycle capacity online December 2024

    Addition of 1,341 MW of combined cycle capacity online December 2026.

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 2027.

    Addition of 1,880 MW of combustion turbine capacity online December 2028.

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

    Addition of 940 MW of combustion turbine capacity online December 2032.

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

Addition of 1,410 MW of combustion turbine capacity online December 2030.

13. Short-term market purchases needed to meet load and minimum planning reserve margin.

14. 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.

15. No new Combined Heat and Power projects are included.

16. Addition of 113 MW (80% of usable AC capacity) of energy storage over the years 2020 through 2027.

17. Sum of lines 8 through 17.

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

19. Sum of lines 18 and 19.

20. The difference between lines 20 and 4.

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

    Line 21 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. DEP 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:

DEP 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.

[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.

Adequacy of Projected Reserves:

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.

DEP's resource plan reflects winter reserve margins ranging from approximately 17.1% to 22.4%. Reserves projected in DEP'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 2025 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 9-C below shows a comparison of DEP'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 changes to the short-term market purchases, a one-year deferral of a CT block from 2031 to 2032 and a one-year deferral of a CT block from 2033 to 2034. 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 DEP reserve margin to decline to 16% for a given year would increase the loss of load expectation to approximately 0.13 days/year for DEP, which equates to one expected firm load shed event approximately every 7.7 years.

Table 9-C: 16% Reserve Margin Sensitivity

**Winter Projections of Load, Capacity, and Reserves
for Duke Energy Progress 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)	14,623	14,584	14,707	14,799	14,993	14,965	15,106	15,326	15,502	15,690	15,883	16,073	16,276	16,461	16,653
Undesignated Future Resources (MW)															
Combined Cycle						1,341		1,341							
Combustion Turbine									470	1,880		470		940	1,410
Short-Term Market Purchase	200	100	200	100	500	(200)	(100)	(200)	(100)	(500)					
Generating Reserves	2,574	2,567	2,534	2,525	2,577	3,352	2,580	2,962	2,833	2,975	2,805	3,100	2,908	3,164	2,988
% Reserve Margin	**17.6%**	**17.6%**	**17.2%**	**17.1%**	**17.2%**	**22.4%**	**17.1%**	**19.3%**	**18.3%**	**19.0%**	**17.7%**	**19.3%**	**17.9%**	**19.2%**	**17.9%**

(16% Reserve Margin Scenario)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Adjusted System Peak Load (MW)	14,623	14,584	14,707	14,799	14,993	14,965	15,106	15,326	15,502	15,690	15,883	16,073	16,276	16,461	16,653
Undesignated Future Resources (MW)															
Combined Cycle						1,341		1,341							
Combustion Turbine									470	1,880			470	470	1,880
Short-Term Market Purchase		100	300	100	500		(100)	(300)	(100)	(500)					
Generating Reserves	2,374	2,367	2,434	2,425	2,477	3,452	2,680	2,962	2,833	2,975	2,805	2,630	2,908	2,694	2,988
% Reserve Margin	**16.2%**	**16.2%**	**16.6%**	**16.4%**	**16.5%**	**23.1%**	**17.7%**	**19.3%**	**18.3%**	**19.0%**	**17.7%**	**16.4%**	**17.9%**	**16.4%**	**17.9%**

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 DEP system. For instance, during winter months, DEP'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 DEP 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 DEP 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 9-D DEP Base Case Resources– Winter (with CO_2)

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

Year	Resource				MW			
2020	Asheville CC	Nuclear Uprates	Solar	Energy Storage	560	6	204	15
2021	Solar	Energy Storage			269	15		
2022	Solar	Energy Storage			203	15		
2023	Solar + Storage	Solar	Energy Storage		10 (2)	297	18	
2024	Solar	Energy Storage			203	18		
2025	Nuclear Uprates	New CC	Solar	Energy Storage	4	1,341	82	20
2026	Solar + Storage	Solar	Energy Storage		54 (14)	34	20	
2027	Solar + Storage	New CC	Solar	Energy Storage	37 (9)	1,341	16	20
2028	Nuclear Uprates	New CT	Solar + Storage	Solar	6	470	36 (9)	16
2029	New CT	Solar + Storage	Solar		1880	42 (11)	22	
2030	Nuclear Uprates	Solar + Storage	Solar		10	38 (10)	18	
2031	New CT	Solar + Storage	Solar		470	40 (10)	20	
2032	Solar + Storage	Solar			35 (9)	15		
2033	New CT	Solar + Storage	Solar		940	45 (12)	26	
2034	New CT	Solar + Storage	Solar		1410	43 (11)	23	

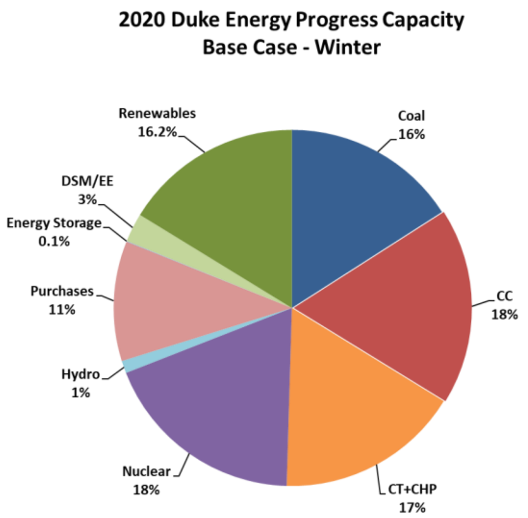
Notes: (1) Table includes both designated and undesignated capacity additions
(2) Incremental solar additions represent nameplate ratings and do not include solar coupled with storage
(3) Incremental Energy Storage additions represent useable AC MW capacity
(4) Solar + Storage values in ( ) represent useable AC MW storage behind solar inverter
(5) Future additions of other renewables, EE and DSM not included
(6) Table does not include short term PPA purchases in 2020 through 2024.

Table 9-E DEP Base Case Resources (with CO_2) Cumulative Winter Totals

DEP Base Case Resources Cumulative Winter Totals - 2020 - 2034	
Nuclear	26
Solar	1,448
Solar + Storage	380 (97)
CC	3,242
CT	5,170
CHP	0
Energy Storage	141
Total	10,407

The following charts illustrate both the current and forecasted capacity by fuel type for the DEP system, as projected in the Base Case. As demonstrated in Chart 9-A, the capacity mix for the DEP system changes with the passage of time. In 2034, the Base Case projects that DEP will have a smaller percentage reliance on coal, nuclear and external purchases, and a higher reliance on gas-fired resources, renewable resources, energy storage and EE as compared to the current state.

Chart 9-A 2020 & 2034 Base Case Winter Capacity Mix [7]



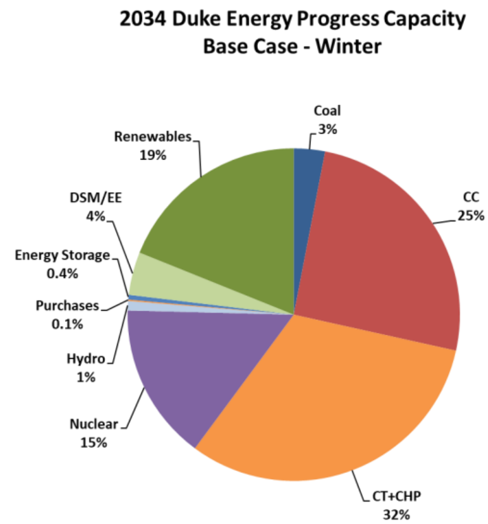
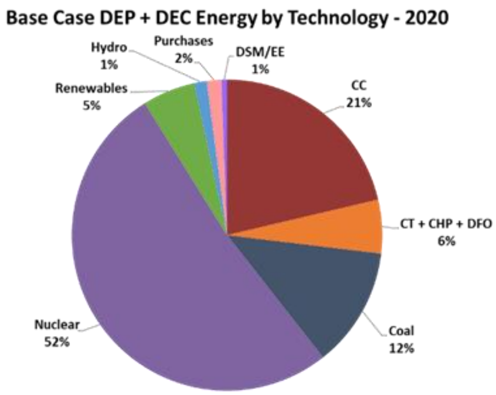
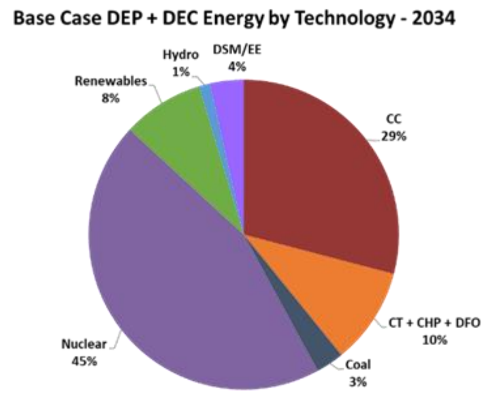


Chart 9-B represents the energy of both the DEC and DEP Base Case over time. Due to the joint dispatch agreement (JDA), it is prudent to combine the energy of both utilities to develop a meaningful energy figure. From 2020 to 2034, the figure shows that nuclear resources will continue to serve almost 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.

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

Chart 9-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 that assumes no carbon regulations. The expansion plan for this case is shown below in Table 9-F.

Table 9-F No Carbon Case - Winter

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

Year	Resource				MW			
2020	Asheville CC	Nuclear Uprates	Solar	Energy Storage	560	6	204	15
2021	Solar	Energy Storage			269	15		
2022	Solar	Energy Storage			203	15		
2023	Solar + Storage	Solar	Energy Storage		10 (2)	297	18	
2024	Solar	Energy Storage			203	18		
2025	Nuclear Uprates	New CC	Solar	Energy Storage	4	1,341	82	20
2026	Solar + Storage	Solar	Energy Storage		54 (14)	34	20	
2027	Solar + Storage	New CC	Solar	Energy Storage	37 (9)	1,341	16	20
2028	Nuclear Uprates	New CT	Solar + Storage	Solar	6	470	36 (9)	16
2029	New CT	Solar + Storage	Solar		1880	42 (11)	22	
2030	Nuclear Uprates	Solar + Storage	Solar		10	38 (10)	18	
2031	New CT	Solar + Storage	Solar		470	40 (10)	20	
2032	Solar + Storage	Solar			35 (9)	15		
2033	New CT	Solar + Storage	Solar		940	45 (12)	26	
2034	New CT	Solar + Storage	Solar		1410	43 (11)	23	

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
(6) Table does not include short term PPA purchases in 2020 through 2024.

10. DEP 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 and expiring purchase power contracts 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 purchase 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 to be executed.

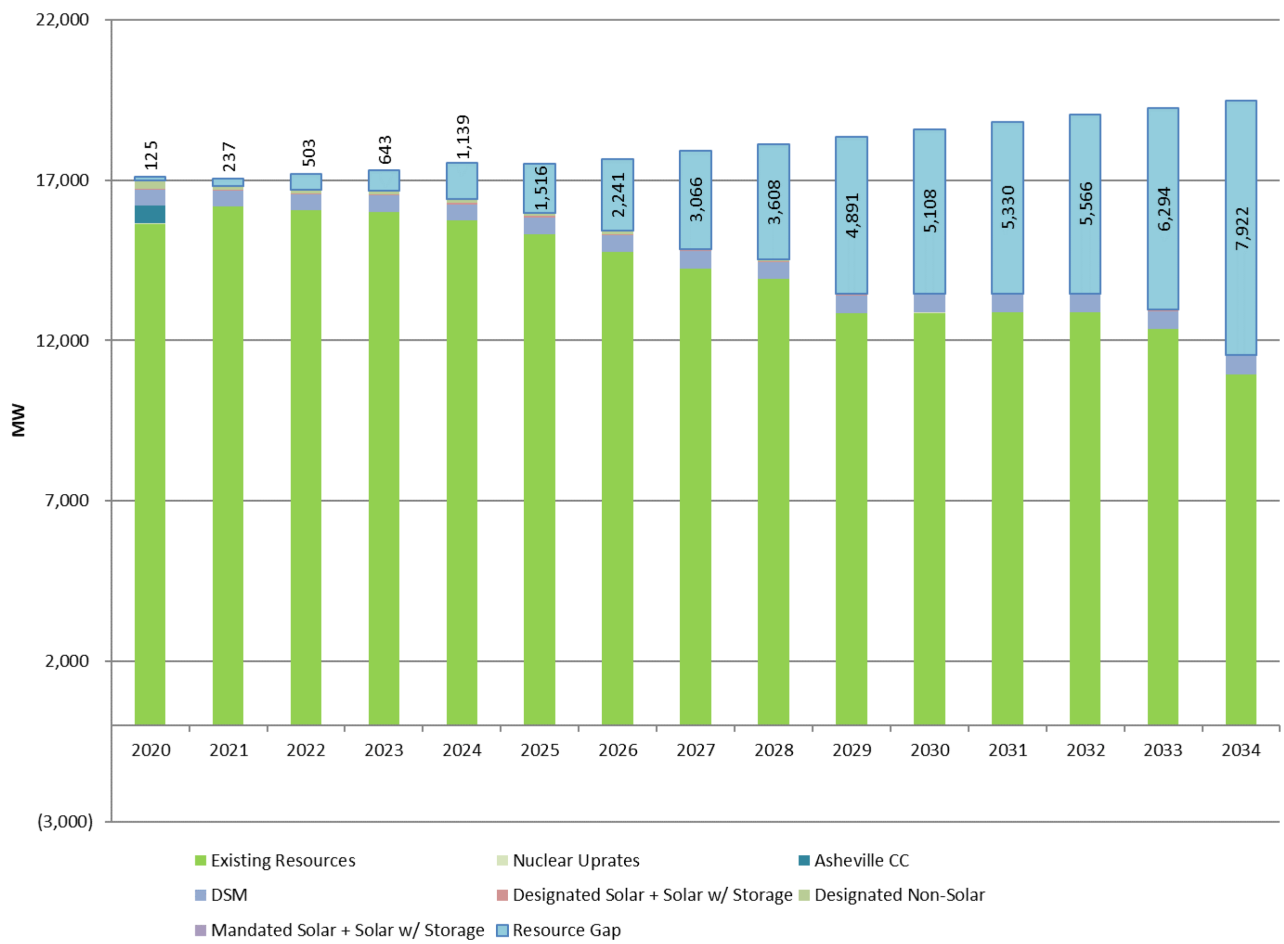
Only designated and mandated resources are considered when determining the first need for purposes of the determination of standard offer avoided capacity rates.

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

- Asheville Combined Cycle
- Designated and mandated renewable resources
- Nuclear Uprates
- Designated wholesale contracts
- DSM/EE programs

Including only the designated and mandated resources, Chart 10-A demonstrates the first need for DEP is in 2020. To the extent current contracts under negotiation become executed and move from an undesignated to a designated resource, the timing of the first need will change accordingly.

Chart 10-A Load Resource Balance for DEP First Need



11. 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 DEP 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) other EE research & development pilots.

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

Continued Focus on Renewable Energy Resources

DEP is committed to the addition of significant renewable generation in 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 DEP's aggressive plans to grow its renewable resources. DEP is also committed to meeting its targets for the SC DER Program.

Under NC HB 589, DEP and DEC successfully procured approximately 550 MW of solar capacity through tranche one of CPRE and intend 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.

DEP 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 DEP system. 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. 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.

In line with these objectives, DEP will complete construction of a 9 MW battery storage project adjacent to a company-owned substation in south Asheville, near Rock Hill Road that will be used to help the electric system operate more efficiently and reliably for customers in that area. Additionally, the company is beginning construction on a 2 MW solar / 4 MW battery storage system microgrid project in Hot Springs, N.C. that was approved by the NCUC in May 2019. This asset will be used to improve reliability of the Hot Springs community while also provide benefits to allow the bulk system to operate more efficiently. There are a number of additional projects under development on both the transmission and distribution systems. The Company also plans to further study the capacity value of storage in the Carolinas and will include any learnings in the 2020 IRP.

Addition of Clean Natural Gas Resources

- Continue to evaluate older CTs on the DEP system. The Company is evaluating the condition and economic viability of the older CTs on the system. In doing so, DEP is preparing for the potential retirement of these units. This includes determining the type of resources needed to reliably replace these units to maintain a minimum planning reserve margin.

    - Darlington CT Unit 5 was officially retired in May 2018.

    - Darlington CT Units1-4, 6-8 and 10 are projected to retire in 2020.

- Weatherspoon and Blewett CT Units are projected to retire in 2024.

- Complete construction and commission the new combined cycle units at the Asheville facility (560 MW/ 495 MW winter/summer) by year-end 2019 as part of the Western Carolinas Modernization Project (WCMP).

  - Asheville Coal Units will retire upon the commercial operation of the Asheville combined cycle.

- Take actions to ensure capacity need beginning in the winter of 2025 is met. The 2019 IRP continues to project that the best resources to meet this 2025 demand are combined cycle units.

Expiration of Wholesale Purchase Contracts and Short-Term Need

The 2018 IRP reflected the impact of approximately 1,500 MW of purchase power contract expirations by 2025. The expiration of these contracts, along with the increase in the winter peak demand forecast and the planned retirement of nearly 500 MW of aging CT units at the Darlington CT Complex, created a significant short-term resource need. The Company has worked diligently to address this short-term need by issuing a Request for Proposals (RFP) resource solicitation in 2018. DEP received a significant response to the solicitation and, as a result, DEP is currently in the process of negotiating contracts with short-listed bidders to fulfill its near-term needs.

As discussed in Section 10, contracts that have been executed as part of this solicitation as of August 1, 2019 are included as firm designated resources in this year's IRP while others are still under negotiation. Contracts that have yet to be executed are not included as designated resources in the IRP and, as such, the IRP continues to reflect a resource need as early as the winter of 2020. The Company fully expects to fill this resource gap through future execution of these contracts.

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 the DEP 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 state 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 Chapter 7 of this Updated IRP, the traditional methods of utility resource planning are continuing to evolve. DEP 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 DEP to serve its customers with newer technologies. These enhancements in planning are 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 December 2013, all of DEP's older, un-scrubbed coal units have been retired. In total, DEP has retired 1,600 MW of older vintage coal units since 2011. Additionally, over the same period, DEP has retired approximately 400 MW of older vintage fuel-oil turbines bringing total retirements to 2,000 MW.

- The 2019 IRP shows more than 1,100 MW of additional retirements over the 5-year duration of the short-term action plan with nearly 400 MW of coal being retired at the Asheville site and over 700 MW of combustion turbines being retired at the Darlington, Weatherspoon, and Blewett sites. Weatherspoon and Blewett are expected to retire in December 2024, making them unavailable for the winter of 2025. As such, they are not represented in Table 11-A. Additionally, nearly 2,500 MW of coal are expected to be retired at the Roxboro site over the remainder of the 15-year IRP horizon.

- 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.

- 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 over the next five years for the base plan in the 2019 IRP is shown in Table 11-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 11-A DEP Short-Term Action Plan

2019 Duke Energy Progress 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	384 MW Asheville 1-2	560 MW Asheville CC 6 MW Nuc Uprate 15 MW Energy Storage 200 MW Short-Term PPA	3,005	0	264	48	478
2021	497 MW Darlington CT 1-4, 6-8, 10	15 MW Energy Storage 100 MW Short-Term PPA	3,274	0	116	90	487
2022		15 MW Energy Storage 200 MW Short-Term PPA	3,477	0	116	131	495
2023		18 MW Energy Storage 100 MW Short-Term PPA	3,774	10 w/ 2 Storage	113	170	505
2024		18 MW Energy Storage 500 MW Short-Term PPA	3,977	10 w/ 2 Storage	112	226	514

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.

12. CONCLUSIONS

DEP 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 DEP 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, DEP expects to add 10,407 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, DEP's 2019 IRP focuses on the following:

- Continue construction of the two new combined cycle units at the Asheville facility in the 2019 timeframe as part of the WCMP.
- Pursue investment in a limited number of battery storage projects to gain additional operational and technical experience with evolving utility-scale storage technologies.
- Take actions to ensure short-term system capacity needs beginning in 2020 are met.
- Take necessary steps to ensure that the combined cycle capacity need in 2025 is met.
- 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 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.
- Retire Asheville coal units and Darlington 1-4, 6-8, and 10.
- Continue with plan for subsequent license renewal of existing nuclear units.

Long-Term

Beyond the next 5 years, DEP'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, those are new combined cycle units and combustion turbine 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 DEP 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 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 Weatherspoon and Blewett CTs and Roxboro 1-4 coal units.

DEP's goal is to continue to diversify the DEP 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, renewables, storage, EE and DSM.

13. DUKE ENERGY PROGRESS OWNED GENERATION

Duke Energy Progress' 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 Progress-owned generation, as well as purchased power, is evaluated on a real-time basis to select and dispatch the lowest-cost resources to meet system load requirements.

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

Existing Generating Units and Ratings [1, 3]
All Generating Unit Ratings are as of January 1, 2019 unless otherwise noted.

Coal						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
Asheville	1	192	189	Arden, NC	Coal	Intermediate
Asheville	2	192	189	Arden, NC	Coal	Intermediate
Mayo [2]	1	746	727	Roxboro, NC	Coal	Intermediate
Roxboro	1	380	379	Semora, NC	Coal	Intermediate
Roxboro	2	673	668	Semora, NC	Coal	Intermediate
Roxboro [2]	3	698	694	Semora, NC	Coal	Intermediate
Roxboro [2]	4	711	698	Semora, NC	Coal	Intermediate
Total Coal		3,592	3,544			

Combustion Turbines						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
Asheville	3	185	160	Arden, NC	Natural Gas/Oil	Peaking
Asheville	4	185	160	Arden, NC	Natural Gas/Oil	Peaking
Blewett	1	17	13	Lilesville, NC	Oil	Peaking
Blewett	2	17	13	Lilesville, NC	Oil	Peaking
Blewett	3	17	13	Lilesville, NC	Oil	Peaking
Blewett	4	17	13	Lilesville, NC	Oil	Peaking
Darlington	1	63	50	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	2	61	48	Hartsville, SC	Oil	Peaking
Darlington	3	63	50	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	4	60	48	Hartsville, SC	Oil	Peaking
Darlington	6	62	43	Hartsville, SC	Oil	Peaking
Darlington	7	61	47	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	8	62	44	Hartsville, SC	Oil	Peaking
Darlington	10	65	49	Hartsville, SC	Oil	Peaking
Darlington	12	133	118	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	13	133	116	Hartsville, SC	Natural Gas/Oil	Peaking
Smith [4]	1	189	157	Hamlet, NC	Natural Gas/Oil	Peaking
Smith [4]	2	187	156	Hamlet, NC	Natural Gas/Oil	Peaking
Smith [4]	3	185	155	Hamlet, NC	Natural Gas/Oil	Peaking
Smith [4]	4	186	159	Hamlet, NC	Natural Gas/Oil	Peaking
Smith [4]	6	187	145	Hamlet, NC	Natural Gas/Oil	Peaking
Sutton	4	49	39	Wilmington, NC	Natural Gas/Oil	Peaking
Sutton	5	49	39	Wilmington, NC	Natural Gas/Oil	Peaking
Wayne	1/10	192	177	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	2/11	192	174	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	3/12	193	173	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	4/13	191	170	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	5/14	195	163	Goldsboro, NC	Oil/Natural Gas	Peaking
Weatherspoon	1	41	31	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	2	41	31	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	3	41	32	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	4	41	30	Lumberton, NC	Natural Gas/Oil	Peaking
Total NC		2,597	2,203			
Total SC		763	613			
Total CT		3,360	2,816			

Combined Cycle						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Lee	CT1A	225	170	Goldsboro, NC	Natural Gas/Oil	Base
Lee	CT1B	227	170	Goldsboro, NC	Natural Gas/Oil	Base
Lee	CT1C	228	170	Goldsboro, NC	Natural Gas/Oil	Base
Lee	ST1	379	378	Goldsboro, NC	Natural Gas/Oil	Base
Smith [4]	CT7	194	154	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	CT8	194	153	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	ST4	182	169	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	CT9	216	174	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	CT10	216	175	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	ST5	248	248	Hamlet, NC	Natural Gas/Oil	Base
Sutton	CT1A	224	170	Wilmington, NC	Natural Gas/Oil	Base
Sutton	CT1B	224	171	Wilmington, NC	Natural Gas/Oil	Base
Sutton	ST1	271	266	Wilmington, NC	Natural Gas/Oil	Base
Total CC		3,028	2,568			

Hydro						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Blewett	1	4	4	Lilesville, NC	Water	Intermediate
Blewett	2	4	4	Lilesville, NC	Water	Intermediate
Blewett	3	4	4	Lilesville, NC	Water	Intermediate
Blewett	4	5	5	Lilesville, NC	Water	Intermediate
Blewett	5	5	5	Lilesville, NC	Water	Intermediate
Blewett	6	5	5	Lilesville, NC	Water	Intermediate
Marshall	1	2	2	Marshall, NC	Water	Intermediate
Marshall	2	2	2	Marshall, NC	Water	Intermediate
Tillery	1	21	21	Mt. Gilead, NC	Water	Intermediate
Tillery	2	18	18	Mt. Gilead, NC	Water	Intermediate
Tillery	3	21	21	Mt. Gilead, NC	Water	Intermediate
Tillery	4	24	24	Mt. Gilead, NC	Water	Intermediate
Walters	1	36	36	Waterville, NC	Water	Intermediate
Walters	2	40	40	Waterville, NC	Water	Intermediate
Walters	3	36	36	Waterville, NC	Water	Intermediate
Total Hydro		227	227			

Nuclear						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
Brunswick [2]	1	975	938	Southport, NC	Uranium	Base
Brunswick[2]	2	953	932	Southport, NC	Uranium	Base
Harris [2]	1	1009	964	New Hill, NC	Uranium	Base
Robinson	2	797	741	Hartsville, SC	Uranium	Base
Total NC		2,937	2,834			
Total SC		797	741			
Total Nuclear		3,734	3,575			

Solar [5]						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
NC Solar		1.4	49.3	NC	Solar	Intermittent

Total Generation Capability		
	Winter Capacity (MW)	**Summer Capacity (MW)**
TOTAL DEP SYSTEM - N.C.	12,382	11,425
TOTAL DEP SYSTEM - S.C.	1,560	1,354
TOTAL DEP SYSTEM	13,942	12,779

Note 1: Ratings reflect compliance with NERC reliability standards.

Note 2: Duke Energy Progress completed the purchase from NCEMC of jointly owned Roxboro 4, Mayo 1, Brunswick 1 & 2 and Harris 1units effective 7/31/2015.

Note 3: Resource type based on NERC capacity factor classifications which may alternate over the forecast period.

Note 4: Richmond County Plant renamed to Sherwood H. Smith Jr. Energy Complex.

Note 5: Solar capacity ratings reflect contribution to winter and summer peak values.

Planned Uprates			
Unit	Completion Date	Winter MW	Summer MW
Brunswick 1 [1]	Spring 2024	4	2
Brunswick 2 [1]	Spring 2027	6	4
Brunswick 2 [1]	Spring 2029	4	2
Brunswick 2 [1]	Spring 2029	6	4

Note 1: Capacity not reflected in Existing Generating Units and Ratings section.

Retirements					
Unit & Plant Name	Location	Capacity (MW) Winter / Summer		Fuel Type	Retirement Date
Cape Fear 5	Moncure, NC	148	144	Coal	10/1/12
Cape Fear 6	Moncure, NC	175	172	Coal	10/1/12
Cape Fear 1A	Moncure, NC	14	11	Combustion Turbine	3/31/13
Cape Fear 1B	Moncure, NC	14	12	Combustion Turbine	3/31/13
Cape Fear 2A	Moncure, NC	15	12	Combustion Turbine	3/31/13
Cape Fear 2B	Moncure, NC	14	11	Combustion Turbine	10/1/12
Cape Fear 1	Moncure, NC	12	11	Steam Turbine	3/31/11
Cape Fear 2	Moncure, NC	12	7	Steam Turbine	3/31/11
Darlington 5	Hartsville, SC	66	51	Combustion Turbine	5/31/18
Darlington 9	Hartsville, SC	65	50	Combustion Turbine	6/30/17
Darlington 11	Hartsville, SC	67	52	Combustion Turbine	11/8/15
Lee 1	Goldsboro, NC	80	74	Coal	9/15/12
Lee 2	Goldsboro, NC	80	68	Coal	9/15/12
Lee 3	Goldsboro, NC	252	240	Coal	9/15/12
Lee 1	Goldsboro, NC	15	12	Combustion Turbine	10/1/12
Lee 2	Goldsboro, NC	27	21	Combustion Turbine	10/1/12
Lee 3	Goldsboro, NC	27	21	Combustion Turbine	10/1/12
Lee 4	Goldsboro, NC	27	21	Combustion Turbine	10/1/12
Morehead 1	Morehead City, NC	15	12	Combustion Turbine	10/1/12
Robinson 1	Hartsville, SC	179	177	Coal	10/1/12
Robinson 1	Hartsville, SC	15	11	Combustion Turbine	3/31/13
Weatherspoon 1	Lumberton, NC	49	48	Coal	9/30/11
Weatherspoon 2	Lumberton, NC	49	48	Coal	9/30/11
Weatherspoon 3	Lumberton, NC	79	74	Coal	9/30/11

Retirements (cont.)					
Unit & Plant Name	**Location**	**Capacity (MW) Winter / Summer**	**Fuel Type**	**Retirement Date**	**Unit & Plant Name**
Sutton 1	Wilmington, NC	98	97	Coal	11/27/13
Sutton 2	Wilmington, NC	95	90	Coal	11/27/13
Sutton 3	Wilmington, NC	389	366	Coal	11/4/13
Sutton GT1	Wilmington, NC	12	11	Combustion Turbine	3/1/17
Sutton GTA	Wilmington, NC	31	23	Combustion Turbine	7/8/17
Sutton GTB	Wilmington, NC	33	25	Combustion Turbine	7/8/17
Total		2,154 MW	1,972 MW		

Planning Assumptions – Unit Retirements [a, b]					
Unit & Plant Name	**Location**	**Winter Capacity (MW)**	**Summer Capacity (MW)**	**Fuel Type**	**Expected Retirement**
Asheville 1	Arden, N.C.	192	189	Coal	11/2019
Asheville 2	Arden, N.C.	192	189	Coal	11/2019
Mayo 1	Roxboro, N.C.	746	727	Coal	12/2035
Roxboro 1	Semora, N.C.	380	379	Coal	12/2028
Roxboro 2	Semora, N.C.	673	665	Coal	12/2028
Roxboro 3	Semora, N.C.	698	691	Coal	12/2033
Roxboro 4	Semora, N.C.	711	698	Coal	12/2033
Darlington 1	Hartsville, S.C.	63	52	Natural Gas/Oil	12/2020
Darlington 2	Hartsville, S.C.	64	48	Oil	12/2020
Darlington 3	Hartsville, S.C.	63	52	Natural Gas/Oil	12/2020
Darlington 4	Hartsville, S.C.	66	50	Oil	12/2020
Darlington 6	Hartsville, S.C.	62	45	Oil	12/2020
Darlington 7	Hartsville, S.C.	65	51	Natural Gas/Oil	12/2020
Darlington 8	Hartsville, S.C.	66	48	Oil	12/2020
Darlington 10	Hartsville, S.C.	65	51	Oil	12/2020
Blewett 1	Lilesville, N.C.	17	13	Oil	12/2024
Blewett 2	Lilesville, N.C.	17	13	Oil	12/2024
Blewett 3	Lilesville, N.C.	17	13	Oil	12/2024
Blewett 4	Lilesville, N.C.	17	13	Oil	12/2024
Weatherspoon 1	Lumberton, N.C.	41	32	Natural Gas/Oil	12/2024
Weatherspoon 2	Lumberton, N.C.	41	32	Natural Gas/Oil	12/2024
Weatherspoon 3	Lumberton, N.C.	41	33	Natural Gas/Oil	12/2024
Weatherspoon 4	Lumberton, N.C.	41	31	Natural Gas/Oil	12/2024
Total		4,338	4,115		

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

Planning Assumptions – Unit Additions					
Unit & Plant Name	**Location**	**Winter Capacity (MW)**	**Summer Capacity (MW)**	**Fuel Type**	**Expected Commercial Date**
Asheville CC	Arden, N.C.	560	495	Natural Gas	11/2019

Operating License Renewal

Planned Operating License Renewal				
Unit & Plant Name	**Location**	**Original Operating License Expiration**	**Date of Approval**	**Extended Operating License Expiration**
Blewett #1-6 [1]	Lilesville, NC	04/30/08	April 2015	2055
Tillery #1-4 [1]	Mr. Gilead, NC	04/30/08	April 2015	2055
Robinson #2	Hartsville, SC	07/31/10	04/19/2004	07/31/2030
Brunswick #2	Southport, NC	12/27/14	06/26/2006	12/27/2034
Brunswick #1	Southport, NC	09/08/16	06/26/2006	09/08/2036
Harris #1	New Hill, NC	10/24/26	12/12/2008	10/24/2046

Note 1: The license renewal for the Blewett and Tillery Plants was received in April 2015. The license extension was granted for 40 years.

14. 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 14-A Wholesale Sales Contracts

DEP Aggregated Wholesale Sales Contracts									
Commitment (MW)									
2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
3,750	4,107	4,100	4,148	4,199	4,249	4,045	4,095	4,043	4,094

Notes:

- For wholesale contracts, Duke Energy Progress/Duke Energy Carolinas assume all wholesale sales contracts will renew unless there is an indication that the contract will not be renewed.
- Table represents winter capacity.

Table 14-B Firm Wholesale Purchase Power Contracts

Purchased Power Contract	Summer Capacity (MW)	Location	Volume of Purchases (MWh) Jul 17-Jun 18
Peaking / Gas	1583	NC/SC	2,518,800
Intermediate / Gas	150	NC	1,342,585

Notes:

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

15. FUEL COMMODITY PRICES

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

DEP Annual Average Fuel Prices, $/MMBtu			
Year	Natural Gas Henry Hub	Coal DEP Average	Fuel Oil Average
2020	$2.50	$2.49	$14.48
2021	$2.57	$2.52	$14.15
2022	$2.61	$2.55	$13.97
2023	$2.68	$2.63	$14.13
2024	$2.78	$2.93	$14.55
2025	$2.90	$3.24	$14.99
2026	$3.01	$3.54	$15.44
2027	$3.12	$3.85	$15.90
2028	$3.25	$4.15	$16.38
2029	$3.39	$4.45	$16.87
2030	$3.68	$4.55	$17.53
2031	$4.07	$4.67	$18.20
2032	$4.50	$4.82	$18.86
2033	$5.04	$4.93	$19.52
2034	$5.30	$5.07	$20.18

TABLE 16-A CROSS-REFERENCE TABLE

This section contains a cross-reference table, Table 16-A, that provides the document location of information required by both NCUC and PSCSC in this 2019 IRP Update report.

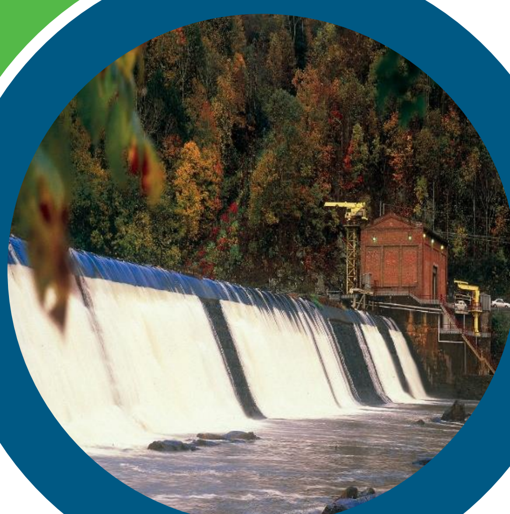
	REQUIREMENT:	CHAPTER LOCATION:
1.	Summary of significant amendments or revisions to most recently filed biennial report (including amendments to type and size of resources identified	Chapters 2, 4
2.	The electric utility's annual update must describe the impact of the updated base planning assumptions on the selected resource plan.	Chapter 9
3.	Short-Term Action Plan	Chapter 11
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, 9
8.	Description of future supply-side resources including type of capacity / resource (MW rating, fuel source, base, intermediate, or peaking)	Chapter 9
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 13
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 9, 10, 11

	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 15
13.	Cumulative resource additions necessary to meet load obligation & reserve margins	Chapters 9, 10, 11, 12

DUKE ENERGY.
PROGRESS

ATTACHMENT I:

The Duke Energy Progress NC Renewable Energy & Energy Efficiency Portfolio Standard (NC REPS)



DUKE ENERGY PROGRESS NC REPS COMPLIANCE PLAN CONTENTS:

I. INTRODUCTION

Duke Energy Progress, LLC ("DEP" 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 Progress 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 Progress' 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 Progress 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. The Company's contracts with wholesale customers for whom it supplied REPS compliance services terminated on December 31, 2017; therefore, this Compliance Plan only reflects REPS compliance services for DEP's retail customers. Table 1 below shows the Company's retail customers' REPS Compliance Obligation.

[1] For the purposes of this Compliance Plan, Compliance Obligation is more specifically defined as Duke Energy Progress' native load obligations for the Company's retail sales. The Company's contracts with the Town of Sharpsburg, the Town of Stantonsburg, the Town of Lucama, the Town of Black Creek and the Town of Winterville terminated on December 31, 2017.

Table 1: Duke Energy Progress' NC REPS Compliance Obligation

Compliance Year	Previous Year DEP Retail Sales (MWhs) (1)	Solar Set-Aside (RECs)	Swine Set-Aside (RECs)	Poultry Set-Aside (RECs)	REPS Requirement (%)	Total REPS Compliance Obligation (RECs)
2019	38,687,268	77,375	27,081	197,318	10%	3,868,727
2020	37,964,762	75,930	26,575	253,695	10%	3,796,476
2021	38,124,840	76,250	53,375	253,695	12.5%	4,765,605

(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.

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. 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 77,375 RECs in 2019. Based on forecasted retail sales, the Solar Set-Aside is projected to be approximately 75,930 RECs in 2020 and 76,250 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.

- Camp Lejeune Solar Facility – 13MW, located in Onslow County, placed in service in November 2015;
- Warsaw Solar Facility – 65MW, located in Duplin County, placed in service in December 2015;
- Fayetteville Solar Facility – 23MW, located in Bladen County, placed in service in December 2015; and
- Elm City Solar Facility – 40MW, located in Wilson County, placed in service in March 2016.

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 27,081 RECs in 2019, 26,575 RECs in 2020, and 53,375 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[2] 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 three contracts to purchase swine waste-derived directed biogas from projects in North Carolina. One of these projects, Optima KV, successfully interconnected

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

with Piedmont in March 2018 and is sending biogas to DEP's Smith Energy Complex where swine RECs are being generated, and the other two projects are expected to come online in 2020. 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.

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[3] 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) 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; (3) explores modifications to current biomass and set-asides contracts by working with developers to add swine waste to their fuel mix; (4) continues pursuit of swine-derived

[3] "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.

directed biogas from North Carolina facilities to be directed to DEP's combined cycle plants for combustion and generation; (5) utilizes the broker market for out-of-state swine RECs available in the market; (6) 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 (7) participates in the North Carolina Energy Policy Council Biogas Working Group.

In spite of Duke Energy Progress' active and diligent efforts to comply with its Swine Waste Set-Aside requirements, current projections indicate that DEP will not be able to comply with the swine waste set-aside in 2019, as existing contracts have not been able to reach contracted levels of production, and new contracts have not come online in the timeframe originally planned. Several swine projects are scheduled to come online over the next few years. The ability of these facilities to achieve projected delivery requirements and commercial operation milestones will determine the levels of compliance that DEP is able to meet in 2020 and 2021. 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 two contracts for swine waste RECs since 2017 due to failure to perform, the Company was notified by another project in January 2019 that the project will not be continuing due to failure to operate. Due to its expected non-compliance in 2019, the Company will submit a motion to the Commission for approval of a request to lower the 2019 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 28%, the Company's Poultry Waste Set-Aside is estimated to be 197,318 RECs in 2019, 253,695 RECs in 2020, and 253,695 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 Progress 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 facility came online in 2018, and another is expected to come online in the third quarter of 2019. However, a third is undergoing an outage to perform repairs, and three contracts for out-of-state poultry waste RECs were terminated due to failure to perform or force majeure issues. DEP'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, DEP is required to comply with its Total Obligation by submitting for retirement a total volume of RECs equivalent to 10% of prior-year retail sales in North Carolina in 2019 and, 2020, and 12.5% of prior-year retail sales in North Carolina in 2021. Based on the Company's actual retail sales in 2018, the Total Requirement is 3,868,727 RECs in 2019. Based on forecasted retail sales, the Total Requirement is projected to be approximately 3,796,476 RECs in 2020, and 4,765,605 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 3,566,953 RECs in 2019, 3,440,276 RECs in 2020, and 4,382,286 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 otherwise procured, 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 Progress plans to meet a significant 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 is using solar resources to contribute to our compliance efforts beyond the Solar Set-Aside minimum threshold for NC REPS, and will continue to do so during the Planning Period.

i. Net Metering Facilities

Under the current Net Metering for Renewable Energy Facilities Rider offered by DEP (Rider NM-4B), a customer receiving electric service under a schedule other than a time-of-use schedule with demand rates shall provide any RECs to DEP at no cost. Per the NCUC's June 2018 *Order Approving Rider and Granting Waiver Request*, filed in Docket No. E-2, Sub 1106, since net metering generators are not individually metered, DEP is permitted to estimate the RECs generated by these facilities using the PVWatts Solar Calculator developed by the National Renewable Energy Laboratory. Thus, DEP 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 DEP's net metering tariff, DEP retains the rights to the RECs from these facilities, as described in the net metering section above. In addition, under HB 589, DEP 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. 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 Progress 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 Progress 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 Progress plans to use hydroelectric power from hydroelectric generation suppliers whose facilities have received Qualifying Facility (QF or QF Hydro) status. RECs from QF Hydro facilities will be used towards the General Requirements of Duke Energy Progress' retail customers. Please see Exhibit A for more information on these contracts.

5. Wind

Duke Energy Progress considers wind a potential viable option to support increased diversity of the renewables portfolio and potentially long-term general compliance needs. 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. DEP 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 Progress 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. COST IMPLICATIONS OF REPS COMPLIANCE PLAN

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 DEP 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

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

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

Table 3: Retail Sales

	2018 Actual	2019 Forecast	2020 Forecast	2021 Forecast
Retail MWh Sales	38,687,268	37,964,762	38,124,840	38,208,829

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.

Table 4: Retail Year-end Number of Customer Accounts

	2018 (Actual)	2019 (Projected)	2020 (Projected)	2021 (Projected)
Residential Accts	1,210,740	1,220,728	1,233,140	1,246,567
General Accts	195,967	198,344	199,900	199,936
Industrial Accts	1,810	1,800	1,790	1,777

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

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	$ 244,072,357	$ 252,126,388	$ 233,984,530
Recovered through the Fuel Rider	$ 201,068,979	$ 203,028,452	$ 183,187,701
Total incremental costs (REPS Rider)	$ 43,003,378	$ 49,097,936	$ 50,796,828
Total including Regulatory Fee	$ 43,063,667	$ 49,166,769	$ 50,868,043
Projected Annual Cost Caps (REPS Rider)	$ 63,895,030	$ 64,511,427	$ 65,069,892

EXHIBIT A

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

[BEGIN CONFIDENTIAL]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[END CONFIDENTIAL]

EXHIBIT B

Duke Energy Progress, LLC’s 2019 REPS Compliance Plan
Duke Energy Progress, 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	21,361,415	21,046,461	18,501,587
Energy Education Program for Schools	3,781,055	4,083,659	4,042,979
Multi-Family Energy Efficiency	13,509,474	13,888,978	13,194,824
My Home Energy Report	99,252,843	98,147,032	103,767,203
Neighborhood Energy Saver	1,922,046	1,197,596	1,197,596
Residential Energy Assessments	5,700,445	10,905,498	11,817,810
Residential New Construction	4,963,168	2,187,745	2,297,132
Residential Smart $aver® Energy Efficiency	5,355,774	4,913,142	4,922,903
Low Income Weatherization Pay for Performance Pilot	8,714	0	0
Sub Total	**155,854,935**	**156,370,110**	**159,742,034**
Non-Residential Programs	**2019**	**2020**	**2021**
Non-Residential Smart $aver® EE Products & Assessment	67,632,538	91,015,448	99,287,245
Non-Residential Smart $aver® Performance Incentive	325,540	3,120,818	4,340,451
Small Business Energy Saver	35,886,412	33,358,290	31,676,953
EnergyWise for Business	49,099	46,746	46,746
Sub Total	**103,893,589**	**127,541,302**	**135,351,395**
Combined Residential and Non-Residential Programs	**2019**	**2020**	**2021**
Energy Efficient Lighting	69,170,415	32,724,972	24,052,824
Sub Total	**69,170,415**	**32,724,972**	**24,052,824**
Total	**328,918,938**	**316,636,384**	**319,146,253**

DEP Energy Efficiency Programs

DEP 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 EE Programs
- Energy Efficient Appliances and Devices
- Energy Efficiency Education
- Multi-Family Energy Efficiency
- My Home Energy Report
- Neighborhood Energy Saver
- Residential Energy Assessments
- Residential New Construction
- Residential Smart $aver® Energy Efficiency
- Low Income Weatherization Pay for Performance Pilot

Non-Residential EE Programs
- Non-Residential Smart $aver® Energy Efficiency Products and Assessment
- Non-Residential Smart $aver® Performance Incentive
- Small Business Energy Saver
- EnergyWise for Business

Combined Residential/Non-Residential EE Programs
- Energy Efficient Lighting

Residential EE Programs

Energy Efficient Appliances and Devices Program

The Energy Efficient Appliances and Devices Program is a new program that combines DEP's previous "Save Energy and Water Kit" with a variety of high efficiency products available through the Company's Online Savings Store, including but not limited to Air Purifiers, Dehumidifiers and LED Fixtures. The Save Energy and Water kit offers low flow water fixtures and insulating pipe tape to residential single-family homeowners with electric water heaters. Program participants are eligible for one kit shipped free of charge to their home. Kits are available in two sizes for homes with one or more full bathrooms and contain varying quantities of shower heads, bathroom aerators, kitchen aerator and insulating pipe tape.

Energy Efficiency Education Program

The 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 Progress. 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.

Multi-Family Energy Efficiency Program

The 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 Progress to target multi-family apartment complexes with an alternative delivery channel. 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

The My Home Energy Report (MyHER) 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.

Neighborhood Energy Saver (Low-Income) Program

DEP's Neighborhood Energy Saver Program reduces energy usage through the direct installation of energy efficiency measures within the households of income qualifying residential customers. The Program utilizes a Company-selected vendor to: (1) provide an on-site energy assessment of the residence to identify appropriate energy conservation measures, (2) install a comprehensive package of energy conservation measures at no cost to the customer, and (3) provide one-on-one energy education. Program measures address end-uses in lighting, refrigeration, air infiltration and HVAC applications.

Program participants receive a free energy assessment of their home followed by a recommendation of energy efficiency measures to be installed at no cost to the resident. A team of energy technicians will install applicable measures and provide one-on-one energy education about each measure emphasizing the benefit of each and recommending behavioral changes to reduce and control energy usage.

Residential Energy Assessments Program

The 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.

Residential New Construction Program

The Residential New Construction Program provides incentives for new single family and multi-family residential dwellings (projects of three stories and less) that fall within the 2012 North Carolina

Residential Building Code to meet or exceed the 2012 North Carolina Energy Conservation Code High Efficiency Residential Option ("HERO"). If a builder or developer constructing to the HERO standard elects to participate, the Program offers the homebuyer an incentive guaranteeing the heating and cooling consumption of the dwelling's total annual energy costs. Additionally, the Program incents the installation of high-efficiency heating, ventilating and air conditioning ("HVAC") and heat pump water heating ("HPWH") equipment in new single family, manufactured, and multi-family residential housing units.

New construction represents a unique opportunity for capturing cost effective EE savings by encouraging the investment in energy efficiency features that would otherwise be impractical or more costly to install at a later time.

Residential Smart $aver® Energy Efficiency Program

The Residential Smart $aver® EE Program offers DEP customers a variety of energy conservation measures designed to increase energy efficiency in existing residential dwellings. The Program utilizes a network of participating contractors to encourage the installation of: (1) high efficiency central air conditioning (AC) and heat pump systems with optional add on measures such as Quality Installation and Smart Thermostats, (2) attic insulation and sealing, (3) heat pump water heaters, and (4) high efficiency variable speed pool pumps.

The prescriptive menu of energy efficiency measures provided by the program allows customers the opportunity to participate based on the needs and characteristics of their individual homes. A referral channel provides free, trusted referrals to customers seeking reliable, qualified contractors for their energy saving home improvement needs.

Low Income Weatherization Pay for Performance Pilot

The Low Income Weatherization Pay for Performance Pilot was designed to provide payments, based on kilowatt-hour ("kWh") savings, to local non-profit organizations that provide weatherization and other energy saving upgrades to residential low-income households. These payments are intended to assist the organizations in expanding the number of customers they serve through their programs. The Pilot is also intended to leverage funding from other third-party sources. The Company is proposing that this Pilot remain in place for thirty-six months and begin in Buncombe County, North Carolina.

Non-Residential EE Programs

Non-Residential Smart $aver® Energy Efficient Products and Assessment Program

The Non-Residential Smart $aver® Energy Efficient Products and Assessment Program provides incentives to DEP commercial and industrial customers to install high efficiency equipment in applications involving new construction and retrofits and to replace failed equipment.

Commercial and industrial customers can have significant energy consumption but may lack knowledge and understanding of the benefits of high efficiency alternatives. The Program provides financial incentives to help reduce the cost differential between standard and high efficiency equipment, offer a quicker return on investment, save money on customers' utility bills that can be reinvested in their business, and foster a cleaner environment. 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.

The program provides incentives through prescriptive measures, custom measures and technical assistance.

- ***Prescriptive Measures*****:** Customers receive incentive payments after the installation of certain high efficiency equipment found on the list of pre-defined prescriptive measures, including lighting; heating, ventilating and air conditioning equipment; and refrigeration measures and equipment.
- ***Custom Measures*****:** Custom measures are designed for customers with electrical energy saving projects involving more complicated or alternative technologies, whole-building projects, or those measures not included in the Prescriptive measure list. 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 Prescriptive portion of the program, all Custom measure incentives require pre-approval prior to the project implementation.
- ***Energy Assessments and Design Assistance*****:** Incentives are available to assist customers with energy studies such as energy audits, retro commissioning, and system-specific energy audits for existing buildings and with design assistance such as energy modeling for new construction. Customers may use a contracted Duke Energy vendor to perform the work or they may select their own vendor. Additionally, the Program assists customers who identify measures that may qualify for Smart $aver Incentives with their applications. Pre-approval is required.

Non-Residential Smart $aver® Performance Incentive Program

The Non-Residential Smart $aver® Energy Efficient Products and Assessment Program offers financial assistance to qualifying commercial, industrial and institutional customers to enhance their ability to adopt and install cost-effective electrical energy efficiency projects. The Program 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. Incentive payments are provided to offset a portion of the higher cost of energy efficient installations that are not eligible under either the Smart $aver® Prescriptive or Custom programs. The Program requires pre-approval prior to project initiation.

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. The intent of the Program is to broaden participation in non-residential efficiency programs by being able to provide incentives for projects that previously were deemed too unpredictable to calculate an acceptably accurate savings amount, and therefore ineligible for incentives. This Program provides a platform to understand new technologies better. Only projects that demonstrate that they clearly reduce electrical consumption and/or demand are eligible for incentives.

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.

Small Business Energy Saver Program

The Small Business Energy Saver Program reduces energy usage through the direct installation of energy efficiency measures within qualifying non-residential customer facilities. Program measures address major end-uses in lighting, refrigeration, and HVAC applications. The program is available to existing non-residential customers that are not opted-out of the Company's EE/DSM rider and have an average annual demand of 180 kW or less per active account.

Program participants receive a free, no-obligation energy assessment of their facility followed by a recommendation of energy efficiency measures to be installed in their facility along with the projected energy savings, costs of all materials and installation, and up-front incentive amount from Duke Energy Progress. The customer makes the final determination of which measures will be installed after receiving the results of the energy assessment. The Company-authorized vendor schedules the installation of the energy efficiency measures at a convenient time for the customer, and electrical subcontractors perform the work.

EnergyWise for Business Program

EnergyWise for Business is both an energy efficiency and demand response ("DR") 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/back up 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.

Combined Residential/Non-Residential Customer Programs

Energy Efficient Lighting Program

The Energy Efficient Lighting Program partners with lighting manufacturers and retailers across North and South Carolina to provide marked-down prices at the register to DEP customers purchasing energy efficient lighting products. Starting in 2017, the Program removed CFLs and only offers LEDs and energy-efficient fixtures.

As the program enters its eighth year, the DEP Energy Efficient Lighting Program will continue to encourage customers to adopt energy efficient lighting through incentives on a wide range of energy efficient lighting products. Customer education is imperative to ensure customers are purchasing the right bulb for the application in order to obtain high satisfaction with lighting products and subsequent purchases.

ATTACHMENT II:

The Duke Energy Progress 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:

<u>(i) Fostering Diversification of Siting of Additional Renewable Energy Resources</u>[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

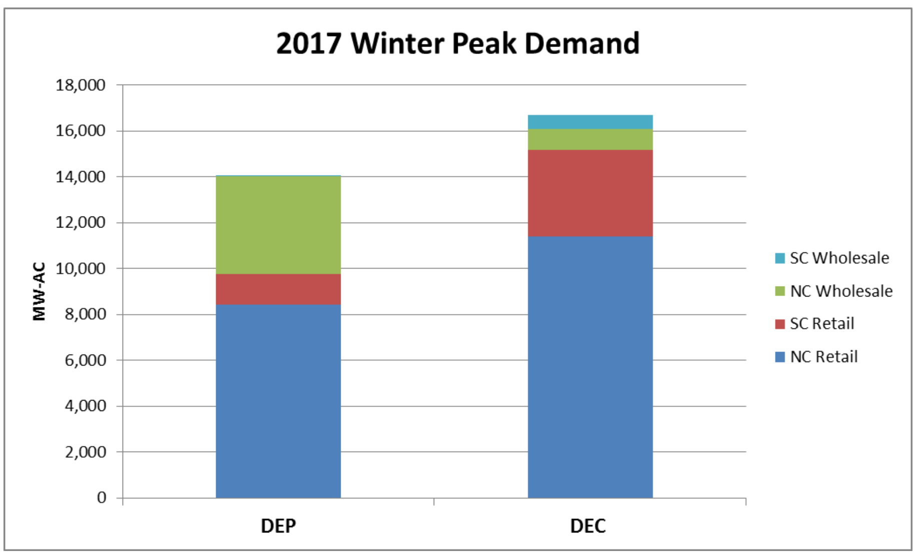
[3] All Proposals bid into the Tranche 1 CPRE RFP Solicitation were utility-scale solar generating facilities. The Companies have primarily analyzed the need for additional diversification of siting for utility-scale solar resources. The Companies may consider the need to analyze diversification of siting 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]



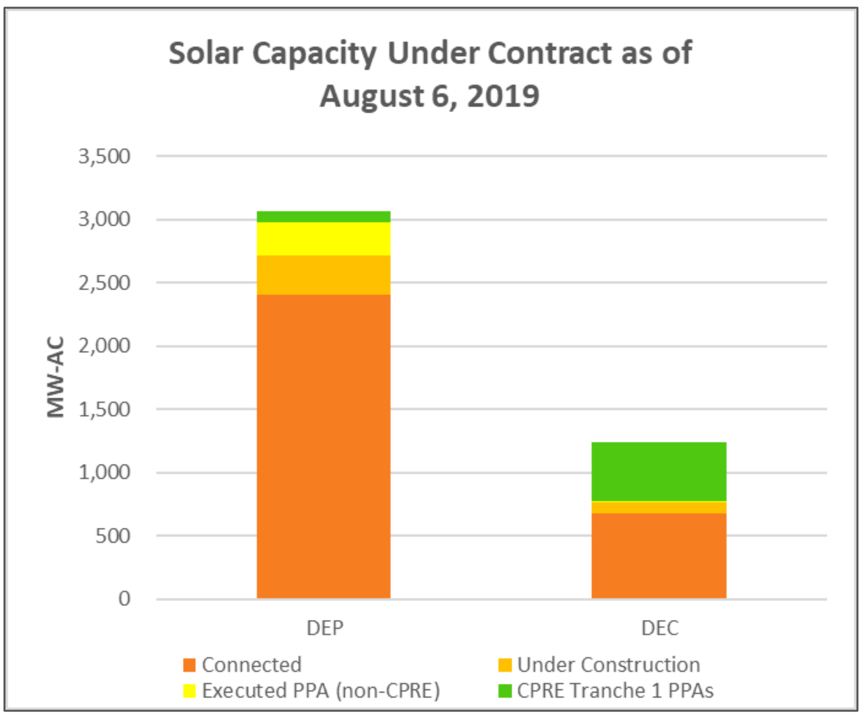
While DEP is a smaller BA, the Companies have experienced a significantly greater concentration of utility-scale solar development in DEP compared to DEC. As of August 6, 2019, the Companies are contractually obligated to purchase from third-party owners approximately 3,748 MW of solar under REPS and 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



<u>(ii) System Operations and Reliability Impacts</u>

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.

BUILDING A **SMARTER** ENERGY FUTURE℠

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