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August 31, 2018

VIA ELECTRONIC FILING

The Honorable Jocelyn G. Boyd
Chief Clerk / Administrator
Public Service Commission of South Carolina
101 Executive Center Drive, Suite 100
Columbia, SC 29210

Re: Duke Energy Carolinas, LLC 2018 Integrated Resource Plan

Dear Ms. Boyd:

Pursuant to SC Code § 58-37-40, enclosed for filing is Duke Energy Carolinas, LLC's ("DEC") 2018 Integrated Resource Plan Annual Report ("2018 DEC IRP"). In addition to the 2018 DEC IRP being electronically filed with the Commission, we are also hand-delivering bound copies to the Office of Regulatory Staff and the State Energy Office.

Please contact me should you have any questions.

Kind regards,

Sam Wellborn

SJW:tch

Enclosures

cc w/enc: Jeffrey M. Nelson, ORS Chief Legal Officer (via email & hand delivery)
Dawn Hipp, ORS Utility Rates & Services Director (via email)
Anthony James, State Energy Office Director of Energy Policy (via email & hand delivery)
Heather Shirley Smith, Deputy General Counsel (via email)
Rebecca J. Dulin, Senior Counsel (via email)

DUKE ENERGY CAROLINAS

DUKE ENERGY CAROLINAS

SOUTH CAROLINA
INTEGRATED RESOURCE PLAN

2018

DEC SC 2018 IRP CONTENTS:

ABBREVIATIONS:

10 CFR	**Title 10 of the Code of Federal Regulations**
AC	**Alternating Current**
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**
CCS	**Carbon Capture and Sequestration**
CECPCN	**Certificate of Environmental Compatibility and Public Convenience and Necessity (SC)**
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**
DIY	**Do It Yourself**
DOE	**Department of Energy**
DOJ	**Department of Justice**
DSM	**Demand-Side Management**
EE	**Energy Efficiency Programs**
EIA	**Energy Information Administration**
EPA	**Environmental Protection Agency**
EPC	**Engineering, Procurement, and Construction Contractors**
EPRI	**Electric Power Research Institute**
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**
GEH	**GE Hitachi**
GHG	**Greenhouse Gas**
GWh	**Gigawatt-hour**
HB 589	**North Carolina House Bill 589**
HVAC	**Heating, Ventilation and Air Conditioning**
HRSG	**Heat Recovery Steam Generator**
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	**Investment Tax Credit**
IVVC	**Integrated Volt-Var Control**
JDA	**Joint Dispatch Agreement**
kW	**Kilowatt**
kWh	**Kilowatt-hour**
LCR Table	**Load, Capacity, and Reserves Table**
LEED	**Leadership in Energy and Environmental Design**
LED	**Light Emitting Diodes**
LEO	**Legally Enforceable Obligation**
LFE	**Load Forecast Error**
LNG	**Liquified Natural Gas**
LOLE	**Loss of Load Expectation**
MACT	**Maximum Achievable Control Technology**
MATS	**Mercury Air Toxics Standard**
MGD	**Million Gallons Per Day**
MW	**Megawatt**
MWh	**Megawatt-hour**
NAPP	**Northern Appalachian Coal**
NAAQS	**National Ambient Air Quality Standards**
NAP	**Northern Appalachian Coal**
NEMS	**National Energy Modeling Systems**
M&V	**Measurement and Verification**
NC	**North Carolina**
NCCSA	**North Carolina Clean Smokestacks Act**

ABBREVIATIONS:

NCDAQ	North Carolina Division of Air Quality
NCEMC	North Carolina Electric Membership Corporation
NCMPA1	North Carolina Municipal Power Agency #1
NCTPC	NC Transmission Planning Collaborative
NCUC	North Carolina Utilities Commission
NERC	North American Electric Reliability Corp
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_x	Nitrogen Oxide
NES	Neighborhood Energy Saver
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standard
NYMEX	New York Mercantile Exchange
NUREG	Nuclear Regulatory Commission Regulation
OATT	Open Access Transmission Tariff
O&M	Operating and Maintenance
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 Requirements
QF	Qualifying Facility
RCRA	Resource Conservation Recovery Act
REC	Renewable Energy Certificates
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

ABBREVIATIONS:

SCE&G	**South Carolina Electric & Gas**
SC DER or SC ACT 236	**South Carolina Distributed Energy Resource Program**
SCR	**Selective Catalytic Reduction**
SEPA	**Southeastern Power Administration**
SERC	**SERC Reliability Corporation**
SERVM	**Strategic Energy Risk Valuation Model**
SG	**Standby Generation**
SIP	**State Implementation Plan**
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**
T&D	**Transmission & Distribution**
TAG	**Technology Assessment Guide**
TRC	**Total Resource Cost**
TVA	**Tennessee Valley Authority**
THE COMPANY	**Duke Energy Carolinas**
THE PLAN	**Duke Energy Carolinas Annual Plan**
UEE	**Utility Energy Efficiency**
UG/M^3	**Micrograms Per Cubic Meter**
UCT	**Utility Cost Test**
VACAR	**Virginia/Carolinas**
VAR	**Volt Ampere Reactive**
WERP	**Weatherization and Equipment Replacement Program**
ZELFRS	**Zero – Emitting Load Following Resources**

1. EXECUTIVE SUMMARY

For more than a century, Duke Energy Carolinas (DEC or the Company) has provided affordable and reliable electricity to customers in South Carolina (SC) and North Carolina (NC) now totaling more than 2.6 million in number. The Company continues to serve its growing number of customers by planning for future resource needs in the most reliable and economic way possible while using increasingly clean forms of energy to meet those needs.

Historically, each year, as required by the Public Service Commission of South Carolina (PSCSC) and the North Carolina Utilities Commission (NCUC), DEC submits a long-range planning document called the Integrated Resource Plan (IRP). The IRP details potential infrastructure needed to match the forecasted electricity requirements and a reasonable reserve margin to maintain system reliability for our customers over the next 15 years.

The Company files separate IRPs for South Carolina and North Carolina. However, the IRP analyzes the system as one DEC utility across both states including customer demand, energy efficiency (EE), demand-side management (DSM), renewable resources and traditional supply-side resources. As such, the quantitative analysis contained in both the South Carolina and North Carolina filings is identical, while certain sections dealing with state-specific issues such as state renewable standards or environmental standards may be specific to that state's IRP.

This report is intended to provide stakeholders insight into the Company's planning process for meeting forecasted customer peak demand and cumulative energy needs over the 15-year planning horizon. Such stakeholders include: legislative policymakers, public utility commissioners and their staffs, other regulatory entities, retail customers, wholesale customers, environmental advocates, renewable resource industry groups and the general public.

2018 IRP SUMMARY

Objectives:

The 2018 IRP is the best projection of how the Company's resource portfolio is expected to evolve based on current data and assumptions. This projection may change over time as variables such as the projected load forecasts, fuel price forecasts, federal and state regulations, technology performance and cost characteristics and other outside factors change.

Consistent with the Company's commitment to a smarter energy future, the resource plans presented within this IRP meet the following objectives:

- Improve the environmental footprint of the resource portfolio reducing carbon dioxide (CO_2) emissions by at least 40% from 2005 levels by 2030 with approximately 60% of electricity coming from carbon-free clean energy sources.
- Ensure adequate resource reserves are available over the planning horizon to provide reliable electric service 365 days a year, 24 hours a day, especially during periods of high demand such as cold winter mornings.
- Develop resource plans that result in the lowest reasonable cost to customers in order to provide affordable power for the residents, businesses and communities that depend on DEC.
- Produce robust plans that recognize current trends and future uncertainty in the way power is both produced and consumed given technology advancements in power supply and consumer usage.

Resource Need:

To maintain long-term reliability, new resource additions are required to meet growing customer demand and to allow for the retirement of aging resources. While extensive Company-sponsored energy efficiency programs help to reduce energy consumption, industry, businesses and residents continue to grow and expand in DEC's service territory. The Company projects the addition of 445,000 new customers contributing to approximately 2,650 MW of additional winter peak demand on the system with annual energy consumption growing by approximately 12,000 GWh between 2019 and 2033. This represents an annual demand growth rate of 0.9% and an energy growth rate of 0.8%. In addition to growing demand, DEC is planning for the potential retirement of some of its older, less efficient generation, creating an additional need of 1,258 MW. Finally, beyond just meeting expected consumer demand and replacing retired resources, the plan must also be capable of covering uncertainty caused by variables such as extreme cold weather events or unexpected resource outages. Planning for this uncertainty requires the incorporation of a 17% winter planning reserve margin ensuring that adequate resources are available to reliably serve customers despite these uncertainties. In total, customer growth, retirements and necessary reserves will result in the need for approximately 4,059 MW of new resources over the planning horizon.

Planned Additions:

As discussed in more detail in this report, the company examined several different resource portfolio options to see how each would perform under varying future state assumptions. The development of the base resource plans that best met the previously stated objectives resulted in the addition of a diverse mix of energy efficiency (EE), Demand-Side Management (DSM), renewable energy resources, additional hydro-pumped storage resources and natural gas resources. The plans also contemplate the addition of grid-connected battery storage projects given their potential to provide solutions for the generation, transmission and distribution systems with the possibility of simultaneously providing benefits to the generation resource portfolio. Technical advancements and declining cost trends in distributed energy resources such as battery storage, distributed solar generation and demand-side management initiatives give rise to a future resource portfolio that is comprised of both centralized resources as well as a growing penetration of distributed resources. This document discusses the Company's efforts to evolve its planning models to better evaluate these distributed resources as they are integrated into the generation, transmission and distribution systems along with centralized generation, such as natural gas and nuclear generation facilities. The graph below shows the Company's 2019 starting resource portfolio capacity mix in the upper left pie chart while the upper right chart shows the 2033 projected portfolio at the end of the planning horizon. The pie chart on the bottom illustrates the incremental resource additions made over the planning horizon.

Figure Exec-1: 2019 and 2033 Capacity Mix and Sources of Incremental Capacity Additions

As shown in Figure Exec-1, DEC continues to reduce its dependence on coal fired generation with installed coal capacity dropping from 29% of the total portfolio in 2019 to a projection of only 18% by 2033. Renewable resources, energy efficiency and demand-side management double, growing from 8% of the capacity mix in 2019 to 16% in 2033, while natural gas resources also increase by 8% growing to 32% of the mix by 2033.

As the bottom pie chart indicates, the plan calls for significant additions of predominantly solar renewable generation, as well as, efficient natural gas resources to provide dispatchable power at night or when solar output is interrupted due to cloud cover, snow cover or other factors. Additionally, battery storage and previously mentioned enhancements to the existing hydro-pumped storage facilities will provide incremental energy storage to the DEC portfolio. This additional storage will further help to integrate distributed solar resources into the resource portfolio.

No new nuclear generation is added to the system, nor do the base plans contemplate nuclear retirements over the planning period. The slight drop in nuclear capacity from 25% of the portfolio to 21% between 2019 and 2033 is a simple result of the same level of nuclear capacity representing a smaller percentage of a larger portfolio by the end of the planning horizon.

Nuclear Generation:

Low natural gas prices, the absence of national carbon regulation and other industry factors have collectively moved the need for new nuclear generation outside the current planning window. Clean, carbon-free nuclear generation from existing units provides approximately 25% of the installed capacity in DEC's resource portfolio while accounting for nearly one half of the total energy produced.

Unlike almost all other resource options, nuclear units provide clean power around the clock every day of the year, except for small periods of outages for refueling and maintenance. As such, nuclear generation is an essential component of the Company's commitment to the provision of affordable, reliable and increasingly clean power.

DEC currently has operating licenses from the Nuclear Regulatory Commission (NRC) that allows the Company to operate its units for sixty years. To ensure these valuable resources are available for the next generation, the Company is working within the framework established by the NRC to evaluate the potential for subsequent license renewals (SLR) of its nuclear units.

SLR would give the Company the option to operate an additional twenty years. Chapter 10 describes the Company's ongoing efforts toward the evaluation of SLR.

Renewable Energy and Energy Efficiency:

DEC continues to aggressively pursue additional cost-effective renewable resources as a growing part of its energy portfolio. The Company's commitment, coupled with supporting federal tax credits and state legislation such as South Carolina's Distributed Energy Resource Program Act (SC DER or SC Act 236), North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS) and NC House Bill 589 (HB 589) have led to significant growth in renewable resource development in the Carolinas. DEC is now among the national leaders in the adoption of solar generation with this year's plan, showing a near tripling of the amount of installed solar capacity over the planning horizon. The 2018 IRP calls for installed solar capacity to grow from approximately 1,200 MW in 2019 to over 3,400 MW in 2033. Chapter 5 of the plan discusses the importance of the Competitive Procurement of Renewable Energy (CPRE) process as a mechanism to acquire new solar resources at the lowest possible cost for customers. Additionally, Chapter 5 discusses future physical and economic factors that will ultimately influence the amount of solar generation that can reliably and affordably be incorporated into DEC's resource portfolio.

In addition to growing renewable generation in the plan, DEC is actively investing in EE and DSM programs that promote, educate and incentivize the efficient utilization of power. DEC offers a wide range of EE programs to its residential, commercial and industrial customers to help them reduce their power consumption. These efforts are expected to help decrease the projected growth in annual energy consumption by approximately 20% over the planning horizon.

Dispatchable Natural Gas:

An important component of DEC's resource portfolio is the addition of dispatchable natural gas resources that are required for long-term system reliability, as well as for the provision of day-to-day, hour-to-hour and even minute-to-minute load following capabilities. Improvements in natural gas turbine technology provides additional flexibility to the resource portfolio relative to older assets that are being retired, while efficiency improvements reduce the amount of fuel required to produce the same amount of electricity. These technology developments make these natural gas technologies attractive, resulting in a resource portfolio with a smaller environmental footprint while also providing additional real-time ramping capabilities to better follow changes in system load requirements and varying levels of solar output. At times, these resources may be needed for short durations to provide power during high load periods caused by extreme temperatures. In other instances, these dispatchable resources are needed to run for days, or even weeks at a time, to provide power when other units are offline for maintenance or during periods of extended cloud cover that reduce the output of solar generation. DEC's resource plans call for approximately 3,600 MW of simple cycle combustion turbine (CT) and combined cycle (CC) generation technology to help meet load growth and replace unit retirements to optimally meet the needs of the system.

Conclusion:

In summary, the 2018 IRP Base Cases, discussed later in this document, show planned resource additions necessitated by load growth and retirement of aging generation resources. The plans are consistent with DEC's commitment to a smarter energy future, providing customers with reliable, affordable and increasingly clean sources of energy. Additionally, they maintain the Company's sustainability goals to reduce DEC's carbon emissions by more than 40% from 2005 levels by 2030. The plans accomplish this goal, despite serving significantly more customer demand over the planning period and without federal or state carbon mandates. Achieving robust base plans that balance the previously stated objectives requires a diverse mix of additional EE, DSM, renewable resources, energy storage and new efficient dispatchable natural gas resources. Plans that concentrate too much on a single resource result in additional customer costs, higher carbon emissions or both.

The following chapters of this document provide an overview of the assumptions, inputs, analysis and results included in the 2018 IRP. In addition to two Base Case plans, five different resource portfolios were analyzed under multiple sensitivities. The appendices to the document give even greater detail and specific information regarding the input development and the analytic process utilized in the 2018 IRP. A more detailed presentation of the Base Cases, as described in the above Executive Summary, is included in this document in Chapter 12 and Appendix A.

Finally, DEC will continue to closely monitor changes in key variables such as technology cost trends, the system load forecast, fuel price forecasts, emerging technology performance characteristics, the pace of adoption of distributed resources, advancements in storage technologies, new federal or state energy policies and other key variables. To the extent these variables change over time, DEC will incorporate such changes in subsequent annual IRP reports.

2. SYSTEM OVERVIEW

DEC provides electric service to an approximately 24,088-square-mile service area in western South Carolina and central and western North Carolina. In addition to retail sales to approximately 2.58 million customers, the Company also sells wholesale electricity to incorporated municipalities and to public and private utilities. Recent historical values for the number of customers and sales of electricity by customer groupings may be found in Appendix C.

DEC currently meets energy demand, in part, by purchases from the open market, through longer-term purchased power contracts and from the following electric generation assets. All capacities represent winter ratings, unless otherwise noted:

- Three nuclear generating stations with a combined capacity of 7,383 MW
- Four coal-fired stations with a combined capacity of 6,818 MW
- 28 hydroelectric stations (including two pumped-storage facilities) with a combined capacity of 3,245 MW
- Four CT stations and three CC stations with a combined capacity of 5,508 MW
- 18 utility-owned small solar facilities with a combined capacity of 8.5 MW (nameplate)[1]
- Two utility-owned solar farms with a combined capacity of 75 MW (nameplate)
- One natural gas boiler with a capacity of 173 MW

The Company's power delivery system consists of approximately 104,374 miles of distribution lines and 13,069 miles of transmission lines. The transmission system is directly connected to all of the Transmission Operators that surround the DEC service territory. There are 36 tie-line circuits connecting with nine different Transmission Operators: Duke Energy Progress (DEP), PJM Interconnection, LLC (PJM), Tennessee Valley Authority (TVA), Smoky Mountain Transmission, Southern Company, Cube Hydro, Southeastern Power Administration (SEPA), South Carolina Electric & Gas (SCE&G) and Santee Cooper. These interconnections allow utilities to work together to provide an additional level of reliability. The strength of the system is also reinforced through coordination with other electric service providers in the Virginia-Carolinas (VACAR) sub-region, SERC Reliability Corporation (SERC; formerly Southeastern Electric Reliability Council) and North American Electric Reliability Corporation (NERC).

[1] The capacity represented in this listing only includes utility-owned solar capacity. Capacity from purchased power contracts are not included.

Figure 2-A: Duke Energy Carolinas Service Area

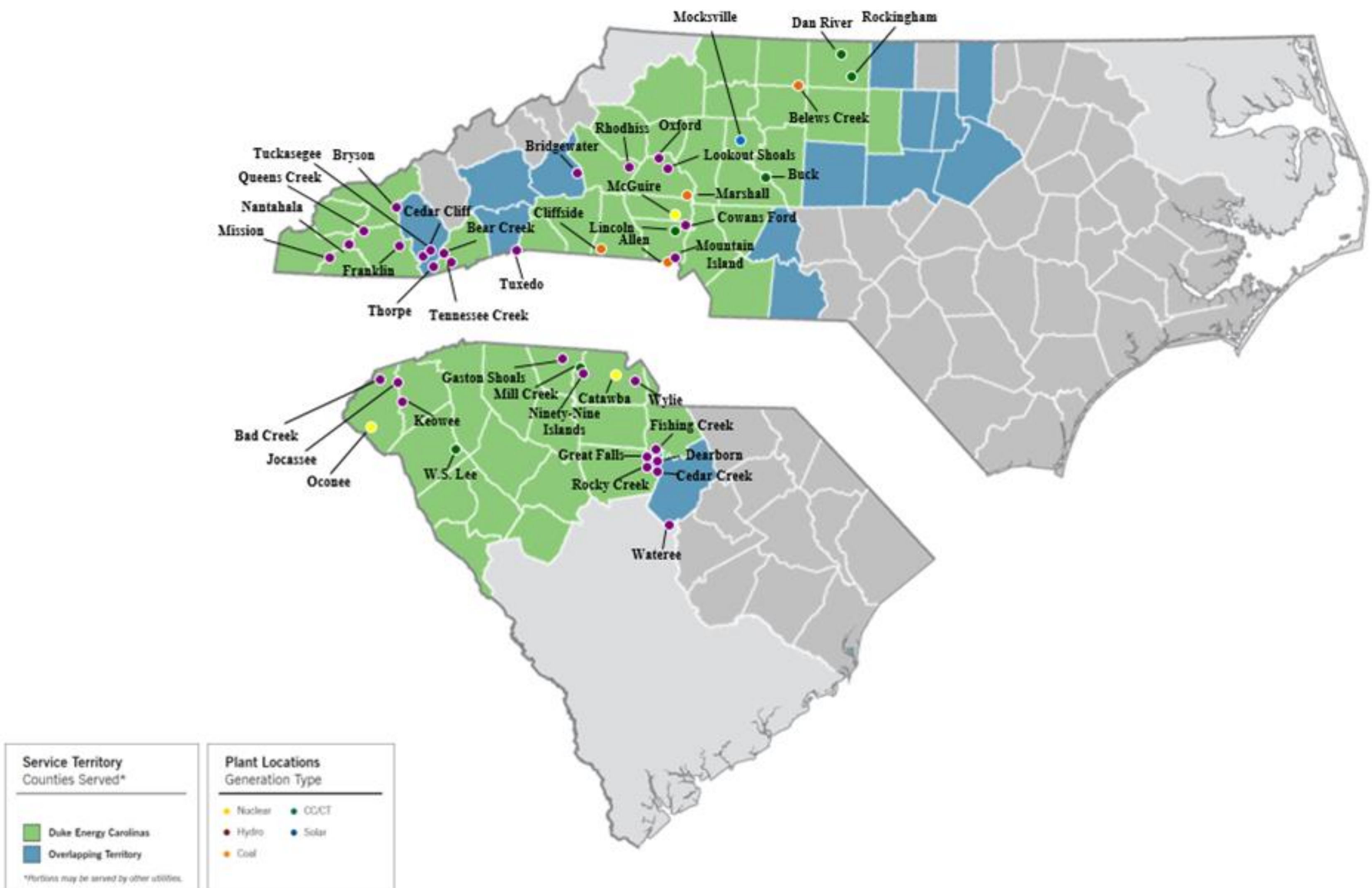
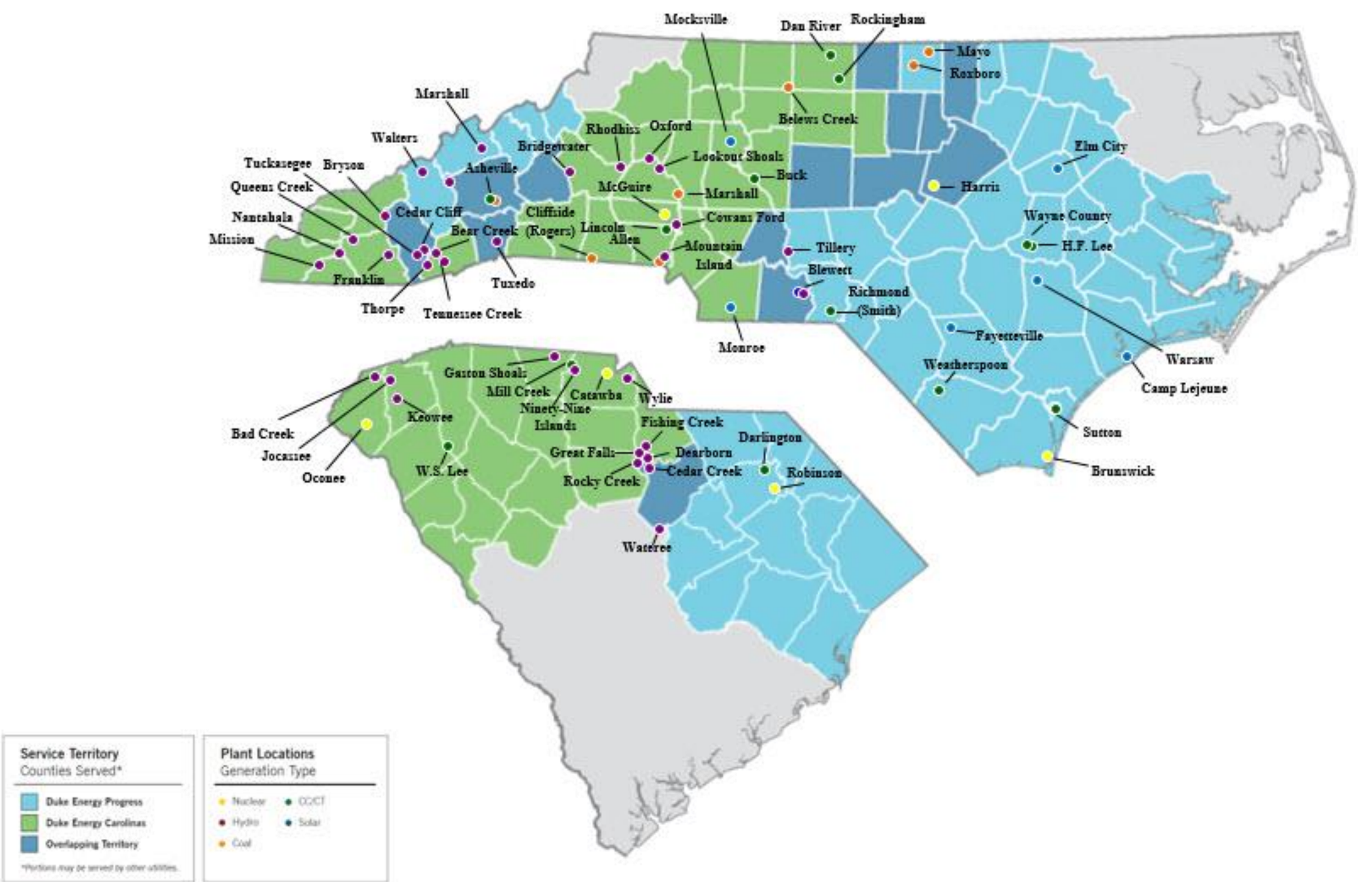


Figure 2-B: DEC and DEP Service Area

With the closing of the Duke Energy Corporation and Progress Energy Corporation merger, the service territories for both DEC and DEP lend to future opportunities for collaboration and potential sharing of capacity to create additional savings for South Carolina and North Carolina customers of both utilities. An illustration of the service territories of the Companies are shown in the map below.



3. ELECTRIC LOAD FORECAST

The Duke Energy Carolinas Spring 2018 Forecast provides projections of the energy and peak demand needs for its service area. The forecast covers the time period of 2019–2033 and represents the needs of the Retail customers and Wholesale customers.

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. Regression analysis is utilized and has yielded consistently reasonable results over the years.

The economic projections used in the Spring 2018 Forecast are obtained from Moody's Analytics, a nationally recognized economic forecasting firm, and include economic forecasts for the states of South Carolina and North Carolina.

Moody's Analytics supplies the Company with economic and demographic projections, which are used in the energy and demand models. Preliminary analysis of Moody's historical projections versus actuals resulted in smaller variances and minimum bias during normal economic periods. However, the likelihood of greater forecast variance and forecast bias increases during unique disruptive economic periods like the Great Recession. Load Forecasting will continue to monitor Moody's forecast error going forward.

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 slightly negative to flat through much of the forecast horizon, so most of the growth is primarily due to increases in the number of customers being added to the system. The projected energy growth rate of Residential in the Spring 2018 Forecast after all adjustments for Utility Energy Efficiency (UEE) programs, Solar and Electric Vehicles from 2019 to 2033 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 0.7%, after all adjustments.

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 energy sales are expected to grow 0.6% over the forecast horizon, after all adjustments.

Peak Demand and Energy Forecast:

The Spring 2018 Forecast is lower than the Spring 2017 Forecast. The decrease in the Spring 2018 peak forecast is primarily driven by the removal of a backstand agreement for North Carolina Electric Membership Corporation's (NCEMC's) share of Catawba from the Load Forecast (backstand agreement – average of 530 MW for both summer and winter peaks). This allows for the peak forecast to better align with history. The Spring 2018 Forecast also declined due to several large industrial plants closing, strong UEE accomplishments in recent years, and stronger projected heating and cooling efficiencies. The load forecast projection for energy and capacity, including the impacts of UEE, rooftop solar, and electric vehicles, that was utilized in the 2018 IRP is shown in Table 3-A.

Table 3-A: Load Forecast with Energy Efficiency Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWh)
2019	18,136	17,776	90,721
2020	18,270	17,924	91,423
2021	18,381	18,017	91,825
2022	18,460	18,128	92,132
2023	18,547	18,173	92,515
2024	18,764	18,373	93,614
2025	18,954	18,478	94,490
2026	19,192	18,778	95,529
2027	19,409	18,970	96,397
2028	19,737	19,241	97,823
2029	19,984	19,494	98,857
2030	20,218	19,657	99,806
2031	20,501	19,873	100,937
2032	20,792	20,242	102,248
2033	20,986	20,423	102,955
Avg. Annual Growth Rate	1.0%	0.9%	0.8%

Note: Tables 12-E and 12-F differ from these values due to a 47 MW Piedmont Municipal Power Agency (PMPA) backstand contract through 2020.

A detailed discussion of the electric load forecast is provided in Appendix C.

4. ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT

DEC is committed to making sure electricity remains available, reliable and affordable and that it is produced in an environmentally sound manner and, therefore, DEC advocates a balanced solution to meeting future energy needs in the Carolinas. That balance includes a strong commitment to energy efficiency (EE) and demand-side management (DSM).

Since 2009, DEC has been actively developing and implementing new EE and DSM programs throughout its South Carolina and North Carolina service areas to help customers reduce their electricity demands. DEC's EE and DSM plan is designed to be flexible, with programs being evaluated on an ongoing basis so that program refinements and budget adjustments can be made in a timely fashion to maximize benefits and cost-effectiveness. Initiatives are aimed at helping all customer classes and market segments use energy more wisely. The potential for new technologies and new delivery options is also reviewed on an ongoing basis in order to provide customers with access to a comprehensive and current portfolio of programs.

DEC's EE programs encourage customers to save electricity by installing high efficiency measures and/or changing the way they use their existing electrical equipment. DEC evaluates the cost-effectiveness of EE/DSM programs from the perspective of program participants, non-participants, all customers as a whole, and total utility spending using the four California Standard Practice tests (i.e., Participant Test, Rate Impact Measure (RIM) Test, Total Resource Cost (TRC) Test and Utility Cost Test (UCT), respectively) to ensure the programs can be provided at a lower cost than building supply-side alternatives. The use of multiple tests can ensure the development of a reasonable set of programs and indicate the likelihood that customers will participate. DEC will continue to seek approval from State utility commissions to implement EE and DSM programs that are cost-effective and consistent with DEC's forecasted resource needs over the planning horizon. DEC currently has approval from the Public Service Commission of South Carolina (PSCSC) and the North Carolina Utilities Commission (NCUC) to offer a large variety of EE and DSM programs and measures to help reduce electricity consumption across all types of customers and end-uses.

For IRP purposes, these EE-based demand and energy savings are treated as a reduction to the load forecast, which also serves to reduce the associated need to build new supply-side generation, transmission and distribution facilities. DEC also offers a variety of DSM (or demand response) programs that signal customers to reduce electricity use during select peak hours as specified by the Company. The IRP treats these "dispatchable" types of programs as resource options that can be dispatched to meet system capacity needs during periods of peak demand.

In 2016, DEC commissioned an EE market potential study to obtain estimates of the technical, economic and achievable potential for EE savings within the DEC service area. The final report was prepared by Nexant, Inc. and was completed in December 2016. The results of the market potential study are suitable for integrated resource planning purposes and use in long-range system planning models. However, the study did not attempt to closely forecast short-term EE achievements from year to year. Therefore, the Base Case EE/DSM savings contained in this IRP were projected by blending DEC's five-year program planning forecast into the long-term achievable potential projections from the market potential study.

DEC prepared a Base Portfolio savings projection that was based on DEC's five-year program plan for 2018-22. For periods beyond 2027, the Base Portfolio assumed that the Company could achieve the annual savings projected in the Achievable Portfolio presented in Nexant's Market Potential Study. For the period of 2023 through 2027, the Company employed an interpolation methodology to blend together the projection from DEC's program plan and the Market Potential Study Achievable Potential.

DEC also prepared a High EE Portfolio savings projection based on the Enhanced Scenario contained in Nexant's Market Potential Study, which assumed the implementation of potential new technologies and programs not currently offered by DEC can encourage additional customer participation and savings.

Additionally, for both the Base and High Portfolios described above, DEC included an assumption that, when the EE measures included in the forecast reach the end of their useful lives, the impacts associated with these measures are removed from the future projected EE impacts. This concept of "rolling off" the impacts from EE programs is explained further in Appendix C.

See Appendix D for further detail on DEC's EE, DSM and consumer education programs, which also includes a discussion of the methodology for determining the cost effectiveness of EE and DSM programs.

5. RENEWABLE ENERGY STRATEGY / FORECAST

The growth of renewable generation in the United States continues to outpace that of non-renewable generation. According to EIA, in 2017, including small-scale solar, 14.5 GW of wind and solar capacity were installed nationwide compared to 9.3 GW of natural gas. About 4 GW of natural gas was retired in 2017 and over 6 GW of coal was retired with no new coal-fired generation installed.[2]

North Carolina ranked second in the country in solar capacity added in 2017, and remains second behind only California in total solar capacity online. According to GTM Research, South Carolina also cracked the top 10 in 2018, adding nearly 400 MW in 2017. Duke Energy's compliance with the SC Distributed Energy Resource Program (SC DER), the North Carolina Renewable Energy and Energy Efficiency Portfolio Standards (NC REPS), and 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 continued to grow, with the DEC and DEP combined solar queue representing approximately 12 GW. Key drivers to queue growth have been the implementation of South Carolina Act 236 (SC Act 236), upcoming procurement for HB 589 (described below), and North Carolina's historically favorable avoided cost rate and 15-year contract terms for qualifying facilities (QFs) under PURPA.

The implementation of North Carolina House Bill 589 (HB 589), which calls for the addition of 2,660 MW of competitively procured renewable resources over a 45-month period, is 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 2018 IRP. The following key assumptions regarding renewable energy were included in the 2018 IRP:

- Installed solar capacity increases in DEC from 1,218 MW in 2019 to 3,440 MW in 2033;
- Compliance with NC REPS continues to be met through a combination of solar, other renewables, EE, and Renewable Energy Certificate (REC) purchases;
- Achievement of the SC Act 236 goal of 120 MW of solar capacity located in DEC-SC; and
- Implementation of HB 589 and continuing solar cost declines drive solar capacity growth above and beyond SC Act 236 requirements and NC REPS requirements.

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

HB 589 Competitive Procurement of Renewable Energy (CPRE):

HB 589 establishes 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. South Carolina and North Carolina projects may submit proposals into CPRE.

The Companies expect to issue three "tranches" of requests for bids. Future tranches of CPRE may be affected by capacity referred to in this document as the "Transition MW." 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, provided that they 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 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; conversely, if the Transition falls short of 3,500 MW the Companies will conduct additional competitive procurement. The Company believes the Transition MW will easily total 3,500 MW and possibly exceed it by as much as 1,200 MW.

In preparation for the HB 589 competitive procurement process, the Company continues to build its relationships with suppliers, Engineering, Procurement, and Construction Contractors (EPCs), and other entities to create greater efficiencies in the supply chain, reduce construction costs, reduce operating and maintenance costs (O&M), and enhance system design. In anticipation of future solar growth, DEC is positioning itself to properly integrate renewable resources to the grid regardless of ownership.

In addition to ensuring DEC has operational control over future solar associated with HB 589, the intermittency of solar output will require the Company to evaluate and invest in technologies to provide solutions for voltage, volt-ampere reactive (VAR), and/or higher ancillary reserve requirements.

Interconnection Queue:

Through the end of 2017, DEC had more than 600 MW of utility scale solar on its system, with over 100 MW interconnecting in 2017. When renewable resources were evaluated for the 2018 IRP, DEC reported nearly 300 MW of third-party solar under construction and more than 5,000 MW in the interconnection queue. The interconnection queue information in Appendix I provides details on the number of pending projects and pending capacity by state.

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.

NC REPS Compliance:

DEC remains committed to meeting the requirements of NC REPS, including the poultry waste, swine waste, and solar set-asides, and the general requirement, which will be met with additional renewable and energy efficiency resources. DEC's long-term general compliance needs are expected to be met through a combination of renewable resources, including RECs obtained through the HB 589 competitive procurement process.

HB-589 Competitive Procurement and Utility-Owned Solar:

DEC continues to evaluate utility-owned solar additions to grow its renewables portfolio. For example, DEC owns and operates two utility-scale solar projects as part of its efforts to encourage emission free generation resources and help meet its compliance targets, totaling 75 MW-AC:

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

In addition, the Wood leaf Solar Facility, 6 MW located in Rowan County, North Carolina is under construction with expected commercial operation in December 2018.

No more than 30% of the CPRE Program requirement may be satisfied through projects in which Duke Energy or its affiliates have an ownership interest at the time of bidding. DEC intends to bid into the first and future tranches of the CPRE and will also evaluate the potential for acquiring facilities where appropriate. HB 589 does not stipulate a limit for DEC'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. First, potential changes in the Company's avoided cost may impact the development of projects under PURPA and HB 589. 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 rate. 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 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% 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 and/or systems with higher inverter load ratios (ILR) which change the hourly profile of solar output and increase expected capacity factors. DEC now models fixed tilt and SAT system hourly profiles with a range of ILRs as high as 1.6 (DC/AC ratio).

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

HB 589 Customer Programs:

In addition to the CPRE program, 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.

As part of HB 589, the renewable energy procurement program for large customers such as military installations and universities directs Duke Energy to procure energy and capacity from new renewable energy resources on behalf of participating customers. 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 UNC system (250 MW of the 600 MW). The 2018 IRP Base Cases assume all 600 MW of this program materialize, with the DEC/DEP split expected to be roughly equal. If all 600 MW are not utilized, the remainder will roll back to the competitive procurement, increasing its volume.

The community solar portion of HB 589 calls for up to 20 MW of shared solar in DEC. This program is similar to the SC Act 236 shared solar program, and allows customers who cannot or do not want to put solar on their property to take advantage of the economic and environmental benefits of solar by subscribing to the output of a centralized facility. The 2018 IRP Base Cases assume that all 20 MW of the HB 589 shared solar program materializes.

HB 589 also calls for a rebate program for rooftop solar. The rebate program opened in July and the program has already proven to spur greater interest in solar installations and therefore, more net metered customers in NC. Through May 2018, DEC has installed nearly the same capacity installed in all of 2017. Enough customers were processed in the first two weeks of the rebate program to fill the 2018 allotment for residential and commercial customers.

***SC Act 236*:**

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

- Tier I: 40 MW of solar capacity from facilities each >1 MW and ≤ 10 MW in size.
- Tier II: 40 MW of behind-the-meter solar facilities for residential, commercial and industrial customers, each ≤1 MW, 25% of which must be ≤ 20 kilowatts (kW). Since Tier II is behind the meter, the expected solar generation is embedded in the load forecast as a reduction to expected load.
- Tier III: Investment by the utility in 40 MW of solar capacity from facilities each >1 MW and ≤10 MW in size. Upon completion of Tiers I and II (to occur no later than 2021), the Company may directly invest in additional solar generation to complete Tier III.

DEC has executed five PPAs totaling approximately 10 MW and is working to complete Tier I. Tier II incentives have resulted in growth in rooftop solar in DEC, which now has over 60 MW of rooftop solar installed, and has reached the 2% net metering application cap of 80 MW established in Act 236.

The Company will launch its first Shared Solar program in DEC as part of Tier I in the fourth quarter of 2018. Duke Energy designed its initial SC shared solar program to have strong appeal to residential and commercial customers who rent or lease their premises, residential customers who reside in multifamily housing units or shaded housing or for whom the relatively high up-front costs of solar PV make net metering unattainable, and non-profits who cannot monetize the ITC.

Wind:

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

Summary of Expected Renewable Resource Capacity Additions:

The 2018 IRP incorporates the Base Case renewable capacity forecast below. This case includes renewable capacity components of the Transition MW of HB 589, such as capacity required for compliance with NC REPS, PURPA purchases, the SC DER Program, legacy NC Green Source Rider program, and the additional three components of HB 589 (competitive procurement, renewable energy procurement for large customers, and community solar). This year's Base Case also includes additional projected solar growth beyond HB 589. While certain regions of DEC may become saturated with solar, it is the Company's belief that continued declines in the installation cost of solar and storage will enable solar and coupled "solar plus storage" systems to contribute to growing energy needs. The Company also believes supportive policies for solar and solar plus storage will continue to exist in SC and NC even beyond the HB 589 procurement horizon.

The Company anticipates a diverse portfolio including solar, biomass, hydro, wind, 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, 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 5-A below.

While solar is not at its maximum output at the time of DEC's expected peak load in the summer, solar's contribution to summer peak load is large enough that it may push the time of summer peak to a later hour if solar penetration levels continue to increase. However, solar is unlikely to have a similar impact on the morning winter peak due to lower solar output in the morning hours. Solar capacity contribution to summer and winter peak demands is discussed more fully in Chapter 9.

Table 5-A: DEC Base Case Total Renewables

DEC Base Renewables - Compliance + Non-Compliance										
	MW Nameplate			MW Contribution to Summer Peak			MW Contribution to Winter Peak			
	Solar	Biomass/ Hydro	Total	Solar	Biomass/ Hydro	Total		Solar	Biomass/ Hydro	Total
2019	1218	119	1337	405	119	524	2019	12	119	131
2020	1588	140	1728	497	140	637	2020	16	140	156
2021	1948	118	2067	587	118	705	2021	19	118	138
2022	2285	98	2383	671	98	769	2022	23	98	121
2023	2532	83	2615	733	83	816	2023	25	83	108
2024	2773	81	2853	793	81	874	2024	28	81	108
2025	2864	69	2932	816	69	885	2025	29	69	97
2026	2975	68	3043	844	68	912	2026	30	68	98
2027	3086	62	3149	872	62	934	2027	31	62	93
2028	3197	85	3282	899	85	984	2028	32	85	117
2029	3307	78	3385	927	78	1004	2029	33	78	111
2030	3417	71	3487	954	71	1025	2030	34	71	105
2031	3424	54	3478	956	54	1010	2031	34	54	88
2032	3432	52	3484	958	52	1010	2032	34	52	86
2033	3440	52	3492	960	52	1012	2033	34	52	86

* Solar includes 0.5% per year degradation

** Capacity listed excludes REC-Only contracts

Given the significant volume and uncertainty around solar penetration, high and low solar portfolios were compared to the Base Case described above. The portfolios do not envision a specific market condition, but rather the potential combined effect of a number of factors. For example, the high sensitivity could occur given events such as high carbon prices, lower solar capital costs, economical solar plus storage, continuation of renewable subsidies, and/or stronger renewable energy mandates. On the other hand, the low sensitivity may occur given events such as lower fuel prices for more traditional generation technologies, higher solar installation and interconnection costs, and/or high ancillary costs which may drive down the economic viability of future incremental solar additions. These events may cause solar projections to fall short of the Base Case if the CPRE, renewable energy procurement for large customers, and/or the community solar programs of HB 589 do not materialize or are delayed. Tables 5-B and 5-C below provide the high and low solar nameplate capacity summaries as well as their corresponding expected contributions to summer and winter peaks.

Table 5-B: DEC High Case Total Renewables

DEC High 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
2019	1360	95	1455	440	95	535	2019	14	95	109
2020	1771	116	1887	543	116	658	2020	18	116	133
2021	2115	94	2209	629	94	723	2021	21	94	115
2022	2550	91	2640	737	91	828	2022	25	91	116
2023	3049	76	3125	862	76	938	2023	30	76	107
2024	3455	74	3528	964	74	1037	2024	35	74	108
2025	3687	68	3756	1022	68	1090	2025	37	68	105
2026	3844	67	3911	1038	67	1105	2026	38	67	105
2027	4000	62	4062	1052	62	1114	2027	38	62	101
2028	4155	85	4239	1066	85	1151	2028	39	85	124
2029	4309	78	4387	1080	78	1157	2029	40	78	118
2030	4462	71	4533	1094	71	1164	2030	41	71	112
2031	4475	54	4528	1095	54	1148	2031	41	54	94
2032	4488	52	4540	1096	52	1148	2032	41	52	93
2033	4500	52	4552	1097	52	1149	2033	41	52	93

* Solar includes 0.5% per year degradation

** Capacity listed excludes REC-Only contracts

Table 5-C: DEC Low Case Total Renewables

DEC Low 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
2019	1203	95	1298		401	95	496		2019	12	95	107
2020	1524	116	1640		481	116	597		2020	15	116	131
2021	1689	94	1783		522	94	616		2021	17	94	111
2022	1945	91	2036		586	91	677		2022	19	91	110
2023	2257	76	2333		664	76	740		2023	23	76	99
2024	2441	74	2515		710	74	784		2024	24	74	98
2025	2467	68	2535		717	68	785		2025	25	68	93
2026	2580	67	2648		745	67	812		2026	26	67	93
2027	2693	62	2755		773	62	835		2027	27	62	89
2028	2806	85	2891		801	85	886		2028	28	85	113
2029	2918	78	2996		829	78	907		2029	29	78	107
2030	3029	71	3100		857	71	928		2030	30	71	101
2031	3029	54	3083		857	54	911		2031	30	54	84
2032	3029	52	3081		857	52	909		2032	30	52	82
2033	3029	52	3081		857	52	909		2033	30	52	82

* Solar includes 0.5% per year degradation
** Capacity listed excludes REC-Only contracts

6. INTEGRATED SYSTEMS AND OPERATIONS PLANNING (ISOP) AND BATTERY STORAGE

The Industry is Rapidly Changing:

In recent years, the electric utility industry has undergone extraordinary transformation that has directly resulted in an increasingly dynamic environment for which the Company must plan and operate. This transformation is driven by several key trends including rapidly changing technologies, evolving customer expectations and the progression towards a smarter grid. New technologies are being developed at an exponential rate, creating a multitude of new possibilities of assets to serve customers. Many Duke Energy customers have come to realize the benefits that technology can provide and are no longer inactive recipients of a simple commodity at the least possible cost. These customers are now expecting more choices and services to control their energy use and desire active interaction with their energy choices. Duke Energy Carolinas is committed to serving its customers in new and improved ways that recognize the increasing differences between its customers. To do so will make planning more complex. For example, the Company will need much better data on how our customers want to be served, and that data will not be easy to obtain. Providing safe, reliable, cleaner and affordable power, however, will always be at the heart of Duke Energy's foundation. Furthermore, the commitment to provide transparency to both customers and other stakeholders is of utmost importance, due to the belief that taking advantage of the collective knowledge of the parties will ultimately benefit all customers.

Implications for the IRP:

The Company, as well as others in the electric utility industry, are recognizing that the traditional methods of utility resource planning must be enhanced to keep pace with changes occurring in the industry. As a result, beginning this year, Duke Energy Carolinas will begin to adapt its IRP to adjust to this changed world, recognizing that this process will continue to evolve. The planning tools that have been used in the past are limited in their ability to value some aspects of the newer technologies. Historically, the Company has not been able to identify the locational value of distributed generation sources and are now developing models to do so, as well as more tightly linking our distribution plans to the bulk power (generation and transmission) plans. DEC also recognizes the operational impacts of sub-hourly intermittency of some supply resources and is developing modeling capabilities needed to quantify these operational impacts. As the single entity responsible for the reliable operations of the system, DEC is required to address what it will take to operate its system under a wider variety of futures, which will directly result in the consideration of more scenarios. Also, with the accelerated pace of change, the Company must place a higher value on the flexibility of the resource plan to adapt to changing circumstances.

Changes Reflected in This Year's IRP:

Based on recent developments, the amount of renewables on the DEC system has increased to reflect HB 589 requirements and the expected renewable adoption is now forecasted to exceed the legislatively mandated limits. As a result, the need for real-time system regulation and balancing increases over time as more intermittent renewables are integrated into the system. While the models are not yet perfected, DEC can now make reasonable estimates for these real-time system impacts and those estimates have been included them in the long-term planning models for the first time. DEC has also assumed the deployment of more grid-connected battery storage within the next few years which, if deployed appropriately, have the potential to provide benefits to the transmission and distribution system, as well as, the bulk power system.

Changes to be Included in Future IRPs:

Duke Energy is further addressing these shifting trends through an Integrated System and Operations Planning (ISOP) effort. ISOP envisions the creation of a broader process by which all energy resources are evaluated fully and fairly valued on functional capability irrespective of the resource location on the grid. ISOP strives to identify the appropriate tools and examine the performance of different asset portfolios across a variety of potential futures. ISOP has completed evaluations of the current planning practices and has identified future enhancements to be addressed in a systematic, disciplined manner to realize this future vision.

One key goal of ISOP is for the planning models to reasonably mimic the future operational realities to allow DEC to serve its customers with newer technologies. The introduction of balancing and regulating reserve requirements with respect to growing renewable generation in this IRP is an indication of this effort. Additionally, ISOP has a number of other workstreams addressing the identified future enhancements to the modeling tools, the need for granularity in location and time, as well as, the approach for stacking functional benefits across the system. These future enhancements in planning are expected to be addressed over the next several years, as soon as the modeling tools, processes and data development will allow.

Duke Energy recognizes the substantial effort it will take to continue down this integrated planning path for years to come, and is committed to the development and delivery of these new methods. There are considerable risks and learning curves with a number of these new workstreams as many of the modeling tools and functionalities are currently in developmental stages throughout the industry. Given that some of the most promising emerging resource solutions, such as battery storage and leading-edge intelligent grid controls, are still in the early stages, Duke Energy is committed to understanding and capturing these capabilties. There will also be a heightened need to address data challenges such as the increased levels of granularity associated with automated systems and data storage requirements. Duke Energy is committed to addressing these and other potential risks. The Company recognizes that it is proceeding with the first few steps of an evolutionary journey. DEC looks forward to public feedback as the IRP process evolves, and is committed to openly considering all viewpoints and new data that will improve the ability to plan for and meet the needs of its customers.

Battery Storage:

As introduced in the ISOP discussion, 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 above.

The Company will begin 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 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. The Company believes such investments are consistent with the direction of state policy in both SC and NC under the SC DER Program and NC HB 589, respectively. Additionally, the Company continues to participate in an energy storage study to assess the economic potential for customers, as mandated by HB 589. Results of the study are expected in December 2018.

7. SCREENING OF GENERATION ALTERNATIVES

As previously discussed, the Company develops the load forecast and adjusts for the impacts of EE programs that have been pre-screened for cost-effectiveness. The growth in this adjusted load forecast and associated reserve requirements, along with existing unit retirements or purchased power contract expirations, creates a need for future generation. This need is partially met with DSM resources and the renewable resources required for compliance with SC Act 236, NC REPS, and HB 589. The remainder of the future generation needs can be met with a variety of potential supply side technologies.

For purposes of the 2018 IRP, the Company considered a diverse range of technology choices utilizing a variety of different fuels, including ultra-supercritical pulverized coal (USCPC) units with carbon capture and sequestration (CCS), integrated gasification combined cycle (IGCC) with CCS, CTs, CCs with duct firing, Combined Heat and Power (CHP), reciprocating engines, and nuclear units. In addition, Duke Energy Carolinas considered renewable technologies such as Wind, Solar PV, and Landfill Gas and storage options such as Pumped Storage Hydro (PSH) and Lithium Ion Batteries in the screening analysis. Hybrids of the above technologies were also considered (i.e. solar steam augmentation and solar PV plus battery).

For the 2018 IRP screening analysis, the Company screened technology types within their own respective general categories of baseload, peaking/intermediate, renewable, and storage, with the goal of screening to pass the best alternatives from each of these four categories to the integration process. As in past years, the reason for the initial screening analysis is to determine the most viable and cost-effective resources for further evaluation on the DEC system. This initial screening evaluation is necessary to narrow down options to be further evaluated in the quantitative analysis process as discussed in Appendix A.

The results of these screening processes determine a smaller, more manageable subset of technologies for detailed analysis in the expansion planning model. The following list details the technologies that were evaluated in the screening analysis phase of the IRP process. The technical and economic screening is discussed in detail in Appendix F.

<u>Dispatchable (Winter Ratings)</u>

- 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 – 667 MW – 1x1x1 Advanced Combined Cycle (No Inlet Chiller and Fired)
- Base load – 1,339 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 – 600 MW – Small Modular Reactor (SMR)
- Peaking/Intermediate – 196 MW 4 x LM6000 Combustion Turbines (CTs)
- Peaking/Intermediate – 202 MW, 12 x Reciprocating Engine Plant
- Peaking/Intermediate – 574 MW 2 x G/H-Class Combustion Turbines (CTs)
- Peaking/Intermediate – 754 MW 2 x J-Class Combustion Turbines (CTs)
- Peaking/Intermediate – 919 MW 4 x 7FA.05 Combustion Turbines (CTs)
- Storage – 5 MW / 5 MWh Li-ion Battery
- Storage – 20 MW / 80 MWh Li-ion Battery
- Storage – 1,400 MW Pumped Storage Hydro (PSH)
- Renewable – 2 MW Solar PV plus 2 MW / 8 MWh Li-ion Battery
- Renewable – 75 MW Wood Bubbling Fluidized Bed (BFB, biomass)
- Renewable – 5 MW Landfill Gas

<u>Non-Dispatchable (Nameplate)</u>

- Renewable – 150 MW Wind - On-Shore
- Renewable – 50 MW Solar PV, Fixed-tilt (FT)
- Renewable – 50 MW Solar PV, Single Axis Tracking (SAT)

8. 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. The Company 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 as described below.

2016 Resource Adequacy Study:

The Company retained Astrapé Consulting in 2016 to conduct an updated resource adequacy study.[3] 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.

Methodology:

The 2016 resource adequacy study incorporated the uncertainty of weather, economic load growth, unit availability, and the availability of transmission and generation capacity for emergency assistance. Astrape analyzed the optimal planning reserve margin based on providing an acceptable level of physical reliability and minimizing economic costs to customers. The most common

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

physical reliability metric used in the industry is to target a system reserve margin that satisfies the one day in 10 years Loss of Load Expectation (LOLE) standard. This standard is interpreted as one firm load shed event every 10 years due to a shortage of generating capacity. From an economic perspective, as planning reserve margin increases, the total cost of reserves increases while the costs related to reliability events decline. Similarly, as planning reserve margin decreases, the cost of reserves decreases while the costs related to reliability events increase, including the costs to customers for loss of power. Thus, there is an economic optimum point where the cost of additional reserves plus the cost of reliability events to customers is minimized.

Winter Capacity Planning:

In the past, loss of load risk was typically concentrated during the summer months and a summer reserve margin target provided adequate reserves in both the summer and winter periods. However, the incorporation of recent winter load data and the significant amount of solar penetration included in the 2016 study, shows that the majority of loss of load risk is now heavily concentrated during the winter period. The shift in seasonal LOLE is the result of greater winter load volatility, as well as the high penetration of solar resources and the associated capacity contribution to summer reserves compared to winter reserves. The seasonal shift of LOLE to the winter period also increases as greater amounts of solar capacity are added to the system. Thus, increasing solar penetrations shift the planning process to a winter focus. Winter load and resources now drive the timing need for new capacity additions and a winter planning reserve margin target is now needed to ensure that adequate resources are available throughout the year to meet customer demand.

Results:

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.

Adequacy of Projected Reserves:

DEC's resource plan reflects winter reserve margins ranging from approximately 17% to 24%. Reserves projected in DEC's IRP meet the minimum planning reserve margin target and thus satisfy the one day in 10 years LOLE criterion. Projected reserve margins often exceed the minimum 17% winter target by 3% or more in years immediately following new resource additions. For example, reserves exceed the 17% minimum target by 3% or more during 2019 through 2025 primarily as a result of the recent addition of the Lee combined cycle unit combined with a reduction in the load forecast. Reserves also exceed the minimum 17% target by 3% or more as a result of combined cycle additions in 2028 and 2031.

The IRP provides general guidance in the type and timing of resource additions. As previously noted, 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. Reserves projected in the Company's IRP are appropriate for providing an economic and reliable power supply.

9. CAPACITY VALUE OF SOLAR

As DEC and DEP continue to add solar to their systems, understanding the reliability contribution of solar resources is critical for generation planning and projecting capacity needs as part of its Integration Resource Plan. Conventional thermal resources are typically counted as 100% of net capability in reserve margin calculations for future generation planning since these resources are fully dispatchable resources when not on forced outage or planned maintenance. Due to the diurnal pattern and intermittent nature of solar resources, it is not reasonable to assume that these resources provide the same capacity value as a fully dispatchable resource. Peak loads for DEC and DEP in the winter occur in the early morning and late evening when the solar output is low, while peak loads in the summer occur across the afternoon and early evening which is more coincident with solar output. Solar output shapes and the timing of peak demand periods must be considered to determine the capacity value or reliability contribution of a solar resource compared to a fully dispatchable resource such as a combustion turbine.

Astrapé performed this solar capacity value study for the Companies using the Strategic Energy Risk Valuation Model (SERVM) which was the same model utilized for the 2016 Resource Adequacy Studies. Extensive work went into the development of fixed-tilt and single-axis-tracking solar profiles across a 13-location grid in South Carolina and North Carolina.

Astrapé calculated the incremental capacity value of solar across five solar penetration levels for each company. The table below shows the different penetration levels of renewable solar generation for both DEC and DEP. These levels are consistent with the Companies' estimates of penetration at the time of this analysis. Consistent with NC House Bill 589, solar additions were divided up into the categories of Existing plus Transition and then an additional four tranches of solar that are expected over the next few years. However, note that the tranches discussed in this study reflect the Companies' total expected solar procurement which includes all utility scale requirements under NC HB 589 (CPRE, large customer programs and community solar). While the exact timing and amounts of transition and incremental solar additions may change over time, it is reasonable to assume the levels provided in the table below given the current procurement targets of the companies.

Table 9-A: Simulated Solar Penetration Levels

	DEC	DEC	DEP	DEP
	Incremental MW	Cumulative MW	Incremental MW	Cumulative MW
0 MW Level	-	-	-	-
Existing Plus Transition MW	840	840	2,950	2,950
Tranche 1	680	1,520	160	3,110
Tranche 2	780	2,300	180	3,290
Tranche 3	780	3,080	160	3,450
Tranche 4	420	3,500	135	3,585

Table 9-B below shows the seasonal LOLE weightings for the different increments of solar for DEC. As solar is added to the system, a higher percentage of the LOLE will occur in the winter because the output of solar in the summer during peak load hours which occur in the afternoon and early evening, is naturally higher than the output during the winter peak load hours which occur early in the morning or late in the evening. In other words, when 1 MW of nameplate solar is added to the system, the 1 MW of solar reduces summer LOLE more than it reduces winter LOLE, thereby further shifting the seasonal weighting of LOLE more to the winter. This is apparent by examining the LOLE results in the table. For example, the no solar scenario for DEC shows a seasonal LOLE weighting of 59% summer and 41% winter. However, after adding the existing and transition solar, the seasonal weighting makes a dramatic shift to 69% winter and 31% summer. After Tranche 4 solar is added, the winter weighting increases to 93% and summer reduces to about 7%.

Table 9-B: DEC Seasonal LOLE Percentage

	DEC Incrementa l Solar MW	DEC Cumulative Solar MW	DEC LOLE Summer %	DEC LOLE Winter %
0 MW Level	-	-	59%	41%
Existing Plus Transition MW	840	840	31%	69%
Tranche 1	680	1,520	21%	79%
Tranche 2	780	2,300	11%	89%
Tranche 3	780	3,080	7%	93%
Tranche 4	420	3,500	7%	93%

Table 9-C shows the solar capacity value results for DEC. The table illustrates the declining capacity value of solar as greater amounts of solar resources are added to the system. The first MW of solar in DEC provides a 27% annual capacity value but after 840 MW (Existing Plus Transition) are added, the next MW provides only an 11% equivalent annual capacity value.[4] The summer value proves to have very little weight in the annual value at high levels of solar because over 90% of the LOLE occurs in the winter. The table also shows slightly greater capacity values for tracking versus fixed solar arrays.

[4] Capacity values represent the incremental capacity value of the next MW given the referenced solar penetration. The average capacity contribution for an entire block of solar resources can be estimated by averaging the incremental value for the first MW of the block and the incremental value for the first MW of the next block.

Table 9-C: DEC Capacity Value Results by Solar Penetration

Solar Capacity at Each Penetration Level (Incremental MW)	Solar Capacity at Each Penetration Level (Cumulative MW)	Penetration Level	Winter	Summer	Annual
0	0	DEC – 0 Solar	2.5%	44.7%	27.2%
840	840	DEC – 840 Existing + Transition	0.9%	33.6%	11.1%
680	1,520	DEC – Tranche 1 – Fixed	0.5%	29.5%	6.5%
780	2,300	DEC – Tranche 2 – Fixed	0.4%	23.1%	2.9%
780	3,080	DEC – Tranche 3 – Fixed	0.2%	19.4%	1.6%
420	3,500	DEC – Tranche 4 – Fixed	0.2%	14.6%	1.2%
680	1,520	DEC – Tranche 1 – Tracking	2.0%	45.3%	10.9%
780	2,300	DEC – Tranche 2 – Tracking	1.8%	36.6%	5.6%
780	3,080	DEC – Tranche 3 – Tracking	1.3%	31.9%	3.4%
420	3,500	DEC – Tranche 4 – Tracking	1.1%	25.6%	2.9%

In summary, the winter LOLE to summer LOLE ratio drives the annual solar equivalent capacity values. Because the company has higher winter LOLE values in hours when solar is not available, the resulting equivalent annual solar capacity values are significantly reduced. As solar penetration increases, the capacity values decrease further since the firm load shed events are shifted even further into hours when there is less solar output. However, single-axis-tracking resources do bring some additional capacity value compared to fixed-tilt resources due to more output in morning and evening hours.

10. NUCLEAR AND SUBSEQUENT LICENSE RENEWAL (SLR)

Nuclear Assumptions in the 2018 IRP:

With respect to nuclear generation overall, the Company will continue to monitor and analyze key developments on factors impacting the potential need for, and viability of, future new baseload nuclear generation. Such factors include further developments on the Vogtle project and other new reactor projects worldwide, progress on existing unit relicensing efforts, nuclear technology developments, and changes in fuel prices and carbon policy.

Subsequent License Renewal (SLR) for Nuclear Power Plants:

DEC and DEP collectively provide approximately one half of all energy served in their SC and NC service territories from clean carbon free nuclear generation. This highly reliable source of generation provides power around the clock every day of the year. While nuclear unit outages are needed for maintenance and refueling, outages are generally relatively short in duration and are spread across the nuclear fleet in months of lower power demand. In total the fleet has a capacity factor, or utilization rate, of well over 90% with some units achieving 100% annual availability depending on refueling schedules. Nuclear generation is foundational to Duke's commitment to providing affordable, reliable electricity while also reducing the carbon footprint of its resource mix. Currently, all units within the fleet have operating licenses from the Nuclear Regulatory Commission (NRC) that allow the units to run 60 years from their original license date.

License Renewal is governed by Title 10 of the Code of Federal Regulations (10 CFR) Part 54, *Requirements for Renewal of Operating Licenses for Nuclear Power Plants.* Currently the Nuclear Regulatory Commission (NRC) has approved applications to extend licenses to up to 60 years for 89 nuclear units across the country, with applications for four nuclear units currently under review.

SLR would cover a second license renewal period, for a total of as much as 80 years. The NRC has issued regulatory guidance documents, NUREG-2191 [Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report] and NUREG-2192 [Standard Review Plan for the Review of Subsequent License Renewal (SRP-SLR) Applications for Nuclear Power Plants], establishing formal regulatory guidance for SLR.

NextEra submitted the industry's first SLR application to the NRC on January 31, 2018 for its Turkey Point station. The SLR application was accepted by NRC as sufficient for review allowing the NRC to begin their comprehensive review of the application. The NRC review is expected to take 18 months not including the time needed to perform the sufficiency review.

On July 10, 2018, Exelon Corporation submitted an SLR application for its Peach Bottom plant. The NRC is currently performing the sufficiency review of the Peach Bottom SLR application with a decision expected 3Q2018. Dominion Energy announced it would pursue SLR for its Surry and North Anna plants targeting an SLR application submittal to the NRC in early-2019 for Surry and 2020 for North Anna.

Based on recent industry progress in SLR including published NRC guidance, the NextEra and Exelon Corporation application submittals, and announcements from Dominion Energy, the Company's Base Cases assume SLR for existing nuclear generation to 80 years for planning purposes in this year's IRP. The Company will continue to monitor industry and NRC developments related to SLR.

The Company views all of its existing nuclear fleet as excellent candidates for SLR based on current conditions and expected operating expenditures, regardless of future carbon constraints. Duke Energy intends to pursue SLR for all its nuclear plants that show benefit for the customer. Work continues on development of the Oconee Nuclear Station SLR.

11. 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.

Duke Energy is exploring and working with potential customers with continuous large thermal loads on a regulated CHP offer. The CHP asset is included as part of Duke Energy's IRP as a placeholder for future projects as described below. The steam sales revenue would be 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 would result in CO_2 emission reductions, and is an economic development opportunity for the state.

DEC has signed agreements and obtained regulatory approval for a 15 MW CHP at Clemson University, which is expected to be in service by 2020. Filing for a Certificate of Public Convenience and Necessity (CPCN) for a 21 MW CHP at Duke University has been delayed pending the resolution of issues raised by the University. Discussions with other potential steam hosts are currently underway.

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

2020: 22 MW (winter)
2021: 22 MW (winter)

As CHP development continues, future IRPs will incorporate additional CHP, as appropriate.
Additional technologies evaluated as part of this IRP are discussed in Chapter 7 and Appendix F.

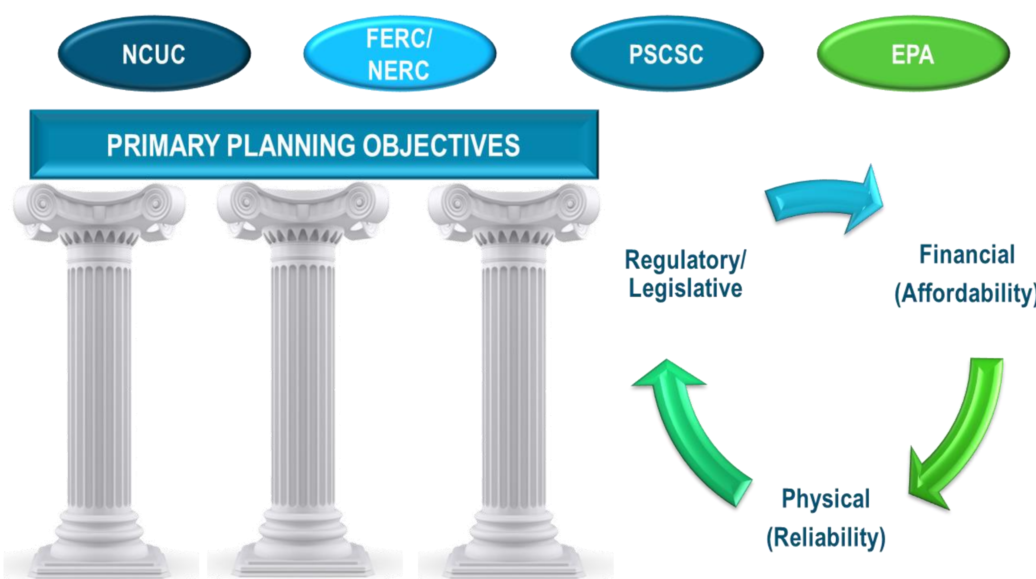
12. EVALUATION AND DEVELOPMENT OF THE RESOURCE PLAN

As described in Chapter 8, DEC continues to plan to winter planning reserve margin criteria in the IRP process. To meet the future needs of DEC's customers, it is necessary for the Company to adequately understand the load and resource balance. For each year of the planning horizon, DEC develops a load forecast of cumulative energy sales and hourly peak demand. To determine total resources needed, the Company considers the peak demand load obligation plus a 17% minimum planning winter reserve margin. The projected capability of existing resources, including generating units, EE and DSM, renewable resources and purchased power contracts is measured against the total resource need. Any deficit in future years will be met by 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. It should be noted that DEC considers the non-firm energy purchases and sales associated with the Joint Dispatch Agreement (JDA) with DEP in the development of its independent Base Cases and five alternative portfolios, as discussed later in this chapter and in Appendix A.

Three Pillars of the IRP:

The IRP process has changed as the industry has changed. While the intent of the IRP remains to develop a 15-year plan that is reliable and least cost to meet future customer demand, other factors also must be considered when selecting a plan.

Figure 12-A : Three Pillars of the IRP



There are three pillars which determine the primary planning objectives in the IRP. These pillars are as follows:

- Regulatory/Legislative
- Financial (Affordability)
- Physical (Reliability)

The Regulatory and Legislative pillar of the IRP process takes into consideration various policies set by state and federal entities. Such entities include NCUC, PSCSC, FERC, NERC, SERC, NRC, and EPA, along with various other state and federal regulatory entities. Each of these entities develop policies that have a direct bearing on the inputs, analysis and results of the IRP process. Examples of such policies include NC HB 589 and SC DER program that set targets for the addition of renewable resources. Environmental legislation at the state and federal level can impact the cost and operations of existing resources as well as future assets. In addition, reliability and operational requirements imposed on the system also influence the IRP process.

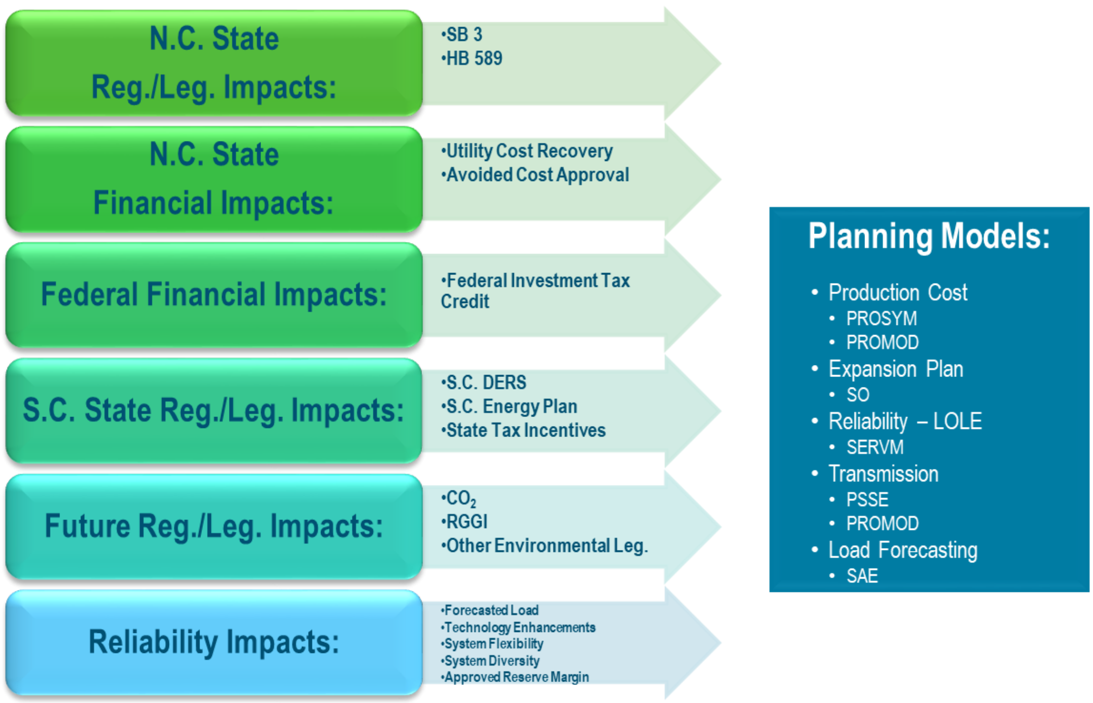
The Financial, or Affordability, pillar is another basic criterion for the IRP. The plan that is selected must be cost-effective for the customers of the Company. DEC's Carolinas' service territory, located in the southern United States, has climate conditions that require more combined electric heating and cooling per customer than any other region in the country. As such, DEC's customers require more electricity than customers from other regions, highlighting the need for affordable power. Changing customer preferences and usage patterns will continue to influence the load forecast incorporated in the Company's IRPs. Furthermore, as new technologies are developed and continue to evolve, the costs of these technologies are projected to decline. These downward impacts are contemplated in the planning process and changes to those projections will be closely monitored and captured in future IRPs.

Finally, Physical Reliability is the third pillar of the IRP process. Reliability of the system is vitally important to meeting the needs of today's customers as well as the future needs that comes with substantial customer growth projected in the region. DEC's customers expect energy to be provided to them when they need it both today and into the future. As discussed previously, the addition of new types of generation has impacted the operation of the system. As such, different ways of managing the system operations to ensure the Company reliably meets customer demand have been incorporated. The Company continues to plan to a reasonable 17% reserve margin, which helps to ensure that the reliability of the system is maintained.

Each of these pillars must be evaluated and balanced in the IRP in order to meet the intent of the process. The Company has adhered to the principles of these pillars in the development of this IRP and the portfolios evaluated as part of the IRP process.

Figure 12-B below graphically represents examples of how issues from each of the pillars may impact the IRP modeling process and subsequent portfolio development.

Figure 12-B : Impacts of Three Pillars on the IRP Modeling Process



IRP Analysis Process:

The following section summarizes the Data Input, Generation Alternative Screening, Portfolio Development and Detailed Analysis steps in the IRP process. A more detailed discussion of the IRP Process and development of the Base Cases and additional portfolios is provided in Appendix A.

Data Inputs:

Refreshing input data is the initial step in the IRP development process. For the 2018 IRP, data inputs such as load forecast, EE and DSM projections, fuel prices, projected CO_2 prices, individual plant operating and cost information, and future resource information were updated with the most current data. These data inputs were developed and provided by Company subject matter experts and/or based upon vendor studies, where available. Furthermore, DEC and DEP continue to benefit from the combined experience of both utilities' subject matter experts utilizing best practices from each utility in the development of their respective IRP inputs. Where appropriate, common data inputs were utilized.

As expected, certain data elements and issues have a larger impact on the IRP than others. Any changes in these elements may result in a noticeable impact to the plan, and as such, these elements are closely monitored. Some of the most consequential data elements are listed below. A detailed discussion of each of these data elements has been presented throughout this document and are examined in more detail in the appendices.

- Load Forecast for Customer Demand
- EE/DSM Forecast
- Renewable Resources and Cost Projections
- Fuel Costs Forecasts
- Technology Costs and Operating Characteristics
- Environmental Legislation and Regulation

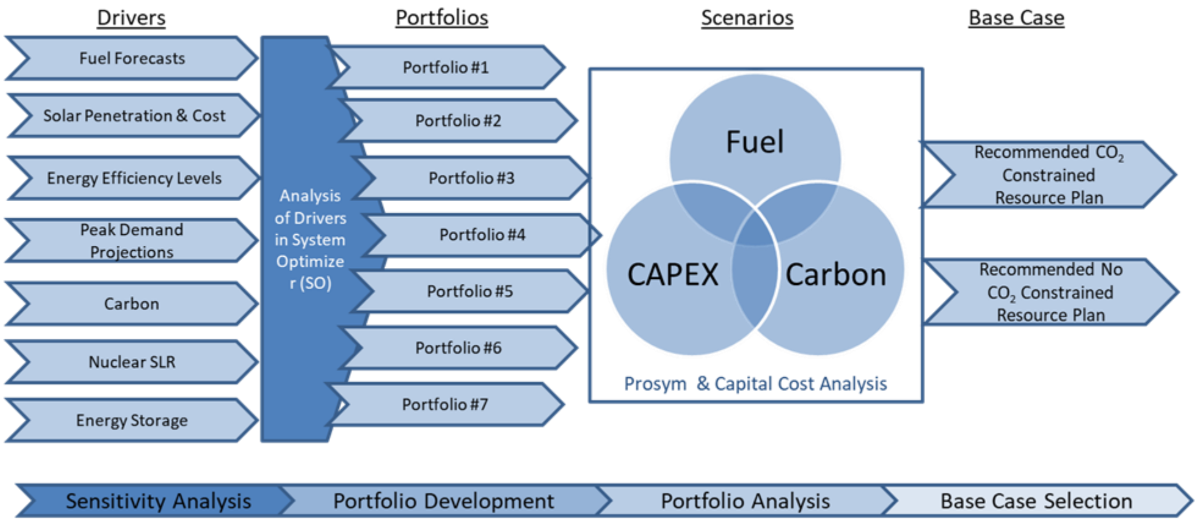
Generation Alternative Screening:

DEC reviews generation resource alternatives on a technical and economic basis. Resources must also be demonstrated to be commercially available for utility scale operations. The resources that are found to be both technically and economically viable are then passed to the detailed analysis process for further analysis.

Portfolio Development and Detailed Analysis:

The following figure provides an overview of the process for the portfolio development and detailed analysis phase of the IRP.

Figure 12-C: Overview of Portfolio Development and Detailed Analysis Phase



The Sensitivity Analysis and Portfolio Development phases rely upon the updated data inputs and results of the generation alternative screening process to derive resource portfolios or resource plans. The Sensitivity Analysis and Portfolio Development phases utilize an expansion planning model, System Optimizer (SO), to determine the best mix of capacity additions for the Company's short- and long-term resource needs with an objective of selecting a robust plans that meets reliability targets, minimizes the PVRR to customers and is environmentally sound by complying with or exceeding all State and Federal regulations.

Sensitivity analysis of input variables such as load forecast, fuel costs, renewable energy, EE, and capital costs are considered as part of the quantitative analysis within the resource planning process. Utilizing the results of these sensitivities, possible expansion plan options for the DEC system are developed. These expansion plans are reviewed to determine if any overarching trends are present across the plans, and based on this analysis, specific portfolios are developed to represent these trends. Finally, the portfolios are analyzed using a capital cost model and an hourly production cost model (PROSYM) under various fuel price, capital cost and carbon scenarios to evaluate the robustness and economic value of each portfolio under varying input assumptions. After this comprehensive analysis is completed, the Base Case portfolios are selected.

In addition to evaluating these portfolios solely within the DEC system, the potential benefits of sharing capacity within DEC and DEP are examined in a common Joint Planning Case. A detailed discussion of these portfolios is provided in Appendix A.

Selected Portfolios:

For the 2018 IRP, seven representative portfolios were identified through the Sensitivity Analysis and Portfolio Development steps. As described below, the portfolios range from diverse portfolios with varying fuel sources such as nuclear, solar, natural gas, and coal, to more technology concentrated resources such as CT Centric and CC Centric resources. Additionally, some portfolios increase the amount and adoption rate of renewables, EE, and energy storage.

Portfolio 1 (Base CO_2 Future)

This portfolio represents a balanced generation portfolio with CCs and CTs making up the generation mix with incremental solar additions just beyond the 15-year window. While CCs are the preferred initial generating options in both DEC and DEP, CTs make up the vast majority of additional resources at the end of, and just beyond, the 15-year planning horizon. This portfolio also includes base EE and renewable assumptions, along with 1,000 MW of economically selected solar just beyond the planning horizon. Additionally, 150 MW of nameplate battery storage placeholders are included. These placeholders represent a limited amount of grid connected battery storage projects that have the potential to provide solutions for the transmission and distribution systems with the possibility of simultaneously providing benefits to the generation resource portfolio.

Portfolio 2 (Base No CO_2 Future)

This portfolio contains a high concentration of CTs in the 15-year planning window and is similar to the CT Centric portfolio (Portfolio #3). The Base No CO_2 portfolio also includes base EE and renewable assumptions, along with 150 MW of nameplate battery storage placeholders. No additional solar was selected in this portfolio.

Portfolio 3 (CT Centric)

For DEC, this portfolio is the same as Portfolio 2 since Portfolio 2 already includes a high concentration of CT generation in the planning horizon. However, in DEP there is a greater concentration of CTs in this Portfolio which impacts the dispatch of generating assets in DEC through the JDA.

Portfolio 4 (CC Centric – No Nuclear Future)

This portfolio represents a future where all existing nuclear assets are retired at the end of their current extended license period, and those nuclear assets are replaced with CCs rather than new nuclear generation. The CC Centric Portfolio doubles the number of CCs in the 15-year planning horizon in DEC. This portfolio also includes base EE and renewable assumptions, along with 1,000 MW of economically selected solar just prior to the end of, and beyond, the planning horizon. Additionally, 150 MW of nameplate battery storage placeholders are included.

Portfolio 5 (High EE / High Renewables)

This portfolio includes the High EE and High Renewable assumptions in DEC. Solar nameplate capacity increases at a more rapid pace, and the total MW of solar is 1,100 MW greater in the High Renewable case. Additionally, inclusion of High EE has the effect of deferring the first CC and first CT by one year. Finally, this case also includes 150 MW of nameplate battery storage placeholders.

Portfolio 6 (CT Centric / High Renewables)

Similar to Portfolios 2 & 3, Portfolio 6 includes a high concentration of CT generation in the 15-year planning horizon. However, this portfolio includes the High Renewable assumption which accelerates solar additions in DEC while increasing the total amount of solar by approximately 1,100 MW. Portfolio 6 includes Base EE assumptions along with 150 MW of nameplate battery storage placeholders. This portfolio is especially illustrative when evaluating additional energy storage added in Portfolio 7.

Portfolio 7 (CT Centric with Battery Storage and High Renewables)

This portfolio converts the first 460 MW block of CT in Portfolio 6 to 575 MW (nameplate) of 4-hour Lithium-ion battery storage. The additional 575 MW of battery storage is assumed to only provide generation and energy transfer capability that is 100% controlled by the Company. As such, the battery storage installation is assumed to provide 460 MW of winter peak capacity. The total amount of nameplate battery storage in DEC in this case is 725 MW by 2028.

Portfolio Analysis & Base Case Selections:

The seven portfolios identified in the screening analysis were evaluated in more detail with an hourly production cost model under a matrix of nine carbon and fuel cost scenarios. Additionally, each of the portfolios were further studied under high and low capital costs scenarios to determine how changing capital costs impacted their relative value under the varying fuel and carbon scenarios. Table 12-A shows the matrix that each of the scenarios was tested under.

Table 12-A: Scenarios Matrix for Portfolio Analysis

	No CO_2	Base CO_2	High CO_2
Low Fuel			
Base Fuel			
High Fuel			

Tables 12-B details the results of the PVRR analysis under the varying carbon and fuel scenarios while Tables 12-C and 12-D provide the same results but under low capital cost and high capital cost futures respectively.

Table 12-B: Lowest PVRR (thru 2068) Portfolios Under Each Scenario (2018 dollars in Millions)

PVRR thru 2068 (2018 $M)	No CO_2	Base CO_2	High CO_2
Low Fuel	Portfolio 2 (-$101 M vs Port 1)	Portfolio 1 (-$647 M vs Port 2)	Portfolio 1 (-$302 M vs Port 5)
Base Fuel	Portfolio 1 (-$55 M vs Port 2)	Portfolio 1 (-$382 M vs Port 5)	Portfolio 5 ($100 M vs Port 1)
High Fuel	Portfolio 1 (-$342 M vs Port 5)	Portfolio 5 ($141 M vs Port 1)	Portfolio 5 ($668 M vs Port 1)

Table 12-C: Lowest PVRR (thru 2068) Portfolios Under Each Scenario – Low Capital Cost Sensitivity (2018 dollars in Millions)

PVRR thru 2068 (2018 $M)	No CO_2	Base CO_2	High CO_2
Low Fuel	Portfolio 2 (-$116 M vs Port 1)	Portfolio 1 (-$632 M vs Port 5)	Portfolio 1 (-$196 M vs Port 5)
Base Fuel	Portfolio 1 (-$40 M vs Port 2)	Portfolio 1 (-$278 M vs Port 5)	Portfolio 5 ($206M vs Port 1)
High Fuel	Portfolio 1 (-$236 M vs Port 5)	Portfolio 5 ($247 M vs Port 1)	Portfolio 5 ($774 M vs Port 1)

Table 12-D: Lowest PVRR (thru 2068) Portfolios Under Each Scenario – High Capital Cost Sensitivity (2018 dollars in Millions)

PVRR thru 2068 (2018 $M)	No CO_2	Base CO_2	High CO_2
Low Fuel	Portfolio 2 (-$94 M vs Port 1)	Portfolio 1 (-$655 M vs Port 2)	Portfolio 1 (-$376 M vs Port 5)
Base Fuel	Portfolio 1 (-$62 M vs Port 2)	Portfolio 1 (-$458 M vs Port 5)	Portfolio 5 ($27 M vs Port 1)
High Fuel	Portfolio 1 (-$407 M vs Port 5)	Portfolio 5 ($67 M vs Port 1)	Portfolio 5 ($595 M vs Port 1)

Carbon Constrained Base Case:

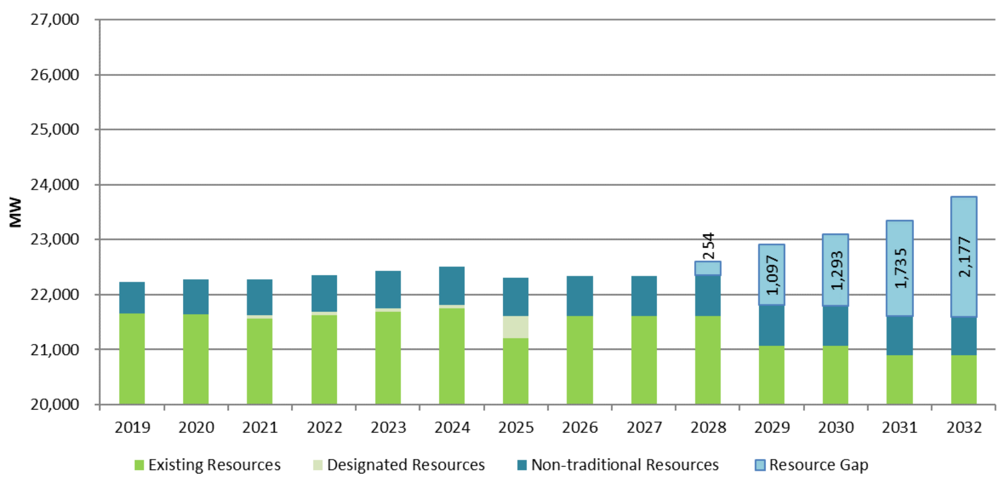
For planning purposes, Duke Energy considers both a carbon constrained future and a no carbon future in the development of the Base Case portfolios. If a carbon constrained future is either delayed or is more restrictive than the base plan, or other variables, such as fuel price and capital costs, change significantly from the base assumptions, the selected carbon constrained portfolio should be adequately robust to still provide value in those futures. Another factor that is considered when selecting the base portfolio is the likelihood that the selected portfolio can be executed as shown. Under those considerations, the Company selected Portfolio 1 (Base CO_2 Future) as the base portfolio for planning assumptions.

Portfolio 1 includes a diverse compilation of resources including CCs, CTs, battery storage, and increasing amounts of EE/DSM and solar resources in conjunction with existing nuclear, natural gas, renewables and other assets already on the DEC system. This portfolio also enables the Company to lower carbon emissions under a range of future scenarios at a lower cost than most other scenarios.

It is important to note that Portfolio 5 (High EE / High Renewables) provides significant value in a high carbon and/or high fuel price future as increased amounts of EE and renewables lower the energy required from more conventional generators on the system. However even in a high CO_2 and high fuel price environment, concerns regarding interconnection costs of incremental solar generation, along with the feasibility and cost risk of increasing the adoption of EE measures beyond the base assumption, the ability to fully execute Portfolio 5 is questionable. Assuming interconnection costs can be mitigated and new EE programs become better established, along with successful implementation and testing of newer technologies such as utility scale battery storage, Portfolio 5, or some version thereof, may become the preferred portfolio over time if the energy markets migrate to higher natural gas prices with strict carbon mandates. Finally, the Carbon Constrained Base Case was developed utilizing consistent assumptions and analytic methods between DEC and DEP, where appropriate. This case does not consider the sharing of capacity between DEC and DEP. However, the Base Case incorporates the JDA between DEC and DEP, which represents a non-firm energy only commitment between the Companies. A Joint Planning Case that begins to explore the potential for DEC and DEP to share firm capacity was also developed and is discussed later in this chapter and in Appendix A.

The Load and Resource Balance graph shown in Figure 12-D illustrates the resource needs that are required for DEC to meet its load obligation inclusive of a required reserve margin. The existing generating resources, designated resource additions and EE resources do not meet the required load and reserve margin beginning in 2028. As a result, the resource plan analyses described above have determined the most robust plan to meet this resource gap.

Figure 12-D: DEC Carbon Constrained Base Case Load Resource Balance (Winter)



Cumulative Resource Additions to Meet Winter Load Obligation and Reserve Margin (MW)

Year	2019	2020	2021	2022	2023	2024	2025	2026
Resource Need	0	0	0	0	0	0	0	0
Year	2027	2028	2029	2030	2031	2032	2033	
Resource Need	0	254	1,097	1,293	1,735	2,177	2,936	

Tables 12-E and 12-F present the Load, Capacity and Reserves (LCR) tables for the Carbon Constrained Base Case analysis that was completed for DEC’s 2018 IRP.

Table 12-E: Carbon Constrained Load, Capacity and Reserves Table - Winter

Winter Projections of Load, Capacity, and Reserves
For Duke Energy Carolinas 2018 Annual Plan

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Load Forecast																
1	DEC System Winter Peak	17,871	18,060	18,145	18,291	18,386	18,621	18,762	19,096	19,320	19,611	19,877	20,047	20,265	20,636	20,821
2	Catawba Owner Backstand - NCEMC	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82
3	Cumulative New EE Programs	(48)	(89)	(128)	(163)	(214)	(248)	(284)	(318)	(350)	(370)	(383)	(390)	(392)	(394)	(398)
4	**Adjusted Duke System Peak**	**17,905**	**18,053**	**18,099**	**18,210**	**18,255**	**18,455**	**18,560**	**18,860**	**19,052**	**19,323**	**19,576**	**19,739**	**19,954**	**20,324**	**20,505**
Existing and Designated Resources																
5	Generating Capacity	21,418	21,418	21,418	21,483	21,548	21,613	21,678	21,476	21,476	21,476	21,476	20,950	20,950	20,777	20,777
6	Designated Additions / Uprates	-	-	65	65	65	65	402	-	-	-	-	-	-	-	-
7	Retirements / Derates	-	-	-	-	-	-	(604)	-	-	-	(526)	-	(173)	-	(547)
8	**Cumulative Generating Capacity**	**21,418**	**21,418**	**21,483**	**21,548**	**21,613**	**21,678**	**21,476**	**21,476**	**21,476**	**21,476**	**20,950**	**20,950**	**20,777**	**20,777**	**20,230**
Purchase Contracts																
9	**Cumulative Purchase Contracts**	**259**	**259**	**173**	**151**	**151**	**152**	**147**	**148**	**148**	**146**	**132**	**132**	**132**	**124**	**123**
	Non-Compliance Renewable Purchases	27	29	29	12	12	13	8	8	7	7	7	7	7	7	7
	Non-Renewables Purchases	233	231	145	139	138	139	139	140	141	139	125	125	125	117	117
Undesignated Future Resources																
10	Nuclear															
11	Combined Cycle										1,338			1,338		
12	Combustion Turbine															460
13	Solar															
Renewables																
14	**Cumulative Renewables Capacity**	104	127	109	108	96	95	90	90	86	110	104	98	81	79	79
15	**Combined Heat & Power**	-	22	22	-	-	-	-	-	-	-	-	-	-	-	-
16	**Energy Storage**		4	16	20	20	20	20	20	-	-	-	-	-	-	-
17	**Cumulative Production Capacity**	**21,782**	**21,830**	**21,829**	**21,892**	**21,964**	**22,050**	**21,857**	**21,878**	**21,874**	**23,234**	**22,688**	**22,682**	**23,830**	**23,820**	**23,733**
Demand-Side Management (DSM)																
18	**Cumulative DSM Capacity**	**447**	**450**	**454**	**458**	**462**	**458**	**458**	**458**	**458**	**458**	**458**	**458**	**458**	**458**	**458**
19	**Cumulative Capacity w/ DSM**	**22,229**	**22,280**	**22,283**	**22,350**	**22,425**	**22,507**	**22,314**	**22,336**	**22,332**	**23,692**	**23,145**	**23,140**	**24,287**	**24,278**	**24,190**
Reserves w/ DSM																
20	Generating Reserves	4,324	4,227	4,184	4,140	4,171	4,052	3,755	3,476	3,280	4,369	3,569	3,401	4,333	3,954	3,686
21	**% Reserve Margin**	**24.1%**	**23.4%**	**23.1%**	**22.7%**	**22.8%**	**22.0%**	**20.2%**	**18.4%**	**17.2%**	**22.6%**	**18.2%**	**17.2%**	**21.7%**	**19.5%**	**18.0%**

Table 12-F: Carbon Constrained Load, Capacity and Reserves Table – Summer

Summer Projections of Load, Capacity, and Reserves
For Duke Energy Carolinas 2018 Annual Plan

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Load Forecast																
1	DEC System Summer Peak	18,294	18,494	18,618	18,755	18,899	19,175	19,428	19,727	20,004	20,374	20,652	20,909	21,209	21,516	21,727
2	Catawba Owner Backstand - NCEMC	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82
3	Cumulative New EE Programs	(112)	(176)	(237)	(295)	(351)	(411)	(474)	(535)	(595)	(637)	(668)	(691)	(708)	(724)	(741)
4	**Adjusted Duke System Peak**	**18,264**	**18,399**	**18,463**	**18,542**	**18,629**	**18,846**	**19,036**	**19,274**	**19,491**	**19,818**	**20,066**	**20,300**	**20,582**	**20,874**	**21,067**
Existing and Designated Resources																
5	Generating Capacity	20,388	20,388	20,453	20,518	20,583	20,648	20,648	20,431	20,431	20,431	20,431	19,915	19,915	19,755	19,755
6	Designated Additions / Uprates	0	65	65	65	65	0	365	0	0	0	0	0	0	0	0
7	Retirements / Derates	0	0	0	0	0	0	(582)	0	0	0	(516)	0	(160)	0	(545)
8	**Cumulative Generating Capacity**	**20,388**	**20,453**	**20,518**	**20,583**	**20,648**	**20,648**	**20,431**	**20,431**	**20,431**	**20,431**	**19,915**	**19,915**	**19,755**	**19,755**	**19,210**
Purchase Contracts																
9	**Cumulative Purchase Contracts**	**353**	**397**	**313**	**294**	**304**	**324**	**344**	**343**	**342**	**338**	**322**	**320**	**319**	**310**	**309**
	Non-Compliance Renewable Purchases	120	167	168	154	166	184	205	203	201	199	197	196	194	193	192
	Non-Renewables Purchases	233	231	145	139	138	139	139	140	141	139	125	125	125	117	117
Undesignated Future Resources																
10	Nuclear															
11	Combined Cycle										1,198			1,198		
12	Combustion Turbine															426
13	Solar															
Renewables																
14	**Cumulative Renewables Capacity**	403	470	537	615	650	689	680	709	733	785	807	829	815	817	820
15	**Combined Heat & Power**	0	16	16	0	0	0	0	0	0	0	0	0	0	0	0
16	**Energy Storage**	0	4	16	20	20	20	20	20	0	0	0	0	0	0	0
17	**Cumulative Production Capacity**	**21,144**	**21,340**	**21,420**	**21,563**	**21,694**	**21,773**	**21,587**	**21,635**	**21,658**	**22,904**	**22,394**	**22,415**	**23,438**	**23,430**	**23,312**
Demand-Side Management (DSM)																
18	**Cumulative DSM Capacity**	**1,035**	**1,059**	**1,082**	**1,104**	**1,111**	**1,109**	**1,109**	**1,109**	**1,109**	**1,109**	**1,109**	**1,109**	**1,109**	**1,109**	**1,109**
19	**Cumulative Capacity w/ DSM**	**22,180**	**22,400**	**22,502**	**22,667**	**22,805**	**22,882**	**22,696**	**22,744**	**22,767**	**24,013**	**23,503**	**23,524**	**24,547**	**24,539**	**24,421**
Reserves w/ DSM																
20	Generating Reserves	3,915	4,001	4,039	4,125	4,176	4,036	3,660	3,470	3,276	4,195	3,438	3,224	3,964	3,665	3,354
21	**% Reserve Margin**	**21.4%**	**21.7%**	**21.9%**	**22.2%**	**22.4%**	**21.4%**	**19.2%**	**18.0%**	**16.8%**	**21.2%**	**17.1%**	**15.9%**	**19.3%**	**17.6%**	**15.9%**

DEC - Assumptions of Load, Capacity, and Reserves Table

The following notes are numbered to match the line numbers on the Winter Projections of Load, Capacity, and Reserves tables. All values are MW (winter ratings) except where shown as a percent. Dates represented are commercial operation dates (COD), unless otherwise noted.

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

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

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

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

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

5. Existing generating capacity reflecting designated additions, planned uprates, retirements and derates as of July 1, 2018.

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

6. Designated Capacity Additions include:

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

   402 MW Lincoln CT 17 included in December 2024.

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

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

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

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

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

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

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

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

   All retirement dates are subject to review on an ongoing basis. Dates used in the 2018 IRP are for planning purposes only, unless already planned for retirement.

8. Sum of lines 5 through 7.

9. Cumulative Purchase Contracts including purchased capacity from PURPA Qualifying Facilities, an 86 MW Cherokee County Cogeneration Partners contract which began in June 1998 and expires June 2020 and miscellaneous other QF projects.

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

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

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

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

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

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

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

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

    Addition of 1,338 MW of combined cycle capacity online December 2027.

    Addition of 1,338 MW of combined cycle capacity online December 2030.

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

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

    Addition of 460 MW of combustion turbine capacity online December 2032.

13. New solar resources economically selected to meet load and minimum planning reserve margin above the forecast in Section 5.

    No solar resources were economically selected in the Base Case.

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

14. Resources to comply with NC REPS and HB 589. These resources include solar, landfill gas, poultry and swine resources. Solar resources reflect contribution to peak demand results from the most recent value of solar study.

15. New 22 MW of combined heat and power capacity included in both 2020 and 2021.

16. Addition of 120 MW of energy storage placeholders over the years 2020 through 2026 based on 80% contribution to peak assumption.

17. Sum of lines 8 through 16.

18. Cumulative demand response programs including wholesale demand response.

19. Sum of lines 17 and 18.

20. The difference between lines 19 and 4.

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

    Line 20 divided by Line 4.

    Minimum winter target planning reserve margin is 17%.

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

Table 12-G: DEC Carbon Constrained Base Case

Duke Energy Carolinas Resource Plan (1) Base Case - Winter								
Year	Resource				MW			
2019	Solar				431			
2020	CHP	Solar	Energy Storage		22	370	4	
2021	Bad Creek Uprate	CHP	Solar	Energy Storage	65	22	360	16
2022	Bad Creek Uprate	Solar	Energy Storage		65	337	20	
2023	Bad Creek Uprate	Solar	Energy Storage		65	247	20	
2024	Bad Creek Uprate	Solar	Energy Storage		65	240	20	
2025	Lincoln CT 17	Solar	Energy Storage		402	91	20	
2026	Energy Storage	Solar			20	112		
2027	Solar				111			
2028	New CC	Solar			1,338	111		
2029	Solar				110			
2030	Solar				109			
2031	New CC	Solar			1,338	8		
2032	Solar				8			
2033	New CT	Solar			460	8		

Notes: (1) Table includes both designated and undesignated capacity additions
(2) Incremental solar additions represent nameplate ratings
(3) Future additions of other renewables, EE and DSM not included

Additionally, a summary of the above table is represented below in Table 12-H.

Table 12-H: Summary of DEC Carbon Constrained Base Case Winter Resources

DEC Base Case Resources Cumulative Winter Totals - 2019 - 2033	
Nuclear	0
Solar	2,653
CC	2,676
CT	862
Pumped Storage	260
CHP	44
Energy Storage	120
Total	6,615

The following figures illustrate both the current and forecasted capacity for the DEC system, as projected by the Carbon Constrained Base Case. As demonstrated in Figure 12-E, the capacity mix for the DEC system changes with the passage of time. In 2033, the Carbon Constrained Base Case projects that DEC will have a smaller reliance on coal and a higher reliance on gas-fired resources, nuclear, renewable resources and EE as compared to the current state. It should be noted that the Company's Carbon Constrained Base Case resources depicted in Figure 12-E below reflect a significant amount of solar capacity with nameplate solar growing from 1,218 MW in 2019 to 3,440 MW by 2033. However, given that solar resources only contribute approximately 1% of nameplate capacity at the time of the Company's winter peak, solar capacity contribution to winter peak only grows from 16 MW in 2019 to 34 MW by 2033.

Figure 12-E: Duke Energy Carolinas Capacity Over 15-Year Study Period – Carbon Constrained Base Case [5]

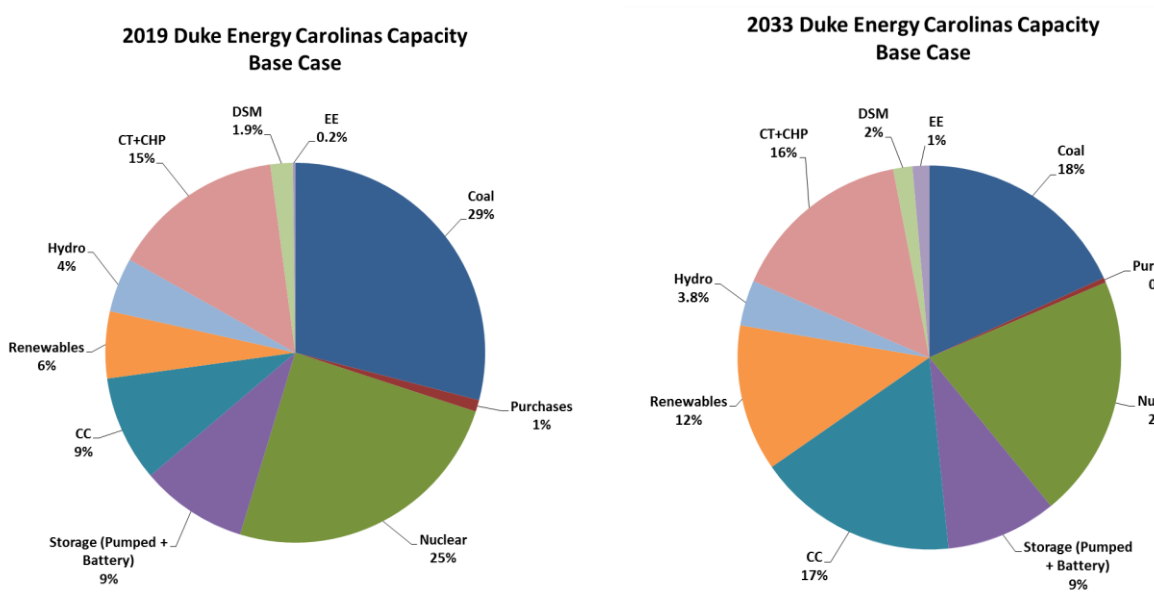
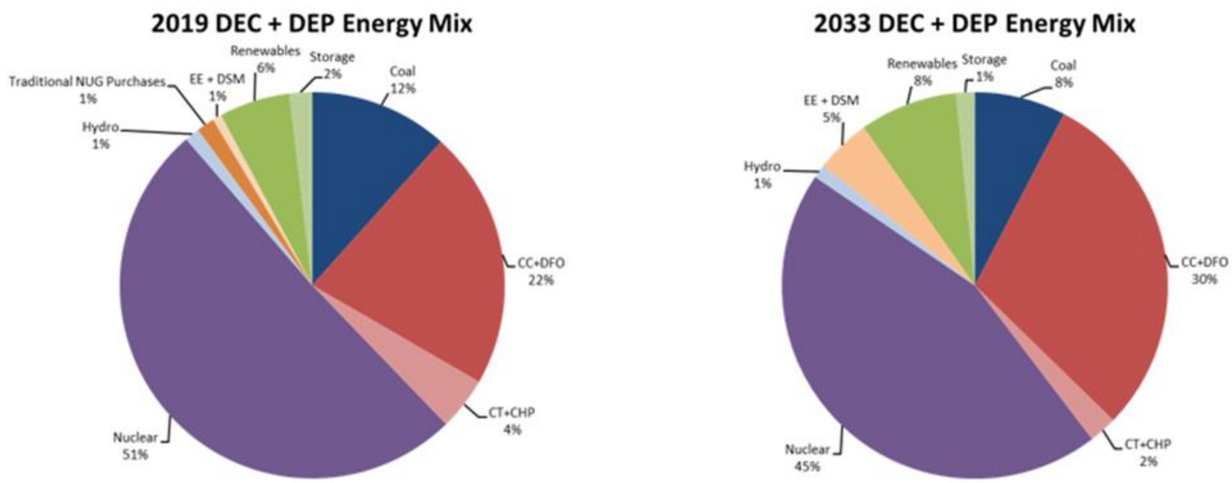


Figure 12-F represents the energy of both the DEC and DEP Carbon Constrained Base Cases over time. Due to the joint dispatch agreement (JDA), it is prudent to combine the energy of both utilities to develop a meaningful Carbon Constrained Base Case energy chart. From 2019 to 2033, the graphs show that 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 energy served by natural gas, renewables and EE.

[5] All capacity based on winter ratings (renewables which are based on nameplate).

Figure 12-F: DEC and DEP Energy Over 15-Year Study Period – Carbon Constrained Base Case [6]



A detailed discussion of the assumptions, inputs and analytics used in the development of the Base Cases are contained in Appendix A. As noted, the further out in time planned additions or retirements are within the 2018 IRP, the greater the opportunity for input assumptions to change. Thus, resource allocation decisions at the end of the planning horizon have a greater possibility for change as compared to those earlier in the planning horizon.

No Carbon Base Case:

While Duke Energy presents a base resource plan that was developed under a carbon constrained future, the Company also provides a No Carbon (or No CO_2) Base Case expansion plan that reflects a future without CO_2 constraints. In DEC, this expansion plan is represented by Portfolio 2 (Base No CO_2 Future). As shown in Tables 12-I and 12-J below, during the 15-year planning horizon, there is a significant shift towards CT technology from the Carbon Constrained Base Case. However, beyond the 15-year window there is a shift back to CC technology in Portfolio 2. Additionally, without a CO_2 constraint, incremental solar additions are delayed further beyond the planning horizon.

[6] All capacity based on winter ratings except renewables which are based on nameplate.

Table 12-I: DEC No Carbon Base Case

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

Year	Resource				MW			
2019	Solar				431			
2020	CHP	Solar	Energy Storage		22	370	4	
2021	Bad Creek Uprate	CHP	Solar	Energy Storage	65	22	360	16
2022	Bad Creek Uprate	Solar	Energy Storage		65	337	20	
2023	Bad Creek Uprate	Solar	Energy Storage		65	247	20	
2024	Bad Creek Uprate	Solar	Energy Storage		65	240	20	
2025	Lincoln CT 17	Solar	Energy Storage		402	91	20	
2026	Energy Storage	Solar			20	112		
2027	Solar				111			
2028	New CT	Solar			460	111		
2029	New CT	Solar			920	110		
2030	Solar				109			
2031	New CT	Solar			460	8		
2032	New CT	Solar			460	8		
2033	New CT	Solar			920	8		

Notes: (1) Table includes both designated and undesignated capacity additions
(2) Incremental solar additions represent nameplate ratings
(3) Future additions of other renewables, EE and DSM not included

Table 12-J: Summary of DEC No Carbon Case Winter Resources

DEC No CO_2 Case Resources
Cumulative Winter Totals - 2019 - 2033

Nuclear	0
Solar	2,653
CC	0
CT	3,622
Pumped Storage	260
CHP	44
Energy Storage	120
Total	6,699

Joint Planning Case:

A Joint Planning Case that begins to explore the potential for DEC and DEP to share firm capacity between the Companies was also developed. The focus of this case is to illustrate the potential for the Utilities to collectively defer generation investment by utilizing each other's capacity when available and by jointly owning or purchasing new capacity additions. This case does not address the specific implementation methods or issues required to implement shared capacity. Rather, this case illustrates the benefits of joint planning between DEC and DEP with the understanding that the actual execution of capacity sharing would require separate regulatory proceedings and approvals.

Table 12-K below represents the annual non-renewable incremental additions reflected in the combined DEC and DEP winter Base Cases as compared to the Joint Planning Case. The plan contains the undesignated additions for DEC and DEP over the planning horizon. As presented in Table 12-K, the Joint Planning Case allows for the delay of a CC resource and several blocks of CT resources through the 15-year study period. Though not shown below, the ability to share capacity between DEC and DEP would also limit the amount of undesignated short-term market purchases identified in the 2020 to 2024 timeframe in the DEP IRP.

Table 12-K: DEC and DEP Joint Planning Case

DEC and DEP Combined Resource Plan [1] Base Case - Winter		
Year	**Resource**	**MW**
2019		
2020		
2021		
2022		
2023		
2024		
2025	New CC	1,338
2026		
2027	New CC	1,338
2028	New CC	1,338
2029	New CT	1,840
2030		
2031	New CC	1,338
2032	New CT	460
2033	New CT	920

Notes: (1) Table only includes undesignated conventional capacity additions.

Delay

Delay 460 MW

Delay 460 MW

Delay 460 MW Beyond Study Period

DEC and DEP Joint Planning Resource Plan [1] Base Case - Winter		
Year	**Resource**	**MW**
2019		
2020		
2021		
2022		
2023		
2024		
2025	New CC	1,338
2026		
2027	New CC	1,338
2028		
2029	New CC New CT	1,338 1,380
2030		
2031	New CC	1,338
2032		
2033	New CT	1,380

A comparison of both the DEC and DEP Combined Base Case and Joint Planning Base Case by resource type is represented below in Table 12-L.

Table 12-L: DEC and DEP Base Case and Joint Planning Case Comparison by Resource Type

DEC and DEP Combined Base Case Resources

Cumulative Winter Totals - 2019 - 2033

Nuclear	0
CC	5,352
CT	3,220
Total	8,572

DEC and DEP Joint Base Case Resources

Cumulative Winter Totals - 2019 - 2033

Nuclear	0
CC	5,352
CT	2,760
Total	8,112

13. SHORT-TERM ACTION PLAN

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

Continued Reliance on EE and DSM Resources:

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

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

- Continue on-going collaborative work to develop and implement additional cost-effective EE and DSM products and services, such as: (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 and development pilots.

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

Continued Focus on Renewable Energy Resources:

DEC is committed to the addition of significant renewable generation into its resource portfolio. Over the next five years DEC is projecting to grow its renewable portfolio from 1,337 MW to 2,615 MW. Supporting policy such as SC Act 236, and NC REPS and NC HB 589 have all contributed to DEC's aggressive plans to grow its renewable resources. DEC is committed to meeting its targets for the SC DER Program and under HB 589, DEC and DEP are responsible for procuring renewable energy and capacity through a competitive procurement program. These activities will be done in a manner that allows the Companies to continue to reliably and cost-effectively serve customers' future energy needs. The Companies, under their competitive procurement program, are required to procure energy and capacity from renewable energy facilities in the aggregate amount of 2,660 MW through request for proposals. DEC/DEP plan to jointly implement the CPRE Program across their SC and NC service territories. For further details, refer to Chapter 5.

Integration of Battery Storage on System:

The Company will begin investing in multiple grid connected storage systems dispersed throughout its South and North 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 operation and maintenance cost impacts of batteries deployed at a significant scale. Additionally, the Company continues to participate in an energy storage study to assess the economic potential for NC customers, mandated by HB 589. Results of the study are expected in December 2018.

Continue to Find Opportunities to Enhance Existing Clean Resources:

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

Addition of Clean Natural Gas Resources: [7]

- The Company continues to consider advanced technology combined cycle units as excellent options to meet future demand. The improving efficiency and reliability of CCs coupled with the continued trend of lower natural gas prices make this resource very attractive. As older units on the DEC system are retired, CC units continue to play an important role in the Company's future diverse portfolio.

    - A combined cycle unit 683 MW (net of NCEMC 100 MW ownership) has recently come online at the Lee site in South Carolina. The CC's commercial operation date was April 5, 2018.

    - An advanced combustion turbine unit will begin extended commissioning at the Lincoln CT Plant in North Carolina in 2019. The Company will take care, custody, and control of the completed 402 MW unit in 2024.

[7] Capacities represent winter ratings.

- As mentioned previously, two 22 MW blocks of Combined Heat & Power are considered in the 2018 IRP and are included as resources for meeting future generation needs. DEC has signed agreements and obtained regulatory approval for a 15 MW CHP at Clemson University, which is expected to be in service by 2020. Filing for a CPCN for a 21 MW CHP at Duke University has been delayed pending the resolution of issues raised by the University. Discussions with other potential steam hosts are currently underway. Future IRP processes will incorporate additional CHP as appropriate.

A summarization of the capacity resource changes for the reference plan in the 2018 IRP is shown in Table 13-A below. Capacity retirements and additions are presented as incremental values in the year in which the change impacts the winter peak. The values shown for renewable resources, EE and DSM represent cumulative totals.

Table 13-A: DEC Short-Term Action Plan

Duke Energy Carolinas Short-Term Action Plan (1) (2)						
			Compliance Renewable Resources (Cumulative Nameplate MW)			
Year	**Retirements**	**Additions (5)**	**Solar (3)**	**Biomass/Hydro**	**EE**	**DSM (4)**
2019			1,218	119	48	447
2020		22 MW CHP 4 MW Energy Storage	1,588	140	89	450
2021		22 MW CHP 16 MW Energy Storage 65 MW Bad Creek Upgrade	1,948	118	128	454
2022		20 MW Energy Storage 65 MW Bad Creek Upgrade	2,285	98	163	458
2023		20 MW Energy Storage 65 MW Bad Creek Upgrade	2,532	83	214	462

Notes:

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

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

(3) Capacity is shown in nameplate ratings.

(4) Includes impacts of grid modernization.

(5) Energy Storage capacity represents 80% of nameplate.

Continue with Plan for Subsequent License Renewal of Existing Nuclear Units:

As discussed in Chapter 10, 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 Development and Implementation of Capacity Value of Solar:

Conventional thermal resources are typically counted as 100% of net capability in reserve margin calculations for future generation planning since these resources are fully dispatchable resources when not on forced outage or planned maintenance. Due to the diurnal pattern and intermittent nature of solar energy resources, it is not reasonable to assume that these resources provide the same capacity credit as a fully dispatchable resource. An outside consultant calculated the incremental capacity credit of solar across five solar penetration levels for DEC and DEP and a trend of capacity credit can be fit to a curve to estimate the capacity credit of each MW of solar added to the system.

Continued Transition Toward Integrated System and Operations Planning:

As explained in Chapter 6, the traditional methods of utility resource planning are continuing to evolve. DEC is committed to moving toward an integrated planning process to meet the changing needs of planning in the future. The traditional methods of utility resource planning must be enhanced to address shifting trends through an Integrated System and Operations Planning (ISOP) effort.

In the 2018 IRP, DEC has begun to adapt its IRP to adjust to this changed world, recognizing that this process will continue to evolve. One key goal of ISOP is for the planning models to reasonably mimic the future operational realities to allow DEC to serve its customers with newer technologies. These enhancements in planning are expected to be addressed over the next several years, as soon as the modeling tools, processes and data development will allow.

Continued Focus on Environmental Compliance and Wholesale:

- Retire older coal generation.
    - As of April 2015, approximately 1,700 MW of older coal generation has been retired and replaced with clean-burning natural gas, renewable energy resources or energy efficiency.

- The final older, un-scrubbed coal units at Lee Steam Station were retired in November 2014.
- Currently, Duke Energy Carolinas has no remaining older, un-scrubbed coal units in operation.[8]

- Continue to investigate the future environmental control requirements and resulting operational impacts associated with existing and potential environmental regulations such as EPA's Clean Power Plan (Section 111d of Clean Air Act regulating CO_2 from existing power plants), Mercury Air Toxics Standard (MATS), the Coal Combustion Residuals (CCR) rule, the Cross-State Air Pollution Rule (CSAPR).

- Continue to pursue existing and potential opportunities for wholesale power sales agreements within the Duke Energy balancing authority area.

- Continue to monitor energy-related statutory and regulatory activities.

- Continue to examine the benefits of joint capacity planning and pursue appropriate regulatory actions.

- Review existing purchased power contracts

  - Over the next five years, DEC has 124 MW of contracts that expire under the current contract terms.
  - The Company plans to engage the marketplace to determine the feasibility of extending existing contracts or replacing them with other purchased power arrangements to economically meet customer demand.

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

DEC Request for Proposal (RFP) Activity:

Supply-Side:

Outside of renewable solicitations, no supply-side RFPs have been issued since the filing of DEC's last IRP.

Renewable Energy:

Duke Energy Carolinas/Progress Swine Waste Fueled RFP – North Carolina

See DEP Renewable Energy section for the information on the Duke Energy Carolinas/Progress Swine Waste RFP that was released December 15, 2017 that covered both DEC and DEP service territories in North Carolina.

Duke Energy Carolinas – South Carolina Distributed Energy Resource RFP – Solar PV

Duke Energy Carolinas, LLC released an RFP on August 1, 2018 to continue its efforts to solicit proposals for solar photovoltaic generation capacity located in and directly interconnected to DEC's retail service area in South Carolina. The previously-released South Carolina DER Utility Scale RFP, released in 2015, is still underway and projects on that shortlist are still being considered. This RFP was released to identify additional projects from which DEC may procure solar PV renewable energy capacity and all associated renewable attributes, such as Renewable Energy Certificates to comply with DEC's Utility Scale Program requirements under the South Carolina Distributed Energy Resource Program Act. DEC is seeking approximately 40 MW_{AC} of nameplate solar PV capacity in total. Proposal structure allowed for this RFP is for Purchase Power Agreements with 15-year term duration. RFP scheduled to close on September 4, 2018.

Duke Energy Carolinas Wind RFP:

Duke Energy Carolinas, LLC released an RFP on August 15, 2017 soliciting proposals for delivered energy, capacity and associated Renewable Energy Certificates produced by wind generators. Energy had to be delivered on a firm basis into the DEC transmission system that was slated to be used to meet DEC's customers' load requirements as well as expand and diversify DEC's renewable generation portfolio and satisfy its "in state" General REC Requirement under the North Carolina Renewable Energy and Efficiency Portfolio Standard. RFP requested wind capacity to be delivered to DEC from 100 MW to 500 MW facilities with proposals in the form of Purchase Power Agreements (5 to 20-year term), Build-Own-Transfers, or Asset Purchases of Existing Facilities.

Delivery of wind energy to DEC required to be delivered on or before December 31, 2022 inclusive of all environmental attributes. RFP closed on September 27, 2017 with no contracts executed.

APPENDICES

APPENDICES CONTENTS:

APPENDIX A: QUANTITATIVE ANALYSIS

This appendix provides an overview of the Company's quantitative analysis of the resource options available to meet customers' future energy needs. Sensitivities on major inputs resulted in multiple portfolios that were then evaluated under several scenarios that varied fuel prices, capital costs, and CO_2 constraints. These portfolios were analyzed using a least cost analysis to determine the Base Case for the 2018 IRP. The selection of this plan takes into account the cost to customers, resource diversity, reliability and the long-term carbon intensity of the system.

The future resource needs were optimized for DEC and DEP independently. However, an additional case representative of jointly planning future capacity on a DEC/DEP combined system basis using the Base Case assumptions was also analyzed to demonstrate potential customer savings, if this option was available in the future.

A. Overview of Analytical Process

The analytical process consists of four steps:

1. Assess resource needs.
2. Identify and screen resource options for further consideration.
3. Develop portfolio configurations.
4. Perform portfolio analysis over various scenarios.

1. Assess Resource Needs

The required load and generation resource balance needed to meet future customer demands was assessed as outlined below:

- Customer peak demand and energy load forecast – identified future customer aggregate demands to determine system peak demands and developed the corresponding energy load shape.
- Existing supply-side resources – summarized each existing generation resource's operating characteristics including unit capability, potential operational constraints and life expectancy.
- Operating parameters – determined operational requirements including target planning reserve margins and other regulatory considerations.

Customer load growth, the expiration of purchased power contracts and additional asset retirements result in resource needs to meet energy and peak demands in the future. The following assumptions impacted the 2018 resource plan:

- Peak Demand and Energy Growth - The growth in winter customer peak demand after the impact of energy efficiency averaged 0.9% from 2019 through 2033. The forecasted compound annual growth rate for energy is 0.8% after the impacts of energy efficiency programs are included.
- Generation
  - Runner upgrades totaling 260 MW between 2020 and 2024 at Bad Creek Pumped-Storage Generating Station
  - Completion of the 402 MW Lincoln CT Unit #17 in 2024

- Retirements - Retirement of 604 MW at Allen Steam Station (Units 1 – 3) in December 2024 and the remaining 557 MW at Allen Steam Station in June 2028 (Units 4 and 5)
- Reserve Margin - A 17% minimum winter planning reserve margin for the planning horizon

2. Identify and Screen Resource Options for Further Consideration

The IRP process evaluated EE, DSM and traditional and non-traditional supply-side options to meet customer energy and capacity needs. The Company developed EE and DSM projections based on existing EE/DSM program experience, the most recent market potential study, input from its EE/DSM collaborative and cost-effectiveness screening for use in the IRP. Supply-side options reflect a diverse mix of technologies and fuel sources (gas, nuclear, renewable, and energy storage). Supply-side options are initially screened based on the following attributes:

- Technical feasibility and commercial availability in the marketplace
- Compliance with all Federal and State requirements
- Long-run reliability
- Reasonableness of cost parameters

The Company compared the capacity size options and operational capabilities of each technology, with the most cost-effective options of each being selected for inclusion in the portfolio analysis phase. An overview of resources screened on technical basis and a levelized economic basis is discussed in Appendix F.

Resource Options:

Supply-Side:

Based on the results of the screening analysis, the following technologies were included in the quantitative analysis as potential supply-side resource options to meet future capacity needs:

- Base load – 600 MW – Small Modular Reactor (SMR)
- Base load – 1,339 MW – 2x2x1 Advanced Combined Cycle (No Inlet Chiller and Fired)
- Base load – 22 MW – Combined Heat & Power (Combustion Turbine)
- Peaking/Intermediate – 460 MW – 2 x 7FA.05 CTs
    - (Based upon the cost to construct 4 units, available for brownfield sites only)
- Peaking/Intermediate – 919 MW 4 x 7FA.05 Combustion Turbines (CTs)
- Renewable – 50 MW Solar PV, Fixed-tilt (FT)
- Renewable – 50 MW Solar PV, Single Axis Tracking (SAT)
- Storage – Grid Tied 20 MW / 80 MWh Li-ion Battery

Energy Efficiency and Demand-Side Management:

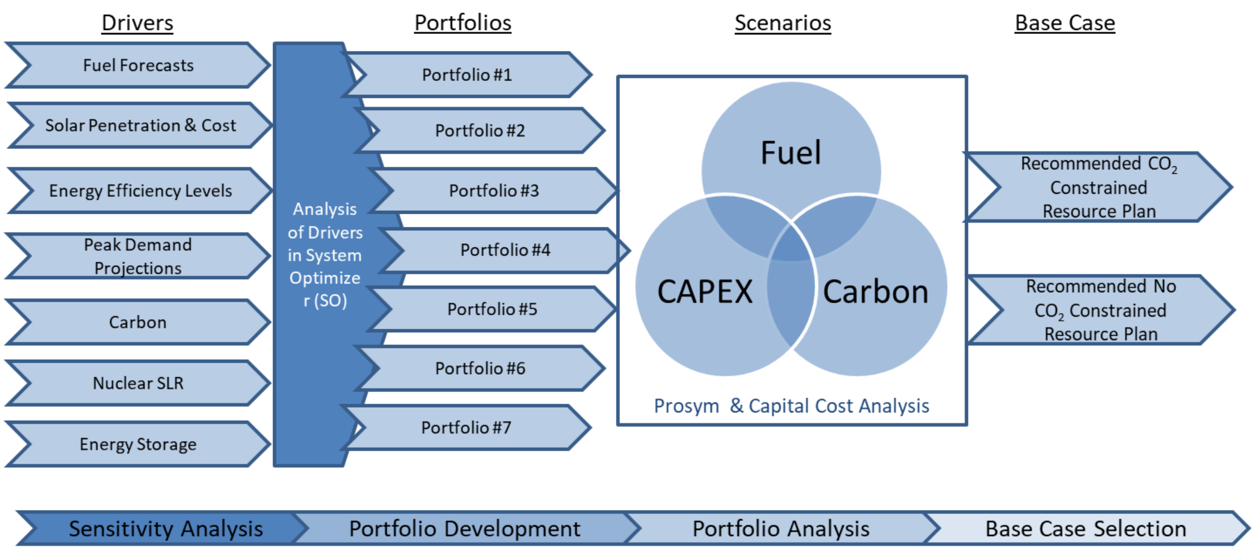
EE and DSM programs continue to be an important part of Duke Energy Carolinas' system mix. The Company considered both EE and DSM programs in the IRP analysis. As described in Appendix D, EE and DSM measures are compared to generation alternatives to identify cost-effective EE and DSM programs.

In the Base Case, the Company modeled the program costs associated with EE and DSM based on a combination of both internal company expectations and projections based on information from the 2016 market potential study. In the DEC and DEP Merger Settlement Agreement, the Company agreed to aspire to a more aggressive implementation of EE throughout the planning horizon. The impacts of this goal were incorporated in one of the portfolios evaluated. The program costs used for this analysis leveraged the Company's internal projections for the first five years and in the longer term, utilized the updated market potential study data incorporating the impacts of customer participation rates over the range of potential programs.

3. Develop Portfolio Configurations

Once the load and generation balance was assessed, and resource options were screened, the portfolios and scenarios were developed, and the preferred base cases were selected, based on the following simplified diagram.

Figure A-1: Simplified Process Flow Diagram for Development and Selection of Base Cases



The Company conducted a sensitivity analysis of various drivers using the simulation modeling software, *System Optimizer* (SO). The expansion plans produced by SO were compared and seven portfolios that encompass the impact of the range of input sensitivities were identified. The seven portfolios were then analyzed in multiple scenarios in the hourly production cost model, PROSYM, to determine the optimum base case. An overview of the base planning assumptions and sensitivities considered in both SO and PROSYM are outlined below:

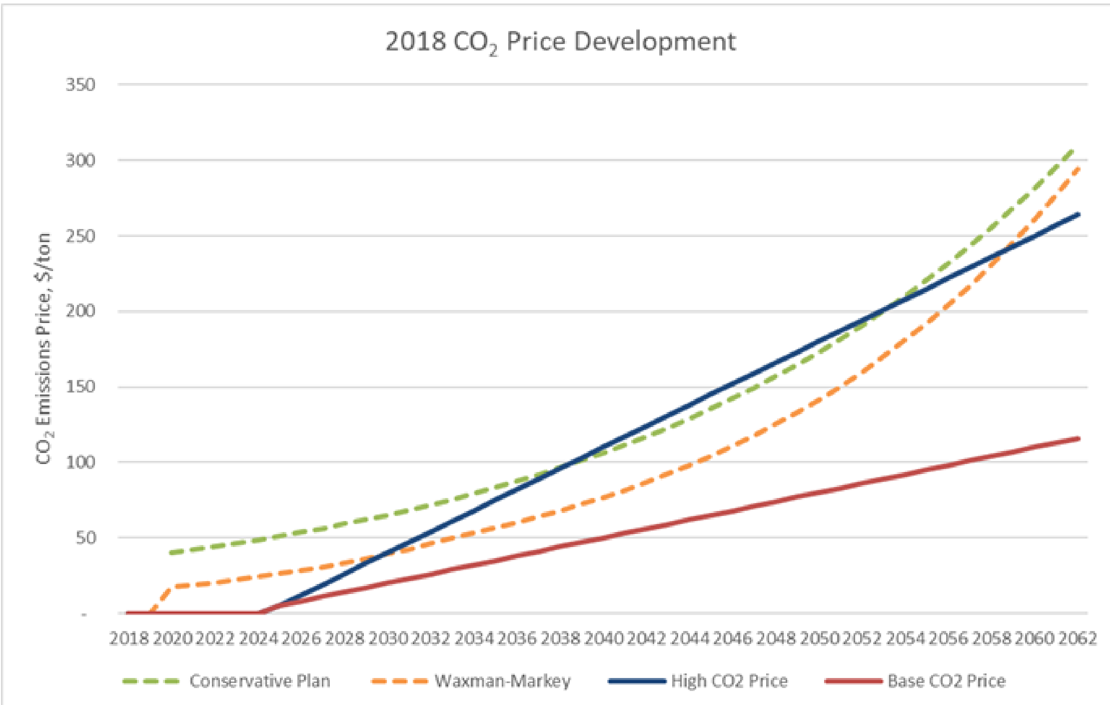
- Impact of potential carbon constraints
  - In the current legislative/regulatory environment, predicting future carbon constraints is becoming increasingly difficult. In October 2017, the EPA began the formal process to change EPA rules and repeal the previous administration's Clean Power Plan (CPP). With the CPP likely repealed in the next year to two years, the Company developed an internal CO_2 allowance price, or "Base CO_2

Price," which would lead to a 40% CO_2 reduction from a 2005 baseline by 2030, a 50% reduction by 2040, and a 60% reduction by 2050 for the Company's regulated utilities (Duke Energy Indiana (DEI), Duke Energy Kentucky (DEK), Duke Energy Florida (DEF), DEP, and DEC). The "Base CO_2 Price" falls between the expected CPP price on the low end, and the previously proposed Waxman/Markey legislation on the high end. Additionally, the Company developed a "High CO2 Price" that was based on the Waxman-Markey legislation and the recently proposed "Conservative Plan[9]". The "High CO_2 Price" would support a CO_2 reduction of 80% by 2050. Figure A-2 presents a view of the carbon prices used in the analysis, along with the Conservative Plan and Waxman-Markey legislation prices.

- Base CO_2 Price – Incorporated an intrastate CO_2 tax starting at $5/ton in 2025 and escalating at $3/ton annually that was applied to all carbon emissions.
- High CO_2 Price – Incorporated an intrastate CO_2 tax starting at $5/ton in 2025 and escalating at $7/ton annually that was applied to all carbon emissions.

[9] https://www.clcouncil.org/media/TheConservativeCaseforCarbonDividends.pdf

Figure A-2: Comparison of CO_2 Prices and Other CO_2 Reference Prices



- **Retirements**

  - Coal assets – For the purpose of this IRP, the depreciation book life was used as a placeholder for future retirement dates for coal assets. Based on this assumption, Allen Steam Station Units 1-3 were retired in December 2024, Allen Steam Station Units 4 and 5 were retired in 2028 and Cliffside 5 was retired in 2033.

- **Nuclear assets**
  - Oconee Nuclear Station's current operating license has been extended to 60 years and expires in 2033. NextEra's Turkey Point Station and Exelon Corporation's Peach Bottom plant have each submitted a Subsequent License Renewal (SLR) application to the Nuclear Regulatory Commission (NRC). Additionally, Dominion Energy has announced its intention to pursue SLRs for its Surry and North Anna plants. The Company views all of its existing nuclear fleet as excellent candidates for license extensions based on current condition and expected operation expenditures regardless of future carbon constraints. Based on recent NRC guidance for SLR, the NextEra and Exelon Corporation application submittals, and the announcement from Dominion Energy, the Company's Base

Cases assume SLR for all existing nuclear generation, including Oconee Nuclear Station, from 60 to 80 years for planning purposes in this year's IRP.

- A sensitivity was performed assuming SLRs were not pursued for any of the Company's nuclear assets.

- SMR technology was "screened out" in the Technology Screening phase of the analysis as discussed in Appendix F. However, given the severity of the "High CO_2 Price" sensitivity, and the need for zero-emitting, load following resources (ZELFRs), additional nuclear generation in the form of SMRs was allowed to be selected.

- **Coal and natural gas fuel prices**

  - Short-term pricing:
    - Natural Gas based on market prices from 2018 through 2028 transitioning to 100% fundamental by 2033.
    - Coal based on market observations through 2022 transitioning to 100% fundamental by 2028.
  - Long-term pricing: based on the Company's fundamental fuel price projections.

    - High Fuel Price Sensitivity – A high fuel price sensitivity was developed where the short-term, or market, natural gas price was increased based on statistical analysis that produced a +1 Standard Deviation (Std) from the base market price. The average cumulative probability of the +1 Std was 90% (i.e. in 90% of the cases, the average price will be lower than this scenario). The long-term pricing component was increased based on the U.S. Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2018 report which provided a "Low Resource and Technology" curve.
    - Low Fuel Price Sensitivity - A low fuel price sensitivity was developed where the short-term, or market, natural gas price was decreased based on statistical analysis that produced a -1 Std from the base market price. The average cumulative probability of the -1 Std was 6.7% (i.e. in 6.7% of the cases, the average price will be lower than this scenario). The long-term pricing component was increased based on the U.S. Energy Information

Administration's (EIA) Annual Energy Outlook (AEO) 2018 report which provided a "High Resource and Technology" curve.

- **Capital Cost Sensitivities**

  - As discussed in Appendix F, most technologies include technology specific Technology Forecast Factors which were sourced from the Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2017 which provides costs projections for various technologies through the planning period as an input to the National Energy Modeling System (NEMS) utilized by the EIA for the AEO. More nascent technologies, such as battery storage and, to a lesser extent, PV solar, have relatively steep projected cost declines over time compared to more established technologies such as CCs and CTs. The capital cost sensitivities conducted were as follows:

    - Low Capital Cost - Technology forecast factors were doubled thereby increasing the cost declines of all technologies over time.

    - High Capital Cost – Technology forecast factors were reduced by half, thereby decreasing the rate of cost decline of all technologies over time.

  - Solar – The Base Case includes renewable capacity components of the Transition MW of HB 589 such as capacity required for compliance with NC REPS, PURPA renewable purchases, the SC DER Program, legacy Green Source Rider program, and the additional three components of HB 589 (competitive procurement, renewable energy procurement for large customers, and community solar). The Base Case also includes additional projected solar growth beyond HB 589. Below is an overview of the solar base planning assumptions and the sensitivities performed:

    - Base – Solar facility costs continue to decrease over the next decade with a 30% Federal Investment Tax Credit (ITC) through 2019, 26% ITC in 2020, 22% ITC in 2021 and 10% ITC thereafter. Additional solar beyond compliance was allowed to be selected if economical.

    - Low Cost - To determine if a lower cost would impact the economic selection of additional solar resources, a capital cost sensitivity was performed where solar prices were reduced by 10%.

  - Higher Solar Penetration – Given the significant volume uncertainty around solar penetration, a high solar penetration scenario was performed to account for a number of potential factors that could increase solar additions over the planning horizon. These factors include events such as high carbon prices, lower solar capital costs, economical solar plus storage, continuation of renewable subsidies, and/or stronger renewable energy mandates.

- **EE and Renewables – Two different options were evaluated with regards to the amount of EE and Renewables**

  - Base EE and Base Renewables

    - Base EE corresponds to the Company's current projections for achievable cost-effective EE program acceptance.

    - Base renewables corresponds to the resources needed to meet components of the Transition MW of HB 589 such as capacity required for compliance with NC REPS, PURPA renewable purchases, the SC DER Program, legacy Green Source Rider program, and the additional three components of HB 589 (competitive procurement, renewable energy procurement for large customers, and community solar). Base renewables also includes additional projected solar growth beyond HB 589.

  - High EE and High Renewables

    - Evaluated to assess the impact of additional EE and renewables on the expansion plan.

    - High EE – Established as part of the Duke Energy Carolinas-Progress Energy Merger Settlement Agreement. The cumulative EE achievements since 2009 are counted toward the cumulative settlement agreement impacts. By 2033, the high EE case accounts for an additional 234 MW of winter peak demand reduction versus the base EE case.

    - High Renewables – Added 1,103 MW of additional solar to the base SC and NC renewable planning assumptions by 2033 versus the base renewable case.

- While not explicitly evaluated, the impacts of a Low EE future on the expansion, are similar to the impacts of the "high load" sensitivity that was evaluated in SO and that is discussed later in this section.

- **Energy Storage**

  - 150 MW of 4-hour Lithium ion batteries are included in the Base Case as placeholders for future assets to provide operational experience on the DEC system. These placeholders represent a limited amount of grid connected battery storage projects that have the potential to provide solutions for the transmission and distribution systems with the possibility of simultaneously providing benefits to the generation resource portfolio. As discussed in various sections throughout this document, the extent to which 4-hour battery storage can provide generation deferral benefits is still being evaluated, particularly when a single battery storage installment is expected to provide multiple services in addition to generation and energy benefits. Additionally, the benefits of battery storage are most realized when the asset is grid-tied and the Company has real-time control of when the battery storage is dispatched to, or charged from, the system.

    The deployment of utility scale battery storage over the next decade will provide valuable real-world experience for optimizing and assessing the benefits of battery storage. Given the uncertainties in future battery deployments and the ability to fully contribute to generation deferral, the Base Case assumes that the 150 MW of placeholder battery storage provides 120 MW (or 80% of nameplate capacity)[10] towards meeting winter peak demand. These assumptions are likely to change as the Company gains experience operating utility-scale battery storage technologies. An additional battery storage sensitivity was also considered:

    - A battery storage sensitivity was also included in which a 575 MW 4-hour Lithium ion battery replaced a 460 MW CT block in a high renewable future.

[10] Based on EPRI's "Technical Update: Evaluating the Capacity Value of Energy Storage (E. Lannoye & E. Ela, December 2017)" which provides several methodologies for calculating capacity value of Energy Storage. The results range from ~40% to 100% of nameplate capacity as potential capacity value. For the purposes of the 2018 IRP, 80% was selected for planning purposes assuming the projects are 100% controlled by the Company.

- High and Low Load – The annual average load growth rate before impacts of EE from 2020 through 2033 was increased from 1.1% to 2.0% in the high load sensitivity and the annual average growth rate was reduced from 1.1% to 0.2% in the low load sensitivity.

- A sensitivity was performed assuming joint planning with DEC and DEP to demonstrate the benefits of shared resources and how new generation could be delayed.

Sensitivy Analysis Results:

A review of the results from the sensitivity analysis conducted in SO yielded some common themes.

Initial Resource Needs – The first resource need after Lincoln CT #17 begins providing capacity in 2024 occurs in December 2027 in all cases other than the high EE and low load sensitivities which delay the need for the generating asset to December 2028 and December 2032 respectively. As shown in Table A-1 below, the type of asset selected is dependent on the fuel and CO_2 assumptions. In all High CO_2 sensitivities, the type of generation selected is CC, however in all No CO_2 sensitivities, the type of generation selected is CT. In the base CO_2 assumptions, fuel price is the driver for the generation asset selected. In base CO_2 sensitivities that use base or low fuel prices, the generating asset selected is CC, and in high fuel price sensitivities (with base CO_2) the asset selected is CT.

Table A-1: DEC Initial Resource Need with Varying CO_2 and Fuel Assumptions

	No CO_2	Base CO_2	High CO_2
Low Fuel	CT	CC	CC
Base Fuel	CT	CC	CC
High Fuel	CT	CT	CC

- Joint Planning Case - The first three resource needs are CCs, two in DEP, in 2024/2025 and 2026/2027, and one in DEC in 2027/2028. When joint capacity planning, the DEP CCs are not delayed, but the DEC CC is delayed one year to 2028/2029.

Renewable Generation – The timing of incremental solar beyond the capacity included in the Base Case was dependent on the CO_2 and fuel price assumptions as shown in Table A-2 below. It must be noted that incremental solar additions in DEC are only credited with approximately1% contribution to winter peak capacity across the planning horizon. The incremental solar additions are only providing energy value and essentially no capacity value.

Table A-2: First Year of Incremental Solar Additions in DEC

	No CO_2	Base CO_2	High CO_2
Low Fuel	Not Selected	2037	2030
Base Fuel	2039	2034	2028
High Fuel	2033	2028	2027

Additionally, in the case where solar prices were reduced by 10%, the first year of incremental solar additions accelerated from 2034 to 2030 in the Base CO_2 / Base Fuel case.

New Nuclear Selection – New nuclear additions, in the form of SMRs, were selected in the SO analysis in all High CO_2 cases, as well as, in the Base CO_2 / High Fuel case. As shown in Table A-3 below, the timing of new nuclear selection in the High CO_2 cases is dependent on the fuel price assumptions.

Table A-3: First Year of New Nuclear Additions

	No CO_2	Base CO_2	High CO_2
Low Fuel	Not Selected	Not Selected	2048
Base Fuel	Not Selected	Not Selected	2037
High Fuel	Not Selected	2036	2030

In the No SLR scenario for existing nuclear units, the timing for new nuclear generation accelerated from 2037 to 2034 in the High CO_2 / Base Fuel case. As continues to be the case, in order to meet potentially stringent CO_2 emission regulations, new nuclear generation will likely be needed. The timing of new nuclear generation is highly dependent on fuel price projections, as well as, subsequent license renewal of the existing nuclear generation fleet.

High EE and High Renewables – Within the 15-year planning horizon, the impact from High EE, in combination with High Renewables, was to delay the need for the initial generating asset in DEC from December 2027 to December 2028. A CT in 2032 timeframe was also delayed by one year due to the reduction in peak demand from increased EE.

Gas Firing Technology Options – The number of CCs selected over the planning horizon varied with the fuel and CO_2 assumptions as shown in Table A-4 below.

Table A-4: Number of CCs Selected in 15-Year Planning Horizon

	No CO_2	Base CO_2	High CO_2
Low Fuel	0	2	3
Base Fuel	0	2	3
High Fuel	0	0	1

It is important to note that just outside of the planning horizon (in 2034 or 2035) a CC was selected in nearly all scenarios regardless of CO_2 or fuel price assumptions. The only cases where a CC was not selected just outside the planning horizon were in High CO_2 cases when new nuclear generation was the preferred resource.

Portfolio Development

Using insights gleaned from the sensitivity analysis, seven portfolios were developed. These portfolios were developed to assess the relative value of various generating technologies including CCs, CTs, Renewables, and Nuclear, as well as, energy storage under multiple scenarios. A description of the seven portfolios follows:

Portfolio 1 (Base CO_2 Future):

This portfolio represents a balanced generation portfolio with CCs and CTs making up the generation mix with incremental solar additions just beyond the 15-year window. While CCs are the preferred initial generating options in both DEC and DEP, CTs make up the vast majority of additional resources at the end of, and just beyond, the 15-year planning horizon. This portfolio also includes base EE and renewable assumptions, along with 1,000 MW of economically selected solar just beyond the planning horizon. Additionally, 150 MW of nameplate battery storage placeholders are included. These placeholders represent a limited amount of grid connected battery storage projects that have the potential to provide solutions for the transmission and distribution systems with the possibility of simultaneously providing benefits to the generation resource portfolio.

Portfolio 2 (Base No CO_2 Future):
This portfolio contains a high concentration of CTs in the 15-year planning window and is similar to the CT Centric portfolio (Portfolio 3). The Base No CO_2 portfolio also includes base EE and renewable assumptions, along with 150 MW of nameplate battery storage placeholders. No additional solar was selected in this portfolio.

Portfolio 3 (CT Centric):
For DEC, this portfolio is the same as Portfolio 2 since Portfolio 2 already includes a high concentration of CT generation in the planning horizon. However, in DEP there is a greater concentration of CTs in this Portfolio which impacts the dispatch of generating assets in DEC through the JDA. PVRR analysis reflects the difference in dispatch between Portfolio 2 and Portfolio 3 in DEC as a result of the changes in DEP.

Portfolio 4 (CC Centric – No Nuclear Future):
This portfolio represents a future where all existing nuclear assets are retired at the end of their current extended license period, and those nuclear assets are replaced with CCs rather than new nuclear generation. The CC Centric Portfolio doubles the number of CCs in the 15-year planning horizon in DEC. This portfolio also includes base EE and renewable assumptions, along with 1,000 MW of economically selected solar just prior to the end of, and beyond, the planning horizon. Additionally, 150 MW of nameplate battery storage placeholders are included.

Portfolio 5 (High EE / High Renewables):
This portfolio includes the High EE and High Renewable assumptions in DEC. Solar nameplate capacity increases at a more rapid pace, and the total MW of solar is 1,100 MW greater in the High Renewable case. Additionally, inclusion of High EE has the effect of deferring the first CC and first CT by one year. Finally, this case also includes 150 MW of nameplate battery storage placeholders.

Portfolio 6 (CT Centric / High Renewables):
Similar to Portfolios 2 and 3, Portfolio 6 includes a high concentration of CT generation in the 15-year planning horizon. However, this portfolio includes the High Renewable assumption which accelerates solar additions in DEC while increasing the total amount of

solar by approximately 1,100 MW. Portfolio 6 includes Base EE assumptions along with 150 MW of nameplate battery storage placeholders. This portfolio is especially illustrative when evaluating additional energy storage added in Portfolio 7.

Portfolio 7 (CT Centric with Battery Storage and High Renewables):

This portfolio converts the first 460 MW block of CT in Portfolio 6 to 575 MW (nameplate) of 4-hour Lithium-ion battery storage. The 575 MW of battery storage is assumed to only provide generation and energy transfer capability that is 100% controlled by the Company. As such, the battery storage installation is assumed to provide 460 MW of winter peak capacity. The total amount of nameplate battery storage in DEC in this case is 725 MW by 2028.

An overview of the resource needs of each portfolio are shown in Table A-5 below.

Table A-5: Portfolio Summary for Duke Energy Carolinas[1, 2]

	Portfolio 1 (Base CO_2)	**Portfolio 2 (No CO_2)**	**Portfolio 3 (CT Centric)**	**Portfolio 4 (CC Centric)**	**Portfolio 5 (High EE / High Renewables)**	**Portfolio 6 (CT Centric / High Renewables)**	**Portfolio 7 (CT Centric / High Renewables w/ Battery Storage)**
2024	Total Solar = 2834 Total Storage = 100 EE* = 248	Total Solar = 2834 Total Storage = 100 EE* = 248	Total Solar = 2834 Total Storage = 100 EE* = 248	Total Solar = 2834 Total Storage = 100 EE* = 248	Total Solar = 3517 Total Storage = 100 EE* = 383	Total Solar = 3517 Total Storage = 100 EE* = 248	Total Solar = 3517 Total Storage = 100 EE* = 248
2025	Total Solar = 2939 Total Storage = 125 EE* = 284	Total Solar = 2939 Total Storage = 125 EE* = 284	Total Solar = 2939 Total Storage = 125 EE* = 284	Total Solar = 2939 Total Storage = 125 EE* = 284	Total Solar = 3767 Total Storage = 125 EE* = 443	Total Solar = 3767 Total Storage = 125 EE* = 284	Total Solar = 3767 Total Storage = 125 EE* = 284
2026	Total Solar = 3065 Total Storage = 150 EE* = 318	Total Solar = 3065 Total Storage = 150 EE* = 318	Total Solar = 3065 Total Storage = 150 EE* = 318	Total Solar = 3065 Total Storage = 150 EE* = 318	Total Solar = 3942 Total Storage = 150 EE* = 495	Total Solar = 3942 Total Storage = 150 EE* = 318	Total Solar = 3942 Total Storage = 150 EE* = 318
2027	Total Solar = 3191 Total Storage = 150 EE* = 350	Total Solar = 3191 Total Storage = 150 EE* = 350	Total Solar = 3191 Total Storage = 150 EE* = 350	Total Solar = 3191 Total Storage = 150 EE* = 350	Total Solar = 4117 Total Storage = 150 EE* = 540	Total Solar = 4117 Total Storage = 150 EE* = 350	Total Solar = 4117 Total Storage = 150 EE* = 350
2028	CC = 1338 Total Solar = 3317 Total Storage = 150 EE* = 370	CT = 460 Total Solar = 3317 Total Storage = 150 EE* = 370	CT = 460 Total Solar = 3317 Total Storage = 150 EE* = 370	CC = 1338 Total Solar = 3317 Total Storage = 150 EE* = 370	Total Solar = 4292 Total Storage = 150 EE* = 570	CT = 460 Total Solar = 4292 Total Storage = 150 EE* = 370	Total Solar = 4292 Total Storage = 725 EE* = 370
2029	Total Solar = 3443 Total Storage = 150 EE* = 383	CT = 920 Total Solar = 3443 Total Storage = 150 EE* = 383	CT = 920 Total Solar = 3443 Total Storage = 150 EE* = 383	Total Solar = 3443 Total Storage = 150 EE* = 383	CC = 1338 Total Solar = 4467 Total Storage = 150 EE* = 592	CT = 920 Total Solar = 4467 Total Storage = 150 EE* = 383	CT = 920 Total Solar = 4467 Total Storage = 725 EE* = 383
2030	Total Solar = 3569 Total Storage = 150 EE* = 390	Total Solar = 3569 Total Storage = 150 EE* = 390	Total Solar = 3569 Total Storage = 150 EE* = 390	Total Solar = 3569 Total Storage = 150 EE* = 390	Total Solar = 4642 Total Storage = 150 EE* = 607	Total Solar = 4642 Total Storage = 150 EE* = 390	Total Solar = 4642 Total Storage = 725 EE* = 390
2031	CC = 1338 Total Solar = 3594 Total Storage = 150 EE* = 392	CT = 460 Total Solar = 3594 Total Storage = 150 EE* = 392	CT = 460 Total Solar = 3594 Total Storage = 150 EE* = 392	CT = 460 Total Solar = 3594 Total Storage = 150 EE* = 392	CC = 1338 Total Solar = 4677 Total Storage = 150 EE* = 616	CT = 460 Total Solar = 4677 Total Storage = 150 EE* = 392	CT = 460 Total Solar = 4677 Total Storage = 725 EE* = 392
2032	Total Solar = 3619 Total Storage = 150 EE* = 394	CT = 460 Total Solar = 3619 Total Storage = 150 EE* = 394	CT = 460 Total Solar = 3619 Total Storage = 150 EE* = 394	CC = 1338 Total Solar = 3619 Total Storage = 150 EE* = 394	Total Solar = 4712 Total Storage = 150 EE* = 624	CT = 460 Total Solar = 4712 Total Storage = 150 EE* = 394	CT = 460 Total Solar = 4712 Total Storage = 725 EE* = 394
2033	CT = 460 Total Solar = 3644 Total Storage = 150 EE* = 398	CT = 920 Total Solar = 3644 Total Storage = 150 EE* = 398	CT = 920 Total Solar = 3644 Total Storage = 150 EE* = 398	CC = 2676 Total Solar = 3844 Total Storage = 150 EE* = 398	Total Solar = 4747 Total Storage = 150 EE* = 632	CT = 920 Total Solar = 4747 Total Storage = 150 EE* = 398	CT = 920 Total Solar = 4747 Total Storage = 725 EE* = 398

[1] EE represents the cumulative new energy efficiency additions each year.
[2] Solar does not include 0.5% degredation.

4. Perform Portfolio Analysis

Each of the seven portfolios identified in the screening analysis were evaluated in more detail with an hourly production cost model (PROSYM) under a future fuel price and CO_2 scenarios to determine the robustness of each portfolio under varying fuel and carbon futures. The run matrix for the nine scenarios is summarized in Table A-6 below.

Table A-6: PROSYM Run Matrix for Portfolio Analysis

	No CO_2	Base CO_2	High CO_2
Low Fuel			
Base Fuel			
High Fuel			

The PROSYM model provided the system production costs for each portfolio under the scenarios shown above. The model included DEC's non-firm energy purchases and sales associated with the Joint Dispatch Agreement (JDA) with DEC, and as such, the model optimized both DEC and DEP and provided total system (DEC + DEP) production costs. The PROSYM results were separated to reflect system production costs that were solely attributed to DEC to account for the impacts of the JDA. The DEC specific system production costs were then added to the DEC specific capital costs for each portfolio to develop the total PVRR for each portfolio under the given fuel price and CO_2 conditions.

The seven portfolios were ranked in each of the nine fuel and carbon scenarios, and the portfolio with the lowest PVRR in each of the nine scenarios was identified.

Additionally, high and low capital cost sensitivities were conducted to determine if varying future price projections for each technology would impact the results of the scenario analysis.

PVRR Results:

Table A-7 below reflects the portfolio that performed best (i.e. lowest PVRR) under each scenario, as well as, the delta PVRR to the next lowest portfolio (Port).

Table A-7: Lowest PVRR (thru 2068, $2018M) Portfolios Under Each Scenario

PVRR thru 2068 (2018 $M)	No CO_2	Base CO_2	High CO_2
Low Fuel	Portfolio 2 (-$101 M vs Port 1)	Portfolio 1 (-$647 M vs Port 2)	Portfolio 1 (-$302 M vs Port 5)
Base Fuel	Portfolio 1 (-$55 M vs Port 2)	Portfolio 1 (-$382 M vs Port 5)	Portfolio 5 ($100 M vs Port 1)
High Fuel	Portfolio 1 (-$342 M vs Port 5)	Portfolio 5 ($141 M vs Port 1)	Portfolio 5 ($668 M vs Port 1)

The following table summarizes the total PVRR for each portfolio in the scenarios above versus Portfolio 1.

Table A-8: Total PVRR (thru 2068, $2018M) Comparison of All Portfolios vs Portfolio 1

	Portfolio 2 (Base No CO_2 Future)	Portfolio 3 (CT Centric)	Portfolio 4 (CC Centric)	Portfolio 5 (High EE / High Renew)	Portfolio 6 (CT Centric / High Renew)	Portfolio 7 (CT Centric / High Renew w/ Batt Storage)
Base Fuel / Base CO_2	$899	$1,417	$12,976	$384	$1,942	$2,088
Base Fuel / High CO_2	$1,834	$2,524	$17,480	($100)	$2,634	$2,721
Base Fuel / No CO_2	$55	$335	$9,295	$830	$1,215	$1,450
High Fuel / BaseCO_2	$1,052	$1,549	$17,354	($141)	$1,740	$1,929
High Fuel / High CO_2	$2,203	$2,959	$21,871	($668)	$2,724	$2,829
High Fuel / No CO_2	$399	$742	$13,554	$342	$1,282	$1,540
Low Fuel / Base CO_2	$647	$1,094	$10,544	$788	$1,885	$1,988
Low Fuel / High CO_2	$1,466	$2,085	$15,011	$302	$2,479	$2,526
Low Fuel / No CO_2	($101)	$179	$6,839	$1,234	$1,286	$1,499

In addition to the sensitivities conducted above, capital cost sensitivities were also conducted. In the low capital cost sensitivity, technology specific forecast factors were decreased (i.e. greater cost declines in technology costs over time). In the high capital cost sensitivity, technology specific forecast factors were increased (i.e. lower cost declines in technology costs over time). One example of the impact of these cost sensitivities, is the impact on project costs of 4-hour Lithium ion battery storage. In the Base Case, battery storage costs are projected to drop by nearly 40% by 2025 in real terms. In the low and high capital cost sensitivities, battery storage costs are projected to drop by slightly over 60% and slightly over 20% respectively, by 2025. The results on the lowest PVRR portfolios due to these capital costs sensitivities are shown in Tables A-9 and A-10.

Table A-9: Lowest PVRR (thru 2068, $2018M) Portfolios Under Each Scenario – Low Capital Cost Sensitivity

PVRR thru 2068 (2018 $M)	No CO_2	Base CO_2	High CO_2
Low Fuel	Portfolio 2 (-$116 M vs Port 1)	Portfolio 1 (-$632 M vs Port 5)	Portfolio 1 (-$196 M vs Port 5)
Base Fuel	Portfolio 1 (-$40 M vs Port 2)	Portfolio 1 (-$278 M vs Port 5)	Portfolio 5 ($206M vs Port 1)
High Fuel	Portfolio 1 (-$236 M vs Port 5)	Portfolio 5 ($247 M vs Port 1)	Portfolio 5 ($774 M vs Port 1)

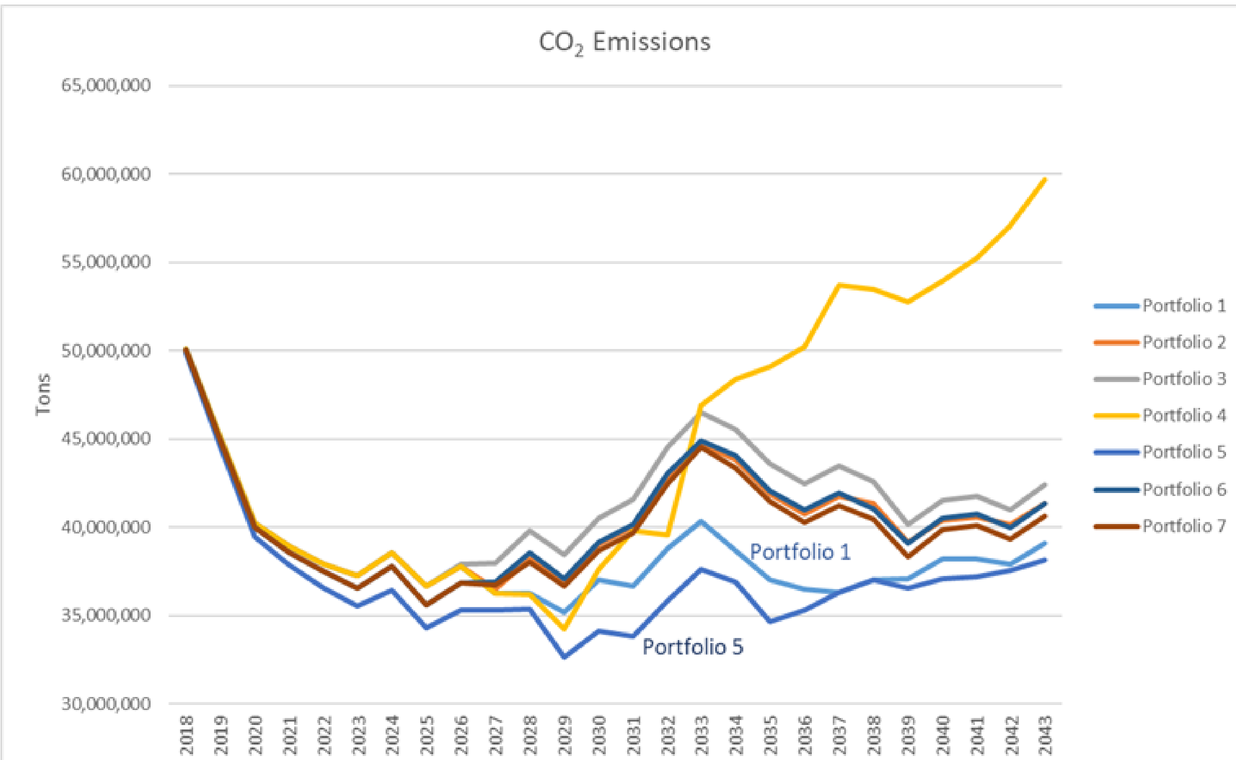
Table A-10: Lowest PVRR (thru 2068, $2018M) Portfolios Under Each Scenario – High Capital Cost Sensitivity

PVRR thru 2068 (2018 $M)	No CO_2	Base CO_2	High CO_2
Low Fuel	Portfolio 2 (-$94 M vs Port 1)	Portfolio 1 (-$655 M vs Port 2)	Portfolio 1 (-$376 M vs Port 5)
Base Fuel	Portfolio 1 (-$62 M vs Port 2)	Portfolio 1 (-$458 M vs Port 5)	Portfolio 5 ($27 M vs Port 1)
High Fuel	Portfolio 1 (-$407 M vs Port 5)	Portfolio 5 ($67 M vs Port 1)	Portfolio 5 ($595 M vs Port 1)

CO_2 Emissions:

Over the next 15 years, and beyond, Portfolio 1 provides significant CO_2 emission reductions as shown in Figure A-3 below. Only Portfolio 5 (High EE / High Renewables) provides similar or increased carbon reductions over the life of the plan. Additionally, if existing nuclear generation was not extended in DEC, or was not replaced with new nuclear generation, CO_2 emissions would rise significantly as each nuclear plant was retired as shown in Portfolio 4 (Yellow).

Figure A-3: DEC + DEP Carbon Emissions Summary – All Portfolios



<u>**Conclusions:**</u>

<u>***Base CO_2 Portfolio Selection:***</u>

For planning purposes, Duke Energy considers both a carbon constrained future and a no carbon future in the development of the base case portfolios. If a carbon constrained future is either delayed or is more restrictive than the base plan, or other variables, such as fuel price and capital costs, change significantly from the base assumptions, the selected carbon constrained portfolio should be adequately robust to still provide value in those futures. Another factor that is considered when selecting the base portfolio is the likelihood that the selected portfolio can be executed as shown. Under those considerations, the Company selected Portfolio 1 (Base CO_2 Future) as the base portfolio for planning assumptions.

Portfolio 1 includes a diverse compilation of resources including CCs, CTs, battery storage, and increasing amounts of EE/DSM and solar resources in conjunction with existing nuclear, natural gas, renewables and other assets already on the DEC system. This portfolio also enables the Company to lower carbon emissions under a range of future scenarios at a lower cost than most other scenarios.

It is important to note that Portfolio 5 (High EE / High Renewables) provides significant value in a high carbon and/or high fuel price future as increased amounts of EE and renewables lower the energy required from more conventional generators on the system. However even in a high CO_2 and high fuel price environment, concerns regarding interconnection costs of incremental solar generation, along with the feasibility and cost risk of increasing the adoption of EE measures beyond the base assumption, the ability to fully execute Portfolio 5 is questionable. Assuming interconnection costs can be mitigated and new EE programs become better established, along with successful implementation and testing of newer technologies such as utility scale battery storage, Portfolio 5, or some version thereof, may become the preferred portfolio over time if the energy markets migrate to higher natural gas prices with strict carbon mandates.

No CO_2 Portfolio Selection:

While Duke Energy presents a base resource plan that was developed under a carbon constrained future, the Company also provides a No CO_2 Base Case expansion plan that reflects a future without CO_2 constraints. In DEC, this expansion plan is represented by Portfolio 2 (Base No CO_2 Future). During the 15-year planning horizon, there is a significant shift towards CT technology from the Carbon Constrained Base Case. However, beyond the 15-year window there is a shift back to CC technology in Portfolio 2. Additionally, without a CO_2 constraint, incremental solar additions are delayed further beyond the planning horizon.

It should be noted that in the Base Fuel / No CO_2 scenario, the 50-year PVRR for the No CO_2 portfolio is slightly higher than the PVRR of Portfolio 1. Over the 50-year PVRR period, the fuel savings from building CCs in the late 2020s outweighs the capital cost savings from building CTs. However, given the relatively small PVRR difference between the two cases in DEC, and the fact that Portfolio 2 was lower cost in the DEP IRP, the Company selected the Base No CO_2 Future expansion plan to represent a No CO_2 portfolio.

Other Findings:

Based on the analysis discussed above, other conclusions regarding the future of nuclear and battery storage assets on the system can be inferred.

- Existing nuclear assets
    - Portfolio 4 (CC Centric) represents a future where licenses for existing nuclear assets are allowed to expire and those nuclear assets are mainly replaced with CC technology. This portfolio increases capital costs versus the base portfolio as nuclear assets are retired and replaced with CCs, and the system production cost penalty of replacing nuclear assets that provide nearly 50% of the Company's energy at almost zero fuel cost and zero CO_2 emissions, with CC technology is severe. While retiring existing nuclear assets may provide more value if new nuclear technology such as SMRs become more established at lower costs, current projections show that maintaining the option to continue operating the Company's existing nuclear fleet provides value for the Company and it's customers.
- Battery storage
    - Portfolio 7 (CT Centric / High Renewables / Battery Storage) was developed off Portfolio 6 (CT Centric / High Renewables). In Portfolio 7, a 460 MW block of CT generation in the winter of 2027/2028 was converted to 575 MW of battery storage. In each of the nine carbon and fuel scenarios, replacing CT generation with battery storage resulted in a higher PVRR (i.e. higher cost) when compared to Portfolio 6. There are several factors to consider when evaluating these battery storage results including:
        - This case does not suggest that battery storage does not have any value to the DEC system. While these results imply that 4-hour battery storage may have limited value as a generation deferral and energy arbitrage asset, it is likely that the value of battery storage may be greater under other applications such as distribution or transmission asset deferral. Additionally, and as discussed

elsewhere in this document, the value of battery storage for generation deferral, energy arbitrage, and/or ancillary services may be diminished if the battery is also providing support for voltage control, distribution asset deferral, or emergency back-up power as part of other use cases.

- A similar case was studied in the DEP IRP, and in that scenario, battery storage showed a reduction in PVRR versus the CT Centric / High Renewable portfolio. While both cases included a 50% reduction in battery costs versus today's prices, other factors may have contributed to the difference in results between the two Companies including: 1) DEC already includes 2,400 MW of storage in the form of pumped hydro storage so the incremental value of storage in DEC may be diminished versus DEP which does not have any pumped hydro storage, and 2) DEP has overall more MW of solar than DEC which could be contributing to more value of battery storage on the DEP system.

- The battery storage in this case is a grid tied asset that can be charged with system energy. It is likely that the battery's value would diminish further if it were only allowed to charge with solar energy. In that case, the battery would lose the value of being charged with off-peak energy that is generated when solar is not available.

- The model assumes the Company has real-time control of the battery to maximize the battery's value. Without real-time control, the value of the battery would be further diminished on the DEC system.

To better understand the true value of battery storage in DEC, it is important for the Company to operate utility storage on it's system to properly evaluate the abilities and value of battery storage.

Value of Joint Planning:

To demonstrate the value of sharing capacity with DEP, a Joint Planning Case was developed to examine the impact of joint capacity planning on the resource plans. The impacts were determined by comparing how the combined Base Cases of DEC and DEP would change if a 17% minimum winter planning reserve margin was applied at the combined system level, rather than the individual company level.

An evaluation was performed comparing the optimally selected Portfolio 1 for DEC and DEP to a combined Joint Planning Case in which existing and future capacity resources could be shared between DEC and DEP to meet the 17% minimum winter planning reserve margin. Table A-11 shows the base expansion plans (Portfolio #1 for both DEC and DEP) through 2033, if separately planned, compared to the Joint Planning Case. The sum of the two combined resource requirements is then compared to the amount of resources needed if DEC and DEP could jointly plan for capacity. Years where the Joint Planning Case differ from the individual Utility cases are highlighted.

Table A-11: Comparison of Carbon Constrained Base Case Portfolio to Joint Planning Case

	DEC Portfolio 1 (Base CO_2)	DEP Portfolio 1 (Base CO_2)	1 BA (Base CO_2)
2024	Total Solar = 2834 Total Storage = 100 EE* = 248	Total Solar = 4061 Total Storage = 101 EE* = 120	Total Solar = 6895 Total Storage = 201 EE* = 368
2025	Total Solar = 2939 Total Storage = 125 EE* = 284	CC = 1338 Total Solar = 4161 Total Storage = 121 EE* = 138	CC = 1338 Total Solar = 7100 Total Storage = 246 EE* = 422
2026	Total Solar = 3065 Total Storage = 150 EE* = 318	Total Solar = 4215 Total Storage = 141 EE* = 155	Total Solar = 7280 Total Storage = 291 EE* = 473
2027	Total Solar = 3191 Total Storage = 150 EE* = 350	CC = 1338 Total Solar = 4269 Total Storage = 141 EE* = 173	CC = 1338 Total Solar = 7460 Total Storage = 291 EE* = 522
2028	**CC = 1338** Total Solar = 3317 Total Storage = 150 EE* = 370	Total Solar = 4323 Total Storage = 141 EE* = 187	Total Solar = 7640 Total Storage = 291 EE* = 557
2029	Total Solar = 3443 Total Storage = 150 EE* = 383	**CT = 1840** Total Solar = 4377 Total Storage = 141 EE* = 200	CC = 1338 CT = 1380 Total Solar = 7820 Total Storage = 291 EE* = 583
2030	Total Solar = 3569 Total Storage = 150 EE* = 390	Total Solar = 4431 Total Storage = 141 EE* = 211	Total Solar = 8000 Total Storage = 291 EE* = 601
2031	CC = 1338 Total Solar = 3594 Total Storage = 150 EE* = 392	Total Solar = 4456 Total Storage = 141 EE* = 221	CC = 1338 Total Solar = 8050 Total Storage = 291 EE* = 613
2032	Total Solar = 3619 Total Storage = 150 EE* = 394	**CT = 460** Total Solar = 4481 Total Storage = 141 EE* = 229	Total Solar = 8100 Total Storage = 291 EE* = 623
2033	CT = 460 Total Solar = 3644 Total Storage = 150 EE* = 398	CT = 460 Total Solar = 4506 Total Storage = 141 EE* = 236	CT = 1380 Total Solar = 8150 Total Storage = 291 EE* = 634
Total	CC = 2676 CT = 460 Total Solar = 3644 Total Storage = 150 EE* = 398	CC = 2676 CT = 2760 Total Solar = 4506 Total Storage = 141 EE* = 236	CC = 5352 CT = 2760 Total Solar = 8150 Total Storage = 291 EE* = 634

A comparison of the DEC and DEP Combined Base Case resource requirements to the Joint Planning Scenario requirements illustrates the ability to defer a CC and CT resource in the late 2020s. Consequently, the Joint Planning Case also results in a lower overall reserve margin. This is confirmed by a review of the reserve margins for the Combined Base Case as compared to the Joint Planning Case, which averaged 20.3% and 19.5%, respectively, from the first resource need in 2020 through 2033. The lower reserve margin in the Joint Planning Case indicates that DEC and DEP more efficiently and economically meet capacity needs when planning for capacity jointly. This is reflected in a capital PVRR savings of $250 million for the Joint Planning Case as compared to the Combined Base Case. Though not included in the Joint Planning Case analysis, the ability to share capacity between DEC and DEP would also limit the amount of undesignated short-term market purchases identified in the 2020 to 2024 timeframe in the DEP IRP.

B. Quantitative Analysis Summary

The quantitative analysis resulted in several key takeaways that are important for near-term decision-making, as well as in planning for the longer term.

1. The first undesignated resource need is in December of 2027 to meet the minimum reserve margin requirement in the winter of 2027/2028. The results of this analysis show that this need is best met with CC generation.

2. Additional EE and solar resources may provide benefit to the system if carbon emission regulations are more stringent than the base plan and/or fuel prices increase significantly versus the Base Case. However, the cost of integrating additional renewables beyond the Base Case, and the likelihood of achieving higher EE adoption rates must be considered when evaluating the benefits of this portfolio.

3. The ability to jointly plan capacity with DEP provides customer savings by allowing for the deferral of new generation resources over the 15-year planning horizon.

4. Nuclear generation, whether relicensing or new build, is essential for continuing to lower CO_2 emissions on the system.

APPENDIX B: DUKE ENERGY CAROLINAS OWNED GENERATION

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

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

Existing Generating Units and Ratings [a, b, c, d, e]
All Generating Unit Ratings are as of July 1, 2018

Coal						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
Allen	1	167	162	Belmont, N.C.	Coal	Peaking
Allen	2	167	162	Belmont, N.C.	Coal	Peaking
Allen	3	270	258	Belmont, N.C.	Coal	Peaking
Allen	4	267	257	Belmont, N.C.	Coal	Intermediate
Allen	5	259	259	Belmont, N.C.	Coal	Peaking
Belews Creek	1	1110	1110	Belews Creek, N.C.	Coal	Base
Belews Creek	2	1110	1110	Belews Creek, N.C.	Coal	Base
Cliffside	5	546	544	Cliffside, N.C.	Coal	Peaking
Cliffside	6	844	844	Cliffside, N.C.	Coal	Intermediate
Marshall	1	380	370	Terrell, N.C.	Coal	Intermediate
Marshall	2	380	370	Terrell, N.C.	Coal	Intermediate
Marshall	3	658	658	Terrell, N.C.	Coal	Base
Marshall	4	660	660	Terrell, N.C.	Coal	Base
Total Coal		6818	6764			

Combustion Turbines						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
Lee	7C	48	42	Pelzer, S.C.	Natural Gas/Oil-Fired	Peaking
Lee	8C	48	42	Pelzer, S.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	1	98	76	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	2	99	76	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	3	99	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	4	98	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	5	97	74	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	6	97	73	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	7	98	76	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	8	98	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	9	97	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	10	98	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	11	98	74	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	12	98	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	13	98	74	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	14	97	74	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	15	98	73	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	16	97	73	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	1	92	71	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	2	92	70	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	3	92	71	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	4	92	70	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	5	90	69	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	6	92	71	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	7	92	70	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	8	93	71	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	1	179	165	Rockingham, N.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	2	179	165	Rockingham, N.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	3	179	165	Rockingham, N.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	4	179	165	Rockingham, N.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	5	179	165	Rockingham, N.C.	Natural Gas/Oil-Fired	Peaking
Total NC		2,460	2,018			
Total SC		831	647			
Total CT		3,291	2,665			

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

Combined Cycle						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Buck	CT11	206	178	Salisbury, N.C.	Natural Gas	Base
Buck	CT12	206	178	Salisbury, N.C.	Natural Gas	Base
Buck	ST10	304	312	Salisbury, N.C.	Natural Gas	Base
Buck CTCC		716	668			
Dan River	CT8	199	171	Eden, N.C.	Natural Gas	Base
Dan River	CT9	199	171	Eden, N.C.	Natural Gas	Base
Dan River	ST7	320	320	Eden, N.C.	Natural Gas	Base
Dan River CTCC		718	662			
WS Lee	CT11	223	216	Pelzer, N.C.	Natural Gas	Base
WS Lee	CT12	223	216	Pelzer, N.C.	Natural Gas	Base
WS Lee	ST10	337	321	Pelzer, N.C.	Natural Gas	Base
WS Lee CTCC		783	753			
Total CTCC		2,217	2,083			

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

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

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

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

Solar						
		Winter (MW)	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
NC Solar		4.19	38.6	N.C.	Solar	Intermediate
Total Solar		4.19	38.6			

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

Total Generation Capability		
	Winter Capacity (MW)	**Summer Capacity (MW)**
TOTAL DEC SYSTEM - N.C.	14,686.1	14,016.9
TOTAL DEC SYSTEM – S.C.	8,445.2	8,128.9
TOTAL DEC SYSTEM	23,131.3	22,145.8

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

Note b: Cliffside also called the Rogers Energy Center

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

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

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

Planned Uprates			
Unit	**Date**	**Winter MW**	**Summer MW**
N/A	N/A	N/A	N/A

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

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

Retirements				
Unit and Plant Name	**Location**	**Capacity (MW) Summer**	**Fuel Type**	**Retirement Date**
Buck 3[a]	Salisbury, N.C.	75	Coal	05/15/11
Buck 4[a]	Salisbury, N.C.	38	Coal	05/15/11
Cliffside 1[a]	Cliffside, N.C.	38	Coal	10/1/11
Cliffside 2[a]	Cliffside, N.C.	38	Coal	10/1/11
Cliffside 3[a]	Cliffside, N.C.	61	Coal	10/1/11
Cliffside 4[a]	Cliffside, N.C.	61	Coal	10/1/11
Dan River 1[a]	Eden, N.C.	67	Coal	04/1/12
Dan River 2[a]	Eden, N.C.	67	Coal	04/1/12
Dan River 3[a]	Eden, N.C.	142	Coal	04/1/12
Buzzard Roost 6C[b]	Chappels, S.C.	22	Combustion Turbine	10/1/12
Buzzard Roost 7C[b]	Chappels, S.C.	22	Combustion Turbine	10/1/12
Buzzard Roost 8C	Chappels, S.C.	22	Combustion Turbine	10/1/12
Buzzard Roost 9C[b]	Chappels, S.C.	22	Combustion Turbine	10/1/12
Buzzard Roost 10C[b]	Chappels, S.C.	18	Combustion Turbine	10/1/12
Buzzard Roost 11C[b]	Chappels, S.C.	18	Combustion Turbine	10/1/12
Buzzard Roost 12C[b]	Chappels, S.C.	18	Combustion Turbine	10/1/12
Buzzard Roost 13C[b]	Chappels, S.C.	18	Combustion Turbine	10/1/12
Buzzard Roost 14C[b]	Chappels, S.C.	18	Combustion Turbine	10/1/12
Buzzard Roost 15C[b]	Chappels, S.C.	18	Combustion Turbine	10/1/12
Riverbend 8C[b]	Mt. Holly, N.C.	0	Combustion Turbine	10/1/12
Riverbend 9C[b]	Mt. Holly, N.C.	22	Combustion Turbine	10/1/12
Riverbend 10C[b]	Mt. Holly, N.C.	22	Combustion Turbine	10/1/12
Riverbend 11C[b]	Mt. Holly, N.C.	20	Combustion Turbine	10/1/12
Buck 7C[b]	Spencer, N.C.	25	Combustion Turbine	10/1/12
Buck 8C[b]	Spencer, N.C.	25	Combustion Turbine	10/1/12
Buck 9C[b]	Spencer, N.C.	12	Combustion Turbine	10/1/12

Retirements (cont.)				
Dan River 4C [b]	Eden, N.C.	0	Combustion Turbine	10/1/12
Dan River 5C [b]	Eden, N.C.	24	Combustion Turbine	10/1/12
Dan River 6C [b]	Eden, N.C.	24	Combustion Turbine	10/1/12
Riverbend 4 [a]	Mt. Holly, N.C.	94	Coal	04/1/13
Riverbend 5 [a]	Mt. Holly, N.C.	94	Coal	04/1/13
Riverbend 6 [c]	Mt. Holly, N.C.	133	Coal	04/1/13
Riverbend 7 [c]	Mt. Holly, N.C.	133	Coal	04/1/13
Buck 5 [c]	Spencer, N.C.	128	Coal	04/1/13
Buck 6 [c]	Spencer, N.C.	128	Coal	04/1/13
Lee 1 [d]	Pelzer, S.C.	100	Coal	11/6/14
Lee 2 [d]	Pelzer, S.C.	100	Coal	11/6/14
Lee 3 [e]	Pelzer, S.C.	170	Coal	05/12/15*
Great Falls 3	Great Falls, S.C.	0	Hydro	05/31/18
Great Falls 4	Great Falls, S.C.	0	Hydro	05/31/18
Great Falls 7	Great Falls, S.C.	0	Hydro	05/31/18
Great Falls 8	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 1	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 2	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 3	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 4	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 5	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 6	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 7	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 8	Great Falls, S.C.	0	Hydro	05/31/18
	Total	2037 MW		

*converted to NG

Note a: Retirement assumptions associated with the conditions in the NCUC Order in Docket No. E-7, Sub 790, granting a CPCN to build Cliffside Unit 6.

Note b: The old fleet combustion turbines retirement dates were accelerated in 2009 based on derates, availability of replacement parts and the general condition of the remaining units.

Note c: The decision was made to retire Buck 5 and 6 and Riverbend 6 and 7 early on April 1, 2013. The original expected retirement date was April 15, 2015.

Note d: Lee Steam Units 1 and 2 were retired November 6, 2014.

Note e: The conversion of the Lee 3 coal unit to a natural gas unit was effective March 12, 2015.

Planning Assumptions – Unit Retirements [a,b]

Unit & Plant Name	Location	Winter Capacity (MW)	Summer Capacity (MW)	Fuel Type	Expected Retirement
Allen 1	Belmont, NC	167	162	Coal	12/2024
Allen 2	Belmont, NC	167	162	Coal	12/2024
Allen 3	Belmont, NC	270	261	Coal	12/2024
Allen 4	Belmont, NC	282	276	Coal	12/2028
Allen 5	Belmont, NC	275	266	Coal	12/2028
Belews Creek 1	Belews Creek, NC	1,110	1,110	Coal	12/2038
Belews Creek 2	Belews Creek, NC	1,110	1,110	Coal	12/2038
Cliffside 5	Cliffside, NC	546	544	Coal	12/2032
Cliffside 6	Cliffside, NC	844	844	Coal	12/2048
Marshall 1	Terrell, NC	380	370	Coal	12/2034
Marshall 2	Terrell, NC	380	370	Coal	12/2034
Marshall 3	Terrell, NC	658	658	Coal	12/2034
Marshall 4	Terrell, NC	660	660	Coal	12/2034
Lee 3	Pelzer, SC	173	160	NG	12/2030
Queens Creek	Topton, NC	1.4	1.4	Hydro	12/2032
Total		9,641	9,508		

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

Note b: For planning purposes, the 2018 IRP Base Case assumes subsequent license renewal for existing nuclear facilities beginning at end of current operating licenses. Total planning retirements exclude nuclear capacities.

Operating License Renewal

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

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

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

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

APPENDIX C: ELECTRIC LOAD FORECAST

Methodology:

The Duke Energy Carolinas' Spring 2018 Forecast provides projections of the energy and peak demand needs for its service area. The forecast covers the time period of 2019 – 2033 and represent the needs of the following customer classes:

- Residential
- Commercial
- Industrial
- Other Retail
- Wholesale

Energy projections are developed with econometric models using key economic factors such as income, electricity prices, industrial production indices, along with weather, appliance efficiency trends, rooftop solar trends, and electric vehicle trends. Population is also used in the Residential customer model. DEC has used regression analysis since 1979 and this technique has yielded consistently reasonable results over the years.

The economic projections used in the Spring 2018 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 Analytics supplies the Company with economic and demographic projections, which are used in the energy and demand models. Preliminary analysis of Moody's historical projections versus actuals resulted in smaller variances and minimum bias during normal economic periods. However, the likelihood of greater forecast variance and forecast bias increases during unique disruptive economic periods like the Great Recession. The Load Forecasting team will continue to monitor Moody's forecast error going forward.

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, electric price and appliance efficiencies.

The usage per customer forecast was derived using a Statistical Adjusted End-Use Model. This is a regression based framework that uses projected appliance saturation and efficiency trends developed by Itron using 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 2018 forecast, including the impacts of Utility Energy Efficiency programs (UEE), rooftop solar and electric vehicles from 2019 to 2033 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 0.7% 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 0.6% over the forecast horizon.

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

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

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

Forecast Enhancements:

In 2013, The Company began using the statistically adjusted end use (SAE) 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. The appliance saturation and efficiency trends are developed by ITRON using data from the EIA. ITRON is a recognized firm providing forecasting services to the electric utility industry. These appliance trends are used in the residential and commercial sales models. 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 2018 forecast utilizes:

- Moody's Analytics January 2018 base and consensus economic projections.
- End use equipment and appliance indexes reflect the 2017 update of ITRON's end-use data, which is consistent with the Energy Information Administration's 2017 Annual Energy Outlook.
- A calculation of normal weather using the period 1987-2016.

As instructed by the North Carolina Utilities Commission after review of the 2016 IRP, the company continues to research the weather sensitivity of summer and winter peaks, hourly shaping of sales and load research data. As a result of the study, several improvements were identified and incorporated into the current forecast, as follows:

- **Retail Peak Weather Normalization**
  - The peak weather Rank/Sort process was updated using the ITRON forecasting software rank/sort functionality. For purposes of projecting peaks, a seasonal rank/sort approach was used to capture historical weather patterns that may have occurred outside of the normal peak month.
  - The peak model was updated to capture the actual historical average daily temperature on the day of peak. Previous models selected the coldest average daily temperature during the month of peak.
- **Load History –** Conducted a detail review of historical loads, and the definitions of the loads in order to better align historical results with future projections.
- **Wholesale Assumptions -** The wholesale forecast process was better integrated with the retail forecast process. Additional reporting detail was provided for wholesale history and wholesale customer classes, resulting in an improved load shape.

Assumptions:

Below are the projected average annual growth rates of several key drivers from DEC's Spring 2018 Forecast.

	2019-2033
Real Income	2.3%
Manufacturing Industrial Production Index (IPI)	1.1%
Population	1.3%

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:

Utility Energy Efficiency Programs (UEE) continue to have a large impact in the acceleration of the adoption of energy efficiency. When including the energy and peak impacts of UEE, careful attention must be paid to avoid the double counting of UEE efficiencies with the naturally occurring efficiencies included in the SAE modeling approach. To ensure there is not a double counting of these efficiencies, the forecast "rolls off" the UEE savings at the conclusion of its measure life. For example, if the accelerated benefit of a residential UEE program is expected to have occurred seven years before the energy reduction program would have been otherwise adopted, then the UEE effects after year seven 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 C-1: UEE Program Life Process (MWh)

	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
2019	91,431	11	91,442	(721)	-	(721)	90,721
2020	92,542	43	92,584	(1,161)	-	(1,161)	91,423
2021	93,296	103	93,399	(1,574)	-	(1,574)	91,825
2022	93,887	211	94,098	(1,967)	1	(1,966)	92,132
2023	94,501	372	94,873	(2,360)	2	(2,358)	92,515
2024	95,800	564	96,363	(2,752)	3	(2,750)	93,614
2025	96,842	787	97,629	(3,146)	7	(3,139)	94,490
2026	98,027	1,013	99,040	(3,540)	29	(3,511)	95,529
2027	99,052	1,208	100,259	(3,935)	73	(3,862)	96,397
2028	100,551	1,367	101,918	(4,330)	236	(4,095)	97,823
2029	101,602	1,484	103,086	(4,728)	499	(4,228)	98,857
2030	102,572	1,549	104,122	(5,128)	813	(4,315)	99,806
2031	103,715	1,583	105,298	(5,534)	1,173	(4,361)	100,937
2032	105,063	1,600	106,663	(5,946)	1,531	(4,415)	102,248
2033	105,810	1,600	107,410	(6,364)	1,908	(4,456)	102,955

***Wholesale**:*

For a description of the Wholesale forecast, please see Appendix H.

Customer Growth:

Tables C-2 and C-3 show the history and projections for DEC customers.

Table C-2: Retail customers (annual average in thousands)

Year	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Retail Customers
2008	2,012	334	7	14	2,367
2009	2,024	331	7	14	2,377
2010	2,034	333	7	14	2,389
2011	2,041	335	7	14	2,397
2012	2,053	337	7	14	2,411
2013	2,068	339	7	14	2,428
2014	2,089	342	7	15	2,452
2015	2,117	345	6	15	2,484
2016	2,148	349	6	15	2,519
2017	2,182	354	6	15	2,557
Avg. Annual Growth Rate	0.9%	0.6%	-1.7%	1.3%	0.9%

Table C-3: Retail Customers (Thousands, Annual Average)

	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Retail Customers
2019	2,235	358	6	16	2,615
2020	2,264	361	6	16	2,647
2021	2,296	364	6	16	2,682
2022	2,328	366	6	16	2,717
2023	2,361	369	6	17	2,752
2024	2,394	371	5	17	2,787
2025	2,426	373	5	17	2,821
2026	2,458	375	5	17	2,856
2027	2,490	377	5	18	2,890
2028	2,522	380	5	18	2,925
2029	2,553	383	5	18	2,959
2030	2,585	385	5	18	2,993
2031	2,615	388	5	18	3,027
2032	2,646	391	5	19	3,060
2033	2,676	394	5	19	3,060
Avg. Annual Growth Rate	1.2%	0.6%	-1.5%	1.2%	1.1%

Note: Tables 12-E and 12-F differ from these values due to a 47 MW PMPA backstand contract through 2020.

Electricity Sales:

Table C-4 shows the actual historical GWh sales. As a note, the values in Table C-4 are not weather adjusted sales.

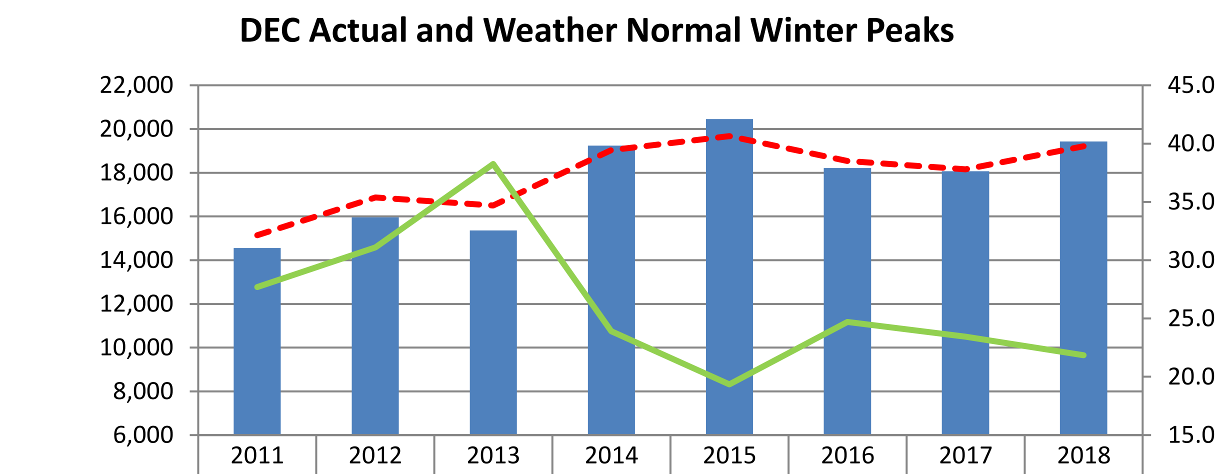
Table C-4: Electricity Sales (GWh)

Year	Residential GWh	Commercial GWh	Industrial GWh	Military & Other GWh	Retail GWh	Wholesale GWh	Total System GWh
2008	27,335	27,288	22,634	284	77,541	3,525	81,066
2009	27,273	26,977	19,204	287	73,741	3,788	77,529
2010	30,049	27,968	20,618	287	78,922	5,166	84,088
2011	28,323	27,593	20,783	287	76,986	4,866	81,852
2012	26,279	27,476	20,978	290	75,023	5,176	80,199
2013	26,895	27,765	21,070	293	76,023	5,824	81,847
2014	27,976	28,421	21,577	303	78,277	6,559	84,836
2015	27,916	28,700	22,136	305	79,057	6,916	85,973
2016	27,939	28,906	21,942	304	79,091	7,614	86,705
2017	26,593	28,388	21,776	301	77,059	7,558	84,617
Avg. Annual Growth Rate	-0.3%	0.4%	-0.4%	0.6%	-0.1%	8.8%	0.5%

System Peaks:

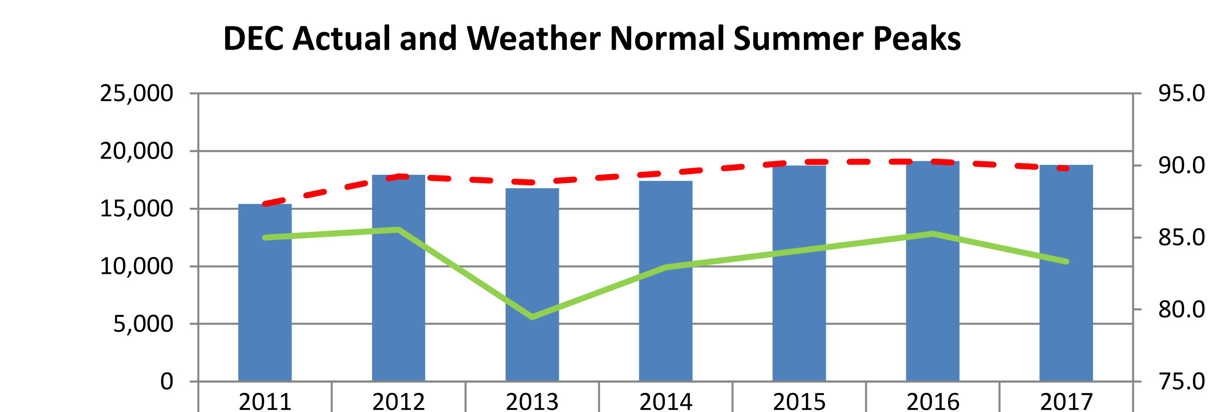
Table C-5 and C-6 shows the historical actual and weather normalized peaks for the system:

Table C-5: Winter Peaks



	2011	2012	2013	2014	2015	2016	2017	2018
Actual	14,561	15,962	15,363	19,232	20,455	18,213	18,069	19,436
WN Peak	15,141	16,875	16,500	19,040	19,674	18,544	18,162	19,204
Temp	27.7	31.1	38.3	23.9	19.4	24.7	23.4	21.9

Table C-6: Summer Peaks



	2011	2012	2013	2014	2015	2016	2017
Actual	15,420	17,933	16,757	17,397	18,742	19,119	18,811
WN Peak	15,410	17,803	17,269	18,063	19,051	19,086	18,495
Temp	85.0	85.5	79.5	82.9	84.1	85.3	83.3

Forecast Results:

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

- Table C-7: Forecasted energy sales by class (Including the impacts of UEE, rooftop solar, and electric vehicles)
- Table C-8: Summary of the load forecast without UEE programs and excluding any impacts from demand reduction programs
- Table C-9: Summary of the load forecast with UEE programs and excluding any impacts from demand reduction programs

These projections are at generation and include Wholesale.

Load duration curves, with and without UEE programs are shown as Figures C-1 and C-2.

The values in these tables reflect the loads that Duke Energy Carolinas is contractually obligated to provide and cover the period from 2019 to 2033.

As a note, all of the loads and energy in the tables and figuress below are at generation, except for the class sales forecast, which is at the meter.

Table C-7: Forecasted energy sales by class

Year	Residential Gwh	Commercial Gwh	Industrial Gwh	Other Gwh	Retail Gwh
2019	28,054	28,774	22,056	291	79,175
2020	28,376	28,917	22,191	285	79,769
2021	28,665	28,913	22,262	280	80,119
2022	29,095	29,038	22,193	274	80,600
2023	29,471	29,182	22,008	269	80,930
2024	30,002	29,496	22,159	264	81,922
2025	30,391	29,684	22,383	259	82,718
2026	30,834	29,981	22,588	255	83,658
2027	31,213	30,269	22,708	251	84,441
2028	31,731	30,724	23,043	247	85,746
2029	32,088	31,014	23,341	244	86,687
2030	32,516	31,263	23,515	241	87,535
2031	33,007	31,541	23,777	238	88,562
2032	33,566	31,908	24,044	235	89,753
2033	33,903	32,079	24,152	232	90,366
Avg. Annual Growth Rate	1.3%	0.7%	0.6%	-1.5%	0.9%

Table C-8: Summary of the load forecast without UEE programs and excluding any impacts from demand reduction programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2019	18,247	17,824	91,442
2020	18,447	18,013	92,584
2021	18,618	18,145	93,399
2022	18,755	18,291	94,098
2023	18,899	18,387	94,873
2024	19,176	18,622	96,363
2025	19,431	18,763	97,629
2026	19,737	19,101	99,040
2027	20,029	19,333	100,259
2028	20,450	19,654	101,918
2029	20,810	19,968	103,086
2030	21,163	20,197	104,122
2031	21,573	20,483	105,298
2032	21,990	20,922	106,663
2033	22,320	21,177	107,410
Avg. Annual Growth Rate	1.4%	1.2%	1.1%

Chart C-1: Load Duration Curve without Energy Efficiency Programs and Before Demand Reduction Programs

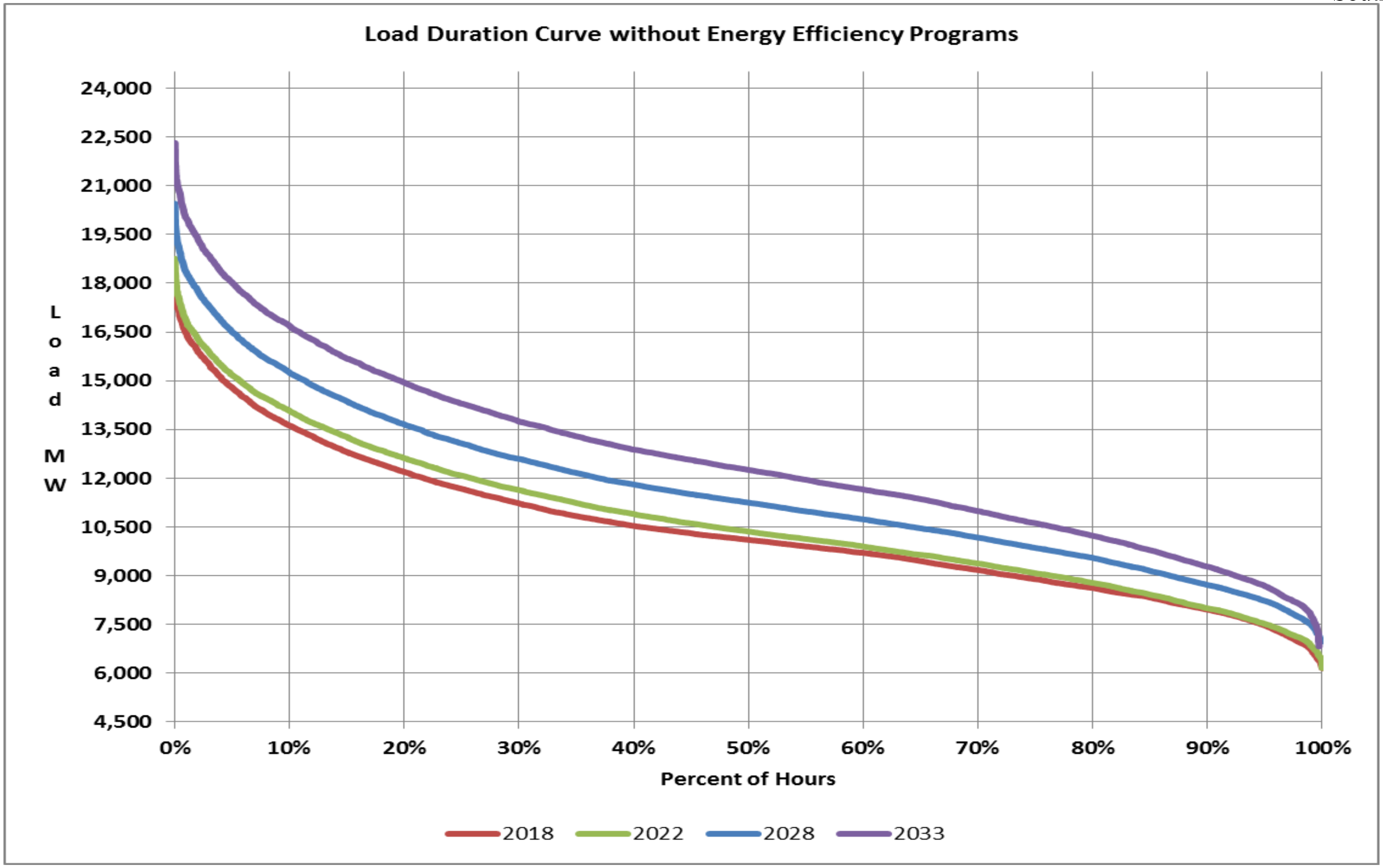
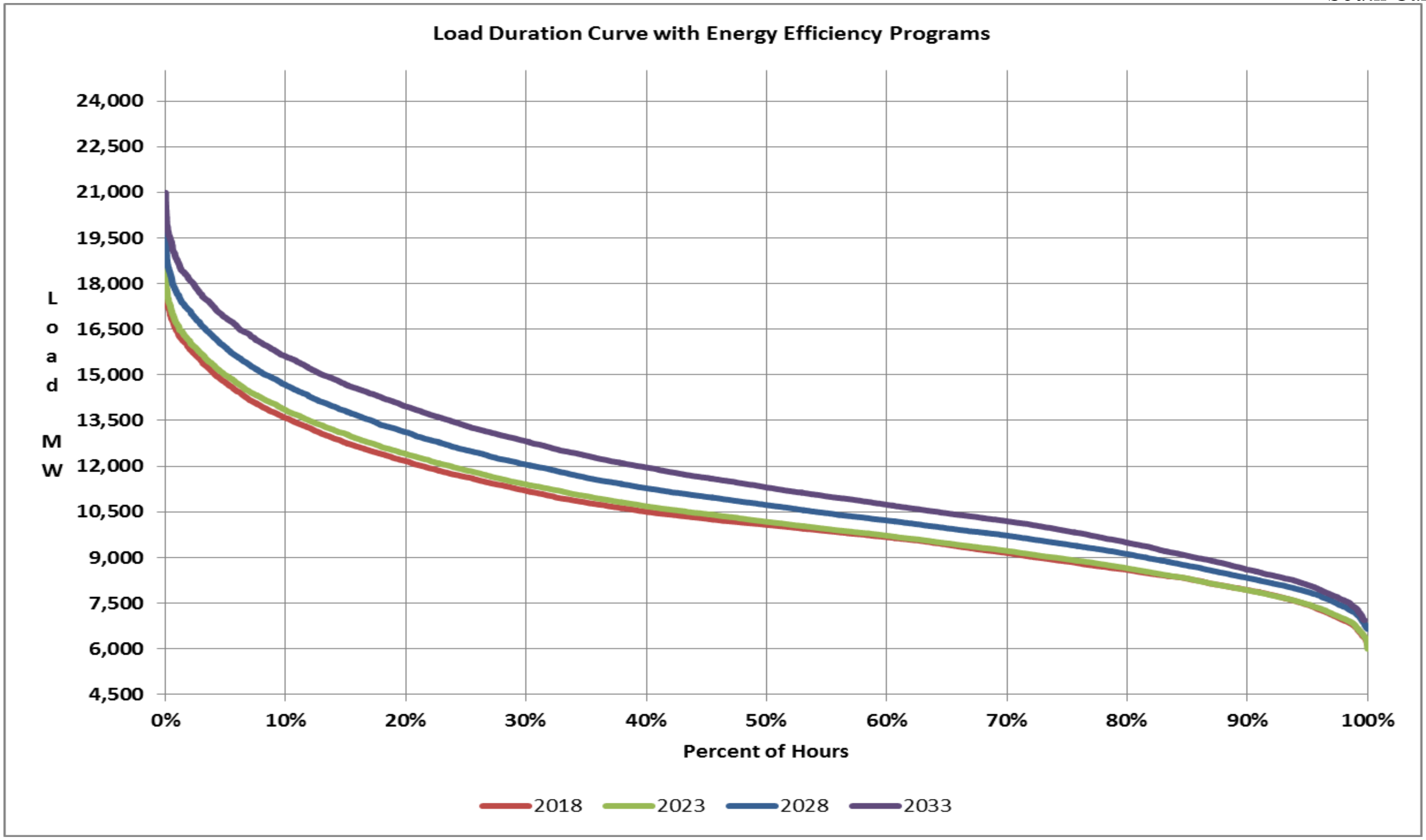


Table C-9: Summary of the load forecast with UEE programs and excluding any impacts from demand reduction programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2019	18,136	17,776	90,721
2020	18,270	17,924	91,423
2021	18,381	18,017	91,825
2022	18,460	18,128	92,132
2023	18,547	18,173	92,515
2024	18,764	18,373	93,614
2025	18,954	18,478	94,490
2026	19,192	18,778	95,529
2027	19,409	18,970	96,397
2028	19,737	19,241	97,823
2029	19,984	19,494	98,857
2030	20,218	19,657	99,806
2031	20,501	19,873	100,937
2032	20,792	20,242	102,248
2033	20,986	20,423	102,955
Avg. Annual Growth Rate	1.0%	0.9%	0.8%

Chart C-2: Load Duration Curve with Energy Efficiency Programs and Before Demand Reduction Programs



APPENDIX D: ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT

Current Energy Efficiency and Demand-Side Management Programs:

DEC uses EE and DSM programs in its IRP to efficiently and cost-effectively alter customer demands and reduce the long-run supply costs for energy and peak demand. These programs can vary greatly in their dispatch characteristics, size and duration of load response, certainty of load response, and level and frequency of customer participation. In general, programs are offered in two primary categories: Energy efficiency (EE) programs that reduce energy consumption and demand-side management (DSM) programs that reduce peak demand (demand-side management or demand response programs and certain rate structure programs).

Following are the EE and DSM programs available through DEC as of December 31, 2017:

Residential EE Programs:

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

Non-Residential EE Programs:

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

Residential DSM Programs:

- Power Manager

Non-Residential DSM Programs:

- PowerShare®
- EnergyWise^{SM} for Business

***Energy Efficiency Programs*:**

Energy Efficiency programs are typically non-dispatchable education or incentive-based programs. Energy and capacity savings are achieved by changing customer behavior or through the installation of more energy-efficient equipment or structures. All cumulative effects (gross of Free Riders, at the Plant[11]) since the inception of these existing programs through the end of 2017 are summarized below. Please note that the cumulative impacts listed below include the impact of any Measurement and Verification performed since program inception and also note that a "Participant" in the information included below is based on the unit of measure for the specific energy efficiency measure (e.g. number of bulbs, kWh of savings, tons of refrigeration, etc.), and may not be the same as the number of customers that actually participate in these programs. The following provides more detail on DEC's existing EE programs:

Residential Programs:

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 Energy Assessments			
		Gross Savings (at plant)	
Cumulative as of:	Number of Participants	MWh Energy	Peak kW
December 31, 2017	131,465	65,236	10,270

[11] "Gross of Free Riders" means that the impacts associated with the EE programs have not been reduced for the impact of Free Riders. "At the Plant" means that the impacts associated with the EE programs have been increased to include line losses.

Two previously offered Residential Energy Assessment measures were no longer offered in the new portfolio effective January 1, 2014. The historical performance of these measures through December 31, 2013 is included below.

Personalized Energy Report			
	Number of	**Gross Savings (at plant)**	
Cumulative as of:	**Participants**	**MWh Energy**	**Peak kW**
December 31, 2013	86,333	24,502	2,790

Online Home Energy Comparison Report			
	Number of	**Gross Savings (at plant)**	
Cumulative as of:	**Participants**	**MWh Energy**	**Peak kW**
December 31, 2013	12,902	3,547	387

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

- Energy Efficient Lighting: DEC customers can take advantage of several program options and delivery mechanisms to improve lighting efficiency, including:

    a. The Free LED program offers free 9-watt A19 Light Emitting Diodes (LED) lamps to install in high-use fixtures. The LEDs are offered through multiple channels to eligible customers. The on-demand ordering platform enables eligible customers to request LEDs and have them shipped directly to their homes.

    b. The Duke Energy Savings Store is an extension of the on-demand ordering platform enabling eligible customers to purchase specialty bulbs and have them shipped directly to their homes. The Store offers a variety LEDs including; Reflectors, Globes, Candelabra, 3-Way, Dimmable and A-Line type bulbs.

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

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

This program previously offered variable speed pool pump and heat pump water heaters, however, in late 2017 those measures were moved to the Residential Smart $aver® Energy Efficiency Program.

The tables below show actual program performance for all current and past program measures.

Residential Smart $aver® EE Program – Residential CFLs			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2017	31,413,492	1,267,682	135,650

Energy Efficient Appliances and Devices Program - Residential LEDs			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2017	5,620,923	176,498	24,423

Energy Efficient Appliances and Devices Program – Retail Lighting			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2017	3,189,669	111,311	16,523

Residential Smart $aver® EE Program – Specialty Lighting			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2017	2,012,884	89,116	10,840

Residential Smart $aver® EE Program – Water Measures			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2017	1,464,659	90,458	15,003

Residential Smart $aver® EE Program – Pool Equipment			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2017	1,707	4,246	1,070

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

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

Energy Efficiency Education			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2017	186,462	45,082	8,421

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

- Neighborhood Energy Saver (NES) is available only to individually-metered residences served by Duke Energy Carolinas in neighborhoods selected by the Company, which are considered low-income based on third party and census data, which includes income level and household size. Neighborhoods targeted for participation in this program will typically have approximately 50% or more of the households with income below 200% of the poverty level established by the U.S. Government. This approach allows the Company to reach a larger audience of low income customers than traditional government agency flow-through methods. The program provides customers with the direct installation of measures into the home to increase the EE and comfort level of the home. Additionally, customers receive EE education to encourage behavioral changes for managing energy usage and costs.
- Weatherization and Equipment Replacement Program (WERP) recognizes the existence of customers whose EE needs surpass the standard low-cost measure offerings provided through NES. WERP is available to income-qualified customers in the Duke Energy Carolinas service territory for existing, individually metered, single-family, condominiums, and mobile homes. Funds are available for weatherization measures and/or heating system replacement with a 15 or greater SEER heat pump. A full energy audit of the residence is used to determine the measures eligible for funding. Customers are placed into a tier based on energy usage, where Tier 1 provides up to $600 for energy efficiency services; while Tier 2 provides up to $4,000 for energy efficiency services, including insulation, thus allowing high energy users to receive more extensive weatherization measures.
- The Refrigerator Replacement Program (RRP) includes, but is not limited to, replacement of inefficient operable refrigerators in low income households. The program will be available to homeowners, renters, and landlords with income qualified tenants that own a qualified appliance. Income eligibility for RRP will mirror the income eligibility standards for the North Carolina Weatherization Assistance Program.

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

Income Qualified Energy Efficiency and Weatherization			
Cumulative as of:	Number of Participants	Gross Savings (at plant)	
		MWh Energy	Peak kW
December 31, 2017	53,946	25,437	3,858

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

The tables below show actual program performance for current and past program measures.

Multi-Family Energy Efficiency – Property Manager CFLs			
Cumulative as of:	Number of Participants	Gross Savings (at plant)	
		MWh Energy	Peak kW
December 31, 2017	1,184,198	49,600	5,217

Multi-Family Energy Efficiency – Property Manager LEDs			
Cumulative as of:	Number of Participants	Gross Savings (at plant)	
		MWh Energy	Peak kW
December 31, 2017	259,071	10,064	1,098

Multi-Family Energy Efficiency – Water Measures			
Cumulative as of:	Number of Participants	Gross Savings (at plant)	
		MWh Energy	Peak kW
December 31, 2017	487,039	40,581	3,798

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

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

My Home Energy Report			
	Number of	**Gross Savings (at plant)**	
Capability as of:	**Participants**	**MWh Energy**	**Peak kW**
December 31, 2017	1,394,693	311,369	79,070

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

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

This program previously offered HVAC Tune-Ups and Duct Insulation, however, those measures were removed due to no longer being cost-effective.

The tables below show actual program performance for all current and past program measures.

Residential Smart $aver® Energy Efficiency			
Cumulative as of:	Number of Participants	Gross Savings (at plant)	
		MWh Energy	Peak kW
December 31, 2017	120,613	75,206	23,398

Non-Residential:

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

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

- **Non-Residential Smart $aver® Energy Efficient HVAC Products** provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of new high efficient HVAC equipment in new and existing non-residential establishments and efficiency-directed repairs to maintain or enhance efficiency levels in currently installed equipment. Measures include, but are not limited to, chillers, unitary and rooftop air conditioners, programmable thermostats, and guest room energy management systems.

- **Non-Residential Smart $aver® Energy Efficient Information Technologies (IT) Products** provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of high efficiency new IT equipment in new and existing non-residential establishments and efficiency-directed repairs to maintain or enhance efficiency levels in currently-installed equipment. Measures include, but are not limited to, Energy Star-rated desktop computers and servers, PC power management from network, server virtualization, variable frequency drives (VFD) for computer room air conditioners and VFD for chilled water pumps.

- **Non-Residential Smart $aver® Energy Efficient Lighting Products** provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of new high efficiency lighting equipment in new and existing non-residential establishments and the efficiency-directed repairs to maintain or enhance efficiency levels in currently installed equipment. Measures include, but are not limited to, interior and exterior LED lamps and fixtures, reduced wattage and high performance T8 systems, T8 and T5 high bay fixtures, and occupancy sensors.

- **Non-Residential Smart $aver® Energy Efficient Process Equipment Products** provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of new high efficiency equipment in new and existing non-residential establishments and efficiency-directed repairs to maintain or enhance high efficiency levels in currently installed equipment. Measures include, but are not limited to, VFD air compressors, barrel wraps, and pellet dryer insulation.

- **Non-Residential Smart $aver® Energy Efficient Pumps and Drives Products** provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of new high efficiency equipment in new and existing non-residential establishments and efficiency-directed repairs to maintain or enhance efficiency levels in currently installed equipment. Measures include, but are not limited to, pumps and VFD on HVAC pumps and fans.

Non-Residential Smart $aver® Prescriptive			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2017	16,721,011	1,631,857	265,005

Non-Residential Smart $aver® Custom Program offers financial assistance to qualifying commercial, industrial and institutional customers (that have not opted-out of the Company's EE/DSM Rider) to enhance their ability to adopt and install cost-effective electrical energy efficiency projects. The Program is designed to meet the needs of the Company's customers with electrical energy saving projects involving more complicated or alternative technologies, or those measures not covered by the Non-Residential Smart $aver® Prescriptive Program. The intent of the Program is to encourage the implementation of energy efficiency projects that would not otherwise be completed without the Company's technical or financial assistance.

Unlike the Non-Residential Smart $aver® Prescriptive Program, the Program requires pre-approval prior to the project initiation. Proposed energy efficiency measures may be eligible for customer incentives if they clearly reduce electrical consumption and/or demand.

Non-Residential Smart $aver® Custom			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2017	128,000	283,820	39,141

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

Non-Residential Smart $aver® Custom Assessment			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2017	2,781	48,028	5,287

Non-Residential Smart $aver Performance Incentive Program

The Non-Residential Smart $aver® Performance Incentive 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 Non-Residential Smart $aver Energy® Custom 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.

Non-Residential Smart $aver® Performance Incentive			
	Number of	**Gross Savings (at plant)**	
Cumulative as of:	**Participants***	**MWh Energy**	**Peak kW**
December 31, 2017	19	15	3

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

Small Business Energy Saver			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2017	217,790,530	257,886	49,772

Demand-Side Management Programs:

DEC's current DSM programs will be presented in two sections: Demand Response Direct Load Control Programs and Demand Response Interruptible Programs and Related Rate Tariffs.

Demand Response – Direct Load Control Programs:

These programs can be dispatched by the utility and have the highest level of certainty due to the participant not having to directly respond to an event. DEC's current direct load control programs are:

Residential:

Power Manager® provides residential customers a voluntary demand response program that allows Duke Energy Carolinas to limit the run time of participating customers' central air conditioning (cooling) systems to reduce electricity demand. Power Manager® may be used to completely interrupt service to the cooling system when the Company experiences capacity problems. In addition, the Company may intermittently interrupt (cycle) service to the cooling system. For their participation in Power Manager®, customers receive bill credits during the billing months of July through October.

Power Manager® provides DEC with the ability to reduce and shift peak loads, thereby enabling a corresponding deferral of new supply-side peaking generation and enhancing system reliability.

Participating customers are impacted by (1) the installation of load control equipment at their residence, (2) load control events which curtail the operation of their air conditioning unit for a period of time each hour, and (3) the receipt of bill credits from DEC in exchange for allowing DEC the ability to control their electric equipment.

Power Manager®			
Cumulative as of:	**Participants (Customers)**	**Devices (Switches)**	**Summer 2017 Capability (MW)**
December 31, 2017	215,436	257,527	511.5

The following table shows Power Manager® program activations that were not for testing purposes from June 1, 2016 through December 31, 2017.

Power Manager® Program Activations				
Date	**Start Time**	**End Time**	**Duration (Minutes)**	**MW Load Reduction**
6/23/2016	2:30 PM	5:00 PM	150	219
7/14/2016	2:30 PM	6:00 PM	210	228
9/08/2016	3:30 PM	6:00 PM	150	180
9/19/2016	2:30 PM	6:00 PM	210	150
7/13/2017	3:00PM	6:00PM	180	220.5

Non-Residential:

Demand Response – Interruptible Programs and Related Rate Structures

These programs rely either on the customer's ability to respond to a utility-initiated signal requesting curtailment, or on rates with price signals that provide an economic incentive to reduce or shift load. Timing, frequency, and nature of the load response depend on customers' actions after notification of an event or after receiving pricing signals. Duke Energy Carolinas' current interruptible and time-of-use rate programs include:

PowerShare® is a non-residential curtailment program consisting of four options: an emergency only option for curtailable load (PowerShare® Mandatory), an emergency only option for load curtailment using on-site generators (PowerShare® Generator), an economic based voluntary option (PowerShare® Voluntary) and a combined emergency and economic option that allows for increased notification time of events (PowerShare® CallOption).

PowerShare® Mandatory: Participants in this emergency only option will receive capacity credits monthly based on the amount of load they agree to curtail during utility-initiated emergency events. Participants also receive energy credits for the load curtailed during events. Customers enrolled may also be enrolled in PowerShare® Voluntary and eligible to earn additional credits.

PowerShare® Mandatory			
Cumulative as of:	**Participants**	**Summer 2017 Capability (MW)**	**Winter 2017 Capability (MW)**
December 31, 2017	150	325	313

The following table shows PowerShare® Mandatory program activations that were not for testing purposes from July 1, 2016 through December 31, 2017.

PowerShare® Mandatory Program Activations				
Date	**Start Time**	**End Time**	**Duration (Minutes)**	**MW Load Reduction**
7/13/2016	4:30 pm	7:00 pm	150	331
7/14/2016	2:00 pm	7:00 pm	300	331
7/25/2016	2:00 pm	8:00 pm	360	314
7/26/2016	2:00 pm	8:00 pm	360	315

PowerShare® Generator: Participants in this emergency only option will receive capacity credits monthly based on the amount of load they agree to curtail (i.e. transfer to their on-site generator) during utility-initiated emergency events and their performance during monthly test hours. Participants also receive energy credits for the load curtailed during events.

PowerShare® Generator Statistics			
As of:	**Participants**	**Summer 2017 Capability (MW)**	**Winter 2017 Capability (MW)**
December 31, 2017	10	9.2	8.9

The following table shows PowerShare® Generator program activations that were not for testing purposes from July 1, 2016 through December 31, 2017.

PowerShare® Generator Program Activations				
Date	**Start Time**	**End Time**	**Duration (Minutes)**	**MW Load Reduction**
7/13/2016	4:30 pm	7:00 pm	150	12
7/14/2016	2:00 pm	7:00 pm	300	12
7/25/2016	2:00 pm	8:00 pm	360	12
7/26/2016	2:00 pm	8:00 pm	360	12

PowerShare® Voluntary: Enrolled customers will be notified of pending emergency or economic events and can log on to a website to view a posted energy price for that event. Customers will then have the option to participate in the event and will be paid the posted energy credit for load curtailed. Since this is a voluntary event program, no capacity benefit is recognized for this program and no capacity incentive is provided. The values below represent participation in PowerShare® Voluntary only and do not double count the participants in PowerShare® Mandatory that also participate in PowerShare® Voluntary.

PowerShare® Voluntary			
As of:	**Participants**	**Summer 2017 Capability (MW)**	**Winter 2017 Capability (MW)**
December 31, 2017	0	N/A	N/A

The following table shows PowerShare® Voluntary program activations that were <u>not</u> for testing purposes from July 1, 2016 through December 31, 2017.

PowerShare® Voluntary Program Activations				
Date	**Start Time**	**End Time**	**Duration (Minutes)**	**MW Load Reduction**
7/13/2016	4:30 pm	7:00 pm	150	0
7/14/2016	2:00 pm	7:00 pm	300	0
7/25/2016	2:00 pm	8:00 pm	360	0
7/26/2016	2:00 pm	8:00 pm	360	0

PowerShare® CallOption (Closed in NC effective January 31, 2018): This program offered participating customers the ability to receive credits when they agree, at the Company's request, to reduce and maintain its load by a minimum of 100 kW during Emergency and/or Economic Events. Credits are paid for the load available for curtailment, and charges are applicable when the customer fails to reduce load in accordance with the participation option it has selected. Participants are obligated to curtail load during emergency events. CallOption offers four participation options to customers: PS 0/5, PS 5/5, PS 10/5 and PS 15/5. All options include a limit of five Emergency Events and set a limit for Economic Events to 0, 5, 10 and 15, respectively.

PowerShare® CallOption			
As of:	**Participants**	**Summer 2017 Capability (MW)**	**Winter 2017 Capability (MW)**
December 31, 2017	0	0	0

The PowerShare® CallOption program was not activated during the period from July 1, 2016 through December 31, 2017.

PowerShare® CallOption 200 (Closed effective January 31, 2018): This CallOption offering was targeted at customers with very flexible load and curtailment potential of up to 200 hours of economic load curtailment each year. This option will function essentially in the same manner as the Company's other CallOption offers. However, customers who participate would experience considerably more requests for load curtailment for economic purposes. Participants remain obligated to curtail load during up to 5 emergency events.

PowerShare® CallOption 200 Program			
As of:	**Participants**	**Summer 2017 Capability (MW)**	**Winter 2017 Capability (MW)**
December 31, 2017	0	0	0

The PowerShare® CallOption 200 program was not activated during the period from July 1, 2016 through December 31, 2017.

EnergyWise℠ for Business: is both an energy efficiency and demand response program for non-residential customers that allows DEC to reduce the operation of participants' air conditioning units to mitigate system capacity constraints and improve reliability of the power grid.

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. 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.

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 adjust their schedules or notify their employees of the upcoming conservation periods.

EnergyWise^{SM} for Business Program				
		MW Capability		**MWh Energy Savings (at plant)**
Cumulative as of:	**Participants***	**Summer**	**Winter**	
December 31, 2017	5,344	6.7	1.8	3,300

* Number of participants represents the number of measures under control.

The following table shows **EnergyWise^{SM} for Business** program activations that were <u>not</u> for testing purposes from July 1, 2016 through December 31, 2017.

EnergyWise^{SM} for Business Program Activations				
Date	**Start Time**	**End Time**	**Duration (Minutes)**	**MW Load Reduction**
7/8/2016	3:30 pm	6:00 pm	150	0.7
7/14/2016	3:00 pm	6:00 pm	180	0.7
7/27/2016	3:00 pm	6:00 pm	180	0.7
6/14/2017	3:00 pm	6:00 pm	180	3.6
7/13/2017	3:00 pm	6:00 pm	180	3.6
7/21/2017	3:00 pm	6:00 pm	180	3.6
8/17/2017	3:30 pm	6:00 pm	150	3.9
8/22/2017	3:00 pm	6:00 pm	180	3.9

Demand-Side Management Program Resources:

The NCUC, in their approval of the 2017 Integrated Resource Plans and REPS Compliance Plans dated April 16, 2018 in Docket E-100, Sub147, issued the following Order relative to a decline in winter DSM resources:

7. *In contrast with the success of DEP's DSM efforts, the Commission notes that DEC's 2017 IRP includes winter DSM resources that are approximately 80 MW less than*

included in its 2016 IRP Report. The Commission is concerned with this development. The Commission expects DEC to place at least as much emphasis on DSM and energy efficiency in its integrated resource planning as that given DSM and EE by DEP. As a result, the Commission directs that DEC include in its 2018 IRP a detailed discussion of its decline in winter DSM during 2017, and its plans for re-emphasizing DSM.

This Order that is specific to DSM is addressed in the following section.

Decline in DSM Resources in DEC's 2017 IRP Report:

The loss of DEC's winter DSM resources that occurred between the 2016 and 2017 IRP submissions was primarily attributable to the large non-residential programs and involved a comparable loss of summer DSM resources due to the program's required year-round load reduction commitment. Although the efforts to acquire and maintain MW resources are consistent across the jurisdictions, there were several reasons why similar losses were not experienced with DEP's seasonal DSM resources. The primary distinction between the DEC and DEP program MW losses was driven by the relative size of generator programs that were affected by changes to EPA regulations that year, the impact of an increased frequency of curtailment events on industrial customers (*10 events for DEC during the 2014-16 timeframe compared to 4 events for DEP*), and fluctuations in customer loads from the previous year. Despite new enrollments of approximately 15 MW during the year in question, these factors led to a net reduction of more than 100 MW from the loss of 58 DEC participants. Below is a detailed summary of the losses incurred.

- **EPA REGULATIONS:** DEC and DEP were able to avoid a significant loss of non-residential demand response participants from a May 3, 2014 implementation of the EPA's RICE (*Reciprocating Internal Combustion Engines*) NESHAP (*National Emission Standards for Hazardous Air Pollutants*) Rule by making adjustments to the design of certain programs that allowed for continued use of standby generators with emergency classification. However, on May 1, 2016, the DC Circuit Court of Appeals mandated vacatur of the 100-hour demand response provision in the rule that permitted use of those generators, thus invalidating the changes made to the programs. As a result, thirty PowerShare Generator participants representing more than 35 MW in load reduction capability had to terminate their PowerShare agreements in order to remain compliant with EPA regulations. In contrast, DEP programs only lost a total of 5 MW due to the change in regulations.

- **INCREASED ACTIVITY:** Beginning with the first Carolinas Polar Vortex occurrence in January 2014, DEC has experienced a significant increase in utilization of the non-residential DSM programs. DEC has dispatched the non-residential programs 12 times in the last 5 years compared to 2 times in the previous 5 years. This increased activity, particularly given that there were five instances of events on back-to-back days, created considerable hardships for many participants, especially large industrial customers, and caused them to reevaluate the overall value of participation. The programs experienced a loss of some participants early during that period, but the losses peaked following the four events that occurred in July 2016. That series of events led to the loss of 15 participants representing more than 15 MW over the next several months as their contract terms expired.

- **REDUCED LOADS:** Each year, DEC updates the load reduction capabilities for individual DSM program participants using meter data from the most recent seasonal peak periods. These true-ups can be impacted by major year-over-year swings in average temperatures, but will also capture shifts in customer loads caused by operational changes. In some years, DEC programs realize an increase in program capabilities from the true-up process, while in others there will be a decrease. For the 2016 true-ups, the reported capabilities for DEC's PowerShare program dropped 24 MW due primarily to a reduction in industrial loads.

Discontinued Demand-Side Management and Energy Efficiency Programs

Since the last biennial Resource Plan filing, DEC discontinued the following DSM/EE programs.

- **Appliance Recycling Program** – promoted the removal and responsible disposal of operating refrigerators and freezers from DEC residential customers. The Program recycled approximately 95% of the material from the harvested appliances.

  The implementation vendor for this program abruptly discontinued operations in November 2015 and the program was subsequently closed. The table below presents the final actual program accomplishments.

Appliance Recycling			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2017	31,090	31,867	4,355

- **Smart Energy in Offices Program** – was designed to engage commercial building stakeholders in energy management best practices that address operational and behavioral opportunities to achieve energy savings. The program aimed to build awareness and drive impact through targeted action campaigns and challenges, with mechanisms to recognize and reward building operators, tenant champions and individual employees stepping up to make a difference in their community.

- **Business Energy Report Pilot** – was a periodic comparative usage report that compares a customer's energy use to their peer groups. Comparative groups were identified based on the customer's energy use, type of business, operating hours, square footage, geographic location, weather data and heating/cooling sources. Pilot participants received at least six reports over the course of a year, which included targeted energy efficiency tips informing them of actionable ideas to reduce their energy consumption. With the cost effectiveness of the program expected to decline below the allowable threshold, the program was terminated in 2017.

- **PowerShare CallOption** – Due to a lack of customer interest, DEC closed the PowerShare CallOption (Rider PSC) program in North Carolina effective January 31, 2018, pursuant to an NCUC Order issued in Docket E-7, Sub 1130, dated August 23, 2017. The Company is currently seeking approval to close the program in South Carolina.

Future EE and DSM Programs:

DEC is continually seeking to enhance its EE and DSM portfolio by: (1) adding new programs or expanding existing programs to include additional measures, (2) program modifications to account for changing market conditions and new M&V results, and (3) other EE pilots.

Potential new programs and/or measures will be reviewed with the DSM Collaborative then submitted to the Public Utility Commissions as required for approval.

EE and DSM Program Screening:

The Company uses the DSMore model to evaluate the costs, benefits, and risks of EE and DSM programs and measures. DSMore is a financial analysis tool designed to estimate of the capacity and energy values of EE and DSM measures at an hourly level across distributions of weather conditions and/or energy costs or prices. By examining projected program performance and cost effectiveness over a wide variety of weather and cost conditions, the Company is in a better position to measure the risks and benefits of employing EE and DSM measures versus traditional generation capacity additions, and further, to ensure that DSM resources are compared to supply side resources on a level playing field.

The analysis of energy efficiency and demand-side management cost-effectiveness has traditionally focused primarily on the calculation of specific metrics, often referred to as the California Standard tests: Utility Cost Test, Rate Impact Measure Test, Total Resource Cost Test and Participant Test. DSMore provides the results of those tests for any type of EE or DSM program.

- The UCT compares utility benefits (avoided costs) to the costs incurred by the utility to implement the program, and does not consider other benefits such as participant savings or societal impacts. This test compares the cost (to the utility) to implement the measures with the savings or avoided costs (to the utility) resulting from the change in magnitude and/or the pattern of electricity consumption caused by implementation of the program. Avoided costs are considered in the evaluation of cost-effectiveness based on the projected cost of power, including the projected cost of the utility's environmental compliance for known regulatory requirements. The cost-effectiveness analyses also incorporate avoided transmission and distribution costs, and load (line) losses.
- The RIM Test, or non-participants test, indicates if rates increase or decrease over the long-run as a result of implementing the program.
- The TRC Test compares the total benefits to the utility and to participants relative to the costs to the utility to implement the program along with the costs to the participant. The benefits to the utility are the same as those computed under the UCT. The benefits to the participant are the same as those computed under the Participant Test, however, customer incentives are considered to be a pass-through benefit to customers. As such, customer incentives or rebates are not included in the TRC.
- The Participant Test evaluates programs from the perspective of the program's participants. The benefits include reductions in utility bills, incentives paid by the utility and any State, Federal or local tax benefits received.

The use of multiple tests can ensure the development of a reasonable set of cost-effective DSM and EE programs and indicate the likelihood that customers will participate.

Energy Efficiency and Demand-Side Management Program Forecasts

Forecast Methodology:

In 2016, DEC commissioned a new EE market potential study to obtain new estimates of the In 2016, DEC commissioned a new EE market potential study to obtain new estimates of the technical, economic and achievable potential for EE savings within the DEC service area. The final reports (one for South Carolina and one for North Carolina) were prepared by Nexant Inc. and issued on December 19, 2016.

The Nexant study results are suitable for IRP purposes and for use in long-range system planning models. This study also helps to inform utility program planners regarding the extent of EE opportunities and to provide broadly defined approaches for acquiring savings. This study did not, however, attempt to closely forecast EE achievements in the short-term or from year to year. Such an annual accounting is highly sensitive to the nature of programs adopted as well as the timing of the introduction of those programs. As a result, it was not designed to provide detailed specifications and work plans required for program implementation. The study provides part of the picture for planning EE programs. Fully implementable EE program plans are best developed considering this study along with the experience gained from currently running programs, input from DEC program managers and EE planners, feedback from the DSM Collaborative and with the possible assistance of implementation contractors.

The Nexant market potential study (MPS) included projections of Energy Efficiency impacts over a 25-year period for a Base and Enhanced Scenario, which were used in conjunction with expected EE savings from DEC's five-year program plan to develop the Base Case and High Case EE savings forecasts, respectively, for this IRP. The Base Case EE savings forecast represents a merging of the projected near-term savings from DEP's five-year plan (2018-2022) with the long-term savings from the Nexant MPS (2028-onward). Savings during the five-year period (2023-2027) between the two sets of projections represents a merging of the two forecasts to ensure a smooth transition. The High Case EE savings forecast was developed by applying the difference between the Nexant Enhanced and Base Scenarios for all years to the final DEC Base Case forecast. Additionally, the cumulative savings projections for both the Base and High Case EE forecasts included an assumption that when the EE measures included in the forecast reach the end of their useful lives, the impacts associated with these measures are removed from the future projected EE impacts, a process defined as "rolloff".

The tables below provide the projected MWh load impacts for both the Base Case and High Case forecasts of all DEC EE programs implemented since the approval of the save-a-watt recovery mechanism in 2009 on a Net of Free Riders basis. The Company assumes total EE savings will continue to grow on an annual basis throughout the planning period, however, the components of future programs are uncertain at this time and will be informed by the experience gained under the current plan. Please note that this table includes a column that shows historical EE program savings since the inception of the EE programs in 2009 through the end of 2017, which accounts for approximately an additional 4,096 gigawatt-hour (GWh) of net energy savings.

The following forecast is presented without the effects of "rolloff":

Projected MWh Impacts of EE Programs
Base Case

Year	Annual MWh Load Reduction - Net	
	Including measures added in 2018 and beyond	Including measures added since 2009
2009-17		4,096,214
2018	457,007	4,553,221
2019	887,403	4,983,616
2020	1,300,965	5,397,178
2021	1,679,020	5,775,233
2022	2,053,771	6,149,984
2023	2,429,142	6,525,356
2024	2,805,135	6,901,349
2025	3,181,749	7,277,963
2026	3,558,985	7,655,198
2027	3,936,841	8,033,054
2028	4,315,318	8,411,532
2029	4,696,455	8,792,668
2030	5,081,308	9,177,522
2031	5,471,391	9,567,605
2032	5,869,066	9,965,280
2033	6,270,015	10,366,228

**The MWh totals included in the table above represent the annual year-end impacts associated with EE programs, however, the MWh totals included in the load forecast portion of this document represent the sum of the expected hourly impacts.*

Projected MWh Impacts of EE Programs
High Case

Year	Annual MWh Load Reduction - Net	
	Including measures added in 2018 and beyond	Including measures added since 2009
2009-17		4,096,214
2018	654,868	4,751,082
2019	1,295,541	5,391,754
2020	1,928,116	6,024,330
2021	2,534,523	6,630,736
2022	3,143,794	7,240,008
2023	3,754,190	7,850,404
2024	4,361,480	8,457,694
2025	4,961,129	9,057,343
2026	5,553,157	9,649,371
2027	6,136,510	10,232,723
2028	6,713,088	10,809,301
2029	7,282,658	11,378,872
2030	7,853,703	11,949,917
2031	8,429,080	12,525,293
2032	9,012,556	13,108,770
2033	9,600,608	13,696,822

**The MWh totals included in the table above represent the annual year-end impacts associated with EE programs, however, the MWh totals included in the load forecast portion of this document represent the sum of the expected hourly impacts.*

The MW impacts from the EE programs are included in the Load Forecasting section of this IRP. The table below provides the projected summer and winter peak MW load impacts of all current and projected DEC DSM programs.

Projected MW Load Impacts of DSM Programs

Year	Summer Peak MW Reduction					
	IS	SG	PowerShare	PowerManager	EnergyWise for Business	Total Summer Peak
2018	103	10	327	525	8	973
2019	98	9	330	539	16	992
2020	93	9	337	552	24	1,015
2021	89	9	344	564	33	1,038
2022	84	8	352	575	41	1,060
2023	80	8	355	575	49	1,067
2024	79	8	355	575	49	1,065
2025	79	8	355	575	49	1,065
2026	79	8	355	575	49	1,065
2027	79	8	355	575	49	1,065
2028	79	8	355	575	49	1,065
2029	79	8	355	575	49	1,065
2030	79	8	355	575	49	1,065
2031	79	8	355	575	49	1,065
2032	79	8	355	575	49	1,065
2033	79	8	355	575	49	1,065

Note: For DSM programs, Gross and Net are the same.

Projected MW Load Impacts of DSM Programs

Year	Winter Peak MW Reduction					
	IS	SG	PowerShare	PowerManager	EnergyWise for Business	Total Winter Peak
2018	104	10	313	0	1	428
2019	96	9	310	0	2	417
2020	91	9	316	0	4	420
2021	86	8	323	0	5	424
2022	82	8	331	0	7	427
2023	78	7	337	0	8	431
2024	75	7	337	0	8	427
2025	75	7	337	0	8	427
2026	75	7	337	0	8	427
2027	75	7	337	0	8	427
2028	75	7	337	0	8	427
2029	75	7	337	0	8	427
2030	75	7	337	0	8	427
2031	75	7	337	0	8	427
2032	75	7	337	0	8	427
2033	75	7	337	0	8	427

Note: For DSM programs, Gross and Net are the same.

Programs Evaluated but Rejected:

Duke Energy Carolinas has not rejected any cost-effective programs as a result of its EE and DSM program screening.

Looking to the Future - Grid Modernization (Smart Grid Impacts):

Duke Energy Carolinas is in the process of performing a cost/benefit review for an Integrated Volt-Var Control (IVVC) project that will better manage the application and operation of voltage regulators (the Volt) and capacitors (the VAR) on the Duke Energy Carolinas distribution system. The cost/benefit review will be used to inform future deployment plans, but as of the time of this filing the Company does not have plans to implement a wide scale IVVC program.

APPENDIX E: FUEL SUPPLY

Duke Energy Carolinas' current fuel usage consists of a mix of coal, natural gas and uranium. Oil is used for peaking generation and natural gas continues to play an increasing role in the fuel mix due to lower pricing and the addition of a significant amount of combined cycle generation. A brief overview and issues pertaining to each fuel type are discussed below.

Natural Gas:

During 2017 New York Mercantile Exchange (NYMEX) Henry Hub natural gas prices averaged approximately \$3.10 per million BTU (MMBtu) and U.S. lower-48 net dry production averaged approximately 73 billion cubic feet per day (BCF/day). Natural gas spot prices at the Henry Hub averaged approximately \$3.71 per MMBtu in January 2018. Henry Hub spot pricing decreased throughout the remaining winter months and averaged \$2.65 per MMBtu at the end of March 2018 The lower short-term spot prices in February and March 2018 were driven by both fundamental supply and demand factors.

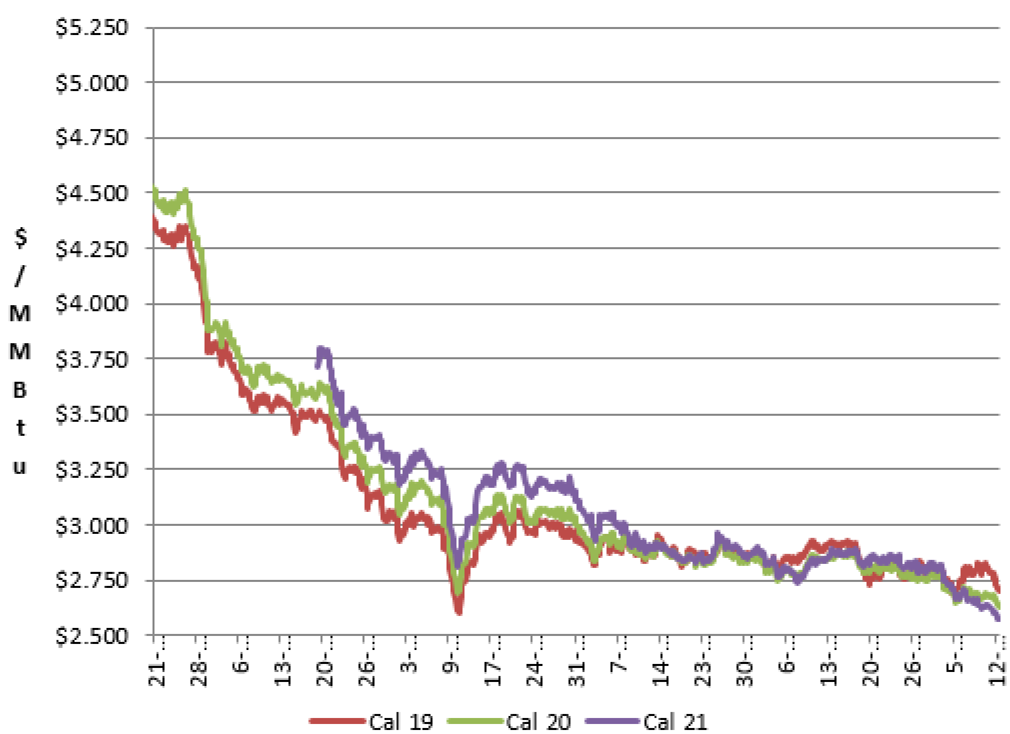
Average daily U.S. net dry production levels of approximately 76.7 BCF/day in the first quarter of 2018 were 5.4BCF/day higher than the comparable period in 2017. Storage ended the winter withdrawal season at approximately 1.4 trillion cubic feet (TCF) as of March 31, 2018. Lower-48 U.S. overall demand in the first quarter of 2018 was higher than normal due to the cold winter weather which raised residential heating needs and resulted in gas storage withdrawals through late April 2018.

Summer 2018 spot natural gas prices have decreased from the end of January 2018 prices that were in the low \$3.60's per MMBtu. The Henry Hub spot price settled in a range between approximately \$2.74 to \$2.90 per MMBtu in mid-July 2018. Working gas in storage remains below the 5-year average and storage balances from a year ago, however, market prices have declined over the last few months with expectations of continued record supply of dry gas production approaching 81.3 Bcf/d forecasted by the latest July 2018 EIA short term gas outlook. Observed average NYMEX Henry Hub prices for the winter period November 2018 through March 2019 have decreased to approximately \$2.90 per MMBtu from the prices observed in late March 2018. Although predicting actual storage balances at the end of the typical injection season is not possible, current projections are roughly 3.4 to 3.5 TCF of working gas in storage at the end of the injection season.

Natural gas consumption is expected to remain strong through the remainder of 2018 increasing 2.4 Bcf/d from 2017 levels, due primarily to increases in electric power usage. Per the EIA's short-term energy outlook released on July 10, 2018, this year also reflects higher residential and commercial demand because the first quarter of 2018 was colder than the first quarter of 2017. EIA expects the share of U.S. total utility-scale electricity generation from natural gas-fired power plants to rise from 32% in 2017 to 34% in 2018 and 35% in 2019. As a result, coal's forecast share of electricity generation falls from 30% in 2017 to 28% in 2018 and to 27% in 2019. The EIA estimates that total natural gas production will average 81.3Bcf/d in 2018, which will establish a new record. EIA also expects natural gas production will rise an additional 3.1 Bcf/d in 2019 to 84.5 Bcf/d. With advanced drilling techniques, producers appear able to adjust drilling programs in response to changing market prices to shorten or extend the term of the producing well. According to Baker Hughes, as of July 20, 2018, the U.S. Natural Gas rig count was at 187. This is flat from last year at the same time and up from all time low rig count of 81 in August of 2016.

In addition to the trends in shorter term natural gas spot price levels for 2018, in late February 2018, the observed forward market prices for the periods of 2019 through 2021 averaged approximately $2.77 per MMBtu. During this time period, the forward price curve is relatively flat reflecting an expectation of balanced supply and demand fundamentals. Prices have decreased in the last few months to approximately $2.64 per MMBtu as of late July 2018. This is illustrated in the graph below.

FORWARD MARKET PRICES



Looking forward, the forward five and ten-year observable market curves are at $2.61 and $2.73 per MMBtu, respectively as of the July 20, 2018 close. In addition, as of the close of business on July 21, 2018, the one (1), three (3) and five (5) years strips were all approximately $2.63 per MMBtu. As illustrated with these price levels and relationships, the forward NYMEX Henry Hub price curve is extremely flat with the periods of 2020 and 2021 currently trading at discounts to 2019 prices. The gas market is expected to remain relatively stable due to an improving economic picture which may allow supply and demand to further come into balance. Demand for natural gas from the power sector for 2018 is expected to be higher than coal generation due to coal retirements, which are tied to the implementation of the EPA's MATS rule covering mercury and acid gasses. This increase is expected to be followed by new demand in the industrial and liquified natural gas (LNG) export sectors, which both ramp up through the 2020 timeframe. The long-term fundamental gas price outlook continues to be little changed from the previous forecast even though it includes higher overall demand. The North American gas resource picture is a story of unconventional gas production dominating the gas industry. Shale gas now accounts for approximately 97% of net natural gas production today, which has increased from approximately 38% in 2014. As noted earlier, per the Short-Term EIA outlook dated July 10, 2018, the EIA expects dry gas production to average 81.3 Bcf/d by the end of 2018 and rise by an additional 3.1 Bcf/d in 2019 to 84.5 Bcf/d. The United States was a net exporter of natural gas in the first quarter of 2018, with net exports averaging 0.5 Bcf/d. Rising LNG exports and pipeline exports have contributed to a shift from being a net importer of natural gas to an exporter. According to the EIA forecast, the US should have a total liquefaction capacity of 9.6 Bcf/d by the end of 2020.

The US power sector still represents the largest area of potential new gas demand, but increased usage is expected to be somewhat volatile as generation dispatch is sensitive to price. Looking forward, economic dispatch competition is expected to continue between gas and coal, although forward natural gas prices have continued to decline and there has been permanent loss in overall coal generation due to the number of coal unit retirements. Overall declines in energy consumption tend to result from the adoption of more energy-efficient technologies and policies that promote energy efficiency.

In order to ensure adequate natural gas supplies, transportation and storage, the company has gas procurement strategies that include periodic RFPs, market solicitations, and short-term market engagement activities to procure a reliable, flexible, diverse, and competitively priced natural gas supply and transportation portfolio that supports DEC's CC and CT facilities. With respect to storage and transportation needs, the company has continued to add incremental firm pipeline capacity and gas storage as its gas generation fleet as grown.

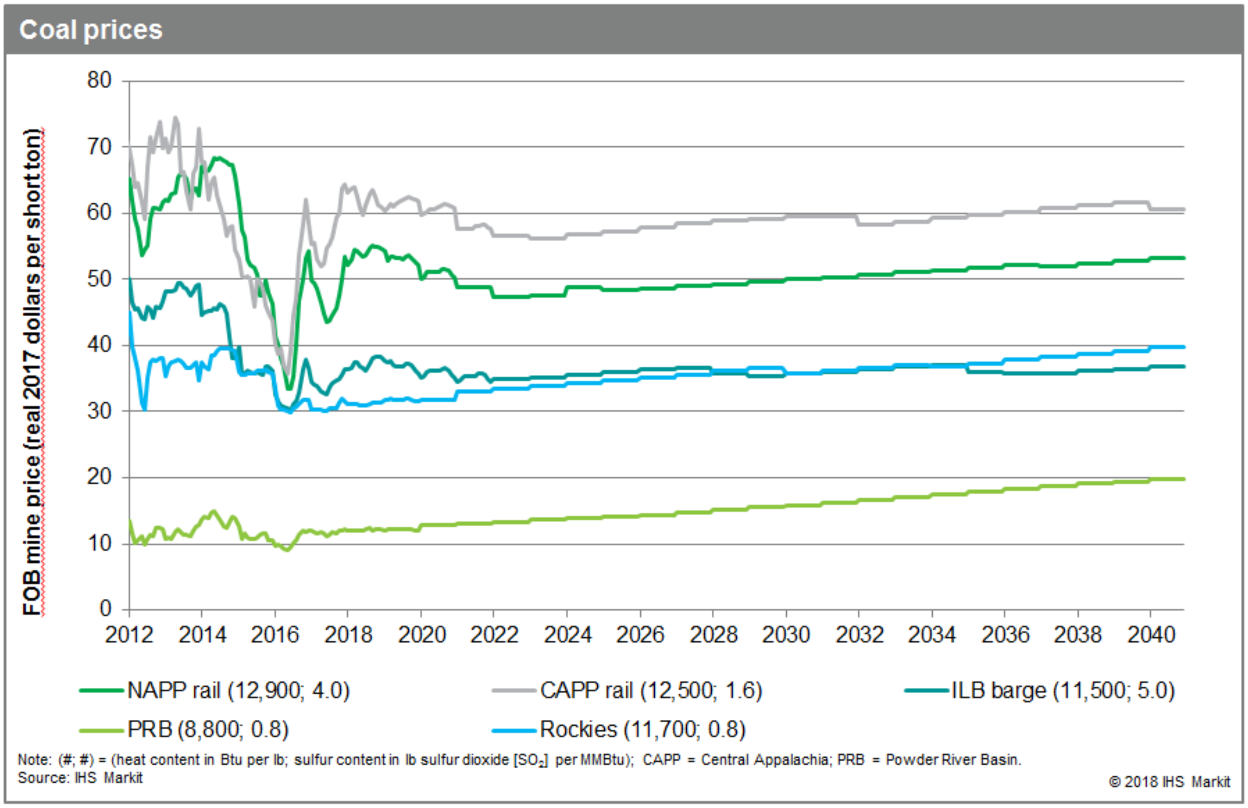
The company will continue to evaluate competitive options to meet its growing need for gas pipeline infrastructure as the gas generation fleet grows.

Coal:

The main determinants for power sector coal demand are electricity demand growth and non-coal electric generation, namely nuclear, gas, hydro and renewables. With electricity demand growth remaining very low, continued steady nuclear and hydro generation, and increasing gas-fired and renewable generation, coal-fired generation continues to be the marginal fuel experiencing declines. According to the EIA, electric power sector demand has been steadily dropping and accounted for 665 million tons (86%) of total demand for coal in 2017. Additionally, projections show continued strong supply and low prices for natural gas which, when combined with the addition of new gas-fired combined cycle generating capacity and new projects to enable gas to be co-fired at coal burning stations, continues to result in reduced, but more volatile, coal burns. Increasing renewable generation, particularly in North Carolina, is also contributing to increased volatility for coal generation.

Coal markets continue to be impacted by a number of factors, including: (1) uncertainty around proposed, imposed, and stayed U.S. Environmental Protection Agency (EPA) regulations for power plants; (2) continued abundant natural gas supply and storage resulting in lower natural gas prices, which has reduced overall coal demand; (3) continued changes in global market demand for both steam and metallurgical coal; (4) uncertainty surrounding regulations for mining operations; and (5) tightening supply as bankruptcies, consolidations and company reorganizations have allowed coal suppliers to restructure and settle into new, lower on-going production levels.

According to IHS Markit, future coal prices for the CAPP, NAPP and ILB coals are expected to be in a steady downward trend until 2022 when they flatten and begin to modestly and steadily rise. Future pricing for Western coals are expected to be steadily rising for the next 20 years.



The U.S. Supreme Court granted a stay, halting implementation of the EPA's Clean Power Plan pending the resolution of legal challenges to the program in court. Though stayed, the fundamental outlook anticipates the eventual implementation of CPP beginning in 2022 which makes coal capacity less desirable, resulting in a long-term decline in power generation from coal. IHS Markit expects 34 GW of coal plant retirements from 2017 to 2020 – with 16.6 GW in 2018 alone, followed by 44 GW from 2021 to 2025, and 23 GW from 2026 to 2030.

One bright spot is coal exports are at historically high levels (low 100 million tons range) which has provided some support for coal producers, but margins have been eroded by increased ocean freight costs and more volatile index pricing. IHS Markit expects US exports to remain strong, and there is additional potential upside if supply does truly tighten. A key to US export growth is low-cost but high-sulfur coal. Certain key markets (primarily India and Europe) have become accustomed to the high sulfur, and the low production costs for efficient long-wall production of these types of coals enables it to compete very well. In addition to the upside from India, Turkey now appears likely to increase the maximum sulfur allowed in its coal plants. This is bullish for NAPP and ILB exports.

The Company continues to maintain a comprehensive coal procurement strategy that has proven successful over the years in limiting average annual fuel price changes while actively managing the dynamic demands of its fossil fuel generation fleet in a reliable and cost-effective manner. Aspects of this procurement strategy include having an appropriate mix of contract and spot purchases for coal, staggering coal contract expirations which thereby limit exposure to market price changes, diversifying coal sourcing as economics warrant, as well as working with coal suppliers to incorporate additional flexibility into their supply contracts. In response to the unpredictable and volatile nature of the demand for coal, the Company has implemented more frequent procurement practices. However, coal inventory levels have dropped and recent experience has shown that producers and transporters of coal are experiencing significant challenges with responding to unexpected periods of increased demand.

Nuclear Fuel:

To provide fuel for Duke Energy's nuclear fleet, the Company maintains a diversified portfolio of natural uranium and downstream services supply contracts from around the world.

Requirements for uranium concentrates, conversion services and enrichment services are primarily met through a portfolio of long-term supply contracts. The contracts are diversified by supplier, country of origin and pricing. In addition, DEC staggers its contracting so that its portfolio of long-term contracts covers the majority of fleet fuel requirements in the near-term and decreasing portions of the fuel requirements over time thereafter. By staggering long-term contracts over time, the Company's purchase price for deliveries within a given year consists of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. Diversifying fuel suppliers reduces the Company's exposure to possible disruptions from any single source of supply. Near-term requirements not met by long-term supply contracts have been and are expected to be fulfilled with spot market purchases.

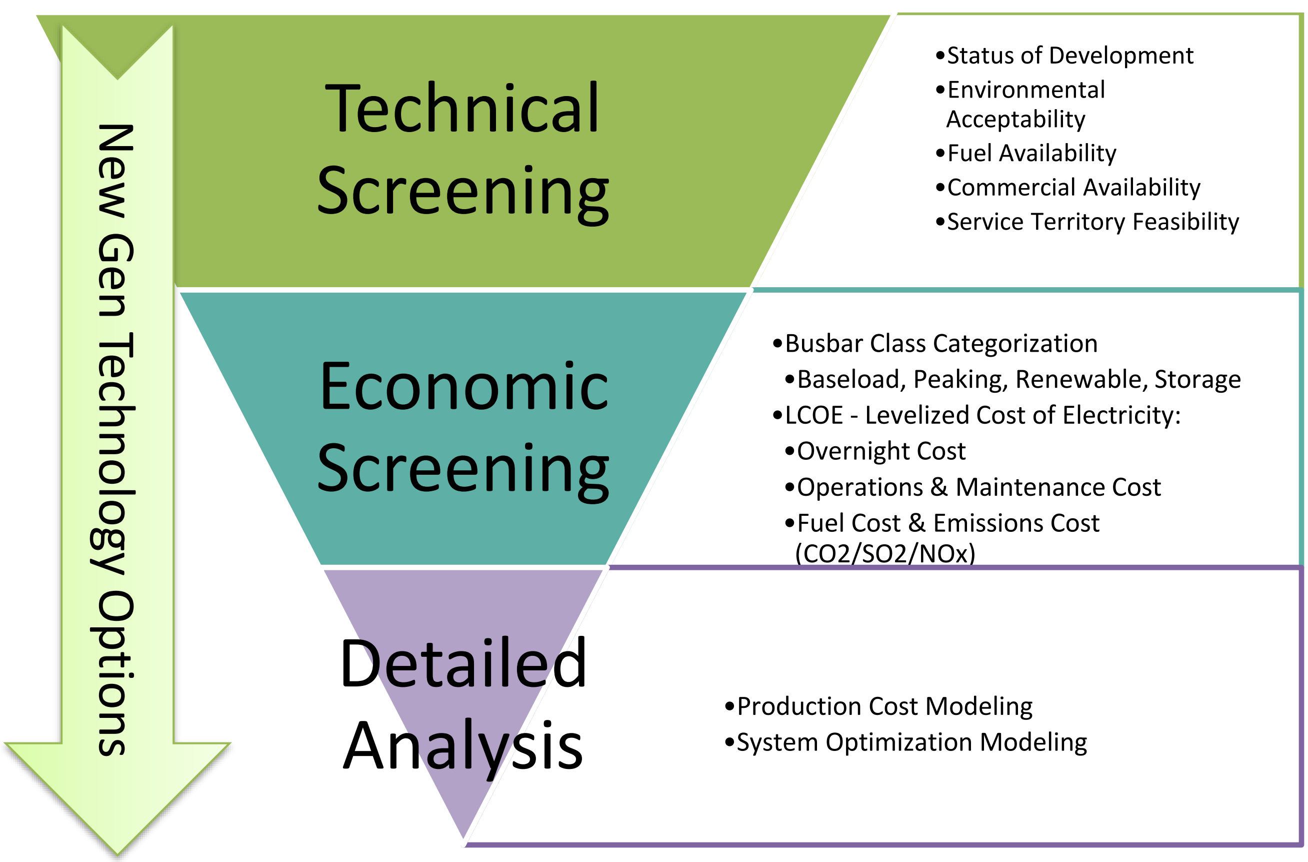
Due to the technical complexities of changing suppliers of fuel fabrication services, DEC generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts. As fuel with a low-cost basis is used and lower-priced legacy contracts are replaced with contracts at higher market prices, nuclear fuel expense is expected to increase in the future. Although the costs of certain components of nuclear fuel are expected to increase in future years, nuclear fuel costs are expected to be competitive with alternate generation and customers will continue to benefit from the Company's diverse generation mix.

APPENDIX F: SCREENING OF GENERATION ALTERNATIVES

The Company screens generation technologies prior to performing detailed analysis in order to develop a manageable set of possible generation alternatives. Generating technologies are screened from both a technical perspective, as well as an economic perspective. In the technical screening, technology options are reviewed to determine technical limitations, commercial availability issues and feasibility in the Duke Energy Carolinas service territory.

Economic screening is performed using relative dollar per kilowatt-year ($/kW-yr) versus capacity factor screening curves. The technologies must be technically and economically viable in order to be passed on to the detailed analysis phase of the IRP process.

Figure F-1: New Generation Technologies Screening Process

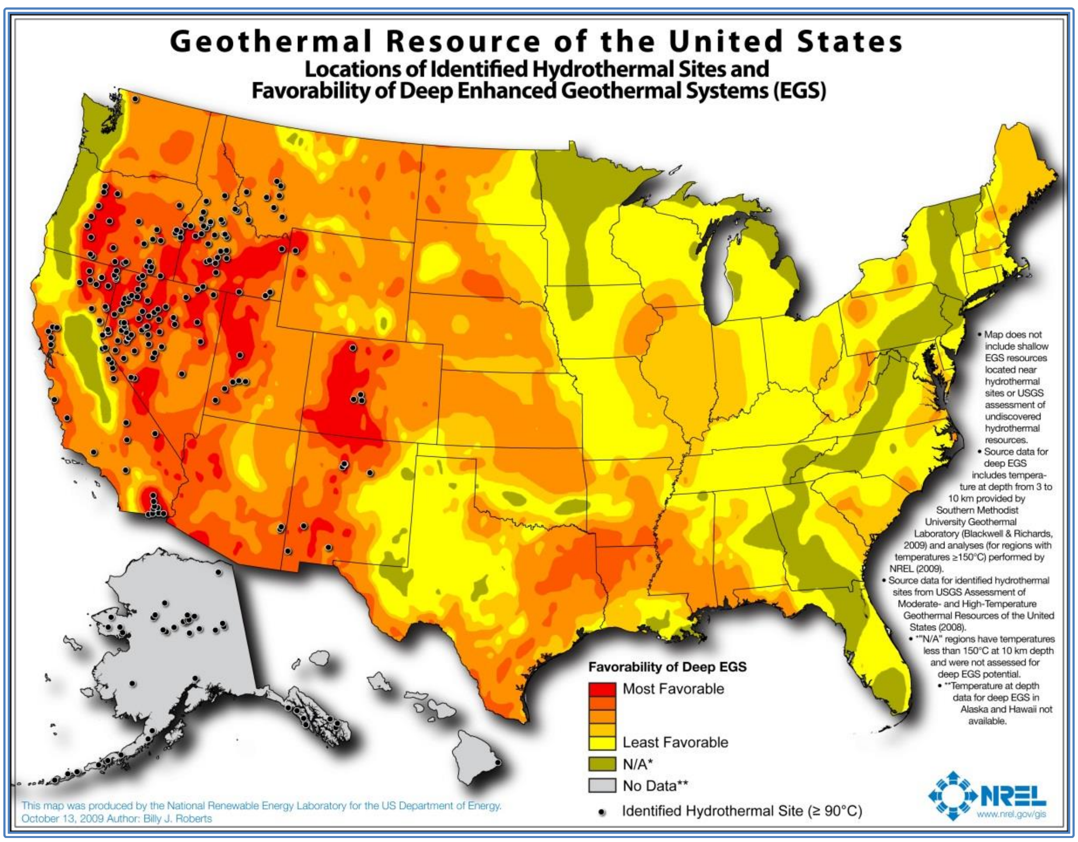


Technical Screening:

The first step in the Company's supply-side screening process for the IRP is a technical screening of the technologies to eliminate those that have technical limitations, commercial availability issues, or are not feasible in the Duke Energy Carolinas service territory. A brief explanation of the technologies excluded at this point and the basis for their exclusion follows:

- **Geothermal** was eliminated because there are no suitable geothermal resources in the region to develop into a power generation project. See Figure F-2, below.

Figure F-2: NREL Geothermal Resource Map of the US.

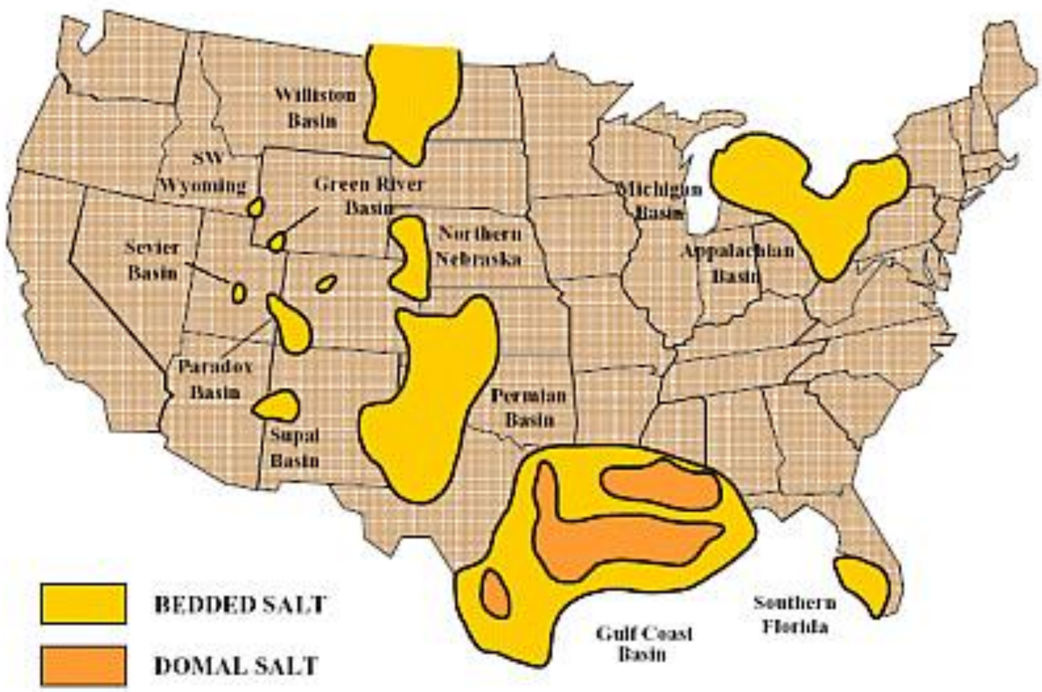


- **Pumped Storage Hydropower (PSH)** is the only conventional, mature, commercial, utility-scale electricity storage option available currently. This technology consumes off-peak electricity by pumping water from a lower reservoir to an upper reservoir.

When the electric grid needs more electricity and when electricity prices are higher, water is released from the upper reservoir. As the water flows from the upper reservoir to the lower reservoir, it goes through a hydroelectric turbine to generate electricity. Many operational pumped storage hydropower plants are providing electric reliability and reserves for the electric grid in high demand situations. PSH can provide a high amount of power because its only limitation is the capacity of the upper reservoir. Typically, these plants can be as large as 4,000 MW, and have an efficiency of 76% - 85% (EPRI, 2012). Therefore, this technology is effective at meeting electric demand and transmission overload by shifting, storing, and producing electricity. This is important because an increasing supply of intermittent renewable energy generation such as solar, will cause challenges to the electric grid. PSH installations are greatly dependent on regional geography and face several challenges including: environmental impact concerns, a long permitting process, and a relatively high initial capital cost. Duke Energy currently has two PSH assets, Bad Creek Reservoir and Jocassee Hydro with an approximate combined generating capacity of 2,140 MW.

- **Compressed Air Energy Storage (CAES)**, although demonstrated on a utility scale and generally commercially available, is not a widely applied technology and remains relatively expensive. Traditional systems require a suitable storage site, commonly underground where the compressed air is used to boost the output of a gas turbine. The high capital requirements for these resources arise from the fact that suitable sites that possess the proper geological formations and conditions necessary for the compressed air storage reservoir are relatively scarce, especially in the Carolinas. However, above-ground compressed air energy storage (AGCAES) technologies are under development but at a much smaller scale, approximately 0.5 – 20 MW. Several companies have attempted to develop cost effective CAES systems using above ground storage tanks. Most attempts to date have not been commercially successful, but their development is being monitored.

Figure F-3: Compressed Air Energy Storage (CAES) - Potential U.S. Salt Cavern Site Depiction, NETL



- **Liquid Air Energy Storage (LAES)** uses electricity to cool air until it liquefies, stores the liquid air in a tank, brings the liquid air back to a gaseous state (by exposure to ambient air or with waste heat from an industrial process) and uses that gas to turn a turbine and generate electricity. Although demonstrated through several pilot projects, the scaling of this technology and the resultant economics is not yet completely understood. As research and pilots continues with LAES, Duke Energy will continue to monitor as the technology offers bulk energy storage without the need for reservoir construction.

- **Small Modular Nuclear Reactors (SMR)** are generally defined as having capabilities of less than 300 MW per reactor. They typically have the capability of grouping a number of reactors in the same location to achieve the desired power generating capacity for a plant. In 2012, the U.S. Department of Energy (DOE) solicited bids for companies to participate in a small modular reactor grant program with the intent to "promote the accelerated commercialization of SMR technologies to help meet the nation's economic energy security and climate change objectives." SMRs continue to gain interest as they contribute no emissions to the atmosphere and, unlike their predecessors, provide flexible operations capabilities, as well as, reduced footprints coupled with inherently safer designs.

NuScale Power is the leader in SMR design and licensing in the US. They recently announced that its small modular reactor will be able to generate 20% more power than originally planned. The increase is from 50 MW to 60 MW for each module (reactor) or 600 MW to 720 MW for a 12-module plant. The increase requires very little additional capital cost so it lowers the projected cost of a 12-module facility by approximately 16% per kilowatt. The approval date for the SMR Design Certification Application (DCA) is September 2020. NuScale will need NRC approval of a revised DCA before SMR customers will be able to take advantage of the additional power.

Other SMR designs under development domestically include the Holtec SMR-160, a 160 MW pressurized water reactor being developed for deployment both in the U.S. and abroad. In addition, GE Hitachi (GEH) recently announced the development of a new SMR, the BWRX300.

While SMRs were "screened out" in the Technical Screening phase of the technology evaluations, they were allowed to be selected as a resource in the System Optimizer (SO) model in order to allow the model to meet the high CO_2 emission constraints in the sensitivity analysis. As a result, SMRs have been depicted on the busbar screening curves as an informative item. Duke Energy will be monitoring the progress of the SMR projects for potential consideration and evaluation for future resource plans as they provide an emission-free, diverse, flexible source of generation.

- **Advanced Reactors** are typically defined as nuclear power reactors employing fuel and/or coolant significantly different from that of current light water reactors (LWRs) and offering advantages related to safety, cost, proliferation resistance, waste management and/or fuel utilization. These reactors are characteristically typed by coolant with the main groups including liquid metal cooled, gas cooled, and molten salt fueled/cooled. There are approximately 25 domestic companies working on one or multiple advanced reactor designs funded primarily by venture capital investment, and even more designs are being considered at universities and national labs across the country. There is also significant interest internationally, with at least as many international companies pursuing their own advanced reactor designs in several countries across the world.

Specifics of the reactor vary significantly by both coolant type and individual designs. The reactors are projected to range in size from the single MW scale to over 1000 MW, with the majority of the designs proposing a modular approach that can scale capacity based on demands. All designs are exploring a flexible deployment approach which could scale power outputs to align with renewable/variable outputs. The first commercially available advanced reactors are targeting the late 2020s for deployment, although most designs are projected to be available in the 2030s. Significant legislative efforts are currently being made to further the development of advanced reactors in both the house and senate at the national level, and new bills continue to be introduced.

Duke Energy has been part of an overall industry effort to further the development of advanced reactors since joining the Nuclear Energy Institute Advanced Reactor Working Group at its formation in early 2015. Additionally, Duke Energy participates on two Advanced Reactor companies' industry boards and has hosted several reactor developers for early design discussions. Duke Energy has also participated in several other industry efforts such as EPRI's Owner-Operator Requirements Document, which outlines requirements and recommendations for Advanced Reactor designs. Duke Energy will continue to allot resources to follow the progress of the advanced reactor community and will provide input to the proper internal constituents as additional information becomes available.

- **Fuel Cells**, although originally envisioned as being a competitor for combustion turbines and central power plants, are now targeted to mostly distributed power generation systems. The size of the distributed generation applications ranges from a few kW to tens of MW in the long-term. Cost and performance issues have generally limited their application to niche markets and/or subsidized installations. While a medium level of research and development continues, this technology is not commercially viable/available for utility-scale application.

- **Supercritical CO_2 Brayton Cycle** is of increasing interest; however, the technology is not mature or ready for commercialization. Several pilots are underway and Duke Energy will continue to monitor their development as a potential source of future generation needs.

- **Poultry waste and swine waste digesters** remain relatively expensive and are often faced with operational and/or permitting challenges. Research, development, and demonstration continue, but these technologies remain generally too expensive or face obstacles that make them impractical energy choices outside of specific mandates calling for use of these technologies. See Appendix D for more information regarding current and planned Duke Energy poultry and swine waste projects.

- **Off-shore Wind**, although demonstrated on a utility scale and commercially available, is not a widely applied technology and not easily permitted in the United States although that trend may be changing. This technology remains expensive even with the five-year tax credit extension granted in December 2015. There are over twenty-five projects in various phases of development in U.S. coastal waters and more are anticipated as technology and construction advancements allow for installation in deeper waters further offshore. The Block Island project developed by Deepwater Wind is the first to reach commercial operation, and Duke Energy Renewables is performing remote monitoring and control services for the project. This 30 MW project is located about 3 miles off the coast of Rhode Island.

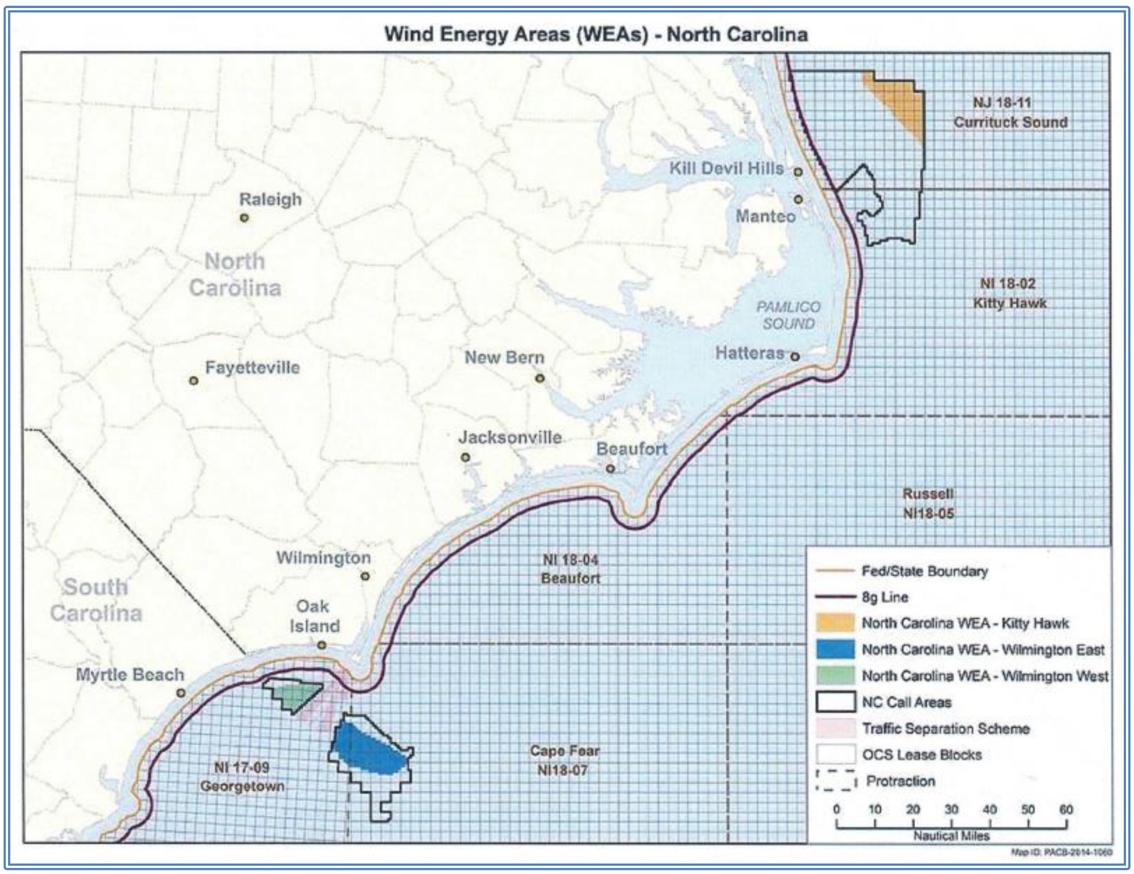
  Duke Energy and NREL studied the potential for offshore integration off the coast of the Carolinas in March 2013. In 2015, the U.S. Bureau of Ocean Energy Management (BOEM) completed environmental assessments at three potential Outer Continental Shelf (OCS) sites off the coast of North Carolina. In March 2017, BOEM administered a competitive lease auction for wind energy in federal waters and awarded Avangrid Renewables the rights to develop an area off the shores of Kitty Hawk. Avangrid has plans for a project that may be as large as 1,500 MW.

  Several coastal states including New York, New Jersey, Maryland, Massachusetts, California, and Hawaii are facilitating industry growth. New York has an Offshore Wind Master Plan aimed at 2,400 MW of offshore projects by 2030, and Statoil is developing the 1,500 MW Empire Wind project near New York City, aiming for completion in 2025.

  The unique constraints of the industry and the increasingly competitive global market are driving R&D improvements that allow wind farms to be sited further offshore. Installation and siting require careful consideration to bathymetry and offshore construction concerns, but siting is further complicated by shipping lanes, fishing rights, wildlife migration patterns, military operations, and other environmental concerns. Plus, coastal residents and tourists prefer an unobstructed ocean view, so the larger turbines require longer distances to keep them out of sight.

Industry leaders are working to define equipment and installation standards and codes. They are coordinating with the oil and gas industry to improve construction processes and working with the telecommunications industry to advance submarine cable technologies. Improved foundation designs are helping to reduce installation time and costs, and floating designs are being tested for deployment in deep waters.

Figure F-4: NC Wind Energy Areas (WEAs) (developed in joint venture by Duke Energy and NREL)



- **Solar Steam Augmentation** systems utilize solar thermal energy to supplement a Rankine steam cycle such as that in a fossil generating plant. The supplemental steam could be integrated into the steam cycle and support additional MW generation similar in concept to the purpose of duct firing a heat recovery steam generator. This technology, although attractive has several hurdles yet to clear, including a clean operating history and initial capital cost reductions. This technology is very site specific and Duke Energy will continue to monitor developments in the area of steam augmentation.

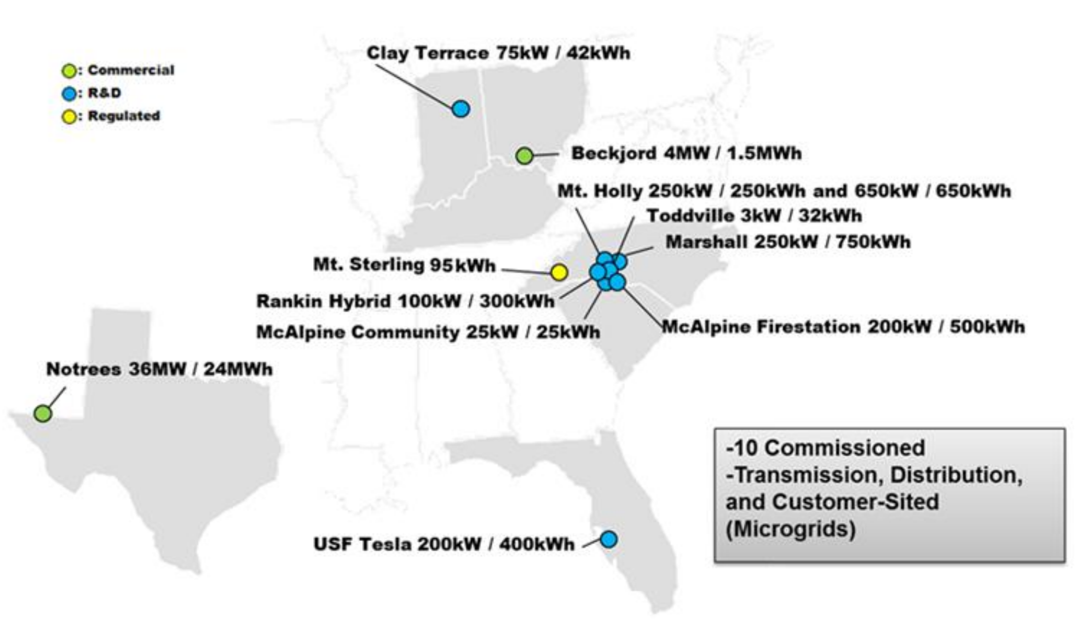
A brief explanation of the technology additions for 2018 and the basis for their inclusion follows:

- **Addition of Battery Storage Options to the IRP**

  Energy storage solutions are becoming a viable tool in support of grid stability at peak demand times and in support of energy shifting and smoothing from renewable sources. Energy Storage in the form of battery storage is becoming more feasible with the advances in battery technology (Tesla Lithium-ion battery technology) and the reduction in battery cost; however, their uses (even within Duke Energy) have been concentrated on frequency regulation, solar smoothing, and/or energy shifting from localized renewable energy sources with a high incidence of intermittency (i.e. solar and wind applications). In order to generically evaluate the potential value of a generation-connected battery storage system an unencumbered battery dedicated to capacity and energy services will be utilized for screening purposes. *Encumbrances* to the battery are other uses which may limit, or even eliminate the battery system's ability to provide capacity and energy storage services. These encumbrances may include (but are not limited to) frequency response, asset deferral, back-up power, black start, ancillary services, etc. Duke Energy recognizes the potential benefits that battery connected systems can provide, especially at the Transmission & Distribution level which resides outside the scope of this IRP. Evaluation of potential T&D benefits, along with other uses that can be "stacked" with these T&D benefits, are being assessed on a case-by-case basis at this time through pilot projects.

  Duke Energy has several projects in operation since 2011, mainly in support of regulating output voltages/frequencies from renewable energy sources to the grid. Each of these applications supports frequency regulation, solar smoothing, or energy shifting from a local solar array. See Figure F-5, below for a depiction of the existing, operational battery energy storage assets.

Figure F-5: Existing, Operational Duke Energy Battery Storage Assets



These examples are only a few in support of a growing trend of coupling Battery Storage with an intermittent renewable energy source such as solar or wind in an effort to stabilize output and increase a facility's (renewable plus storage) net capacity factor.

Battery Briefing:

Electrochemical energy storage systems utilize chemical reactions within a battery cell to facilitate electron flow, converting electrical energy to chemical energy when charging and generating an electric current when discharged. Electrochemical technology is continually developing as one of the leading energy storage and load following technologies due to its modularity, ease of installation and operation, and relative design maturity. Development of electrochemical batteries has shifted into three categories, commonly termed “flow,” “conventional,” and “high temperature” battery designs. Each battery type has unique features yielding specific advantages compared to one another.

A **conventional battery** contains a cathodic and an anodic electrode and an electrolyte sealed within a cell container than can be connected in series to increase overall facility storage and output. During charging, the electrolyte is ionized such that when discharged, a reduction-oxidation reaction occurs, which forces electrons to migrate from the anode to the cathode thereby generating electric current. Batteries are designated by the electro-chemicals utilized within the cell; the most popular conventional batteries are lead acid and lithium ion type batteries.

Lead acid batteries are the most mature and commercially accessible battery technology, as their design has undergone considerable development since conceptualized in the late 1800s. The Department of Energy (DOE) estimates there is approximately 110 MW of lead acid battery storage currently installed worldwide. Although lead acid batteries require relatively low capital cost, this technology also has inherently high maintenance costs and handling issues associated with toxicity, as well as low energy density (yields higher land and civil work requirements). Lead acid batteries also have a relatively short life cycle at 5 to 10 years, especially when used in high cycling applications.

Lithium ion (Li-ion) batteries contain graphite and metal-oxide electrodes and lithium ions dissolved within an organic electrolyte. The movement of lithium ions during cell charge and discharge generates current. Li-ion technology has seen a resurgence of development in recent years due to its high energy density, low self-discharge, and cycling tolerance. Many Li-ion manufacturers currently offer 15-year warranties or performance guarantees. Consequently, Li- ion has gained traction in several markets including the utility and automotive industries.

Li-ion battery prices are trending downward, and continued development and investment by manufacturers are expected to further reduce production costs. While there is still a wide range of project cost expectations due to market uncertainty, Li-ion batteries are anticipated to expand their reach in the utility market sector. At present, Li-ion Battery Technology is the only battery technology considered for the 2018 IRP.

Flow batteries utilize an electrode cell stack with externally stored electrolyte material. The flow battery is comprised of positive and negative electrode cell stacks separated by a selectively permeable ion exchange membrane, in which the charge-inducing chemical reaction occurs, and liquid electrolyte storage tanks, which hold the stored energy until discharge is required. Various control and pumped circulation systems complete the flow battery system in which the cells can be stacked in series to achieve the desired voltage difference.

The battery is charged as the liquid electrolytes are pumped through the electrode cell stacks, which serve only as a catalyst and transport medium to the ion-inducing chemical reaction. The excess positive ions at the anode are allowed through the ion-selective membrane to maintain electroneutrality at the cathode, which experiences a buildup of negative ions. The charged electrolyte solution is circulated back to storage tanks until the process is allowed to repeat in reverse for discharge as necessary.

In addition to external electrolyte storage, flow batteries differ from traditional batteries in that energy conversion occurs as a direct result of the reduction-oxidation reactions occurring in the electrolyte solution itself. The electrode is not a component of the electrochemical fuel and does not participate in the chemical reaction. Therefore, the electrodes are not subject to the same deterioration that depletes electrical performance of traditional batteries, resulting in high cycling life of the flow battery. Flow batteries are also scalable such that energy storage capacity is determined by the size of the electrolyte storage tanks, allowing the system to approach its theoretical energy density. Flow batteries are typically less capital intensive than some conventional batteries but require additional installation and operation costs associated with balance of plant equipment.

High temperature batteries operate similarly to conventional batteries, but they utilize molten salt electrodes and carry the added advantage that high temperature operation can yield heat for other applications simultaneously. The technology is considered mature with ongoing commercial development at the grid level. The most popular and technically developed high temperature option is the Sodium Sulfur (NaS) battery. Japan-based NGK Insulators, the largest NaS battery manufacturer, installed a 4 MW system in Presidio, Texas in 2010 following operation of systems totaling more than 160 MW since the project's inception in the 1980s.

The NaS battery is typically a hermetically sealed cell that consists of a molten sulfur electrolyte at the cathode and molten sodium electrolyte at the anode, separated by a Beta-alumina ceramic membrane and enclosed in an aluminum casing. The membrane is selectively permeable only to positive sodium ions, which are created from the oxidation of sodium metal and pass through to combine with sulfur resulting in the formation of sodium polysulfides. As power is supplied to the battery in charging, the sodium ions are dissociated from the polysulfides and forced back through the membrane to re-form elemental sodium. The melting points of sodium and sulfur are approximately 98 ^{o}C and 113 ^{o}C, respectively. To maintain the electrolytes in liquid form and for optimal performance, the NaS battery systems are typically operated and stored at around 300 ^{o}C, which results in a higher self-discharge rate of 14% to 18%. For this reason, these systems are usually designed for use in high-cycling applications and longer discharge durations.

NaS systems are expected to have an operable life of approximately 15 years and are one of the most developed chemical energy storage technologies. However, unlike other battery types, costs of NaS systems have historically held, making other options more commercially viable at present.

Generation Flexibility:

As more intermittent generation becomes associated with Duke's system, the greater need there may be for generation that has rapid load shifting and ancillary support capabilities. This generation would need to be dispatchable, possess desirable capacity, and ramp at a desired rate. Some of the technologies that have 'technically' screened in possess these qualities or may do so in the near future. Effort is being made to value the characteristics of flexibility and quantify that value to the system. As a result of the flexible generation need, some features of 'generic' plant's base designs have been modified to reflect the change in cost and performance to accomplish a more desired plant characteristic to diminish the impact of the intermittent generation additions.

Economic Screening:

The Company screens all technologies using relative dollar per kilowatt-year ($/kW-yr) versus capacity factor screening curves, also referred to as *busbar* curves. By definition, the *Busbar* curve estimates the revenue requirement (i.e. life-cycle cost) of power from a supply option at the "busbar," the point at which electricity leaves the plant (i.e. the high side of the step-up transformer). Duke Energy provides some additional evaluation of a generic transmission and/or interconnection cost adder associated with each technology.

The screening within each general class of busbar (Baseload, Peaking/Intermediate, Renewables and Storage), as well as the final screening across the general classes uses a spreadsheet-based screening curve model developed by Duke Energy. This model is considered proprietary, confidential and competitive information by Duke Energy. For the 2018 IRP year, Duke Energy has provided an additional busbar to represent Storage technology comparisons. As Storage technologies are not traditional generating resource options, they should be compared independently from generating resources. In addition, there has been no *charging* cost associated with the storage busbar buildup. This charging cost is excluded as it is dependent upon what the next marginal unit is in the dispatch stack as to what would be utilized to "charge" the storage resource. For resource options inclusive of or coupled with storage, it is assumed that the storage resource is being directly charged by the generating resource (i.e. Solar PV plus Battery Storage option).

This screening (busbar) curve analysis model includes the total costs associated with owning and maintaining a technology type over its lifetime and computes a levelized $/kW-year value over a range of capacity factors. The Company repeats this process for each supply technology to be screened resulting in a family of lines (curves). The lower envelope along the curves represents the least costly supply options for various capacity factors or unit utilizations. Some technologies have screening curves limited to their expected operating range on the individual graphs. Lines that never become part of the lower envelope, or those that become part of the lower envelope only at capacity factors outside of their relevant operating ranges, have a very low probability of being part of the least cost solution, and generally can be eliminated from further analysis.

The Company selected the technologies listed below for the screening curve analysis. While Clean Power Plan (CPP) regulation may effectively preclude new coal-fired generation, Duke Energy Carolinas has included ultra-supercritical pulverized coal (USCPC) with carbon capture sequestration (CCS) and integrated gasification combined cycle (IGCC) technologies with CCS of 1400 pounds/net MWh capture rate as options for base load analysis consistent with the pending version of the EPA Clean Power Plan for new coal plants. Additional detail on the expected impacts from EPA regulations to new coal-fired options is included in Appendix G. 2018 additions include Solar PV plus Battery Storage, additional Lithium ion Battery Storage options, and Pumped Storage Hydro as a renewable technology.

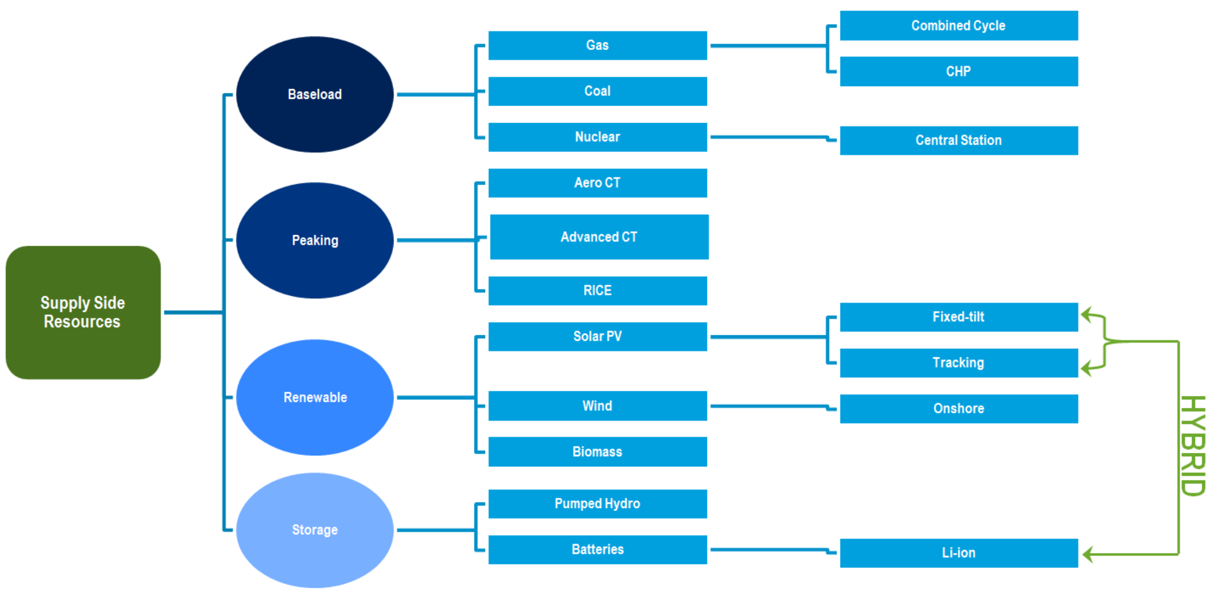
Dispatchable (Winter Ratings)

- 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 – 667 MW – 1x1x1 Advanced Combined Cycle (No Inlet Chiller and Fired)
- Base load – 1,339 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 – 600 MW – Small Modular Reactor (SMR)
- Peaking/Intermediate – 196 MW 4 x LM6000 Combustion Turbines (CTs)
- Peaking/Intermediate – 202 MW, 12 x Reciprocating Engine Plant
- Peaking/Intermediate – 574 MW 2 x G/H-Class Combustion Turbines (CTs)
- Peaking/Intermediate – 754 MW 2 x J-Class Combustion Turbines (CTs)
- Peaking/Intermediate – 919 MW 4 x 7FA.05 Combustion Turbines (CTs)
- Storage – 5 MW / 5 MWh Li-ion Battery
- Storage – 20 MW / 80 MWh Li-ion Battery
- Storage – 1,400 MW Pumped Storage Hydro (PSH)
- Renewable – 2 MW Solar PV plus 2 MW / 8 MWh Li-ion Battery
- Renewable – 75 MW Wood Bubbling Fluidized Bed (BFB, biomass)
- Renewable – 5 MW Landfill Gas

Non-Dispatchable (Nameplate)

- Renewable – 150 MW Wind - On-Shore
- Renewable – 50 MW Solar PV, Fixed-tilt (FT)
- Renewable – 50 MW Solar PV, Single Axis Tracking (SAT)

Figure F-6: Duke Energy, Screened-In Supply Side Resource Alternatives



Information Sources:

The cost and performance data for each technology being screened is based on research and information from several sources. These sources include, but may not be limited to the following internal Departments: Duke Energy's Project Management and Construction, Emerging Technologies, and Generation and Regulatory Strategy. The following external sources may also be utilized: proprietary third-party engineering studies, the Electric Power Research Institute (EPRI) Technical Assessment Guide (TAG®), and Energy Information Administration (EIA). In addition, fuel and operating cost estimates are developed internally by Duke Energy, or from other sources such as those mentioned above, or a combination of the two. EPRI information or other information or estimates from external studies are not site-specific, but generally reflect the costs and operating parameters for installation in the Carolinas. Finally, every effort is made to ensure that capital, operating and maintenance costs (O&M), fuel costs and other parameters are current and include similar scope across the technologies being screened. The supply-side screening analysis uses the same fuel prices for coal and natural gas, and NO_x, SO_2, and CO_2 allowance prices as those utilized downstream in the detailed analysis (discussed in Appendix A). Screening curves were developed for each technology to show the economics with and without carbon costs (i.e. No CO_2, With CO_2) in the four major categories defined (Baseload, Peaking/Intermediate, Renewables, Storage).

Screening Results:

The results of the screening within each category are shown in the figures below. Results of the baseload screening show that natural gas combined cycle generation is the least-cost base load resource. With lower gas prices, larger capacities and increased efficiency, natural gas combined cycle units have become more cost-effective at higher capacity factors in all carbon scenario screening cases (i.e. No CO_2, With CO_2). Although CHP can be competitive with CC, it is site specific, requiring a local steam and electrical load. The baseload curves also show that projected SMR nuclear generation may be a cost-effective option at high capacity factors with CO_2 costs included. Carbon capture systems have been demonstrated to reduce coal-fired CO_2 emissions to levels similar to natural gas and will continue to be monitored as they mature; however, their current cost and uncertainty of safe, reliable storage options has limited the technical viability of this technology in Duke Energy territories.

The peaking technology screening included F-frame combustion turbines, fast start aero-derivative combustion turbines, and fast start reciprocating engines. The screening curves show the F-frame CTs to be the most economic peaking resource unless there is a special application that requires the fast start capability of the aero-derivative CTs or reciprocating engines. Reciprocating engine plants offer the lowest heat rates and fastest start times among simple cycle options. Simple cycle aeroderivative gas turbines remain in close contention with reciprocating engines. Should a need be identified for one of these two types of resources, a more in-depth analysis would be performed.

The renewable screening curves show solar is a more economical alternative than wind and landfill gas generation. Solar and wind projects are technically constrained from achieving high capacity factors making them unsuitable for intermediate or baseload duty cycles. Landfill gas and biomass projects are limited based on site availability but are dispatchable. Solar projects, like wind, are not dispatchable and therefore less suited to provide consistent peaking capacity/energy. Aside from their technical limitations, solar and wind technologies are not currently economically competitive generation technologies without State and Federal subsidies. These renewable resources do play an important role in meeting the Company's NC REPS requirements and sustainability initiatives.

Centralized generation, as depicted above, will remain the backbone of the grid for Duke Energy in the near term; however, in addition it is likely that distributed generation and storage (see ISOP discussions) will begin to share more and more grid responsibilities over time as technologies such as energy storage increase our grid's flexibility and tolerance for intermittent, distributed resources.

The screening curves are useful for comparing costs of resource types at various capacity factors but cannot be solely utilized for determining a long-term resource plan because future units must be optimized with an existing system containing various resource types. Results from the screening curve analysis provide guidance for the technologies to be further considered in the more detailed quantitative analysis phase of the planning process.

Capital Cost Forecast:

A capital cost forecast was developed with support from a third party to project not only Renewables and Battery Storage capital costs, but the costs of all resource technologies technically screened in. The Technology Forecast Factors were sourced from the Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2017 which provides costs projections for various technologies through the planning period as an input to the National Energy Modeling System (NEMS) utilized by the EIA for the AEO.

Using 2018 as a base year, an "annual forecast factor is calculated based on the macroeconomic variable tracking the metals and metal products producer price index, thereby creating a link between construction costs and commodity prices." (NEMS Model Documentation 2016, July 2017)

From *NEMS Model Documentation 2016, July 2017*:

"*Uncertainty about investment costs for new technologies is captured in the Electric Capacity Planning module of NEMS (ECP) using technological optimism and learning factors.*

- *The technological optimism factor reflects the inherent tendency to underestimate costs for new technologies. The degree of technological optimism depends on the complexity of the engineering design and the stage of development. As development proceeds and more data* *become available, cost estimates become more accurate and the technological optimism factor declines.*

- *Learning factors represent reductions in capital costs due to learning-by-doing. Learning factors are calculated separately for each of the major design components of the technology. For new technologies, cost reductions due to learning also account for international experience in building generating capacity. Generally, overnight costs for new, untested components are assumed to decrease by a technology specific percentage for each doubling of capacity for the first three doublings, by 10% for each of the next five doublings of capacity, and by 1% for each further doubling of capacity. For mature components or conventional designs, costs decrease by 1% for each doubling of capacity."*

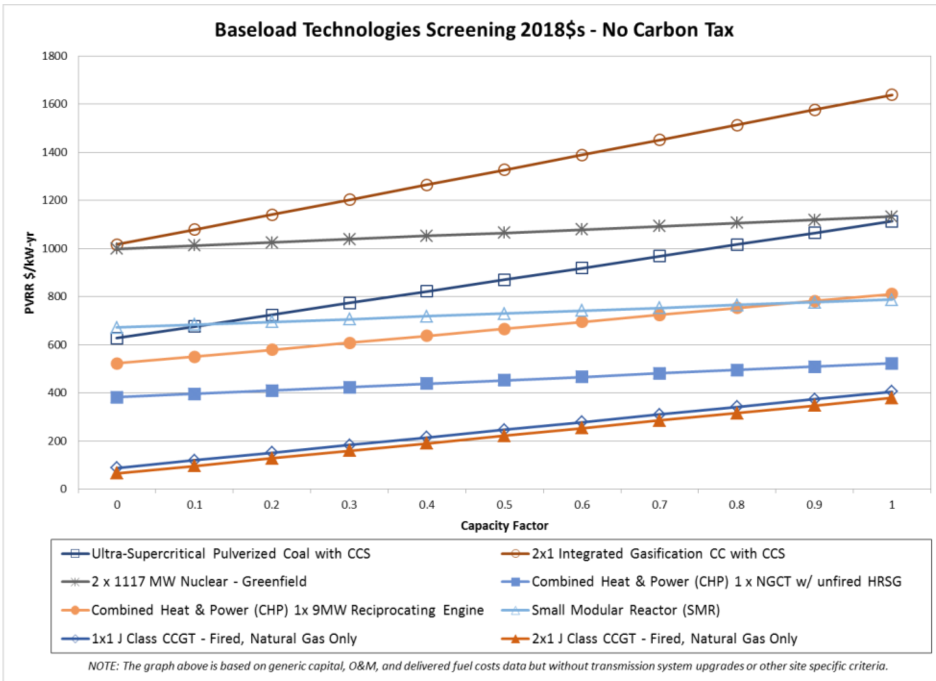
The resulting Forecast Factor Table developed from the EIA technology maturity curves for each corresponding technology screened is depicted in Table F-1. A third-party vendor assisted in the alignment of the technologies screened to their representative forecast factors available from the EIA for technologies not captured by the EIA. Examples of this include Reciprocating Internal Combustion Engines (RICE), Battery Storage, and gas turbine technology configurations among others.

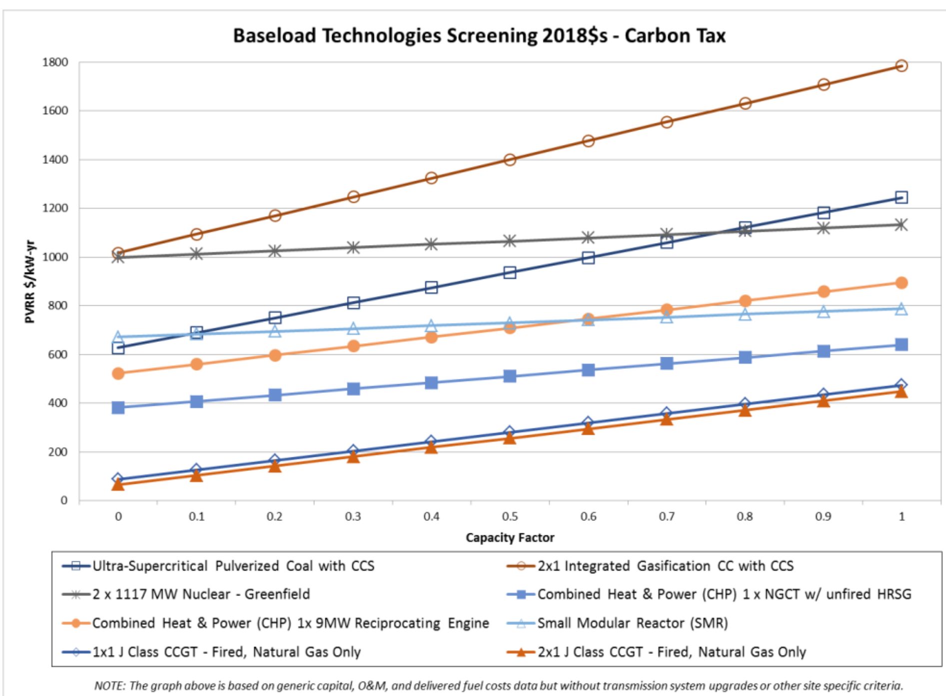
Table F-1: Snip from Forecast Factor Table by Technology (EIA - AEO 2017)

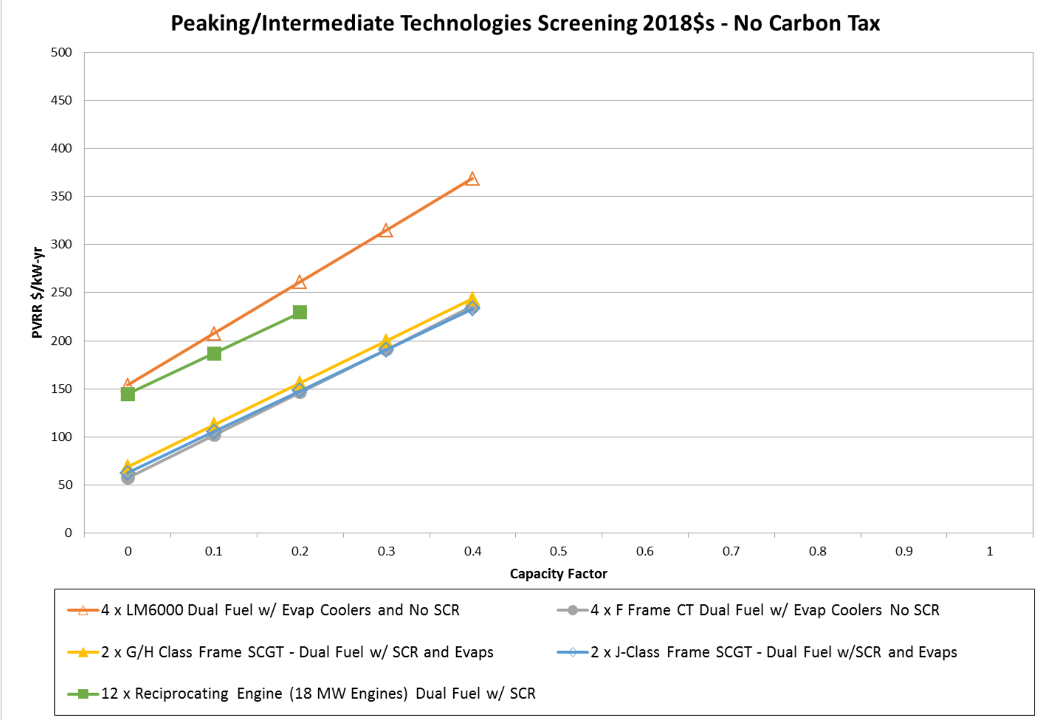
Year	Aero CT	F Class Frame CT	J Class Frame CT	RICE	Onshore Wind	1x1 J Class Combined Cycle	2x1 J Class Combined Cycle
2018	1.000	1.000	1.000	1.000	1.000	1.000	1.000
2019	0.996	0.995	0.995	0.996	0.996	0.995	0.995
2020	0.993	0.990	0.990	0.993	0.993	0.991	0.990
2021	0.989	0.984	0.984	0.989	0.989	0.986	0.984
2022	0.983	0.978	0.978	0.983	0.983	0.980	0.978
2023	0.974	0.967	0.967	0.974	0.974	0.970	0.967
2024	0.965	0.957	0.957	0.965	0.965	0.960	0.957
2025	0.954	0.942	0.942	0.954	0.954	0.947	0.942
2026	0.941	0.920	0.920	0.941	0.941	0.928	0.920
2027	0.928	0.902	0.902	0.928	0.928	0.913	0.902
2028	0.918	0.877	0.877	0.918	0.918	0.894	0.877
2029	0.910	0.859	0.859	0.910	0.910	0.879	0.859
2030	0.901	0.840	0.840	0.901	0.901	0.864	0.840
2031	0.892	0.827	0.827	0.892	0.892	0.853	0.827
2032	0.884	0.815	0.815	0.884	0.884	0.842	0.815

Screening Curves:

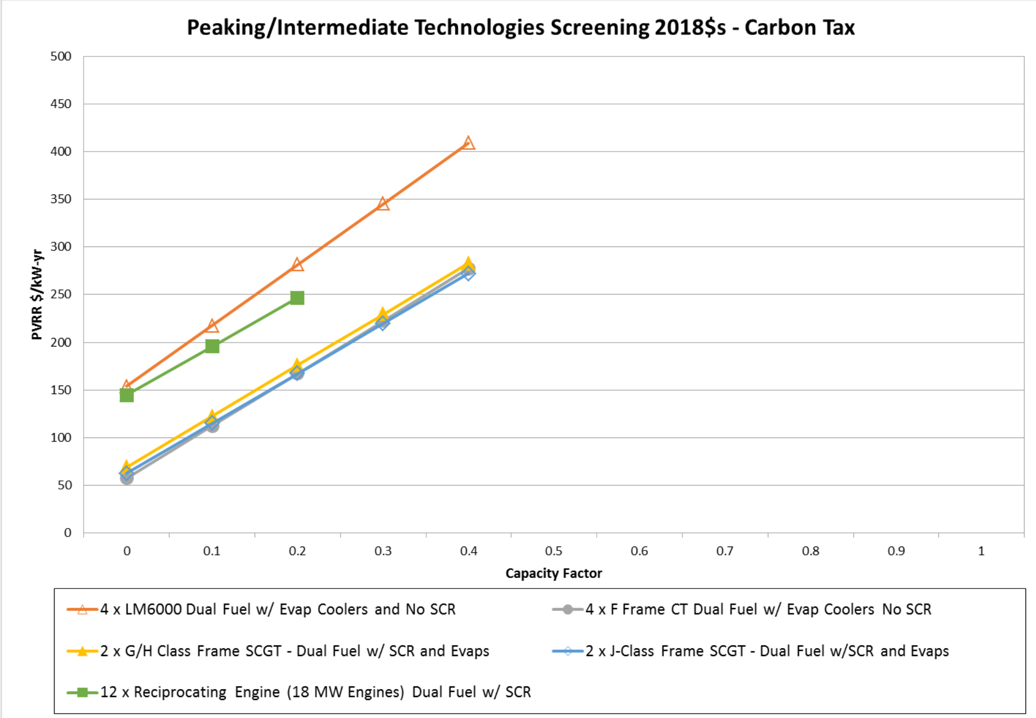
The following pages contains the technology screening curves for baseload, peaking/intermediate, renewable and storage technologies.



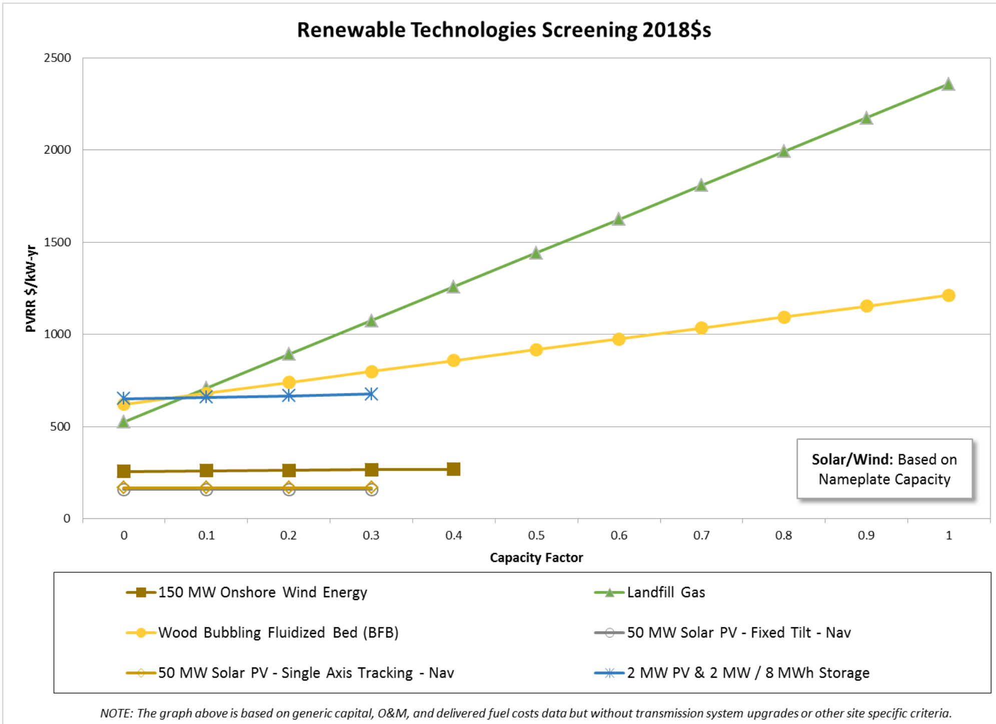


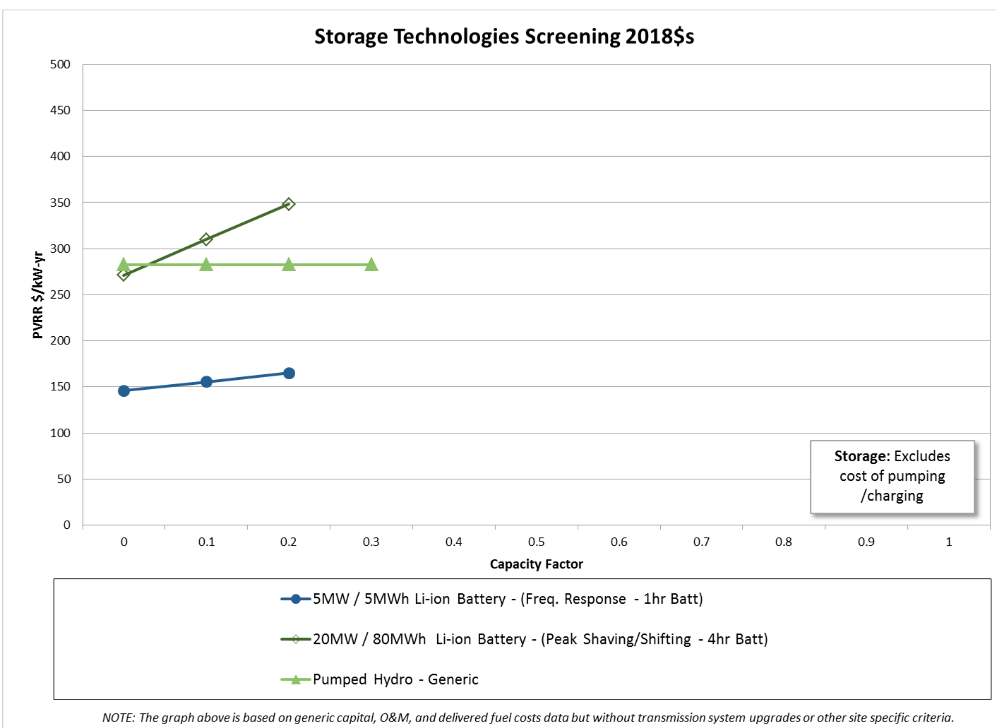


NOTE: The graph above is based on generic capital, O&M, and delivered fuel costs data but without transmission system upgrades or other site specific criteria.



NOTE: The graph above is based on generic capital, O&M, and delivered fuel costs data but without transmission system upgrades or other site specific criteria.


Renewable Technologies Screening 2018$s
PVRR $/kW-yr
2500
2000
1500
1000
500
0
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Capacity Factor
Solar/Wind: Based on Nameplate Capacity
150 MW Onshore Wind Energy
Landfill Gas
Wood Bubbling Fluidized Bed (BFB)
50 MW Solar PV - Fixed Tilt - Nav
50 MW Solar PV - Single Axis Tracking - Nav
2 MW PV & 2 MW / 8 MWh Storage
NOTE: The graph above is based on generic capital, O&M, and delivered fuel costs data but without transmission system upgrades or other site specific criteria.


Storage Technologies Screening 2018$s
PVRR $/kW-yr
500
450
400
350
300
250
200
150
100
50
0
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Capacity Factor
Storage: Excludes cost of pumping /charging
5MW / 5MWh Li-ion Battery - (Freq. Response - 1hr Batt)
20MW / 80MWh Li-ion Battery - (Peak Shaving/Shifting - 4hr Batt)
Pumped Hydro - Generic
NOTE: The graph above is based on generic capital, O&M, and delivered fuel costs data but without transmission system upgrades or other site specific criteria.

APPENDIX G: ENVIRONMENTAL COMPLIANCE

Duke Energy Carolinas, which is subject to the jurisdiction of Federal agencies including the Federal Energy Regulatory Commission, EPA, and the NRC, as well as State commissions and agencies, is potentially impacted by State and Federal legislative and regulatory actions. This section provides a high-level description of several issues Duke Energy Carolinas is actively monitoring or engaged in that could potentially influence the Company's existing generation portfolio and choices for new generation resources.

Air Quality:

Duke Energy Carolinas is required to comply with numerous State and Federal air emission regulations, including the Cross-State Air Pollution Rule NO_X and SO_2 cap-and-trade program, the Mercury and Air Toxics Standards (MATS) rule, and the 2002 North Carolina Clean Smokestacks Act (NC CSA).

As a result of complying with the NC CSA, Duke Energy Carolinas reduced SO_2 emissions by approximately 96% from 2000 to 2017. The law also required additional reductions in NO_X emissions beyond Federal requirements, and Duke Energy Carolinas has achieved an overall reduction of 88% from 1997 to 2017. This landmark legislation, which was passed by the North Carolina General Assembly in June of 2002, calls for some of the lowest state-mandated emission levels in the nation, and was passed with Duke Energy Carolinas' input and support.

The following is a summary of the major air related federal regulatory programs that are currently impacting or that could impact Duke Energy Carolinas operations in North Carolina.

Cross-State Air Pollution Rule (CSAPR):

In August 2011, EPA finalized the Cross-State Air Pollution Rule. The CSAPR established state-level caps on annual SO_2 and NOx emissions and ozone season NOx emissions from electric generating units (EGUs) across the Eastern U.S., including North Carolina. The CSAPR was set up as a two-phase program with Phase I taking effect in 2012 and Phase II taking effect in 2014. Legal challenges to the rule resulted in Phase I implementation being delayed until 2015 and Phase II implementation being delayed until 2017. Duke Energy Carolinas complied with Phase I of the CSAPR and with the Phase II annual programs beginning in 2017.

The CSAPR ozone season NOx program was designed to address interstate transport for the 80 parts per billion (ppb) ozone standard that was established in 1997. In 2008 the EPA lowered the ozone standard to 75 ppb. In September 2016 EPA published the CSAPR Update Rule to revise Phase II of the CSAPR ozone season NOx program to address interstate transport for the 75 ppb standard. EPA did not include North Carolina in the CSAPR Update rule, stating that the state is not linked to any downwind nonattainment or maintenance receptors for the seasonal ozone standard. Beginning in 2017, Duke Energy Carolinas plants are not subject to any CSAPR ozone season NOx emission limitations.

Mercury and Air Toxics Standards (MATS) Rule:

In February 2012 EPA finalized the MATS rule to regulate emissions of mercury and other hazardous air pollutants from coal-fired EGUs. The rule established unit-level emission limits for mercury, acid gases, and non-mercury metals. Compliance with the emission limits was required by April 16, 2015, or April 16, 2016 if the state permitting authority granted up to a 1-year compliance extension. Duke Energy Carolinas is complying with all rule requirements.

National Ambient Air Quality Standards (NAAQS):

8-Hour Ozone NAAQS:

In October 2015, EPA finalized a revision to the 8-Hour Ozone NAAQS, lowering it from 75 to 70 ppb. EPA finalized area designations for the 2015 ozone standard in late 2017 and early 2018. EPA did not designate any nonattainment areas in North Carolina.

The 70 ppb ozone standard is being challenged in court by numerous parties. Some are challenging the standard as being too low, while others are challenging the standard as not being low enough. Duke Energy Carolinas cannot predict the outcome of the litigation or assess the potential impact of the lower standard on future operations in North Carolina at this time.

SO_2 NAAQS:

On June 22, 2010, EPA finalized a rule establishing a 75 ppb 1-hour SO_2 NAAQS. Since then, EPA has completed two rounds of area designations, neither of which resulted in any areas in North Carolina being designated nonattainment.

In August 2015, the EPA finalized its Data Requirements Rule which established requirements for state air agencies to characterize SO_2 air quality levels around certain EGUs using ambient air quality monitoring or air quality modeling. The Data Requirements Rule also laid out the timeline for state air agencies to complete air quality characterizations and submit the information to EPA, and for EPA to finalize area designations.

The North Carolina Department of Environmental Quality provided air quality modeling to EPA to characterize SO_2 air quality around the Duke Energy Carolinas Belews Creek, Marshall, and Allen stations. Based on these modeling analyses, EPA formally designated the areas surrounding these three stations as “attainment/unclassifiable” in 2017.

On June 8, 2018, after the five-year review required under the Clean Air Act, EPA proposed to retain the 2010 SO_2 NAAQS.

Fine Particulate Matter ($PM_{2.5}$) NAAQS:

On December 14, 2012, the EPA finalized a rule establishing a 12 microgram per cubic meter annual $PM_{2.5}$ NAAQS. The EPA finalized area designations for this standard in December 2014. That designation process did not result in any areas in North Carolina being designated nonattainment.

Greenhouse Gas Regulation:

On August 3, 2015, the EPA finalized a rule establishing CO_2 new source performance standards for coal and natural gas combined cycle EGUs that initiated or that initiates construction after January 8, 2014. The EPA finalized emission standards of 1,400 lb CO_2 per gross MWh of electricity generation for coal units and 1,000 lb CO_2 per gross MWh for NGCC units. The standard for coal units can only be achieved with carbon capture and sequestration technology. Duke Energy Carolinas views the EPA rule as barring the development of new coal-fired generation because CCS is not a demonstrated and available technology for applying to coal units. Duke Energy Carolinas considers the standard for NGCC units to be achievable. Numerous parties have filed petitions with the U.S. Court of Appeals for the District of Columbia (D.C. Circuit) challenging the EPA’s final emission standard for new coal units. On March 28, 2017, President Trump signed an executive order directing EPA to review the rule and determine whether to suspend, revise or rescind it. On the same day, the Department of Justice (DOJ) filed a motion with the D.C. Circuit Court requesting that the court stay the litigation of the rule while it is reviewed by EPA. Subsequent to the DOJ motion, the D.C. Circuit Court canceled oral argument in the case. On August 10, 2017, the court ordered that the litigation be suspended indefinitely. The rule remains in effect pending the outcome of litigation and EPA's review. EPA has not announced a schedule for completing its review. Duke Energy Carolina cannot predict the outcome of these matters, but does not expect the impacts of the current final standards will be material to the company's operations.

On October 23, 2015, the EPA published in the Federal Register the final Clean Power Plan (CPP) rule to regulate CO_2 emissions from existing fossil fuel-fired EGUs. The CPP established CO_2 emission rates and mass cap goals that apply to existing fossil fuel-fired EGUs (existing EGUs are units that commenced construction prior to January 8, 2014). Petitions challenging the rule were filed by numerous groups and on February 9, 2016, the Supreme Court issued a stay of the final CPP rule, halting implementation of the CPP until legal challenges are resolved. Oral arguments before 10 of the 11 judges on the D.C. Circuit Court were heard on September 27, 2016. The court has not issued its opinion in the case.

On March 28, 2017, President Trump signed an executive order directing EPA to review the CPP and determine whether to suspend, revise or rescind the rule. On the same day, the Department of Justice filed a motion with the D.C. Circuit Court requesting that the court stay the litigation of the rule while it is reviewed by EPA. On April 28, 2017, the court issued an order to suspend the litigation for 60 days. On August 8, 2017, the court, on its own motion, extended the suspension of the litigation for an additional 60 days. On October 16, 2017, EPA issued a Notice of Proposed Rulemaking (NPR) to repeal the CPP based on a change to EPA's legal interpretation of the section of the Clean Air Act on which the CPP was based. The comment period on EPA's NPR ended April 26, 2018. On December 28, 2017, EPA issued an Advance Notice of Proposed Rulemaking (ANPRM) in which it sought public comment on various aspects of a potential CPP replacement rule. The comment period on the ANPRM ended February 26, 2018. On July 9, 2018, EPA sent a proposed CPP replacement rule to the Office of Management and Budget for review; after that review is completed, EPA will issue its proposal for public comment. Litigation of the CPP remains on hold in the D.C. Circuit Court and the February 2016 U.S. Supreme Court stay of the CPP remains in effect. Duke Energy Carolina cannot predict the outcome of these matters.

Water Quality and By-product Issues:

CWA 316(b) Cooling Water Intake Structures:

Federal regulations implementing §316(b) of the Clean Water Act (CWA) for existing facilities were published in the Federal Register on August 15, 2014 with an effective date of October 14, 2014. The rule regulates cooling water intake structures at existing facilities to address environmental impacts from fish being impinged (pinned against cooling water intake structures) and entrained (being drawn into cooling water systems and affected by heat, chemicals or physical stress). The final rule establishes aquatic protection requirements at existing facilities and new on-site generation that withdraw 2 million gallons per day (MGD) or more from rivers, streams, lakes, reservoirs, estuaries, oceans, or other waters of the United States. All DEC nuclear fueled, coal-fired and combined cycle stations, in South Carolina and North Carolina are affected sources, with the exception of Smith Energy [12].

The rule establishes two standards, one for impingement and one for entrainment. To demonstrate compliance with the impingement standard, facilities must choose and implement one of the following options:

- Closed cycle re-circulating cooling system; or
- Demonstrate the maximum design through screen velocity is less than 0.5 feet per second (fps) under all conditions; or
- Demonstrate the actual through screen velocity, based on measurement, is less than 0.5 fps; or
- Install modified traveling water screens and optimize performance through a two-year study; or
- Demonstrate a system of technologies, practices, and operational measures are optimized to reduce impingement mortality; or
- Demonstrate the impingement latent mortality is reduced to no more than 24% annually based on monthly monitoring.

In addition to these options, the final rule allows the state permitting agency to establish less stringent standards if the capacity utilization rate is less than 8% averaged over a 24-month contiguous period. The rule, also, allows the state permitting agency to determine no further action warranted if impingement is considered *de minimis*. Compliance with the impingement standard is not required until requirements for entrainment are established.

The entrainment standard does not mandate the installation of a technology but rather establishes a process for the state permitting agency to determine necessary controls, if any, required to reduce entrainment mortality on a site-specific basis. Facilities that withdraw greater than 125 MGD are required to submit information to characterize the entrainment and assess the engineering feasibility,

[12] Richmond County(a public water supply system) supplies cooling water to Smith Energy; therefore the rule is not applicable.

costs, and benefits of closed-cycle cooling, fine mesh screens and other technological and operational controls. The state permitting agency can determine no further action is required, or require the installation of fine mesh screens, or conversion to closed-cycle cooling.

The rule requires facilities with a NPDES permit that expires after July 14, 2018 to submit all necessary 316(b) reports with the renewal application. For facilities with a NPDES permit that expire prior to July 14, 2018 or are in the renewal process, the state permitting agency is allowed to establish an alternate submittal schedule. We expect submittals to be due in the 2019 to 2023 timeframe and intake modifications, if necessary to be required in the 2021 to 2025 timeframe, depending on the NPDES permit renewal date and compliance schedule developed by the state permitting agency.

Steam Electric Effluent Guidelines

Federal regulations revising the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (ELG Rule) were published in the Federal Register on November 3, 2015 with an effective date of January 4, 2016. While the ELG Rule is applicable to all steam electric generating units, waste streams affected by these revisions are generated at DEC's coal-fired facilities. The revisions prohibit the discharge of bottom and fly ash transport water, and flue gas mercury control wastewater, and establish technology based limits on the discharge of wastewater generated by Flue Gas Desulfurization (FGD) systems, and leachate from coal combustion residual landfills and impoundments. The rule, also, establishes technology based limits on gasification wastewater, but this waste stream is not generated at any of the DEC facilities. As originally written, the new limits must be incorporated into the applicable stations' National Pollutant Discharge Elimination System permit based on a date determined by the permitting authority that is as soon as possible beginning November 1, 2018, but no later than December 31, 2023, except the limits for CCR leachate, which are effective upon issuance of the permit after the effective date of the rule. For discharges to publically owned treatment works (POTW), the limits must be met by November 1, 2018, as originally written. Petitions challenging the rule were filed by several groups and all challenges to the rule were consolidated in the Fifth Circuit Court of Appeals. On August 22, 2017, the Fifth Circuit Court of Appeals granted EPA's Motion to Govern Further Proceedings, thereby severing and suspending the claims related to flue gas desulfurization wastewater, bottom ash transport water and gasification wastewater.

Separate from the litigation, on August 11, 2017, EPA announced the decision to conduct a rulemaking to potentially revise the new, more stringent BAT effluent limitations and pretreatment standards for existing sources in the ELG rule that apply to bottom ash transport water and FGD wastewater. Subsequently, EPA finalized a rule on September 18, 2017, postponing the earliest applicability date for bottom ash transport water and FGD wastewater from Nov. 1, 2018 to Nov. 1, 2020 and retained the end applicability date of Dec. 31, 2023. Also, as part of the rule, EPA reiterated its intent to conduct a new rulemaking to review the limitation guidelines for bottom ash transport water and FGD wastewater. EPA projects that a new rule on these two issues will be finalized by December 2019.

The extent to which the rule will affect a particular steam electric generating unit will depend on the treatment technology currently installed at the station. A summary of the impacts are as follows:

- Fly Ash Transport Water: All DEC coal-fired units either handling fly ash dry during normal operation or are in the process of converting to dry fly ash handling. However, to ensure fly ash is handled dry without disruptions to generation, dry fly ash reliability projects are being completed.

- Bottom Ash Transport Water: All DEC coal-fired units, except for Rogers / Cliffside 6, are installing a closed-loop bottom ash transport water recirculating system or a non-bottom ash transport water handling system.

- FGD Wastewater: All DEC coal-fired units, except for Rogers / Cliffside 6 will be required to upgrade or completely replace the existing FGD wastewater treatment system. Even though Allen and Belews Creek Steam Stations utilize the model technology, which was the basis for the limits, additional treatment is expected to be required to ensure compliance.

- CCR Leachate: The revised limits for CCR leachate from impoundments and landfills are same as the existing limits for low volume waste. Potential impacts are being evaluated on a facility basis.

Coal Combustion Residuals

In January 2009, following Tennessee Valley Authority's Kingston ash pond dike failure December 2008, Congress issued a mandate to EPA to develop federal regulations for the disposal of coal combustion residuals. CCR includes fly ash, bottom ash, and flue gas desulfurization solids. As part of that rulemaking, EPA conducted structural integrity inspections of surface impoundments nationwide that were used for disposal of CCR. On April 17, 2015, EPA finalized the first federal regulations for the disposal of CCR (CCR rule). The CCR rule regulates CCR as a nonhazardous waste under Subtitle D of RCRA and allows for beneficial use of CCR with some restrictions. The effective date of the rule was October 19, 2015.

The CCR rule applies to all new and existing landfills, new and existing surface impoundments still receiving CCR and existing surface impoundments that are no longer receiving CCR but contain liquid located at stations currently generating electricity (regardless of fuel source). The rule establishes national minimum criteria that includes location restrictions, design standards, structural integrity criteria, groundwater monitoring and corrective action, closure requirements and post-closure care, and recordkeeping, reporting, and other operational procedures to ensure the safe disposal and management of CCR.

On March 15, 2018, EPA proposed amendments to the CCR rule to reflect the rule's implementation through state or federal permit programs and to address issues that were remanded back to the agency by the U.S. Court of Appeals for the D.C. Circuit following a settlement with industry and environmental petitioners. On July 17, 2018, EPA finalized a set of changes to the federal CCR rule (Phase One, Part One rule), revising the groundwater protection standards for four constituents and revising the deadline to commence closure of unlined coal ash impoundments that fail to meet groundwater protection standards or the aquifer separation location requirement. EPA also finalized changes that apply only to states with approved CCR permit programs, or where EPA is permitting authority. Currently, no Duke Energy states have approved permit programs. EPA has stated it will address the other proposed revisions in a subsequent rulemaking.

Notably, the Phase One, Part One rule did not change any of the major compliance requirements in the CCR rule, including design criteria, location restrictions, requirements for groundwater monitoring, structural integrity standards, inspections and corrective action.

In addition to the requirements of the federal CCR regulation, CCR landfills and surface impoundments will continue to be independently regulated by the state. On September 20, 2014, the North Carolina Coal Ash Management Act of 2014 (CAMA) became law and was amended on July 14, 2016.

CAMA establishes requirements regarding the beneficial use of CCR, the closure of existing CCR surface impoundments, the disposal of CCR at active coal plants, and the handling of surface and groundwater impacts from CCR surface impoundments. CAMA requires eight CCR surface impoundments in North Carolina to be closed no later than December 31, 2019. It also requires state regulators to provide risk ranking classifications to determine the method and timing for closing the remaining CCR surface impoundments. Currently, North Carolina Department of Environmental Quality (NCDEQ) has categorized all remaining CCR surface impoundments as intermediate risk. CAMA also grants NCDEQ the authority to change an impoundment's classification based on completion of dam safety repairs and the establishment of permanent replacement water supplies within a one-half-mile radius of CCR impoundments. The impact from both state and federal CCR regulations to Duke Energy Carolinas is significant.

APPENDIX H: NON-UTILITY GENERATION AND WHOLESALE

This appendix contains wholesale sales contracts and firm wholesale purchased power contracts.

Table H-1: Wholesale Sales Contracts

DEC Aggregated Wholesale Sales Contracts									
Commitment (MW)									
2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1,781	1,590	1,600	1,563	1,542	1,552	1,561	1,567	1,576	1,583

Notes:

- For wholesale contracts, Duke Energy Carolinas/Duke Energy Progress assume all wholesale contracts will renew unless there is an indication that the contract will not be renewed.
- For the period that the wholesale load is undesignated, contract volumes are projected using the same methodology as was assumed in the original contract (e.g. econometric modeling, past volumes with weather normalization and growth rates etc.).

Table H-2: Firm Wholesale Purchased Power Contracts

Purchased Power Contract	Summer Capacity (MW)	Location	Volume of Purchases (MWh) Jul 17-Jun 18
Gas	86	SC	558,335
Hydro	7	SC	13,047
Nuclear	32	NC	280,320
Fuel Oil	5	NC	21,240
Fuel Oil	29	NC	48
Fuel Oil	3	NC	48
Fuel Oil	11	NC	48
Fuel Oil	10	NC	48
Hydro	3	SC	0
Gas	4	NC	736
Nuclear	3	NC	26,270
Gas	1	NC	223
Hydro	1	SC	1,680
System	3	NC	24,648
System	2	NC	17,520
System	2	NC	9,427
Nuclear	16	NC	140,640

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

APPENDIX I: QF INTERCONNECTION QUEUE

Qualified Facilities contribute to the current and future resource mix of the Company. QFs that are under contract are captured as designated resources in the base resource plan. QFs that are not yet under contract but in the interconnection queue may contribute to the undesignated additions identified in the resource plans. It is not possible to precisely estimate how much of the interconnection queue will come to fruition, however the current queue clearly supports solar generation's central role in DEC's NC REPS compliance plan and HB 589.

Below is a summary of the interconnection queue as of June 30, 2018:

Table I-1: DEC QF Interconnection Queue

Utility	Facility State	Energy Source Type	Number of Pending Projects	Pending Capacity (MW AC)
DEC	**NC**	Biomass	4	12.9
		Hydroelectric	1	4.0
		Natural Gas	5	3,444.0
		Solar	149	2,496.1
	NC Total		**159**	**5,957.0**
DEC	**SC**	Biomass	1	4.8
		Hydroelectric	1	160.0
		Natural Gas	4	4,038.8
		No Data	3	24.0
		Solar	139	2,852.7
	SC Total		**148**	**7,080.3**
DEC Total			**307**	**13,037.3**

Note: (1) Above table includes all QF projects that are in various phases of the interconnection queue and not yet generating energy.
(2) Table does not include net metering interconnection requests.

APPENDIX J: TRANSMISSION PLANNED OR UNDER CONSTRUCTION

This appendix lists the planned transmission line additions and discusses the adequacy of DEC's transmission system. Table J-1 lists the line projects that are planned to meet reliability needs. This appendix also provides information pursuant to the North Carolina Utilities Commission Rule R8-62.

Table J-1: DEC Transmission Line Additions

	Location		Capacity	Voltage	
Year	**From**	**To**	**MVA**	**KV**	**Comments**
2020	Lincoln CTs	Longview Tie	N/A	230	Install new 230/100 kV tie station in existing double circuit line near Maiden, NC
2021	Sadler Tie	Ernest Switching Station	N/A	230	Install a switchable series reactor on the Sadler Tie – Ernest Switching Station 230 kV transmission line.

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

(p) Plans for the construction of transmission lines in North Carolina (161 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 2018.

(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;

There are presently no new lines, 161 kV and above, under construction in DEC's service area.

DEC Transmission System Adequacy:

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

The Company monitors transmission system reliability by evaluating changes in load, generating capacity, transactions and topography. A detailed annual screening ensures compliance with DEC's Transmission Planning Guidelines for voltage and thermal loading. The annual screening uses methods that comply with SERC policy and NERC Reliability Standards and the screening results identify the need for future transmission system expansion and upgrades. Transmission planning and requests for transmission service and generator interconnection are interrelated to the resource planning process. DEC currently evaluates all transmission reservation requests for impact on transfer capability, as well as compliance with the Company's Transmission Planning Guidelines and the FERC Open Access Transmission Tariff (OATT). The Company performs studies to ensure transfer capability is acceptable to meet reliability needs and customers' expected use of the transmission system. Generator interconnection requests are studied in accordance with the FERC Large and Small Generator Interconnection Procedures in the OATT and state Generation Interconnection Procedures.

Southeastern Reliability Corporation (SERC) audits DEC every three years for compliance with NERC Reliability Standards. Specifically, the audit requires DEC to demonstrate that its transmission planning practices meet NERC standards and to provide data supporting the Company's annual compliance filing certifications. SERC conducted a NERC Reliability Standards compliance audit of DEC in December 2016. The scope of this audit included standards impacting the Transmission Planning area. DEC received "No Findings" from the audit team in the Transmission Planning area.

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

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

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

- Ensure interconnected system compliance with NERC Reliability Standards.

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

APPENDIX K: ECONOMIC DEVELOPMENT

Customers Served Under Economic Development:

In the NCUC Order issued in Docket No. E-100, Sub 73 dated November 28, 1994, the NCUC ordered North Carolina utilities to review the combined effects of existing economic development rates within the approved IRP process and file the results in its short-term action plan. The incremental load (demand) for which customers are receiving credits under economic development rates and/or self-generation deferral rates (Rider EC), as well as economic redevelopment rates (Rider ER) as of June 2018 is:

Rider EC:
163 MW for North Carolina
108 MW for South Carolina

Rider ER:
0 MW for North Carolina
0 MW for South Carolina

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Hydro: Oconee
Nuclear: Bad Creek
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Uptown Greenville, SC
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Duke Energy Lineman
Duke Energy Transmission Line