DUKE ENERGY CAROLINAS
SOUTH CAROLINA
INTEGRATED RESOURCE PLAN UPDATE

2022

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INTRODUCTION AND OVERVIEW

Introduction

As one of the largest investor-owned utilities in the country, Duke Energy has a strong history of delivering affordable, reliable and increasingly cleaner energy to its customers at rates below the national average. Duke Energy Carolinas ("DEC"), a public utility subsidiary of Duke Energy, utilizes a diverse resource mix, comprised of coal, natural gas, nuclear, solar, and hydroelectric generation, to serve over 2.7 million customers in a 24,000 square-mile service area of North Carolina and South Carolina. In planning for the future, Duke Energy is transforming the way it does business by investing in increasingly cleaner resources, modernizing the grid and transforming the customer experience.

The South Carolina Energy Freedom Act of 2019 ("Act 62") requires DEC to submit comprehensive Integrated Resource Plans ("IRP") for review by the Public Service Commission of South Carolina ("PSCSC" or the "Commission") at least every three years. DEC filed its most recent comprehensive IRP with the Commission on September 1, 2020, setting forth six resource portfolios that included various assumptions on future potential resource mixes. On August 27, 2021, DEC subsequently filed its Supplemental Portfolios & Analysis, providing an additional nine resource portfolios, which, together with the September 2020 IRP, constituted DEC's SC Modified IRP. DEC selected Portfolio C1 ("Earliest Practicable Coal Retirements") as its "Preferred Plan." In Order No. 2022-332, the PSCSC rejected Portfolio C1 as DEC's preferred resource plan and directed that DEC use Portfolio A2 as the selected base plan for its modified 2020 IRP.

Pursuant to Act 62, this document serves as the annual update to DEC's SC Modified 2020 IRP, reflecting required updates to base planning assumptions for Portfolio A2 for compliance purposes. DEC plans to file its next comprehensive IRP with the Commission in 2023.

2022 SC IRP Update Overview

Act 62 requires that DEC submit annual updates to its most recently accepted resource plan, including updates to certain base planning assumptions, and requires that the update "describe the impact of the updated base planning assumptions on the selected resource plan."[1] Accordingly, in compliance with Act 62 and Order Nos. 2021-509 and 2022-332, the Company is providing this update to its base planning assumptions relative to its resource plan, which has been selected by the Commission as Portfolio A2.

This 2022 SC IRP Update ("SC IRP Update" or "IRP Update") illustrates how updates to base planning assumptions impact the selected resource plan. For example, the IRP Update includes updates to the Company's load forecast, energy efficiency projections, the capacity value of renewable resources and batteries (through the updated Effective Load Carrying Capability Study), and updated cost projections and operational assumptions for all supply-side resources evaluated in the plan update. However, evolving economics, regulatory requirements, federal and state policies, and technological advancements underlying key resource planning assumptions will drive significant changes to the upcoming comprehensive IRP. Further, applicable Commission orders require additional resource planning analysis that will also influence the IRP modeling and results that will be presented in 2023. For these reasons, the IRP Update does not result in a resource plan that is fully suitable for execution, as the Company's comprehensive integrated resource plan is expected to change significantly in 2023.

For example, the price for 20-year solar power purchase agreements ("PPA") in this IRP Update remains at $38/MWh, a price that is based on historic market intelligence that is almost four years stale as of the time of this IRP Update. As discussed in Chapter 5, in the 2023 comprehensive IRP, the Company expects to have updated market intelligence to develop a solar PPA price that will be more reflective of current market conditions. In a similar fashion, as directed by the Commission, this update assumes battery storage costs based on the National Renewable Energy Laboratory's ("NREL") most aggressive price decline forecast for utility-scale battery storage technology. For the 2023 comprehensive IRP, the Company will seek to incorporate updated market data as it becomes available in order to better align planning assumptions with current market realities for battery storage. Ongoing regulatory proceedings for resource planning in North Carolina will conclude in December of this year. Given the integrated dual-state systems operated by DEC and DEP in the Carolinas, the outcome of that proceeding will be foundational to the next comprehensive IRP to be filed in South Carolina in 2023. This Commission also set forth a number of updates and new requirements that must also be incorporated into the next comprehensive IRP pursuant to Order No. 2021-447, which are not a part of this 2022 IRP Update. All of these elements will be addressed in DEC's next comprehensive IRP in 2023 and will result in a significantly different resource plan.

In sum, DEC's 2022 SC IRP Update complies with the requirements of Act 62 and the requirements of Order Nos. 2021-447 and 2022-332. Given the factors described above, the results of the SC IRP Update

[1] S.C. Code Ann. § 58-37-40(D)(1). Recognizing that DEC's 2020 Modified IRP was only recently approved by Order No. 2022-332 in May 2022, the Company is submitting this IRP Update in compliance with S.C. Code Ann. § 58-37-40(D)(1) to meet the statutory requirements for 2021 and 2022.

serve to illustrate the impact of updating base planning assumptions, but do not create an executable, long-term resource plan. The Company looks forward to presenting a comprehensive IRP to the Commission in 2023, addressing all of these factors.

2022 SC IRP Update Modeling Results

Table 1-A and Figure 1-A below provide a summary of the 2022 SC IRP modeling results.

Table 1-A: Portfolio A2 Update Results – DEC and DEP/DEC Combined System

	Duke Energy Carolinas	DEP/DEC Combined System
System CO_2 Reduction by 2037[1]	52%	52%
Present Value of Revenue Requirements (PVRR, $B)	$48.3	$75.4
Total System Solar (MW) by Beginning of 2037[2,3]	4,599	10,544
Incremental Onshore Wind (MW) by Beginning of 2037	0	0
Incremental Offshore Wind (MW) by Beginning of 2037	0	0
Incremental SMR (MW) by Beginning of 2037	0	0
Incremental Storage (MW) by Beginning of 2037[2,4]	1,719	3,192
Incremental Gas (MW) by Beginning of 2037	1,677	4,740
Total Contribution from Energy Efficiency and Demand Response Initiatives (MW) by Beginning of 2037[5]	1,971	3,432
Remaining Dual Fuel Coal Capacity by Year-End 2037 (MW)	3,069	3,069

[1]Combined DEP/DEC system CO_2 reductions from 2005 baseline

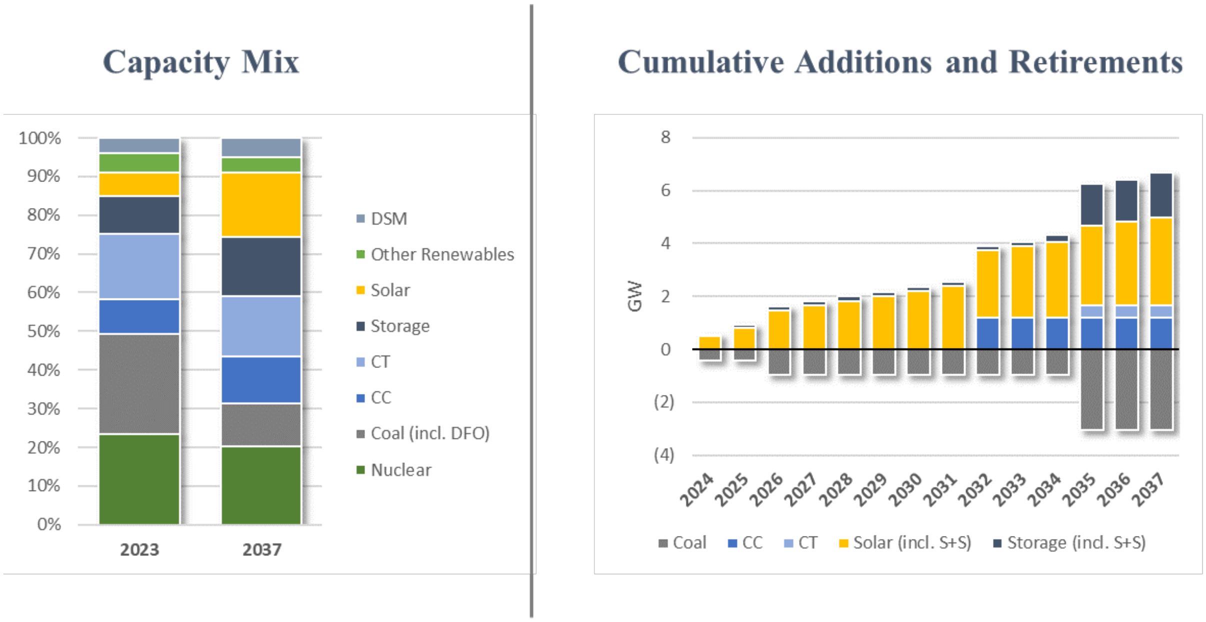
[2]Nameplate

[3]Includes solar-plus-storage resources

[4]Includes batteries paired with solar

[5]Contribution in peak winter planning hour

Figure 1-A: DEC Portfolio A2 Update – Winter (Nameplate for Renewables and Storage)



The specific modeling assumptions and explanation of modeling process, as well as results are included in subsequent chapters.

UPDATES TO BASE PLANNING ASSUMPTIONS

In the development of an IRP update, modeling data is updated to reflect the most current data available to Duke Energy Carolinas ("DEC" or the "Company"). Act 62 describes the IRP update requirements as follows:

> *an electrical utility and the Public Service Authority shall each submit annual updates to its integrated resource plan to the commission. An annual update must include an update to the electric utility's or the Public Service Authority's base planning assumptions relative to its most recently accepted integrated resource plan, including, but not limited to: energy and demand forecast, commodity fuel price inputs, renewable energy forecast, energy efficiency and demand-side management forecasts, changes to projected retirement dates of existing units, along with other inputs the commission deems to be for the public interest.*

This chapter provides an overview of updates made to the base planning assumptions for several of the major inputs, relative to assumptions used to develop Portfolio A2 in the 2020 SC Modified IRP. The updated Portfolio A2 discussed in this document reflects these changes.

Use of EnCompass Model

In 2022, the Company moved to the EnCompass suite of resource planning models from Anchor Power Solutions to address the enhanced planning needs of the Company. As described in the 2020 IRP proceeding, the plans to shift to the new EnCompass model were based, in part, on feedback from stakeholders as part of the 2020 IRP development process. The transition to the EnCompass models is complete and has been utilized in the development of Portfolio A2 in the 2022 SC IRP Update.

Load Forecast

The DEC Fall 2021 load forecast used in this IRP Update includes projections of the energy and peak demand needs for the Company's service area. The forecast covers the time period of 2023 – 2037 and represents the needs of the following customer classes:

DEC LOAD FORECAST CUSTOMER CLASSES

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

The economic projections used in the Fall 2021 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 forecasts consist of economic and demographic projections, which are used in the energy and demand models.

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

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

Each time the load forecast is updated, the most currently available historical and projected data is used. The Fall 2021 forecast used in this IRP update is based on:

- Moody's Analytics July 2021 base and consensus economic projections.

- End use equipment and appliance indexes reflect the 2021 update of Itron's end-use data, which is consistent with the EIA's 2021 Annual Energy Outlook.

- A calculation of normal weather using the period 1991-2020.

The Company also researches weather sensitivity of summer and winter peaks, peak history, hourly shaping of sales, and load research data in a continuous effort to improve forecast accuracy. Historical peaks and forecasted peaks are provided in Chapter 3 – Electric Load Forecast.

Table 2-A below depicts the projected average annual growth rates of several key drivers for DEC's Fall 2021 forecast, with comparison to drivers for the Spring 2020 forecast used in the Modified 2020 IRP.

Table 2-A: Fall 2021 vs. Spring 2020 Annualized Growth Rates of Key Economic Drivers

	Fall 2021 Forecast (2023 – 2037)	Spring 2020 Forecast (2021 – 2035)
Real Income	0.6%	2.9%
Manufacturing Industrial Production Index ("IPI")	1.3%	1.1%
Population	1.6%	1.5%

In addition to economic, demographic, and efficiency trends, the forecast also incorporates the expected impacts of utility energy efficiency ("UEE" or "EE")[1], as well as projected effects of electric vehicles ("EV") and behind the meter solar technology ("PV").

Table 2-B below provides a comparison of the average annual growth rates of forecasted energy sales by customer class, including the impacts of UEE, EV, and PV for the Fall 2021 load forecast used in this IRP Update and the Spring 2020 load forecast used in the 2020 Modified IRP.

[1] UEE specifically refers to the approved programs offered by the Company where participants actively take part in conservation and demand response measures offered under the EE/DSM riders within the service territory. For purposes of this document, UEE and EE terms may be used interchangeably to refer to approved utility programs unless otherwise noted.

Table 2-B: Fall 2021 vs. Spring 2020 Average Annual Growth Rates of Forecasted Energy Sales by Customer Class

	Fall 2021 Forecast (2023 – 2037)	Spring 2020 Forecast (2021 – 2035)
Residential	0.9%	1.0%
Commercial	0.5%	0.5%
Industrial	1.3%	-0.2%
Other	-0.8%	-0.8%
Total Retail	0.9%	0.5%

Note: Includes impacts of UEE, rooftop solar and electric vehicles.

Additionally, Table 2-C below represents a comparison of the average annual growth rates of forecasted winter and summer peak demands, as well as energy demands for the Fall 2021 and Spring 2020 load forecasts.

Table 2-C: Fall 2021 Load Forecast Growth Rates vs. Spring 2020 Load Forecast Growth Rates (Inclusive of Retail and Wholesale Load)

	Fall 2021 Forecast (2023 – 2037)			Spring 2020 Forecast (2021 – 2035)		
	Summer Peak Demand	Winter Peak Demand	Energy	Summer Peak Demand	Winter Peak Demand	Energy
Excludes impact of new EE programs	1.2%	1.1%	1.0%	0.9%	0.7%	0.7%
Includes impact of new EE programs	1.1%	1.0%	0.9%	0.8%	0.6%	0.5%

Additional detail on the Fall 2021 load forecast is provided in Chapter 3 – Electric Load Forecast.

Energy Efficiency, Demand Response, and IVVC

Per PSCSC Order No. 2021-447, "Duke is required to use the Utility Cost Test (UCT) when developing EE/DSM scenarios and savings projections in its future IRPs, IRP updates, and market potential studies." DEC and DEP worked with Nexant to update the information in the 2020 Market Potential Study to use UCT to calculate achievable energy efficiency savings for use in the 2022 SC IRP Update. Table 2-D below shows the growth in impacts of Base EE programs over the fifteen-year time horizon which achieves a Compound Annual Growth Rate of 12.8% and an overall growth rate of approximately 511%.

Table 2-D: Annual MWh Load Reduction from Base EE Programs

Annual MWh Load Reduction (Net of Free Riders)	
Year	Including Measures Added in 2022 and Beyond
2022	759,896
2037	4,646,329

For demand response, the Companies have incorporated results of the winter peak study discussed in the 2020 IRP in the demand response ("DR") projections utilized in this 2022 SC IRP Update. Table 2-E below shows the growth in impacts of DR programs over time at Winter Peak, achieving a Compound Annual Growth Rate of 3.1% and an overall growth of 59.1% over the fifteen-year time horizon.

Table 2-E: Growth Impact of Winter DR Programs

Year	Power Manager	Powershare Mandatory	Powershare Generator	IS	SG	Energywise Business	ADR	Total Winter Peak
2022	17	314	9	84	2	2	0	428
2037	250	313	9	66	2	8	33	681

Note: Data excludes the impact of wholesale DR programs.

In the 2020 IRP, DEC included the impacts of an Integrated Volt-Var Control program to be deployed in the service territory. The impacts of this program included approximately 190 megawatts ("MW") of peak shaving capacity by 2036 based upon deployment across 61% of eligible circuits. For the 2022 SC IRP Update, the Company has filed a more aggressive deployment that will upgrade 96% of eligible circuits by 2036 representing 214 MW of peak shaving capacity by 2036.

Please see Chapter 4 – Energy Efficiency, Demand-Side Management and Voltage Optimization, for a detailed account of the impacts of EE/DSM and IVVC on the DEC system.

Renewable Energy

The 2022 SC IRP Update includes several updates to operational assumptions for solar resources that are available to be selected by the model. Future solar resources are assumed to have bifacial panels and it is assumed that 60% of future solar would be located in the DEP service territory with the remaining 40% assumed to be located in DEC. Consistent with PSCSC Order No. 2021-447 and Portfolio A2 of the 2020 Modified IRP, the Companies applied a 750 MW annual solar interconnection constraint. Consistent with the Commission's previous orders, the Companies also included third-party solar PPAs with a price of $38/MWh as a selectable resource, with the base case allowing up to 50% of the solar available to be selected as the $38/MWh PPA option, and with the alternative case allowing 100% of the solar to be selected at this option.

DEC also includes onshore wind as a selectable resource, comparable to the 2020 Modified IRP. The model assumes a generation profile that serves as a proxy for high-capacity factor wind imported from regions such as PJM or MISO.

Chapter 5 – Renewable Energy and Energy Storage Resources includes additional detail on the renewable energy assumptions used in this 2022 SC IRP update.

Energy Storage

Energy storage will serve in the future to support additional deployment of intermittent solar resources and act as an important dispatchable resource supporting future coal plant retirements.

The Company continues to include 4-hour and 6-hour battery energy storage as model-selectable resources in the IRP analysis, and has added an 8-hour option for this IRP update. For the 2022 SC IRP Update, DEC added a 2-hour battery paired with solar option to be selected along with the 4-hour battery paired with solar option that was available in the 2020 Modified IRP.

As directed by the Commission, the Company's selectable battery storage resource prices are consistent with the "Advanced Costs" assumption from the 2021 NREL Annual Technology Baseline ("ATB") report.

Chapter 5 – Renewable Energy and Energy Storage Resources includes additional detail on the energy storage assumptions used in this IRP update.

Effective Load Carrying Capability ("ELCC") Study

Consistent with Order No. 2021-447, the Companies have made several adjustments to the solar and storage ELCCs. The specific changes required by the Commission are discussed in more detail in Chapter 6 – Development of the Resource Plan. This 2022 SC IRP Update incorporates these changes as directed by the Commission.

DEC and DEP worked with Astrapé Consulting to conduct a new ELCC study to understand the reliable capacity contributions of solar, onshore wind, offshore wind, and storage for use in the planning process. Importantly, these ELCC results reflect the "synergistic benefits" of other variable resources present on the system. The solar and storage ELCC values used in EnCompass reflect the synergistic effect that these resources have on each other's capacity values as their deployment increases on the system. The Companies applied discrete ELCC values for solar, storage, and wind resources that capture this synergistic value.

Additional detail on the ELCC Study and ELCC values used in the 2022 SC IRP Update can be found in Chapter 6 –Development of the Resource Plan as well as the ELCC Study Report provided as Attachment I.

Retirement Dates of Existing Resources

The 2020 IRP included a detailed coal plant retirement analysis to determine the most economic retirement dates for each of the Company's coal assets. These coal retirement dates were reflected in Portfolio A2 in the 2020 IRP and 2020 SC Modified IRP. The Company continues to rely on these retirement dates for the purposes of the 2022 SC IRP Update. These retirement dates are provided in Table 2-F below.

Table 2-F: Coal Retirement Dates in the Approved 2020 Resource Plan

Coal Plant	Retirement Year (Jan 1)
Allen 1 & 5	2024
Cliffside 5	2026
Marshall 1 – 4	2035
Belews Creek 1	2039
Belews Creek 2	2039
Cliffside 6	2049

Since the filing of the 2020 IRP, Allen Unit 3 (270 MW) was retired March 31, 2021, and Allen Units 2 and 4 (434 MW) were retired on December 31, 2021. Additionally, DEC's natural gas boiler unit, Lee Unit 3 (170 MW), was retired March 31, 2022.[2]

Finally, since the 2020 IRP filing, the Company has further reviewed the retirement dates for the existing natural gas combustion turbine units on the DEC system. Based on this review, the Company determined that the retirement date for the Lincoln CTs must be extended to 2041 (from 2036) to ensure reliability to the DEC system as coal units are retired and additional variable energy resources are added.

Fuel Costs

As directed by the PSCSC, the natural gas price forecast used in the development of Portfolio A2 in the 2020 SC Modified IRP consisted of eighteen months of market pricing, followed by an eighteen-month transition from market to fundamentals-based pricing, and then relies on fundamentals-based pricing for the remainder of the planning period. This IRP update uses the same forecasting methodology for both gas and coal prices. In addition, to reduce forecast volatility and limit reliance on any one set of forecast assumptions, the fundamentals-based fuel price forecast used in the 2022 SC IRP Update is an average of fundamentals-based forecasts from four providers. Additional detail is provided in Chapter 9 – Fuel Commodity Prices.

[2] These capacities represent winter ratings.

Selectable Resource Technologies

The capital, operating, and associated transmission costs of selectable resources represent the Company's most current estimates at the time the dataset is locked for modeling purposes. Similar to the 2020 IRP, the Company considered a diverse range of technology choices utilizing a variety of different fuels in order to meet future generation needs in the 2022 SC IRP Update. Technologies available for selection in the 2022 SC IRP Update capacity expansion process are listed below.

Technologies (Winter Ratings):

- Base load – 1,216 MW 2x2x1 Advanced Combined Cycle (No Inlet Chiller and Fired)
- Base Load – 285 MW Small Modular Reactor (SMR)
- Base Load – 345 MW Advanced Nuclear Reactor (AR) with Thermal Storage
- Peaking/Intermediate – 924 MW 4 x 7FA.05 Combustion Turbines (CTs)
- Storage – 60 MW / 240 MWh Li-Ion Battery (4-hour)
- Storage – 60 MW / 360 MWh Li-Ion Battery (6-hour)
- Storage – 50 MW / 400 MWh Li-Ion Battery (8-hour)
- Intermittent – 75 MW Solar PV, Bifacial and Single Axis Tracking (SAT)
- Intermittent – 75 MW Solar PV plus 20 MW / 80 MWh or 40 MW / 80 MWh Li-ion Battery
- Intermittent – 150 MW Onshore Wind

Additional detail regarding technology changes included in the 2022 SC IRP Update may be found in Chapter 6 – Development of the Resource Plan.

Combined Heat and Power

The 2020 IRP included placeholders for 60 MW of Combined Heat and Power ("CHP") systems. These are not included in the 2022 SC IRP Update. The only CHP resource in the Portfolio A2 Update is the existing 15.5 MW (winter)/12.5 MW (summer) CHP at Clemson University.

ELECTRIC LOAD FORECAST

Pursuant to Act 62, Duke Energy Carolinas' ("DEC" or the "Company") 2022 SC IRP Update includes an update to the Company's electric load forecast. The DEC Fall 2021 Forecast provides projections of the energy and peak demand needs for its service area and is an update from the DEC Spring 2020 Forecast, which was used in the 2020 DEC Integrated Resource Plan.

Customer Classes

The forecast covers the time period of 2023 to 2037 and represents the needs of the following customer classes shown in Figure 3-A below:

Figure 3-A: DEC Load Forecast Customer Classes

DEC developed its energy projections 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. The residential customer model also uses population factors.

The DEC Fall 2021 Forecast reflects economic projections obtained from Moody's Analytics, a nationally recognized economic forecasting firm, including economic forecasts for the states of South Carolina and North Carolina. Moody's forecasts consist of economic and demographic projections, which are used in the energy and demand models.

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

DEC derived the usage per customer forecast using a Statistical Adjusted End-Use Model ("SAE"). This is a regression-based framework that uses projected appliance saturation and efficiency trends developed by Itron using Energy Information Administration ("EIA") data. It incorporates naturally occurring efficiency trends and government mandates more explicitly than other models. The outlook for usage per customer is essentially flat through much of the forecast horizon, so most of the growth is primarily due to customer increases. The average annual growth rate for the residential class in the DEC Fall 2021 Forecast, including the impacts of Utility Energy Efficiency ("UEE") programs, rooftop solar and electric vehicles from 2023 to 2037 is 0.9%.

DEC also uses an SAE model to develop the Commercial forecast and 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 0.5% per year over the forecast horizon.

DEC derived its Industrial class forecast using a standard econometric model, with drivers such as total manufacturing output and the price of electricity. Overall, Industrial sales are expected to grow 1.3% per year over the forecast horizon.

Weather impacts are incorporated into the models 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.

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

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

Each time the forecast is updated, the Company uses the most current available historical and projected data. The current forecast utilizes:

- Moody's Analytics July 2021 base and consensus economic projections.
- The 2021 update of Itron's end-use data, which is consistent with the EIA's 2021 Annual Energy Outlook (for end-use equipment and appliance indexes).
- A calculation of normal weather using the period 1991-2020.

The Company also researches weather sensitivity of summer and winter peaks, peak history, hourly shaping of sales, and load research data in a continuous effort to improve forecast accuracy. Historical peaks and forecasted peaks can be viewed later in this Chapter.

Assumptions

Table 3-A shows the projected average annual growth rates of several key drivers from the DEC Fall 2021 Forecast.

Table 3-A: Annualized Growth Rates of Key Economic Drivers

	2023-2037
Real Income	0.6%
Manufacturing Industrial Production Index ("IPI")	1.3%
Population	1.6%

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

Utility Energy Efficiency

UEE programs continue to have a large impact accelerating 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, continuing to reduce the forecasted load resulting from energy efficiency adoption.

Table 3-B below illustrates this process on sales:

Table 3-B: UEE Program Life Process (GWh)

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
2023	92,638	5	92,642	(992)	333	(659)	91,983
2024	93,357	43	93,401	(1,430)	333	(1,097)	92,303
2025	93,752	134	93,886	(1,867)	333	(1,534)	92,352
2026	94,341	294	94,634	(2,293)	334	(1,959)	92,676
2027	94,962	526	95,488	(2,693)	335	(2,358)	93,130
2028	95,789	818	96,607	(3,050)	337	(2,712)	93,894
2029	96,733	1,065	97,798	(3,358)	343	(3,014)	94,783
2030	97,580	1,386	98,965	(3,617)	362	(3,255)	95,710
2031	98,680	1,603	100,282	(3,828)	414	(3,415)	96,867
2032	99,766	1,745	101,511	(3,991)	516	(3,476)	98,035
2033	100,802	1,827	102,629	(4,125)	646	(3,479)	99,150
2034	101,840	1,867	103,707	(4,251)	807	(3,444)	100,263
2035	102,895	1,882	104,777	(4,371)	1,014	(3,358)	101,419
2036	103,938	1,882	105,820	(4,487)	1,247	(3,240)	102,580
2037	104,903	1,882	106,785	(4,597)	1,567	(3,030)	103,756

Critical Peak Pricing

The Critical Peak Pricing ("CPP") Rate Rider is a dynamic overlay option for DEC's electric service, including both its existing flat volumetric rates as well as its existing and newly proposed time-of-use ("TOU") rates. This time variant pricing option allows the Company to call critical events up to 20 times per year (20 CP) based on system conditions such as when there is expected to be extreme temperatures, high energy usage, high market energy costs, or major generation or transmission outages. Customers enrolled will be alerted the day before a critical event and agree to pay a higher price for peak time electricity use during these critical events, encouraging reductions in demand. DEC included daily load and peak impacts for CPP in the peak demand projections for DEC. The critical events (20 CP) were modeled to impact the projected 10 highest winter days and 10 highest summer days in each year.

Table 3-C below shows the CPP projected peak reduction capabilities for Winter and Summer demands:

Table 3-C: CPP Peak Reduction Capabilities (MW) - DEC

Year	Summer (MW)	Winter (MW)
2023	20	13
2024	39	29
2025	62	50
2026	91	76
2027	125	107
2028	164	144
2029	206	185
2030	251	229
2031	296	274
2032	339	318
2033	378	359
2034	413	396
2035	441	428
2036	465	454
2037	484	475

Rooftop Solar

Net energy metering ("NEM") is currently available in the Carolinas. The forecast used in the 2022 SC IRP Update reflects impacts from approved NEM rates in the Carolinas as of January 1, 2022, which are decremented directly from the initial Itron model output. Table 3-D below summarizes the number of current customers enrolled in net metering rate programs for both the DEC and DEP service areas by customer class, as well as the total energy in megawatt-hours ("MWh") forecasted to be generated from behind-the-meter ("BTM") solar generation on customer sites in 2022.

Table 3-D: Number of Customers Enrolled in Net Metering Rate Programs and Forecasted BTM Generation

	2022 Enrollment (as of 1/1/2022)		2022 BTM Generation Forecast	
System	Residential	Non-Residential	Residential	Non-Residential
DEC	22,252	745	223,447 MWh	86,816 MWh

Modeling NEM Adoption

Residential rooftop solar systems are limited in size pursuant to state law in both South Carolina and North Carolina which require a facility to be less than 20 kilowatts-alternating current ("kW-AC"), also referred to as nameplate capacity for solar facilities. Non-residential customers' solar systems may not exceed the lesser of 1,000 kW-AC or 100% of the customer's contract demand, which approximates the customer's maximum expected demand. Table 3-E below shows the average size of rooftop solar facilities in the Carolinas.

Table 3-E: Average Rooftop Solar Capacity (kW-AC)

Customer Class	DEC -NC	DEC -SC
Residential	6.2	8.3
Non-residential	68	105

The rooftop solar generation forecast is derived from a series of capacity forecasts and hourly production profiles tailored to residential, commercial and industrial customer classes.

Each capacity forecast is the product of a customer adoption forecast and an average capacity value. The Company developed the adoption forecasts using economic models of payback, which is a function of installed cost, regulatory incentives, regulatory statutes and bill savings. A relationship between payback and customer adoption is developed through regression modeling, with the resulting regression equations used to predict future customer adoptions based on projected payback curves.

DEC sourced historical and projected technology costs from Guidehouse, while projected incentives and bill savings are based on current regulatory policies as well as input from internal subject matter experts. Average system size (capacity) values are based on trends in historical adoption.

The hourly production profiles have 12x24 resolution, which equates to one 24-hour profile for each month. Profiles are derived from actual production data, where available, and solar photovoltaic ("PV") modeling. The PV modeling is performed in the PVsyst model using 20+ years of historical irradiance data sourced from Solar Anywhere, and Solcast. Models are created for 13 irradiance locations across DEC's service area and nine irradiance locations across DEP's service area with 21 tilt/azimuth configurations. The results for each jurisdiction are combined on a weighted average basis to produce the final profiles.

Table 3-F below shows the Company's growth projection for new solar customers and new energy benefits

from 2022 through 2037 under the currently approved net metering rate designs in the Carolinas as of January 1, 2022.

Table 3-F: 2037 Rooftop Solar, Net New from 2022 through 2037

	DEC	
	Residential	**Non-Residential**
Number of Customers	77,071	1,835
Energy (MWh)	718,541	165,324

Electric Vehicles

Major automakers, including Ford, GM and Stellantis (which is comprised of 16 auto brands, including Chrysler, Dodge, and Jeep), have announced a goal to achieve 40%-50% of new vehicle sales be electric by 2030. Also, in August 2021, the Biden Administration announced a goal of 50% of new U.S. passenger car and light truck sales being electric by 2030.[1] New vehicle sales are only a portion of the vehicles in operation, but the load growth associated with charging electric vehicles ("EV") is expected to accelerate over the planning horizon.

The Company's EV load forecast is derived using the Vehicle Analytics and Simulation Tool ("VAST"). VAST generates a series of EV forecasts and load charging profiles are generated to produce an hourly load forecast broken down by three duties: light, medium and heavy. All three duties are calculated using similar methodology and make up the EV load forecast that is added to the DEC load forecast.

Multiple parameters are accounted for when developing the EV adoption forecast including historical data, such as vehicle registrations, vehicle utilization characteristics, projections of cost, vehicle availability, charging infrastructure availability and consumer acceptance.

Based on the adoption forecast and the projected amount of energy needed to charge the EVs, hourly EV demand profiles are developed in VAST using third-party charging characteristic data for the different types of vehicles and chargers. The VAST tool then combines the EV vehicle forecast and the hourly load profiles to develop jurisdictional hourly level load profiles that are used in the DEC load forecast.

Table 3-G below shows the projected incremental additions of EVs in operation, along with the impacts on energy, near the beginning and ending of the planning horizon.

[1] FACT SHEET: President Biden Announces Steps to Drive American Leadership Forward on Clean Cars and Trucks | The White House (Aug. 5, 2021), *available at* https://www.whitehouse.gov/briefing-room/statements-releases/2021/08/05/fact-sheet-president-biden-announces-steps-to-drive-american-leadership-forward-on-clean-cars-and-trucks/.

Table 3-G: Electric Vehicles, EVs in Operation and Load Impacts – DEC

Year	EVs in Operation	Percent of Vehicle Fleet	Load (MWh/Year)
2022	33,424	0.59%	24,500
2037	611,463	6.82%	3,600,000

Net Impact of Rooftop Solar and Electric Vehicles

Figures 3-B through 3-D illustrate the impacts on annual energy, winter peak demand and summer peak demand from rooftop solar and EVs by customer class across the planning horizon. The load forecast is incremented by these projections.

Figure 3-B: Percent Impact of PV and EV on Annual Load in DEC, Net New from 2022

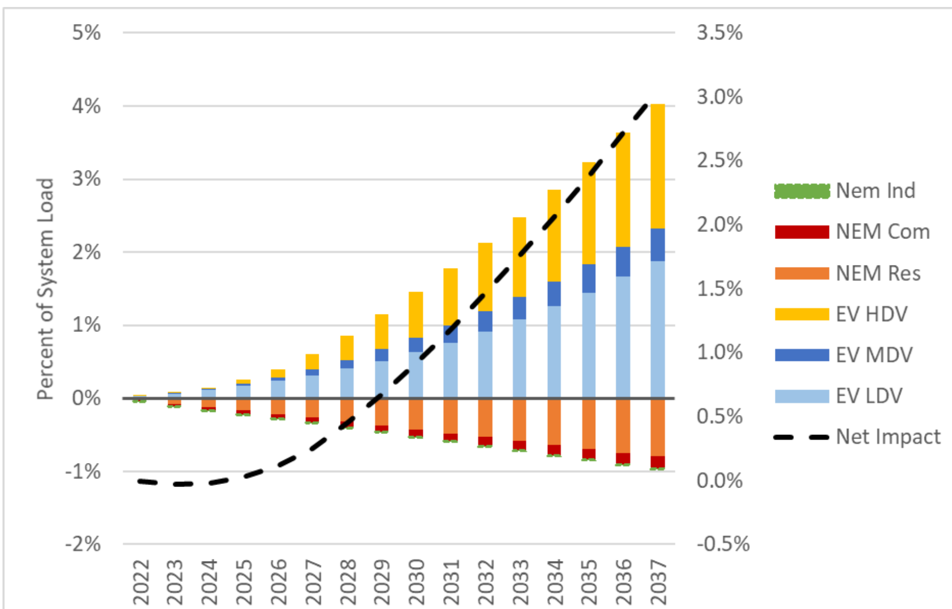


Figure 3-C: Percent Impact of PV and EV on Winter Peak Load in DEC, Net New from 2022

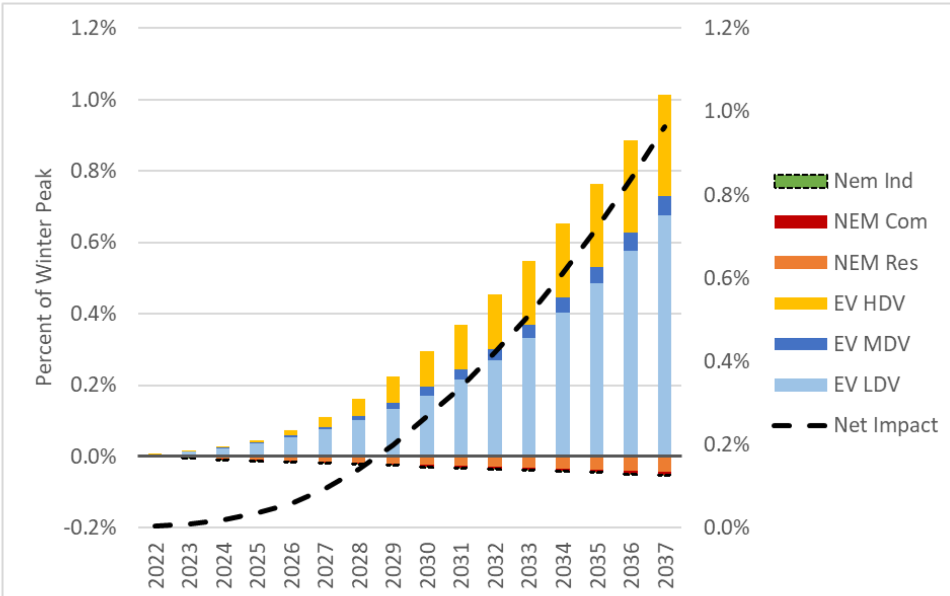
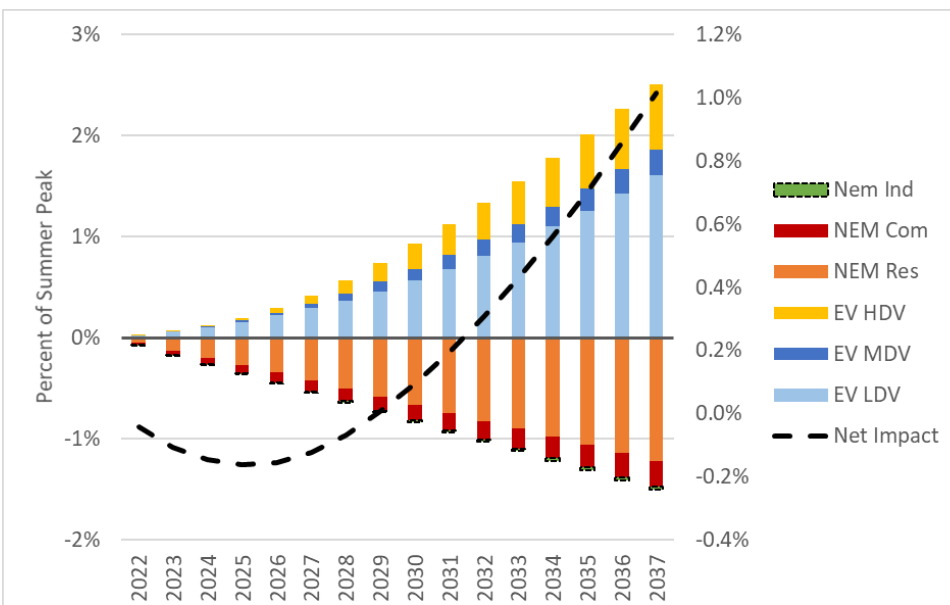


Figure 3-D: Percent Impact of PV and EV on Summer Peak Load in DEC, Net New from 2022



Customer Growth

Tables 3-H and 3-I show the history and projections for DEC customers.

Table 3-H: Retail Customers (Annual Average in Thousands)

Year	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Retail Customers
2012	2,053	337	7	14	2,411
2013	2,068	339	7	14	2,428
2014	2,089	342	7	15	2,452
2015	2,117	345	6	15	2,484
2016	2,148	349	6	15	2,519
2017	2,182	354	6	15	2,557
2018	2,215	358	6	17	2,596
2019	2,261	362	6	22	2,651
2020	2,306	367	6	23	2,702
2021	2,350	392	6	16	2,764
Avg. Annual Growth Rate	1.5%	1.7%	-1.4%	1.4%	1.5%

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

Year	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Retail Customers
2023	2,427	407	6	13	2,853
2024	2,451	409	6	13	2,879
2025	2,472	412	6	13	2,902
2026	2,491	415	6	13	2,924
2027	2,512	418	6	13	2,948
2028	2,535	420	6	13	2,974
2029	2,560	423	6	13	3,001
2030	2,585	426	6	13	3,030
2031	2,611	430	6	13	3,059
2032	2,636	433	6	13	3,087
2033	2,661	436	5	13	3,115
2034	2,686	439	5	13	3,143
2035	2,709	442	5	13	3,169
2036	2,731	445	5	13	3,193
2037	2,751	448	5	13	3,217
Avg. Annual Growth Rate	0.9%	0.7%	-0.8%	-0.2%	0.9%

Electricity Sales

Table 3-J below shows the actual historical gigawatt hour (GWh) sales. As a note, the values in Table 3-J are not weather adjusted Sales.

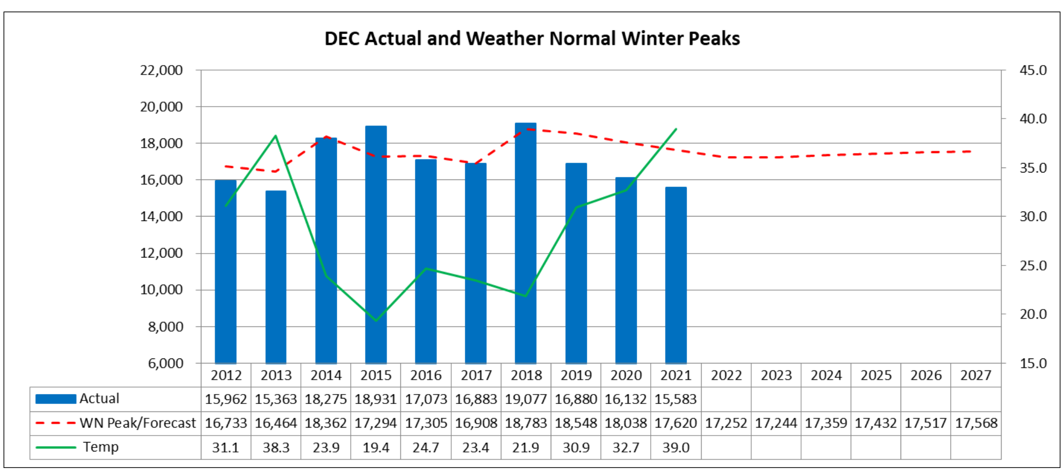
Table 3-J: Electricity Sales (GWh)

Year	Residential GWh	Commercial GWh	Industrial GWh	Military & Other GWh	Retail GWh	Wholesale GWh	Total System GWh
2012	26,279	27,476	20,978	290	75,023	5,176	80,199
2013	26,895	27,765	21,070	293	76,023	5,824	81,847
2014	27,976	28,421	21,577	303	78,277	6,559	84,836
2015	27,916	28,700	22,136	305	79,057	6,916	85,973
2016	27,939	28,906	21,942	304	79,091	7,614	86,705
2017	26,593	28,388	21,776	301	77,059	7,558	84,617
2018	29,717	29,656	21,720	306	81,399	8,889	90,288
2019	28,861	29,628	21,299	320	80,109	8,317	88,426
2020	27,963	27,637	19,593	314	75,506	7,616	83,123
2021	29,244	28,760	20,611	300	78,915	7,966	86,880
Avg. Annual Growth Rate	1.2%	0.5%	-0.2%	0.4%	0.6%	4.9%	0.9%

System Peaks

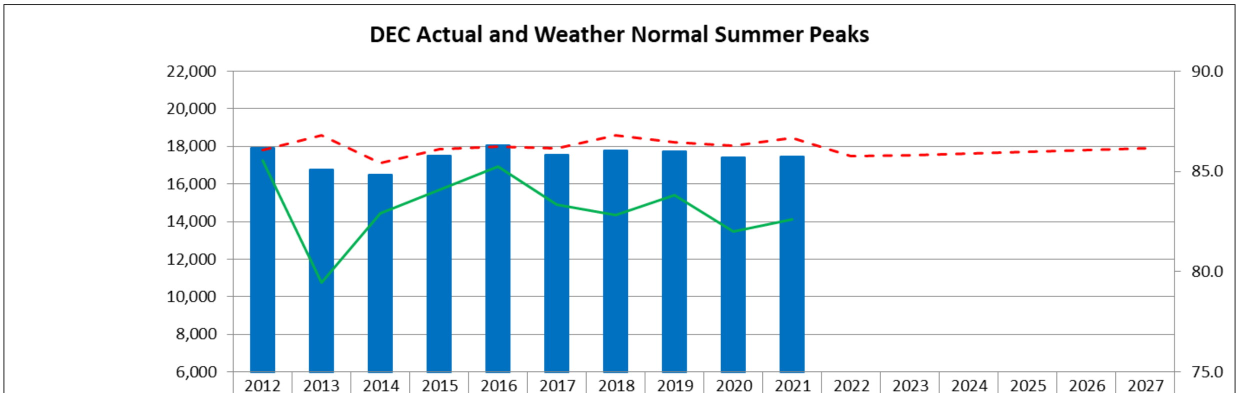
Figures 3-E and 3-F below show the historical actual and weather normalized peaks for the system:

Figure 3-E: DEC Actual and Weather Normal Winter Peaks



Note: WN Peak/Forecast values in years 2022-2027 are forecasted peak values from the 2021 Fall Forecast. The Temperatures are the average daily temperature on the day of the peak.

Figure 3-F: DEC Actual and Weather Normal Summer Peaks



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Actual	17,933	16,757	16,501	17,529	18,037	17,539	17,779	17,736	17,405	17,471						
WN Peak/Forecast	17,822	18,593	17,093	17,832	17,992	17,917	18,613	18,233	18,044	18,432	17,495	17,541	17,605	17,698	17,795	17,905
Temp	85.5	79.5	82.9	84.1	85.3	83.3	82.8	83.8	82.0	82.6						

Note**:** WN Peak/Forecast values in years 2022-2027 are forecasted peak values from the 2021 Fall Forecast. The Temperatures are the average daily temperature on the day of the peak.

Forecast Results

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

- Table 3-K: Forecasted energy sales by class (Including the impacts of UEE, rooftop solar, and electric vehicles)
- Table 3-L: Forecast energy sales – gross load to net load (walkthrough of impacts from UEE, rooftop solar, electric vehicles and voltage control program)
- Table 3-M: Summary of the load forecast without UEE programs and excluding any impacts from demand reduction programs
- Table 3-N: Summary of the load forecast with UEE programs and excluding any impacts from demand reduction programs

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

Load duration curves, with and without UEE programs are shown as Figures 3-G and 3-H. The values in these tables reflect the loads that Duke Energy Carolinas is contractually obligated to provide and cover the period from 2023 to 2037.

Table 3-K: Forecasted Energy Sales by Class

Year	Residential GWh	Commercial GWh	Industrial GWh	Other GWh	Retail GWh
2023	30,293	28,453	20,921	279	79,945
2024	30,399	28,426	21,029	280	80,134
2025	30,443	28,308	21,081	279	80,111
2026	30,625	28,338	21,098	278	80,338
2027	30,959	28,255	21,195	277	80,686
2028	31,268	28,356	21,411	275	81,310
2029	31,570	28,502	21,750	273	82,095
2030	31,894	28,653	22,080	270	82,897
2031	32,244	28,875	22,542	268	83,929
2032	32,600	29,128	22,994	265	84,987
2033	32,931	29,365	23,438	262	85,996
2034	33,283	29,603	23,845	259	86,991
2035	33,636	29,857	24,274	257	88,024
2036	33,983	30,137	24,673	254	89,046
2037	34,290	30,441	25,135	251	90,117
Avg. Annual Growth Rate	0.9%	0.5%	1.3%	-0.8%	0.9%

Note: Values are at meter.

Table 3-L: Forecasted Energy Sales – Gross Load to Net Load

Year	Gross Retail Sales	Energy Efficiency	Rooftop Solar	Electric Vehicles	Voltage Control (IVVC)	Critical Peak Pricing (CPP)	Net Retail Sales
2023	80,666	(659)	(86)	62	(37)	(1)	79,945
2024	81,323	(1,097)	(136)	120	(74)	(2)	80,134
2025	82,000	(1,534)	(181)	202	(374)	(3)	80,111
2026	82,587	(1,959)	(229)	320	(377)	(4)	80,338
2027	83,225	(2,358)	(279)	484	(381)	(6)	80,686
2028	84,050	(2,712)	(333)	697	(384)	(8)	81,310
2029	84,955	(3,014)	(389)	940	(388)	(10)	82,095
2030	85,792	(3,255)	(446)	1,210	(391)	(12)	82,897
2031	86,760	(3,415)	(505)	1,498	(395)	(14)	83,929
2032	87,631	(3,476)	(566)	1,813	(398)	(17)	84,987
2033	88,384	(3,479)	(626)	2,137	(402)	(19)	85,996
2034	89,064	(3,444)	(689)	2,486	(405)	(21)	86,991

Year	Gross Retail Sales	Energy Efficiency	Rooftop Solar	Electric Vehicles	Voltage Control (IVVC)	Critical Peak Pricing (CPP)	Net Retail Sales
2035	89,713	(3,358)	(753)	2,853	(409)	(22)	88,024
2036	90,296	(3,240)	(820)	3,246	(413)	(24)	89,046
2037	90,834	(3,030)	(884)	3,637	(416)	(25)	90,117

Note: Values are at meter.

Table 3-M: Summary of the Load Forecast without UEE Programs and Excluding any Impacts from Demand Reduction Programs

Year	Summer (MW)	Winter (MW)	Energy (GWh)
2023	17,669	17,325	92,642
2024	17,808	17,512	93,401
2025	17,977	17,658	93,886
2026	18,145	17,812	94,634
2027	18,319	17,958	95,488
2028	18,539	18,149	96,607
2029	18,803	18,402	97,798
2030	19,062	18,538	98,965
2031	19,359	18,853	100,282
2032	19,633	19,124	101,511
2033	19,906	19,356	102,629
2034	20,168	19,505	103,707
2035	20,427	19,807	104,777
2036	20,596	19,987	105,820
2037	20,849	20,255	106,785
Avg. Annual Growth Rate	1.2%	1.1%	1.0%

Figure 3-G: Load Duration Curve Without Energy Efficiency Programs and Before Demand Reduction Programs

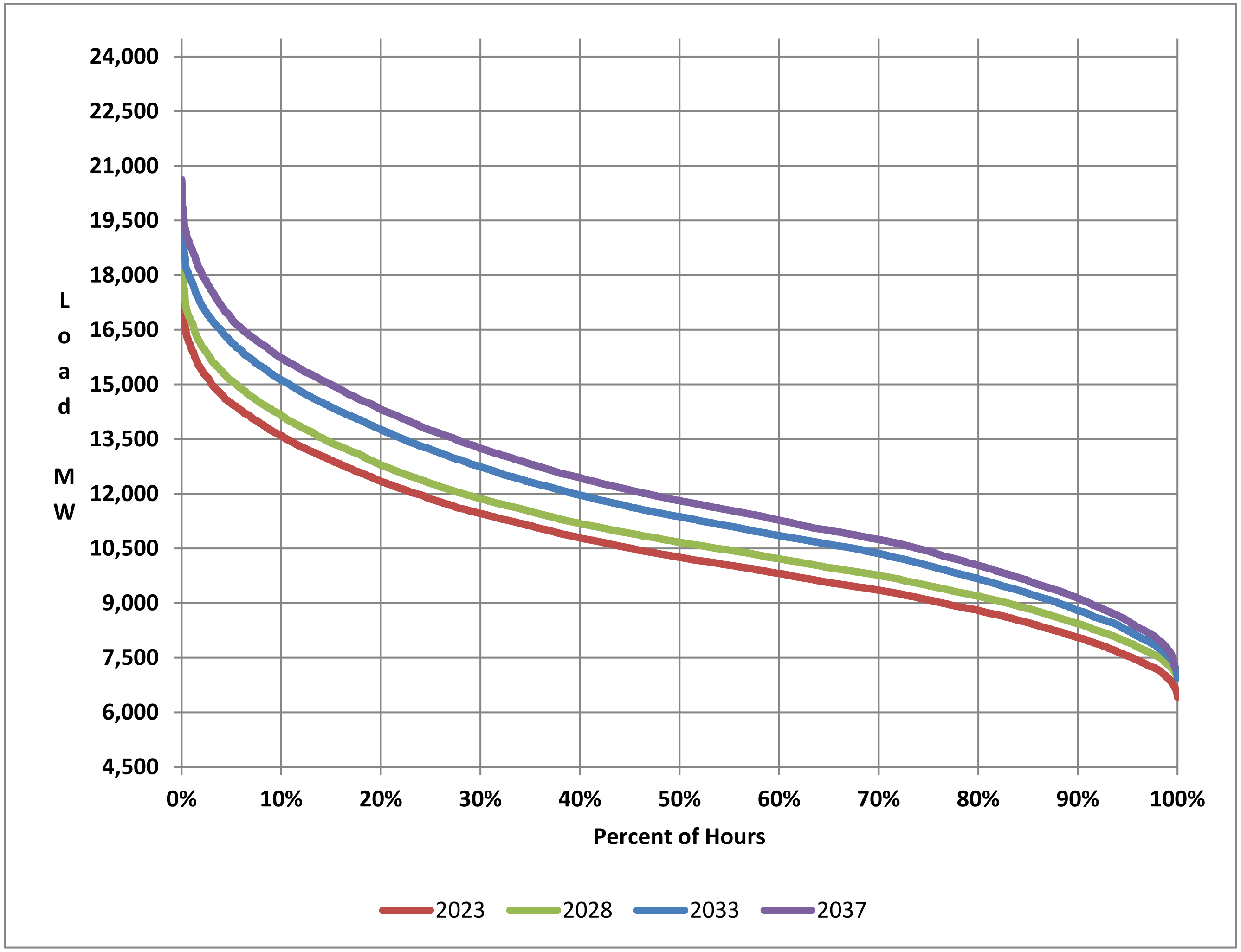
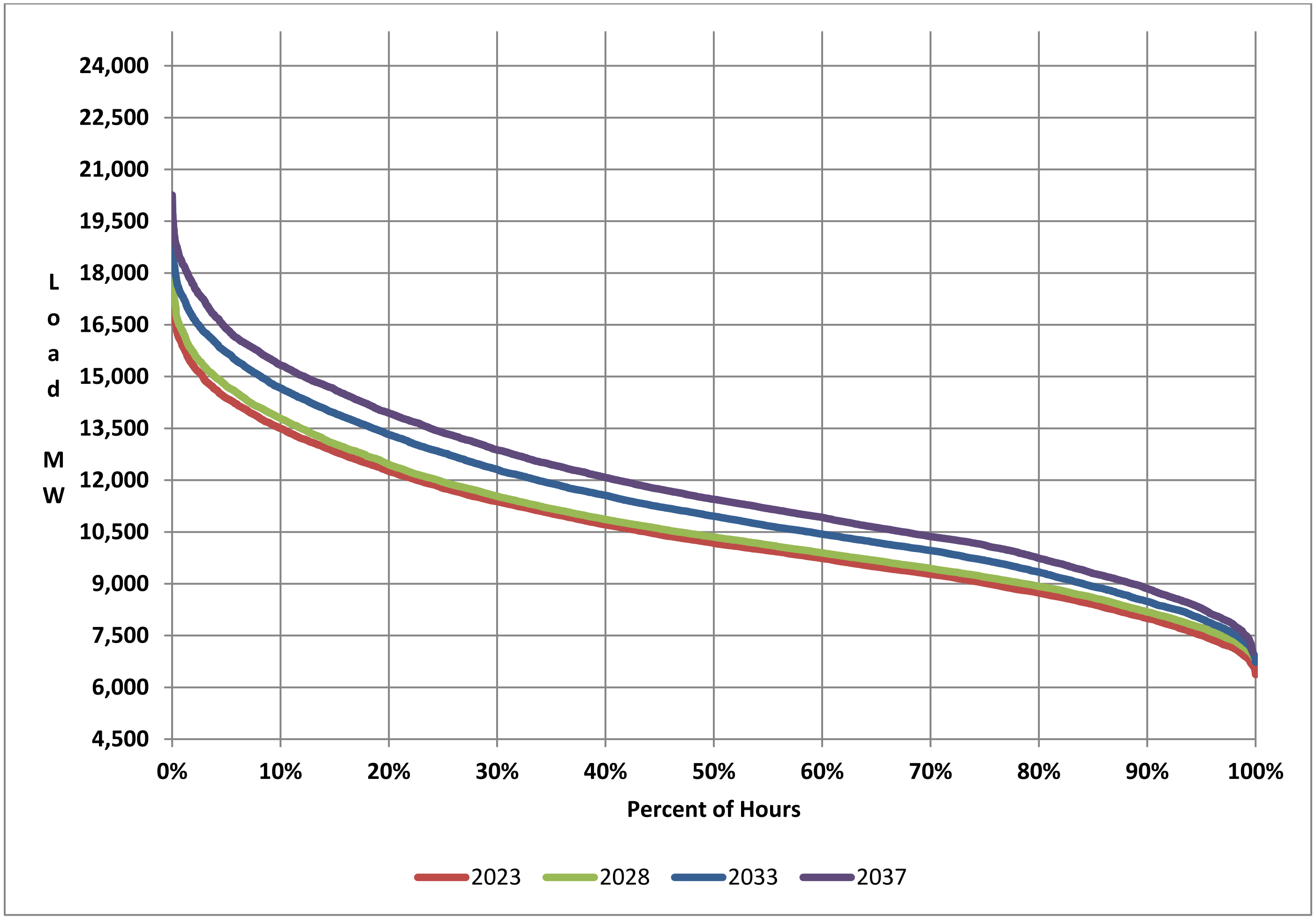


Table 3-N: Summary of the Load Forecast with UEE Programs and Excluding any Impacts from Demand Reduction Programs

Year	Summer (MW)	Winter (MW)	Energy (GWh)
2023	17,541	17,244	91,983
2024	17,605	17,359	92,303
2025	17,698	17,432	92,352
2026	17,795	17,517	92,676
2027	17,905	17,568	93,130
2028	18,068	17,705	93,894
2029	18,281	17,909	94,783
2030	18,501	18,008	95,710
2031	18,772	18,298	96,867
2032	19,038	18,563	98,035
2033	19,310	18,795	99,150
2034	19,576	18,949	100,263
2035	19,849	19,263	101,419
2036	20,143	19,462	102,580
2037	20,421	19,762	103,756
Avg. Annual Growth Rate	1.1%	1.0%	0.9%

Figure 3-H: Load Duration Curve with Energy Efficiency Programs and Before Demand Reduction Programs



ENERGY EFFICIENCY, DEMAND-SIDE MANAGEMENT AND VOLTAGE OPTIMIZATION

Current Energy Efficiency and Demand-Side Management Programs

Duke Energy Carolinas ("DEC" or the "Company") continues to pursue a long-term, balanced capacity and energy strategy to meet the future electricity needs of its customers. This balanced strategy includes a strong commitment to demand-side management ("DSM") and energy efficiency ("EE") 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: EE programs that reduce energy consumption and DSM programs that reduce peak demand (demand-side management or demand response programs and certain rate structure programs).

Figure 4-A below shows the EE and DSM programs available through DEC as of December 31, 2021:

Figure 4-A: DEC's Available EE and DSM Programs

Residential EE Programs	Non-Residential EE Programs	Residential DSM Programs	Non-Residential DSM Programs
Energy Efficient Appliances and Devices	Non-Residential Smart $aver® Energy Efficient Products and Assessment	Power Manager	PowerShare®
Energy Efficiency Education	Non-Residential Smart $aver® Performance Incentive		Interruptible Service (IS)
Multi-Family Energy Efficiency	Small Business Energy Saver		Standby Generator (SG)
My Home Energy Report			EnergyWise® Business
Income-Qualified Energy Efficiency and Weatherization Assistance			
Energy Assessments			
Smart $aver® Energy Efficiency			

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.

Demand-Side Management Programs

Residential

Power Manager®

Power Manager® provides residential customers a voluntary demand response program that allows DEC 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® Statistics					
Cumulative As of:	Participants (Customers)	Devices (Switches)	Devices (Thermostats)	Summer 2021 Capability (MW)	Winter 2021 Capability (MW)
December 31, 2021	274,055	296,731	40,608	488.41	8.1

The following table shows Power Manager® program activations that were for the general population from January 1, 2020, through December 31, 2021.

Power Manager® Activations				
Date	Start Time	End Time	Duration (Minutes)	MW Load Reduction
6/3/2020	3:30 PM	3:45 PM	15	225
6/22/2020	4:30 PM	4:45 PM	15	286
7/15/2020	4:00 PM	6:00 PM	120	BYOT Test

Power Manager® Activations				
Date	**Start Time**	**End Time**	**Duration (Minutes)**	**MW Load Reduction**
7/17/2020	3:00 PM	5:00 PM	120	BYOT Test
7/27/2020	4:00 PM	5:00 PM	60	BYOT Test
8/27/2020	4:30 PM	4:45 PM	15	359
8/27/2020	5:00 PM	6:00 PM	60	BYOT Test
9/2/2020	4:30 PM	4:57 PM	27	320
9/3/2020	3:30 PM	5:30 PM	120	BYOT Test
9/11/2020	4:30 PM	5:12 PM	42	262
6/30/2021	5:30 PM	5:58 PM	28	297
7/1/2021	3:00 PM	5:00 PM	60	BYOT Test
7/16/2021	4:00 PM	4:28 PM	28	208
7/28/2021	3:55 PM	5:00 PM	65	235
7/30/2021	3:55 PM	5:00 PM	65	BYOT EM&V
8/11/2021	4:00 PM	4:28 PM	28	Switch EM&V
8/11/2021	4:00 PM	4:28 PM	28	Switch EM&V
8/11/2021	3:55 PM	5:00 PM	65	BYOT EM&V
8/12/2021	4:00 PM	4:28 PM	28	Switch EM&V
8/12/2021	3:55 PM	5:00 PM	65	BYOT EM&V
8/13/2021	3:55 PM	5:00 PM	65	Switch EM&V
8/13/2021	3:55 PM	5:00 PM	65	BYOT EM&V
8/23/2021	4:00 PM	4:28 PM	28	Switch EM&V
8/23/2021	3:55 PM	5:00 PM	65	BYOT EM&V
8/24/2021	4:55 PM	6:00 PM	65	BYOT EM&V
8/27/2021	3:55 PM	5:00 PM	65	Switch EM&V
8/30/2021	2:55 PM	5:00 PM	125	Switch EM&V
8/30/2021	3:55 PM	6:00 PM	125	Switch EM&V
8/30/2021	3:55 PM	5:00 PM	65	BYOT EM&V
9/13/2021	3:55 PM	5:00 PM	65	Switch EM&V

Power Manager® added a summer cooling Bring Your Own Thermostat ("BYOT") option in late December 2019. In December of 2020, the program shifted its focus to a year-round BYOT program, adding an electric heating requirement for program participation and aligning with a winter peak need. Customer acquisition for the BYOT program option through December 2021 is 29,000 participants. Summer capability evaluation, measurement and verification ("EM&V") was performed on the program in 2021.

Non-Residential

Demand Response – Curtailable Programs

The DEC non-residential demand response portfolio consists of a combination of programs that rely either on the customer's ability to respond to a utility-initiated notification or on receipt of a signal to control customer equipment, including small business thermostats. Customers are offered ongoing incentives commensurate to the amount of load they are capable of curtailing.

The 2020 Nexant Market Potential Study ("MPS") forecasted minimal summer and winter non-residential DSM growth opportunities in the Carolinas, particularly for the small and medium business segment. Further, given the expected impact of the Enhanced scenario's doubling of incentives on program cost-effectiveness and future DSM rate adjustments, the Base scenario would be considered more applicable for the large non-residential segment. The large business demand response programs are actively marketed to all customer segments that are known to possess the flexibility to curtail load and have demands high enough to comply with program minimums, which means that there is a simultaneous effort to maximize both winter and summer resources. Although they provide for flexibility in contracting for different winter and summer commitments due to seasonal variations in customers' loads and operational characteristics, the programs are designed to incent participants to provide curtailable demand year-round. This allows for availability of the programs even in off-peak months when scheduled generation maintenance, in conjunction with unseasonable temperatures or other weather events, could lead to the need for demand-side management resources.

DEC's current curtailable programs include:

PowerShare®: A non-residential curtailment program consisting of three options: an emergency-only option for curtailable load (PowerShare® Mandatory), an emergency-only option for load curtailment using on-site generators (PowerShare® Generator), and an economic-based voluntary option (PowerShare® Voluntary).

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® 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® 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.

Interruptible Power Service (IS): (North Carolina Only) Participants agree contractually to reduce their electrical loads to specified levels upon request by DEC. If customers fail to do so during an interruption, they receive a penalty for the increment of demand exceeding the specified level.

Standby Generator Control (SG): (North Carolina Only) Participants agree contractually to transfer electrical loads from the DEC source to their standby generators upon request of the Company. The generators in this program do not operate in parallel with the DEC system and therefore, cannot "backfeed" (i.e., export power) into the DEC system.

EnergyWise® Business: This 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.

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 EE/DSM Collaborative (a long-standing stakeholder group dedicated to advancing EE/DSM programs within DEC and DEP) and then submitted to the applicable public utility commissions as required.

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 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 ("UCT"), Rate Impact Measure ("RIM") Test, Total Resource Cost ("TRC") 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 Commission approved settlement agreements for DEC and DEP through Order Nos. 2021-32 and 2021-33 approving certain changes to the EE/DSM mechanism that governs program approval and cost recovery. As part of the approved settlement agreements, the Companies are required to use the UCT as the determinative cost-effectiveness test in South Carolina.

Energy Efficiency and Demand-Side Management Program Forecasts

Forecast Methodology

In 2019, DEC commissioned a new EE Market Potential Study (MPS) 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 in May 2020 with a final revision completed in June 2020.

In 2021, DEC again retained Resource Innovations (formerly Nexant) to perform a comprehensive update to the 2020 MPS to incorporate Commission required changes as well as address stakeholder and intervenor concerns. As required by PSCSC Order No. 2021-447, the MPS update uses the UCT for economic screening rather than TRC as was used in the original MPS. Additionally, the Company and Resource Innovations worked with the EE/DSM Collaborative to incorporate their feedback and allow for stakeholders to provide additions to the comprehensive measure list, provide input on program design/delivery changes, and assist the Company in identifying opportunities to overcome market barriers and maximize adoption of efficiency measures. The MPS update project is anticipated to be complete in August 2022 and all findings will assist the Company and Collaborative in increasing market acceptance and adoption of existing and emerging energy saving technologies.

The MPS 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 EE/DSM Collaborative and with the possible assistance of implementation contractors.

The MPS included projections of energy efficiency impacts over a 25-year period for Base, Enhanced and Avoided Energy Cost Sensitivity Scenarios, which were used in conjunction with expected EE savings from DEC's five-year program plan to develop the updated Base Case EE savings forecast for this IRP update.

The Base Case EE savings forecast represents a merging of the projected near-term savings from DEC's five-year plan (2021-2025) with the long-term MPS savings projections under UCT economic screening (2031-onward). Savings during the five-year period (2026-2030) between the two sets of projections represents a merging of the two forecasts to ensure a smooth transition. Additionally, the cumulative savings projections include 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 the updated Base Case forecast 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 from the inception of the EE programs in 2009 through the end of 2021, which accounts for an additional 5,731 gigawatt-hour ("GWh") of net energy savings.

The following forecasts are presented without the effects of "roll off":

Projected MWh Impacts of EE Programs - Base Case

Year	ANNUAL MWH LOAD REDUCTION - NET	
	Including Measures Added in 2022 and Beyond	Including Measures Added Since 2009
2009-21		5,731,451
2022	759,896	6,491,347
2023	1,189,495	6,920,946
2024	1,634,810	7,366,261
2025	2,064,850	7,796,301
2026	2,486,614	8,218,065
2027	2,869,172	8,600,623
2028	3,203,331	8,934,782
2029	3,489,089	9,220,540
2030	3,726,447	9,457,898
2031	3,915,404	9,646,855
2032	4,055,962	9,787,413
2033	4,184,496	9,915,947
2034	4,307,588	10,039,039
2035	4,425,606	10,157,057
2036	4,538,993	10,270,444
2037	4,646,329	10,377,780

*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 Chapter 3 – Electric Load Forecast. The tables below provide the projected winter and summer peak MW load impacts of all current and projected DEC DSM programs.

MW Load Impacts of DSM Programs

WINTER PEAK MW REDUCTION								
Year	Power Manager	Powershare Mandatory	Powershare Generator	Interruptible Service (IS)	Standby Generation (SG)	Energywise Business	Advanced Demand Response (ADR)	Total Winter Peak
2022	17	314	9	84	2	2	0	428
2023	61	304	9	80	2	4	8	468
2024	81	307	9	76	2	4	9	488
2025	101	310	9	72	2	4	10	509
2026	122	313	9	69	2	4	11	530
2027	141	313	9	66	2	5	13	548
2028	150	313	9	66	2	5	14	559
2029	160	313	9	66	2	5	16	570
2030	171	313	9	66	2	5	18	583
2031	182	313	9	66	2	6	19	596
2032	193	313	9	66	2	6	21	610
2033	205	313	9	66	2	6	23	624

Projected MW Load Impacts of DSM Programs

SUMMER PEAK MW REDUCTION								
Year	Power Manager	Powershare Mandatory	Powershare Generator	Interruptible service (IS)	Standby Generation (SG)	Energywise Business	Advanced Demand Response (ADR)	Total Summer Peak
2022	17	314	9	84	2	2	0	428
2023	61	304	9	80	2	4	8	468
2024	81	307	9	76	2	4	9	488
2025	101	310	9	72	2	4	10	509
2026	122	313	9	69	2	4	11	530
2027	141	313	9	66	2	5	13	548
2028	150	313	9	66	2	5	14	559
2029	160	313	9	66	2	5	16	570
2030	171	313	9	66	2	5	18	583
2031	182	313	9	66	2	6	19	596
2032	193	313	9	66	2	6	21	610
2033	205	313	9	66	2	6	23	624
2034	656	336	10	70	2	25	37	1136
2035	666	336	10	70	2	26	40	1150

SUMMER PEAK MW REDUCTION								
Year	Power Manager	Powershare Mandatory	Powershare Generator	Interruptible service (IS)	Standby Generation (SG)	Energywise Business	Advanced Demand Response (ADR)	Total Summer Peak
2036	676	336	10	70	2	27	43	1164
2037	684	336	10	70	2	28	47	1177

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

Programs Evaluated but Rejected

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

Integrated Volt-Var Control

Program Description

DEC is beginning implementation of 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 DEC distribution system. IVVC is the coordinated control of distribution equipment in substations and on distribution lines to optimize voltages and power factors on the distribution grid. This allows the distribution system to operate as efficiently as possible without violating load and voltage constraints, while supporting the reactive power needs of the bulk power system. DEC IVVC will begin operations in 2023 and has been modeled to achieve a rollout across 96% of eligible circuits in DEC's service territory over a multi-year timeframe. IVVC has two modes of operation, Peak-Shaving mode, which is counted as a firm capacity resource, and Conservation Voltage Reduction ("CVR") mode, which reduces gross retail load. The Peak-Shaving and CVR modes of operation will be managed by a centralized Distribution Management System ("DMS"). CVR mode will eventually support voltage reduction and energy conservation on a year-round basis across 90% of the hours in the year, as opposed to Peak-Shaving mode which will reduce demand during the remaining peak 10% of hours as a firm capacity resource (similar to demand response programs).

Benefits

The benefits of IVVC include (1) reduced distribution line losses due to lower overall voltage; (2) a more efficient grid due to lower line losses and reduced reactive power; and (3) less generation fuel consumed and lower emissions due to grid efficiencies. Additionally, integrated control of capacitor banks provides greater ability to reduce reactive power, resulting in less apparent load on the system, and less peak load on the grid could result in a reduced need to build additional peaking generation. Finally, optimized control of Volt-VAR devices improves the grid's ability to respond to intermittency and helps to manage integration of distributed energy resources.

DEC (North Carolina & South Carolina) IVVC Annual Estimated Energy Reduction (KWh) Operating CVR 90% of the Hours*		
Year	**IVVC Deployment (%)**	**Total Reduction (KWh)***
2023	10%	36,728,974
2024	20%	74,119,079
2025	100%	373,930,707
2026	100%	377,296,083
2027	100%	380,691,248
2028	100%	384,117,974
2029	100%	387,575,035
2030	100%	391,063,211
2031	100%	394,582,780
2032	100%	398,134,025
2033	100%	401,717,231
2034	100%	405,332,686
2035	100%	408,980,680
2036	100%	412,661,506
2037	100%	416,375,170

*(Energy reduction does not account for system losses upstream of distribution retail substations).

DEC (North Carolina & South Carolina) IVVC Annual Estimated Demand Reduction (KW)* Peak Shaving Mode Approximately ≤10% of the Hours		
Year	**IVVC Deployment (%)**	**Total Reduction (KW)***
2023	10%	16,951
2024	20%	34,207
2025	100%	174,702
2026	100%	178,421
2027	100%	197,354
2028	100%	199,130
2029	100%	200,922
2030	100%	202,731
2031	100%	204,555
2032	100%	206,396
2033	100%	208,254
2034	100%	210,128
2035	100%	212,019
2036	100%	213,927
2037	100%	215,466

*(Demand reduction does not account for system losses upstream of distribution retail substations).

RENEWABLE ENERGY AND ENERGY STORAGE RESOURCES

In this IRP Update, Duke Energy Carolinas ("DEC" or the "Company") has updated its assumptions regarding the forecast for solar and battery storage expected to be operational over the planning horizon ("forecasted solar" and "forecasted storage"), as well as the cost and operational assumptions underlying the solar and other renewable resources available to be selected through the modeling process. Solar development has benefited from a long history of supportive policies, resulting in significant growth of the industry in the Carolinas. As of December 31, 2021, approximately 4,350 megawatts ("MW") of utility-scale solar was connected on the DEC and DEP systems. North Carolina ranked fourth in the country in total solar capacity online as of 2021 while South Carolina ranked 14th.[1]

Supportive policies including competitive procurement of renewable energy and customer programs now being implemented under North Carolina Session Law 2017-192 ("NC HB 589") have contributed to the amount of solar projected to be operational during the first several years of the planning horizon on the Company's system. Longer-term growth of solar, battery storage, and other renewables will be driven by trends in technology costs, customer needs for clean energy solutions, as well as supportive federal and state policies, such as extension of the federal investment tax credit ("ITC") and production tax credit ("PTC"), South Carolina Act 62 ("SC Act 62"), and North Carolina House Bill 951 ("NC HB 951").

The following key assumptions regarding renewable energy were included in the 2022 SC IRP Update:

- All future solar is assumed to be single-axis tracking with bifacial solar panels.
- Annual interconnection limit of 750 MW/year solar beginning by year-end 2026.
- 300 MW/year wind resources available for selection by year-end 2028 across DEC and DEP.
- "Forecasted solar" has been updated consistent with current expectations of solar development pursuant to existing regulatory requirements.

[1] Solar Energy Industries Association State-By-State Map, *available at* https://www.seia.org/states-map.

- All solar capacity under NC HB 589 Competitive Procurement of Renewable Energy ("CPRE") program is assumed to be procured and in service by year-end 2025 with 1,621 MW of the total 1,781 MW located in DEC.
- Renewable and storage resources that may be selected by the model in DEC include: controllable utility owned and operated solar, $38/MWh PPA solar, solar paired with storage, onshore wind, and stand-alone battery storage.

Overview of Results

Based on the assumptions above, some of the key renewable and storage modeling results include:

- Installed solar capacity increases in DEC from 1,453 MW by the end of 2022 to 4,711 MW in 2037.
- Incremental standalone storage additions selected totaling 1,620 MW.
- Neither solar paired with storage, nor onshore wind, are selected in the plan.
- In the alternative case that allows 100% of solar selected to be $38/MWh PPA solar, the model selects the maximum available solar in all years, other than in 2026 when it selects zero solar.

Overview of Forecasted Solar

"Forecasted" solar in the 2022 SC IRP Update includes certain solar resources that are expected to be developed pursuant to existing regulatory requirements and programs in the Carolinas. Similar to the 2020 Modified IRP, the term "Designated" refers to solar that is operational today or that has an executed purchase power agreement ("PPA") but is not yet operational. "Mandated" refers to solar that is not yet operational and has not entered into a PPA, but which is required pursuant to regulatory obligations. "Undesignated" refers to all other solar resources, including those that are selected by the model.[2] The 2022 IRP Update includes an update to the Designated and Mandated categories of solar, based on existing conditions as of February 2022. The Companies have not included any solar expected from the upcoming 2022 Solar Procurement as "forecasted solar," as certainty around the volumes associated with that resource procurement will not be known until later in 2022.

Solar Modeling Assumptions

The 2022 SC IRP Update includes several updates to operational assumptions for solar resources that are available to be selected by the model. Table 5-A below summarizes key solar assumptions included for selectable solar:

[2] Expiring "Designated" solar PPAs are assumed to be replaced in kind and are reflected as "Undesignated" at the end of the contract period.

Table 5-A: Utility Owned and Third-Party PPA Standalone Solar Modeling Assumptions for DEC

Modeling Parameter	
Build Increments	75 MW AC
DC / AC Ratio	1.4
Capacity Factor	27.8%
Dispatchability	Fully Curtailable Down
First Year Available for Model Selection	YE 2026

Standalone solar included in the 2022 SC IRP Update continues to reflect single-axis tracking configuration as was included in the 2020 Modified IRP. An additional modification made in this IRP Update is the assumption that future solar is designed with bifacial panels that further increase the energy output of solar facilities. Additionally, the Companies assumed, for modeling purposes, that up to 60% of future solar would be located in the DEP service territory with the remaining 40% assumed to be located in DEC which reflects the Companies' current expectations of the location of future solar development.

Based on current timelines for interconnection study and construction of required upgrades to interconnect to the grid, the Company estimates that solar resources entering the interconnection process in 2022 would be operational no earlier than 2026. Accordingly, the first year that selectable solar resources are available in the model is 2026.

750 MW Per Year Solar Interconnection Constraint

Consistent with the Commission's directives regarding the volume of solar expected to be interconnected on an annual basis, the 2022 SC IRP Update includes a 750 MW per year constraint on the amount of solar and solar paired with storage that can be selected across DEC and DEP. The 2022 SC IRP Update includes the cost assumed to enable 750 MW per year of solar interconnections, and future IRPs will reflect the Company's estimates of the costs for connecting additional solar. DEC and DEP are also actively working to identify new practices to advance interconnection timelines, as well as, evaluating both the cost and scope of proactive transmission projects needed to increase the annual connections of solar and other resources. While the Companies have assumed a 750 MW annual constraint on the interconnection of solar and storage resources for purposes of this 2022 SC IRP Update, evolving transmission planning and generator interconnection practices may enable increased solar interconnection. Duke Energy will continue to analyze that pace at which new solar can be interconnected in DEC and DEP and reflect any changes to this planning assumption in future IRPs.

Selectable $38/MWh PPA Option

Consistent with the Commission's directives in Order Nos. 2021-447 and 2022-332, the Company has included a $38/MWh PPA option, which the model may select as 50% of the solar available on an annual basis. Additionally, the Company included an alternative case to evaluate 100% of future selectable solar resources being available at the $38/MWh PPA price.

Certain factors suggest that $38/MWh no longer reflects market prices for a 20-year PPA in the Company's service territory, including the overall significant volatility in the solar marketplace today and the anticipated sunsetting of the solar ITC (which has yet to be extended as of June 2022). The Company will gain more market intelligence regarding PPA prices in the Carolinas through the 2022 Solar Procurement, which commenced in June 2022 and is seeking to procure longer-term 25-year controllable solar PPAs. The Company also expects to gain more clarity on federal tax policy and solar panel prices in the coming months and years. As this information is known, the Company will update solar PPA price assumptions in its next comprehensive IRP.

Energy Storage Overview and Forecast

Energy storage is already contributing to the Company's resource mix today and will serve in the future to support additional deployment of intermittent solar resources and act as an important dispatchable resource supporting future coal plant retirements. DEC's Jocassee and Bad Creek pumped storage hydro systems are already contributing 2,300 MW of long-duration storage, and DEC and DEP have been piloting emerging battery storage technologies at several sites in the Carolinas for over a decade. At the state-of-the-art research center in Mount Holly, N.C., the Companies collaborate with vendors, utilities, research labs and government agencies to develop and commercialize an interoperability framework that enables the integration of distributed resources and demonstrates alternative approaches for microgrid operations.

A summary of all energy storage currently installed in DEC is presented in Table 5-B below.

Table 5-B: Energy Storage Systems Located in DEC

System	Location	Type of System	Service Date	Size
Jocassee	Pickens/Oconee County, SC	Pumped Storage Hydro	1973	780 MW
Bad Creek	Oconee County, SC	Pumped Storage Hydro	1991	1,520 MW

In addition to the Company's existing storage resources, approximately 60 MW of 1- and 2-hour battery storage and 50 MW of longer duration storage are included as forecasted resources that represent projects in development on the DEC system. This represents a limited amount of grid-connected battery storage projects that 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.

While there are various types of storage technologies, in the near term, the Company plans to deploy megawatt-scale electrochemical batteries and continue to partner with diverse suppliers who can provide the latest battery technology expertise and resources. DEC will simultaneously continue evaluation of new long-duration storage technologies, including their cost, timing of commercial viability, and value to the grid.

Energy Storage Modeling Assumptions

Energy storage included in the 2022 SC IRP Update as a selectable resource includes both stand-alone storage and solar paired with storage across a range of durations.

Table 5-C below summarizes the storage options that were included in the model:

Table 5-C: Energy Storage Options in 2022 SC IRP Update

Stand-alone Storage	Solar paired with Storage
60 MW / 240 MWh	75 MW solar + 20 MW / 80 MWh battery
60 MW / 360 MWh	75 MW solar + 40 MW / 80 MWh battery
50 MW / 400 MWh	

DEC continues to include solar paired with storage options for selection in the capacity expansion model. For the 2022 SC IRP Update, DEC added a 2-hour battery paired with solar option to be selected along with the 4-hour battery paired with solar option that was available in the 2020 Modified IRP.

Table 5-D: Solar Paired With Storage (50% Battery Ratio) Modeling Assumptions for DEC

Modeling Parameter	
Fuel	N/A
Build Increments	75 MW AC
DC / AC Ratio	1.6
Capacity Factor	32.4%
Battery Power Capacity	40 MW
Battery Storage Capacity	80 MWh
Dispatchability	Fully Curtailable Down

Table 5-E: Solar Paired With Storage (25% Battery Ratio) Modeling Assumptions for DEC

Modeling Parameter	
Fuel	N/A
Build Increments	75 MW AC
DC / AC Ratio	1.6
Capacity Factor	31.8%
Battery Power Capacity	20 MW

Modeling Parameter	
Battery Storage Capacity	80 MWh
Dispatchability	Fully Curtailable Down

NREL ATB Low Battery Storage Costs

Consistent with PSCSC Order No. 2022-332, the Company's selectable battery storage resource prices are consistent with the "Advanced Costs" assumption from the 2021 NREL Annual Technology Baseline ("ATB") report. The NREL ATB Advanced costs are the lowest battery costs in the 2021 report and do not reflect the current supply chain constraints and other factors that are driving battery storage costs higher in the short-term. For the 2023 comprehensive IRP, the Company will seek to incorporate updated market data as it becomes available in order to better align planning assumptions with current market realities for battery storage.

Wind Modeling Assumptions

As in the 2020 SC Modified IRP, onshore wind is included as a selectable resource in DEC. Given that onshore wind is unlikely to be physically located in the DEC service territory, the model assumes a generation profile that serves as a proxy for high-capacity factor wind imported from regions such as PJM or Midcontinent Independent System Operator ("MISO"). The DEC wind resource also includes an estimated wheeling cost for importing wind into the balancing authority.

2022 SC IRP Update Renewable Energy Resource Selection

The details of the renewable energy and battery storage resource additions identified in this 2022 DEC SC IRP Update are summarized in Table 5-F below.

Solar is first allowed to be selected in the model in 2026, and the model selects all of the $38/MWh PPA solar available from that point forward. By the end of the planning horizon in 2037, 1,800 MW of solar is selected, all of which is the $38/MWh PPA option. In the alternative case, which includes all solar as $38/MWh PPA solar, the model does not select any solar in 2026 in DEC, but selects all available solar beginning in 2027. By the end of the planning horizon, 3,300 MW of solar is selected in the 100% $38/MWh PPA case. Solar paired with storage is not selected in either case.

Standalone storage, priced at the NREL ATB Advanced prices, is economically selected in DEC beginning in 2033. By the end of the planning horizon, 1,620 MW of incremental 4-hour, standalone storage is selected by the model. In the alternative case, where 100% of available solar is the $38/MWh option, storage selection is accelerated one year to 2032 and the total amount of storage selected is 1,860 MW with 60 MW being 6-hour storage.

Wind resources are not selected in the 2022 SC IRP Update.

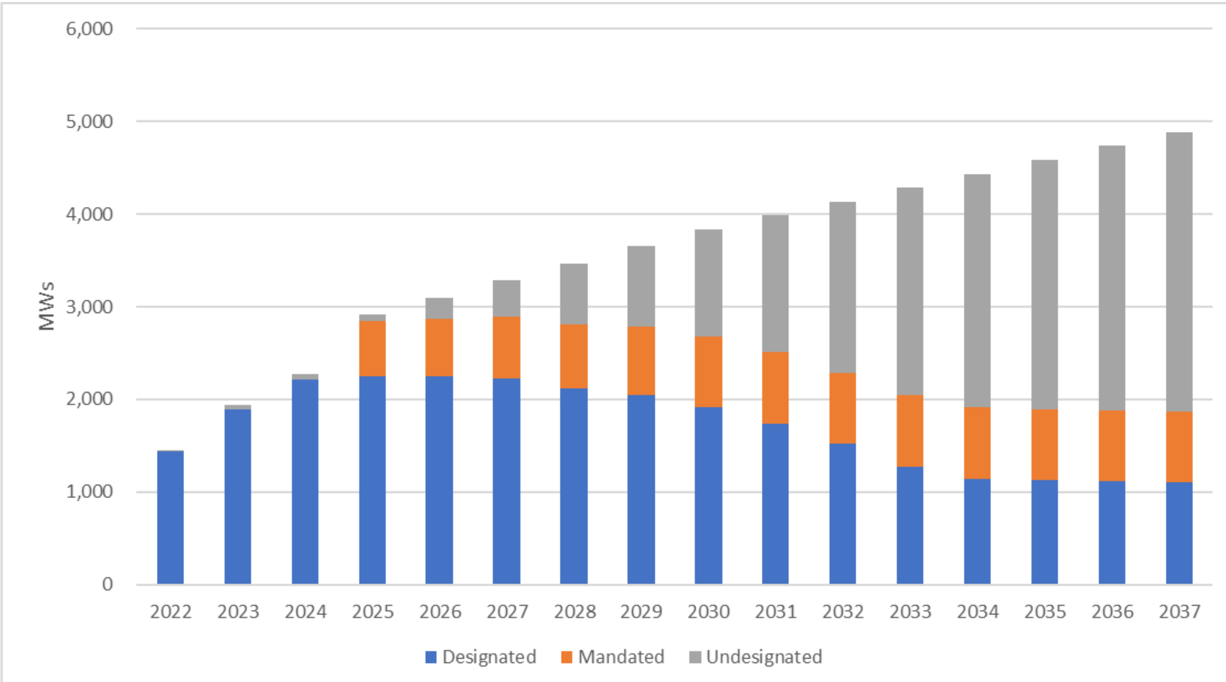
Table 5-F: DEC Base Case Total Renewables and Energy Storage[1]

Year	Solar Only	Solar With Storage	Biomass / Hydro	Wind	Stand Alone Storage[2]	Total Renewables & Storage
2022	1,453	0	103	0	2,300	2,403
2023	1,865	75	92	0	2,329	2,496
2024	2,155	115	69	0	2,382	2,566
2025	2,741	175	61	0	2,412	2,648
2026	2,925	175	54	0	2,412	2,641
2027	3,109	175	41	0	2,412	2,628
2028	3,293	175	40	0	2,412	2,627
2029	3,477	175	38	0	2,412	2,625
2030	3,661	175	24	0	2,412	2,611
2031	3,811	175	13	0	2,412	2,600
2032	3,961	175	2	0	2,412	2,589
2033	4,111	175	0	0	2,532	2,707
2034	4,261	175	0	0	3,852	4,027
2035	4,411	175	0	0	3,852	4,027
2036	4,561	175	0	0	3,972	4,147
2037	4,711	175	0	0	4,032	4,207

Notes: (1) Data presented on a year-end basis. Capacity listed is solar nameplate capacity.
(2) Includes existing pumped storage hydro

Figure 5-A below shows DEC's solar resource additions by designated, mandated, and undesignated categories, which are explained above.

Figure 5-A: DEC Cumulative Solar Capacity



Factors Impacting Future Renewable Energy and Storage Growth

The low-cost assumptions for solar PPAs and battery storage drive significant volumes of solar and battery storage to be selected as economic by the model. Given the disparity between the costs included in the modeling assumptions and the costs of the solar and storage resources available for purchase in the market today, the practical applicability of these modeling results is limited. Numerous economic factors challenge predictability in renewable energy development at this time, including ongoing supply chain constraints and the uncertainty regarding future policies on solar panel tariffs, which will continue to strain the availability of the market to provide solar and battery resources at prices that are consistent with those prices the Commission has required for modeling purposes in this 2022 SC IRP Update.

In the 2023 comprehensive IRP, the Company will further evaluate these forecasted costs to develop assumptions that are more reflective of the prevailing market conditions at that time. Solar resources that are expected to be procured pursuant to other regulatory requirements, such as the 2022 solar procurement underway now, will also be included. Moreover, the Company anticipates updating its Green Source Advantage Programs and other clean energy programs for large customers, which will likely impact the volumes of solar resources shown in future IRP modeling.

DEVELOPMENT OF THE RESOURCE PLAN

Duke Energy Carolinas ("DEC" or the "Company") continues to plan to a winter planning reserve margin criterion in the IRP process as further discussed below. 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 winter planning 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. A high-level representation of the IRP process is represented in Figure 6-A below.

Figure 6-A: Simplified IRP Process

Resource Adequacy and Planning Reserve Margin

Resource adequacy means having sufficient resources available to reliably serve electric demand especially during extreme conditions.[1] Adequate reserve capacity must be available to account for unplanned outages of generating equipment, economic load forecast uncertainty and higher-than-projected demand due to weather extremes. The Company utilizes a reserve margin target in the planning process to ensure resource adequacy. Reserve margin is defined as total resources[2] minus peak demand, divided by peak demand. The reserve margin target is established based on probabilistic reliability assessments.

2020 Resource Adequacy Study

DEC and DEP retained Astrapé Consulting to conduct new resource adequacy studies to support development of the Companies' 2020 IRPs.[3] Astrapé analyzed the planning reserve margin needed to provide an acceptable level of physical reliability based on the industry standard "one-day-in-ten-years" Loss of Load Expectation ("LOLE") metric (or, 0.1 LOLE). This standard is interpreted as one firm load shed event every 10 years due to a shortage of generating capacity.

As described in the resource adequacy studies included and evaluated as part of the 2020 IRPs, Astrapé recommended that DEC and DEP continue to maintain a minimum 17% winter reserve margin for IRP planning purposes. Consistent with this outcome, DEC used a minimum 17% winter reserve margin in the development of the 2022 SC IRP Update. The 2020 DEC Resource Adequacy Study Report was provided as Attachment III to the Company's 2020 IRP.

Effective Load Carrying Capability of Renewable and Storage Resources

The IRP Update includes the addition of significant levels of variable renewable resources and energy-limited storage resources to the system. The effective load carrying capability ("ELCC") or "capacity value" of a resource can be thought of as a measure of the reliable capacity contribution of a resource being added to an existing generation portfolio. Conventional thermal resources are typically dispatchable and available to meet load when not in forced outage or planned maintenance. However, due to the variable energy nature of solar and wind resources and the energy-limited nature of storage resources, it is critical to understand the reliable capacity contributions of these resources in the generation planning

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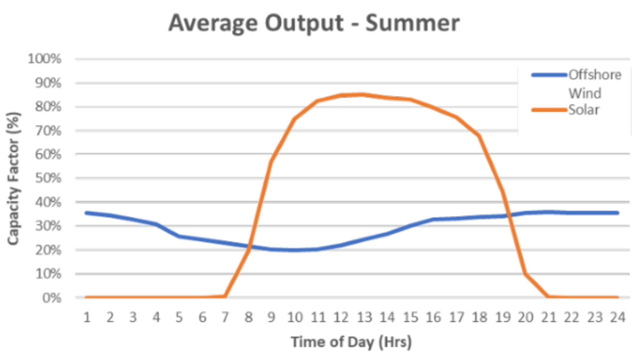
[1] NERC defines "Adequacy" as "[t]he ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components." N. American Elec. Reliability Corp., 2021 Long-Term Reliability Assessment, at 11, *available at* https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf.

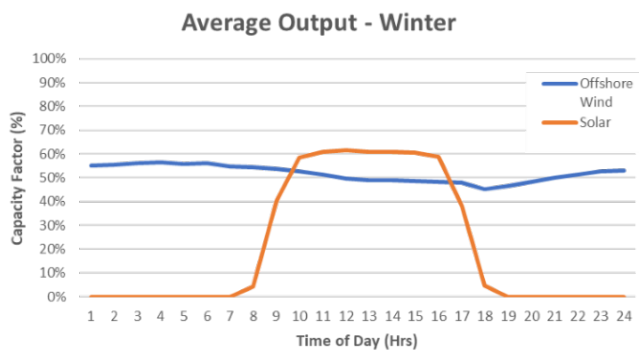
[2] Total resources reflect contribution to peak values for variable resources such as solar and energy-limited resources such as batteries.

[3] Astrapé Consulting is an energy consulting firm with expertise in resource adequacy and integrated resource planning. Astrapé has conducted several Resource Adequacy Studies and Effective Load Carrying Capability Studies for DEC and DEP in recent years.

process. For example, winter peak load for DEC occurs 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. Like solar, onshore and offshore wind resources are also variable energy resources. However, deployment of wind resources can complement solar resources by providing energy to the system during overnight hours or winter months when solar energy is low or not available. Average summer and winter solar and offshore wind profiles are illustrated in Figure 6-B below, which shows the availability of wind generation during hours when solar generation is not available.

Figure 6-B: Average Offshore Wind and Solar Generation Summer and Winter Profiles, Utilized in Encompass Modeling





ELCC Study

The Commission's order requiring modifications to the Companies' 2020 Integrated Resource Plans required the Companies to make several adjustments to the solar and storage ELCC studies as outlined below.[4] This 2022 SC IRP Update incorporates these changes as directed by the Commission.

1. Perform surface ELCCs for solar and storage:

   To accommodate the surface ELCC, Astrapé performed solar only ELCC analyses, storage only ELCC analyses, and storage and solar aggregated ELCC analyses to ensure any synergistic benefits were included. As described in the DEC and DEP ELCC Study report being provided as Attachment I to the IRP Update, this analysis was performed over a broad range of capacity and storage durations. Previously, in the 2020 Storage ELCC Study, the storage ELCC analysis was performed with significant solar on the system, so all synergistic value was given to storage. Similar surface analyses were performed for wind and solar.

[4] South Carolina Docket Nos. 2019-224-E and 2019-225-E, Order No. 2021-447, June 28, 2021, at 87.

2. Use of 2035 Load Forecasts in the Analysis:

   Utilizing the 2035 load forecast captures a larger system and provides these resources more capacity value than would be attributed to the resources if system needs were lower.[5]

3. Use higher capacity factor solar resources:

   All future solar additions were modeled as bifacial, single-axis tracking resources.

4. Incorporate the Company's Winter Peak Demand Reduction Potential Assessment:

   The Winter Peak Study, which included additional demand response programs, adds demand response capacity in both winter and summer.[6]

DEC and DEP worked with Astrapé to conduct a new ELCC study to understand the reliable capacity contributions of solar, onshore wind, offshore wind, and storage for use in the planning process. As previously noted, the ELCC or "capacity value" of a resource can be thought of as a measure of the reliable capacity contribution of a resource being added to an existing generation portfolio. The ELCC of a resource depends on many factors including the load and load shape to be served, the existing resource mix, as well as the adoption level of different resource technologies. A variable renewable resource typically exhibits declining capacity value as adoption increases since saturation occurs, and reliability events shift to periods when that particular resource is not available. The incremental capacity value of a resource may also change as the resource mix of the portfolio evolves around those resources.

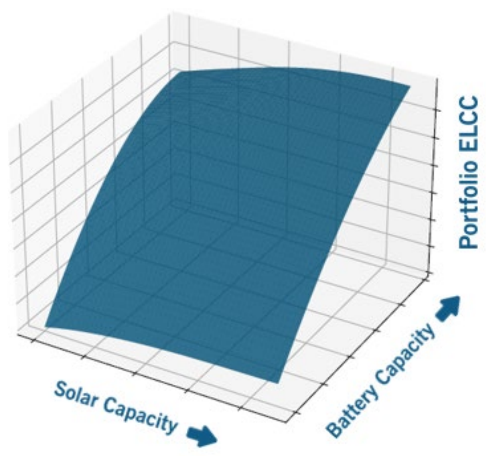
Additionally, the capacity value of variable energy resources can increase as other variable energy resources are added to the system. To evaluate the "synergistic benefits" of adding portfolios of resources together, and in response to stakeholder feedback on the ELCC studies presented in support of the Companies' 2020 IRPs, Astrapé conducted an ELCC surface study rather than a standalone ELCC study where capacity values of resources are evaluated individually.

The surface study revealed that as the deployment of solar resources increases on the system, storage capacity value improves as more energy is available to charge the storage resource. Similarly, storage provides synergistic value to solar capacity value as the dispatch of stored energy can shift peak demand periods from times when solar is not available to hours when the sun is shining.

[5] Given this assumption, ELCCs could potentially be overstated prior to 2035.
[6] The 2020 Winter Peak Demand Reduction Potential Assessment (also referred to as the Winter Peak Study) was prepared for Duke Energy by Dunsky Energy Consulting in partnership with Tierra Resource Consultants. The objective of the study was to identify the potential for new demand response programs and measures to reduce the winter peak demand in each of the DEC and DEP systems.

Figure 6-C below illustrates a typical ELCC surface for solar and storage with one axis representing the adoption of solar, one axis representing the adoption of storage, and the height of the surface representing the combined portfolio ELCC of the resources.

Figure 6-C: Depiction of a Solar and Storage ELCC Surface



Application of ELCC Study in the IRP Update

The EnCompass model selects reliability resources in the capacity expansion process utilizing the incremental capacity value that a resource provides to the system as part of the selection process. For this reason, the ELCC results shown below represent the incremental capacity value allocated to incremental tranches of resources in the EnCompass model.

Importantly, these ELCC results reflect the "synergistic benefits" of other variable resources present on the system. The solar and storage ELCC values used in EnCompass reflect the synergistic effect that these resources have on each other's capacity values as their deployment increases on the system. Additionally, onshore and offshore wind ELCCs were developed at increasing deployments of solar on the system in order to capture the synergistic impact that solar can have on wind capacity value. While the EnCompass model can consider a range of ELCC inputs for multiple technologies, EnCompass cannot presently use a multidimensional ELCC surface as an input. As the model attempts to optimize thousands of combinations of resource options, it can experience difficulty solving within reasonable time parameters. Attempting to integrate any such n-dimensional surface would further inhibit the model's ability and accuracy in assessing resources. For this reason, the Companies applied discreet ELCC values for solar, storage, and wind resources that still recognize the synergistic value that these technologies can provide toward each technology's capacity value.

Finally, as noted above, DEC is a winter planning utility and plans its system to satisfy a minimum winter reserve margin. This means that the hours in which the Company has the most risk of not meeting demand occur during the winter period. When resources are selected in the EnCompass model for the purpose of maintaining adequate reserves, the resources are selected based on their winter capacity value. As such, the tables below represent the incremental winter ELCC values for each resource in the IRP Update.

Solar ELCC

Table 6-A below represents the incremental capacity values attributed to solar resources in the EnCompass capacity expansion model. Capacity tranches are represented in megawatts ("MW").

Table 6-A: DEC Winter Solar Incremental ELCC Values

Capacity Tranche [MW]	ELCC
0 - 2,000	6%
2,001 - 3,000	3%
3,001 - 4,000	2%
4,001 - 5,000	2%
5,001 - 6,000	1%
6,001 - 8,000	1%
8,000+	1%

Storage ELCC

Table 6-B below represents the incremental capacity values attributed to standalone storage resources in the EnCompass model. The Company included a variety of storage durations for the model to select from. The incremental capacity value of the next storage asset added to the system is impacted by the total storage already on the system and the duration of the storage already on the system when the next storage asset is considered. The ELCCs in the tables below reflect that impact.

Table 6-B: DEC Standalone Storage Incremental ELCC Values

Capacity Tranche [MW]	Battery Duration	ELCC
0 - 1,200*	4	100%
1,201 – 2,400	4	95%
2,401 - 3,200	4	80%
3,201 - 4,000	6	70%
4,001 – 5,000	6	50%

Solar Paired with Storage ("SPS") ELCC

The capacity value of storage paired with solar was assumed to be additive between the two resources. Table 6-C below reflects the ELCC values of the total SPS facility for each of the SPS options included in the EnCompass model. For example, a 400 MW facility that is paired with 50%, 2-hour duration storage reflects a 400 MW solar plant paired with 200 MW of 2-hour storage. The ELCC of that facility is 26% or 104 MW (26% * 400 MW).

Table 6-C: DEC Winter Solar Paired with Storage Incremental ELCC Values

Capacity Tranche [MW]	% Storage Paired with Solar	Battery Duration	ELCC
0 – 800	50%	2	26%
0 – 500	25%	4	31%
501 – 1,000	25%	4	30%
1,001 – 1,500	25%	4	29%
1,501 – 2,000	25%	4	29%
2,001 – 2,500	25%	4	28%
2,501 – 3,000	25%	4	27%

Wind ELCC

Table 6-D below details the capacity values for DEC onshore wind.

Table 6-D: DEC Winter Onshore Wind Incremental ELCC Values

Capacity Tranche [MW]	ELCC
0 – 1,000	37%
1,001 – 2,000	32%
2,001 – 3,000	27%

Resource Technologies Considered

Resource technologies included in the 2022 IRP Update as selectable resources are listed below.

Technologies (Winter Ratings):

- Base load – 1,216 MW 2x2x1 Advanced Combined Cycle (No Inlet Chiller and Fired)
- Base Load – 285 MW Small Modular Reactor (SMR)
- Base Load – 345 MW Advanced Nuclear Reactor (AR) with Thermal Storage
- Peaking/Intermediate – 924 MW 4 x 7FA.05 Combustion Turbines (CTs)
- Storage – 60 MW / 240 MWh Li-Ion Battery (4-hour)
- Storage – 60 MW / 360 MWh Li-Ion Battery (6-hour)
- Storage – 50 MW / 400 MWh Li-Ion Battery (8-hour)
- Intermittent – 75 MW Solar PV, Bifacial and Single Axis Tracking (SAT)

- Intermittent – 75 MW Solar PV plus 20 MW / 80 MWh or 40 MW / 80 MWh Li-ion Battery
- Intermittent – 150 MW Onshore Wind

Costs for all technology resources have been updated for this IRP Update. The discussion below provides an overview of adjustments to the technical and operational assumptions for these resource technologies.

Combined Cycle Technology: A 2x1 advanced class CC continues to be used without any significant technology changes.

Small Modular Reactor Technology: The base technology utilized for modeling Small Modular Reactors ("SMRs") has changed, and the SMR option is intended to represent the technology as a whole rather than a specific design. The size change to smaller units allows for greater flexibility for the models.

Advanced Reactor Technology: A new technology option considered an Advanced Reactor ("AR") has been included. ARs are advanced nuclear options that have additional benefits compared to the current operating fleet and do not use light water in the design. ARs are a developing technology similar to SMRs, and significant DOE funding has been awarded to advance the technology. The first AR full scale demonstrations are expected to be online before the end of the decade, paving the way for additional deployments in the 2030s. The AR chosen for modeling includes thermal storage integrated with the design which leads to enhanced flexibility of the plant. There are many technology options considered ARs and similar to SMRs the inclusion represents the technology as a whole rather than a specific company or design.

Combustion Turbine Technology: A 4-unit F.05 Class CT continues to be used without any significant technology changes.

Energy Storage Technology: Lithium-Ion technology remains the dominant energy storage being deployed across the industry. Four-hour, 6-hour, and 8-hour options are included in the modeling. No major adjustments have been made to the energy storage information in the update.

Solar PV Technology: The major adjustment to solar PV is the assumption that panels are now bifacial instead of monofacial, which leads to an increased capacity factor. All solar PV is assumed to utilize a single axis tracking system.

Solar PV Plus Storage Technology: Similar to the solar PV change, all solar PV plus storage assumes panels are bifacial instead of monofacial in the update. The model allows for selection of two different solar plus storage options. The first option is a 20 MW (80 MWh) Li-Ion storage asset included with the solar, which is consistent with the 2020 IRP. For the 2022 IRP Update, DEC included a new storage option consisting of a 40 MW (80 MWh) storage asset.

Onshore Wind Technology: There have been no major technology changes for the onshore wind option.

Portfolio A2 Update Results

As directed by the PSCSC, this 2022 SC IRP Update provides an update to Portfolio A2 as defined in the 2020 SC Modified IRP. Portfolio A2 was developed using the assumption that no federal or state carbon policy would be adopted over the entirety of the planning horizon. In addition, the analysis that resulted in Portfolio A2 was based on certain other assumptions specified by the PSCSC in Order No. 2021-447, including the schedule used to blend market and fundamentals-based natural gas prices, the price at which third-party solar resources will be available, the future costs of energy storage resources, and others. These PSCSC-directed inputs are discussed in more detail throughout this IRP update. It is also noted that DEC considers the non-firm energy purchases and sales associated with the joint dispatch agreement ("JDA") with DEP in the update of Portfolio A2 for the 2022 SC IRP Update.

Tables 6-E and 6-F represent the winter and summer Load, Capacity and Reserves ("LCR") tables for Portfolio A2. The updated Portfolio A2 presented in this document calls for the addition of approximately 3.3 GW of new solar and solar-plus-storage capacity, 1.7 GW of new energy storage capacity, one new combined-cycle generator (1.2 GW) and approximately 0.5 GW of new combustion turbine capacity by 2037. These resource additions would meet growing customer load and replace 3 GW of retiring coal capacity. This analysis continues to assume the most economic retirement dates for the coal units developed in the 2020 IRP, as discussed in Chapter 2 – Updates to the 2020 IRP.

Table 6-E: DEC Portfolio A2 Load, Capacity and Reserves Table – Winter

		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Load Forecast																
1	DEC System Winter Peak	17,312	17,485	17,608	17,736	17,850	18,006	18,217	18,309	18,579	18,805	18,997	19,109	19,496	19,555	19,821
2	Catawba Owner Backstand - NCEMC	84	84	98	98	98	98	98	98	98	98	98	98	98	98	98
3	Cumulative New EE Programs	(81)	(153)	(226)	(295)	(389)	(444)	(493)	(530)	(554)	(561)	(561)	(556)	(563)	(542)	(506)
4	**Adjusted Duke System Peak**	**17,315**	**17,417**	**17,481**	**17,540**	**17,560**	**17,660**	**17,823**	**17,878**	**18,123**	**18,343**	**18,534**	**18,651**	**19,032**	**19,111**	**19,413**
Existing and Designated Resources																
5	Generating Capacity	20,583	20,693	20,307	20,709	20,163	20,163	20,163	20,163	20,163	20,163	20,163	20,163	20,163	18,085	18,085
6	Designated Additions / Uprates	110	80	402												
7	Retirements / Derates	-	(466)	-	(546)	-	-	-	-	-	-	-	-	(2,078)	-	-
8	**Cumulative Generating Capacity**	**20,693**	**20,307**	**20,709**	**20,163**	**20,163**	**20,163**	**20,163**	**20,163**	**20,163**	**20,163**	**20,163**	**20,163**	**18,085**	**18,085**	**18,085**
Purchase Contracts																
9	**Cumulative Purchase Contracts**	**207**	**211**	**202**	**204**	**207**	**208**	**211**	**214**	**208**	**212**	**212**	**212**	**213**	**213**	**213**
	Non-Compliance Renewable Purchases	54	56	46	48	49	49	51	52	44	48	48	48	47	47	47
	Non-Renewables Purchases	154	155	156	156	157	159	160	162	163	164	164	165	165	166	166
Undesignated Future Resources																
10	Nuclear															
11	Combined Cycle										1,216					
12	Combustion Turbine													462		
13	Solar					5	4	4	4	4	4	4	4	3	3	3
14	Wind															
15	Battery												120	1,320		120
Renewables																
16	**Cumulative Renewables Capacity**	**172**	**176**	**213**	**205**	**196**	**198**	**199**	**187**	**187**	**175**	**177**	**300**	**1,622**	**1,624**	**1,746**
	Renewables w/o Storage	150	141	160	152	139	138	135	120	117	101	99	99	99	99	98
	Solar plus Storage	23	35	53	53	53	52	52	52	51	51	51	51	50	50	50
17	**Combined Heat & Power**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
18	**Grid-connected Energy Storage**	**25**	**29**	**53**	**31**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
19	**Cumulative Production Capacity**	**21,142**	**20,792**	**21,275**	**20,753**	**20,747**	**20,751**	**20,755**	**20,746**	**20,740**	**21,948**	**21,950**	**22,073**	**21,780**	**21,782**	**21,905**
Demand Side Management (DSM)																
20	**Cumulative DSM Capacity**	**501**	**522**	**542**	**563**	**581**	**592**	**604**	**615**	**629**	**643**	**657**	**671**	**685**	**699**	**713**
21	**IVVC Peak Shaving**	**17**	**34**	**175**	**178**	**197**	**199**	**201**	**203**	**205**	**206**	**208**	**210**	**212**	**214**	**215**
22	**Cumulative Capacity w/ DSM**	**21,660**	**21,348**	**21,992**	**21,495**	**21,526**	**21,543**	**21,559**	**21,564**	**21,573**	**22,797**	**22,815**	**22,955**	**22,677**	**22,695**	**22,833**
Reserves w/ DSM																
23	Generating Reserves	4,345	3,932	4,511	3,955	3,967	3,883	3,737	3,687	3,451	4,454	4,281	4,303	3,645	3,584	3,420
24	**% Reserve Margin**	**25%**	**23%**	**26%**	**23%**	**23%**	**22%**	**21%**	**21%**	**19%**	**24%**	**23%**	**23%**	**19%**	**19%**	**18%**

Table 6-F: DEC Portfolio A2 Load, Capacity and Reserves Table – Summer

		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Load Forecast																
1	DEC System Summer Peak	17,650	17,772	17,919	18,060	18,203	18,387	18,611	18,792	18,977	19,203	19,411	19,813	19,993	20,420	20,631
2	Catawba Owner Backstand - NCEMC	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
3	Cumulative New EE Programs	(127)	(204)	(279)	(350)	(414)	(471)	(522)	(459)	(410)	(415)	(414)	(408)	(398)	(384)	(363)
4	**Adjusted Duke System Peak**	**17,621**	**17,667**	**17,738**	**17,809**	**17,887**	**18,014**	**18,187**	**18,432**	**18,665**	**18,887**	**19,095**	**19,504**	**19,694**	**20,134**	**20,366**
Existing and Designated Resources																
5	Generating Capacity	19,673	19,768	19,307	19,672	19,128	19,128	19,128	19,128	19,128	19,128	19,128	19,128	19,128	17,070	17,070
6	Designated Additions / Uprates	95	-	365	-	-	-	-	-	-	-	-	-	-	-	-
7	Retirements / Derates	-	(461)	-	(544)	-	-	-	-	-	-	-	-	(2,058)	-	-
8	**Cumulative Generating Capacity**	**19,768**	**19,307**	**19,672**	**19,128**	**19,128**	**19,128**	**19,128**	**19,128**	**19,128**	**19,128**	**19,128**	**19,128**	**17,070**	**17,070**	**17,070**
Purchase Contracts																
9	**Cumulative Purchase Contracts**	629	645	563	577	593	606	621	638	610	646	646	646	646	645	645
	Non-Compliance Renewable Purchases	475	490	408	422	435	448	461	477	447	483	482	481	480	480	479
	Non-Renewables Purchases	154	155	156	156	157	159	160	162	163	164	164	165	165	166	166
Undesignated Future Resources																
10	Nuclear															
11	Combined Cycle										1,155					
12	Combustion Turbine													419		
13	Solar					23	11	11	11	11	11	11	11	6	6	6
14	Wind															
15	Battery												120	1,320		120
Renewables																
16	**Cumulative Renewables Capacity**	**930**	**1,076**	**1,294**	**1,275**	**1,274**	**1,273**	**1,271**	**1,254**	**1,281**	**1,242**	**1,248**	**1,377**	**2,701**	**2,705**	**2,829**
	Renewables w/o Storage	860	968	1,130	1,112	1,089	1,078	1,066	1,039	1,056	1,007	1,004	1,002	1,001	999	998
	Solar plus Storage	71	108	164	163	162	161	160	160	159	158	157	156	156	155	154
17	**Combined Heat & Power**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
18	**Energy Storage**	**25**	**29**	**53**	**31**	**25**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
19	**Cumulative Production Capacity**	**21,379**	**21,108**	**21,663**	**21,145**	**21,184**	**21,197**	**21,210**	**21,210**	**21,209**	**22,361**	**22,367**	**22,496**	**22,180**	**22,184**	**22,308**
Demand Side Management (DSM)																
20	**Cumulative DSM Capacity**	**1,001**	**1,023**	**1,045**	**1,060**	**1,065**	**1,088**	**1,100**	**1,113**	**1,127**	**1,142**	**1,156**	**1,171**	**1,186**	**1,200**	**1,212**
21	**IVVC Peak Shaving**	**17**	**34**	**175**	**178**	**197**	**199**	**201**	**203**	**205**	**206**	**208**	**210**	**212**	**214**	**215**
22	**Cumulative Capacity w/ DSM**	**22,398**	**22,166**	**22,882**	**22,383**	**22,447**	**22,484**	**22,511**	**22,526**	**22,541**	**23,709**	**23,732**	**23,877**	**23,578**	**23,598**	**23,736**
Reserves w/ DSM																
23	Generating Reserves	4,777	4,499	5,144	4,575	4,560	4,470	4,324	4,094	3,875	4,822	4,636	4,373	3,884	3,464	3,370
24	**% Reserve Margin**	**27%**	**25%**	**29%**	**26%**	**25%**	**25%**	**24%**	**22%**	**21%**	**26%**	**24%**	**22%**	**20%**	**17%**	**17%**

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.

Line Item	Line Inclusion[7]
1.	Peak demand for the Duke Energy Carolinas System as defined in Chapter 3 – Electric Load Forecast. This line is net of rooftop solar, electric vehicles, voltage optimization, IVVC load reductions, and net energy metering.
2.	Firm sale of Catawba backstand for NCEMC per contract as follows: 2021 – 2024: (579 MW * 14.5% RM) = 84 MW 2025+: (579 MW * 17% RM) = 98 MW [8]
3.	Cumulative new energy efficiency and conservation programs (does not include demand response programs).
4.	Peak load adjusted for firm sales, NCEMC backstand and cumulative new energy efficiency.
5.	Existing generating capacity reflecting the impacts of designated additions, planned uprates, retirements and derates as of March 1, 2022.
	Includes 103 MW Nantahala hydro capacity.
	Includes only DEC portion of Catawba Nuclear Station capacity.
	Includes Lee CC capacity of 683 MW, which is net of NCEMC ownership of 100 MW.
6.	Designated Capacity Additions
	Bad Creek Runner for Units 3 and 4 upgrades (80 MW per unit deployed in years 2023 and 2024). Once upgrades are made on all units, the total plant will experience a 40 MW derate.
	Lincoln CT 17 of 402 MW in 2025.
	Nuclear uprates: Oconee 1-3; 15 MW per unit deployed in years 2022-2023.
7.	Estimated retirement dates for planning that represent most economical retirement date for coal units as determined in Coal Retirement Analysis developed in the 2020 IRP. Other units represent estimated retirement dates based on the depreciation study approved in the most recent DEC rate case, except as adjusted for reliability purposes: Allen 1 and 5 (426 MW): December 2023 Cliffside 5 (546 MW): December 2025 Marshall 1-4 (2,078 MW): December 2034
	All nuclear units are assumed to have subsequent license renewal at the end of the current license.
	All hydro facilities are assumed to operate through the planning horizon.

[7] Capacity must be on-line by December 1 to be included in available capacity for the winter peak for the following year and by June 1 to be included in available capacity for the summer peak of that year.
[8] DEC is responsible for backstanding the NCEMC capacity.

Line Item	Line Inclusion[7]
	All retirement dates are subject to review on an ongoing basis. Dates used in the 2022 SC IRP Update are for planning purposes only, unless the unit is already planned for retirement.
8.	Sum of lines 5 through 7.
9.	Cumulative Purchase Contracts from traditional resources and renewable energy resources not used for NCREPS and NC HB589 compliance. This is the sum of the next two lines.
	Non-Compliance Renewable Purchases includes purchases from renewable energy resources for which DEC does not own the renewable energy certificate (REC).
	Non-Renewables Purchases are those purchases made from traditional generating resources.
10.	New nuclear resources economically selected to meet load and minimum planning reserve margin. No nuclear resources were selected in Portfolio A2.
11.	New combined cycle resources economically selected to meet load and minimum planning reserve margin.
12.	New combustion turbine resources economically selected to meet load and minimum planning reserve margin.
13.	New solar resources economically selected to meet load and minimum planning reserve margin. The value in the table represents the contribution to peak of the selected solar facilities. See Table 6-A provided earlier in this chapter for ELCC values of solar.
14.	New wind resources economically selected to meet load and minimum planning reserve margin. No wind resources were selected by the models in Portfolio A2.
15.	New battery storage resources economically selected to meet load and minimum planning reserve margin. See Table 6-B provided earlier in this chapter for ELCC values of energy storage.
16.	Cumulative Renewables Capacity includes forecasted renewable energy resources forecasted and model-selected renewable resources. This is the sum of the next two lines combined with the sums of lines 13 through 15.
	Renewables w/o Storage includes projected purchases from solar energy resources not paired with storage and other types of renewables.
	Solar w/ Storage includes projected purchases from solar paired with storage.
17.	Combined Heat and Power projects. No CHP projects are forecasted for DEC.
18.	Grid-connected energy storage additions.
19.	Cumulative total of lines 8 through 18.
20.	Cumulative demand response programs including wholesale demand response.
21.	Cumulative capacity associated with peak shaving of IVVC program.
22.	Sum of lines 19 through 21.
23.	The difference between lines 22 and 4.
24.	Reserve Margin RM = (Cumulative Capacity-System Peak Demand)/System Peak Demand. Line 23 divided by Line 4. Minimum winter target planning reserve margin is 17%.

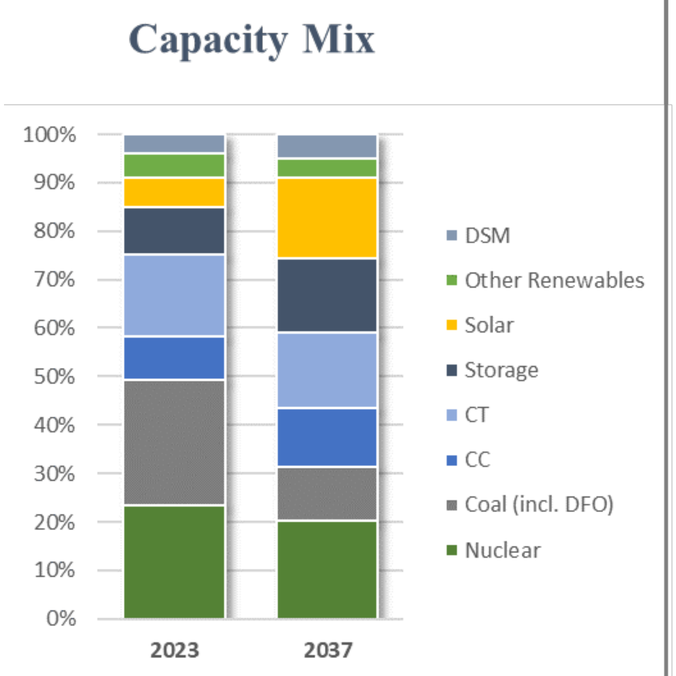
PVRR Results

The present value of revenue requirement ("PVRR") for Portfolio A2 in the 2022 IRP Update for DEC is approximately $48.3 billion. PVRR is a common Integrated Resource Planning cost metric calculated by assessing all future costs associated with a given resource portfolio and discounting those future costs to customers to present day costs using the Company's weighted average cost of capital. This metric captures the cost of adding new generation as well as system production costs. These production costs include operating and maintaining the generation units, fuel costs, labor costs, and other costs to operate and maintain a reliable system. PVRR analysis is typically limited to costs associated with generating electricity to serve load, but starting in the September 2020 IRP, the Company included generic "proxy" estimates of the transmission costs associated with adding new generation and retiring existing units. These generation-related proxy transmission costs are included in the calculations for this IRP update as well.

Portfolio A2 Expansion Plan and Resource Mix

A graphical presentation of Portfolio A2 as represented in the above winter LCR table is shown in Figure 6-D below.

Figure 6-D: DEC Portfolio A2 Update – Winter (Nameplate for Renewables and Storage)



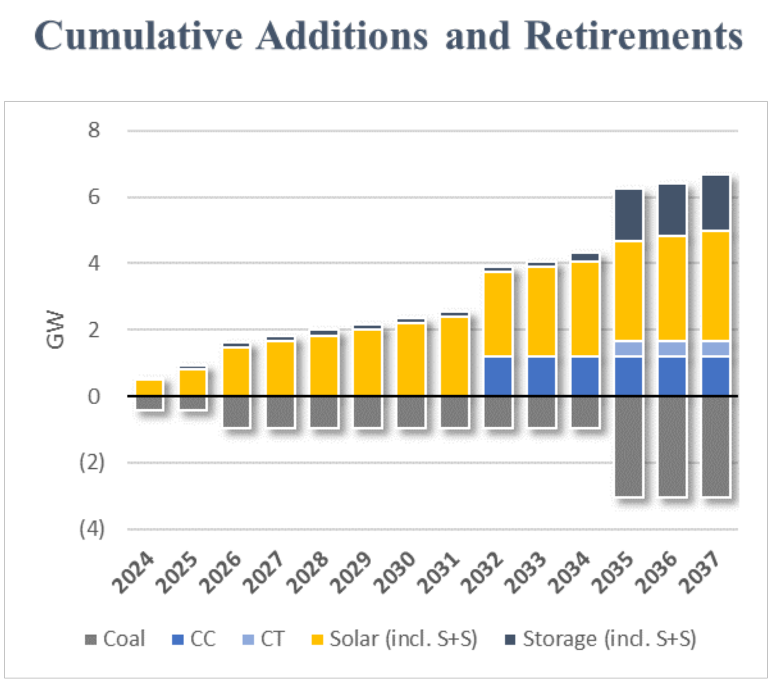


Figure 6-E illustrates both the current and forecasted capacity by fuel type for the DEC system, as developed in Portfolio A2 in more granular detail.

Figure 6-E: DEC 2023 and 2037 Portfolio A2 Winter Capacity Mix [9]

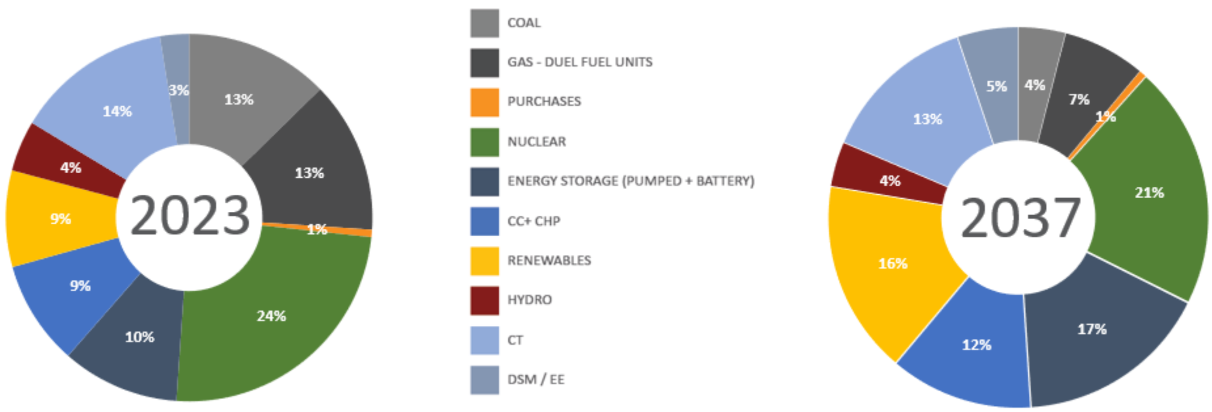


Figure 6-F below represents the incremental resources added in DEC from 2023 to 2037 in Portfolio A2**.**

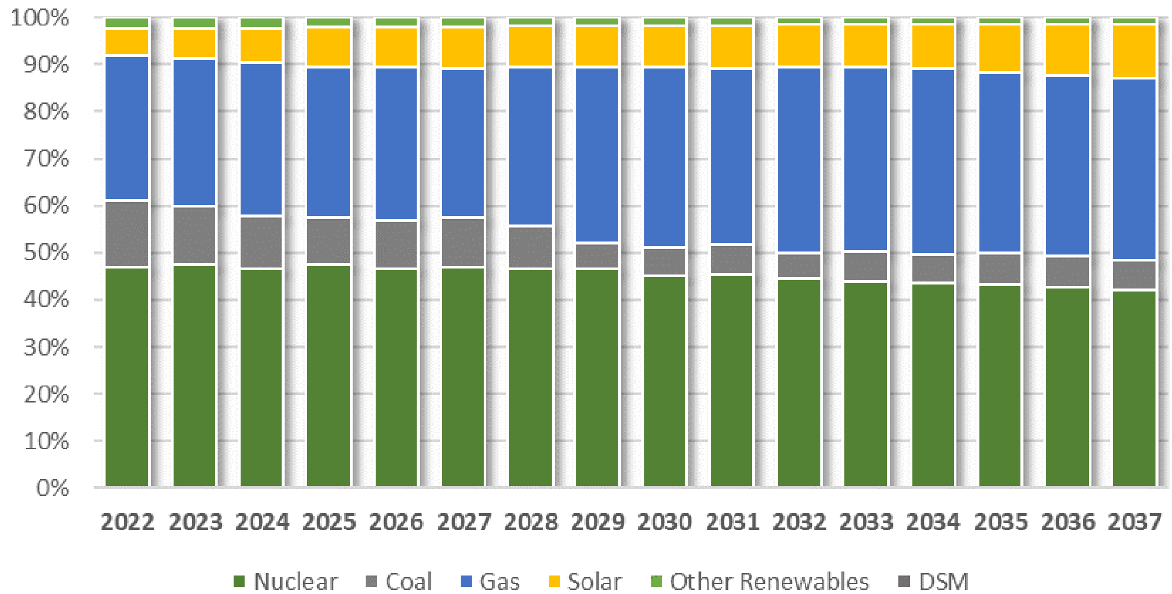
Figure 6-F: DEC Capacity Resources added from 2023 to 2037 in Portfolio A2 (Winter)

Resource Type:	% Added:
Energy Storage (Pumped + Battery)	30%
CC + CHP	17%
Renewables	36%
CT	6%
DSM/EE	12%

[9] EE represents incremental EE and does not reflect impacts of historical efforts. All capacity represents reliable capacity at time of peak with the exception of renewable resources, which represent nameplate capacity.

Figure 6-G represents the energy of both DEC and DEP Portfolio A2 over time. Due to the joint dispatch agreement ("JDA") in place between the Companies, it is prudent to combine the energy of both utilities to develop a meaningful energy figure. From 2023 to 2037, the figure shows that nuclear resources will continue to serve almost half of the energy needs for DEC and DEP. Additionally, Portfolio A2 shows a reduction in the energy served by coal and an increase in the energy served by natural gas, renewables and EE.

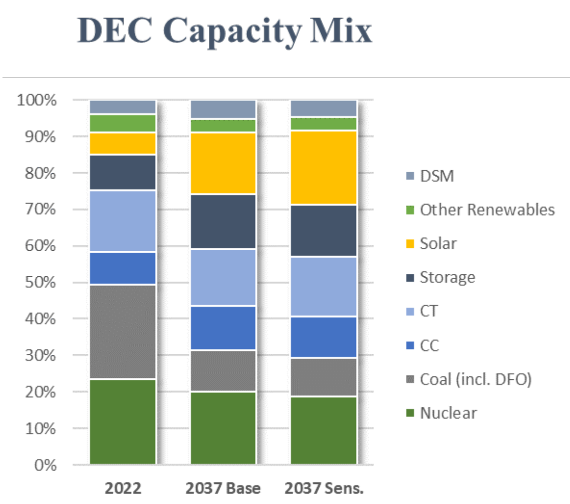
Figure 6-G: Combined DEC and DEP Energy Mix Over Time– Portfolio A2 Update

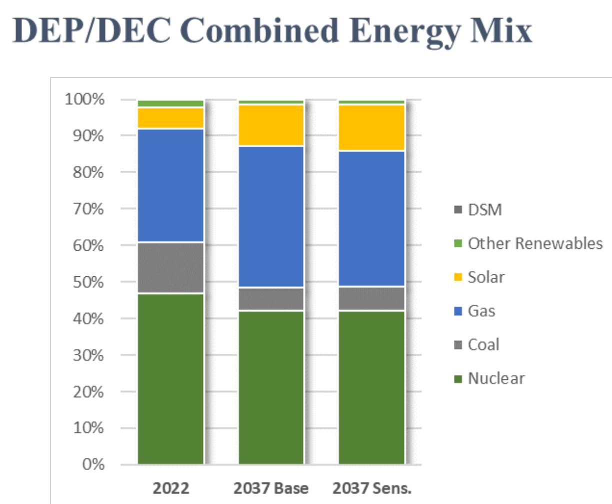


Solar PPA Sensitivity

As described in Chapter 5 – Renewable Energy and Energy Storage Resources, and as directed by the Commission, the Company included a sensitivity analysis in this 2022 SC IRP Update to explore potential changes to the resource portfolio and associated PVRR under the assumption that the $38/MWh solar PPA resource option could comprise up to 100% of new model-selected solar resources. Changing this assumption to increase the portion of new solar that could be comprised of $38/MWh PPAs resulted in the selection of approximately 1.4 GW of additional PPA solar and 0.1 GW of additional battery energy storage above the amounts selected in the base case Portfolio A2 update by 2037 in DEC. No other resource types were affected. Figure 6-H below shows a comparison of the capacity and energy mixes for the base case and the sensitivity case.

Figure 6-H: Portfolio A2 Update Base Case and PPA Sensitivity Capacity and Energy Mixes





As illustrated in Figure 6-H above, the additional solar and storage did not displace any new gas generation in the PPA sensitivity case. The model still selected one new CC unit and approximately 0.5 GW of new CT capacity. Increasing the selectable amount of $38/MWh energy from these PPAs slightly reduced the portion of total DEP/DEC energy supplied by gas resources (a difference of approximately 1.6 percentage points in 2037 from the base case to the sensitivity), but total portfolio PVRR was largely unaffected at $48.2 billion in the PPA sensitivity case compared to $48.3 billion in the base case for DEC. As explained in Chapter 5 – Renewable Energy and Energy Storage Resources, the $38/MWh price is unlikely to be achievable for a 20-year solar PPA.

DEC-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.

Tables 7-A through 7-M below list the Duke Energy Carolinas' plants in service in South Carolina and North Carolina with plant statistics, planned uprates, projected retirement dates, estimated remaining life, relicensing status, and the system's total generating capability. All generating unit ratings are as of January 1, 2022.

Table 7-A: DEC Coal – Existing Generating Units and Ratings

Coal									
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type	Age (Years)	Estimated Remaining Life	Relicensing Status
Allen	1	167	162	Belmont, NC	Coal	Peaking	65	1	N/A
Allen	5	259	259	Belmont, NC	Coal	Peaking	61	1	N/A
Belews Creek *	1	1110	1110	Belews Creek, NC	Coal/Natural Gas	Base	48	16	N/A
Belews Creek *	2	1110	1110	Belews Creek, NC	Coal/Natural Gas	Base	47	16	N/A
Cliffside *	5	546	544	Cliffside, NC	Coal/Natural Gas	Peaking	50	3	N/A
Cliffside *	6	849	844	Cliffside, NC	Coal/Natural Gas	Intermediate	10	26	N/A
Marshall *	1	380	370	Terrell, NC	Coal/Natural Gas	Intermediate	57	12	N/A
Marshall *	2	380	370	Terrell, NC	Coal/Natural Gas	Intermediate	56	12	N/A
Marshall *	3	658	658	Terrell, NC	Coal/Natural Gas	Base	53	2	N/A
Marshall *	4	660	660	Terrell, NC	Coal/Natural Gas	Base	52	2	N/A
Total DEC Coal		6,119	6,087						

Note: Cliffside also called the Rogers Energy Center.

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

Note: *Denotes unit is capable of dual fuel operations (coal and natural gas). Percentage of capacity for maximum standalone natural gas for each unit: Belews Creek 1, Belews Creek 2, Marshall 3, Marshall 4: Up to 50% capable; Cliffside 5, Marshall 1, Marshall 2: Up to 40% capable; Cliffside 6: Up to 100% capable.

Table 7-B: DEC Combustion Turbines – Existing Generating Units and Ratings

Combustion Turbines									
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type	Age (Years)	Estimated Remaining Life	Relicensing Status
Lee	7C	48	42	Pelzer, SC	Natural Gas/Oil	Peaking	15	25	N/A
Lee	8C	48	42	Pelzer, SC	Natural Gas/Oil	Peaking	15	25	N/A
Lincoln	1	94	73	Stanley, NC	Natural Gas/Oil	Peaking	27	18	N/A
Lincoln	2	96	74	Stanley, NC	Natural Gas/Oil	Peaking	27	18	N/A
Lincoln	3	95	73	Stanley, NC	Natural Gas/Oil	Peaking	27	18	N/A
Lincoln	4	94	73	Stanley, NC	Natural Gas/Oil	Peaking	27	18	N/A
Lincoln	5	93	72	Stanley, NC	Natural Gas/Oil	Peaking	27	18	N/A
Lincoln	6	93	72	Stanley, NC	Natural Gas/Oil	Peaking	27	18	N/A
Lincoln	7	95	72	Stanley, NC	Natural Gas/Oil	Peaking	27	18	N/A
Lincoln	8	94	72	Stanley, NC	Natural Gas/Oil	Peaking	27	18	N/A
Lincoln	9	94	71	Stanley, NC	Natural Gas/Oil	Peaking	27	18	N/A
Lincoln	10	96	73	Stanley, NC	Natural Gas/Oil	Peaking	27	18	N/A
Lincoln	11	95	73	Stanley, NC	Natural Gas/Oil	Peaking	27	18	N/A
Lincoln	12	94	73	Stanley, NC	Natural Gas/Oil	Peaking	27	18	N/A
Lincoln	13	93	72	Stanley, NC	Natural Gas/Oil	Peaking	27	18	N/A
Lincoln	14	94	72	Stanley, NC	Natural Gas/Oil	Peaking	27	18	N/A
Lincoln	15	94	73	Stanley, NC	Natural Gas/Oil	Peaking	27	18	N/A
Lincoln	16	93	73	Stanley, NC	Natural Gas/Oil	Peaking	27	18	N/A
Mill Creek	1	94	71	Blacksburg, SC	Natural Gas/Oil	Peaking	19	21	N/A
Mill Creek	2	94	70	Blacksburg, SC	Natural Gas/Oil	Peaking	19	21	N/A
Mill Creek	3	95	71	Blacksburg, SC	Natural Gas/Oil	Peaking	19	21	N/A
Mill Creek	4	94	70	Blacksburg, SC	Natural Gas/Oil	Peaking	19	21	N/A
Mill Creek	5	94	69	Blacksburg, SC	Natural Gas/Oil	Peaking	19	21	N/A

Combustion Turbines									
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type	Age (Years)	Estimated Remaining Life	Relicensing Status
Mill Creek	6	92	71	Blacksburg, SC	Natural Gas/Oil	Peaking	19	21	N/A
Mill Creek	7	95	70	Blacksburg, SC	Natural Gas/Oil	Peaking	19	21	N/A
Mill Creek	8	93	71	Blacksburg, SC	Natural Gas/Oil	Peaking	19	21	N/A
Rockingham	1	179	165	Reidsville, NC	Natural Gas/Oil	Peaking	21	18	N/A
Rockingham	2	179	165	Reidsville, NC	Natural Gas/Oil	Peaking	21	18	N/A
Rockingham	3	179	165	Reidsville, NC	Natural Gas/Oil	Peaking	21	18	N/A
Rockingham	4	179	165	Reidsville, NC	Natural Gas/Oil	Peaking	21	18	N/A
Rockingham	5	179	165	Reidsville, NC	Natural Gas/Oil	Peaking	21	18	N/A
Total DEC CT		3,249	2,633						

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

Table 7-C: DEC Combined Cycle – Existing Generating Units and Ratings

Combined Cycle									
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type	Age (Years)	Estimated Remaining Life	Relicensing Status
Buck	CT11	206	182	Salisbury, NC	Natural Gas	Base	11	25	N/A
Buck	CT12	206	182	Salisbury, NC	Natural Gas	Base	11	25	N/A
Buck	ST10	306	304	Salisbury, NC	Natural Gas	Base	11	25	N/A
Buck CTCC		718	668						
Dan River	CT8	206	177	Eden, NC	Natural Gas	Base	10	30	N/A
Dan River	CT9	206	177	Eden, NC	Natural Gas	Base	10	30	N/A
Dan River	ST7	306	308	Eden, NC	Natural Gas	Base	10	30	N/A
Dan River CTCC		718	662						
WS Lee	CT11	248	237	Pelzer, SC	Natural Gas	Base	4	28	N/A
WS Lee	CT12	248	236	Pelzer, SC	Natural Gas	Base	4	28	N/A
WS Lee	ST10	313	313	Pelzer, SC	Natural Gas	Base	4	28	N/A
WS Lee CTCC		809	786						
Total DEC CTCC		2,245	2,116						

Note: 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 North Carolina Electric Membership Corporation ("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: Resource type based on NERC capacity factor classifications which may vary over the forecast period.

Table 7-D: DEC Combined Heat & Power – Existing Generating Units and Ratings

Combined Heat & Power									
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type	Age (Years)	Estimated Remaining Life	Relicensing Status
Clemson CHP	GT01	15.5	12.5	Pickens, SC	Natural Gas	Base	3	N/A	N/A
Total DEC CHP		15.5	12.5						

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

Table 7-E: DEC Pumped Storage Hydro – Existing Generating Units and Ratings

Pumped Storage Hydro									
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type	Age (Years)	Estimated Remaining Life	Relicensing Status
Jocassee	1	195	195	Salem, SC	Pumped Storage	Peaking	49	24	2046
Jocassee	2	195	195	Salem, SC	Pumped Storage	Peaking	49	24	2046
Jocassee	3	195	195	Salem, SC	Pumped Storage	Peaking	49	24	2046
Jocassee	4	195	195	Salem, SC	Pumped Storage	Peaking	49	24	2046
Bad Creek	1	420	420	Salem, SC	Pumped Storage	Peaking	31	5	2027
Bad Creek	2	420	420	Salem, SC	Pumped Storage	Peaking	31	5	2027
Bad Creek	3	340	340	Salem, SC	Pumped Storage	Peaking	31	5	2027
Bad Creek	4	340	340	Salem, SC	Pumped Storage	Peaking	31	5	2027
Total DEC Pumped Storage Hydro		2,300	2,300						

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

Table7-F: DEC Hydro – Existing Generating Units And Ratings

Hydro									
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type	Age (Years)	Estimated Remaining Life	Relicensing Status
99 Islands	1	4.2	4.2	Blacksburg, SC	Hydro	Peaking	112	14	2036
99 Islands	2	3.4	3.4	Blacksburg, SC	Hydro	Peaking	112	14	2036
99 Islands	3	4.2	4.2	Blacksburg, SC	Hydro	Peaking	112	14	2036
99 Islands	4	3.4	3.4	Blacksburg, SC	Hydro	Peaking	112	14	2036
Bear Creek	1	9.5	9.5	Tuckasegee, NC	Hydro	Peaking	68	19	2041
Bridgewater	1	15	15	Morganton, NC	Hydro	Peaking	103	33	2055
Bridgewater	2	15	15	Morganton, NC	Hydro	Peaking	103	33	2055
Bridgewater	3	1.5	1.5	Morganton, NC	Hydro	Peaking	103	33	2055
Cedar Cliff	1	6.4	6.4	Tuckasegee, NC	Hydro	Peaking	70	19	2041
Cedar Cliff	2	0.4	0.4	Tuckasegee, NC	Hydro	Peaking	70	19	2041
Cedar Creek	1	15	15	Great Falls, SC	Hydro	Peaking	96	33	2055
Cedar Creek	2	15	15	Great Falls, SC	Hydro	Peaking	96	33	2055
Cedar Creek	3	15	15	Great Falls, SC	Hydro	Peaking	96	33	2055
Cowans Ford	1	81	81	Stanley, NC	Hydro	Peaking	59	33	2055
Cowans Ford	2	81	81	Stanley, NC	Hydro	Peaking	59	33	2055
Cowans Ford	3	81	81	Stanley, NC	Hydro	Peaking	59	33	2055
Cowans Ford	4	81	81	Stanley, NC	Hydro	Peaking	59	33	2055
Dearborn	1	14	14	Great Falls, SC	Hydro	Peaking	99	33	2055
Dearborn	2	14	14	Great Falls, SC	Hydro	Peaking	99	33	2055
Dearborn	3	14	14	Great Falls, SC	Hydro	Peaking	99	33	2055
Fishing Creek	1	11	11	Great Falls, SC	Hydro	Peaking	106	33	2055
Fishing Creek	2	10	10	Great Falls, SC	Hydro	Peaking	106	33	2055
Fishing Creek	3	10	10	Great Falls, SC	Hydro	Peaking	106	33	2055

Hydro									
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type	Age (Years)	Estimated Remaining Life	Relicensing Status
Fishing Creek	4	11	11	Great Falls, SC	Hydro	Peaking	106	33	2055
Fishing Creek	5	9	9	Great Falls, SC	Hydro	Peaking	106	33	2055
Great Falls	1	0	0	Great Falls, SC	Hydro	Peaking	115	33	2055
Great Falls	2	0	0	Great Falls, SC	Hydro	Peaking	115	33	2055
Great Falls	5	0	0	Great Falls, SC	Hydro	Peaking	115	33	2055
Great Falls	6	0	0	Great Falls, SC	Hydro	Peaking	115	33	2055
Keowee	1	76	76	Seneca, SC	Hydro	Peaking	51	24	2046
Keowee	2	76	76	Seneca, SC	Hydro	Peaking	51	24	2046
Lookout Shoals	1	9	9	Statesville, NC	Hydro	Peaking	107	33	2055
Lookout Shoals	2	9	9	Statesville, NC	Hydro	Peaking	107	33	2055
Lookout Shoals	3	9	9	Statesville, NC	Hydro	Peaking	107	33	2055
Mountain Island	1	14	14	Mount Holly, NC	Hydro	Peaking	99	33	2055
Mountain Island	2	14	14	Mount Holly, NC	Hydro	Peaking	99	33	2055
Mountain Island	3	17	17	Mount Holly, NC	Hydro	Peaking	99	33	2055
Mountain Island	4	17	17	Mount Holly, NC	Hydro	Peaking	99	33	2055
Nantahala	1	45	45	Topton, NC	Hydro	Peaking	80	20	2042
Oxford	1	20	20	Conover, NC	Hydro	Peaking	94	33	2055
Oxford	2	20	20	Conover, NC	Hydro	Peaking	94	33	2055
Queens Creek	1	1.4	1.4	Topton, NC	Hydro	Peaking	73	10	2032
Rhodhiss	1	9.5	9.5	Rhodhiss, NC	Hydro	Peaking	97	33	2055
Rhodhiss	2	11.5	11.5	Rhodhiss, NC	Hydro	Peaking	97	33	2055
Rhodhiss	3	12.4	12.4	Rhodhiss, NC	Hydro	Peaking	97	33	2055
Tennessee Creek	1	11.5	11.5	Tuckasegee, NC	Hydro	Peaking	67	19	2041
Thorpe	1	19.7	19.7	Tuckasegee, NC	Hydro	Peaking	81	19	2041

Hydro									
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type	Age (Years)	Estimated Remaining Life	Relicensing Status
Tuckasegee	1	2.5	2.5	Tuckasegee, NC	Hydro	Peaking	72	19	2041
Wateree	1	17	17	Ridgeway, SC	Hydro	Peaking	103	33	2055
Wateree	2	17	17	Ridgeway, SC	Hydro	Peaking	103	33	2055
Wateree	3	17	17	Ridgeway, SC	Hydro	Peaking	103	33	2055
Wateree	4	17	17	Ridgeway, SC	Hydro	Peaking	103	33	2055
Wateree	5	6	6	Ridgeway, SC	Hydro	Peaking	103	33	2055
Wylie	1	18	18	Fort Mill, SC	Hydro	Peaking	97	33	2055
Wylie	2	18	18	Fort Mill, SC	Hydro	Peaking	97	33	2055
Wylie	3	18	18	Fort Mill, SC	Hydro	Peaking	97	33	2055
Wylie	4	6	6	Fort Mill, SC	Hydro	Peaking	97	33	2055
Total DEC Hydro		1,054	1,054						
Note: Resource type based on NERC capacity factor classifications which may vary over the forecast period.									

Table 7-G: DEC Solar – Existing Generating Units and Ratings

Solar								
	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type	Age (Years)	Estimated Remaining Life	Relicensing Status
NC Solar	182	182	NC	Solar	Intermittent	Various	N/A	N/A
Total DEC Solar	182	182						

Note: Solar capacity ratings reflect nameplate capacity.

Table 7-H: DEC Nuclear – Existing Generating Units and Ratings

Nuclear									
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type	Age (Years)	Estimated Remaining Life	Relicensing Status
McGuire	1	1199	1158	Huntersville, NC	Nuclear	Base	41	19	2041
McGuire	2	1187.2	1157.6	Huntersville, NC	Nuclear	Base	38	21	2043
Catawba	1	1198.7	1160.1	York, SC	Nuclear	Base	37	21	2043
Catawba	2	1179.8	1150.1	York, SC	Nuclear	Base	36	21	2043
Oconee	1	865	847	Seneca, SC	Nuclear	Base	49	11	2033
Oconee	2	872	848	Seneca, SC	Nuclear	Base	48	11	2033
Oconee	3	881	859	Seneca, SC	Nuclear	Base	48	11	2034
Total DEC Nuclear		7,383	7,180						

Note: Catawba Units 1 and 2 capacity reflects 100% of the station's capability. Breakdown of Catawba ownership: Duke Energy Carolinas 19.246%; North Carolina Electric Membership Corporation ("NCEMC") 30.754%; NCMPA#1 37.5%; PMPA 12.5%.

Table 7-I: Total Generation Capability

Total Generation Capability		
	Winter Capacity (MW)	Summer Capacity (MW)
Total DEC System – N.C.	13,236	12,599
Total DEC System – S.C.	9,311	8,965
Total DEC System	22,547	21,564

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

Table 7-J: Planned Adoptions/Uprates

Planned Additions / Uprates			
Unit	Date	Winter MW	Summer MW
Bad Creek	Sept 2022	80	80
Bad Creek	Sept 2023	80	80
Oconee 1	Jan 2023	15	15
Oconee 2	Jan 2022	15	15
Oconee 3	May 2022	15	15

Note: This capacity not reflected in unit ratings in above tables.

Note: Nuclear dates represent projected work completion dates, not MNDC uprate date.

Table 7-K: Unit Retirements

Unit Retirements					
Unit Name	Location	Capacity (MW) Winter / Summer		Fuel Type	Retirement Date
99 Islands 5	Blacksburg, SC	0	0	Hydro	12/31/18
99 Islands 6	Blacksburg, SC	0	0	Hydro	12/31/18
Allen 2	Belmont, NC	167	162	Coal	12/31/21
Allen 3	Belmont, NC	270	258	Coal	3/31/21
Allen 4	Belmont, NC	267	257	Coal	12/31/21
Bryson City 1 [A]	Whittier, NC	0.5	0.5	Hydro	8/16/19
Bryson City 2 [A]	Whittier, NC	0.4	0.4	Hydro	8/16/19
Buck 3	Salisbury, NC	76	75	Coal	5/15/11
Buck 4	Salisbury, NC	39	38	Coal	5/15/11
Buck 5	Spencer, NC	131	128	Coal	4/1/13
Buck 6	Spencer, NC	131	128	Coal	4/1/13
Buck 7C	Spencer, NC	30	25	Natural Gas/Oil	10/1/12
Buck 8C	Spencer, NC	30	25	Natural Gas/Oil	10/1/12
Buck 9C	Spencer, NC	15	12	Natural Gas/Oil	10/1/12
Buzzard Roost 6C	Chappels, SC	22	22	Natural Gas/Oil	10/1/12
Buzzard Roost 7C	Chappels, SC	22	22	Natural Gas/Oil	10/1/12
Buzzard Roost 8C	Chappels, SC	22	22	Natural Gas/Oil	10/1/12
Buzzard Roost 9C	Chappels, SC	22	22	Natural Gas/Oil	10/1/12
Buzzard Roost 10C	Chappels, SC	18	18	Natural Gas/Oil	10/1/12
Buzzard Roost 11C	Chappels, SC	18	18	Natural Gas/Oil	10/1/12
Buzzard Roost 12C	Chappels, SC	18	18	Natural Gas/Oil	10/1/12
Buzzard Roost 13C	Chappels, SC	18	18	Natural Gas/Oil	10/1/12
Buzzard Roost 14C	Chappels, SC	18	18	Natural Gas/Oil	10/1/12
Buzzard Roost 15C	Chappels, SC	18	18	Natural Gas/Oil	10/1/12
Cliffside 1	Cliffside, NC	39	38	Coal	10/1/11
Cliffside 2	Cliffside, NC	39	38	Coal	10/1/11
Cliffside 3	Cliffside, NC	62	61	Coal	10/1/11
Cliffside 4	Cliffside, NC	62	61	Coal	10/1/11
Dan River 1	Eden, NC	69	67	Coal	4/1/12
Dan River 2	Eden, NC	69	67	Coal	4/1/12
Dan River 3	Eden, NC	145	142	Coal	4/1/12
Dan River 4C	Eden, NC	0	0	Natural Gas/Oil	10/1/12
Dan River 5C	Eden, NC	31	24	Natural Gas/Oil	10/1/12
Dan River 6C	Eden, NC	31	24	Natural Gas/Oil	10/1/12
Franklin 1[A]	Franklin, NC	0.5	0.5	Hydro	8/16/2019

Unit Retirements					
Unit Name	**Location**	**Capacity (MW) Winter /**	**Summer**	**Fuel Type**	**Retirement Date**
Franklin 2[A]	Franklin, NC	0.5	0.5	Hydro	8/16/2019
Gaston Shoals 3[A]	Blacksburg, SC	0	0	Hydro	8/16/2019
Gaston Shoals 4[A]	Blacksburg, SC	0	0	Hydro	8/16/19
Gaston Shoals 5[A]	Blacksburg, SC	2	2	Hydro	8/16/19
Gaston Shoals 6 [A]	Blacksburg, SC	2.5	2.5	Hydro	8/16/19
Great Falls 3	Great Falls, SC	0	0	Hydro	5/31/18
Great Falls 4	Great Falls, SC	0	0	Hydro	5/31/18
Great Falls 7	Great Falls, SC	0	0	Hydro	5/31/18
Great Falls 8	Great Falls, SC	0	0	Hydro	5/31/18
Lee 1	Pelzer, SC	100	100	Coal	11/6/14
Lee 2	Pelzer, SC	102	100	Coal	11/6/14
Lee 3	Pelzer, SC	170	170	Coal	5/12/15
Lee 3	Pelzer, SC	170	170	Natural Gas Boiler	3/31/22
Mission 1 [A]	Murphy, NC	0.6	0.6	Hydro	8/16/19
Mission 2 [A]	Murphy, NC	0.6	0.6	Hydro	8/16/19
Mission 3 [A]	Murphy, NC	0.6	0.6	Hydro	8/16/19
Riverbend 4	Mt. Holly, NC	96	94	Coal	4/1/13
Riverbend 5	Mt. Holly, NC	96	94	Coal	4/1/13
Riverbend 6	Mt. Holly, NC	136	133	Coal	4/1/13
Riverbend 7	Mt. Holly, NC	136	133	Coal	4/1/13
Riverbend 8C	Mt. Holly, NC	0	0	Natural Gas/Oil	10/1/12
Riverbend 9C	Mt. Holly, NC	30	22	Natural Gas/Oil	10/1/12
Riverbend 10C	Mt. Holly, NC	30	22	Natural Gas/Oil	10/1/12
Riverbend 11C	Mt. Holly, NC	30	20	Natural Gas/Oil	10/1/12
Rocky Creek 1	Great Falls, SC	0	0	Hydro	5/31/18
Rocky Creek 2	Great Falls, SC	0	0	Hydro	5/31/18
Rocky Creek 3	Great Falls, SC	0	0	Hydro	5/31/18
Rocky Creek 4	Great Falls, SC	0	0	Hydro	5/31/18
Rocky Creek 5	Great Falls, SC	0	0	Hydro	5/31/18
Rocky Creek 6	Great Falls, SC	0	0	Hydro	5/31/18
Rocky Creek 7	Great Falls, SC	0	0	Hydro	5/31/18
Rocky Creek 8	Great Falls, SC	0	0	Hydro	5/31/18
Tuxedo 1 [A]	Flat Rock, NC	3.2	3.2	Hydro	8/16/19
Tuxedo 2 [A]	Flat Rock, NC	3.2	3.2	Hydro	8/16/19
Total DEC Retirements		3,010	2,899		

Note A: Sold to Northbrook Energy on August 16, 2019.

Table 7-L: Planning Unit Retirements

Planning Unit Retirements					
Unit & Plant Name	Winter Capacity (MW)	Summer Capacity (MW)	Location	Fuel Type	Expected Retirement
Allen 1	167	162	Belmont, NC	Coal	12/2023
Allen 5	275	266	Belmont, NC	Coal	12/2023
Cliffside 5	546	544	Cliffside, NC	Coal	12/2025
Marshall 1	380	370	Terrell, NC	Coal	12/2034
Marshall 2	380	370	Terrell, NC	Coal	12/2034
Marshall 3	658	658	Terrell, NC	Coal	12/2034
Marshall 4	660	660	Terrell, NC	Coal	12/2034
Total DEC	3,066	3,030			

Note: Retirement assumptions are for planning purposes only; retirement dates determined in analysis.

Note: Coal retirement dates represent the most economic retirement dates as developed in the 2020 IRP and utilized in the 2020 SC Modified IRP.

Note: All retirement dates assume retirement at the end of year represented.

Note: For planning purposes, the 2022 SC IRP Update assumes subsequent license renewal for existing nuclear facilities beginning at end of current licenses. Total planning retirements exclude nuclear capacities.

Table 7-M: 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	3/3/2041
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: For planning purposes, the 2022 SC IRP Update assumes subsequent license renewal for existing nuclear facilities beginning at end of current licenses. Total planning retirements exclude nuclear capacities.

WHOLESALE CONTRACTS

The following tables describe the wholesale sales and purchases contracts for Duke Energy Carolinas ("DEC").

Wholesale Sales Contracts

Aggregated Table 8-A below includes wholesale sales contracts that are included in the Fall 2021 Load Forecast.

Wholesale Purchase Contracts

Aggregated Table 8-B below includes all wholesale purchase contracts that are included as resources in the DEC 2022 SC IRP Update.

Table 8-A: DEC Wholesale Sales Contracts

DEC Aggregated Wholesale Sales Contracts Commitment (MW)									
2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1,960	1,984	2,007	2,033	2,051	2,077	2,100	2,121	2,140	2,161

Note: Backstand contract values represent the reserve margin amount. For example, for NCEMC Backstand of Catawba 17% *579 = 98 MWs.

Note: For wholesale contracts, Duke Carolinas assumes all wholesale sales contracts will renew unless there is an indication that the contract will not be renewed.

Note: Table represents winter capacity.

Table 8-B: DEC Aggregated Firm Wholesale Purchase Power Contracts

Purchased Power Contract	Winter Capacity (MW)	Location	Volume of Purchases (MWh) Jan 21 – Dec 21
Peaking / Fuel Oil	21	NC	21,268
Peaking / Gas	91	NC/SC	399,572
Peaking / Hydro	8	GA/AL/SC	38,006
Base / Nuclear	51	NC	280,443
System	4	NC	148,791

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

FUEL COMMODITY PRICES

Natural Gas

The natural gas price forecast used for this 2022 SC IRP Update incorporates both a short-term, market-based price forecast and longer-term, fundamentals-based price forecasts, as well as a transition period from market-based pricing to fundamentals-based pricing. Specifically, the natural gas price forecast consists of eighteen months of market-based pricing (2023 to mid-2024), an eighteen-month transition from market to fundamentals-based pricing (mid-2024 to 2025), and fundamentals-based pricing for the remainder of the study period (2026-2037).

In addition to short-term market price volatility, longer-term natural gas price forecasts have also varied among fundamentals providers and can be significantly impacted by the assumptions made in each provider's forecast and the time at which each forecast is issued especially when some forecasts are only produced once or twice per year. To limit reliance on any single fundamentals-based forecast, for this 2022 SC IRP Update the Company used an average of the following four recent natural gas price forecasts:

- Energy Information Administration's ("EIA") Annual Energy Outlook ("AEO") Reference Case (2021 AEO)
- Wood Mackenzie North American Power Markets (Base Case) (2021)
- EVA FuelCast (2021)
- IHS Markit Long-Term Natural Gas Outlook (August 2021)

Coal

Coal market volatility has increased in recent years for a variety of reasons, all of which increase risks to coal supply assurance in the Carolinas. There have been significant coal generation retirements across the nation as power generators transition their fleets to lower carbon energy sources, such as renewables and natural gas. Additional planned retirements for the nation's aging coal facilities contribute to the continuing deterioration of the domestic coal supply chain. Customer fuel cost and fuel unavailability risks increase as coal production continues to decrease. The decline in supply flexibility and increase in market uncertainty create future risks for coal supply assurance and ultimately create risks for customers. While the Company continues to focus on coal supply assurance, these affordability and reliability risks support retiring coal facilities and developing new advanced generation dispatch methodologies to manage the energy transition. Full consideration of these evolving risks is beyond the limited purpose of IRP updates, and the Company looks forward to addressing these issues more completely in its next comprehensive IRP filing.

The coal price forecast used for this IRP Update consists of eighteen months of market-based pricing (2023 to mid-2024), an eighteen-month transition from market to fundamentals-based pricing (mid-2024 to 2025), and fundamentals-based pricing for the remainder of the study period (2026-2037). The fundamentals-based price forecast is an average of recent forecasts from the same four providers used for the natural gas price forecast.

Table 9-A below provides the fuel commodity prices used in the DEC 2022 SC IRP Update for natural gas, coal, and fuel oil.

Table 9-A: DEC Annual Average Fuel Prices ($/MMBtu)

Year	Natural Gas Henry Hub	Coal DEC Average	Fuel Oil Average
2023	$6.08	$6.97	$24.98
2024	$4.97	$5.74	$21.10
2025	$3.83	$4.82	$21.73
2026	$3.31	$3.79	$22.38
2027	$3.44	$3.87	$23.05
2028	$3.58	$3.97	$23.75
2029	$3.70	$4.07	$24.46
2030	$3.82	$4.14	$25.19
2031	$3.94	$4.22	$25.95
2032	$4.07	$4.30	$26.73
2033	$4.22	$4.38	$27.53
2034	$4.31	$4.47	$28.35
2035	$4.46	$4.58	$29.21
2036	$4.61	$4.67	$30.08
2037	$4.74	$4.78	$30.98

CROSS REFERENCE – ACT 62 REQUIREMENTS AND COMMISSION ORDER NOS. 2021-447 AND 2022-332

Requirement	Source	Location
An electrical utility and the Public Service Authority shall each submit annual updates to its integrated resource plan to the commission. An annual update must include an update to the electric utility's or the Public Service Authority's base planning assumptions relative to its most recently accepted integrated resource plan, including, but not limited to: energy and demand forecast, commodity fuel price inputs, renewable energy forecast, energy efficiency and demand-side management forecasts, changes to projected retirement dates of existing units, along with other inputs the commission deems to be for the public interest.	§ 58-37-40(D)(1)	Ch. 2- Updates to Base Planning Assumptions (overview of updates to base planning assumptions) Ch. 3 – Electric Load Forecast (energy & demand forecast) Ch. 4 – Energy Efficiency, Demand Side Management and Voltage Optimization (EE/DSM forecast) Ch. 5 – Renewable Energy and Energy Storage Resources (renewable energy forecast) Ch. 7 – DEC-Owned Generation (unit retirement dates) Ch. 8 – Wholesale Contracts (wholesale

Requirement	Source	Location
		purchases/sales) Ch. 9 – Fuel Commodity Prices (fuel price inputs)
The electrical utility's or Public Service Authority's annual update must describe the impact of the updated base planning assumptions on the selected resource plan.	§ 58-37-40(D)(1)	Ch. 2 – Updates to Base Planning Assumptions
Duke is required to use the UCT when developing EE/DSM scenarios and savings projections in its future IRPs, IRP updates, and market potential studies.	Order No. 2021-447 Ordering Paragraph 2 Finding of Fact Nos. 2-4	Ch. 4 – Energy Efficiency, Demand Side Management and Voltage Optimization
In future IRPs, IRP updates and market potential studies, Duke must work with the EE/DSM Collaborative to identify a set of reasonable assumptions surrounding 1) increased market acceptance of existing technologies and 2) emerging technologies to incorporate into EE/DSM saving forecasts.	Order No. 2021-447 Ordering Paragraph 3 Finding of Fact Nos. 2-4	Ch. 4 – Energy Efficiency, Demand Side Management and Voltage Optimization
Duke should make a number of changes to its development of effective load carrying capability ("ELCC") values and revisions to its capacity expansion modeling that incorporates those ELCC values, including: (a) Applying single step-optimization rather than multi-step optimization when conducting its capacity expansion modeling; (b) Creating an ELCC "surface" that determines the combined capacity value of different portfolios of solar and storage; (c) Revising ELCC studies by: (i) Varying ELCC as a function of load, including applying a 2035 load profile; (ii) Modeling all future solar as single-axis tracking consistent with industry trends; and (iii) Updating DR values to include those identified in the Winter Peak Demand Reduction Potential Assessment.	Order No. 2021-447 Ordering Paragraph 6 Finding of Fact Nos. 6-10	Ch. 6 – Development of Resource Plan Attachment I Updated 2022 ELCC Study
In its Modified IRP, IRP Update, and future full IRPs, Duke shall remodel its portfolios using natural gas pricing forecasts that rely on market prices for eighteen months before transitioning over eighteen	Order No. 2021-447 Ordering Paragraph 10 Finding of Fact Nos.	Ch. 9 – Fuel Commodity Prices

Requirement	Source	Location
months to the average of at least two fundamentals-based forecasts, as recommended by CCEBA Witness Lucas.	12-14	
In the Modified IRP and IRP Update, Duke shall include third-party solar PPAs priced at $38/MWh as a selectable resource. Any change to this pricing in subsequent IRPs or IRP Updates shall be supported by a reasonable investigation into market conditions in Duke's service territories. For purposes of modeling solar PPAs as a selectable resource, the Company shall assume a contract term of at least 20 years, and operational characteristics identical to CPRE projects.	Order No. 2021-447 Ordering Paragraph 11-12 Finding of Fact Nos. 15-17	Ch. 5 – Renewable Energy and Energy Storage Resources
In its Modified IRP and future IRPs, Duke shall use the NREL ATB Low figures for battery storage costs	Order No. 2021-447 Ordering Paragraph 16 Finding of Fact No. 20	Ch. 5 – Renewable Energy and Energy Storage Resources
In its Modified IRP and next IRP Update, Duke shall assume a 750 MW annual limitation on the interconnection of solar and storage resources.	Order No. 2021-447 Ordering Paragraph 17 Finding of Fact Nos. 21-23	Ch. 5 – Renewable Energy and Energy Storage Resources
In future IRPs, including Modified IRPs and IRP Updates, Duke shall perform and include a minimax regret analysis of the type described and performed in this proceeding by CCEBA Witness Lucas.[1]	Order No. 2021-447 Ordering Paragraph 19 Finding of Fact No. 24	N/A (DEC's 2022 SC IRP Update models updated base planning assumptions for Portfolio A2. No other portfolios were developed for comparison purposes required to perform a minimax regret analysis. Such analysis will be conducted in the 2023 IRP.)
In all future IRPs and IRP Updates, Duke shall	Order No. 2021-447	Ch. 5 – Renewable

[1] In Order No. 2021-509, the Commission clarified that the Companies were to perform the minimax regret analysis recommended and described by ORS Witness Kollen.

Requirement	Source	Location
include a solar purchase power resource option as a sensitivity.	Ordering Paragraph 20	Energy and Energy Storage Resources
Recommend the Companies provide additional justification for its Battery Energy Storage fixed O&M cost and capacity factor assumptions.	Order No. 2021-447 Ordering Paragraph 22	Ch. 5 – Renewable Energy and Energy Storage Resources
Duke Energy Progress, LLC and Duke Energy Carolinas, LLC shall include the following modeling or scenarios to be evaluated and examined as part of the next IRP filing, whether an update or comprehensive plan: pricing and support per Order No. 2021-447, third-party solar PPAs as a selectable option for (a) fifty percent (50%) or half of the 750 MW renewable interconnection limit per year; and (b) one hundred percent (100%) of the 750 MW renewable interconnection limit per year.	Order No. 2022-332 Ordering Paragraph 2	Ch. 5 – Renewable Energy and Energy Storage Resources

GLOSSARY OF TERMS

AC or A/C	Alternating Current
ACT 62	South Carolina Energy Freedom Act of 2019
AEO	Annual Energy Outlook
AR	Advanced Reactor
ATB	Annual Technology Baseline
BOEM	Bureau of Ocean Energy Management
BTM	Behind-the-meter
BYOT	Bring Your Own Thermostat
CC	Combined Cycle
CHP	Combined Heat and Power
CIG	Commercial, Industrial and Governance
COD	Commercial Operation Date
COMMISSION	Public Service Commission of South Carolina
CPP	Critical Peak Pricing
CPRE	Competitive Procurement of Renewable Energy
CT	Combustion Turbine
CVR	Conservation Voltage Reduction
DEC	Duke Energy Carolinas, LLC
DEP	Duke Energy Progress, LLC
DMS	Distribution Management System
DOE	Department of Energy
DR	Demand Response
DSM	Demand-Side Management
EE	Energy Efficiency
EEE	Energy Efficiency Engineers
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability

GLOSSARY OF TERMS

EV	Electric Vehicles
GW	Gigawatt
GWh	Gigawatt-hour
HRSG	Heat Recovery Steam Generator
IPI	Industrial Production Index
IRP	Integrated Resource Plan
IS	Interruptible Service
ITC	Federal Investment Tax Credit
IVVC	Integrated Volt-Var Control
JDA	Joint Dispatch Agreement
kW	Kilowatt
kW-AC	Kilowatts-alternating current
kWh	Kilowatt-hour
LCR Table	Load, Capacity and Reserves Table
Li-ION	Lithium Ion
LOLE	Loss of Load Expectation
M&V	Measurement and Verification
MISO	Midcontinent Independent Operator
MPS	Market Potential Study
MMBtu	Million British Thermal Units
MW	Megawatt
MWh	Megawatt-hour
NC	North Carolina
NC HB 589	North Carolina House Bill 589
NC HB 951	North Carolina House Bill 951
NC REPS or REPS	North Carolina Renewable Energy and Energy Efficiency Portfolio Standard
NCEMC	North Carolina Electric Membership Corporation
NCUC	North Carolina Utilities Commission
NEM	Net Energy Metering
NREL	National Renewable Energy Laboratory
O&M	Operating and Maintenance
PPA	Purchase Power Agreement
PSCSC	Public Service Commission of South Carolina
PSH	Pumped Storage Hydro
PTC	Production Tax Credit
PV	Photovoltaic
PVRR	Present Value Revenue Requirement
QF	Qualifying Facility

GLOSSARY OF TERMS

REC	Renewable Energy Certificate
REPS or NC REPS	Renewable Energy and Energy Efficiency Portfolio Standard
RFP	Request for Proposal
RIM	Rate Impact Measure
SAE	Statistical Adjusted End-Use Model
SAT Solar	Single-Axis Tracking Solar
SC	South Carolina
SG	Standby Generation or Standby Generator Control
SLR	Subsequent License Renewal
SMR	Small Modular Reactor
SPS	Solar Paired With Storage
TE	Transportation Electrification
The Company	Duke Energy Carolinas
TOU	Time-of-Use
TRC	Total Resource Cost
UCT	Utility Cost Test
UEE	Utility Energy Efficiency
VAR	Volt Ampere Reactive
VAST	Vehicle Analytics and Simulation Tool
VVO	Volt-Var Optimization