Dominion Energy®

2020 Integrated Resource Plan

Dominion Energy South Carolina, Inc.

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Executive Summary

For decades, utilities created Integrated Resource Plans ("IRP") to show when customer demand growth required the addition of new resources. During that time, the load forecast and fuel price were the most influential factors in determining which resource plans had the most cost-effective features to provide a safe and reliable supply.

Historically load growth was well anticipated, and even fuel prices were relatively well-known. Other factors like demand side management, energy efficiency, environmental regulations, and greenhouse gas emissions have increasingly dictated the research of additional options and consideration of those options against different measures.

Over the planning horizon, Dominion Energy South Carolina, Inc. ("DESC" or "Company") expects societal trends toward clean energy to continue. Many customer segments from universities and financial institutions to retail chains have expressed interest in renewable energy solutions. Indeed, many large companies including some of the State's largest employers have publicly committed to 100% renewable energy. Moreover, South Carolina cities including Columbia and Charleston are each developing clean energy initiatives with the goal of decreasing their overall carbon footprint.

Furthermore, DESC intends to utilize more power generated from clean energy sources. This IRP also reflects DESC's commitment to clean energy in the energy efficiency programs offered to customers and in the probable modifications to the Company's electric transmission and distribution grid which will facilitate the growth of clean energy solutions while assuring that energy continues to be provided in a safe, reliable, and affordable manner. Aside from the expanding interest in clean energy, renewable resources continue to become a more cost-effective means of meeting the growing energy needs of customers. For example, the continuing development of solar photovoltaic technology has made this type of generation more cost-competitive with traditional forms of generation. Currently, this type of generation does not meet all of the needs of a highly dynamic and critical infrastructure system like the electric grid. It will take innovation and research to find a cost-effective combination of generation, transmission, and distribution to provide reliable clean energy for the future.

In addition to these rapidly increasing influences, the South Carolina General Assembly has enacted new requirements beginning with the 2020 IRP that have impacted its content and scope. Some topics not directly relevant to the required content were not carried over from previous IRPs. Instead, the content is highly focused on information needed to understand and interpret the range of model inputs and sensitivities, and ultimately, the comparison of results shown in the Resource Plan Analysis section.

The newly enacted Act No. 62 as codified at S.C. Code Ann. § 58-37-40(B)(1) establishes mandatory content of IRPs as detailed in the table on Page 4 in the Introduction section. Topics and requirements include sensitivities on the load forecast, generation technologies, renewable resources, electric transmission plans, demand side management ("DSM"), generator retirements, fuel costs, and environmental regulations. As directed, multiple resources plans have been created to provide reliability while including a mix of retirements, new generation technologies, and the expansion of renewables. Several sensitivities are modeled by varying the inputs so relevant comparisons can be made. These sensitivities include CO_2 costs, natural gas/commodity pricing, and customer usage/demand.

Part I explains the considerations and analysis that have resulted in the load forecast including consideration of the relatively new electric vehicle ("EV") market in South Carolina. The Charleston Metropolitan area is poised for EV growth. The overall demographics, the DESC partnership with the Charleston Area Regional Transportation Authority and plans by other private entities to add larger more robust charging stations are helping EV growth in the strongest market. The Company anticipates that the strong growth in Charleston will continue to gain strength. The Company is also seeing strong interest for EV charging along major transportation corridors. Similar adoption rates are expected to follow in markets such as Columbia, Hilton Head and Aiken. The increased local energy demand will certainly require adaptation, initially in all urban areas, and later in rural areas. Urban distribution systems will need additional support from automation and hardening investment in the next few years. DESC will continue to evaluate the EV markets and infrastructure and their potential impact on load. The Company is considering the impact of privately-owned cars and trucks, transit buses, school buses, off road vehicles and commercial fleet vehicles. The demand and energy impact from EV charging is expected to impact grid-level planning in this decade, and the IRP will be adjusted as the EV forecast matures.

Although a preferred scenario is not named in the Resource Plan Analysis, focusing on the most likely inputs identifies Resource Plan 2 ("RP2") that features combustion turbines to maintain the Reserve Margin as the least cost. Resource Plan 8 ("RP8") that features the retirement of all coal generation by 2030 shows modestly higher costs but yields the greatest

CO_2 reductions. These results show a path to CO_2 reductions and associated costs. RP8 could result in a 59% CO_2 reduction by 2030 from 2005 levels verses only a 39% reduction in RP2.

DESC concludes that no major changes to the generation fleet are required in the near term to meet customer's energy and capacity needs in a safe, affordable and reliable manner. However, with a commitment to a more sustainable energy future, the Company needs to upgrade its electric system through measures such as rolling out Advanced Metering Infrastructure ("AMI"), converting some of its older peaking generation to more reliable and quick- start peaking generation, continuing to expand DSM, and studying transmission system to minimize the impact of eventual steam unit retirements and additional intermittent renewable generation.

Introduction

This document presents DESC's IRP which includes several resource plans for meeting the energy and capacity needs of its customers over the next fifteen years, 2020 through 2034. This document is filed with the Public Service Commission of South Carolina ("Commission") in accordance with S.C. Code Ann. § 58-37-40 (2019) and Order No. 98-502 and satisfies the annual reporting requirements of the Utility Facility Siting and Environmental Protection Act, S.C. Code Ann. § 58-33-430 (2015). The objective of the Company's IRP is to develop a resource plan that will provide safe, reliable cost-effective energy to the Company's customers while complying with all laws and regulations. Given the dynamic nature of the current electric power industry with respect to societal trends, customer preferences, technological advances, and environmental regulations, it is important that Company remain flexible with respect to expansion plans. As such, the resource plans identified in this 2020 IRP present several plausible paths the Company may or may not elect to pursue. What's most imperative is that the Company remain agile regarding expansion of its electric generation portfolio. Therefore, at this time, the Company recommends following a short-term plan consistent with RP2 (and other grid modifications identified in the Conclusions section of this IRP). Simultaneously, the Company shall continue to study and reasonably develop the alternatives put forth in RP8.

DESC's IRP is organized into four parts:

Part I presents the expected loads and peaks on the DESC system over the next fifteen years. Winter peak load forecasted annual growth fell from 0.9% in DESC's 2019 IRP to 0.7% in the 2020 IRP. Many factors were considered in the load forecast including historical sales data, economic factors impacting the Company's commercial and residential customers, DSM which includes energy efficiency ("EE") and load management, and EVs. Low and high demand growth estimates were also derived as required under §58-37-40(B)(1)(a) of Act No. 62 to validate the reasonableness of the final load forecast.

Part II discusses DESC's programs for meeting its demand and energy forecasts, beginning with existing demand and supply-side resources. Highlights include both current expanded DSM programs that will be proposed to customers over the next five years beginning in 2020 since the Potential Study was completed and approved in 2019. The resulting report "Dominion Energy South Carolina: 2020–2029 Achievable DSM Potential and PY10–PY14 Program Plan" (the "2019 Potential Study") was approved by the Public Service Commission of

South Carolina in December 2019 pursuant to Commission Order No. 2019-880. From this study, the DSM target increased from a 0.33% reduction in retail sales growth in the 2019 IRP to 0.7% by 2023 in the 2020 IRP. The supply-side resources include the current generation portfolio along with discussions about the extreme age of equipment and its end of useful life. A detailed listing can be found in the Existing Long-term Supply Resource Table which lists life expectancy/retirement date as required in Act No. 62 as codified at SC Code Ann. § 58-37-40(B)(1)(a). A detailed Resource Plan Analysis was performed to assess generation scenarios that could meet the future needs of DESC's customers. Several resource plans were created by varying retirements, environmental regulations, and additional renewable resources. While the Company makes observations and conclusions as to which resource plan results in the least cost, the results do not reflect any final decision by the Company for its path forward.

Part III summarizes DESC's transmission planning practices and program development for timely modifications to the DESC transmission system to ensure reliable and economical delivery of power. DESC assesses and designs its transmission system to be compliant with the requirements as set forth in the North American Electric Reliability Corporation ("NERC") Reliability Standards. A summary of the electrical transmission investments planned by the DESC are provided based on the latest assessment studies. The transmission expansion plan is continuously reviewed and may change due to changes in key data and assumptions. This summary of projects does not represent a commitment to build.

Conclusions are presented in Part IV.

Appendix A contains the results of five resource plans run by DESC using the DESC PROSYM production model but with inputs specifically defined by intervening third parties. Although the intervenor resource plans utilized many of the same data inputs, no direct comparisons to DESC's resource plans were included in this IRP due to the low resource cost information provided by the third parties, which in DESC's view, results in a low portfolio cost bias and prevents a practical comparison.

Pursuant to the requirements in S.C. Code Ann. § 58-37-40(B), this IRP (1) demonstrates through various scenarios the resource adequacy and capacity to serve the anticipated peak electrical load and its applicable planning reserve margins, (2) identifies the least cost for consumer affordability, (3) is in compliance with applicable state and federal regulations, (4) ensure power supply reliability, (5) minimizes commodity price risks, and (6) offers diversity in its generation supply. The details of the IRP requirements under Act No. 62 are shown in the following table along with a reference to each section of the Company's IRP demonstrating compliance:

Act 62 Requirements

Act No. 62 58-37-40	Requirement	2020 IRP Section
(B)(1)(a)	a long-term forecast of the utility's sales and peak demand under various reasonable scenarios;	I.A I.B
(B)(1)(b)	the type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including fuel cost sensitivities under various reasonable scenarios;	II.B.5.c
(B)(1)(c)	projected energy purchased or produced by the utility from a renewable energy resource;	II.B.3.c
(B)(1)(d)	a summary of the electrical transmission investments planned by the utility;	III
(B)(1)(e)	several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand response measures, including consideration of the following: (i) customer energy efficiency and demand response programs; (ii) facility retirement assumptions; and (iii) sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks;	II.B.5.c II.B.3.d
(B)(1)(f)	data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio;	II.B.1 II.B.3 II.B.4.a
(B)(1)(g)	plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan;	II.B.5.c
(B)(1)(h)	an analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs; and	II.B.5.c
(B)(1)(i)	a forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.	I.A II.A.1 II.A.2
(B)(2)	An integrated resource plan may include distribution resource plans or integrated system operation plans.	II.A.2 II.B.2

Table of Abbreviations	
Abbreviation	**Name**
ACE	Affordable Clean Energy
ATW	Ash Transport Water
BAA	Balancing Authority Area
BEV	Battery Electric Vehicles
BSER	Best System of Emissions Reduction
CC	Combined Cycle Power Plant
CO_2	Carbon Dioxide
DER	Distributed Energy Resource
DR	Demand Response
DSM	Demand Side Management
EE	Energy Efficiency
EIA	Energy Information Administration
EIPC	Eastern Interconnection Planning Collaborative
ELG	Effluent Limitation Guidelines
EPA	Environmental Protection Agency
ERO	Electric Reliability Organization
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulphurization
GWh	Gigawatt Hour
HVAC	Heating, Ventilation, and Air Conditioning
ICT	Internal Combustion Turbine
kW	Kilowatt
kWh	Kilowatt Hour
MW	Megawatt
MWh	Megawatt Hour
NEEP	Neighborhood Energy Efficiency Program
NERC	North American Electric Reliability Corporation
NPV	Net Present Value
ORS	Office of Regulatory Staff
PHEV	Plug-in Hybrid Electric Vehicles
PPA	Power Purchase Agreement
PV	Photovoltaic
SCADA	Supervisory Control and Data Acquisition
SEPA	Southeastern Power Administration

I. Demand and Energy Forecast for the Fifteen-Year Period Ending 2034

A. DESC's Annual Energy Sales and Peak Demand by Season

The following table shows the Company's annual sales and its gross peak demand, i.e., its total internal demand, by season over the next fifteen years.

Annual Energy and Demand Forecast By Season			
	Annual Sales GWh	Peak Demands Summer MW	Peak Demands Winter MW
2020	24,003	4,816	4,891
2021	24,091	4,847	4,924
2022	24,029	4,879	4,955
2023	24,097	4,905	4,964
2024	24,092	4,916	4,992
2025	24,163	4,941	5,022
2026	24,252	4,967	5,051
2027	24,334	4,993	5,077
2028	24,404	5,019	5,102
2029	24,490	5,041	5,152
2030	24,682	5,090	5,209
2031	24,882	5,146	5,266
2032	25,131	5,201	5,319
2033	25,365	5,256	5,375
2034	25,587	5,309	5,428

Note: winter season follows summer.

Over this planning horizon, the Company is projecting through its statistical and econometric forecasting models that sales will grow at 0.5% while the summer and winter peak demands both grow at 0.7%. The following two tables show the Company's projected demand response capacity and the resulting net firm peak demand, i.e., net internal demand, by season. The net firm peak demand in summer and winter are projected to grow at 0.7%.

Net Firm Peak Hour Demand by Year					
Demand Response			Net Firm Peak		
Year	Peak Demands Summer MW	Peak Demands Winter MW	Year	Peak Demands Summer MW	Peak Demands Winter MW
2020	227	224.4	2020	4,589	4,667
2021	228	225.9	2021	4,619	4,698
2022	229	227.7	2022	4,650	4,727
2023	230	230.2	2023	4,675	4,733
2024	231	234.0	2024	4,685	4,758
2025	232	239.4	2025	4,709	4,782
2026	233	248.9	2026	4,734	4,802
2027	234	261.1	2027	4,759	4,815
2028	235	275.4	2028	4,784	4,826
2029	236	276.4	2029	4,805	4,875
2030	237	277.4	2030	4,853	4,931
2031	238	278.4	2031	4,908	4,987
2032	239	279.4	2032	4,962	5,039
2033	240	280.4	2033	5,016	5,094
2034	241	281.4	2034	5,068	5,146

B. Economic Scenario Analysis

The Company analyzed the sensitivity of its sales growth rate as required by § 58-37-40(B)(1)(a) under Act No. 62. The forecasted growth rate in sales over the 15-year IRP planning horizon of 2020-2034 is 0.5%. To develop a low growth scenario, DESC analyzed the first time it experienced a 15-year negative growth rate which was in 2019 with a compounded annual growth rate of (0.1) %. During this period 2004-2019, DESC lost several wholesale customers. When the growth rate is adjusted for this unusual loss, the growth rate increases to 0%. Given that the State of South Carolina has experienced strong economic growth in recent years, a growth rate of 0% over the long term is highly unlikely. Therefore, the average of this 0% and the base case growth rate of 0.5% was used in the low growth scenario. The low growth rate then is 0.25%. For the high growth scenario, DESC analyzed its growth rate experience prior to the Great Recession which occurred from December 2007 through June 2009. The 15-year growth rates experienced by the Company during this period included a high of 3.4% and a low of 2.7% occurring just prior to the recession, i.e., over the period 1992-2007. When analyzing the detail behind the 2.7% growth rate, the residential and commercial customer growth rates were unusually high, due in part to the housing bubble leading to the recession. Also, the growth in wholesale sales was unreasonable as a proxy for the future because of changes in that class. When the 2.7% was adjusted for these components, the growth rate dropped to 1.7% and was selected as the high growth rate for this scenario analysis. While it is certainly true that DESC's sales could grow less than the low rate of 0.25% or more than the high rate of 1.7%, these rates represent reasonable ranges for the sales forecast. The changes in sales and peak demands from the base case that result are shown in the following table.

Annual Energy Forecast and Seasonal Peak Demand Change from Base Forecast for High and Load DSM

High Scenario: Change from Base				Low Scenario: Change from Base			
Year	Annual Sales GWh	Peak Demands Summer MW	Peak Demands Winter MW	Year	Annual Sales GWh	Peak Demands Summer MW	Peak Demands Winter MW
2020	0.0	0.0	0.0	2020	0.0	0.0	0.0
2021	297.9	59.9	60.9	2021	-49.8	-10.0	-10.2
2022	598.0	121.4	123.3	2022	-99.2	-20.1	-20.5
2023	905.1	184.2	186.4	2023	-149.1	-30.4	-30.7
2024	1214.1	247.7	251.6	2024	-198.6	-40.5	-41.1
2025	1531.5	313.2	318.3	2025	-248.7	-50.9	-51.7
2026	1856.1	380.1	386.5	2026	-299.2	-61.3	-62.3
2027	2186.3	448.6	456.1	2027	-349.9	-71.8	-73.0
2028	2521.5	518.6	527.1	2028	-400.7	-82.4	-83.8
2029	2864.6	589.7	602.6	2029	-451.9	-93.0	-95.1
2030	3227.9	665.7	681.2	2030	-505.5	-104.2	-106.7
2031	3602.1	745.0	762.3	2031	-560.0	-115.8	-118.5
2032	3993.9	826.6	845.3	2032	-616.3	-127.6	-130.4
2033	4394.6	910.6	931.2	2033	-673.2	-139.5	-142.7
2034	4804.4	996.9	1019.1	2034	-730.6	-151.6	-155.0

C. Wholesale Sales Scenario Analysis

Wholesale energy sales represent about 3.6% of the Company's total sales. Wholesale customers are served by the Company through negotiated long-term power supply contracts. For periods of time beyond the terms of the existing long-term power supply contracts, the Company has to compete with other power suppliers for the wholesale customers' business. The

Company plans to successfully renew these contracts with current customers and has included the load in its forecast. The table below shows the level of sales and peak demand attributed in its forecasting process to the Company's wholesale business in its base forecast.

Wholesale Portion of Base Forecast			
	Annual	Peak Demands	
Year	Sales	Summer	Winter
	GWh	MW	MW
2020	871.0	148	147
2021	871.0	148	147
2022	873.0	149	147
2023	876.3	149	148
2024	879.6	150	148
2025	882.9	151	149
2026	886.3	151	150
2027	889.8	152	150
2028	893.3	153	151
2029	896.8	154	152
2030	900.3	154	152
2031	903.9	155	153
2032	908.0	156	154
2033	912.1	157	155
2034	916.2	157	156

D. Electric Vehicle Scenario Analysis

Electric vehicles have become more common as technology and customer desires change. Various automotive original equipment manufacturers ("OEMs") have released more EV models for sale to the public in the Company's service territory. While the overall penetration of EVs has been somewhat low, recent registration data from the South Carolina Department of Motor Vehicles ("DMV") demonstrates steady growth with a total of 4,145 electric vehicles registered in the state as of mid-year 2019, compared to 2,652 in mid-year 2018 (50% growth rate). This growth coincided with the availability of the popular Model 3 Tesla for purchase. The Company did not augment its 2020 IRP load forecast to account for additional load from EVs; therefore, it should be considered conservative. The forecast only includes incremental load from EVs that is imbedded in history. The next few years will provide the Company with a better understanding about EVs and their impact on the SC energy markets. Load forecasts included in future Company IRPs will include a specific adjustment to account for EV incremental growth.

Before discussing EV scenarios, it is important to understand that a scenario is not a forecast, and it is not a prediction of the future. A scenario analysis is only a "What if" analysis. The EV market in South Carolina is emerging but the data cannot yet be relied upon to make meaningful predictions. However, the scenario analysis is still worth performing because EV market penetration is not a question of "if" but a question of "when". The Company is still in the process of refining its methods for forecasting incremental electric demand growth resulting from the expected increase of EVs in the marketplace. Below a linear analysis was completed meaning demand for EVs would grow evenly over time; however, EV demand growth could be nonlinear or even exponentially higher.

The following table shows an estimate of the number of registered vehicles in DESC's territory. It assumes 2.1 vehicles per household applied to the DESC's residential customer forecast. A distinction is not made between two types of EVs: battery electric vehicles ("BEV") and plug-in electric vehicles ("PHEV"). PHEVs run on both electricity and gasoline. Three scenarios are defined by an assumed EV market share at the end of the IRP planning period. The three assumed ending market shares are: 1%, 5% and 10%. The table shows the number of EVs in DESC's service area under each scenario.

EVs within DESC by Scenario				
Year	DESC Vehicles	EV Scenarios 2034 Saturation Scenario 1%	5%	10%
2020	1,356,174	1,085	1,085	1,085
2021	1,375,662	1,293	2,256	2,806
2022	1,393,867	1,505	3,457	4,572
2023	1,411,311	1,722	4,686	6,379
2024	1,428,727	1,943	5,944	8,229
2025	1,446,356	2,170	7,232	10,124
2026	1,464,460	4,100	13,180	22,846
2027	1,482,268	6,077	19,269	35,871
2028	1,499,629	8,098	25,494	49,188
2029	1,516,523	10,161	31,847	62,784
2030	1,532,794	12,262	38,320	76,640
2031	1,550,199	13,177	48,444	96,887
2032	1,567,528	14,108	58,782	117,565
2033	1,584,626	15,054	69,327	138,655
2034	1,601,342	16,013	80,067	160,134

An approximation of the amount of electric power these EVs will need can be calculated by assuming two quantities: the number of miles driven each year, i.e., 15,000 miles and the number of miles per kWh required, i.e., 4 miles per kWh. The following table shows the results of these assumptions on energy sales over the IRP planning horizon. Customers on the DESC system require about 25,000 GWh per year so in the early years serving these EV sales will not require an immediate adjustment to the resource plan.

EV Energy Sales in 2034 (GWh)			
	2034 Saturation Scenarios		
Year	1%	5%	10%
2020	4.1	4.1	4.1
2021	4.8	8.5	10.5
2022	5.6	13.0	17.1
2023	6.5	17.6	23.9
2024	7.3	22.3	30.9
2025	8.1	27.1	38.0
2026	15.4	49.4	85.7
2027	22.8	72.3	134.5
2028	30.4	95.6	184.5
2029	38.1	119.4	235.4
2030	46.0	143.7	287.4
2031	49.4	181.7	363.3
2032	52.9	220.4	440.9
2033	56.5	260.0	520.0
2034	60.1	300.3	600.5

To derive a table of on-peak MW demand, the Company made certain assumptions. It is assumed that with Level 1 charging, it takes 10 hours on average to fully charge the vehicle's battery while with Level 2 charging, it takes 3 hours. A Level 1 charger charges at 120 volts while a Level 2 charger charges at 240 volts. While the amperage varies and has been increasing, a reasonable assumption is to assume a maximum charge of 1.4 kW for Level 1 charging and 9.6 kW for Level 2[1]. Of course, the number of hours to charge will vary with the car and the size of its battery and its power acceptance rate. Another assumption is the split between Level 1 and Level 2 charging and the percent of on-peak charging. For the three scenarios of 1%, 5% and 10%, it is assumed that the percent of Level 1 charging is 80%, 50% and 20% respectively and the MW on-peak percentages are 50%, 30% and 20%. It is assumed that with a higher saturation of EVs DESC will design a time of use rate that provides a more significant advantage to off-peak charging. The adjacent table shows the results of these assumptions.

[1] There are Level 3 chargers, which include direct current fast chargers, that can charge at rates between 50 kW and 350 kW and possibly larger.

EV Peak Demand (MW)			
	2034 Saturation Scenarios		
Year	1%	5%	10%
2020	0.6	0.5	0.5
2021	0.8	1.1	1.3
2022	0.9	1.6	2.1
2023	1.0	2.2	3.0
2024	1.2	2.8	3.8
2025	1.3	3.4	4.7
2026	2.4	6.2	10.7
2027	3.6	9.1	16.8
2028	4.8	12.1	23.0
2029	6.1	15.1	29.3
2030	7.3	18.2	35.8
2031	7.9	23.0	45.2
2032	8.4	27.9	54.9
2033	9.0	32.9	64.8
2034	9.6	38.0	74.8

There are four other EV markets to consider: transit buses, school buses, off-road vehicles and commercial fleet vehicles. Charleston Area Regional Transportation Authority has placed 3 Proterra transit buses in service as of January 2020 with 3 more being delivered in January 2021. Each bus will require an estimated 80,000 kwh per year and a peak demand of 125 KW.

DESC expects EVs to have the largest initial impact on distribution systems in urban growth areas. Although much of the DESC service territory is rural, the Charleston Metropolitan area is already seeing EV growth. The overall demographics, DESC's partnership with the Charleston Area Regional Transportation Authority, and plans by private entities to add larger more robust charging stations in the Charleston area and along major transportation corridors in South Carolina are helping EV growth. The Company anticipates the strong growth in urban Charleston will continue to gain strength. This year will be a pivotal year for EV sales with 40 models of plug-in EV's already offered, and 14 newer and more attractive models being introduced for 2020. As battery prices are decreasing and driving down the cost of EVs, they will appeal to broader cross section of South Carolina customers. Like Charleston, adoption rates are expected to increase in markets like Columbia, Hilton Head and Aiken. The local distribution impacts will certainly require additional planning and investments. A single Tesla supercharger charging bay has a maximum rated output of 250 kW (350 kW stand-alone) which is almost 40 times that of a residential water heater. Commonly arranged in eight charging bays, the supercharger station could demand 1 MW of new load in a single location. Urban distribution systems will need automation and hardening in the next few years.

II. DESC's Program for Meeting Its Demand and Energy Forecasts in an Economic and Reliable Manner

A. Demand Side Management

DSM can be broadly defined as the set of actions that can be taken to influence the level and timing of the consumption of energy. There are two common subsets of Demand Side Management: Energy Efficiency and Load Management (also known as Demand Response). Energy Efficiency typically includes actions designed to increase efficiency by maintaining the same level of production or comfort but using less energy input in an economically efficient way. Load Management typically includes actions specifically designed to encourage customers to reduce usage during peak times or shift that usage to other times.

1. Energy Efficiency

DESC's Energy Efficiency programs include the portfolio of Demand Side Management Programs, and Energy Conservation. A description of each follows:

a. **Demand Side Management Programs**: Beginning in 2018, DESC, through independent third-party consultants, conducted a comprehensive potential study and DSM program analysis. By Commission Order No. 2019-880, dated December 20, 2019, the Commission approved the suite of ten modified, expanded and new DSM programs, which was identified by the 2019 Potential Study, for the next five years beginning in 2020. Eight of these programs are an expansion or modification of existing programs, and two are new programs. The program impacts identified in the 2019 Potential Study are also the basis for the Medium DSM case in the Resource Plan Analysis. The portfolio includes seven (7) programs targeting DESC's residential customer classes and three (3) programs targeting commercial and industrial customer classes that have not opted out of the DSM rider. A description of each program follows:

   1. **Residential Home Energy Reports** provides customers with monthly/bi-monthly reports comparing their energy usage to a peer group and providing household information to help identify, analyze and act upon potential energy efficiency measures and behaviors. Participants are solicited via direct-mail and e-mail campaigns under an opt-in approach. Per the results of the 2019 Potential Study, the program will begin the necessary activities to phase down existing participants

in the current opt-in model and then phase in an opt-out program model which will include expanding participation. It is expected that by 2023, the program will have completed the full transition to opt-out.

2. **Residential Home Energy Check-up** provides customers with a visual energy assessment performed by DESC staff at the customer's home. At the completion of the visit, customers are offered an energy efficiency kit containing simple energy conservation measures, such as energy efficient bulbs, water heater wraps and/or pipe insulation. The Home Energy Check-up (Tier 1) is provided at no additional cost to all residential customers who elect to participate. Per the results of the 2019 Potential Study, DESC will begin developing an implementation timeline for a Tier 2 component. Tier 2 will include customer incentives for the installation of energy efficiency measures that aim to increase efficient operation of the house.
3. **Residential EnergyWise Savings Store** incentivizes residential customers to purchase and install high-efficiency ENERGY STAR® qualified lighting products by providing deep discounts directly to customers. In 2019, DESC continued to offer lighting incentives via an online store, in addition to providing energy efficiency lighting kits to customers at various business office locations, community events and via direct mail. New to the online store, DESC introduced smart thermostats to provide deeper heating and cooling savings to participants.
4. **Residential Heating & Cooling Program** provides incentives to customers for purchasing and installing high efficiency HVAC equipment in existing homes. Additionally, the program provides residential customers with incentives to improve the efficiency of existing air conditioning and heat pump systems through complete duct replacements, duct insulation and duct sealing. Per the results of the 2019 Potential Study, the program will be adding heat pump water heaters, increasing heating and cooling equipment and duct work improvement rebate amounts to encourage participation. An additional new offering will include a rebate for replacing electric resistant heat with a heat pump.
5. **Neighborhood Energy Efficiency Program** ("NEEP") provides income-qualified customers with energy efficiency education and direct installation of multiple low-cost energy conservation measures as part of a neighborhood door-

to-door sweep approach to reach customers. In 2019, neighborhoods in Walterboro, Holly Hill, Charleston and North Charleston participated in the program. Additionally, the NEEP Program continued offerings to mobile and manufactured homes to include additional measures specific to this housing stock. Per the results of the 2019 Potential Study, NEEP will increase customer participation by increasing the number of neighborhoods, increasing penetration into selected neighborhoods and selecting larger neighborhoods,

6. **Residential Appliance Recycling Program** provides incentives to residential customers for allowing DESC to collect and recycle less efficient, but operable, secondary refrigerators, and/or standalone freezers, permanently removing the units from service. Per the results of the 2019 Potential Study, the program will focus on increasing participation through increased marketing and promotional events.
7. **Residential Multifamily** program will focus on helping customers living in non-single-family dwellings, as well as apartment building owners and managers, overcome the split-incentive and other market barriers to residential energy efficiency. The split incentive barrier exists in rental situations: non-occupant building owners are less inclined to make efficiency upgrades when they do not pay efficiency bills, and renters are less likely to make efficiency upgrades because they do not own their dwelling. The program will achieve this goal by directly installing LEDs and water-saving measures in apartments, and by providing high incentives for building common area measures, such as lighting and HVAC upgrades. Although the Neighborhood Energy Efficiency and Home Energy Check-up programs both include multifamily units, the specific targeting of multifamily properties is a new effort and program for DESC.
8. **EnergyWise for Your Business Program** provides incentives to non-residential customers (who have not opted out of the DSM rider) to invest in high-efficiency lighting and fixtures, high efficiency motors and other equipment. To ensure simplicity, the program includes a master list of prescriptive measures and incentive levels that are easily accessible to commercial and industrial customers on DESC's website. Additionally, a custom path provides incentives to commercial and industrial customers based on the calculated efficiency benefits

of their energy efficiency plans or new construction proposals. This program applies to technologies and applications that are more complex and customer specific. All aspects of this program fit within the parameters of retrofits, building tune-ups and new construction projects. Per the 2019 Potential Study, the program will increase customer participation and determine an implementation timeline for offering two new components: Agricultural and Strategic Energy Management.

9. **Small Business Energy Solutions Program** is a turnkey program, tailored to help owners of small businesses manage energy costs by providing incentives for energy efficiency lighting and refrigeration upgrades. The program is available to DESC's small business and small nonprofit customers with an annual energy usage of 350,000 kWh or less, and five or fewer DESC electric accounts. Per the results of the 2019 Potential Study, DESC will increase the incentive levels to reduce the barrier to entry for small business customers.
10. **Municipal LED Lighting** program will offer municipalities in the DESC service territory incentives to replace street lighting with high efficiency LED streetlights. The incentives will allow for a financially neutral option for municipalities to convert while improving performance, providing remote monitoring/outage and better overall customer experience. This is a new program that DESC anticipates will be well received by municipalities.

b. **Energy Conservation:** Energy conservation is a term that has been used interchangeably with energy efficiency. However, energy conservation has the connotation of using less energy in order to save rather than using less energy to perform the same or better function more efficiently. The following is an overview of each DESC energy conservation offering:

i. **Energy Saver / Conservation Rate**: Rate 6 (Energy Saver/ Conservation) rewards homeowners and homebuilders with a reduced electric rate when they upgrade existing homes or build new homes to a high level of energy efficiency.

ii. **Seasonal Rates**: Many of our rates are designed with components that vary by season. Energy provided in the peak usage season is charged a premium to encourage conservation and efficient use.

2. Load Management Programs

The primary goal of DESC's load management programs is to reduce the need for additional generating capacity. There are four existing load management programs: Standby Generator Program, Interruptible Load Program, Real Time Pricing Rate and the Time of Use Rates. A description of each follows:

- **a. Standby Generator Program:** The Standby Generator Program for wholesale customers provides about 27 MW of peaking capacity that can be called upon when reserve capacity is low on the system. This capacity is owned by DESC's wholesale customers and is made available to DESC System Controllers through contractual arrangements. DESC has a retail version of its standby generator program in which DESC can call on participants to run their emergency generators. This retail program provides approximately 10 MW of additional capacity when called upon.
- **b. Interruptible Load Program:** DESC has over 200 megawatts of interruptible customer load under contract. Participating industrial customers receive a discount on their demand charges for shedding load when DESC is short of capacity.
- **c. Real Time Pricing ("RTP") Rate:** A number of customers receive power under DESC's real time pricing rate. During peak usage periods throughout the year when capacity availability is low in the market, the RTP program sends a high price signal to participating customers which encourages conservation and load shifting. Alternatively, during high capacity availability periods, prices are lower.
- **d. Time of Use Rates:** DESC's time of use rates contain higher charges during the peak usage periods of the day and lower charges during off-peak periods. This encourages customers to conserve energy during peak periods and to shift energy consumption to off-peak periods. All DESC customers have the option of purchasing electricity under a time of use rate.
- **e. Winter Peak Clipping:** An investigation of winter peaking programs was performed as part of the 2019 Potential Study. DESC, through independent third-party consultants, modeled a suite of new direct load control and other measures for residential and commercial customers that would rely on AMI being installed. Within the five-year program planning cycle, none of these new DR programs were found to be cost-effective and thus none were pursued further due to the cost of

installing AMI as a DSM program expense. However, the 2019 Potential Study showed that a rollout of AMI system-wide outside of the DSM context would support additional expansion of these DR programs. The study indicated that, with a sufficient saturation of AMI in place, Time of Use and Critical Peak Pricing could be cost effective. In absolute terms, by winter 2029, an additional 43 MW could be achieved. Program plans will be assessed as the installation of AMI meters reaches an appropriate level of saturation and can support cost-effective DR programs.

B. Supply Side Management

1. Existing Sources of Clean Energy

Clean Energy at DESC: Clean energy includes nuclear power, hydro power, some forms of combined heat and power, and renewable energy. Over the planning horizon, DESC expects societal trends toward clean energy to continue. Technological improvements and innovation in areas like renewable natural gas, carbon capture, energy storage, energy efficiency and hydrogen are likely to progress in the future. DESC intends to utilize more power generated from clean energy sources while assuring that electricity continues to be safe, reliable and affordable. DESC will continue to monitor the trends toward clean energy to identify approaches to providing customers a path to clean energy while maintaining the standard of reliability and affordability necessary to fuel South Carolina's modern economy.

Current Generation: DESC utilizes clean energy generated by hydro, nuclear and solar.

a. **Solar Power:** DESC has PPA's with utility scale solar energy providers totaling 641 MW-AC currently in commercial operation in addition to over 95 MW of customer scale solar installations interconnected to its grid. The utility scale supply is expected to grow to 973 MW by December 2020.
b. **Hydro-Power:** DESC owns five hydroelectric generating plants, one of which is a pumped storage facility, that combine for a total of 802 MW of clean capacity in the winter and 794 MW in the summer. The Saluda Hydro plant in Irmo, SC has a generating capacity of 198 MW. Saluda Hydro was put into service in 1930 and in August 2008 DESC filed an application requesting a new fifty-year license with the

Federal Energy Regulatory Commission ("FERC"). The Company is still waiting for the issuance of this new license. In June 2019, DESC filed an application with the FERC requesting a new fifty-year license for the Parr Hydroelectric Project, which consists of the Parr Shoals Development and Fairfield Pumped Storage Development. The current license expires in June 2020. This project is critical for the future of DESC's generation portfolio. With the increased adoption rate of non-dispatchable, intermittent solar generation on the DESC system, Fairfield Pumped Storage is an important asset for grid stability, reliability and power quality for DESC customers. In 2019, DESC's hydroelectric plants produced 288.1 gigawatt-hours ("GWh") of clean energy for SC customers. DESC's pumped storage facility, Fairfield Pumped Storage, has a net dependable generating capacity of 576 MW and is a valuable asset to the DESC generation fleet. Fairfield Pumped Storage contributed 469.5 gigawatt-hours ("GWh") in 2019 and has been a reliable resource for responding to rapid load changes on the DESC system. In 2018, the Company started the process of relicensing the Stevens Creek Hydroelectric Project which expires in October 2025. DESC will file an application with the FERC by October 2023 requesting a new fifty-year license for this project. This project provides fairly constant generation as it re-regulates the releases from the US Army Corps of Engineers J. Strom Thurmond Hydroelectric Project.

c. **Nuclear Power**: Unit 1 at the V. C. Summer Nuclear Station ("VCSNS") produces a substantial amount of clean energy and has a significant beneficial impact on the environment. The Unit came online in January 1984 and has a capacity of 971 MW with DESC owning 650 MW (two-thirds of the output of the facility) and Santee Cooper owning the balance. DESC received a 20-year extension to its original operating license in April 2004 and will enter its period of extended operation in 2022, since it is now licensed to operate until August 2042. Once VCSNS enters its period of extended operation, DESC expects to request and receive approval of a subsequent license renewal, extending its licensed operation to 2062. In 2019, Unit 1 produced over 5,720 gigawatt-hours ("GWh") of clean base load energy, which represented 20% of DESC's energy production. Over these next 22 years Unit 1 should produce approximately 110,000 GWh of clean base load energy for DESC. Nuclear generation currently displaces approximately 3.2 million tons per year of CO_2 that would be emitted if replaced by fossil resources.

2. Distribution Resource Plans

DESC is participating in activities seeking to advance technologies in grid transformation.

Smart Grid Activities:

Advanced Metering Infrastructure: DESC currently has approximately 30,000 AMI meters that are installed predominately on medium and large commercial/industrial customers and all accounts with customer generation (net metering). They are also used for accounts on time-of-use or demand rates. These meters utilize public wireless networks as the communication backbone and have full two-way communication capability. Meter readings and load profile interval data are remotely collected daily from all AMI meters. In addition to traditional metering functions, the technology also provides real-time monitoring capability including power outage/restoration, meter/site diagnostics, and power quality monitoring. Load profile data is made available to customers daily via web applications enabling these customers to have quick access to energy usage allowing better management of their energy consumption. DESC is in the early implementation stage for mass AMI technology for all electric meters with full scale deployment scheduled to begin in 2020. Deployment plans have meter installations ramping from 10,000 meters per month to 35,000 meters per month over the next three years. Depending on customer growth, the final total meter count will be just over 765,000 AMI meters installed in the DESC service territory. This expands the opportunity to field Home Area Network devices that communicate via AMI meters. This project will allow DESC to offer and customers to participate in demand response, demand shifting, and demand shedding programs around load control devices including water heaters, HVAC systems, pool pumps and electric vehicle chargers.

Distribution Automation: DESC is continuing to expand Supervisory Control and Data Acquisition ("SCADA") switching and other intelligent devices throughout the system. DESC has approximately 1,100 SCADA switches and reclosers, most of which can detect system outages and operate automatically to isolate sections of line with problems thereby minimizing outage times and limiting affected customers. Some of these isolating switches can communicate with each other to determine the optimal configuration to restore service to as many customers as possible without operator intervention. DESC continues to evaluate systems that will further enable these automated devices to communicate with each other and safely reconfigure the system in a fully automated fashion, let operators know exactly where the faulted section of a line is, and monitor the status of the system as it is affected by outages, switching, and customer generation (solar). As distributed renewable generation proliferates in the system, identifying issues such as voltage control and load flows are imperative to maintaining reliability now and for future grid stability planning.

3. Future Clean Energy

a. Hydro-Power: DESC plans to continue to rely on clean dispatchable power from all of the existing hydro and pumped storage units through successful completion of the relicensing processes of Saluda, Parr, and Stevens Creek hydroelectric projects and Fairfield Pumped Storage Facility.

b. CO_2 and Methane Goals: As one of the nation's largest producers and transporters of energy, Dominion Energy is committed to providing safe, reliable, affordable and sustainable delivery of energy to its customers. The Dominion Energy expects to cut the electric generating fleet's carbon dioxide emissions 55 percent by 2030 relative to 2005 emissions and reduce methane emissions from its gas assets 65 percent by 2030, 80 percent by 2040, both relative to 2010 emission levels. Dominion Energy has further committed to achieve net zero CO_2 and methane emissions from its electric generation and natural gas infrastructure operations by 2050. To the extent possible, subject to South Carolina stakeholder processes, DESC plans to participate in efforts to meet these corporate commitments.

c. **Renewables:** The following table provides a projection of renewable generation from signed PPAs as used in DESC Resource Plan #2 in the Resource Plan Analysis section.

Resource Plan 2 Renewable Energy by Year (GWh)

Year	GWh
2020	1,609
2021	2,032
2022	2,034
2023	2,034
2024	2,034
2025	2,034
2026	2,030
2027	2,032
2028	2,042
2029	2,032
2030	2,032
2031	2,034
2032	2,036
2033	2,034
2034	2,034

DESC has 973 MW-AC of solar capacity currently under executed PPAs. The preceding table shows the amount of energy projected to be generated by these renewable facilities in each of the 15 years of the IRP planning horizon. Please note, all 973 MW-AC of capacity is expected to be online by January 2021 and the table does not take into consideration solar projects in development without a PPA at this time. Retiring coal-fired generation has the greatest impact on CO_2, and some of that energy can be supplied by additional solar generation. Still, as hundreds and thousands of solar panels are added, significant transmission and distribution upgrades along with a combination of energy storage and quick start combustion turbines will be required on the electric grid due to intermittency.

Photovoltaic solar generation systems are quite different from traditional supply-side resources like coal, nuclear, and natural gas-fired power plants. All levels of the existing electric infrastructure, standards and operating protocols were originally designed for a dispatchable generation fleet, and the system is having to adapt to integrate these new resources. Solar generation systems, in contrast, only produce electricity when the sun is shining; therefore, energy output is variable and cannot be dispatched.

As a NERC registered Balancing Authority, DESC must maintain real time load-interchange-generation balance within its Balancing Authority Area ("BAA") between customer demand and generation (which can include traditional coal, nuclear, gas, and hydro, as well as solar resources and off-system purchases). The criteria within which the Company must operate are defined by multiple NERC Reliability Standards and require the Company to maintain a balance of resources and demand within defined limits. Variability in solar generation can cause sudden swings in this balance and can result in both reliability issues and NERC Standards Violations if operators' actions are insufficient. To counter the swings caused by solar generators, the Company must maintain complementary dispatchable generation online and available to respond to reliability events created by sudden swings in solar generation output.

In particular, downward ramp rates for PV solar generators are nearly instantaneous when cloud cover rolls over panels, so the Company must have compensating supply-side resources online or ready to respond with quick start times and fast ramp rates. For this reason, operating reserves from slow moving coal units are not adequate, making other quick moving resources including pumped storage facilities, batteries and quick start combustion turbines more critical and necessary as intermittent resources are added.

From a supply standpoint, the BAA peak load is approximately 5,000 MW, but loads at this level are only seen a few hours each year. These peak loads occur late in the afternoon on the hottest July and August days, or the coldest early morning hours in January or February just before sunrise. For the Company's 2019 summer peak of 4,714 MWh, PV generation directly connected to the Company's transmission and distribution system contributed 264 MW-AC or 52% of its installed capacity, while for the winter peak of 4,087 MWh to date in 2020 (mild winter), solar generation contributed 9 MW-AC or 1.4% of installed capacity toward meeting the peak. The remainder of load in both scenarios (4,450 MWh in July and 4,078 MWh in January) was balanced with traditional Company generation and off system purchases. At a minimum, these numbers demonstrate that capacity from solar generation is out of sync with peak loads in the winter and only partially in sync in the summer. Therefore, large amounts of energy storage and dispatchable generation must be available to respond to load demand and reliability events on peak days because solar cannot functionally provide that reliability benefit alone.

Quick start, flexible, and reliable combustion turbines are especially critical for capacity and energy supply in the winter. Winter peak demand occurs in the morning and often before sunrise when solar resources are not producing. The issue is further impacted by the fact that in the winter the days are shorter meaning batteries have less charging time. Combustion turbines can cost-effectively meet this peak need when solar plants are producing little or no output. In situations where it is not only cold but also cloudy, as often happens in the winter, combustion turbines provide the energy supply needs of our customers into the day. Another critical energy situation exists when it is cloudy for several days in a row. In this situation, very little solar power is being produced for days. For systems with heavy reliance on solar resources, several cold and cloudy days in a row will be a reliability design issue. A cost-effective strategy must be in place to replace renewable energy during these events. Even batteries paired with solar will not solve the very real and not so distant problem of low solar output for several cloudy days with high demands. Efficient, reliable, combustion turbines are an essential facet of a low carbon future.

DESC anticipates increasing levels of renewable resources along with the research and innovation that will make reliable operations possible. Technical advances must be implemented with regard to cost and reliability and in conjunction with established flexible technologies. The incremental implementation of solar and storage technology with moderate additions over several years will allow the electric grid to adapt to operational impacts in a cost-effective manner.

d. **Cogeneration/Combined Heat and Power:** The Company is open to combined heat and power that provides clean energy or improved efficiency should a specific project present itself. Combined heat and power projects are highly dependent upon the steam user's individual steam requirements and are therefore impossible to accurately model as a generic project. The Company is open to customer-sited generation opportunities; this includes siting generation assets to supply critical infrastructure during system emergencies including (but not limited to): military installations, hospitals, universities, and major government facilities. Such distributed generation assets can also be used for operation during system peak periods. Both Resource Plan 1 ("RP1") and RP2 could be configured to be a cogeneration plan to utilize the waste heat produced.

e. **Energy Storage:** Energy storage is critical to providing continued reliability for our customers as we expand our renewable portfolio. There are several types of energy storage technologies including pump storage, capacitors, compressed air, flywheels and batteries. Except for pump storage and batteries, most of these technologies are not yet cost competitive. Pump storage requires specific land features and lengthy permitting; therefore, this IRP focuses on batteries in conjunction with its existing Fairfield Pump Storage Facility.

The Company continues to evaluate storage as an option to manage minimum loads and integrate increasing levels of renewables onto the system. Because solar generates when the sun is shining and doesn't generate when the sun is not shining, its generation does not always correspond with the system's need for generation. Energy storage can enable the utility to shift solar energy from periods when it's not needed. These minimum and maximum load issues are most visible in the winter. The winter peak occurs in the early morning before the sun comes up. After the sun comes up, in the winter, the load begins to drop as temperatures begin to rise. Solar generation increases as the load drops. This is an example of a minimum load issue that could be resolved by storing solar energy. This stored solar energy can be used to help meet maximum loads during a later period when solar is not generating. Battery storage has made significant strides in recent years, in both efficiency and cost but it is still in the early stages of utility-scaled deployment.

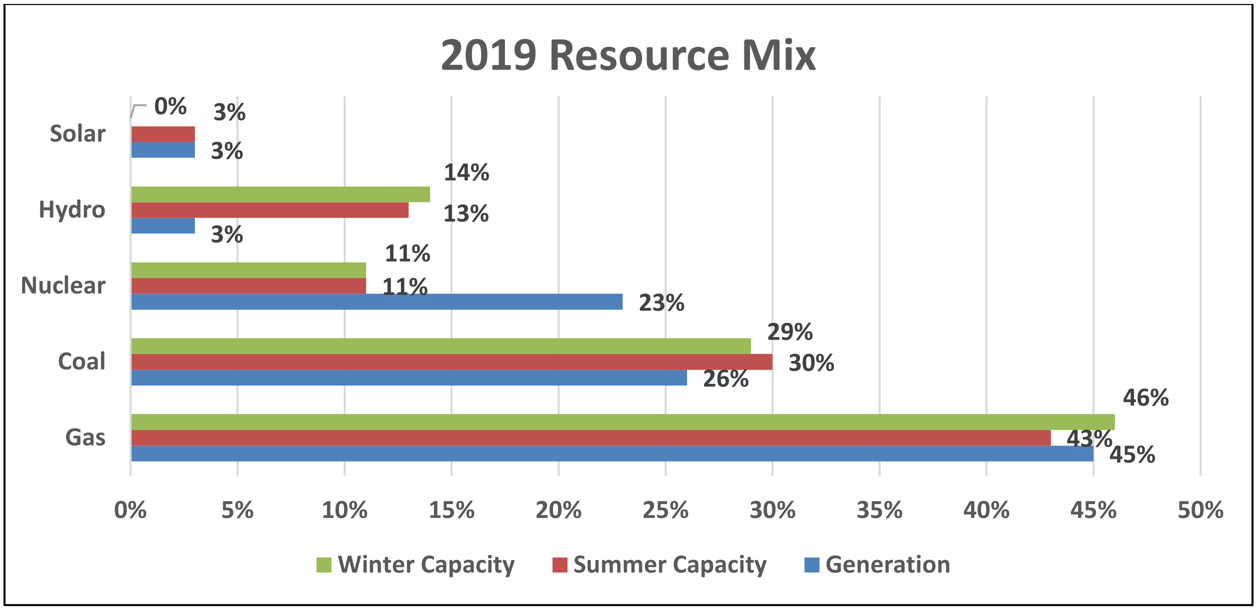
4. Supply Side Resources at DESC

a. **Existing Supply Resources:** DESC currently owns and operates two (2) coal-fired steam plants, one (1) dual-fuel coal and/or natural gas-fired steam plant, two (2) natural gas-fired steam plants, three (3) combined cycle gas turbine/steam generator plants (gas/oil fired), seven (7) peaking turbine facilities, four (4) hydroelectric generating plants, and one pumped storage facility. The total fossil-hydro generating capability rating of these facilities is 5,001 MW in summer and 5,248 MW in winter. These ratings, which are updated at least on an annual basis, reflect the expectation for the coming summer and winter seasons. When DESC includes its nuclear capacity (650 MW in summer and 662 MW in winter), additional capacity (20 MW) provided through a contract with the Southeastern Power Administration and solar capacity, the total supply capacity for 2020 is 6,507 MW in summer and 6,905 MW in winter. This is summarized in the table on Page 33.

Solar only contributes a portion of its capacity toward the summer peak and virtually none of its capacity toward the winter peak. This difference is because the solar profile and DESC's load profile are not congruent. Summer peaks happen in the afternoon after solar generation has begun to decline and winter peaks happen in early mornings before solar begins to generate. The Company continues to assess combining solar technology with batteries and other storage technology to optimize the amount of solar generation that can efficiently serve the Company's peak load demand.

The bar chart below shows DESC's actual 2019 relative energy generation and relative capacity by fuel source. This information includes the summer and winter capacity contribution of Solar PPAs which was 3% of summer capacity and 0% of winter capacity.

DESC 2019 Resource Relative Production



The purpose of this chart is to emphasize the resources that have provided the highest capacity contribution on peak and the most energy supply over a year. Hydro resources provided disproportionately higher capacity value while the nuclear plant contributed well to capacity and extremely well for energy supply. Thermal resources continued to contribute significantly to both energy and capacity needs. Without storage capability, the solar contribution to on peak capacity is low.

Existing Long-Term Supply Resources

The following table shows the DESC available generating capacity in 2020.

	In-Service Date	Probable Retirement[1] Date	Summer 2020 (MW)	Winter 2020 (MW)
Coal-Fired Steam:				
Wateree – Eastover, SC	1970	2044	684	684
Williams – Goose Creek, SC[2]	1973	2047	605	610
Cope[4] - Cope, SC	1996	2071	415	415
Total Coal-Fired Steam Capacity			1,704	1,709
Gas-Fired Steam:				
McMeekin – Irmo, SC	1958	2028	250	250
Urquhart – Beech Island, SC	1954	2028	95	96
Total Gas-Fired Steam Capacity			345	346
Nuclear:				
V. C. Summer - Parr, SC	1982	2062	650	662
Gas Turbines:				
Hardeeville, SC	1968	2018	0	0
Urquhart 1,2,3 – Beech Island, SC	1969	2044	39	48
Urquhart 4 – Beech Island, SC	1999	2059	48	49
Coit – Columbia, SC	1969	2029	26	36
Parr, SC	1970	2030	60	73
Williams – Goose Creek, SC	1997	2057	40	52
Hagood 4 – Charleston, SC	1991	2051	88	99
Hagood 5 – Charleston, SC	2010	2070	18	21
Hagood 6 – Charleston, SC	2010	2070	20	21
Urquhart Combined Cycle – Beech Island, SC	2002	2077	458	484
Jasper Combined Cycle – Jasper, SC	2004	2079	852	924
CEC Combined Cycle – Columbia, SC	2004	2079	519	586
Total I.C. Turbines Capacity			2,168	2,393
Hydro:				
Neal Shoals – Carlisle, SC	1905	2055	3	4
Parr Shoals – Parr, SC	1914	2064	7	12
Stevens Creek - Near Martinez, GA	1929	2079	8	10
Saluda - Irmo, SC	1932	2082	198	198
Fairfield Pumped Storage - Parr, SC	1978	2128	576	576
Total Hydro Capacity			792	800
Solar:[3]				
Company Owned	2011	2031	2.4	2.4
PPA DER Program	2015-2019	2039	64	64
PPA Non-DER Program,	2017-2020	2040	762	909
Total Solar Capacity			828	975
Other:				
Southeastern Power Administration (SEPA)			20	20
Grand Total (Name Plate):			6,507	6,905
				-

Notes:
1. Probable retirement dates are based on the 2014 Depreciation Study.
2. Williams Station is owned by South Carolina Generation Company ("GENCO"), a wholly-owned subsidiary of SCANA Corporation which is a wholly-owned subsidiary of Dominion Energy, Inc. and GENCO's electricity is sold exclusively to DESC.
3. Solar MW are nameplate values and do not represent the contribution to peak demand.
4. Cope Station is dual fuel and is run on both coal and natural gas.

b. Limitations on Existing Resources: DESC is evaluating the possible replacement of existing peaking generation assets as intermittent renewable resources continue to expand in the service territory and several combustion turbines reach end of life. DESC's existing fleet of simple-cycle combustion turbines is on average over 42 years old, with multiple units at or approaching over 50 years since initial commercial operation. DESC's natural gas-fired steam units (McMeekin Units 1 and 2 and Urquhart Unit 3) also typically operate as peaking resources, and these units are over 60 years old. Reliable, fast-starting, and efficient peaking resources provide significant capabilities to balance intermittent renewable generation. Replacement of DESC's aging peaking generation resources with flexible aeroderivative-type combustion turbines is seen as a likely potential path to provide the flexibility to allow for further integration and additional expansion of intermittent renewable resources in the near-term. As discussed above in the Introduction, DESC expects trends toward clean energy to continue. Further, the Company is committed to utilizing more power generated from clean energy sources. As such, the Company will continue in future IRPs to explore generation, transmission, and distribution technologies necessary to achieve this clean energy goal.

This IRP contains references to retiring generators. DESC Transmission Planning must conduct System Impact Studies to determine the impacts of any planned generator interconnection, retirement, or replacement requests. DESC Transmission Planning studies these requests to determine the reliability impact to the DESC Bulk Electric System. Those studies determine what transmission system upgrades are necessary to support the associated generator requests and are performed independently from DESC's Power Generation and DESC Retail Electric organizations.

c. Environmental Rules: DESC continues to closely monitor developments with the US Environmental Protection Agency's ("EPA") Steam Electric Effluent Limitation Guidelines ("ELG") following the Agency's actions after the 2015 final rule was published. This regulation is anticipated to require significant capital expenditures for flue gas desulphurization ("FGD") wastewater treatment at both Wateree and Williams Stations and for modifications to limit or eliminate the discharge of ash transport water at Williams Station. Recent fuel price trends along with increased intermittent renewable generation have resulted in cyclic operation of these facilities along with reduced capacity factors. These conditions make FGD wastewater treatment retrofits challenging and costly.

In November 2019, EPA issued a proposed rule to revise the 2015 standards. In the 2019 proposed rulemaking, EPA proposed significant changes to the rule including new effluent limits and an incentive for early retirement of existing generating units. DESC will continue to closely monitor the EPA's rulemaking in anticipation of a final ELG regulation in 2020. Along with the additional costs of stack emission reductions and the ELG Rule, traditional coal-fired steam boiler generating units emit CO_2 at twice the rate of the highest efficiency natural gas fired combined cycle unit due to fuel carbon content and efficiency. For immediate reductions in CO_2 emissions, coal-fired units must be operated less frequently by reducing demand, operating more natural gas-fired generation, and adding solar generation with batteries along with combustion turbines for back up and load following.

EPA released the final version of the Affordable Clean Energy ("ACE") rule, the replacement for the Clean Power Plan ("CPP") on June 19, 2019. The rule was published on July 8, 2019 and applies to existing coal-fired power plants greater than or equal to 25 MW. Through the ACE rule, the EPA finalized the repeal of the CPP. It is also asserted that the repeal is intended to be severable, such that it will survive even if the remainder of the ACE rule is invalidated.

Under the ACE rule, EPA has set the Best System of Emissions Reduction ("BSER") for existing coal-fired steam electric generating units as heat rate efficiency improvements ("HRI") based on a range of "candidate technologies" and improved operating and maintenance practices that can be applied at the unit level. States are directed to determine which of the candidate technologies apply to each unit and establish standards of performance (expressed as an emissions rate in CO_2 lb/MWh) based on the degree of emission reduction achievable with the application of BSER. EPA requires that each state determine which of the candidate technologies apply to each coal-fired unit based on consideration of remaining useful plant life and other factors such as reasonable cost of the candidate technologies.

The rule requires compliance at the unit level; it does not allow averaging across units at the same facility or between facilities as a compliance option. In addition, it does not allow states to use alternative carbon mitigation programs, such as a cap-and-trade program, to demonstrate compliance as part of their state plans. A steam generating unit that is subject to a federally enforceable permit limiting annual net-electric sales to one-third or less of its potential electric output, or 219,000 MWh or less can be excluded from the ACE rule. The ACE rule requires states to develop plans by July 2022. These state plans must be approved by the EPA by January 2024. If states do not submit a plan or if their submitted plan is not acceptable, the EPA will have two years to develop a federal plan.

5. Resource Plan Analysis

a. Overview

The following pages document a resource planning study that was performed to assess several resource plans to meet customers' need for power while varying future market conditions and regulations. Included in the Company's study were eight resource plans and three sets of DSM scenarios. The eight plans were also evaluated under three levels of natural gas prices and two CO_2 emission cost prices. The Company's base forecast of energy and demands was used in the study. The Load Forecast (discussed in Part I) is called the Medium DSM case. Medium DSM is based on the expected program levels identified in the 2019 Potential Study and are the programs the Company plans to deploy. By modifying the Load Forecast with other levels of DSM, Low and High DSM sensitivities are included in the Resource Plan Analysis. The existing DSM level is called Low DSM. The 2019 Potential Study level is called Medium DSM, and a 1.0% level of DSM is called the High DSM case. The DSM Low and Medium cases were studied for cost-effectiveness and provide a reliable cost estimate that is unique to the portfolio of programs and customers in DESC's electric system. The High DSM case was not supported in the 2019 Potential Study and is based on estimates.

Resource plans were created around retirements, environmental regulations and additional renewable resources. These scenarios create a large array of output data. The following pages include several displays of the high-level output data meant to emphasize the most relevant results. Understanding the common basis of each resource plan and limited changes between resource plans provide for relevant comparisons. Comparing resource plans created with dissimilar assumptions will yield inappropriate conclusions, and care must be taken to understand the inputs that are held constant versus inputs that have changed to avoid such pitfalls.

b. Reserve Margin

DESC's reserve margin policy is summarized in the following table. Peaking reserves are considered the capacity needed during the five highest peak load days in the season while base reserves are needed for the balance of the season.

DESC's Reserve Margin Policy		
	Summer	**Winter**
Base Reserves	**12%**	**14%**
Peaking Reserves	**14%**	**21%**
Increment for Peaking	**2%**	**7%**

Statements about reserve margin are generally addressing Base Reserve criteria.

c. Meeting the Base Resource Need

In the context of base or peaking, base resources are the resources explicitly identified in a resource plan's 40-year schedule to meet the summer or winter base reserve margin. Peaking reserve margin assists in quantifying reliability risk but is not used for deciding on permanent capacity resources. For base resources the winter base reserve margin of 14% was used to determine the timing of adding generation resources. DESC created a list of seven generating resources to be considered. The following table lists these resources. Wateree and Williams are assumed retired when they reach their end of life, which is years 2044 and 2047 respectively, if not retired earlier. The capital costs are escalated or de-escalated from 2020 to the year that the generator is installed. The installation year varies by resource plan. The capacity used in the resource plan schedule for CC and ICT resources is their winter capacity.

Description of Potential Resources

Resource	Capital Cost 2020 $/kW	Escalation Rate	Capacity	Source of Data
Battery Storage	$1,911	-2.463%	100 MW with 4 hour duration	• Dominion Energy Services - Generation Construction Financial Management & Controls • CAPEX Escalation is from NREL Mid Technology Cost Scenario forecast of CAPEX, 30 Year Average
Solar	$1,151	-1.498%	100 or 400 MW	• Dominion Energy Services - Generation Construction Financial Management & Controls • CAPEX Escalation is from NREL Mid Technology Cost Scenario forecast of CAPEX, 30 Year Average
CC 1-on-1	$1,330	3.75%	553 MW	• Dominion Energy Services - Generation Construction Financial Management & Controls • CAPEX Escalation is from Handy Whitman July 2019 15 year Average – Total Plant
ICT Frame J (2x)	$469	3.75%	523 MW	• Dominion Energy Services - Generation Construction Financial Management & Controls • CAPEX Escalation is from Handy Whitman July 2019 15 year Average – Total Plant
ICT Aero (2x)	$918	3.75%	131 MW	• Dominion Energy Services - Generation Construction Financial Management & Controls • CAPEX Escalation is from Handy Whitman July 2019 15 year Average – Total Plant
Solar PPA	N/A	N/A	400 MW	• NREL 2019, Mid Technology Cost Scenario

i. Resource Plans

These six resources above were combined in various ways to develop eight resource plans, some of which consider the retirement of some existing generating units. The eight resource plans are listed in the following table which is followed by a description of each resource plan.

Description of Resource Plans

Resource Plan ID	Resource Plan Name	Resource Plan Description
RP1	CC	Combined Cycle, ICTs
RP2	ICT	ICTs
RP3	Retire Wateree	Wateree 1 & 2 retirement, Combined Cycle, ICTs
RP4	Retire McMeekin	McMeekin and Urquhart 3 retirement, ICTs
RP5	Solar + Storage	Flexible Solar + Battery Storage, Combined Cycle, ICTs
RP6	Solar	Flexible Solar, ICTs
RP7	Solar PPA + Storage	Flexible Solar PPA + Battery Storage, ICTs
RP8	Retire Coal	Replace Wateree and Williams with Combined Cycle, Solar and Battery Storage, ICTs

Flexible solar is a solar facility which can be curtailed when systems conditions require and/or dispatched with system needs

Resource Plan 1: In this resource plan a 553 MW (winter capacity) combined cycle gas generator is added when the winter reserve margin drops below 14%. 523 MW blocks of ICTs are added to maintain the 14% winter reserve margin during the modeling period.

Resource Plan 2: In this resource plan 523 MW (winter capacity) of ICT gas generators are added when the winter reserve margin drops below 14% during the modeling period.

Resource Plan 3: In this resource plan Wateree units 1 and 2 are retired in 2028 and a combined cycle gas generator is added in 2028. Five hundred twenty-three (523) MW blocks of ICTs are added to maintain the 14% winter reserve margin during the modeling period.

Resource Plan 4: In this resource plan McMeekin 1 and 2 along with Urquhart 3 are retired in 2028. Their 346 MW of capacity are replaced by 523 MW of ICT capacity. Five hundred twenty-three (523) MW blocks of ICTs are added to maintain the 14% winter reserve margin during the modeling period.

Resource Plan 5: In this resource plan 400 MW of Company owned flexible solar generation plus 100 MW of battery storage are added in 2026. The next increment of capacity necessary to maintain a 14% winter reserve margin is a 553 MW combined cycle gas generator. After the CC, 523 MW blocks of ICTs are added to maintain the 14% winter reserve margin during the modeling period.

Resource Plan 6: In this resource plan 400 MW of Company owned flexible solar generation is added in 2026. Five hundred twenty-three (523) MW blocks of ICTs are added to maintain the 14% winter reserve margin during the modeling period.

Resource Plan 7: In this resource plan 400 MW of flexible solar PPA generation plus 100 MW of battery storage are added in 2026. Five hundred twenty-three (523) MW blocks of ICTs are added to maintain the 14% winter reserve margin during the modeling period.

Resource Plan 8: In this resource plan Wateree and Williams are retired in 2028 and replaced with a 553 MW 1-on-1 combined cycle plant and Five hundred twenty-three (523) MW of ICTs. Dual fuel capability is eliminated at Cope, so Cope burns only natural gas starting in 2030. Additional tranches of 100 MW of battery storage and 131 MW ICTs are added to maintain the 14% winter reserve margin during the modeling period. Solar is added each year from 2029 to 2048. This resource plan is the low carbon plan.

ii. Methodology

The incremental revenue requirements associated with each of the eight resource plans was computed using the PROSYM computer program to estimate production costs and an EXCEL revenue requirements model to calculate the associated capital costs. The EXCEL revenue requirements model combines the capital costs with the production costs to estimate total incremental revenue requirements over a 40-year planning horizon.

iii. Demand Side Management Assumptions

Three DSM cases were created. The low DSM is equivalent to DSM programs and levels on the DESC electric system prior to the 2019 Potential Study. The medium DSM used the results of the 2019 Potential Study described in Part II.A. High DSM assumed DSM Growth to 1% of retail sales by 2024. It should be noted that the High DSM case was not supported in the 2019 Potential Study and is based only on estimates, likely not achievable and cost effectiveness is unknown.

The three DSM cases created three demand and energy forecasts. A low level of DSM creates higher demands and energy. A high level of DSM creates demands and energies that are lower. The cost for each DSM case was calculated over a 40-year period and applied to the appropriate scenario. Assuming no baseload retirements, the first need for additional capacity occurs in the winter of 2035 when using the Medium DSM demands, in 2032 when using the Low DSM demands and 2038 when using the High DSM demands.

iv. DSM Sensitivity

The following tables summarizes the results for all eight resource plans under the three different DSM cases. (1 – Green = Least cost, 2 – Blue = Second Lowest and 8 - Orange = Highest cost)

Resource Plan Rankings by Levelized NPV for Low, Medium and High DSM

Resource Plan ID	Resource Plan Name	Low DSM	Medium DSM	High DSM
RP1	CC	6	5	4
RP2	ICT	1	1	1
RP3	Retire Wateree	2	6	6
RP4	Retire McMeekin	5	3	5
RP5	Solar + Storage	8	7	8
RP6	Solar	4	4	2
RP7	Solar PPA + Storage	3	2	3
RP8	Retire Coal	7	8	7

Resource Plan Levelized NPV for Low, Medium and High DSM ($000)

Resource Plan ID	Resource Plan Name	Low DSM	Medium DSM	High DSM
RP1	CC	1,254,935	1,249,160	1,244,419
RP2	ICT	1,231,227	1,231,667	1,228,438
RP3	Retire Wateree	1,242,386	1,251,077	1,249,280
RP4	Retire McMeekin	1,248,340	1,239,802	1,248,403
RP5	Solar + Storage	1,272,513	1,266,727	1,264,403
RP6	Solar	1,244,428	1,246,165	1,243,761
RP7	Solar PPA + Storage	1,242,682	1,236,518	1,243,916
RP8	Retire Coal	1,271,348	1,267,624	1,260,246

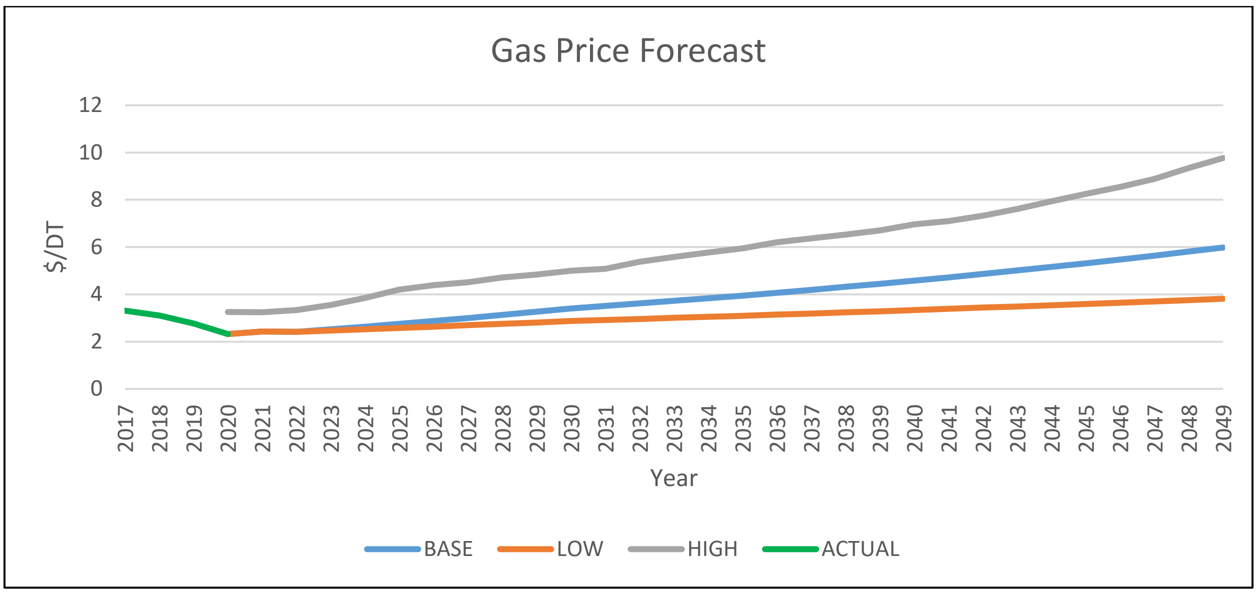
v. Discussion of Results by DSM scenario:

RP2 is the lowest cost resource plan under the assumption of zero cost CO_2 and base gas prices for all levels of DSM modeled. This is driven by the low cost of building two 260 MW ICTs simultaneously several years into planning time frame. Costs in the short-term would have a greater impact on Net Present Value calculations. Since the reserve margin calculation is not a constraining factor until after 2030, the resource plans generally do not show large changes in the first few years. Using RP 2, no resources are added due to reserve margin constraints until 2035 in the Medium DSM case. Due to the timing of the resources, the differences in NPV are separated by about 3% within each level of DSM with the expected scenario. At $0 CO_2 costs and Base Gas Price, RP 2 has the lowest projected cost in each DSM sensitivity. RP 6 – Solar and RP 7 – Solar PPA + Storage also do well in the Medium DSM and High DSM cases.

vi. Emissions and Fuel Sensitivity

The medium DSM case was evaluated using three gas price assumption plus two CO_2 cost assumptions. The combination of the three gas price assumptions and two CO_2 cost assumptions created 6 different scenarios. The chart below shows the three gas price forecasts used. The high gas price forecast is the 2019 EIA gas price forecast. The base gas and low gas scenarios are based on NYMEX gas prices for years 2020-2022 then escalated at two different rates. The base escalation rate is derived from the EIA gas price forecast. The low gas scenario escalation rate is half of the base gas escalation rate. The two CO_2 assumptions used were $0/ton and $25/ton. All plans include assumptions about expenses that will be required to meet ELGs for Wateree and Williams.

Low, Base and High Gas Price Forecast



vii. Resource Plan Rankings by Gas Price and CO_2 Price

The following tables summarizes the 40 year levelized NPV cost results for all eight resource plans under the three different gas price cases and two different CO_2 price cases. (1 - Green= Least cost, 2 – Blue = Second Lowest and 8 - Orange = Highest cost)

Resource Plan Levelized NPV Rankings for Medium DSM

Resource Plan ID	Resource Plan Name	$0/ton CO_2, Low Gas	$0/ton CO_2, Base Gas	$0/ton CO_2, High Gas	$25/ton CO_2, Low Gas	$25/ton CO_2, Base Gas	$25/ton CO_2, High Gas
RP1	CC	6	5	5	7	6	6
RP	ICT	1	1	2	3	4	3
RP3	Retire Wateree	5	6	7	4	3	5
RP4	Retire McMeekin	2	3	4	6	7	8
RP5	Solar + Storage	8	7	6	8	8	7
RP6	Solar	4	4	3	5	5	4
RP7	Solar PPA + Storage	3	2	1	2	2	2
RP8	Retire Coal	7	8	8	1	1	1

Resource Plan Levelized NPV for Medium DSM ($000)

Resource Plan ID	Resource Plan Name	$0/ton CO_2, Low Gas	$0/ton CO_2, Base Gas	$0/ton CO_2, High Gas	$25/ton CO_2, Low Gas	$25/ton CO_2, Base Gas	$25/ton CO_2, High Gas
RP1	CC	$1,166,528	$1,249,160	$1,427,424	$1,385,375	$1,469,436	$1,668,590
RP2	ICT	$1,145,532	$1,231,667	$1,416,354	$1,370,853	$1,461,736	$1,665,599
RP3	Retire Wateree	$1,165,235	$1,251,077	$1,444,505	$1,372,378	$1,460,334	$1,666,688
RP4	Retire McMeekin	$1,154,191	$1,239,802	$1,425,558	$1,380,307	$1,470,231	$1,675,337
RP5	Solar + Storage	$1,186,034	$1,266,727	$1,435,093	$1,394,516	$1,475,915	$1,669,182
RP6	Solar	$1,163,394	$1,246,165	$1,423,590	$1,378,987	$1,465,797	$1,665,995
RP7	Solar PPA + Storage	$1,154,889	$1,236,518	$1,413,532	$1,370,024	$1,455,686	$1,654,813
RP8	Retire Coal	$1,183,714	$1,267,624	$1,467,499	$1,356,160	$1,438,706	$1,646,153

viii. Discussion of Scenario Costs Results:

RP2, RP4, and RP7 are lower cost when CO_2 is assumed to be \$0/ton. These resource plans use ICTs to meet the reserve margin going forward. RP4 includes retirements of McMeekin and Urquhart 3 in 2028 and has higher carbon production. RP7 includes a solar PPA plus storage in 2026. RP1, RP3 and RP5 add combined cycle generation and are generally more expensive when CO_2 costs are zero. RP3 and RP8 include retirement of a coal plant. RP8 retires all coal generating capacity by 2030 and is the least cost resource plan when CO_2 costs are \$25/ton but is more expensive when CO_2 cost is \$0/ton and gas prices are low.

Since RP2 is the least cost alternative under zero cost CO_2, Base Gas, and Medium DSM, it is considered the base case. Under new regulations or changes in the market, however, the base case may change. Given societal trends that are requiring more sustainable sources of clean energy, RP7 and RP8 have significant merits. The Company will continue to study the cost and benefit of portfolio alternatives that lower CO_2 emissions and promote more sources of clean energy.

ix. Resource Plan Rankings by Total Fuel Costs

The following table summarizes the 40 year levelized NPV total fuel cost rankings for all eight resource plans under the three different gas price cases and two different CO_2 price cases.

Resource Plan Rankings by Total Fuel Costs for Medium DSM

Resource Plan ID	Resource Plan Name	\$0/ton CO_2, Low Gas	\$0/ton CO_2, Base Gas	\$0/ton CO_2, High Gas	\$25/ton CO_2, Low Gas	\$25/ton CO_2, Base Gas	\$25/ton CO_2, High Gas
RP1	CC	6	6	5	6	6	5
RP2	ICT	7	7	7	7	7	7
RP3	Retire Wateree	4	5	6	4	5	6
RP4	Retire McMeekin	8	8	8	8	8	8
RP5	Solar + Storage	2	2	2	2	2	2
RP6	Solar	5	4	4	5	4	4
RP7	Solar PPA + Storage	3	3	3	3	3	3
RP8	Retire Coal	1	1	1	1	1	1

Discussion of Resource Plan Fuel Costs Results:

One observation is how consistent the relative rank of each resource plan is with regards to total fuel costs alone. RP 5 and RP8 are consistently least cost based on a ranking of total fuel costs alone. These two resource plans add a combined cycle gas generator with its additional fixed gas transportation costs but still remain least cost based on total fuel costs. RP4 which retires McMeekin 1 and 2 and Urquhart 3 and meets the reserve margin with ICTs is consistently the most expensive.

x. Resource Plan Rankings by 2030 CO_2 Emissions

The following tables summarize the CO_2 emissions results for all eight resource plans under the three different gas price cases and two different CO_2 price cases.

Resource Plan Rankings by CO_2 for Medium DSM

Resource Plan ID	Resource Plan Name	$0/ton CO_2, Low Gas	$0/ton CO_2, Base Gas	$0/ton CO_2, High Gas	$25/ton CO_2, Low Gas	$25/ton CO_2, Base Gas	$25/ton CO_2, High Gas
RP1	CC	7	7	7	7	7	7
RP2	ICT	7	7	7	7	7	7
RP3	Retire Wateree	2	2	2	2	2	2
RP4	Retire McMeekin	6	6	6	6	6	6
RP5	Solar + Storage	4	3	5	4	4	4
RP6	Solar	3	5	4	3	3	3
RP7	Solar PPA + Storage	5	4	3	5	5	5
RP8	Retire Coal	1	1	1	1	1	1

Resource Plan 2030 CO_2 for Medium DSM (K Tons)

Resource Plan ID	Resource Plan Name	$0/ton CO_2, Low Gas	$0/ton CO_2, Base Gas	$0/ton CO_2, High Gas	$25/ton CO_2, Low Gas	$25/ton CO_2, Base Gas	$25/ton CO_2, High Gas
RP1	CC	11,196	11,421	13,262	10,922	11,033	11,595
RP2	ICT	11,196	11,421	13,262	10,922	11,033	11,595
RP3	Retire Wateree	10,069	10,144	10,990	9,967	9,912	10,281
RP4	Retire McMeekin	11,190	11,393	13,177	10,862	10,850	11,452
RP5	Solar + Storage	10,826	11,054	13,073	10,549	10,609	11,230
RP6	Solar	10,788	11,083	12,950	10,512	10,586	11,218
RP7	Solar PPA + Storage	10,826	11,054	12,889	10,549	10,609	11,230
RP8	Retire Coal	7,781	7,781	7,754	7,763	7,750	7,722

xi. Discussion of CO_2 Results by Resource Plan:

Under all scenarios CO_2 is lowest in RP8 which includes the retirement of all coal generation by 2030 and the addition of a new efficient combined cycle, combustion turbines, and batteries. The second lowest CO_2 occurs in RP3 which retires Wateree in 2028. The lowest value in the table is 7,754 K Tons which is a 59% reduction of CO_2 emission from year 2005. This shows that a significant reduction in CO2 can be achieved with a 3% increase in costs.

The $25/ton CO_2 adder had the biggest impact when coupled with high gas prices. Resource Plan 4 includes a retirement of all gas steam plants and doesn't make a significant impact to total CO_2 emissions. Also, RP1 with a combined cycle plant, Resource Plan 2 with combustion turbines, and RP4 that retires three gas fired boilers have the highest CO_2 emission in 2030 and do not achieve CO_2 reduction goals.

xii. Forecast of Renewable Generation

All resource plans include a significant amount of renewables, between 8% and 21% of total generation. The values in the table are the total renewable generation by resource plan, by 10-year period for the Medium DSM, Base Gas, and \$0/ton CO_2 scenarios only.

Energy from Renewable Generation by Decade (GWh)

Resource Plan ID	Resource Plan Name	2020-2029	2030-2039	2040-2049
RP1	CC	19,912	20,338	20,339
RP2	ICT	19,912	20,338	20,339
RP3	Retire Wateree	19,912	20,338	20,339
RP4	Retire McMeekin	19,912	20,338	20,339
RP5	Solar + Storage	22,570	28,758	28,452
RP6	Solar	22,191	27,941	28,307
RP7	Solar PPA + Storage	22,570	28,728	28,448
RP8	Retire Coal	20,429	35,343	59,510

The following resource plan is the least cost resource plan.

Resource Plan 2

SCE&G Forecast of Summer and Winter Loads and Resources - 2020 IRP Update
(MW)

	YEAR	2020		2021		2022		2023		2024		2025		2026		2027		2028		2029		2030		2031		2032		2033		2034	
		S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W
Load Forecast																															
1	Baseline Trend	4816	4891	4847	4948	4903	5003	4955	5037	4992	5089	5043	5143	5095	5197	5148	5249	5202	5301	5252	5351	5301	5408	5357	5465	5412	5518	5467	5574	5520	5627
2	EE Impact	0	0	0	-24	-24	-48	-50	-73	-76	-97	-102	-121	-128	-147	-155	-172	-183	-199	-211	-199	-211	-199	-211	-199	-211	-199	-211	-199	-211	-199
3	Gross Territorial Peak	4816	4891	4847	4924	4879	4955	4905	4964	4916	4992	4941	5022	4967	5050	4993	5077	5019	5102	5041	5152	5090	5209	5146	5266	5201	5319	5256	5375	5309	5428
System Capacity																															
4	Existing	5689	5915	5664	5915	5664	5915	5664	5915	5664	5915	5664	5915	5664	5915	5664	5915	5664	5915	5664	5915	5664	5915	5664	5915	5664	5915	5664	5915	5664	5915
5	Existing Solar	263	0	329	0	448	0	448	0	448	0	448	0	448	0	448	0	448	0	448	0	448	0	448	0	448	0	448	0	448	0
6	Demand Response	227	224	228	226	229	228	230	230	231	234	232	239	233	249	234	261	235	275	236	276	237	277	238	278	239	279	240	280	241	281
	Additions:																														
7	Solar Plant	67	0	118	0																										
8	Peaking/Intermediate																														
9	Baseload																														
10	Retirements	-25																													
11	Total System Capacity	6220	6139	6340	6141	6341	6143	6342	6145	6343	6149	6344	6154	6345	6164	6346	6176	6347	6190	6348	6191	6349	6192	6350	6193	6351	6194	6352	6195	6353	6196
12																															
13	Total Production Capability	6220	6139	6340	6141	6341	6143	6342	6145	6343	6149	6344	6154	6345	6164	6346	6176	6347	6190	6348	6191	6349	6192	6350	6193	6351	6194	6352	6195	6353	6196
Reserves																															
14	Margin (L13-L3)	1404	1248	1493	1217	1462	1188	1436	1182	1426	1157	1403	1133	1378	1113	1353	1100	1327	1089	1306	1040	1258	983.7	1203	927.7	1149	875.7	1095	820.7	1043	768.7
15	% Reserve Margin (L14/L3)	29.2%	25.5%	30.8%	24.7%	30.0%	24.0%	29.3%	23.8%	29.0%	23.2%	28.4%	22.6%	27.7%	22.0%	27.1%	21.7%	26.4%	21.3%	25.9%	20.2%	24.7%	18.9%	23.4%	17.6%	22.1%	16.5%	20.8%	15.3%	19.7%	14.2%

New resources are added to meet either a 12% summer reserve margin or a 14% winter reserve margin. Because of the higher loads in the winter and 972 MW of solar that contribute some capacity to the summer reserves but not in the winter, the need for winter reserves drives the need to add new capacity. Even then, with just a 0.7% peak load growth rate, no new resources are added until 2035 which is outside the fifteen-year window shown above.

The following plan has the lowest CO_2.

Resource Plan 8

	SCE&G Forecast of Summer and Winter Loads and Resources - 2020 IRP Update (MW)																													
	YEAR	2020		2021		2022		2023		2024		2025		2026		2027		2028		2029		2030		2031		2032		2033		2034	
		S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W
Load Forecast																															
1	Baseline Trend	4816	4891	4847	4948	4903	5003	4955	5037	4992	5089	5043	5143	5095	5197	5148	5249	5202	5301	5252	5351	5301	5408	5357	5465	5412	5518	5467	5574	5520	5627
2	EE Impact	0	0	0	-24	-24	-48	-50	-73	-76	-97	-102	-121	-128	-147	-155	-172	-183	-199	-211	-199	-211	-199	-211	-199	-211	-199	-211	-199	-211	-199
3	Gross Territorial Peak	4816	4891	4847	4924	4879	4955	4905	4964	4916	4992	4941	5022	4967	5050	4993	5077	5019	5102	5041	5152	5090	5209	5146	5266	5201	5319	5256	5375	5309	5428
System Capacity																															
4	Existing	5689	5915	5664	5915	5664	5915	5664	5915	5664	5915	5664	5915	5664	5915	5664	5915	5664	5915	5446	5697	5446	5697	5446	5697	5546	5797	5546	5797	5646	5897
5	Existing Solar	263	0	329	0	448	0	448	0	448	0	448	0	448	0	448	0	448	0	448	0	456	0	464	0	472	0	480	0	488	0
6	Demand Response	227	224	228	226	229	228	230	230	231	234	232	239	233	249	234	261	235	275	236	276	237	277	238	278	239	279	240	280	241	281
	Additions:																														
7	Solar Plant	67	0	118	0															8		8		8		8		8		8	
8	Peaking/Intermediate																								100				100		100
9	Baseload																		1076												
10	Retirements	-25																	-1294												
11	Total System Capacity	6220	6139	6340	6141	6341	6143	6342	6145	6343	6149	6344	6154	6345	6164	6346	6176	6347	5972	6138	5973	6147	5974	6156	6075	6265	6076	6274	6177	6383	6278
12																															
13	Total Production Capability	6220	6139	6340	6141	6341	6143	6342	6145	6343	6149	6344	6154	6345	6164	6346	6176	6347	5972	6138	5973	6147	5974	6156	6075	6265	6076	6274	6177	6383	6278
Reserves																															
14	Margin (L13-L3)	1404	1248	1493	1217	1462	1188	1436	1182	1426	1157	1403	1133	1378	1113	1353	1100	1327	870.7	1096	821.7	1056	765.7	1009	809.7	1063	757.7	1017	802.7	1073	850.7
15	% Reserve Margin (L14/L3)	29.2%	25.5%	30.8%	24.7%	30.0%	24.0%	29.3%	23.8%	29.0%	23.2%	28.4%	22.6%	27.7%	22.0%	27.1%	21.7%	26.4%	17.1%	21.8%	15.9%	20.8%	14.7%	19.6%	15.4%	20.4%	14.2%	19.4%	14.9%	20.2%	15.7%

III. Transmission System Assessment and Planning

DESC's transmission planning practices develop and coordinate a program that provides for timely modifications to the DESC transmission system to ensure a reliable and economical delivery of power. This program includes the determination of the current capability of the electrical network and a ten-year schedule of future additions and modifications to the system. These additions and modifications are required to support customer growth, provide emergency assistance and maintain economic opportunities for DESC's customers while meeting DESC and industry transmission performance standards.

DESC has an ongoing process to determine the current and future performance level of the DESC transmission system. Numerous internal studies are undertaken that address the service needs of customers. These needs include: 1) distributed load growth of existing residential, commercial, industrial, and wholesale customers, 2) new residential, commercial, industrial, and wholesale customers, 3) customers who use only transmission services on the DESC system and 4) generator interconnection services.

DESC has developed and adheres to a set of internal Long-Range Planning Criteria which can be summarized as follows:

> *The requirements of the DESC "LONG RANGE PLANNING CRITERIA" will be satisfied if the system is designed so that during any of the following contingencies, only short-time overloads, low voltages and local loss of load will occur and that after appropriate switching and re-dispatching, all non-radial load can be served with reasonable voltages and that lines and transformers are operating within acceptable limits.*

a. Loss of any bus and associated facilities operating at a voltage level of 115kV or above
b. Loss of any line operating at a voltage level of 115kV or above
c. Loss of entire generating capability in any one plant
d. Loss of all circuits on a common structure
e. Loss of any transmission transformer
f. Loss of any generating unit simultaneous with the loss of a single transmission line

Outages are considered acceptable if they will not cause equipment damage or result in uncontrolled cascading outside the local area.

Furthermore, DESC subscribes to the set of mandatory Electric Reliability Organization ("ERO") Standards, also known as the North American Electric Reliability Corporation ("NERC") Reliability Standards for Transmission Planning, as approved by the NERC Board of

Trustees and the Federal Energy Regulatory Commission ("FERC").

DESC assesses and designs its transmission system to be compliant with the requirements as set forth in these standards. A copy of the NERC Reliability Standards is available at the NERC website www.nerc.com.

The DESC transmission system is interconnected with Duke Energy Progress, Duke Energy Carolinas, South Carolina Public Service Authority ("Santee Cooper"), Georgia Power ("Southern Company") and the Southeastern Power Administration ("SEPA") systems. Because of these interconnections with neighboring systems, system conditions on other systems can affect the capabilities of the DESC transmission system just as system conditions on the DESC transmission system can affect other systems. DESC participates with other transmission planners throughout the southeast to develop current and future power flow, stability and short circuit models of the integrated transmission grid for the NERC Eastern Interconnection. All participants' models are merged together to produce current and future models of the integrated electrical network. Using these models, DESC evaluates its current and future transmission system for compliance with the DESC Long Range Planning Criteria and the NERC Reliability Standards.

Electrical transmission investments planned by DESC:

Planned Project	**Tentative Completion Date**
Thomas Island - Jack Primus 115 kV Line: Acquire R/W & Construct	Feb-20
Saluda Hydro-Denny Terrace 115kV: Broad River Rebuild	Apr-20
Hugh Leatherman 115 kV Tap: Construct	Apr-20
Lake Murray-Lexington Jct 115kV: String 1272 ACSR	May-20
Lake Murray - Michelin 115 kV: Pull new wire on existing structure / Rebuild as Double Circuit	May-20
Cope - Denmark 115 kV: Upgrade to 1272 ACSR from Denmark Sub to Str. 68	May-20
Hooks 115kV Switching Station: Construct	May-20
Urquhart - Graniteville - South Augusta 230/115 kV Tielines	Jun-20
Saluda Hydro - Denny Terrace & Lake Murray - Harbison	Oct-20
Batesburg-Gilbert 115 kV Line	Dec-20

Briggs Rd-Stevens Creek 115kV: Rebuild	Dec-20
Stevens Creek - Briggs Road Tie-line Construct	Dec-20
Bluffton - (SCPSA) Bluffton 115 kV Tie Line Construct	Dec-20
Williams Street - Park Street 115 kV: Construct	Dec-20
Pepperhill - Summerville 230 kV Construct	Jan-21
Edmund - Pelion Tap 115 kV Line	Jan-21
Church Creek-Faber Place 230kV & 115kV: Rebuild the Ashley River Crossing	May-21
Emory 230 kV Distribution Sub: Construct	May-21
Queensboro - Ft Johnson 115 kV Tap	May-21
Canadys 230 kV: Add Back-to-Back Bus Tie Breakers	Jun-21
Canadys 230 kV Sub: Reterminate Various Lines	Jun-21
Urq Jct - Toolbeck 230 kV Fold In	Dec-21
Lake Murray - Gilbert 115 kV Line	Dec-21
Lex Westside - Gilbert 115 kV Line	Dec-21
Batesburg - Ward 115 kV Line	Dec-21
Trenton - Briggs Rd 115 kV Line	Dec-21
Toolebeck – Aiken 230kV Tie: Construct	Dec-21
Coit - Gills Creek 115 kV Line: Construct	Dec-22
Burton - Yemassee 115 kV #2 Line Rebuild as Double Circuit	Dec-22
Stevens Creek-Ward-Lake Murray Line and Associated System Hardening Construct	Mar-23
Union Pier 115-13.8 kV Sub: Tap Construct	Dec-24
Canadys - Ritter 115 kV: Rebuild as 230/115 kV Double Circuit	May-27

Note: The projects listed above are the currently planned projects based on the latest assessment studies. The transmission expansion plan is continuously reviewed and may change due to changes in key data and assumptions. This summary of projects does not represent a commitment to build.

To ensure the reliability of the DESC transmission system while considering conditions on other systems and to assess the reliability of the wide-area integrated transmission grid, DESC participates in assessment studies with neighboring transmission planners in South Carolina, North Carolina and Georgia. Also, DESC on a periodic and ongoing basis participates with other transmission planners throughout the southeast to assess the reliability of the southeastern integrated transmission grid for the long-term horizon (up to 10 years) and for upcoming seasonal (summer and winter) system conditions.

The following is a list of joint studies with neighboring transmission planners completed over the past year:

1. SERC NTWG Reliability 2019 Summer Study
2. SERC NTWG Reliability 2019/2020 Winter Study
3. SERC NTWG OASIS 2019 January Studies (19Q1)
4. SERC NTWG OASIS 2019 April Studies (19Q2)
5. SERC NTWG OASIS 2019 July Studies (19Q3)
6. SERC NTWG OASIS 2019 October Studies (19Q4)
7. SERC LTWG 2024 Future Year Study
8. CTCA 2021 Daytime Minimum, 2022 Daytime Minimum, 2024 Summer Peak – Reliability and Transfer Capability Studies
9. SCRTP 2020 Summer and 2023/24 Winter Transfer Studies

The acronyms used above have the following reference:

SERC – SERC Reliability Corporation
NTSG – Near Term Study Group
OASIS – Open Access Same-time Information System
LTSG – Long Term Study Group
CTCA – Carolinas Transmission Coordination Arrangement
SCRTP – South Carolina Regional Transmission Planning

These activities, as discussed above, provide for a reliable and cost-effective transmission system for DESC customers and comply with Federal regulations.

Eastern Interconnection Planning Collaborative (EIPC)

The Eastern Interconnection Planning Collaborative ("EIPC") was initiated by a coalition of regional Planning Authorities (including DESC). These Planning Authorities are entities listed on the NERC compliance registry as Planning Authorities and represent the majority of the Eastern Interconnection.

The EIPC provides a grass-roots approach which builds upon the regional expansion plans developed each year by regional stakeholders in collaboration with their respective NERC Planning Authorities. This approach provides coordinated interregional analysis for the entire Eastern Interconnection.

The EIPC purpose is to model the impact on the grid of various policy options determined to be of interest by state, provincial and federal policy makers and other stakeholders. This work builds upon, rather than replaces, the current local and regional transmission planning processes developed by the Planning Authorities and associated regional stakeholder groups within the entire Eastern Interconnection. Those processes are informed by the EIPC analysis efforts including the interconnection-wide review of the existing regional plans and development of transmission options associated with the various policy options.

Distributed Generation Integration

All levels of the existing electric infrastructure, standards, and operating protocols were originally designed around a fully dispatchable generation fleet required to satisfy variable load conditions. Equipment configurations and operating standards have been designed to ensure grid reliability and stability through the control of system frequency and voltage. In contrast, Solar PV generation systems are intermittent where energy output is variable with limited dispatch capability. Further, traditional generation facilities are typically large centralized plants with high MW ratings while solar PV generating facilities are smaller in size and, in many cases, installed at the distribution level by the end user (e.g., a homeowner, business, or other non-utility entity) – often mounting the PV panels on the roof of a building or on smaller scale developer-built sites. As the movement towards clean energy grows, the Company expects that power from solar PV installations may be injected onto its system from hundreds or even thousands of interconnection points that may either be at the transmission level or at on the distribution level. To accommodate these changes, generation facilities, transmission grids, and distribution systems must allow for two-way power flows all while maintaining the highest level of reliability possible. The Company continues to study this paradigm shift in generation technology and its impact on the Company's transmission grid and distribution system, and the results of this work could require design modifications to assure system stability and reliability. Examples may include partial system re-configuration and/or deployment of new technologies such as batteries, synchronous condensers, and static synchronous compensators ("STATCOM").

DESC plans to continue to study the issues associated with solar PV integration described above. The results of those studies will be published in future IRP's.

IV. Conclusions

The results in this document reflect that in the near term the Company does not need to make any major changes to the baseload generation fleet in order to meet customer's energy and capacity needs in a safe, reliable, and cost-effective manner. However in an effort to produce a more sustainable future, the Company is implementing or evaluating upgrading its distribution network with projects like AMI, replacing older peaking units with quick-start, flexible, and reliable generation, expanding DSM and studying its transmission system to minimize the impact of eventual steam unit retirements and allow for additional intermittent renewable generation.

Some useful results in the Resource Plan Analysis include that RP2 was the least cost plan under all DSM cases, with base gas and \$0/ton CO_2, though the cost difference between all cases was modest. RP7 and RP8 were least cost plans under numerous scenarios. RP8 resulted in the least carbon impact under all scenarios. All resource plans include the addition of combustion turbines or combined cycle plants but Resource Plans 5 – 8 also add renewables. RP2 which adds only combustion turbines, Resource Plan 7 which has solar with storage, and RP8 which retires coal, rank the least cost depending upon the sensitivity selection. RP8 has the lowest 2030 CO_2 emissions by a significant margin, and the lowest cost in some scenarios. All resource plans were within 3% of levelized NPV of each other when the assumptions about DSM, CO_2 and gas were held constant. These differences indicate that the relative rankings could change based on updated information in the future. While the Company makes observations and conclusions as to which resource plan results in the least cost, the results do not reflect a decision by the Company for its path forward

Since the 2019 IRP and 2019 Potential Study, DESC has implemented a much larger commitment to AMI which will increase the potential for deployment of additional cost-effective DSM, which includes both EE and DR. AMI will allow the Company to target new and specific demand response programs for study. End of life retirement of some of the Company's older combustion turbines are the only near-term issue that may adversely impact the Company's ability to maintain the proper level of planning reserves. The Company plans to continue to study this issue and will inform the PSC of its conclusion regarding these older combustion turbines after the final analysis is complete. At this time, however, no immediate action is needed for resource retirements or additions based on the IRP. This IRP does indicate that several potential retirements and other resource plans are viable and will be studied over the next few years. Expenditures over the IRP time horizon will be primarily toward environmental compliance, reliability of supply, grid reliability and the continued shift toward renewable resources. The Company will continue to study these alternatives in detail.

On an energy basis, photovoltaic solar technology is becoming more cost-competitive with traditional forms of generation. Currently, stand-alone solar does not meet all of the needs of a highly dynamic and critical infrastructure system like the electric grid. As previously mentioned, solar provides little winter peaking capacity. It will take innovation and research to find a cost-effective combination of combustion turbine and energy storage technologies to provide reliable clean energy supply for the future. Using the results of several resource plans and scenarios provides a reasonable means of estimating the cost benefit ratio for CO_2 reductions. Comparing RP2 and RP8 shows that a 3% increase in costs could result in significantly better CO_2 reduction by 2030 of 59% reduction verses RP2's 39%, both from 2005 levels. The only substantive CO_2 reductions are a result of reducing or eliminating energy generated from coal resources as shown in RP3 and RP8.

The IRP process is designed to develop and evaluate potential resource plans under various scenarios to understand risks, costs and environmental impacts to reserve margins. Given the dynamic nature of the current electric power industry with respect to societal trends, customer preferences, technological advances, and environmental regulations, it is important that Company remain flexible with respect to future expansion plans. As such, the DESC resource plans identified in this 2020 IRP present several plausible paths the Company may or may not elect to pursue. What's most imperative is that the Company remain agile regarding management of its electric generation portfolio in response to changing energy supply and customer usage.

The Charleston Metropolitan area is poised for EV growth. Several factors are promoting EV growth in the strongest market ahead of more rural areas in the DESC service territory. The Company anticipates that the growth in the Charleston area will continue to gain strength. Similar adoption rates are expected to follow in the Columbia, Hilton Head and Aiken areas. The local increased energy demand will certainly require adaptation initially in all urban areas.

Urban distribution systems will need additional support from automation as adoption increases.

In the next 15 years, DESC will be working toward creating the infrastructure that opens the way for lower cost generation and non-emitting resources, but those steps must also be affordable. However, with a commitment to a more sustainable energy future, the Company needs to upgrade its distribution network through measures such as rolling out Advanced Metering Infrastructure, converting some of its older peaking generation to more reliable and quick- start peaking generation, continuing to expand DSM, and studying transmission system to minimize the impact of eventual steam unit retirements and additional intermittent renewable generation.

Appendix A

Intervenor Provided Resource Plans and Scenarios

As a part of the Dominion Energy/SCANA merger settlement DESC agreed that "During the development of the IRP, intervenors in the previous year's IRP can request (via the Office of Regulatory Staff ("ORS")) that the SCE&G evaluate a limited number of alternative resource plans for modeling during the IRP development. For purposes of this condition, the limited number of alternative resource plans required shall not exceed five and shall be agreed upon by SCE&G in consultation with ORS." The following resources and scenarios were suggested by the intervenors. Although these resource plans utilized many of the same data inputs, no direct comparisons to DESC's resource plans were possible due to the low resource cost information provided by the third parties, which in DESC's view, results in a low portfolio cost bias and prevents a practical comparison.

The following table lists the resources examined in the intervenors' resource plans.

Resource	**Capital Cost 2020 $/kW**	**Description**	**Source of Data**
Stand Alone Battery PPA	N/A	100 MW with 4 hour duration	2019 NREL Low Technology Cost Scenario pricing
Solar PPA	N/A	Various Sizes	2019 NREL Low Technology Cost Scenario pricing
Solar + Storage PPA	N/A	400 MW Solar + 100 MW Battery Storage	2019 NREL Low Technology Cost Scenario pricing
ICT	1097	93 MW aeroderivative	Dominion Energy Services - Generation Construction Financial Management & Controls
Capacity Purchases	N/A	50 MW increments	DESC estimates

These five resources were combined in various ways to develop five resource plans, some of which consider the retirement of some existing generating units. The five resource plans are listed in the following table with a description of each resource plan. Wateree and Williams are retired when they reach their end of life, which is years 2044 and 2047 respectively, if not retired earlier.

Intervenor Resource Plan ID	Intervenor Resource Plan
SBA 1	Solar PPA, ICT, Base DSM
SBA 2	Williams Retirement, 1.25% DSM, Standalone Battery Storage PPA, Solar PPA
SBA 3	Williams and Wateree Retirement, 1.25% DSM, Capacity Purchases, Solar PPA, Standalone Battery Storage, Solar+Storage PPA
SBA 4	McMeekin and Urquhart 3 Retirement, 1.25% DSM, Solar PPA, Standalone Battery Storage
SBA 5	Solar PPA in 2021, Standalone Battery Storage PPA, Base DSM

Intervenor Resource Plan Definitions

Resource Plan SBA 1: In this resource plan a 400 MW Solar PPA is added in 2026. 93 MW of combustion turbines are added to maintain the 14% winter reserve margin during the modeling period.

Resource Plan SBA 2: In this resource plan Williams is retired in year 2028. 831 MW Solar PPA, 358 MW Storage, and DSM equal to 1.25% of retail sales plus 43 MW of DR are added. 100 MW standalone storage are added to maintain the 14% winter reserve margin during the modeling period.

Resource Plan SBA 3: In this resource plan Williams and Wateree are retired in 2026. 1774 MW Solar PPA, 603 MW Storage, 500 MW capacity purchases and DSM equal to 1.25% of retail sales plus 43 MW of DR are added to replace the retired capacity and energy. Capacity purchases terminate in 2029 and are replaced by a 500 MW standalone battery storage PPA. 400 MW Solar +100 MW Storage PPAs are added to maintain the 14% winter reserve margin during the modeling period.

Resource Plan SBA 4: In this resource plan McMeekin 1 and 2 along with Urquhart 3 are retired in 2029. The retired capacity and energy is replaced by 64 MW of standalone battery storage, 94 MW of solar PPA, and DSM equal to 1.25% of retail sales plus 43 MW of DR. 100 MW standalone battery storage PPAs are added to maintain the 14% winter reserve margin during the modeling period.

Resource Plan SBA 5: In this resource plan 200 MW of solar PPA is added in 2021. 43 MW of DR is added in 2029. Base level of DSM is used in this resource plan. 100 MW standalone battery storage is added to maintain the 14% winter reserve margin during the modeling period.

PPA Price Assumptions

The intervenors specified that the renewable costs used in modeling their five resource plans be based on the NREL Annual Technology Baseline database "Low Technology Cost Scenarios." The results would have been more useful had the intervenors specified that DESC use the "Mid Technology Cost Scenarios." Below are NREL definitions for their two scenarios:

- Mid Technology Cost Scenario: based on the median of literature projections of future CAPEX; O&M technology pathway analysis
- Low Technology Cost Scenario: based on the low bound of literature projections of future CAPEX and O&M technology pathway analysis.

The CAPEX forecast for solar under the "Low Technology Cost Scenario" drops an aggressive 61% from 2020 to 2050. Under the "Mid Technology Cost Scenario" the CAPEX forecast for solar drops a more realistic 36% from 2020 to 2050. By specification, the resulting levelized cost for all five intervenor resource plans is very likely to be understated.

Methodology

The incremental revenue requirements associated with each of the five intervenor resource plans was computed using the PROSYM computer program to estimate production costs and a Microsoft® Excel capital cost model to calculate the associated capital costs. The capital cost model is combined the capital costs with the production costs to estimate total incremental revenue requirements over a 40-year planning horizon.

Demand Side Management (DSM) Assumptions

Two DSM cases were used in resource plans provided by the intervenors. Medium DSM is based on the results of the 2019 Potential Study and is used for Resource Plans 1 and 5. DSM specified in Resource Plans 2 – 4 requires that DSM grows to 1.25% by 2024. It should be noted that DSM levels above those provided within the 2019 Potential Study, are not likely to be achievable and cost-effectiveness is unknown. It should also be noted that the costs used to model the 1.25% DSM in Resource Plans 2 – 4 are only estimates. No comprehensive study or program analysis has been completed to determine the actual costs to achieve 1.25% savings and such costs can be expected to grow exponentially as higher and higher levels of energy savings are sought.

Emissions and Fuel Sensitivity

Each resource plan was evaluated using three gas price forecasts plus $0 and $25 per ton CO_2 costs. The combination of the three gas price assumptions and two CO_2 cost assumptions created 6 different scenarios. The high gas price forecast is the 2019 EIA gas price forecast. The base gas and low gas scenarios are based on NYMEX gas prices for years 2020-2022 then escalated at two different rates. The base escalation rate is derived from the EIA gas price forecast. The low gas scenario escalation rate is half of the base gas escalation rate. The two CO_2 assumptions used were $0/ton and $25/ton.

Intervenor Resource Plan Rankings

The following tables summarizes the 40 year levelized NPV cost results for all five resource plans under the three different gas price cases and two different CO_2 price cases.

(1 - Green= Least cost, 2 – Blue = Second Lowest and 8 - Orange = Highest cost)

Resource Plan ID	$0/ton CO_2, Low Gas	$0/ton CO_2, Base Gas	$0/ton CO_2, High Gas	$25/ton CO_2, Low Gas	$25/ton CO_2, Base Gas	$25/ton CO_2, High Gas
SBA 1	4	4	5	4	5	5
SBA 2	1	1	1	2	2	2
SBA 3	3	3	2	1	1	1
SBA 4	5	5	4	5	4	4
SBA 5	2	2	3	3	3	3

40 Year Levelized NPV of the Intervenor Resource Plans

Resource Plan ID	$0/ton CO_2, Low Gas	$0/ton CO_2, Base Gas	$0/ton CO_2, High Gas	$25/ton CO_2, Low Gas	$25/ton CO_2, Base Gas	$25/ton CO_2, High Gas
SBA 1	$1,181,917	$1,259,710	$1,426,579	$1,396,358	$1,475,537	$1,669,170
SBA 2	$1,142,465	$1,211,484	$1,368,241	$1,333,510	$1,406,644	$1,583,127
SBA 3	$1,179,934	$1,236,930	$1,382,570	$1,329,021	$1,389,003	$1,544,806
SBA 4	$1,192,393	$1,261,454	$1,421,922	$1,401,112	$1,472,960	$1,651,763
SBA 5	$1,157,146	$1,233,152	$1,400,031	$1,372,049	$1,451,312	$1,639,753

Discussion of Cost Results:

Resource Plans 2 and 3 are least cost as modeled. Resource Plans 2 through 4 assumed a level of DSM that is not cost effective Therefore, only Resource Plans 1 and 5 provide meaningful results within the constraints specified.

Since $0/Ton CO_2 and Base Gas is the most likely scenario, Resource Plan 1 is the least cost of these scenarios when only Resource Plans 1 and 5 are considered.

2030 CO_2 Emissions Rankings

The following tables summarize the CO_2 emissions results for all five resource plans under the three different gas price cases and two different CO_2 price cases. Green shading denotes the lowest CO_2 production and the number 1 ranking. Blue is second lowest, and brown is the highest CO_2 production at the number 5 ranking

Resource Plan ID	$0/ton CO_2, Low Gas	$0/ton CO_2, Base Gas	$0/ton CO_2, High Gas	$25/ton CO_2, Low Gas	$25/ton CO_2, Base Gas	$25/ton CO_2, High Gas
SBA 1	4	4	4	4	4	4
SBA 2	2	2	2	2	2	2
SBA 3	1	1	1	1	1	1
SBA 4	3	3	3	3	3	3
SBA 5	5	5	5	5	5	5

2030 CO_2 Emissions (K tons)

Resource Plan ID	\$0/ton CO_2, Low Gas	\$0/ton CO_2, Base Gas	\$0/ton CO_2, High Gas	\$25/ton CO_2, Low Gas	\$25/ton CO_2, Base Gas	\$25/ton CO_2, High Gas
SBA 1	10,791	11,096	12,940	10,526	10,569	11,213
SBA 2	8,943	9,082	10,551	8,649	8,722	9,291
SBA 3	6,990	6,986	7,493	6,907	6,904	7,312
SBA 4	10,715	11,045	12,593	10,456	10,495	11,036
SBA 5	11,111	11,281	13,070	10,770	10,794	11,474

Discussion of CO_2 Results:

The resource plan with the least CO_2 emission Resource Plan 3 under all scenarios. Resource Plan 3 included 1,294 MW of coal retirements. The highest emitting resource plan in all scenarios was Resource Plan 5 which adds 200 MW of solar in 2021. The CO_2 emissions in resource plans 2, 3, and 4 are low because the 1.25% DSM scenario was specified and used in these resource plans in addition to coal-fired generation unit retirements in plans 2 and 3. It should also be noted that the costs used to model the 1.25% DSM in Resource Plans 2 through 4 are only estimates. No comprehensive study or program analysis has been completed to determine the actual costs to achieve 1.25% savings.