EXHIBIT H

DESCRIPTION OF PROJECT MANAGEMENT AND NEED FOR PROJECT POWER

STEVENS CREEK HYDROELECTRIC PROJECT

FERC PROJECT NO. 2535

APPLICATION FOR NEW LICENSE

FOR MAJOR PROJECT – EXISTING DAM

EXHIBIT H

DESCRIPTION OF PROJECT MANAGEMENT AND NEED FOR PROJECT POWER

<u>Information to be supplied by all applicants for new license:</u>

1. Dominion Energy South Carolina, Inc. (DESC; Licensee or Applicant) intends to continue to operate and maintain the Stevens Creek Hydroelectric Project (Stevens Creek Project) to provide efficient and reliable electric service as described below.

    a. There are no plans for increasing capacity at the Stevens Creek Project. Potential equipment upgrades were evaluated in a Resource Utilization Study for the Stevens Creek Project (Kleinschmidt 2021). This study concluded that due to the operations of the Stevens Creek Project to function as a re-regulating facility to reduce the high inflow fluctuations caused by the peaking operation of the upstream J. Strom Thurmond (Thurmond Dam) development, there is a limited benefit to increasing capacity.

    b. The Stevens Creek Project will continue to operate in the future as it has in the past, to reregulate flow from Thurmond Dam which is operated by the U.S. Army Corps of Engineers (USACE). This function provides a relatively continuous flow for the downstream Savannah River users and aquatic habitat. The Stevens Creek Project operators receive a daily projected discharge schedule for Thurmond Dam hydro to operate the plant to minimize pool fluctuations while providing discharges in response to Thurmond Dam's planned schedule and maintaining the Stevens Creek Reservoir between elevations 183.0 feet and 187.5 feet 1929 National Geodetic Vertical Datum (NGVD). The Stevens Creek Project is operated by the Applicant as a base load run-of-river generating capacity. Other than for brief forced outages or scheduled maintenance outages, the Stevens Creek Project generating units provide energy as river flow permits.

    c. The Applicant provides for the reliability of its electric system by maintaining an adequate reserve margin of supply capacity and by maintaining daily operating reserves to balance the risk that some of the Applicant's generation capacity may be forced offline on any given day because of mechanical failures, wet coal problems, environmental limitations, or other unforeseen events. The Applicant is a member of the Virginia-Carolinas Electric Reliability Council (VACAR), an organization which coordinates a regional reserve sharing system allowing its members to pool their reserve generation resources on a prorated basis. This VACAR Reserve Sharing Arrangement (VRSA) provides a formal mechanism for VACAR members to share reserve capacity.

d. The Applicant plans to continue to operate the Stevens Creek Project within its own system, and in coordination with others, as described above, which will help minimize the cost of production by providing economical baseload. Continued operation of the Stevens Creek Project is also critical to the Applicant's short- and long-term plans to transition its baseload generation fleet to retire two coal-only facilities and add to the natural gas fired generation along with the existing gas (both conventional steam and combined cycle), and nuclear assets. Conventional hydro, pump storage, and simple cycle gas turning assets will serve peaking and reserve functions, with additional solar generation also being integrated into the Applicant's system as it comes online.

2. The Applicant's need over short and long term for power generated from the Stevens Creek Project is described as follows:

   a. Reasonable costs and availability of alternate sources of power: There would be three reasonable alternatives to replace the Stevens Creek Project's generation if the Applicant is not provided a license: 1) construction of a new generator; 2) redispatch of existing resources; and 3) off-system purchases. These three are discussed below, including the additional cost of each.

   b. A discussion of the increase in fuel, capital, and operation and maintenance (O&M) costs if the license is not granted: Recent fluctuations in both natural gas and coal prices emphasize the need for hydro generation. The following charts (Figure 1 and Figure 2) demonstrate the recent history of fuel prices. Reliable zero fuel costs resources, such as the Stevens Creek Project, are an important component of a diverse generation mix for all the Applicant's residential, commercial, and industrial customers.

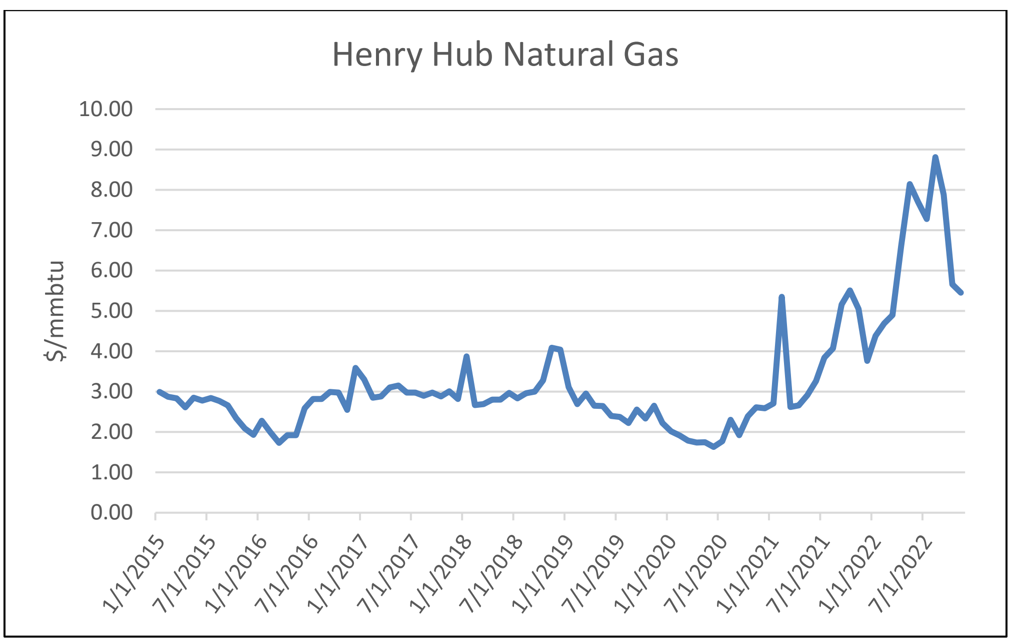

Figure 1 Average Price of Natural Gas (2015-2022)

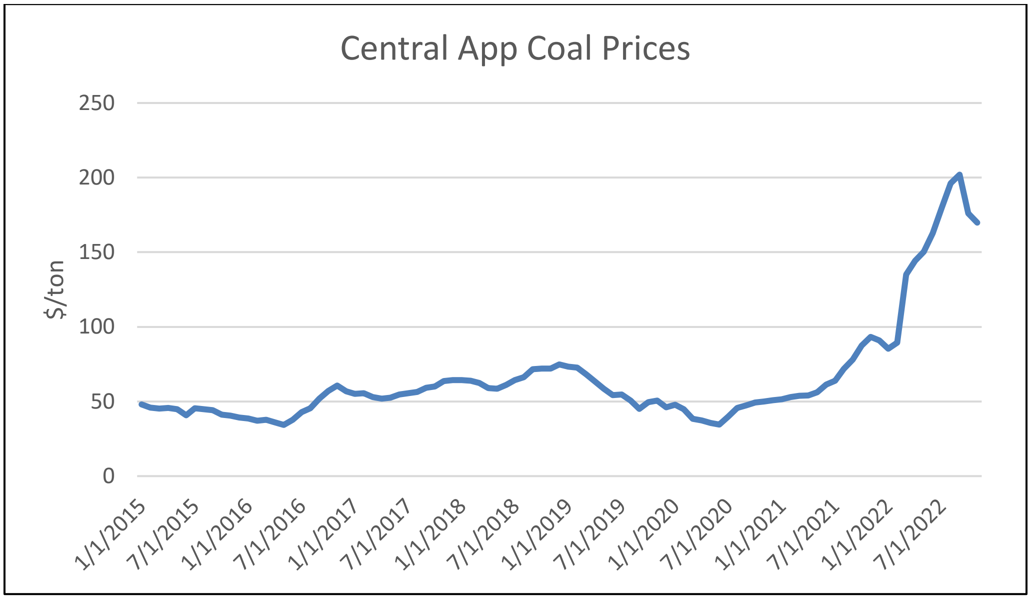

Figure 2 Average Price of Coal (2015-2022)

c. <u>Effect of each alternative source of power on customers, operation and load characteristics, and communities</u>: The most likely source for alternative power would be construction of a new generator. Alternatively, the Applicant would redispatch existing resources and seek off-system purchases. However, neither of these resources offer the level of reliability obtained from the Stevens Creek Project.

Failure to relicense this hydro facility would have an impact on the supply and cost of energy now available to serve customers on the Applicant's system. Energy that is normally produced by the Stevens Creek Project would have to be replaced from another source at a cost higher than currently represented by this plant. The cost of producing electricity at the Stevens Creek Project, as in the Applicant's other hydro plants, is considerably less than the cost to produce electricity at its most efficient steam plants. The average production cost of the energy delivered to the plant bus at the Stevens Creek Project in 2021 was $7.60/megawatt-hours (MWh). The average production cost of the most efficient steam plants on the Applicant's system in 2021 was approximately $35.80/MWh (FERC Form 1 filed with FERC on April 18, 2022).

The loss of license for the Stevens Creek Project would result in a loss of tax revenues to the federal, state, and local governments. The governmental entities affected by this loss in revenue would ultimately have to seek a reduction in expenses or an increase in other sources of revenue.

3. Data showing need, reasonable cost, and availability of alternate source of power:

   a. The average annual cost of power produced by the Stevens Creek Project in 2021 was $7.60 per net MWh (FERC Form 1 filed with the FERC on April 18, 2022).

   b. Projected resources required to meet short- and long-term capacity and energy requirements are presented in the 2023 Integrated Resource Plan (IRP). The Applicant files a copy of its IRP with the South Carolina Public Service Commission (SCPSC) in accordance with S.C. Code Ann. § 58-37-40 (2015), § 58-33-430, and SCPSC Order No. 98-502. This Plan was filed with SCPSC on January 30, 2023.

c. For alternative sources of power including generation of additional power at existing facilities, restarting deactivated units, the purchase of power off-system, the construction or purchase and operations of new power plant, and load management measures such as conservation:

   i. The total annual cost of each alternative source of power to replace Stevens Creek Project power (Table 1). Replacement capacity and energy would likely come from one of the following resources (values provided by EIA 2022 AEO). Assuming a size similar to the Stevens Creek Project, the additional costs to customers would be approximated.

Table 1 Alternative Sources of Power to Replace Stevens Creek Project Power

Technology	Size (MW)	Capital Cost ($/KW)	Variable O&M ($/MWh)	Fixed O&M ($/Kw-yr)	Fuel Costs ($/mmbtu)	Heat rate (Btu/kWh)	All in Cost ($/MWh)	Annual Costs ($)
Internal Combustion Engine	18	$2,018	$5.96	$36.81	6.00	8295	$408.28	$6,437,806
CT Aeroderivative	18	$1,294	$4.92	$17.06	4.00	9124	$260.01	$4,099,889
CT Frame	18	$785	$4.71	$7.33	4.00	9905	$173.49	$2,735,659
Solar	18	$1,327	$0.00	$15.97	0.00	0	$90.91	$3,583,728

If the Stevens Creek Project energy is replaced by a mix of current resources, the additional costs would be as follows:

Table 2 Annual Cost to Replace Stevens Creek Project Power

Year	Stevens Creek Avg Generation (MWh)	System Marginal Costs ($/MWh)	Annual Costs ($)
2023	65,947	63.19	4,167,191
2024	65,947	55.70	3,673,248
2025	65,947	43.27	2,853,527
2026	65,947	41.28	2,722,292
2027	65,947	36.94	2,436,082
2028	65,947	36.44	2,403,109
2029	65,947	38.98	2,570,614
2030	65,947	45.26	2,984,761
2031	65,947	48.03	3,167,434
2032	65,947	47.85	3,155,564
2033	65,947	49.41	3,258,441
2034	65,947	64.46	4,250,944
2035	65,947	53.12	3,503,105
2036	65,947	58.58	3,863,175
2037	65,947	57.39	3,784,698

If the Stevens Creek Project energy had been replaced by off system purchases during 2015 through 2022 it would have been at the average purchase cost as indicated in Figure 3. For 2022 an average purchase price of $80.82/MWh would have increased system costs by $5,329,836 using average annual Stevens Creek Project generation.

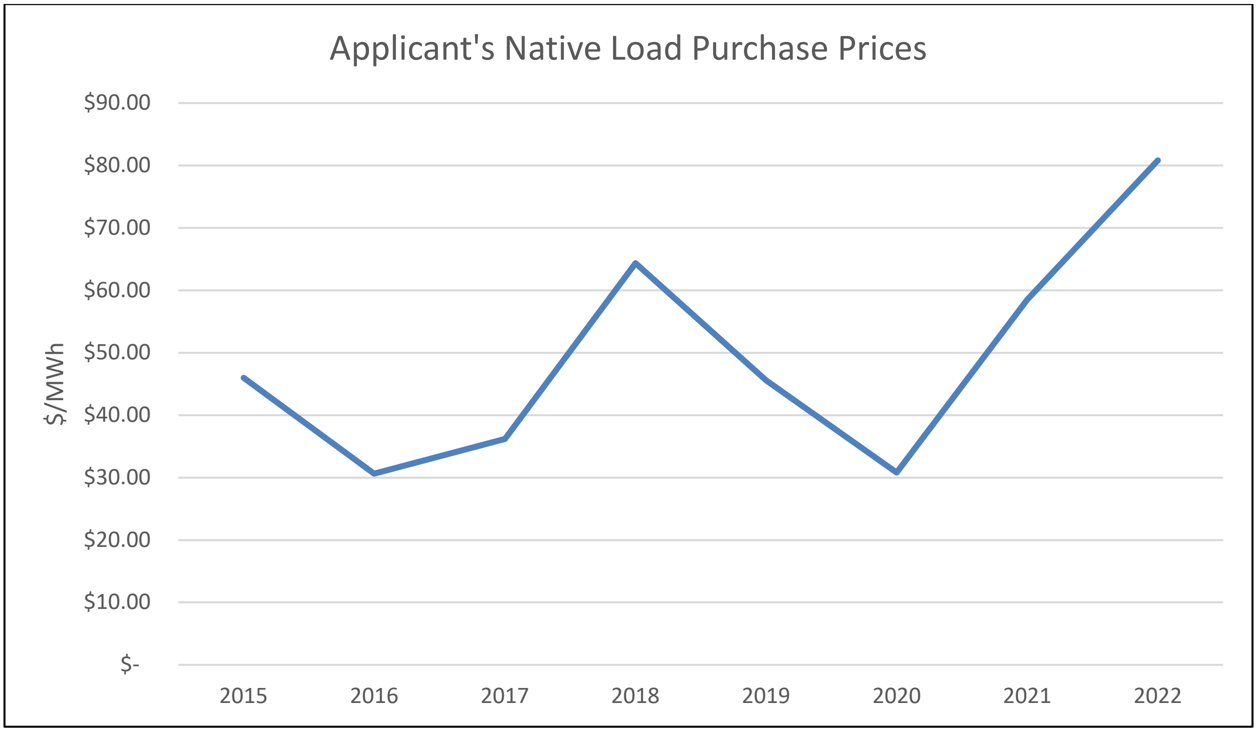

Figure 3 Native Load Purchase Prices (2015-2022)

For 2015 through 2022, the additional system costs from off-system purchases based on actual Stevens Creek Project generation would have been as indicated in Table 3, if the Stevens Creek Project had not been available.

Table 3 Additional System Costs with Stevens Creek Project Absence (2015-2022)

Year	Average Off-System Purchase Cost ($/MWh)	Stevens Creek Generation (MWh)	Total Off-System Replacement Cost ($)
2015	46.00	64,962	2,988,252
2016	30.62	57,309	1,754,802
2017	36.19	44,037	1,593,699
2018	64.35	59,662	3,839,250
2019	45.58	82,955	3,781,089
2020	30.80	99,276	3,057,701
2021	58.52	87,081	5,095,980
2022	80.82	73,362	5,929,117

ii. The basis for the determination of projected annual cost: For new resources, the basis of the annual costs is the U.S. Energy Information Administration's Annual Energy Outlook 2022. For replacement of power using existing resources, the projection of system marginal costs in the Applicant's PLEXOS forecasting model. For projection of off-system purchase costs, the 15-year average Stevens Creek Project generation and Applicant's 2022 average off-system purchase cost.

iii. The relative merits of each alternative, including the issues of the period of availability and dependability of purchased power, average life of alternatives, relative equivalent availability of generating alternatives, and relative impacts on the applicant's power system reliability and other system operating characteristics: The Stevens Creek Project provides flexible power generation and capacity for the Applicant's system and to meet the Applicant's reserve share obligation under the VRSA. The Stevens Creek Project is critical to maintaining the reliability of the Applicant's system as well as contributing to the reliability of the regional transmission grid. Should a new license for the Stevens Creek Project not be granted, the project's generation and capacity would have to be replaced by off system power purchases, constructing new generation facilities, redispatch of existing resources, or some combination of the three.

Alternative 1: Construction of new resources

Construction of new resources provides the system with the greatest level of reliability, reserves, capacity, and energy. The challenge for construction of new resources are issues related to siting, supply chain availability, and time to construct. The cost of financing, constructing, operating, and maintaining such facilities would increase the cost of power to the Applicant's wholesale, residential, commercial, military, and industrial customers.

Alternative 2: Redispatch of existing resources

Redispatch of existing resources is the easiest to implement but does not address the loss of capacity needed for system planning reserve margin. It also does not address the loss of system operating reserves.

Alternative 3: Off-system purchases

Off-system purchases provide the lowest level of reliability since the Applicant is turning to other utilities and suppliers to provide the needed resources. These resources are subject to curtailment. Off-system purchases must also rely on transmission interconnection availability which is also subject to being curtailed.

d. The effect on the direct providers (and their immediate customers) of alternate sources of power. If any of the alternative sources discussed above were to be utilized, there would be an increase to the cost of power to the Applicant's wholesale, residential, commercial, military, and industrial customers.

4. Use of power for Applicant's own industrial facilities: The Applicant is an investor-owned utility and has no non-utility industrial facilities to be affected by loss of electricity from the Stevens Creek Project.

5. Need for Stevens Creek Project to foster the purpose of an Indigenous Tribal Reservation: The Applicant is not an Indigenous Tribe and does not use the electricity generated by the Stevens Creek Project to foster the purposes of a reservation.

6. Impact on the operation and planning of transmission system of receiving or not receiving license: The Stevens Creek Project is an important resource for meeting the Reliability Standards of the North American Electric Reliability Corporation (NERC) for interconnected-

systems operation, in particular Standard BAL-001 – Real Power Balancing Control Performance and Standard BAL-002 – Disturbance Control Performance. These Standards include requirements for balancing load and generation, maintaining steady-state frequency and provide for operating reserves and frequency regulation to address the resolution of inadvertent interchange between electric systems or conditions of insufficient generation resources. The NERC has developed and adopted these Standards for the planning and operation of the bulk electric system through the cooperative efforts of its member utilities. The NERC's Regional Entities have initiated requirements to assess and enforce compliance with NERC Reliability Standards. Enforcement of the Standards developed by NERC has been assigned to the SERC Reliability Corporation (SERC), a Regional Entity of NERC. The Applicant is a registered entity of SERC.

If hydroelectric operations at this facility were to be discontinued, in the short term the Applicant would be required to utilize other generation sources to maintain these and other related operational Standards specified by NERC. The effect on the Applicant's transmission system operation and planning would vary depending upon the generation sources available and their proximity to load centers on the Applicant's system. The potential cost impact of these system modifications would depend on the particular site(s) chosen and their proximity to load centers and system interconnection points. Transmission costs associated with new generation has been estimated by the Applicant's Transmission Planning group to be $18.29 per installed kilowatt (kW) of capacity, or approximately $329,220 in transmission costs associated with replacing the Stevens Creek Project hydroelectric plant with new base load generation on the Applicant's system based on 18 megawatts. This cost per installed kW is an estimate and made without knowing where any future replacement generation would be located or how it would be connected to the Applicant's existing system.

Single-line diagrams are included in Exhibit A (Appendix A-2) of this application.

7. <u>Proposed changes to the Stevens Creek Project facilities or operations:</u> Other than proposed recreation site improvements the applicant has no plans to modify existing project facilities or operations of the Stevens Creek Project.

8. <u>Conformance with Comprehensive Plans for Improving or Developing the Waterway:</u> The Applicant has reviewed approved comprehensive plans for the waterway, as defined in section 10(a)(1) of the Federal Power Act, as further discussed in Exhibit E of this application.

9. <u>The Applicant's financial and personnel resources to meet its obligations under a new license are as follows</u>: The Applicant has adequate personnel resources to continue to operate and maintain the Stevens Creek Project in accordance with the provisions of the license. The permanent staff at the Stevens Creek Project consists of three operator-repairmen, who are on site eight hours per day, five days per week, and perform plant checks on weekends and holidays. In addition, the Applicant can provide additional personnel from its other electric generating facilities in the event of emergencies or major maintenance outages. The Stevens Creek Project personnel receive on-the-job and other in-house training to prepare them to safely operate and maintain the plant, including training for response to environmental and other emergencies. The Applicant's financial resources to meet its obligations under the new license are further detailed in Exhibit D.

10. <u>Proposed changes to the Stevens Creek Project boundary:</u> The Applicant has no proposed changes to the Stevens Creek Project boundary.

11. <u>Statement of energy conservation programs and measures and compliance with applicable regulatory requirements</u>: The Applicant is actively involved in a number of programs to improve the efficiency of electricity generation and consumption on its power system. The Energy Efficiency/Demand Side Management (EE/DSM) portfolio offers a variety of programs and services available to eligible residential and business customers which includes seven residential programs and three commercial and industrial programs designed to encourage

customers to reduce their energy usage and provide energy education. These programs can be divided into two major categories: Energy Efficiency/Demand Side Management Programs and Load Management Programs (which include Standby Generator, Interruptible Load, Real Time Pricing Rate, Time of Use Rates, and Winter Peak Clipping programs). Since the inception of the EE/DSM programs, the Applicant has invested over $163 million dollars in energy efficiency and reported reduced electricity usage by more than 992,000 megawatt hours.

As a corporation organized and existing under the laws of the State of South Carolina, the Applicant must comply with the policies of the Public Service Commission of South Carolina regarding energy conservation/DSM programs. Pursuant to S.C. Code Ann. § 58-37-20 and S.C. Code Ann. Regs. 103- 819 and 103-825, and in compliance with Public Service Commission of South Carolina, the Applicant submits annual updates to the Commission concerning the current status of the Applicant's demand reduction and energy efficiency/DSM programs. The January 2023 filing includes the most significant aspects of program development and implementation approach for each of the approved EE/DSM programs (SC PSC 2023a). Additionally, the Applicant files a copy of its Integrated Resource Plan (IRP) with the Commission in accordance with S.C. Code Ann. § 58-37-40 (2015), § 58-33-430, and SCPSC Order No. 98-502. A copy of the 2023 IRP (SC PSC 2023b) was filed on January 30, 2023. Within the 2023 IRP, a section titled "The 2023 DSM Potential Study" found on page 14, describes the Applicant's recent activities relating to the development of the next set of DSM programs and the DSM modeling assumptions used within the 2023 IRP are explained on page 49. The 2023 DSM Potential Study can also be found in the same link provided for the 2023 IRP.

12. <u>Indigenous Tribes with land on the Stevens Creek Project or who would be affected by the Stevens Creek Project</u>: There are no Indigenous Tribes with land within the Stevens Creek Project boundary. However, on August 2, 2019, federally recognized Native American Tribes were contacted by mail to determine if they wished to be consulting parties for the relicensing of the Stevens Creek Project. Contact information for the tribes contacted is contained in the Initial Statement. The responses of the tribes who were contacted are summarized below in Table 4.

Table 4 Consultation Response from Federally Recognized Indigenous Tribes with Potential Interest in the Stevens Creek Project

Indigenous Tribe	Response/Status
Absentee-Shawnee Tribe	No Response
Catawba Nation	Consulting Party
Cherokee Nation	Consulting Party
Chickasaw Nation	Not interested in being a consulting party
Choctaw Nation of Oklahoma	No Response
Eastern Band of Cherokee Indians	No Response
Eastern Shawnee Tribe of Oklahoma	No Response.
Muscogee (Creek) Nation	Consulting Party
Poarch Band of Creek Indians	No Response
Santee Sioux Tribe of Nebraska	No Response

INFORMATION REQUIRED FROM EXISTING LICENSEES

1. Responses to the information specified in 18 CFR §16.10(a) has been provided in the preceding paragraphs.
2. The Applicant has taken measures to ensure safe management, operation, and maintenance of the Stevens Creek Project, and will continue to do so in the future, as described below.
   a. Operation during flood conditions: The Stevens Creek Project Operating Plan was developed according to Articles 402 and 403 of the current FERC license which was issued November 22, 1995. In Section IV. A. 1. of the Operating Plan Rev. 4 dated July 2023, flood conditions are identified as flow greater than 30,000 cubic feet per second (cfs). During periods of sustained flows of greater than 30,000 cfs from the Savannah River and Stevens Creek, the Stevens Creek Project will generate to its full capability (approximately 8,300 cfs), while spilling all additional flow over the 2,000-foot-long overflow section of the dam (flashboards will be tripped). In this situation, all water coming down the Savannah River passes directly through the Stevens Creek Reservoir. The reservoir elevation may exceed elevation 187.5 feet, depending upon the volume of flow at any given time. If the reservoir and river elevation reach a level which threatens to flood the plant, operation will cease, and personnel will evacuate the plant. At this point, all river flow will be discharged over the spillway. When river flow returns to a level controllable by normal operation at the U.S. Army Corps of Engineers' J. Strom Thurmond Dam (Thurmond Dam), the Stevens Creek Reservoir will be drawn down to about elevation 183.5 feet so that flashboards can be reset. Normal operation of the Stevens Creek Project will resume when any damage to the plant has been repaired and flashboards have been reset.

      A high flow event is identified as inflow of 8,300 cfs to 30,000 cfs. During periods of sustained high flow in the Savannah River, the Stevens Creek Project will generate to its full capability (~8,300 cfs), while spilling all additional flow over the 2,000-foot-long overflow section of the dam (some flashboards will be tripped). In this situation, all water coming down the Savannah River passes directly through the Stevens Creek Reservoir. The reservoir elevation may exceed elevation 187.5 feet, depending upon the volume and duration of the high flow. When river flow returns to a level controllable by normal operation at Thurmond Dam, the Stevens Creek Reservoir will be drawn down to about elevation 183.5 feet so that flashboards can be reset. Normal operation of the Stevens Creek Project will resume when the flashboards have been reset.
   b. Warning devices used to ensure downstream public safety: The Stevens Creek Project has warning signs located above and around the dam and powerhouse to notify the public of the hazards. However, no audible devices are used at the Stevens Creek Project as warning notifications. The public safety signage is identified in the Public Safety Plan as required by the Federal Energy Regulatory Commission (FERC).
   c. Emergency Action Plan: The Applicant maintains an up-to-date Emergency Action Plan (EAP) for the Stevens Creek Project in accordance with FERC requirements. Annual training and drills are conducted, and tabletop and functional exercises are conducted on a five-year schedule. The last full reprint of the Stevens Creek Project EAP was issued in 2020, with an annual update issued in 2021. The next full reprint will be issued in 2025.

      The EAP Coordinator conducts annual refresher training each year, and a statement of annual training, including a list of attendees, is filed with the FERC Atlanta Regional Office (ARO) each year. Annual refresher training includes general discussion of the reasons for having an EAP, routine surveillance, identification and verification of the existence and type of emergencies, the proper initial notification procedures, and follow-up communications with contacted persons. Changes to the EAP from the previous year are emphasized. A review of the Dam Emergency Notification System (DENS) is conducted, and manual backup call procedures are also discussed. The DENS is an automated call out system activated by the Applicant's Corporate Security Response Center (CSRC) staff, who are on duty 24 hours per day 7 days per week. The system is programmed with current contact numbers and e-mail addresses for internal and external personnel and agencies who are to be notified in the event of a dam related emergency. The DENS is tested annually to confirm that all necessary notifications can be made. A drill scenario simulating an emergency condition is presented to plant personnel, who then simulate the steps of verification of the emergency and then follow up with notification calls to all necessary parties, including the CSRC, who then verifies the caller's identity and activates the DENS.

The most recent tabletop and functional exercises were conducted in 2022. These exercises are coordinated with the Edgefield County, Aiken County, and the State of South Carolina Emergency Management Agencies as well as with the Columbia County, Richmond County, and the State of Georgia Emergency Management Agencies in order to enhance the realism of the exercise and to ensure that the EAP could be successfully executed in an actual emergency.

All aspects of this EAP are reviewed annually and updated as necessary. In addition, the EAP is updated whenever organizational changes occur within Applicant staff, and when Applicant is made aware of other necessary changes, such as new contact persons or telephone numbers. All holders of the EAP are furnished these updates and are required to confirm their receipt. EAP Status Reports are submitted annually to the FERC Atlanta Regional Office (ARO).

d. <u>Monitoring devices:</u> The Stevens Creek Project has four load cells: three to monitor the performance of post-tensioned anchors installed in the spillway in 2002 and one to monitor the 2002 anchors installed in the left non-overflow structure. The left non-overflow load cell is manually read once a year by accessing the section on foot from the left abutment area. The spillway load cells are manually read every five years, river flows permitting, by accessing them from a boat on the upstream side of the flashboards. The Stevens Creek Project is observed daily by the plant operators and is visually inspected monthly by a Dam Safety technician or engineer visiting the site and physically observing the condition of the dam and surrounding areas. The Applicant maintains a Surveillance and Monitoring Program and files an annual Dam Safety Surveillance and Monitoring Report (DSSMR) with the FERC ARO.

e. <u>Employee and Public Safety:</u> One first aid incident occurred at the plant on March 23, 2009, and no other employee incidents have occurred to date. Public Safety events resulting in injury or death within the Stevens Creek Project boundary recorded one incident on May 26, 2015, when two individuals in a failed motorboat were swept over the dam. They were rescued by the local Fire Department and no injuries were sustained.

3. <u>Description of Current Operation of the Stevens Creek Project:</u> The Stevens Creek Project operates as a re-regulating plant, mitigating the downstream effects of the routinely wide-ranging discharges due to the peaking operation from the upstream Thurmond Dam. Typical dispatch practices are to have all available turbines on and to adjust generation to re-regulate projected inflows. By dispatching all available units, DESC can remotely increase and decrease online turbines' gate settings to adjust flow releases as needed throughout the daily cycle, precluding the need to start and stop individual turbine units. The operating range for the Stevens Creek Reservoir is 183.0 feet to 187.5 feet, using available storage capacity for day-to-day operations. The normal operating discharge target range for Stevens Creek is to

provide an hourly release of ± 15 percent of the scheduled daily average discharge from Thurmond Dam, if the actual discharge from Thurmond Dam is within 500 cfs of the scheduled discharge. The plant generates as a baseload facility.

4. Discussion of the history of the project and record of programs to upgrade the operation and maintenance of the Stevens Creek Project: The construction history of the Stevens Creek Project is presented in Exhibit C.

5. Summary of any generation lost at the Stevens Creek Project over the last five years because of unscheduled outages: See table below for dates from January 1, 2018 to December 31, 2022.

6. **Table 5 Summary of Generation Loss at the Stevens Creek Project (2018-2022)**

Started	Completed	Duration (hr)	Description	Probable Cause / Corrective Action
Unit 1				
1/1/2018 1:00:00 PM	1/2/2018 1:00:00 PM	24.00	Low Oil Pressure	
3/24/2018 12:00:00 AM	3/24/2018 2:00:00 AM	2.00	Line Default	Restarted the unit.
8/7/2018 6:20:00 PM	8/7/2018 7:20:00 PM	1.00	Storm	Storm caused plant trip.
10/11/2018 4:00:00 AM	10/11/2018 6:00:00 AM	2.00	Storm	Storm - Put back on line
10/15/2018 10:00:00 AM	10/15/2018 2:00:00 PM	4.00	Electrical Problems	Electrical -Put back on line
10/22/2018 2:00:00 AM	10/24/2018 9:00:00 AM	55.00	Electrical Problems	Electrical Problems-Put back on line
4/19/2019 1:30:00 PM	4/19/2019 2:30:00 PM	1.00	Storm	Storm Unit placed back on line
4/27/2019 11:00:00 PM	4/28/2019 12:00:00 AM	1.00	Storm	Storm-Line Default-Placed unit back on line.
10/10/2019 9:00:00 AM	10/10/2019 10:00:00 AM	1.00	Exciter Brushes	Replaced exciter brushes.
1/4/2020 9:00:00 PM	1/4/2020 10:00:00 PM	1.00	Weather	Reset and restarted the unit.
1/9/2020 10:45:00 AM	1/9/2020 11:45:00 AM	1.00	Clean Intake	Cleaned river debris from intake. Placed back on line.
8/3/2020 8:27:00 PM	8/3/2020 10:27:00 PM	2.00	Generator Differential-Storm	The storm caused a relay differential.
8/6/2020 11:00:00 PM	8/7/2020 11:00:00 AM	12.00	Transformer Failure	Transformer failed. Replaced.
9/12/2020 4:00:00 PM	9/12/2020 5:00:00 PM	1.00	Storm-High Winds	Storm-High Winds
10/9/2020 4:00:00 PM	10/9/2020 5:00:00 PM	1.00	Low Oil Pressure	Low Oil Pressure. Reset.

Started	Completed	Duration (hr)	Description	Probable Cause / Corrective Action
6/20/2021 11:00:00 AM	6/20/2021 1:00:00 PM	2.00	Storm	Unit tripped due to the storm. Put back on line.
7/18/2021 8:30:00 PM	7/18/2021 9:30:00 PM	1.00	Storm	Differential Relay tripped due to storm. Restarted unit.
3/12/2022 6:00:00 PM	3/12/2022 8:00:00 PM	2.00	Line Fault	Line Fault due to weather. Unit placed back on line.
3/15/2022 6:30:00 PM	3/15/2022 7:00:00 PM	0.50	Line Fault	Line Fault on 46kv line due to weather. Unit placed back on line.
5/22/2022 8:15:00 AM	5/22/2022 9:22:00 AM	1.12	Line Differential	Unit placed back in service.
5/24/2022 11:00:00 AM	5/24/2022 12:30:00 PM	1.50	Line Fault	Line fault caused generator differential trip. Reset unit.
6/17/2022 5:45:00 PM	6/17/2022 6:45:00 PM	1.00	Storm	Unit placed back in service.
8/21/2022 10:30:00 AM	8/21/2022 11:30:00 AM	1.00	Line Fault	Line fault caused generator differential trip. Reset unit.
11/11/2022 1:30:00 PM	11/11/2022 3:00:00 PM	1.50	Electrical failure	Electrical Failure due to AC Water leak- put unit back online
	Unit 1 Totals:	**120.62**		
Unit 2				
3/24/2018 12:00:00 AM	3/24/2018 2:00:00 AM	2.00	Line Default	Restarted the unit.
8/7/2018 6:20:00 PM	8/7/2018 7:20:00 PM	1.00	Storm	Storm caused plant trip.
9/28/2018 6:00:00 AM	9/28/2018 7:00:00 AM	1.00	Hydraulic Leak	Replaced hydraulic hose.
10/11/2018 4:00:00 AM	10/11/2018 6:00:00 AM	2.00	Storm	Storm- Put Unit back on line
10/12/2018 8:45:00 AM	10/12/2018 10:45:00 AM	2.00	Oil Pressure	Oil Pressure - Repaired Placed back on line
10/16/2018 10:15:00 AM	10/16/2018 2:15:00 PM	4.00	Oil Pressure	Oil Pressure Inspected Placed back on Line

Started	Completed	Duration (hr)	Description	Probable Cause / Corrective Action
2/12/2019 11:00:00 PM	3/8/2019 11:59:59 PM	561.00	Field Breaker Trip	Field breaker tripped unit. Breaker repaired.
4/19/2019 1:30:00 PM	4/19/2019 2:30:00 PM	1.00	Storm	Storm- Placed unit back on line.
4/27/2019 11:00:00 PM	4/28/2019 12:00:00 AM	1.00	Storm	Storm-Line default- Placed Unit back on line
1/4/2020 9:00:00 PM	1/4/2020 10:00:00 PM	1.00	Weather	Reset and restarted the unit.
8/3/2020 8:30:00 PM	8/3/2020 10:30:00 PM	2.00	Generator Differential-Storm	The storm caused a relay differential.
8/5/2020 2:00:00 PM	8/5/2020 4:00:00 PM	2.00	Generator Differential-Storm	The storm caused a relay differential. Unit is back on line.
8/6/2020 11:00:00 PM	8/7/2020 11:00:00 AM	12.00	Transformer Failure	Transformer failed. Replaced.
1/12/2021 6:00:00 AM	1/12/2021 11:00:00 AM	5.00	Low Nitrogen	Added nitrogen and replaced the bladder.
2/12/2021 9:00:00 AM	2/12/2021 11:00:00 AM	2.00	Bladder Issues	Changed bladder.
3/17/2021 3:30:00 AM	3/17/2021 10:30:00 AM	7.00	Low Nitrogen	Added Nitrogen.
4/15/2021 10:00:00 PM	4/15/2021 11:00:00 PM	1.00	Low Nitrogen	Added Nitrogen.
6/20/2021 11:00:00 AM	6/20/2021 1:00:00 PM	2.00	Storm	Unit tripped due to the storm. Put back on line.
7/8/2021 9:30:00 PM	7/8/2021 10:30:00 PM	1.00	Low Nitrogen	Added nitrogen.
7/18/2021 8:30:00 PM	7/18/2021 9:30:00 PM	1.00	Storm	Differential Relay tripped due to storm. Restarted unit.
7/29/2021 9:00:00 PM	7/30/2021 9:00:00 AM	12.00	Exciter Brushes	Changed brushes out and put back on line.
3/15/2022 6:30:00 PM	3/17/2022 1:45:00 PM	43.25	Line Fault	Line fault caused generator differential trip. Reset unit.
4/6/2022 7:15:00 PM	4/6/2022 8:15:00 PM	1.00	Line Fault on 46kv Line	fault on 46kv due to generator differential. Unit placed back on line.

Started	Completed	Duration (hr)	Description	Probable Cause / Corrective Action
5/16/2022 5:50:00 AM	5/16/2022 6:30:00 AM	0.67	Line Fault	Line fault caused generator differential trip. Reset unit.
5/22/2022 8:15:00 AM	5/22/2022 9:22:00 AM	1.12	Line Differential	Unit placed back in service.
5/24/2022 11:00:00 AM	5/24/2022 12:30:00 PM	1.50	Line Fault	Line fault caused generator differential trip. Reset unit.
6/17/2022 5:45:00 PM	6/17/2022 6:45:00 PM	1.00	Storm	Unit placed back in service.
6/17/2022 9:45:00 PM	6/17/2022 10:45:00 PM	1.00	Storm	Unit placed back in service.
8/21/2022 10:30:00 AM	8/21/2022 11:30:00 AM	1.00	Line Fault	Line fault caused generator differential trip. Reset unit.
12/23/2022 7:00:00 AM	12/23/2022 10:00:00 AM	3.00	Line Fault	Line fault caused generator differential trip. Reset unit.
	Unit 2 Totals:	**676.54**		
Unit 3				
8/7/2018 6:20:00 PM	8/7/2018 7:20:00 PM	1.00	Storm	Storm caused plant trip.
8/14/2018 10:00:00 AM	8/15/2018 12:00:00 PM	26.00	Relay Department Trip	Tripped by relay department.
10/11/2018 6:00:00 AM	10/17/2018 2:00:00 PM	152.00	Storm-Excitor	Storm-Excitor damaged
4/19/2019 1:30:00 PM	4/19/2019 2:30:00 PM	1.00	Storm	Storm-Line Default-Placed on line.
4/27/2019 11:00:00 PM	4/28/2019 12:00:00 AM	1.00	Storm	Storm- Line default- Placed on line.
1/4/2020 9:00:00 PM	1/6/2020 3:00:00 PM	42.00	Weather	Reset and restarted the unit.
4/13/2020 5:00:00 AM	4/13/2020 7:00:00 AM	2.00	Storms/High Winds	Put unit back on line.
8/5/2020 12:00:00 PM	8/6/2020 11:00:00 AM	23.00	Generator Relay Issues	Generator relay stuck. Repaired.
12/14/2020 8:00:00 AM	12/14/2020 10:00:00 AM	2.00	Oil Pressure	Oil pressure low(Changed filter)
3/4/2021 11:00:00 AM	3/5/2021 10:00:00 AM	23.00	Pressure Relief Valve	Replaced pressure relief valve.
7/18/2021 8:30:00 PM	7/18/2021 9:30:00 PM	1.00	Storm	Differential Relay tripped due to

Started	Completed	Duration (hr)	Description	Probable Cause / Corrective Action
				storm. Restarted unit.
3/15/2022 6:30:00 PM	3/16/2022 8:30:00 PM	26.00	Line Fault	Line fault caused generator differential trip. Reset unit.
6/17/2022 5:45:00 PM	6/17/2022 7:45:00 PM	2.00	Storm	Unit placed back in service.
	Unit 3 Totals:	**302.00**		
Unit 4				
2/4/2018 11:00:00 AM	2/5/2018 11:00:00 AM	24.00	Low Nitrogen	Low Nitrogen. Added Nitrogen.
3/24/2018 12:00:00 AM	3/24/2018 2:00:00 AM	2.00	Line Default	Restarted the unit.
6/13/2018 8:20:00 AM	6/13/2018 9:20:00 AM	1.00	Replaced Brushes	Replaced brushes.
8/7/2018 6:20:00 PM	8/7/2018 7:20:00 PM	1.00	Storm	Storm caused plant trip.
4/19/2019 1:30:00 PM	4/19/2019 2:30:00 PM	1.00	Storm	Storm
4/26/2019 5:30:00 PM	4/26/2019 6:30:00 PM	1.00	Storm	Storm-Placed back on line.
4/27/2019 11:00:00 PM	4/28/2019 12:00:00 AM	1.00	Storm	Storm-Line Default Placed back on line.
7/3/2019 9:00:00 AM	7/3/2019 10:00:00 AM	1.00	Generator Differential Relay	Generator Differential Relay
10/7/2019 11:00:00 AM	10/7/2019 2:00:00 PM	3.00	Trash Rake	Cleaned trash rake and put back online.
1/4/2020 9:00:00 PM	1/4/2020 10:00:00 PM	1.00	Weather	Reset and restarted the unit.
4/13/2020 5:00:00 AM	4/13/2020 7:00:00 AM	2.00	Storms/High Winds	Put unit back on line.
7/30/2020 6:00:00 PM	7/30/2020 7:00:00 PM	1.00	Storm/Severe Lightning	Storm - severe lightning. Unit back on line.
8/3/2020 8:27:00 PM	8/3/2020 10:27:00 PM	2.00	Generator Differential, Storm	The storm caused a relay differential.
8/6/2020 11:00:00 PM	8/7/2020 11:00:00 AM	12.00	Transformer Failure	Transformer failed. Replaced.
9/12/2020 4:00:00 PM	9/14/2020 9:00:00 AM	41.00	Breaker Issues	Breaker spring failed to charge. Repaired.
6/20/2021 11:00:00 AM	6/20/2021 1:00:00 PM	2.00	Storm	Unit tripped due to the storm. Put back on line.

Started	Completed	Duration (hr)	Description	Probable Cause / Corrective Action
7/18/2021 8:30:00 PM	7/18/2021 9:30:00 PM	1.00	Storm	Differential Relay tripped due to storm. Restarted unit.
11/14/2021 11:00:00 AM	12/31/2022 11:59:59 PM	9,901.00	Thrust Bearing Failure	Repairing bearing.
	Unit 4 Totals:	**9,998.00**		
		Unit 5		
3/24/2018 12:00:00 AM	3/24/2018 2:00:00 AM	2.00	Line Default	Restarted the unit.
8/7/2018 6:20:00 PM	8/7/2018 7:20:00 PM	1.00	Storm	Storm caused plant trip.
10/11/2018 4:00:00 AM	10/11/2018 6:00:00 AM	2.00	Storm	Storm-Put Units back on Line
4/19/2019 1:30:00 PM	4/19/2019 2:30:00 PM	1.00	Storm	Storm Placed Unit back on line
4/27/2019 11:00:00 PM	4/28/2019 12:00:00 AM	1.00	Storm	Storm-Line default-Placed Unit back on line
6/27/2019 11:00:00 AM	6/27/2019 12:00:00 PM	1.00	Low Nitrogen	Low Nitrogen. Added Nitrogen.
1/4/2020 9:00:00 PM	1/4/2020 10:00:00 PM	1.00	Weather	Reset and restarted the unit.
4/3/2020 8:00:00 AM	4/8/2020 1:00:00 PM	125.00	Bad Motor	Replaced Motor.
8/3/2020 8:00:00 AM	8/6/2020 8:00:00 AM	72.00	Generator Differential, Storm	Speed bearing out. Repaired.
1/22/2021 12:00:00 AM	12/31/2022 11:59:59 PM	17,016.00	Broken Shaft	Shaft replacement.
	Unit 5 Totals:	**17,222.00**		
		Unit 6		
3/24/2018 12:00:00 AM	3/24/2018 2:00:00 AM	2.00	Line Default	Restarted the unit.
8/7/2018 6:20:00 PM	8/7/2018 7:20:00 PM	1.00	Storm	Storm caused plant trip.
9/26/2018 8:00:00 AM	11/6/2018 11:59:59 PM	986.00	Trash Rake Issues	Replaced trash rake cable and additional maintenance
4/19/2019 1:30:00 PM	4/19/2019 2:30:00 PM	1.00	Storm	Storm-Placed back on line.
4/27/2019 11:00:00 PM	4/28/2019 12:00:00 AM	1.00	Storm	Storm-Line default-Placed back on line.
7/11/2019 2:00:00 PM	7/12/2019 2:00:00 PM	24.00	Oil Leak	Repaired leak.
8/26/2019 9:30:00 AM	8/26/2019 10:30:00 AM	1.00	Oil Filter Leak	Repaired and replaced filter.

Started	Completed	Duration (hr)	Description	Probable Cause / Corrective Action
1/4/2020 9:00:00 PM	1/4/2020 10:00:00 PM	1.00	Weather	Reset and restarted the unit.
8/3/2020 8:30:00 PM	8/3/2020 10:30:00 PM	2.00	Generator Differential, Storm	The storm caused a relay differential.
6/20/2021 11:00:00 AM	6/20/2021 1:00:00 PM	2.00	Storm	Unit tripped due to the storm. Put back on line.
7/18/2021 8:30:00 PM	7/18/2021 9:30:00 PM	1.00	Storm	Differential Relay tripped due to storm. Restarted unit.
3/15/2022 6:30:00 PM	3/15/2022 8:30:00 PM	2.00	Line Fault	Line fault caused generator differential trip. Reset unit.
4/27/2022 6:30:00 PM	4/27/2022 7:30:00 PM	1.00	Line Fault on 46kv Line	Line fault due to generator differential. Unit placed back in service.
5/16/2022 5:50:00 AM	5/16/2022 6:30:00 AM	0.67	Line Fault	Line fault caused generator differential trip. Reset unit.
5/20/2022 5:45:00 AM	5/20/2022 7:58:00 AM	2.22	Line Fault	Line fault caused generator differential trip. Reset unit.
5/22/2022 8:15:00 AM	5/22/2022 9:22:00 AM	1.12	Line Differential	Unit placed back on line.
5/24/2022 11:00:00 AM	5/24/2022 12:30:00 PM	1.50	Line Fault	Line fault caused generator differential trip. Reset unit.
6/17/2022 5:45:00 PM	6/17/2022 6:45:00 PM	1.00	Storm	Unit placed back in service.
6/17/2022 9:45:00 PM	6/17/2022 10:45:00 PM	1.00	Storm	Unit placed back in service.
8/21/2022 12:00:00 AM	8/21/2022 1:00:00 AM	1.00	Line Fault	Line fault caused generator differential trip. Reset unit.
	Unit 6 Totals:	**1,033.51**		
		Unit 7		
3/24/2018 12:00:00 AM	3/24/2018 2:00:00 AM	2.00	Line Default	Restarted the unit.
7/31/2018 10:00:00 AM	11/15/2018 11:59:59 PM	2,569.00	Bad Bearing	Repair bad bearing.

Started	Completed	Duration (hr)	Description	Probable Cause / Corrective Action
4/27/2019 11:00:00 PM	4/28/2019 12:00:00 AM	1.00	Storm	Storm-Line Default- Placed units back on line.
5/30/2019 8:35:00 AM	5/30/2019 10:35:00 AM	2.00	Low Nitrogen	Low Nitrogen. Added Nitrogen.
1/4/2020 9:00:00 PM	1/4/2020 10:00:00 PM	1.00	Weather	Reset and restarted the unit.
4/13/2020 5:00:00 AM	4/13/2020 7:00:00 AM	2.00	Storms/High Winds	Storms - tornados (high winds) - Put unit back on line.
8/3/2020 8:30:00 PM	8/3/2020 10:30:00 PM	2.00	Generator Differential, Storm	The storm caused a relay differential.
9/12/2020 4:00:00 PM	9/12/2020 5:00:00 PM	1.00	Storm-High Winds	Storm-High Winds. Unit put back on line.
5/18/2021 8:00:00 AM	5/18/2021 11:00:00 AM	3.00	Exciter Brushes	Changed out exciter brushes.
6/20/2021 11:00:00 AM	6/20/2021 1:00:00 PM	2.00	Storm	Unit tripped due to the storm. Put back on line.
7/18/2021 8:30:00 PM	7/18/2021 9:30:00 PM	1.00	Storm	Differential Relay tripped due to storm. Restarted unit.
3/15/2022 6:30:00 PM	3/15/2022 7:00:00 PM	0.50	Line Fault	Line fault caused generator differential trip. Reset unit.
4/6/2022 7:15:00 PM	4/6/2022 8:15:00 PM	1.00	Line Fault on 46 kv Line	Line fault. Unit placed back in service.
5/2/2022 10:30:00 AM	5/2/2022 3:30:00 PM	5.00	Phase Bad on Generator Brkr	Phase bad on Generator Breaker. Unit placed back in service.
5/16/2022 5:50:00 AM	5/16/2022 6:40:00 AM	0.83	Line Fault	Line fault caused generator differential trip. Reset unit.
5/22/2022 8:15:00 AM	5/23/2022 2:46:00 PM	30.52	Breaker Failure - Exciter	Unit repaired and placed back in service.
5/24/2022 11:00:00 AM	5/25/2022 10:00:00 AM	23.00	Line Fault	Line fault caused generator differential trip. Reset unit.
6/17/2022 5:45:00 PM	6/17/2022 6:45:00 PM	1.00	Storm	Unit placed back in service.

Started	Completed	Duration (hr)	Description	Probable Cause / Corrective Action
6/17/2022 9:45:00 PM	6/17/2022 10:45:00 PM	1.00	Storm	Unit placed back in service.
8/27/2022 12:00:00 AM	8/27/2022 1:00:00 AM	1.00	High Bearing Temperature	High Bearing Temperature-Swapped water pump put unit back in service
	Unit 7 Totals:	**2,649.85**		
Unit 8				
1/1/2018 12:00:00 AM	7/11/2018 11:59:59 PM	4,591.00	Stator Rewind	Stator Rewind in progress.
8/7/2018 6:20:00 PM	8/7/2018 7:20:00 PM	1.00	Storm	Storm caused plant trip.
11/19/2018 6:00:00 PM	11/21/2018 2:00:00 PM	44.00	Trash Rack Issues	Bad trash differential. Cleaned trash rack.
4/19/2019 1:30:00 PM	4/19/2019 2:30:00 PM	1.00	Storm	Storm- Placed back on line.
4/27/2019 11:00:00 PM	4/28/2019 12:00:00 AM	1.00	Storm	Storm-Line default-Placed back on line.
12/18/2019 8:00:00 AM	12/18/2019 9:00:00 AM	1.00	Intake Cleaning	Cleaned debris from trash rake.
12/20/2019 7:00:00 AM	12/20/2019 1:00:00 PM	6.00	Generator Wall Leak	Generator wall leak caused fuses to blow. Replaced fuses.
1/4/2020 9:00:00 PM	1/7/2020 1:00:00 PM	64.00	Weather	Reset and restarted the unit.
4/13/2020 5:00:00 AM	4/13/2020 7:00:00 AM	2.00	Storms/High Winds	Storms - tornados (high winds) - Put unit back on line.
8/3/2020 8:30:00 PM	8/3/2020 10:30:00 PM	2.00	Generator Differential, Storm	The storm caused a relay differential. Unit put back on line.
8/5/2020 7:30:00 AM	8/5/2020 10:30:00 AM	3.00	Generator Differential, Storm	The storm caused a relay differential. Unit put back on line.
2/3/2021 12:00:00 AM	12/31/2022 11:59:59 PM	16,728.00	Bad Bearing	Replaced bad bearings.
	Unit 8 Totals:	**21,444.00**		

7. Discussion of record of compliance with the terms and conditions of the existing license, including a list of all incidents of noncompliance, their disposition, and any documentation relating to each incident: The Applicant has made a significant effort to comply with all articles in the existing license, as well as with the FERC's Rules and Regulations, and any directives from the ARO. When necessary, the Applicant has requested additional time to complete work in progress. The Applicant has not been cited for noncompliance during the term of the current license.
8. Discussion of any actions taken that affect the public: No actions affecting the public have been taken.
9. Ownership and operating expenses that would be reduced if the Stevens Creek Project license were transferred from the existing licensee: The costs are as shown in detail in Exhibit D.
10. Statement of annual fees paid under Part I of the Federal Power Act for use of Federal or Indigenous lands within the Stevens Creek Project boundary: There are 104.4 acres of Federal lands administered by the U.S. Forest Service which are part of the Stevens Creek Project. Of that acreage, 104.19 acres have a pre-existing easement in which the Applicant owns flowage easements which predate acquisition of the National Forest Lands by the United States. Exhibit G – 1, General Map of Project Area, contains a tabulation of Federal Lands within the Stevens Creek Project boundary by tract number, along with a designation as to which map sheet each tract is shown on. In 2022, the Applicant paid $25.00 in fees for Federal lands occupied by the Stevens Creek Project. There are no Indigenous lands within the Stevens Creek Project boundary.

References

Kleinschmidt Associates. 2021. Resource Utilization Study for the Stevens Creek Hydroelectric Project. Prepared for Dominion Energy South Carolina, Inc.

South Carolina Public Service Commission (SC PSC) Docket Management System. 2023a. Detail for 2023-42-E: Dominion Energy South Carolina, Inc.'s Annual Update on Demand Side Management Programs and Petition to Update Rider. [Online] URL: https://dms.psc.sc.gov/Web/Dockets/Detail/118470. Accessed March 2023.

SC PSC Docket Management System. 2023b. Detail for 2023-9-E: Dominion Energy South Carolina, Incorporated's 2023 Integrated Resource Plan (IRP). [Online] URL: https://dms.psc.sc.gov/Web/Dockets/Detail/118060. Accessed March 2023.

Appendix H 1

2023 DESC IRP

Dominion Energy South Carolina, Inc.

2023 Integrated Resource Plan

Filed January 30, 2023

Dominion Energy

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Carolina Wren; official state bird of South Carolina

Dominion Energy

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Dominion Energy

Introduction

Intake towers at Lake Murray, SC

Since the 1980s, South Carolina utilities have used integrated resource plans ("IRPs") to identify when growth in customer needs for electricity have required utilities to add new generation resources and to identify what types of resources could meet those needs most reliably and cost effectively.

In past years, IRP evaluations focused on a relatively small set of technologies (principally fossil and nuclear technologies) and a small set of inputs (principally forecasts of fossil fuel prices and customer demand growth). Recently, IRPs have expanded their focus to reflect growing societal demands for cleaner energy and resulting changes in energy markets. These changes have included rapid reductions in the cost of solar and battery storage technologies, the creation of an offshore wind ("OSW") industry in the United States, the ongoing development of small modular nuclear reactor ("SMR") technologies, and the emergence of a powerful combination of tax incentives and stringent environmental regulations to speed up the adoption of these non-carbon emitting technologies.

In keeping with these trends, the South Carolina General Assembly revised the IRP statute in 2019 (the "IRP Statute"), through the enactment of Act No. 62 of 2019. Current IRPs must evaluate an extensive list of topics and sensitivities related to load forecasts, generation technologies, renewable resources, DSM programs, generator retirements, fuel costs, environmental regulations, and electric transmission plans. The IRP Statute requires the Public Service Commission of South Carolina (the "Commission") to balance multiple factors in approving a resource plan including resource adequacy, least cost to customers, environmental compliance, reliability, exposure to commodity price risk, and diversity of generation and fuel supply.

Dominion Energy South Carolina, Inc. ("DESC" or the "Company") files a comprehensive IRP every three years, and this 2023 IRP is DESC's second comprehensive IRP filed under the IRP Statute. DESC's first such IRP was the Modified 2020 IRP, which the Commission approved with revisions in 2021.[1] DESC also files this 2023 IRP in satisfaction of the requirement of S.C. Code of Laws Section 58-33-430 that it annually update its load forecasts with the Commission. **Appendix A** cross-references the sections of this 2023 IRP to the requirements of the IRP Statute, Order No. 2020-832, Order No. 2021-429, and other regulatory requirements.

In this 2023 IRP, DESC has evaluated fourteen build plans or sensitivities, each of which reflects a unique balance of affordability, environmental considerations, carbon emissions, and generation diversity in meeting customers' future energy needs over the planning horizon. Collectively, these fourteen build plans and sensitivities represent a broad range of available options to serve DESC's more than 780,000 customers in South Carolina safely, reliably and cost effectively under a diverse set of potential future market conditions and approaches to carbon reduction. The fourteen build plans envision a dramatic expansion of solar, battery, and other non-carbon emitting resources over the course of the planning horizon and evaluates deploying non-carbon emitting OSW and SMR technology for the first time in a full IRP.

This 2023 IRP also presents a high-level strategy for retiring and replacing DESC's two remaining coal-only generating facilities which are located at Wateree Station ("Wateree") and A.M. Williams Station ("Williams"). DESC intends to retire and replace these facilities by the end of 2028 and 2030, respectively, recognizing that this schedule is dependent upon the timely completion of regulatory, procurement and construction processes and may include the possibility of building high-efficiency, low-emitting natural gas-fired generation in partnership with the South Carolina Public Service Authority ("Santee Cooper").

Underlying this IRP is a significant evolution in the sophistication of the data and inputs DESC uses in

1 Order No. 2021-429, issued in Docket No. 2019-226-E.

planning for customers' future needs. The 2023 IRP incorporates the results of a new probabilistic planning reserve margin study (the "Reserve Margin Study"), a new maximum achievable DSM potential study (the "2023 DSM Potential Study"), and a new electric vehicle adoption study (the "EV Adoption Study")—all done by third-party consulting firms broadly recognized for their independence and expertise in these areas.

Providing safe, reliable, affordable and sustainable energy is the primary commitment of Dominion Energy, Inc. ("Dominion Energy") to the more than three million customers it serves across its utility operations. Dominion Energy's vision is to become the most sustainable energy company in the country and is committed to achieving net zero emissions by 2050. Since 2005, Dominion Energy reduced its carbon emissions across its utility operations by 46% and is now among the lowest carbon emitting utilities in the United States.

DESC believes that the strategies and options evaluated in this IRP will support its continued ability to provide safe, reliable, affordable and increasingly clean electricity to its South Carolina customers.

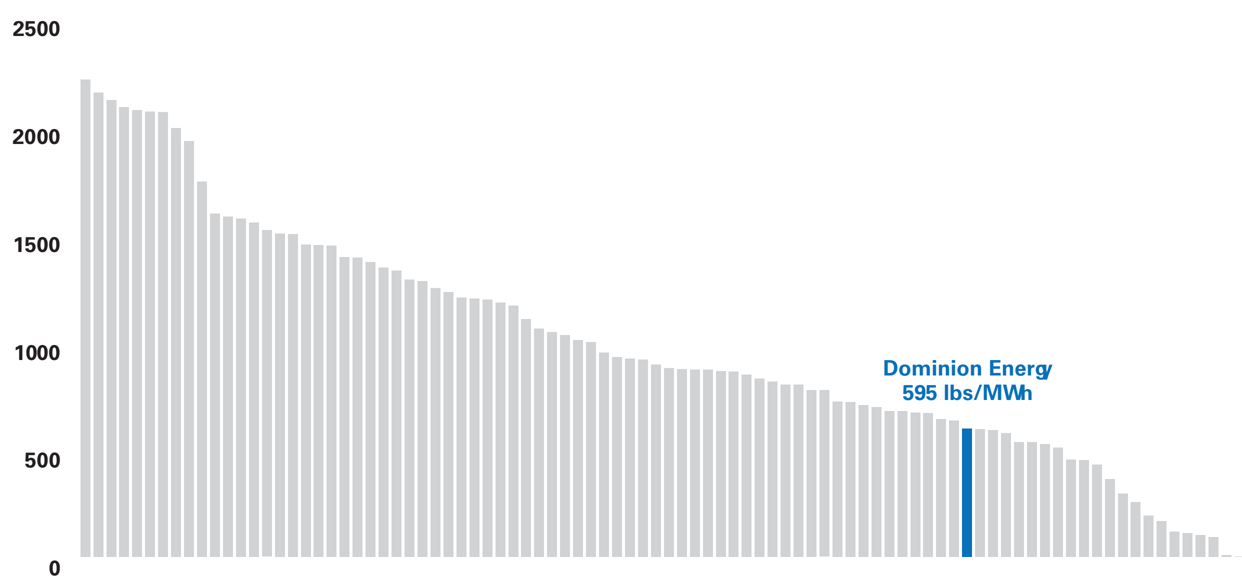
The Role of an IRP

IRPs are snapshots in time based on current forecasts of customers' future energy needs, future environmental constraints, future fuel prices and availability, and the cost or availability of rapidly evolving generation resources like solar, battery, OSW, and SMRs. DESC is filing this 2023 IRP amidst significant disruptions in the global energy and commodity markets and supply chains, mounting global tensions, volatile weather patterns, and significant federal tax and environmental policy changes. These factors add to the likelihood of future changes in inputs and assumptions that could affect future generation planning.

Accordingly, this IRP provides a roadmap and framework of data for future decision making and does not reflect a fixed decision by DESC to pursue any specific action or project. However, DESC plans to move forward in 2023 to identify and analyze specific replacement resources to support the retirement of Williams and Wateree and the resulting decisions will be informed by the analysis contained in this 2023 IRP and feedback from the Commission, the South Carolina Office of Regulatory Staff ("ORS"), and other parties.

Because of the short time between the filing of the 2022 IRP Update and this 2023 IRP, it was not possible for DESC to incorporate all comments that the ORS and stakeholders (the "Stakeholders") filed concerning the 2022 IRP Update in this 2023 IRP. However, DESC has continued to meet with ORS and Stakeholders to receive comments on the methodology and inputs used in this IRP and will continue to review and consider comments and suggestions carefully.

Figure 1: Carbon Emissions by the 100 Largest Electric Utilities CO_2 Emissions Rate (lbs/MWh)



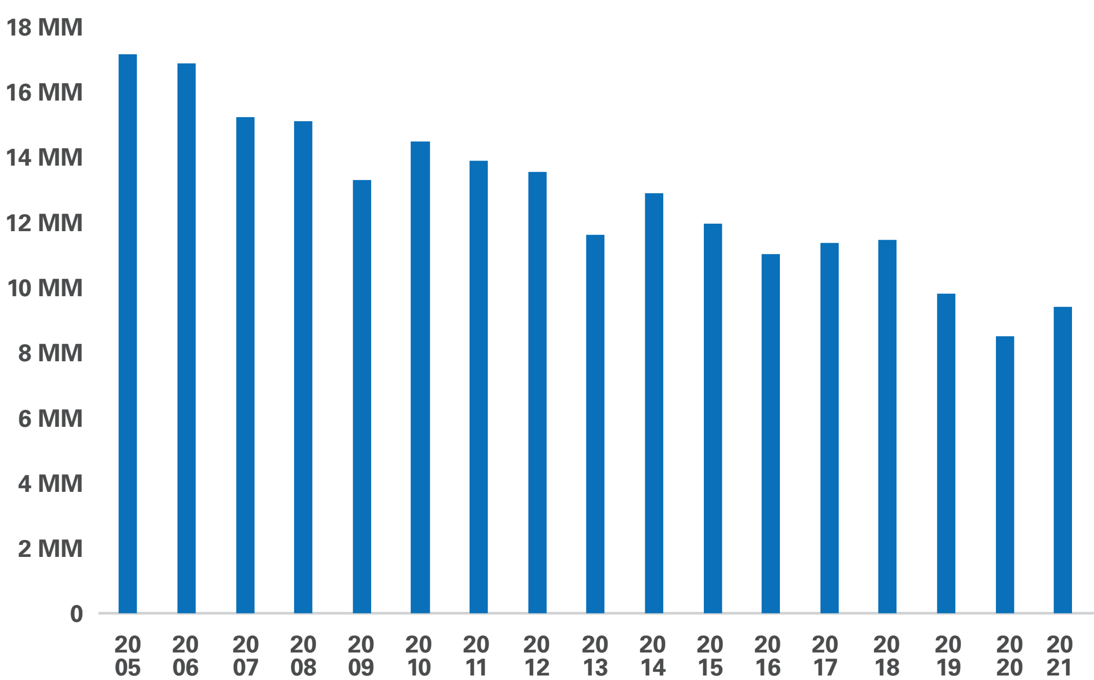
Executive Summary and Key Findings

Dominion Energy Corporate Office; Thomas F. Farrell building; Richmond, VA

DESC's Commitment to Carbon and Methane Emissions Reductions

For nearly two decades, DESC has been reducing carbon emissions by retiring coal plants, integrating third-party solar, and adding high-efficiency natural gas-fired generation while remaining focused on reliability and affordability for its customers. Since 2000, DESC has retired or converted to gas eight of eleven coal units. Since 2005, carbon emissions have fallen by approximately 45%.

Figure 2: DESC's Historical Annual CO_2 Emissions 2005-2021 (MT)



Retiring Wateree

The modeling presented in this 2023 IRP identifies alternative approaches for replacing Wateree if it can be retired by December 31, 2028, as DESC intends. One alternative would replace 300-500 MW of Wateree's capacity with energy storage resources located on the Wateree site (the "Wateree Battery Build Plan"). The other alternative would replace Wateree with a large-capacity simple-cycle Frame Combustion Turbine ("Frame CT") located at the Urquhart site in Aiken County, South Carolina (the "Wateree CT Build Plan") to take advantage of existing site infrastructure and access to natural gas supplies.

The modeling presented here shows that under current assumptions the Wateree Battery Build Plan is the most economical for customers, but the cost difference between the two plans was not great. DESC is proposing to conduct competitive procurement activities for a Wateree replacement and to base its final decision on those results and on schedule and cost considerations as they become better quantified. The timely resolution of regulatory, siting and other uncertainties is in part critical to the feasibility of retiring Wateree by December 31, 2028, because no later than December 31, 2025, DESC must make a binding commitment to retire the plant or undertake significant upgrades to meet the Steam Electric Effluent Limitation Guidelines ("ELGs") Voluntary Incentive Program ("VIP") wastewater treatment requirements. If the plant is not retired, Wateree must be brought into compliance with the ELG rule's VIP requirements by December 31, 2028.

Retiring Williams

Williams is the only large generator on the DESC system in the Charleston area and is critical to providing reliable service to customers there. Electric transmission resources and natural gas supplies are limited in the Charleston area, and the 2022 Coal Plants Retirement Study found it was impracticable to retire and replace Williams before December 31, 2030, at the earliest. The modeling presented here shows that early retirement of Williams remains a lower cost option than continuing to operate it until the end of its useful life. While the December 31, 2030 retirement date is ambitious, the timetable is not driven by ELG compliance as is the case with Wateree since DESC must proceed with an ELG compliance project for Williams even under this ambitious timetable. This reduces the reliability risk associated with the Williams retirement and replacement plan which is important considering its unavoidable complexity.

According to the analysis contained in this IRP, the optimum replacement for Williams is a large and highly efficient natural gas-fired Combined Cycle ("CC") resource shared with Santee Cooper that could be built at one of two sites in the South Carolina Low Country (the "Shared Resource"). In modeling the Shared Resource, DESC assumed it would receive half of its output.

Building a Shared Resource could create economies of scale for all participating utilities, reducing costs to their customers including the electric cooperative utilities Santee Cooper serves, enhancing efficiencies in natural gas pipeline expansions, and reducing the environmental footprint of the generation facilities and natural gas pipeline projects needed to replace coal generation on both systems. It could help anchor an expansion of natural gas supplies for uses other than power generation in areas of the state where economic development is limited by lack of such supplies and create a more certain timetable for achieving carbon reductions on both systems.

Wateree Station; Richland County, SC

The Twenty-Four Core Cases

In preparing the 2023 IRP, DESC modeled ***twenty-four cases***. It did so by evaluating five Core Build Plans (the "Core Build Plans") across the three most likely Market Scenarios resulting in ***fifteen core cases*** (the "Core Cases"). The other nine non-Core Build Plans served as either sensitivity cases ("Sensitivity Cases") or supplemental cases ("Supplemental Cases") to assess how build plans might vary under other sets of market conditions and to satisfy specific statutory and regulatory requirements.

Table 1: The Eight Market Scenarios, 14 Build Plans, 24 Cases and 15 Core Build Plans

Eight Market Scenarios, 14 Build Plans, 24 Cases and 15 Core Build Plans			
Market Scenarios (8)	**Build Plans (14)**	**Cases (24)**	
Core			
Reference	Reference Build Plan	**Five Core Build Plans x Three Market Scenarios = 15 Core Build Plans**	**15**
High Fossil Fuel Prices	High Fossil Fuel Prices Build Plan		
Zero Carbon Cost	Zero Carbon Cost Build Plan		
Reference	70% CO_2 Reduction Build Plan		
Reference	85% CO_2 Reduction Build Plan		
Sensitivities			
Electrification	Electrification High Fossil Fuel Prices Build Plan	**Five Sensitivity Cases**	**5**
Energy Conservation	Energy Conservation Build Plan		
Aggressive Regulation	Aggressive Regulation Build Plan		
Low DSM	Low DSM Build Plan		
High DSM	High DSM Build Plan		
Supplemental Cases			
Reference	Wateree CT Build Plan	**Four Supplemental Cases**	**4**
Reference	Wateree Battery Build Plan		
Reference	Williams 2047 Build Plan		
High Fossil Fuel Prices	Williams High Fossil Fuel Price Build Plan		
		TOTAL	**24**

Each of the five Core Build Plans is optimized to achieve lowest cost for customers under different market conditions or assumptions concerning achieving CO_2 emissions reductions of 70% or 85% by 2050. The Core Cases represent a range of plans to meet a broad range of conditions.

- The Reference Build Plan is optimized under the most reasonable and likely future market conditions.
- The High Fossil Fuel Prices Build Plan assumes high fossil fuel costs and medium CO_2 costs in an environment where policymakers are discouraging investment in fossil fuel supplies and reliance on them by end users.
- The Zero Carbon Cost Build Plan assumes policies neutral or favorable towards fossil fuels with medium fuel costs and no CO_2 costs at all.
- The 70% CO_2 Reduction Build Plan and the 85% CO_2 Reduction Build Plan impose 70% and 85% carbon reduction targets on the generation system, respectively, to be achieved in stages by 2050.

Table 2 below presents the twenty-four cases, with the fifteen Core Cases in blue and the Sensitivity Cases and Supplemental Cases in orange.

Table 2: The Twenty-Four Cases

Case	Fuel	CO_2 Price	Load Forecast	DSM	Williams Retirement
Reference Market Scenario					
Reference Build Plan	Medium	Medium	Reference	Medium	2030
High Fossil Fuel Prices Build Plan	High	Medium	Reference	Medium	2030
Zero Carbon Cost Build Plan	Medium	Zero	Reference	Medium	2030
70% CO_2 Reduction Build Plan	Medium	Medium	Reference	Medium	2030
85% CO_2 Reduction Build Plan	Medium	Medium	Reference	Medium	2030
High Fossil Fuel Prices Market Scenario					
Reference Build Plan	Medium	Medium	Reference	Medium	2030
High Fossil Fuel Prices Build Plan	High	Medium	Reference	Medium	2030
Zero Carbon Cost Build Plan	Medium	Zero	Reference	Medium	2030
70% CO_2 Reduction Build Plan	Medium	Medium	Reference	Medium	2030
85% CO_2 Reduction Build Plan	Medium	Medium	Reference	Medium	2030
Zero Carbon Cost Market Scenario					
Reference Build Plan	Medium	Medium	Reference	Medium	2030
High Fossil Fuel Prices Build Plan	High	Medium	Reference	Medium	2030
Zero Carbon Cost Build Plan	Medium	Zero	Reference	Medium	2030
70% CO_2 Reduction Build Plan	Medium	Medium	Reference	Medium	2030
85% CO_2 Reduction Build Plan	Medium	Medium	Reference	Medium	2030
The Five Sensitivity Cases					
Electrification Build Plan	Low	Zero	High	Medium	2030
Energy Conservation Build Plan	High	Medium	Low	Medium	2030
Aggressive Regulation Build Plan	High	High	High	Medium	2030
High DSM Build Plan	Medium	Medium	Reference	High	2030
Low DSM Build Plan	Medium	Medium	Reference	Low	2030
The Four Supplemental Cases					
Wateree Battery Build Plan	Medium	Medium	Reference	Medium	2030
Wateree CT Build Plan	Medium	Medium	Reference	Medium	2030
Williams 2047 Build Plan	Medium	Medium	Reference	Medium	2047
High Fuel Williams 2047 Build Plan	High	Medium	Reference	Medium	2047

The Core Analysis

The core analysis (the "Core Analysis") compared the results of the five Core Build Plans across the three representative market scenarios ("Core Market Scenarios") for a total of fifteen core cases (the "Core Cases"). To ensure comparability between the results, the five Core Build Plans and three Core Market Scenarios were all based on the Reference load growth projection so that all results show the costs and CO_2 emissions to meet the same level of customer demands.

Table 3: The Fifteen Core Cases

Market Scenario	Case	Build Plan
Reference	1	Reference
	2	High Fossil Fuel Prices
	3	Zero Carbon Cost
	4	70% CO_2 Reduction
	5	85% CO_2 Reduction
High Fossil Fuel Prices	6	Reference
	7	High Fossil Fuel Prices
	8	Zero Carbon Cost
	9	70% CO_2 Reduction
	10	85% CO_2 Reduction
Zero Carbon Cost	11	Reference
	12	High Fossil Fuel Prices
	13	Zero Carbon Cost
	14	70% CO_2 Reduction
	15	85% CO_2 Reduction

Across all fifteen Core Cases, the Reference Build Plan had the lowest, or the second lowest cost to customers expressed as the levelized net present value ("LNPV") cost per year for generation supply. The Zero Carbon Cost Build Plan scored lowest in one Market Scenario and second in the other two. But the LNPV cost differences between those two build plans are relatively small, less than 2%, and the LNPV cost differences between the High Fossil Fuel Prices Build Plan and the Reference Build Plan is never more than 3.7%.

The 85% CO_2 Reduction Build Plan has the highest LNPV cost across all three Core Market Scenarios by a wide margin, with an annual LNPV cost between $411 million and $529 million more annually than the lowest cost plan under each Market Scenario. The difference between the 85% CO_2 Reduction Build Plan and the lowest cost build plan for each Market Scenario was an increase of between 18.8% and 29.3%.

The 85% CO_2 Reduction Build Plan achieves the greatest CO_2 emissions reduction of the Core Build Plans producing an 86.8% to 86.9% reduction in CO_2 emissions from 2005 levels, but at higher LNPV costs. The 70% CO_2 Reduction Build Plan achieves the second highest reduction in CO_2 emissions levels with reductions from 2005 levels of between 71.2% and 71.3%, but also at higher LNPV costs.

Among the Reference Build Plan, the Zero Carbon Cost Build Plan and the High Fossil Fuel Prices Build Plan, CO_2 emissions reductions vary between 55.2% and 63.0% from 2005 levels, with the Zero Carbon Cost Build Plan having the lowest reduction in two cases, and the second lowest in the other.

Rate Impacts

Rate impacts can be measured by the compound annual growth rate ("CAGR") for a typical residential customers' bill (1,000 kWh/month) over a 15-year planning horizon. Because residential customers historically have placed higher demands on the electric system than large industrial or commercial customers, rate impacts on them can be proportionally higher than LNPV costs might indicate.

Under the Reference Market Scenario, the Reference Build Plan and the Zero Carbon Cost Build Plan effectively tie for producing the lowest CAGR in a typical customer's bill. In the other Core Market Scenarios, the Zero Carbon Cost Build Plan has the lowest CAGR and the Reference Plan has the second lowest, but the difference between it and the Reference Build Plan is never greater than 0.09%.

The 70% CO_2 Reduction Build Plan has the highest CAGR in the Reference Market Scenario. Under it, the annual growth in a typical customer's bill is 45% higher than under the Reference Build Plan. The 85% CO_2 Reduction Build Plan has the highest CAGR in the two other Market Scenarios and under it the annual growth in a typical customer's bill is between 28.37% and 63.64% higher than under the Reference Build Plan.

These figures represent only the change in customers' bills due to forecasted changes in generation supply costs under the five Core Build Plans and the application of general inflation indices to other cost categories. They are not a comprehensive forecast of future bills.

Technologies Considered

The PLEXOS modeling software used in this 2023 IRP considered twelve generation resources, including two configurations of stand-alone four-hour duration battery capacity, two configurations of stand-alone solar capacity, three configurations of combustion turbines ("CTs"), three configurations of CC units, OSW, and SMRs. One configuration of stand-alone solar was modeled as a PPA (third-party owned) resource, but all other candidate resources were modeled as utility built.

Solar and Battery Storage

Solar resources ("Solar") and battery storage ("Battery") emerged as a major contributor in each of the Core Build Plans with Solar representing between 59% and 67% of the resources added (on a nameplate basis) over the planning horizon and Battery representing between 13% and 22% of those resources. The five Core Build Plans add between 4,275 MW and 7,500 MW of Solar and between 1,500 MW and 1,600 MW of Battery.

The Role of Natural Gas-Fired Generation

Although most of the resources added in all build plans are non-emitting resources, the modeling shows that natural gas generation is also needed to support reliability and supply low-cost energy. Specifically, while each of the Core Build Plans adds at least 79.5% of non-emitting resources, each also adds at least 1,447 MW of natural gas-fired generation to support system reliability.

The Five Sensitivity Cases

In addition to the Core Analysis, DESC modeled five additional Market Scenarios as Sensitivity Cases to fulfill requirements of the IRP Statute and Commission mandates. The Sensitivity Cases assume varying levels of CO_2 costs, environmental regulations, economic and load growth, and DSM effectiveness and confirm the representative nature of the Core Build Plans and the value of the planning insights they provided.

Table 4: The Five Sensitivity Cases

Market Scenario	Sensitivity Case	Build Plan
Electrification	1	Electrification Build Plan
Energy Conservation	2	Energy Conservation Build Plan
Aggressive Regulation	3	Aggressive Regulation Build Plan
High DSM	4	High DSM Build Plan
Low DSM	5	Low DSM Build Plan

Four Supplemental Cases

In addition to the Sensitivity Cases, DESC modeled four additional build plans to test assumptions regarding Wateree and Williams, the Supplemental Cases. Specifically, the four Supplemental Cases examine the effects of replacing Wateree's generation with Battery or CT resources and examine the effects of delaying the retirement of Williams until 2047 under the Reference and High Fossil Fuel Prices Market Scenarios.

Table 5: The Four Supplemental Cases

Market Scenario	Supplemental Case	Build Plan
Reference	1	Wateree Battery Build Plan
Reference	2	Wateree CT Build Plan
Reference	3	Williams 2047 Build Plan
High Fossil Fuel Prices	4	High Fuel Williams 2047 Build Plan

Generation Diversity

All Core Build Plans envision at least 48% of generation added over the planning horizon being Solar and all involve the elimination of coal. Because the build plans strongly favor Solar, generation diversity is inversely proportional to the Solar resources added. Of the Core Build Plans, the Zero Carbon Cost Build Plan had the greatest generation diversity, and the Reference Build Plan was second. The High Fossil Fuel Prices Build Plan scored lowest.

Reliability

The reliability metric scores each build plan based on its contribution to the system's black start and fast start capability, the geographical diversity of generation, and the proximity of generation to load centers. The Reference and High Fossil Fuel Prices Build Plans scored highest in reliability additions among the Core Build Plans. This result was due principally to the amount of CT capacity added under those plans. The Energy Conservation Build Plan scored lowest reflecting the absence of CT capacity. Battery contributed positively to reliability scores, but the volume of such capacity was not sufficient to offset the larger positive effects of the CT capacity added under other build plans.

Safety and Operations

In 2022, DESC's safety and reliability scores were exemplary. During that year, two summer storms and one winter storm reached its service territory. The system performed well during the two summer storms, and the relatively few customers who lost power were restored quickly.

During the period of December 23 to December 25, 2022, an extra-tropical cyclone that had formed in the Northern Plains of the United States brought extreme cold and high winds to DESC's service territory. Like its neighboring utilities, DESC faced capacity emergencies and firm natural gas supplies were curtailed by upstream pipelines. In the early morning of December 24, 2022, DESC lost generation resources at various times due to factors that in some cases were related to the weather directly and in others were not. Support was not available from neighboring utilities who were engaged in load shedding or otherwise in an emergency posture at that time. To maintain operating reserves, DESC was required to curtail firm off-system sales, impose voltage limitations, and impose a brief curtailment of firm load on the morning of December 24, 2022. Service to all customers was restored within minutes and no further load shedding was required.

Urquhart Station; Beech Island, SC

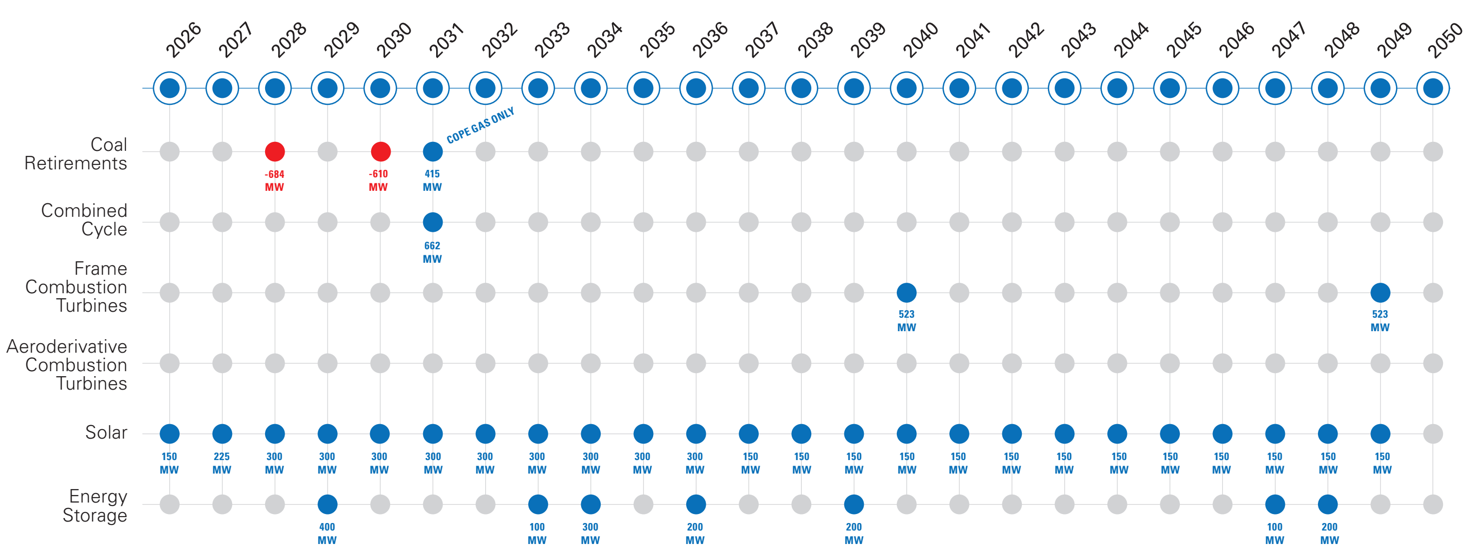
Preferred Plan

DESC has chosen the Reference Build Plan as the Preferred Plan to guide its planning decisions at this time. The Reference Build Plan adds a total of 5,025 MW of Solar and 1,600 MW of Battery over the planning horizon and adds Solar in every year from 2026 through 2049. It has superior scores on LNPV and other metrics related to affordability.

The Reference Build Plan takes a middle-of-the-road approach to replacing Wateree and Williams. Like eleven other build plans, it adds the 662 MW Shared Resource as a key component in retiring Williams by December 31, 2030. The two remaining build plans are the 70% CO_2 Reduction Build Plan and the 85% CO_2 Reduction Build Plan, and they add twice that amount of CC capacity in 2031 and are the highest cost Core Build Plans by a large margin. To support the Wateree retirement, the Reference Build Plan adds Battery supplemented with Solar in 2029 as do three other build plans. The remaining build plans add a 262 MW CT supplemented by Solar and in some cases Battery. The modeling indicates that the costs of these two approaches are relatively evenly balanced based on the information available today. DESC intends to continue to pursue retirement of Wateree and will update the cost of resources available to facilitate its retirement and replacement when determining the mix of resources that will ultimately be built.

For these reasons, DESC has chosen the Reference Build Plan as the build plan best suited to achieve affordable costs for customers under the most likely future conditions on the system. Most other build plans follow similar patterns with some variation in their initial years. By choosing the Reference Build Plan, DESC can pursue affordable energy for customers while retaining the ability to pivot to well-defined alternatives should future conditions warrant.

Figure 3: Resource Additions under the Preferred Plan – Reference Build Plan



Key Developments Since the 2022 IRP Update

Dominion Energy lineman preparing material for service

Stakeholder Process Update

The IRP Stakeholder Advisory Group[2] has met eleven times since it first convened in 2020 and has provided a meaningful exchange of views to inform the IRP process. DESC has previously reported to the Commission on Stakeholder sessions I-VIIIA. Since the last report, DESC conducted Sessions IX and X.

In Session IX (October 19, 2022), the Company and Stakeholders considered, among other topics, Stakeholder engagement since Session VIIIA, key takeaways from the 2022 IRP Update, and planning and changes in inputs for this 2023 IRP. In Session X (December 7, 2022), the Company and Stakeholders considered, among other topics, the 2023 DSM Potential Study, the Reserve Margin Study, the EV Adoption Study, modeling inputs for this 2023 IRP, and implications of the Inflation Reduction Act of 2022 ("IRA") on future IRPs. Session XI is planned to be held in the spring of 2023.

Charles River Associates ("CRA") designed and facilitated all eleven sessions. CRA is a consulting firm with broad national experience in stakeholder processes. DESC has filed the agendas, presentation materials, minutes, and follow-up responses to all Stakeholder sessions to date in Docket 2019-226-E, or the current docket.

2 Stakeholder meetings are open to interested parties. The thirteen invited members of the IRP Stakeholder Advisory Group are:
- Office of Regulatory Staff
- SC Energy Office
- Coastal Conservation League
- SC Small Business Chamber of Commerce
- SC Office of Economic Opportunity
- SC Energy Users Committee
- SC Community Action Partnership
- Southern Alliance for Clean Energy
- Johnson Development Associates, Inc.
- South Carolina Solar Business Alliance
- Sierra Club
- AARP South Carolina
- Walmart, Inc.

The 2023 DSM Potential Study

In late 2021, DESC launched a comprehensive demand side management ("DSM") potential study to determine the maximum levels of DSM energy sales and demand reductions that DESC can achieve for its customers consistent with cost-effectiveness. Cost effectiveness is a statutory requirement for DSM programs, and the Commission requires DESC to use "cost effective, reasonable and achievable" as the standard for evaluating potential DSM savings in future IRPs.[3] DESC's current DSM portfolio is based on the findings of its 2019 DSM Potential Study and 2021 DSM High Case Rapid Assessment. In consultation with the stakeholders comprising the Energy Efficiency Advisory Group ("EEAG"), DESC selected ICF as the third-party provider for the 2023 DSM Potential Study. ICF has conducted numerous potential studies and is a preeminent designer and implementer of DSM programs with a nationwide inventory of DSM measures and real-world results data.

ICF and DESC consulted with stakeholders at each phase of the study and discussed the scope and design of the study, its methodology, customer home and building characteristics, model load shapes to be used, and the universe of DSM measures that ICF would evaluate. Between November 2021 and November 2022, DESC and ICF held seven EEAG meetings—more than twice the number of meetings held in an average year.

Also, in consultation with the EEAG, DESC chose Opinion Dynamics Corporation ("ODC") to undertake a comprehensive market assessment to characterize DESC's customer service territory in terms of the types, ages, and condition of housing and other building stock and energy consuming equipment to provide reliable estimates of the opportunities and barriers for generating savings through DSM programs. ICF's evaluation considered ODC's market

3 Order No. 2021-429

assessment and previous evaluation results obtained through DESC's current portfolio of DSM programs as verified by ODC, who also serves as the evaluation, measurement, and verification ("EM&V") contractor for the current programs.

Based on this data and stakeholder input, ICF assessed both the potential and cost-effectiveness of 454 individual energy efficiency ("EE") measures if implemented in DESC's territory.

The study evaluated the technical, economic, achievable and maximum achievable potential of EE programs in the DESC service area over a 15-year forecast period. ICF identified three DSM scenarios that capture potential levels of energy sales reductions over the forecast period:

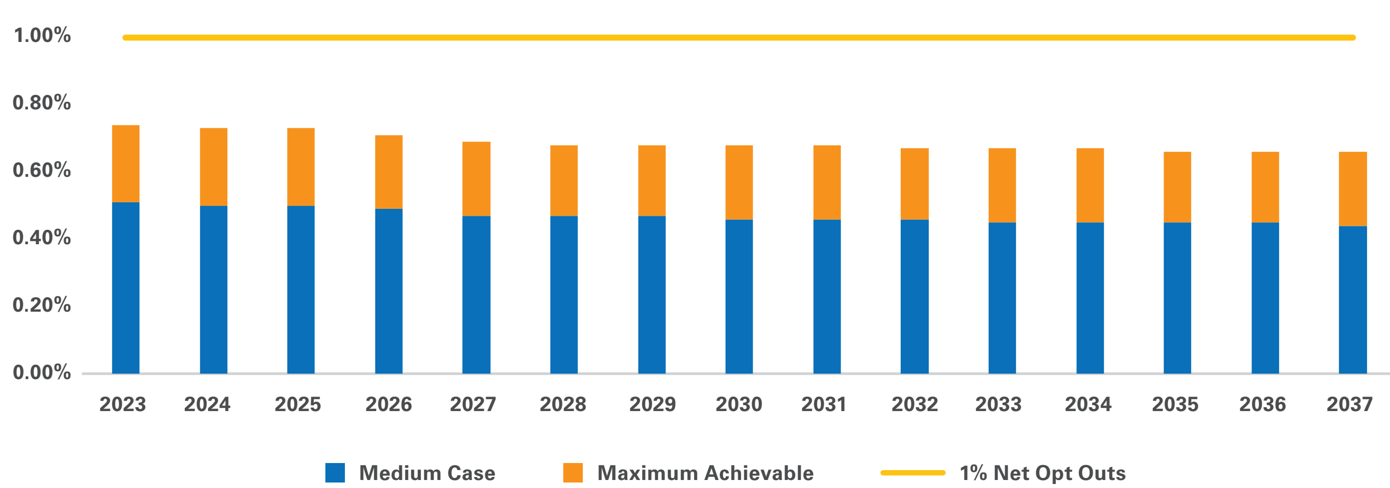
- Medium Case which assumes that DESC offers the revised programs identified in the 2023 Potential Study which are based on the current DSM portfolio of programs and marketing plans with modifications to participation based on the market characterization study, and utility benchmarking.
- High Case which is the maximum achievable potential, and
- Low Case which assumes that DESC achieves only 90% of the results that would be obtained under the Medium Case.

Under the Medium Case, ICF determined what savings were reasonably achievable based on challenging but reasonable assumptions as to implementation scenarios and obstacles, EM&V results, customer response, and resulting energy savings while considering the effect of influences outside of the utility's control like the staffing, pandemic and supply chain disruptions of recent years. Under the Medium Case, ICF determined that DESC could achieve 0.51% energy sales reduction due to EE programs over the 15-year DSM planning horizon.

Under the High Case, ICF did not take into account the same degree of practical limitations it considered under the Medium Case and determined that the maximum energy sales reduction that DESC could achieve consistent with cost-effectiveness is 0.74% of gross sales. ICF based this conclusion on several factors, which included benchmarking of the performance of comparable programs in similar regions, climates, and regulatory jurisdictions to DESC. The High Case also assumed the most aggressive marketing scenarios, customer response rates, and energy savings levels that could be reasonably supported. ICF determined that any scenario higher than the maximum achievable scenario would be hypothetical because it would include measures that are not cost effective, and participation rates beyond the maximum achievable potential.

The Low Case assumes that DESC achieves 90% of the levels described in the Medium Case as a result of more unfavorable conditions than those assumed in the Medium Case which could arise through economic recession, waning of customer interest, staffing shortages, supply chain disruptions and other implementation problems. Under the Low Case, ICF determined that DESC could achieve a 0.46% annual reduction in demand.

Figure 4: Reduction in Growth in Energy Sales from DSM Programs (Maximum Achievable and Medium)

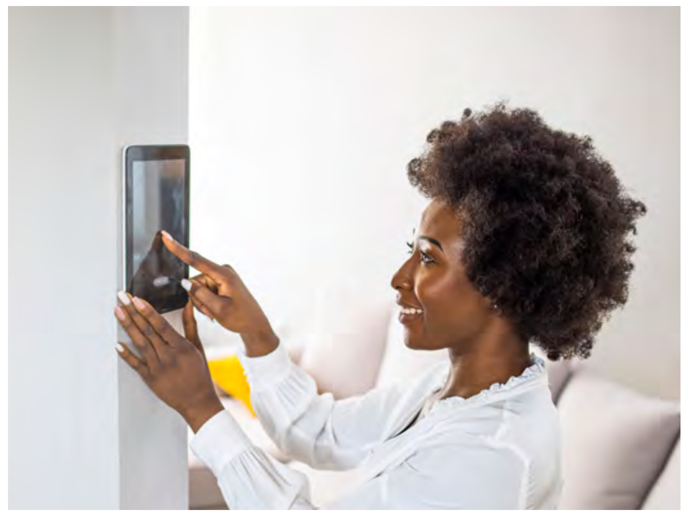


As required by Commission Order No. 2020-832, DESC instructed ICF to evaluate the cost effectiveness and achievability of DSM portfolios reaching annual energy sales reduction levels of 1%, 1.25%, 1.5%, 1.75%, and 2.0%. These evaluations are included in **Appendix C**.

ICF did not find a 1% case or any higher case to be achievable and found that energy sales reductions beyond 0.74% would require non-cost-effective measures or unreasonable program participation assumptions. Among the facts supporting this finding are that DESC's DSM programs are now in their thirteenth program year, and many of the easy-to-reach customers and readily available savings have been captured. In addition, increasingly stringent federal and state energy efficiency standards for lighting, HVAC units, appliances, and electrical equipment, and improved building construction standards and practices limit the additional energy reductions that can be generated through DSM programs or increase the cost of obtaining them. DESC has accounted for these economy-wide increases in energy efficiency through the load forecasts used in the 2023 IRP, but they nonetheless limit DSM potential.

As part of the 2023 DSM Potential Study, ICF also completed a comprehensive evaluation of Demand Response ("DR") programs for both residential and commercial customers with an emphasis on decreasing the winter peak. The roll out of DESC's Automated Metering Infrastructure ("AMI") will provide a direct two-way wireless connection between the Company and the customer's meter to make it possible for DESC to offer DR programs to include its residential and eventually small and medium general service customers. DESC has several longstanding and successful DR programs for large general service customers, which will remain in place. ICF's analysis determined that there are eight DR programs that are potentially cost-effective in certain configurations. Of these, three potential residential programs with high levels of cost-effectiveness and broad potential applicability, were Time of Use Rates ("ToU"), Critical Peak Pricing, and Peak Time Rebate. They involve motivating demand reductions through price signals during peak periods. A Smart Thermostat program for residential customers also scored well. ICF modeled the effects of bundling these programs for each of the three principal customer segments. It modeled the ToU program both on an opt-in and opt-out basis and modeled sensitivities for all programs based on high, medium, and low assumptions concerning participation rates.

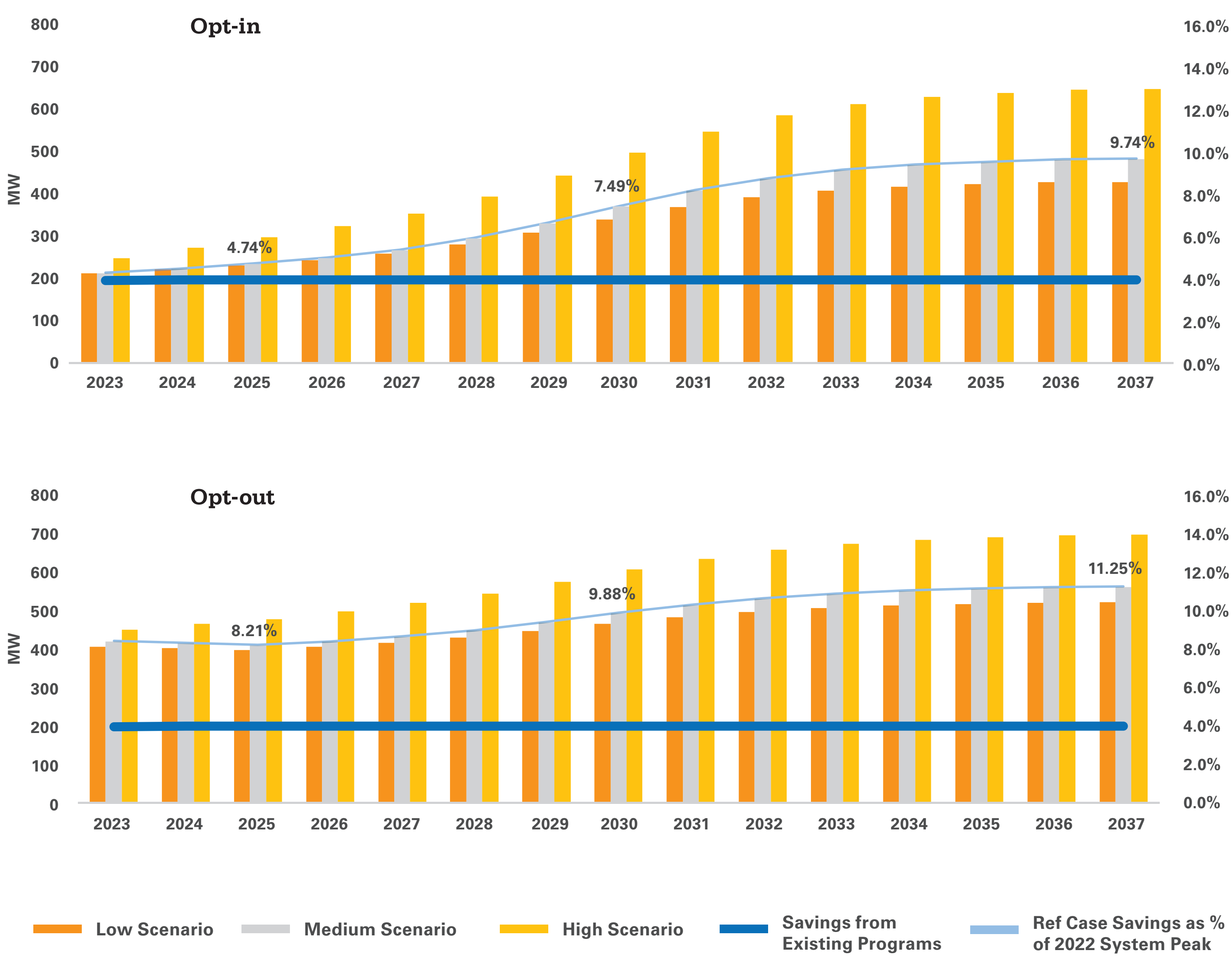
DR programs seek to reduce peak demand on the system, and for that reason, DR programs are principally measured on their ability to reduce system peak. ICF forecasted that under an opt-in scenario for ToU, an achievable reference case suite of DR programs could reduce winter peak demand by 4.74% in 2025, rising to 9.47% in 2037. Under an opt-out scenario, the reference case suite of programs could reduce winter peak demand by 8.21% in 2025, rising to 11.25% in 2037. These results depend on availability of skilled implementation professionals, timely regulatory approval, favorable customer acceptance rates, and other factors.



Customer adjusting a smart thermostat

DESC's new smart meter

Figure 5: Demand Response Savings Across the Study Period (Opt-in vs. Opt-out)



The results of the 2023 DSM Potential Study are included as inputs to the 2023 IRP modeling representing Low, Medium, and High Case DSM Scenarios. Additionally, DESC modeled two DR programs, Residential ToU and Smart Thermostat Opt-In, in the 2023 IRP. Opt-in was chosen for the Smart Thermostat program based on customer acceptance and flexibility considerations.

As next steps and in consultation with the EEAG, ICF will propose a five-year program plan for the implementation of EE programs, which will provide details of implementation and marketing efforts. When complete, DESC will present the suite of revised DSM EE programs for approval by the Commission for it to offer to customers to help them save energy and reduce costs.

Peaking Generation Replacements

In 2021, DESC made a formal proposal to the Commission in Docket 2021-93-E to retire thirteen end-of-life and increasingly hard to maintain natural gas-fired CT units and a natural gas-fired steam unit and replace them with modern generation resources. Despite their age and condition, these units have played an important role in maintaining grid reliability including providing DESC with the ability, if needed, to restart the grid after blackouts through black start capabilities. In November 2021, the Company entered into a Partial Settlement Agreement in Docket 2021-93-E (the "Partial Settlement"), which the Commission approved in Order No. 2022-27.

The Hardeeville, Bushy Park, Parr, and Coit Retirements and the Bushy Park and Parr Replacements

In accordance with the Partial Settlement, the Commission found that DESC could proceed with replacing six CT units at Bushy Park/Williams and Parr with three modern aeroderivative combustion turbine ("Aero CT") units. Detailed engineering and major equipment manufacturing is underway for both sites. The Company anticipates the Bushy Park unit will enter commercial service in the second quarter of 2024 and the Parr units will enter service in the second quarter of 2025. DESC retired the Hardeeville and the Bushy Park CT units effective March 31, 2022, and September 30, 2022, respectively. Currently, the dismantling of the Bushy Park units is nearly complete with construction of the replacement unit to begin in 2023. Dismantling of the Hardeville CT unit and site stabilization and restoration activities are planned to occur in 2023. DESC plans to retire the Parr units on March 31, 2023, with dismantling and construction activities at that site to begin later this year. DESC plans to retire the Coit CT units in the second half of 2024, following the commercial availability of the replacement Bushy Park CT unit, at which point dismantling activities are planned to commence for those units.

Parr Combustion Turbine

Bushy Park Combustion Turbine

Urquhart Replacements

Under the Partial Settlement, DESC agreed to conduct an All-Sources Request for Proposals ("RFP") to replace the four existing CTs and one natural gas-fired conventional steam unit at the Urquhart Station site ("Urquhart All Sources Requests for Proposals" or "Urquhart RFP"). In accordance with the Partial Settlement, CRA was retained by DESC to facilitate the process to obtain stakeholder input into the design of the Urquhart RFP and to serve as the Independent Evaluator and Monitor for the RFP process. Stakeholder feedback was collected through five stakeholder sessions held in 2022. On August 11, 2022, DESC issued the resulting RFP for resources that meet technology-neutral specifications for winter capacity and black start capability located within the DESC Balancing Authority Area. Bids were received by December 22, 2022. The RFP received a robust response from multiple qualified entities bidding a diverse mix of supply-side generation facilities including Solar, Battery, hybrid Solar and Battery, and combustion turbine resources along with proposals for demand response. Almost twenty different facilities were bid into the RFP through over 40 different proposals, contracting mechanisms, or other considerations. DESC's Power Generation group is participating as a bidder with two different options that have been provided for CRA and the DESC RFP team to evaluate. Shortlist notifications from the RFP are expected to be made in February 2023, at which point negotiation of final agreements, as applicable, are expected to begin.

Combined Cycle Uprates and Back-up Fuel Additions

DESC's current services agreements for its CC units include hardware and advanced gas path ("AGP") upgrades to increase the output, lower the fuel consumption, and extend the maintenance intervals for these turbines. The upgrades are being performed as the units are taken offline for their normal scheduled maintenance intervals.

Under this program, DESC has completed the upgrades to the three Jasper units and one Columbia Energy Center unit. In late 2022, Columbia Energy Center Unit 1 was overhauled and upgraded and the final unit to be upgraded under the program, Columbia Energy Center Unit 2, is planned to be upgraded in the spring of 2023. These upgrades, once complete at all units, will have added approximately 123 MW of additional winter capacity and almost 83 MW of additional summer capacity to the system. This additional capacity will be available for dispatch to serve customers

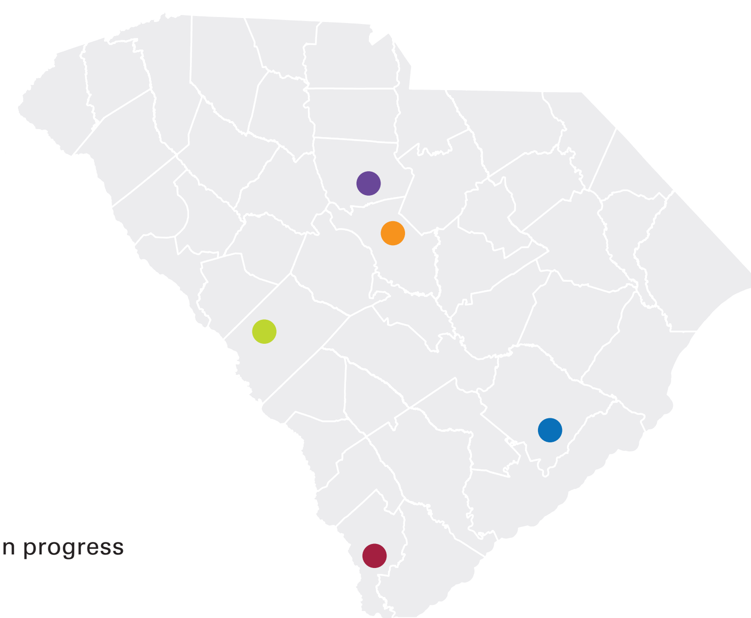
Figure 6: Location of Proposed Combustion Turbine Retirements and Replacements

New Units

- **Parr** – Replaces 4 CTs (73 MW) with 2 new CTs (100 MW)
- **Urquhart** – Replaces 4 CTs and one Boiler (193 MW) with resource TBD*
- **Williams** – Replace 2 CTs (52MW) with 1 new CT (50 MW)

Retirement Units

- **Coit** – Retire 2 CTs (36 MW)
- **Hardeeville** – Retire 1 CT (9 MW)



*Urquhart RFP in progress

once required transmission studies and any required network upgrades are completed. Until then, system operators and DESC customers will benefit from an increase efficiency of the units and access to the additional output as allowed by transmission system operating conditions.

In addition, in 2022, backup fueling capability (in the form of ultra-low sulfur fuel oil) was restored to service on Columbia Energy Center Unit 1. As a result and with the retirement of the oil-only Hardeeville CT unit in 2022, all of DESC's CT units are now capable of operating on alternative fuel when natural gas supplies are limited or curtailed.

Southeast Energy Exchange Market

On November 9, 2022, DESC and twelve other utilities began trading energy in the Southeast Energy Exchange Market ("SEEM") which provides an automated, intra-hour trading platform allowing members to buy and sell energy in 15-minute blocks and deliver it using unused transmission capacity, with no charge to transmission users except for losses. These utilities collectively own approximately 160,000 MW of generating capacity and serve about 640 terawatt hours ("TWh") of energy across ten balancing authority areas and two time zones. Transactions are priced at the midpoint between the offer price and bid price, creating value for customers on both sides of the transaction. DESC analyzes system conditions prior to every 15-minute interval for participation in SEEM and is taking a methodical and careful approach entering this new market. In the first 53 days of SEEM's operations, DESC sold 1,179 MWh of energy and purchased 1,362 MWh, and SEEM facilitated 62,457 MWh of trades in total.

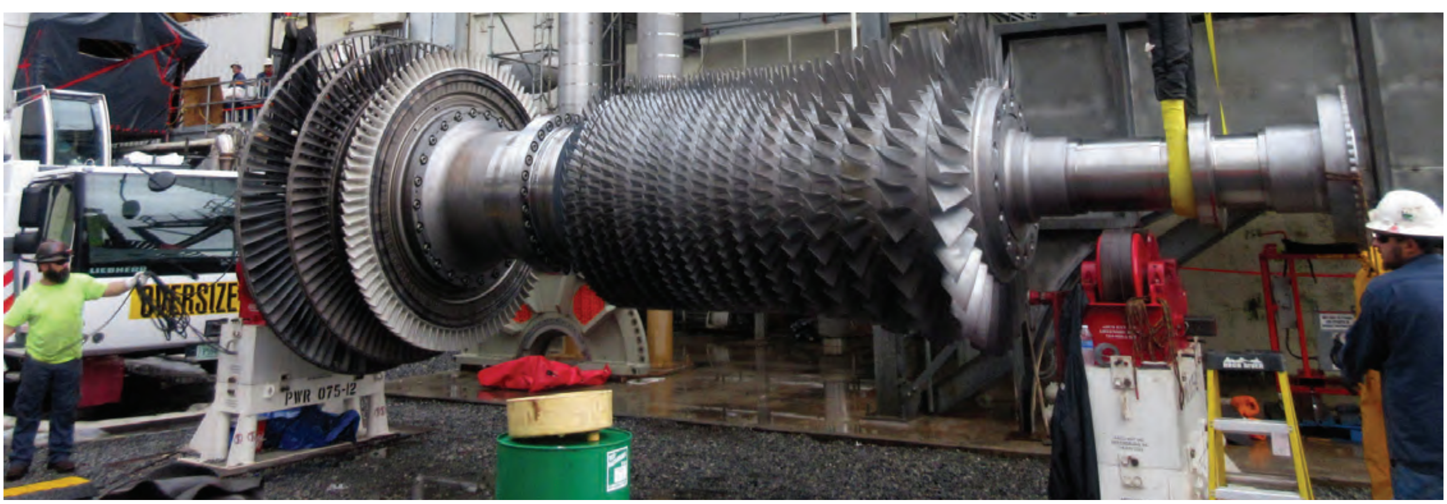
The Infrastructure Investment and Jobs Act

On November 15, 2021, President Biden signed the Infrastructure Investment and Jobs Act ("IIJA"), which, in part, seeks to

- build a national network of high-speed electric vehicle ("EV") chargers;
- upgrade power infrastructure to deliver clean, reliable energy across the country;
- deploy cutting-edge energy technology to support a zero-carbon future; and
- make infrastructure resilient against the impacts of climate change, cyber-attacks, and extreme weather events.

To support these goals, the IIJA provides some funding opportunities directly to utilities, and some based on joint utility/governmental projects, such as electrification of school & transit buses and other governmental fleets.

Apart from tax credits, much of IIJA's funding is awarded on a competitive basis and in many cases will involve negotiating project agreements with state and local governments. DESC is in the process of identifying specific projects benefiting its service area and intends to participate in as many opportunities as possible that align with its operations and provide benefits to its customers. DESC's pursuit of IIJA funding opportunities will continue over the programs' five-year time horizon.



A Jasper Station Turbine Rotor Awaiting Installation after Maintenance and Upgrade

In December 2022, DESC submitted a "Concept Paper" related to the Grid Resilience and Innovation Partnerships program under the IIJA, which provides for the expansion and modernization of the nation's electric grid and is the most relevant funding opportunity to grid operators. The Company is awaiting feedback from the U.S. Department of Energy as to whether it should submit a full application, which is expected in the first quarter of 2023. If the Company is encouraged to apply, it may submit a full application in April 2023. To date, no IIJA grants have been awarded to the Company.

The Inflation Reduction Act of 2022

In August 2022, Congress passed the Inflation Reduction Act ("IRA"), which includes an estimated $369 billion in climate and clean energy provisions, including grants and increased tax credits for new-build renewable and non-emitting generation resources including solar, storage, nuclear, and wind capacity. For the first time, Battery resources are eligible for tax incentives even if not built alongside a solar or another renewable resource. As a result, this IRP has modeled Battery as a stand-alone resource eligible for tax credits. Utilities may now benefit directly from certain renewable energy tax incentives, and nuclear is now on the list of incentivized technologies. The Company is actively reviewing the provisions of the IRA and has incorporated a base level of IRA-based tax incentives into its modeling of resource options.

The IRA introduces a tiered credit system that is applicable for both Investment Tax Credits ("ITC") and Production Tax Credits ("PTC"). The ITC is broken into a base credit that is 6% of qualified basis. The ITC can be increased to 30% of qualified basis if the project meets prevailing wage and apprenticeship requirements. Under the prevailing wage requirements, the taxpayer must ensure that any laborers and mechanics are paid prevailing wages during the construction of a project and, during the relevant credit period, for the alteration and repair of such project. Subject to certain exceptions, the apprenticeship requirements mandate a certain percentage of total labor hours for the construction of the project be performed by qualified apprentices.

The ITC can be further increased by 10% if domestic content is used in the project. This requires that the taxpayer certify that any steel, iron, and a minimum percentage of manufactured products that are part of the facility were produced in the United States. The ITC increases by an additional 10% if the facility is located on a brownfield site, in an area with high unemployment or tax revenues from the coal, oil, or gas industry, or in an area where a coal mine or coal-fired electric generation unit has been retired within a certain look-back period (an "Energy Community"). For solar and wind projects less than 5 MW, additional credits may apply for projects located in a low-income community or on Indian land. Projects less than 5 MW may also include interconnection property in calculating the credit.

A similar tiered system applies to PTCs with a base credit which increases if the project meets labor requirements, and bonus credits for meeting domestic content requirements or locating in an Energy Community. The amount of the PTC is adjusted annually for inflation.

Table 6: Potential Production Tax Credits and Investment Tax Credits for Clean Energy Projects under the Inflation Reduction Act

Type of Credit	PTC	ITC
Base credit, and	0.550 cents/kWH	6% of basis
Increased credit (assuming labor requirements are satisfied)	2.200 cents/kWH	24% of basis
Plus: Bonus credit for domestic content	0.275 cents/kWH	10% of basis
Plus: Bonus credit if located in an Energy Community	0.275 cents/kWH	10% of basis
Total potential credit (Bonus credit + Additional Credits)	**3.300 cents/kWH**	**50% of basis**

The legislation also creates a new technology-neutral ITC and PTC that can apply to Battery and SMR projects. They begin to phase out for qualified facilities beginning construction in 2033 or the first calendar year in which the United States Department of Treasury ("Treasury") determines that the annual greenhouse gas emissions ("GHG") from the production of electricity in the U.S. are equal to or less than 25% of the U.S. GHG emissions for calendar year 2022.

The IRA also provides a $7,500 tax credit in 2023 for EV purchases if vehicle OEM and buyer qualify which becomes an immediate point of sale credit in 2024. The

IRA also provides a 30% tax credit for charging station installation (up to $1,000 for residential), a $35/kwh credit for North American battery manufacturing and a $10/kwh for North American battery assembly. These will accelerate EV adoption and associated electric load and economic development in DESC's territory as South Carolina emerges as a hub for battery and EV vehicle manufacturing and assembly.

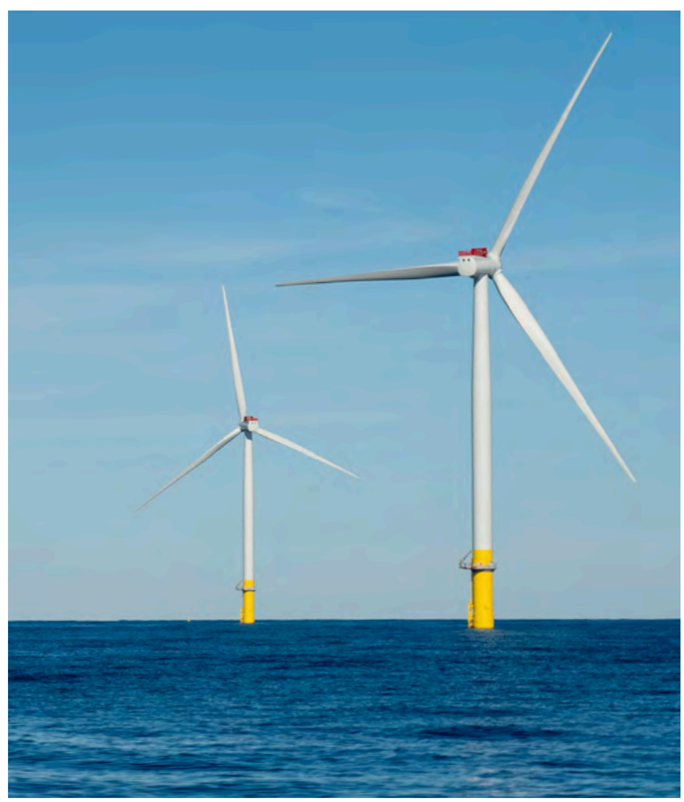
The IRA is a complex statute with many unresolved questions. Formal rulemaking or other official guidance from the Treasury is being issued and must be in place before the provisions of the IRA can be applied with certainty. For purposes of the modeling done in support of this 2023 IRP, PLEXOS assumes that all Solar resources receive a PTC starting at $25.00 per MW (2021$) escalating annually and that Battery resources receive a 30% ITC on 85% of the total project cost. (Under IRS rules, not all project costs qualify for an ITC and 85% is a reasonable estimate of the project components that will qualify.) The modeling presented here assumes that the ITC and PTC apply to projects completed during the life of the program and for two years after the program closes to capture projects grandfathered into eligibility that were begun before the sunset date.

Dominion Energy Carbon and Methane Commitments

As part of its Net Zero strategy, and so long as it can be done in a safe, reliable and affordable manner, Dominion Energy is phasing out the use of higher emitting fuels, like coal and heavy fuel oil, both as fuels for its electric power generation and as fuel for the power it purchases across all its companies. Dominion Energy is committed to achieving Net Zero CO_2 and methane emissions by 2050. In early 2020, Dominion Energy announced its commitment to Net Zero carbon and methane emitted directly from our electric generation and natural gas operations (Scope 1 emissions). In February 2022, Dominion Energy expanded its Net Zero commitment beyond its direct emissions to also cover emissions upstream of its operations (Scope 2) from suppliers and downstream from customers (Scope 3). This broadened Net Zero commitment now covers Scope 2 emissions and the following material categories of Scope 3 emissions: electricity purchased to power the grid, fuel purchased for the company's power stations and gas distribution systems, and consumption of sales gas by natural gas consumers. Dominion Energy committed itself to achieve interim targets to cut Scope 1 carbon emissions from the power generation business by 55% by 2030 compared to 2005 levels and Scope 1 methane emissions from its natural gas business by 65% by 2030 and 80% by 2040 (from 2010 levels). These commitments to a cleaner energy future have played an important role in DESC's evaluation of the plans presented in this 2023 IRP and its plan for retiring Wateree and Williams.

Offshore Wind

On August 13, 2021, the United States Bureau of Ocean Energy Management ("BOEM") awarded leases to two OSW sites totaling 110,092 acres in the Carolina Long Bay lease area. The tracts are in waters offshore of Wilmington, North Carolina, and immediately adjacent to the South Carolina border. When developed, the two tracts are expected to provide over 1,300 MW of wind energy capacity. Globally, installed OSW represents some 35,300 MW of installed capacity, the majority of which is in Northern Europe. OSW has the advantage of generally higher capacity factors than solar generation (approximately 40% vs. 24% for solar) and can be available at night and during overcast conditions when solar is not. U.S. OSW costs are falling as the domestic supply chain is expanding with major projects underway in the Middle Atlantic states and New England.



Dominion Energy's Offshore Wind Project

BOEM has identified an extensive set of OSW call areas off the South Carolina coast between Little River and Charleston. BOEM is conducting detailed mapping and environmental baseline studies of these areas in consultation with the South Carolina Intergovernmental Renewable Energy Task Force, which is made up of representatives from federal, state, local, and tribal governments. Specific lease sites have not been identified and no timetable for leasing has been announced. For planning purposes, DESC has assumed OSW could be added as a resource beginning in December 2040.

Small Modular Reactors

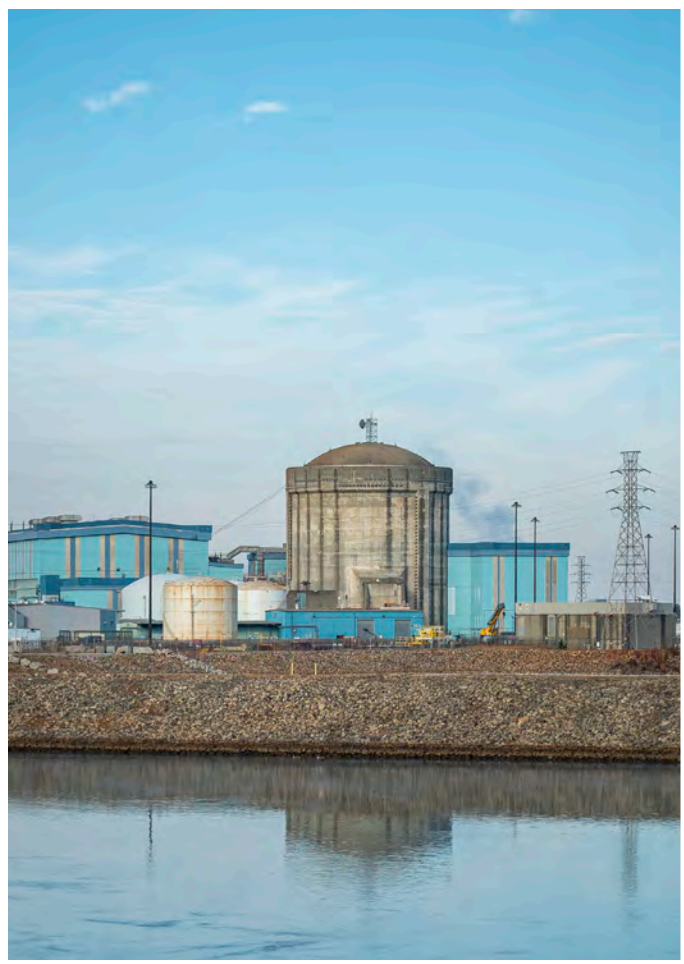
Nuclear generation provides a reliable, carbon-free complement to renewable energy generation that is not subject to weather-related intermittency. SMRs are technologically innovative alternatives to traditional, site-built nuclear power stations and can be built in increments as small as 50 MW or as large as 300 MW. They can be fabricated in a controlled factory environment as modules, or for smaller sized units as largely completed reactors, and delivered to the installation site for integration with other plant systems including turbine generator sets, cooling water systems, and substations.

SMRs incorporate advanced passive safety features that ensure safe shut-down in all foreseeable circumstances without the need for operator action or a source of emergency power. In addition to minimizing safety risks, this design approach reduces the number and complexity of plant systems and the amount of equipment required in the plant.

SMRs are non-carbon emitting resources that are designed to deliver capacity to customers reliably every day, without the weather-related intermittency that limits most renewable resources. For that reason, SMRs will not require battery or gas-fired back up to support system reliability. They are also being designed to be dispatchable so that system operators can ramp their output up and down with response times comparable to natural gas-fired CC facilities. Manufacturing standardized designs in a controlled factory setting can reduce the cost and schedule risk of deploying SMRs. Because of their size and enhanced safety profile, SMRs can be located on sites that would not support traditional nuclear units, including retired coal plant sites, brownfield industrial sites, and sites closer to electric demand centers. The small size of individual SMRs allows them to be scalable in relatively small increments.

The Company anticipates that SMRs could be a feasible supply-side resource as soon as the 2030s and has included SMRs as a supply-side option in this IRP starting in 2040. Some light-water SMR designs utilize current nuclear fuel technologies with an available supply chain, so their commercial availability may be even sooner.

The Company plans to continue evaluating the feasibility, operating parameters, and costs of SMRs and will update modeling assumptions related to SMRs in future filings. Cost reductions may be realized as the design of SMRs matures and as anticipated construction schedules are established. It is conceivable that the deployment of SMRs could be further accelerated by Dominion Energy based on updated capital, operating and maintenance costs, continued progress of licensing timelines, and new policy initiatives or legislative changes, with the first SMR being placed in service within a decade. DESC will monitor the development of this technology carefully.



VC Summer Nuclear Station; Jenkinsville SC

The 2023 Reserve Margin Study and Effective Load Carrying Capacity Determination

In July of 2022, DESC retained Astrapé Consulting ("Astrapé") to conduct the Reserve Margin Study to inform this 2023 IRP. Astrapé is a widely recognized electric system planning firm. It maintains and licenses the Strategic Energy & Risk Valuation Model ("SERVM") planning tool that has been used to inform resource adequacy decisions by Duke Energy, Progress Energy, Santee Cooper, Southern Company, TVA, Louisville Gas & Electric (LG&E), Kentucky Utilities (KU), California Public Utilities Commission, Pacific Gas & Electric, ERCOT, MISO, SPP, Public Service Company of New Mexico, TNB (in Malaysia), and CLECO.

To quantify variability in weather patterns in DESC's service territory, Astrapé analyzed DESC's customer demands for the period 2017-2021 and correlated those demands to historical weather patterns using 42 years of historical weather data for Charleston and Columbia. Using historical forced and scheduled outage rates for DESC's generation assets, Astrapé conducted a Monte Carlo analysis to identify outage risk during peak demand periods. Using NREL's solar irradiance database and historical data from DESC, Astrapé modeled the capacity and energy production of the solar fleet across the 42 weather years. Astrapé based its hydro capacity and energy production on 40 years of DESC's hydro generation data. Using publicly available data, Astrapé modeled the Southeastern United States grid to assess the likelihood that DESC could import power from neighboring utilities in times of capacity shortfalls.

Based on this modeling, Astrapé determined that:

1. For DESC to meet its long-standing reliability standard of one loss of load event ("LOLE") (i.e., generation-related blackout or load shed) every ten years, it would need to maintain a minimum winter reserve margin of 20.1%. The summer reserve margin is consistently lower and acts as a secondary constraint that DESC should not allow to fall below 15%. The Company's reserve margin for the 2022 IRP Update was 21% in winter and 14% in summer. DESC used the new reserve margins as inputs in the 2023 IRP modeling.

2. Astrapé determined that if DESC's system operated in isolation from neighboring systems, DESC would need a 40% reserve margin to meet reliability standards. It reached this conclusion by modeling DESC's system with and without the possibility of assistance from other utilities in times of emergency. Market assistance is principally valuable in meeting capacity requirements in the shoulder months, when major generating units are offline for planned maintenance, and in the evening hours of summer months after solar generation ceases to produce each day. During such times, neighboring utilities often have resources available to provide external market assistance for DESC's system, assuming seasonable weather conditions and available transmission capacity.

3. Battery storage facilities are typically configured to support a four-hour duration of discharge and their capacity is rated at that discharge level. Given the probable duration of extreme weather events or other capacity emergencies on DESC's system, the next 300 MW of four-hour duration battery storage facilities that are installed on DESC's system will provide an effective load carrying capability ("ELCC") of 90% of rated capacity. That figure then drops to 80% for the next 800 MW of four-hour duration capacity to be installed. Both figures assume that the Battery resource is operating in a typical energy shifting mode (i.e., storing power when it is available at low cost and returning it to the systems during higher cost periods).

Due to the timing of winter peak demand periods, incremental solar capacity has a relatively small ELCC value. The next 100 MW increment of solar resources added to DESC's system will have an ELCC of 2.7% of rated capacity. For a 500 MW increment of solar capacity beyond the initial 100 MW addition, the value is 0.7%. For next two 500 MW tranches of incremental solar capacity, the ELCC value is 0.5%.

Table 7: Incremental Estimated Load Carrying Contribution of Incremental Solar Capacity

Incremental Solar	Solar Incremental ELCC
MW	MW
100	2.7%
600 (+500)	0.7%
1,100 (+500)	0.5%
1,600 (+500)	0.5%

The study provides fully distributed outputs concerning LOLE, Loss of Load Hours ("LOLH"), Expected Unserved Energy ("EUE"), and interruption calls under DR programs for multiple potential reserve margins in addition to the reserve margin producing the LOLE of one event every ten years. Astrapé also prepared sensitivity studies to gauge the effect on resource adequacy due to extreme weather conditions, the availability of assistance from neighboring utilities, variations in forced outage rates, and penetration of renewable resources. The results for the base case are shown in the Reserve Margin Study. The full study report with similar data for the sensitivity studies has been filed with the Commission in Docket No. 2022-162-E.

CARTA electric bus system; Charleston, SC

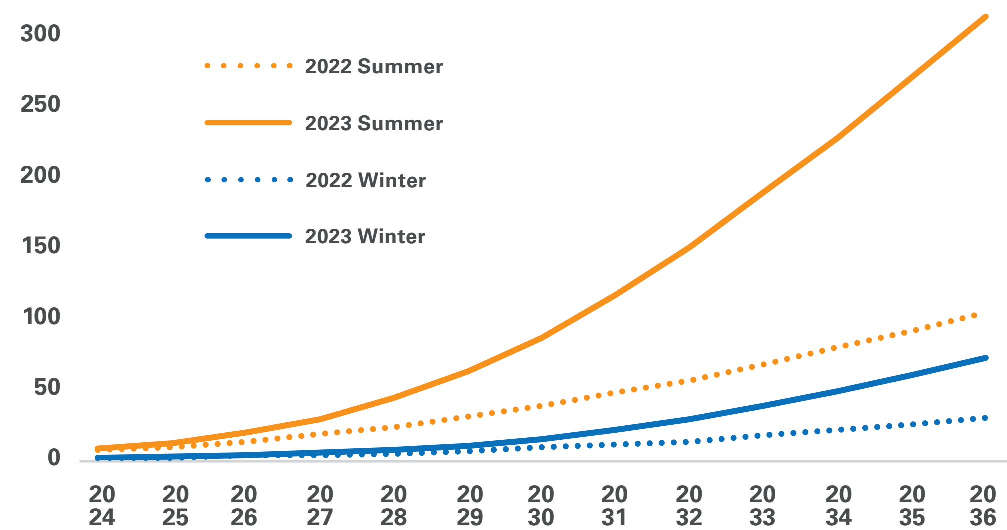
Electric Vehicle Adoption Study

Electric vehicle penetration is expected to grow significantly during the planning period due in part to accelerating demand, increased model availability, and strong political, environmental, and regulatory support. Three states have announced new internal combustion engine ("ICE") vehicle bans by 2035, and the Company anticipates that more states will adopt similar policies in the future. In response, car manufacturers are switching their design and production focus from ICE vehicles to EVs, and this change will rapidly drive EV adoption nationwide. Some automakers have announced goals to reach 40-50% EV model sales by 2030. Additionally, federal vehicle and infrastructure incentives in the IRA and IIJA (i.e., tax credits, high speed charging stations, electric school and transit buses) will boost EV sales, increase customer demand, and decrease "range anxiety" hurdles. With an increase in EV sales, at home vehicle charging by customers will be a driver of EV load growth and annual energy consumption. It is expected that these national developments will have an impact on the DESC service territory independent of future policies or legislation in South Carolina.

DESC retained the Guidehouse consulting firm to conduct an EV Adoption Study to evaluate the anticipated penetration of electric vehicles in DESC's service territory over a fifteen-year period and forecast the expected growth in customer demands as a result. Specifically, Guidehouse determined that EV adoption will have its greatest impact on summer peak load because EV owners are expected to be charging their vehicles at the end of the day when summer peaks occur. In contrast, the winter peaks happen in the early morning hours after most EV charging will be complete, so EV contribution to winter coincident peak is reduced. In 2037, the estimated contribution to summer peak from EV charging is approximately 358 MW or 6.4% of peak summer demand.

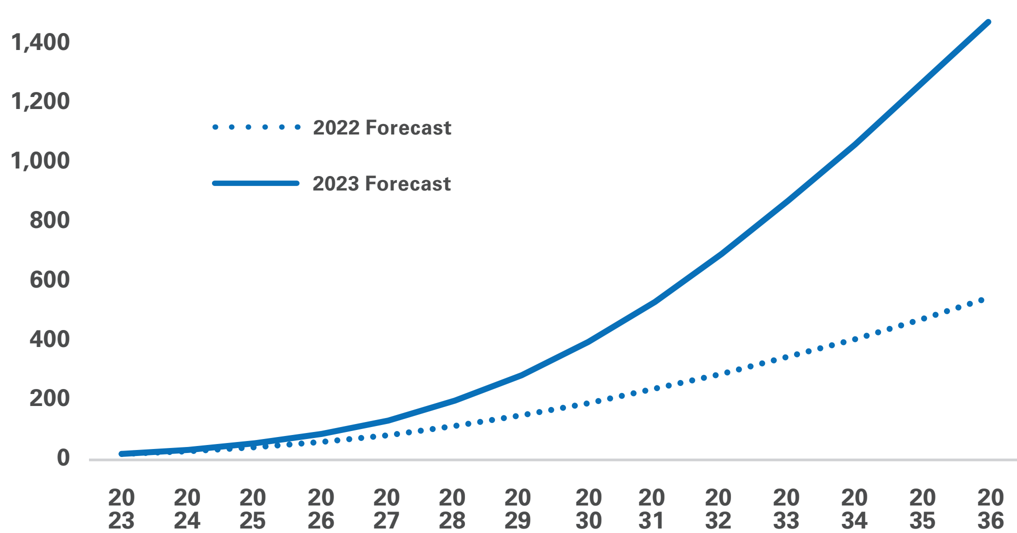
Electric Vehicle (EV) charging station

Figure 7: Estimated Contribution of EV Charging to Coincident Summer and Winter Peak (2022 and 2023 Forecasts Compared)



Guidehouse also determined that the EV contribution to annual energy consumption would reach 337 GWh by 2030 and 4,409 GWh by 2050, the latter is approximately 12% of the total energy consumption in 2050 under the Reference Build Plan and Reference Market Scenario.

Figure 8: Estimated Contribution of EV Charging to Annual Energy (GWh) Consumption (2022 and 2023 Forecasts Compared)



The updated forecasts of EV contributions to future energy demands are included in the 2023 load forecast.

Dominion Energy

Jasper Station; Hardeeville, SC

The 2021 Transmission Impact Analysis

In January 2022, DESC completed and filed with the Commission a Transmission Impact Analysis (the "2021 TIA") that estimated the costs and schedules for transmission system upgrades required to maintain grid reliability if DESC retires Williams and Wateree in 2028. The TIA evaluated five representative replacement options and found that DESC will need to construct significant transmission system upgrades to maintain system reliability under each of them. The most complex and expensive upgrades were those required to support retiring Williams and due to geography and the location of transmission and other generation resources. The transmission system upgrades to support the Wateree retirement would be much less than those required to support the Williams retirement.

The five retirement cases considered in the 2021 TIA Analysis are as follows:

Case 1

- Retire Wateree in 2025 and retire Williams in 2028
- Add a 200 MW of Battery and 200 MW of Solar at Wateree
- Contract for 200 MW off-system purchased power beginning late in 2025
- Build a 534 MW 1X1 CC at Jasper
- Add a 200MW of Battery and 200 MW of Solar at the site of DESC's retired Canadys coal units ("Canadys")

Case 2

- Retire Wateree and Williams in 2028
- Build a 534 MW 1X1 CC at Jasper
- Build 523 MW 2X0 pair of frame CTs at Jasper

Case 3

- Retire Wateree and Williams in 2028
- Build a 534 MW 1X1 CC at Canadys
- Build 523 MW 2X0 pair of frame CTs at Canadys

Case 4

- Retire Wateree and Williams in 2028
- Build a 534MW 1X1 CC at Canadys
- Add a 200 MW of Battery and 200 MW of Solar at Wateree
- Contract for 400 MW off-system purchased power

Case 5

- Retire Wateree and Williams in 2028
- Contract for 1,100 MW off-system long-term power purchase

All Cases

- Add Aero CTs, incrementally, as needed, at the Williams Station site to maintain system reliability or to economically overcome transmission system contingencies (This concept was deferred to the 2022 TIA)

The 2021 TIA found that from a transmission standpoint the least expensive and lowest risk of the five options involved siting gas-fired generation at Canadys which is forty miles north of Charleston, South Carolina. The 2021 TIA indicated that the transmission projects needed to create a path to import permanent replacement power from neighboring utilities would be expensive and time consuming and did not support relying on such supply as a permanent replacement option.

Based on information provided in the 2021 TIA, DESC determined that retiring Wateree by December 31, 2028[4] is supportable as a planning goal but considering the complexity of the transmission and fuel supply projects required to replace Williams, and the time required to permit, site, and construct those projects, the earliest feasible retirement date for Williams is the end of 2030. Both projected dates assumed that the regulatory and legal processes required to authorize, site, and construct the replacement generation and supporting transmission and gas supply infrastructure are not unduly delayed.

The 2022 Coal Plants Retirement Study

DESC also prepared a Coal Plants Retirement Study, which it submitted to the Commission in Docket No. 2021-192-E, to identify an appropriate procedural schedule for retiring Williams and Wateree and identify any relevant statutory and regulatory deadlines, especially those related to ELG compliance at those units. The study supported several high-level conclusions that inform the modeling in this 2023 IRP:

A. Assuming that adequate replacement generation can be obtained, retiring Wateree at the end of 2028 can provide cost benefits to customers by avoiding significant elements of compliance costs associated with the Environmental Protection Agency's ("EPA's") current ELGs.

B. Opting not to comply with current ELG requirements at Wateree creates the risk that Wateree would have to be retired from service even if replacement capacity is not in place by December 31, 2028. If the resource adequacy shortfall is anticipated to be of a sufficiently brief duration, and permitting and construction timetables for alternatives are secure, DESC will evaluate whether the risk is acceptable and whether short-term replacement resources can be obtained while construction is being finalized before making its final, binding decision to retire the plant under the provisions of the ELG rule. If progress towards replacement resources does not support accepting that risk, DESC will proceed with its currently permitted ELG compliance program pathway and may continue operating Wateree into the 2030s to maintain reliable service to customers.

C. Retiring Williams is not reasonably feasible before 2030 considering the complexity of siting and constructing the necessary replacement resources, including electric transmission and fuel supply.

D. Setting December 31, 2030, as the earliest feasible retirement date for Williams is appropriate as a "best case" planning goal subject to much risk and uncertainty. This retirement date includes little, if any, buffer to accommodate regulatory or construction delays or legal challenges to permitting and siting. By proceeding with the upgrades necessary for ELG compliance, the potential costs and risks to customers are reduced if replacement generation is ot online by 2030.

The 2022 Transmission Impact Analysis

On July 22, 2022, DESC's Resource Planning requested the DESC Transmission Planning Group to conduct another TIA (the "2022 TIA") to study nine additional cases for replacing the Wateree capacity by December 31, 2028, and the Williams capacity by December 31, 2030. Three cases evaluate options for replacing the Wateree coal capacity with resources located at the Wateree site, the existing Urquhart site in Aiken County, and elsewhere. The Urquhart site currently hosts multiple natural gas-fired generation units with relatively direct access to upstream interstate natural gas supplies, large quantities of on-site backup liquid fuel storage, and significant interconnectivity to both the Company's 115 KV and 230 KV transmission systems. The remaining six cases evaluate options for replacing the Williams coal capacity with resources located at the Williams site and the Canadys site. The nine replacement cases to be evaluated in the 2022 TIA Analysis are:

Case 1

- Retire Wateree in 2028
- Replace Wateree with a 375 MW/1,500 MWh 4-hour Battery resource and a 150 MW Solar resource at the Wateree site

Case 2

- Retire Wateree in 2028
- Build a 351 MW set of aeroderivative simple cycle CTs at the Urquhart site by 12/31/2028

4 The retirement goal for the Wateree is December 31, 2028, and is referred in this IRP as 2028. Under other planning conventions, a December retirement date is reported as having occurred in the following year, i.e., by 2029 for Wateree. For consistency, this IRP references the actual year of retirement even if the retirement occurs on the last day of that year.

Case 3

- Retire Wateree in 2028
- Purchase off-system capacity and energy for at least two years
- Assume the off-system purchases remain in place until DESC constructs on-system generation resources to support future retirements and load growth

Cases 4-6

- Assume the ending conditions as a result of Case 1 concerning the Wateree Retirement

Cases 4A & 4B

- Retire Williams in 2030
- Case 4A: Build two heavy-duty frame simple cycle CTs totaling 523 MW and one set of Aero CTs totaling 234 MW at Canadys by 12/31/2030
- Case 4B: Build two heavy-duty frame simple cycle CTs totaling 523 MW at the Canadys and one set of Aero CTs totaling 234 MW at Williams by 12/31/2030

Cases 5A, 5B & 5C

- Retire Williams in 2030
- Case 5A: Build a set of simple cycle CTs totaling 757 MW at Canadys and 100 MW/400 MWh of battery ESS at the Williams by 12/31/2030
- Case 5B: Build a set of simple cycle CTs totaling 757 MW at Canadys and 200 MW/800 MWh Battery resource at Williams by 12/31/2030
- Case 5C: Build a set of simple cycle CTs totaling 757 MW at Canadys and 300 MW/1200 MWh of Battery at Williams by 12/31/2030

Case 6

- Retire Williams in 2030
- Build two heavy-duty frame simple cycle CTs totaling 523 MW and one or a set of Aero CTs totaling 234 MW at Canadys by 12/31/2030
- Assume the existing Williams Station generator is converted to a synchronous condenser

DESC expects to complete the 2022 TIA in the first quarter of 2023. In the interim, the DESC Transmission Planning Group has indicated that substantial transmission investment upgrades will be required to support the Wateree CT Build Plan including new Urquhart to Columbia-area 230 KV transmission lines and other upgrades. Estimated costs for these transmission projects in the amount of $180 million are included as cost inputs for this resource in the PLEXOS model.

The Potential Shared Resource to Replace Williams Capacity in Conjunction with Santee Cooper

On November 28, 2022, DESC and Santee Cooper signed a Memorandum of Understanding ("MOU") to evaluate a potential joint project to construct a Shared Resource of between 1,000 and 1,400 MW to replace existing coal capacity for both utilities and to evaluate two possible locations for the Shared Resource. One of the locations is proposed by Santee Cooper in the form of an option-to-purchase land in Hampton County ("Hampton"). The second is the Canadys site, located forty miles north of Charleston. The targeted completion date in this IRP for the Shared Resource is December 31, 2030, which corresponds to the planned retirement date for Williams.

By combining their needs, the two utilities may build a large, high efficiency and low-emissions, advanced-class CC unit as a near-term replacement for retiring coal units with economies of scale in construction and operating costs that would directly benefit electric utility customers. Alternatively, they might share in one unit at each of the two sites to minimize natural gas supply and other costs. The Shared Resource could also anchor the expansion of natural gas service to the Charleston and Beaufort areas and to the economically challenged areas in southern South Carolina where limited gas supply has been a bottleneck to economic development. A principal risk in pursuing a Shared Resource, or other combined cycle generation plant, will be the permitting and construction of pipeline capacity to serve the new plant site(s), as would be expected in the current environment for generation projects that depend on significant new supplies of natural gas in an underserved area.

In one configuration, the Shared Resource could be a 1,325 MW CC unit consisting of two large CTs matched with two heat recovery steam generators and a steam turbine-generator set to extract energy from their exhaust (a "2x1 CC" or a "2x1 CC 50% Shared"). The unit could be located at either Canadys or Hampton depending upon siting factors. From initial studies by the electric and gas transmission providers, upgrades on both systems for the Canadys site can be accomplished almost exclusively on existing right-of-way which is the most effective means to minimizing infrastructure costs and impacts. An alternative configuration that could be evaluated is two smaller 650 MW 1x1 CC units, one at each location.

The Canadys site is a strong contender for the site of the Shared Resource since it is located approximately ten miles from the St. George Switching Station, which is a principal hub for the recently upgraded electric transmission serving Charleston and other parts of the South Carolina Low Country. By locating the project at Canadys, the two utilities could take advantage of existing transmission assets, land, and other infrastructure at the site. Locating all or part of the Shared Resource at the Hampton site has potential benefits in reducing the cost and complexity of providing natural gas service to the project because of its proximity to the robust natural gas pipeline facilities in the greater Savannah, Georgia area.

In modeling the build plans presented here, DESC has included the Shared Resource as a generation option assuming that DESC receives 50% of the cost and output of a 2x1 CC beginning in 2031. In addition, to replace the capacity and voltage support Williams now provides to the Charleston area, DESC would envision pairing the Shared Resource with a 50 MW Aero CT located at the Williams site at Bushy Park. This would be the second such unit located at Bushy Park (the "Second Bushy Park Unit"). As discussed in Section VII, the Build Plan Analysis, the PLEXOS optimization modeling consistently selected the Shared Resource as the best resource to replace Williams across numerous build plans and multiple Market Scenarios and sensitivities, and it has emerged as a preferred option for replacing Williams capacity.

The 2023 Transmission Impact Analysis for the Shared Resource

On January 12, 2023, DESC's Resource Planning Department issued a third TIA request to the DESC Transmission Planning Group to assess the electric transmission costs and construction schedules for the construction of a Shared Resource (the "2023 TIA"). The 2023 TIA scenarios assume that DESC will retire Wateree by the end of 2028 and replace it initially with a 262 MW large Frame CT at the DESC Urquhart site ("Urquhart Frame CT") and a 100 MW of Battery resource at Wateree. From this starting point, DESC's Resource Planning Department asked the DESC Transmission Planning Group to study three cases each assuming that DESC retires Williams by 2030 and receives 50% of a Shared Resource, which could be:

- a 1,325 MW natural gas-fired CC 2x1 located at Canadys; or
- a 1,325 MW natural gas-fired CC 2x1 located at Hampton; or
- two 650 MW natural gas-fired CCs 1x1, one located at each site.

Each case also assumes that DESC constructs the Second Bushy Park Unit Aero CT to support service to the Charleston area.

The specific case descriptions for each case in the 2023 TIA are listed below. As specified in the 2023 TIA request, each resource combination could be augmented by utility-scale solar generation if deemed cost-effective and supported by the 2023 IRP.

Table 8: The 2023 TIA Cases

Case	Location	Primary Williams Replacement	Secondary Williams Replacement
Case 1	Canadys Site	1,361 MW 2X1 CC	50 MW CT Bushy Park
Wateree is retired on December 31, 2028 and replaced with a 100 MW/400 MWh 4-hour Battery resource at the Wateree site and a 262 MW large frame combustion turbine at the DESC Urquhart site ("Urquhart Frame CT"). This resource combination could be augmented by utility-scale solar generation if deemed cost-effective and supported by the IRP. Williams is retired by December 31, 2030, and a new Shared Resource is constructed at the former Canadys site and placed into commercial operation by January 1, 2031. DESC would receive 50% of the new 1,325 MW natural gas-fired 2X1 CC generator constructed at Canadys and receive that energy on the DESC transmission system. Also, a new 50 MW aeroderivative combustion turbine Aero CT would be constructed at the Williams site ("the Second Bushy Park Unit"). 50% of the Shared Resource's output would be delivered to Santee Cooper on their own transmission system. The 2X1 CC has a winter rating of 1,325 MW, a summer rating of 1,110 MW and a full load heat rate of 5,353 Btu/kWh. The Aero CT has a winter rating of 50 MW, a summer rating of 40 MW and a full load heat rate of 9,204 Btu/kWh.			
Case 2	Hampton Site	1,361 MW 2X1 CC	50 MW Aero Bushy Park
Wateree is retired on December 31, 2028, and replaced with a 100 MW Battery resource at the Wateree site and the Urquhart Frame CT. This resource combination could be augmented by utility-scale solar generation if deemed cost-effective and supported by the IRP. Williams is retired by December 31, 2030, and a new Shared Resource is constructed at the new Hampton site and placed into commercial operation by January 1, 2031. DESC would receive 50% of the new 1,325 MW natural gas-fired 2X1 CC generator and receive that energy on the DESC transmission system. Also, the addition of the Second Bushy Park Unit would be constructed by January 1, 2031. 50% of the Shared Resource's output would be delivered to Santee Cooper on their own transmission system. The resource ratings are the same as shown in Case 1.			
Case 3	Hampton & Canadys Sites	Two 650 MW 1X1 CCs	50 MW Aero Bushy Park
Wateree is retired on December 31, 2028, and replaced with a 100 MW Battery resource at the Wateree site and the Urquhart Frame CT. This resource combination could be augmented by utility-scale solar generation if deemed cost-effective and supported by the IRP. Williams is retired by December 31, 2030, and a new 1X1 CC generator is constructed at the former Canadys site. This new CC is placed into commercial operation by January 1, 2031. Also, the addition of the Second Bushy Park Unit would be constructed by January 1, 2031. Santee Cooper will build a new 1X1 CC generator and place it into commercial operation by January 1, 2031. The 1X1 CC has a winter rating of 650 MW, a summer rating of 555 MW and a full load heat rate of 5,375 Btu/kWh. The Aero CT has a winter rating of 50 MW, a summer rating of 40 MW and a full load heat rate of 9,204 Btu/kWh.			

The Plan and Schedule for Replacing Wateree Capacity

DESC is committed to replacing Wateree by the end of 2028 if it can be done while maintaining system reliability. Progress in procuring and siting replacement capacity will be a key driver in deciding whether to pursue ELG compliance for Wateree. DESC has until December 31, 2025, to either commit to retire Wateree or continue making the required ELG upgrades.

Regulatory approvals for the replacement resources and contracts for their procurement or construction must be in hand several months before the deadline to allow a timely decision to be made. Preserving options will require DESC to carry out a prudent level of pre-construction design and engineering for ELG compliance in the interim.

The sequence of events for Wateree replacement is anticipated to include the following:

- Acceptance of this 2023 IRP and Commission acceptance of an early Wateree retirement,
- Execution of an RFP for the suitable replacement resources
- Completion of the required transmission studies and execution of interconnection agreements, as applicable, for replacement resources identified through the RFP process,
- Negotiation and execution of binding contracts with successful bidders for generation assets and selection of contractors for transmission construction projects, as applicable,
- Successful completion of proceedings under the South Carolina Utility Facility Siting and Environmental Protection Act (the "Siting Act") for generation and transmission assets required to replace Wateree, as applicable,
- Procurement of key environmental permits, including any required wetlands and construction permits,
- Completion of planning and evaluation to ensure that construction of the required generation and transmission resources can be completed in time to support Wateree retirement by December 31, 2028, which is the date Wateree must be retired if ELG compliance under the VIP provisions of the rule is not pursued.

Many aspects of this timetable are subject to regulatory review and approval processes with significant schedule risks outside of DESC's direct control. The 2028 retirement date for Wateree assumes that regulatory, procurement and siting processes can be completed without undue delay. It is likely that the Company will need to undertake some of these key milestones in parallel, including beginning the process of soliciting potential replacement resources before the Commission has ruled on this IRP.

The Plan and Schedule for Replacing Williams Capacity

The Williams unit represents approximately 610 MW of capacity. It can support the capacity and energy needs of Charleston and the Low Country. A reliable and reasonably well-assured schedule for replacing that capacity is a prerequisite to retiring Williams. The modeling presented here consistently selected the Shared Resource as the appropriate resource to replace Williams.

The sequence of events for replacing Williams under the Shared Resource option is anticipated to include:

- Acceptance of this 2023 IRP and Commission acceptance of a preferred replacement plan for Williams,
- Conclusion of definitive joint development and ownership agreements with Santee Cooper after joint study and agreement on the siting and configuration of a Shared Resource or Resources,
- Completion of the required transmission studies and execution of interconnection agreements,
- Negotiation and execution of binding contracts with successful bidders for generation assets and selection of contractors for transmission construction projects,
- Commencement of an open season for new firm gas supplies to be delivered to the selected site and FERC permitting of the required gas supply facilities,
- Successful completion of proceedings under the Siting Act for generation and transmission assets required to replace Williams, and
- Procurement of air emissions and other key environmental permits, including any required wetlands and construction permits.

Many aspects of the Williams replacement project will be subject to regulatory, procurement and siting processes that are subject to significant schedule risks outside of DESC's direct control. The proposed 2030 retirement date for Williams assumes that those processes are not unduly delayed. At present, the greatest risk appears to be permitting and construction of required natural gas pipeline capacity by the appropriate FERC-regulated interstate pipeline companies, a process that is ultimately outside of DESC's direct control and the control of South Carolina regulators. However, because DESC is pursuing ELG compliance for Williams, there are currently no environmental deadlines requiring Williams to be taken out of service before replacement capacity is available.

RFP for Potential Williams and Wateree Capacity Replacement

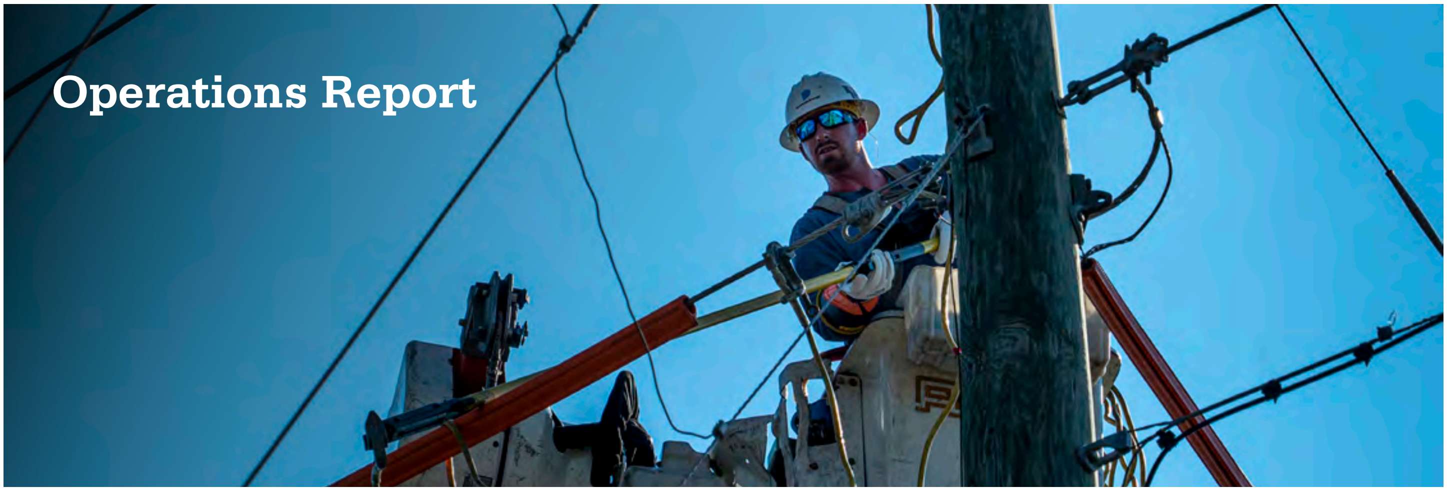
DESC currently believes that the most effective path to achieving the timely retirement of Wateree is for the Company to conduct a competitive procurement activity for the necessary replacement resources. Design of this competitive procurement should be informed by the needs identified in this 2023 IRP, specifically, the need for fully-dispatchable capacity resources which, as modeled under most reasonable planning assumptions, is approximately 400 MW. In accord with the Partial Settlement Agreement entered in Commission Docket 2021-93-E, the Company is conducting an all-source RFP in association with the replacement of the capacity and black start capabilities represented by four CT units and the natural gas steam unit at the Urquhart site. The Urquhart RFP process has included an extensive (and time-consuming) stakeholder process on the front end that has laid the groundwork for the Company to design and execute subsequent competitive procurements. DESC will use the Urquhart Replacements All Sources RFP process to guide the design of a competitive procurement for the Wateree Replacement.

Considering the strict ELG compliance deadlines and the expected time require to permit and construct reliable capacity resources to replace Wateree, such a competitive procurement process must begin expeditiously, and it may be necessary to begin certain stages of the process prior to the Commission's ruling on this IRP. These long-lead time transmission requirements will need to be accounted for in structuring the procurement process. The Wateree replacement plan will have to account for the timing and cost impacts of transmission upgrades, particularly for replacement generation resources not sited at and interconnecting to the existing Wateree site. To meet the schedule for replacing Wateree, and to ensure a workable procurement process, the Company may propose a procurement strategy for Wateree involving one or two alternative plans comprised of specific asset classes, such as intermittent renewables, dispatchable renewables, peaking thermal generation, baseload thermal generation, or others.

The Williams replacement plan involves significantly more complexity than Wateree and a procurement plan for it will depend on multiple factors including the progress of negotiations with Santee Cooper concerning the Shared Resource, new cost and schedule data from the 2023 TIA and more definitive information about natural gas supply costs and timetables from suppliers. Determining the scope and design of a procurement process for this resource will require this data.

Wateree Station; Richland County, SC

Dominion Energy



Operations Report

Dominion Energy Linemann; Charleston, SC

Safety

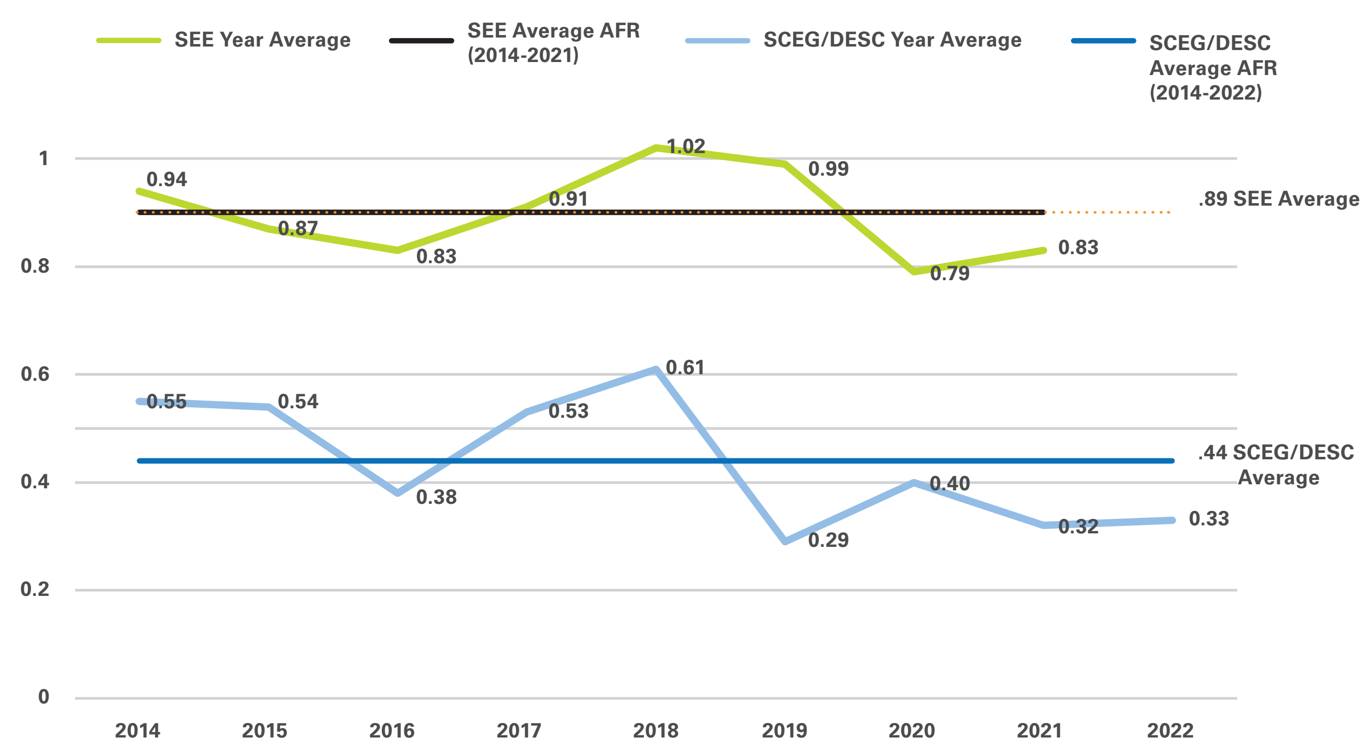
Safety, which is the Company's primary core value, is measured through the accident frequency rate ("AFR"). In 2022, the average AFR on DESC's electric system was approximately one quarter of the southeastern utility average:

In 2022, DESC's OSHA recordable incident rate was 0.33. Its days away from work rate ("DART") rate[5] was 0.19, and its DART severity rate[6] was 25.96. These are excellent results.

5 DART is the rate of incidents involving days away from work, restricted work activities or job transfers.

6 Dart severity rate is equal to (the number of work days lost + light duty days lost) x 200,000 / total hours worked.

Figure 9: Accident Frequency Rate (AFR)



Storms and Storm Response

DESC experienced three major storm events in 2022 that impacted its service territory. The first was Winter Storm Izzy, which occurred on January 16, 2022, at approximately 3:00 a.m. The storm impacted a total of 31,321 customers. The peak outage occurred at 9:54 a.m. on January 16, 2022, with 17,099 customers without power. Restoration was largely complete within 52 hours. The second major storm event to affect DESC's service territory in 2022 was Hurricane Ian, which occurred on September 30, 2022, at approximately 5:00 a.m. The hurricane impacted a total of 206,176 customers. The peak outage occurred at 3:44 p.m. on September 30, 2022, with 108,930 customers without power. Restoration was largely complete within 56 hours.

The third major storm event to affect DESC's service territory in 2022 was Winter Storm Elliott which occurred on December 23, 2022, at approximately 3:30 a.m. with gale force winds. The wind aspects of the storm impacted a total of 53,617 customers. The peak outage occurred at 7:43 a.m. on December 23, 2022, with 26,806 customers without power. Restoration was largely complete within 18 hours.

Table 9: Major Storm Outages and Restoration 2014-2022

Event	Dates	Customers Affected	Days to Restore Service
2014 Winter Storm Pax	2/12/14-2/19/14	151,700	7
Hurricane Matthew	10/7/16-10/16/16	313,300	9
Hurricane Irma	9/11/17-9/14/17	173,300	3
Hurricane Florence	9/14/2018	7,500	1
Hurricane Michael	10/11/18-10/12/18	68,800	2
Hurricane Dorian	9/4/19-9/8/19	186,400	4
April 2020 Tornados	4/13/2020	65,800	1
Tropical Storm Elsa	7/7/21-7/8/21	30,179	1
2022 Winter Storm Izzy	1/16/22-1/18/22	17,099	2
Hurricane Ian	9/30/22-10/2/22	108,930	3
Winter Storm Elliott	12/23/2022	26,806	1

Cold and snow from Winter Storm Elliott caused a reported 102 deaths nationwide and resulted in many utility systems having to implement rolling service interruptions to their native customers. The low temperature in Columbia on the morning of December 24, 2022, was 13 degrees Fahrenheit, which is within one degree of the lowest temperature on record for that day. Additionally, there were significant winds during this winter storm event; sustained wind speeds of approximately 40 miles per hour with gusts up to 51 miles per hour were recorded on December 23, 2022. While wind speeds peaked on the 23rd, they remained high throughout the early morning hours of the 24th resulting in a wind chill well below 0 degrees Fahrenheit. This increased customer demands above what the temperature alone would have indicated.

Like its neighboring utilities, DESC faced a situation of exceptionally high customer demand during the event. Off-system generation capacity and energy were largely unavailable for bilateral market purchase from neighboring utilities, some of whom were themselves engaged in emergency measures, including implementing rolling service interruptions. On the morning of December 24, DESC was required to curtail firm off-system sales, reduce distribution voltage, and impose a roughly fifteen-minute curtailment of firm load. These measures followed issues at some of its generating facilities, including issues not directly related to the extreme cold weather events.

At the time of publication of this IRP, the Company is reviewing the events of this winter storm and is working with regulatory entities, including the North American Electric Reliability Corporation ("NERC"), to capture lessons learned to enhance the Company and the wider utility industry's preparedness for future such extreme weather events. The Company will be closely monitoring investigations into the failure of some natural gas pipeline companies to meet their firm transportation service guarantees during the event.

DESC's Current Generation

DESC currently operates 63 hydro and fossil generating facilities with a dependable net winter generating capacity of approximately 5,247 MW and a single unit nuclear station with a net dependable winter generating capacity of approximately 662 MW (DESC's two-thirds share). These resources are supplemented by approximately 973 MW of solar generation purchased from third parties under long-term power purchase agreements ("PPA") and an additional approximately 142 MW of customer-scale solar. DESC also benefits from a 20 MW allocation of power from the Southeastern Power Administration ("SEPA"), which operates hydro resources on the upper Savannah River.

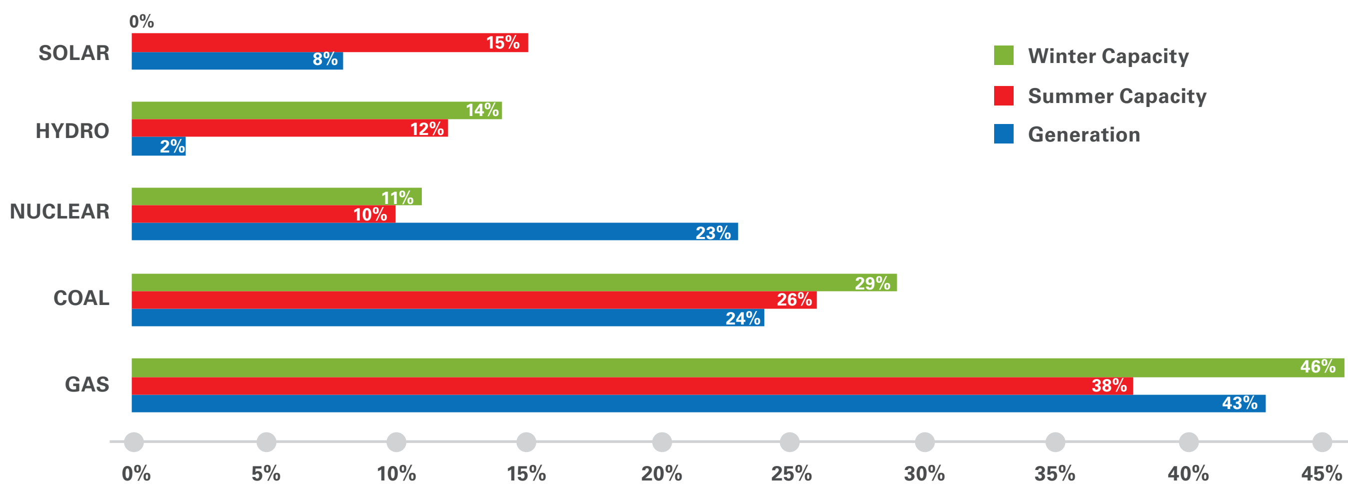
Table 10: DESC's Existing Supply-Side Resources

	In-Service Date	Probable/Planned Retirement [1, 5] Date	Summer 2023 (MW)	Winter 2023 (MW)
Steam				
Wateree – Eastover, SC	1970	2045	684	684
Williams – Goose Creek, SC [2]	1973	2048	605	610
Cope – Cope, SC [4]	1996	2071	415	415
Total Coal-Fired Steam Capacity			**1704**	**1709**
Gas-Fired Steam:				
McMeekin – Irmo, SC	1958	2038	250	250
Urquhart – Beech Island, SC	1954	2027 [5]	95	96
Total Gas-Fired Steam Capacity			**345**	**346**
Nuclear				
V. C. Summer – Parr, SC	1982	2062	650	662
CT/CC[4]				
Urquhart 1, 2, 3 – Beech Island, SC	1969	2027 [5]	39	48
Urquhart 4 – Beech Island, SC	1999	2027 [5]	48	49
Coit – Columbia, SC	1969	2024 [5]	26	36
Parr CTs 1, 2, 3, 4 – Parr, SC	1970	2023 [5]	47	56
Hagood 4 – Charleston, SC	1991	2041	88	95
Hagood 5 – Charleston, SC	2010	2060	18	21
Hagood 6 – Charleston, SC	2010	2060	20	21
Urquhart Combined Cycle – Beech Island, SC	2002	2029 (Steam) /2052 (CTs)	458	484
Jasper Combined Cycle – Jasper, SC	2004	2044	903	961
CEC Combined Cycle – Gaston, SC	2004	2054	519	621
Total Natural Gas CT/CC Capacity			**2166**	**2392**
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 – Jenkinsville, SC	1978	2128	576	576
Total Hydro Capacity			**792**	**800**
Other				
Southeastern Power Administration (SEPA)			20	20
Total Firm Capacity:			**5677**	**5929**
Solar[3]				
PPA DER Program	2015-2019	2039	64	0
PPA Non-DER Program	2017-2020	2040	909	0

1. Probable retirement dates are based on the 2018 Depreciation Study. See Note 5 below regarding certain planned retirements.
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. GENCO's sells to DESC the total capacity and the entire output of Williams Station under a Unit Power Sales Agreement approved by the Federal Energy Regulatory Commission.
3. Solar MW are nameplate values and do not represent the contribution to peak demand.
4. Cope Station operates with coal as its primary fuel source but is also capable of operation on natural gas. All simple cycle CTs and combined cycle CTs can operate on either natural gas or ultra low sulfur fuel oil.
5. Urquhart Steam Unit 3 and CT Units #1-4 are anticipated to retire no later than December 31, 2027 as specified under the Urquhart Replacements All Sources-Request for Proposals for their replacements. Parr CT 1 in mothball status; existing Parr CT Units 1, 2, 3, and 4 are planned to retire effective March 31, 2023 as part of replacement plan. Coit CT Units are planned to retire in second-half of 2024.

In 2022, the five major classes of generation contributed to DESC's safe, reliable and efficient electric service to customers in the following percentages:

Figure 10: DESC'S 2022 Resource Contribution to Energy Supply



Generation Operating Report Update

Solar and Other Renewable Generation

Since 2019, DESC has connected eight new solar farms and increased its installed solar capacity by approximately 402 MW.

Table 11: DESC Utility Scale Solar Resources added in 2020, 2021, and 2022

PURPA PPAs	Nameplate Capacity (MW-AC)	Actual COD
Lily Solar LLC (Allendale County)	70.00	2/28/2020
Huntley Solar, LLC (Orangeburg County)	75.00	4/30/2020
TWE Bowman Solar Project, LLC (Orangeburg County)	74.97	5/15/2020
Midlands Solar LLC (Calhoun County)	72.10	8/7/2020
Denmark Solar, LLC (Bamberg County)	6.00	12/2/2020
Blackville Solar Farm, LLC (Barnwell County)	7.20	12/7/2020
Yemassee Solar, LLC (Hampton County)	10.00	1/8/2021
Trask East Solar, LLC (Beaufort County)	12.00	3/17/2021
Beulah Solar, LLC (Saluda County)	74.97	5/9/2022

In addition, a third-party developer is building the first utility-scale battery storage project on the DESC system under a PPA with DESC for 73.6 MW of Solar and a 18 MW/72 MWh Battery designed for a four-hour energy supply duration which will be directly dispatched by DESC system control. All build plans modeled in this IRP assume that this asset will go into commercial operation in the first quarter of 2023.

DESC has signed a contract for a paired 62 MW solar generating facility and 15.5 MW/62 MWh energy storage facility to enter commercial operation on December 1, 2023. After modeling the 2023 IRP was complete, DESC signed a contract for a paired 66 MW Solar resource and 66 MW/198 MWh Battery to enter commercial operation in 2024. This facility was not included in the modeling presented here because the contract was executed after modeling was complete. In total, DESC has contracts for solar generation totaling 1,174.44 MW.

In 2022, solar generation represented 973 MW of installed capacity and produced approximately 8% of DESC's energy needs as non-carbon emitting energy.

Nuclear Operating Report

Since January 1984, DESC has operated the V.C. Summer Nuclear Station safely and efficiently. DESC owns two-thirds of the Summer Station's capacity. Santee Cooper owns the balance.

In 2022, V.C. Summer Station produced approximately 5,727 GWh of non-carbon emitting base-load energy for DESC, representing 23% of DESC's energy needs. Energy produced by V.C. Summer Station during 2022 displaced approximately 8.68 million tons of CO_2 that would have been emitted if replaced by fossil resources. The 2022 gross (undivided) generation output from V.C. Summer Station was approximately 8,591 GWh.

In 2022, V.C. Summer Station met or exceeded all Nuclear Regulatory Commission safety and environmental requirements and has received favorable ratings from the Institute of Nuclear Power Operations ("INPO") operational standards assessment. V.C. Summer Station's INPO rating was reaffirmed as "exemplary" on June 15, 2022.

In 2022, V.C. Summer Station's net capacity factor, based on reasonable excludable nuclear system reductions, computed under the provisions of S.C. Code Ann. § 58-27-865, was 102.17%, indicating a high degree of reliability. The 2022 Forced Outage Factor for V.C. Summer Unit 1 was zero. Nuclear generation provided 650 MW of summer capacity and 662 MW of winter capacity to support service to DESC customers (based on DESC's two-thirds share in the capacity of the station).

DESC's notice of intent to file a Subsequent License Renewal ("SLR") application with the Nuclear Regulatory Commission to allow DESC to operate until 2062 is pending. The current license expires in 2042.

Combined Cycle Gas Plants Operating Report

In 2022, DESC's combined cycle units produced approximately 39% of DESC's energy needs. The combined cycle units provide 1,880 MW of capacity in the summer and 2,066 MW of capacity in the winter; these ratings are inclusive of the completed AGP upgrades on the three Jasper Station CT units and Columbia Energy Center Unit 1. DESC's combined cycle units' Forced Outage Factor for 2022 was only 0.91%.

Internal Combustion Turbines Operating Report

In 2022, simple cycle CT units produced only approximately 0.22% of DESC's energy needs, reflecting their outdated condition and limited use as peaking generation sources. As of December 31, 2022, DESC's internal CT units were rated to provide 286 MW of capacity in the summer and 326 MW in winter.

DESC officially retired the Hardeeville CT in Jasper County on March 31, 2022 and the Bushy Park CT Units 'A' and 'B' in Berkeley County on September 30, 2022. DESC plans to retire the Parr CT units on March 31, 2023. The Company plans to retire the Coit CT units after the replacement CT unit at Bushy Park enters commercial operation; Coit is planned to retire in the second half of 2024. The replacement CT units at Bushy Park and Parr are planned to enter commercial operation in the second quarters of 2024 and 2025, respectively.

Fossil-Steam Units Operating Report

In 2022, DESC's fossil steam units provided approximately 25% of DESC's energy needs and provided 2,049 MW of summer capacity and 2,055 MW of winter capacity. The 2022 Forced Outage Factor for DESC's coal-fired steam units was 13.87% and 3.81% for its gas-fired steam units. Wateree Unit 2 returned to service in Spring 2022, this Forced Outage Factor reflects the unavailability of this unit for the first four months of 2022.

Attached as **Appendix L** is the Generator Level Performance Data.

Hydroelectric-Power Operating Report

In 2022, DESC's hydroelectric plants (including Fairfield Pumped Storage Units) provided approximately 3% of DESC's energy needs.

Fairfield Pumped Storage. In 2022, Fairfield Pumped Storage returned to the system over 433 GWh of stored energy and provided 576 MW of capacity in both summer and winter. In 2022, the Fairfield Pumped Storage Forced Outage Factor was 0.07%. The remaining hydro units provided 216 MW of capacity in the summer and 224 MW of capacity in the winter.

Saluda Hydro. In July of 2009, DESC entered into a Comprehensive Settlement Agreement with the parties to its FERC proceeding to relicense the Saluda Hydro Project (No. 516). DESC is awaiting FERC's decision on the application. The relicensing of the Stevens Creek Project (No. 2535) is under active review by FERC staff.

The Company is in the process of planning and executing a series of major upgrades on the Saluda Hydro units to ensure their continued availability and reliable service. These upgrades include replacement of the penstock headgate assemblies, rewinds and upgrades of the generators, replacement of the turbine runners, and replacement of generator excitation and control systems. The generator step-up transformer units have already been replaced on all five units and are sized to accommodate future planned generator upgrades. DESC completed rewinding the Saluda Unit 1 generator, which has been in service for over 90 years, at the end of 2022.

The turbine runner replacements and generator upgrades were agreed to in the Comprehensive Settlement Agreement reached through the Saluda Hydro relicensing process, but these upgrades have been deferred for over a decade pending issuance of the final project license by FERC. The Company has elected to begin proceeding with these upgrades due to the reliability and safety risks from continuing to defer this work and for the environmental benefits they are expected to provide to the Lower Saluda River through enhanced dissolved oxygen. This work should increase the capacity from the Saluda Hydro in both summer and winter seasons. The anticipated capacity contribution of these upgrades is expected to be modeled in the 2024 IRP Update once data establishing the increase is available.

Parr Hydro. As part of the renewed license received in late 2020 for the Parr Hydro Project, the Company plans to upgrade all six of the generating units at the Parr Shoals Hydro facility over the next ten years. Completing these upgrades will enhance the reliability and availability of these units, which have been in service for over a century. Replacing or rewinding the generators and replacing the turbine runners are expected to increase the generating capacity of this facility but will not affect the capacity available to the system given the intermittent nature of run of river hydro resources.

Environmental and ELG Compliance

Dominion Energy is subject to multiple federal, state, and local laws and regulations designed to protect human health and the environment. Pending developments related to carbon regulations at the federal level are expected in the first half of 2023.

Federal Carbon Regulations

In December 2018, the EPA proposed revised New Source Performance Standards ("NSPS") for GHG Emissions from New, Modified, and Reconstructed Stationary Sources under Section 111(b) of the Clean Air Act ("CAA"). This action was never finalized. EPA is currently reevaluating the NSPS for new and modified sources including Best System of Emission Reduction ("BSER"). A draft rule is expected in spring 2023. According to EPA's Unified Agenda, the expected timeframe on a final rule is the second quarter of 2024.

On January 19, 2021, the D.C. Circuit Court vacated the Affordable Clean Energy ("ACE") Rule, which was the replacement for the Clean Power Plan. The EPA is currently drafting a new set of guidelines to direct how states must regulate GHG emissions from existing fossil fuel-fired generating units within their borders. According to current guidance, the EPA intends to issue a proposed rule in the second quarter of 2023, with a final rule by the end of 2024.

The ACE Rule was adopted under Section 111(d) of the CAA. On June 30, 2022, the U.S. Supreme Court issued its decision in *West Virginia v. EPA* that limits the scope of the EPA's authority to control GHG emissions from existing power plants under Section 111(d). Absent action from Congress, this decision will impact how GHG emissions can be regulated at existing power plants by the EPA in

Parr Hydro Station; Farifield County, SC future rulemakings. The EPA retains the authority to regulate emissions at the source by proposing mechanisms such as heat rate improvements, but it no longer holds the authority to regulate GHG emissions from power production by requiring a shift in electricity production from fossil fuel-fired power generation sources to cleaner renewable energy sources.

In August 2016, the EPA issued a draft rule proposing to reaffirm that a source's obligation to obtain a prevention of significant deterioration permit for GHGs is triggered only if such permitting requirements are first triggered by non-GHG, or conventional, pollutants that are regulated by the New Source Review program and exceed a significant emissions rate of 75,000 tons per year of CO_2 equivalent emissions. There is no expected timeframe for the final rule.

Particulate Emissions Standards

On January 6, 2023, EPA released a pre-publication version of a proposed rule resulting from its reconsideration of the primary (health-based) National Ambient Air Quality Standards for Particulate Matter ("PM NAAQS"). EPA is proposing to lower the primary annual PM2.5 NAAQS from 12.0 ug/m3 to a level that would fall between 9.0 and 10.0 ug/m3, while soliciting comment on an alternative annual PM2.5 standard within the range of 8.0 to 11.0 ug/m3. EPA is proposing to retain the other PM NAAQs at their current levels, including the secondary 24-hour PM2.5 NAAQS previously under discussion. According to EPA's Unified Agenda, a final rule is expected in third quarter of 2023.

On December 31, 2020, EPA published a final decision retaining the 2015 Ozone National Ambient Air Quality Standards (NAAQs) of 70 parts per billion (ppb). As directed by Executive Order 13990, "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis," signed by President Biden on January 20, 2021, EPA undertook a review of the December 2020 decision. Based on that review, EPA is undertaking a reconsideration of the December decision that retained the 2015 NAAQs. As part of this reconsideration, EPA is developing a policy assessment for the reconsideration to consider all the policy-relevant information developed throughout the 2020 review, and to engage with the Clean Air Scientific Advisory Committee (CASAC) Ozone Review Panel. The Panel is currently reconsidering the decision to retain the 2015 NAAQs for ozone at 70 ppb for both the primary and secondary limits. According to EPA's Unified Agenda, EPA aims to come out with a draft ruling second quarter of 2023 and a final rule by the end of 2023.

Effluent Limitation Guidelines

On January 20, 2021, President Biden signed Executive Order 13990 directing federal agencies to review rules issued in the prior four years that are, or may be, inconsistent with the President's stated environmental policy. On July 26, 2021, the EPA announced that it is initiating a rulemaking process to determine whether to adopt more stringent limitations than those in the 2020 ELG rules for steam electric generating units. The agency intends to issue a proposed rule for public comment in early 2023. The current 2020 rules remain in effect until the EPA concludes this new rulemaking activity. The Company is closely monitoring developments in the ELG rulemaking process due to the potential impacts on the Wateree and Williams coal units and existing compliance strategy based around the 2020 rule.

DESC has begun definitive engineering and procurement activities to support construction of the facilities necessary for Williams to comply with the current ELG rule standards by December 31, 2025. The Coal Plants Retirement Study filed in May 2022 determined that for planning purposes, it was unreasonable to assume that Williams could be retired before the end of 2030. At Wateree, the Company is on track to achieve compliance with the bottom ash transport water requirements of the ELG rule by December 31, 2024, as required under the Company's Applicability Study filed with the South Carolina Department of Health and Environmental Control. The Company is continuing to conduct early-phase engineering and development efforts for Wateree to comply with the flue gas desulphurization ("FGD") wastewater requirements of the ELG rule under the regulation's VIP. Participation in this program provides Wateree with an automatic compliance deadline of December 31, 2028, for FGD wastewater. The Company retains the option to transfer Wateree to an ELG compliance pathway that would require the facility to retire by December 31, 2028 and avoid the need for installation of compliance technologies. Under the ELG rule, the Company must make this election no later than December 31, 2025.

Regulation 316(b)

In October 2014, the final regulations under Section 316(b) of the Clean Water Act ("CWA") that govern existing facilities and new units at existing facilities that employ a cooling water intake structure and that have flow levels exceeding a minimum threshold became effective. These rules concern aquatic species, their eggs and larvae that may become impinged or entrained by intake structures and flows. The rule establishes a national standard for impingement based on seven compliance options, but it forgoes the creation of a single technology standard for entrainment. Instead, the EPA has delegated entrainment technology decisions to state regulators. State regulators are to make case-by-case entrainment technology determinations after an examination of five mandatory facility-specific factors, including a social cost-benefit test, and six optional facility-specific factors. The rule governs all electric generating stations with water withdrawals above two million gallons per day ("MGD,") with a heightened entrainment analysis for those facilities over 125 MGD. Williams, Wateree, Cope, and Urquhart are subject to the final regulations. DESC anticipates that it may have to install impingement control technologies at some of these stations that have once-through cooling systems. DESC is also working with the EPA and state regulatory agencies to assess the applicability of Section 316(b) to five hydroelectric facilities. DESC is currently evaluating the need or potential for entrainment controls under the final rule, as these decisions will be made on a case-by-case basis after a thorough review of detailed biological, technological, and cost-benefit studies. DESC is conducting studies and implementing plans as required by the rule to determine appropriate intake structure modifications at certain facilities to ensure compliance with this rule.

Environmental Justice

Federal agencies must consider environmental justice in their activities under the National Environmental Policy Act (NEPA). Executive Order 12898, "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations," directs each Federal Agency to "make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations," including tribal populations.

By Act 171 of 2007, the General Assembly of the State of South Carolina formed the S.C. Environmental Justice Advisory Committee to study and consider existing practices at state agencies related to environmental justice in economic development and revitalization projects and to make recommendations related to environmental justice issues for these projects. The S.C. Environmental Justice Advisory Committee defines environmental justice as "the fair treatment and meaningful involvement of people of all races, cultures and income with respect to the development, adoption, implementation and enforcement of environmental laws, regulations and policies in working towards increasing prosperity of all South Carolinians." This environmental justice initiative is managed within the Office of Environmental Affairs of the South Carolina Department of Health and Environmental Control, and the promotion of environmental justice is a priority for the Director of the Office of Environmental Affairs.

The clean energy transition requires substantial development of new infrastructure, which has the potential to affect local communities. Dominion Energy and the Company are committed to ensuring that those communities have a meaningful voice in planning and development processes. In cases where a community meets the definition of an "Environmental Justice community," the Company's process requires that it consider proactive and intentional communication and engagement, to ensure that concerns are appropriately responded to and addressed, and that the Company works to mitigate any undue project impacts. The Company's aim is to ensure that all communities affected by its infrastructure projects have a voice in their development and that the Company avoids disproportionately affecting or benefiting any one group as it increasingly builds infrastructure, such as underground distribution lines, middle-mile broadband, and other resources for which community demand outstrips short-term availability. The Company also wants all communities to have the chance to benefit from the economic opportunities presented by clean energy investments.

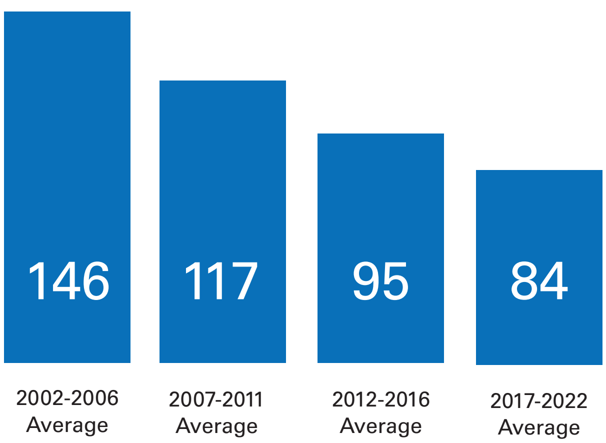
The Company believes that environmental justice is best evaluated on a case-by-case basis, informed by the location of the project in question and project-specific characteristics. The Company notes that increasingly environmental justice will include allocating resources that communities desire, such as underground distribution lines to promote greater reliability, access to EV charging infrastructure, and the Company's middle-mile broadband program. The Company has established an environmental justice review process for evaluating its specific projects and programs that implicate environmental justice consistent with relevant laws and regulations, as well as previously developed EPA guidance and currently accepted best practices. By contrast, attempting to evaluate generic projects in the abstract during integrated resource planning—when resources are evaluated by capacity and type in general, without any specific project facts or location—provides limited value in the Company's view.

Distribution and Transmission Operating Report Update

Outages and Reliability

The industry benchmark for measuring operational effectiveness in transmission and distribution operations is the number of minutes on average a customer is without power, which is the System Average Interruption Duration Index, or SAIDI score. A lower SAIDI score indicates more reliable transmission and distribution systems. DESC's 2022 SAIDI was 78.40 minutes which is an historically low level. DESC reduced an average customer's outage minutes by 0.49 minutes compared to 2021. As reported by the State Energy Office, DESC provided its customers a level of reliability in 2019 that was 49% better than the other regional investor-owned utilities evaluated by that office.[7]

Figure 11: System Average Disruption Index



AMI Roll Out

During 2022, DESC installed 161,462 AMI electric meters for a total during 2022 of 544,525 AMI electric meters installed.

As of the close of 2022, DESC's primary meter vendor, Itron, is still experiencing delays under the force majeure event it declared in July 2021 due to supply chain disruptions.

Although DESC received some meter shipments in 2022, Itron has not been able to fulfill DESC's forecasted meter deliveries for 2022. Itron has not provided a firm timeline on when all orders will be met, however, DESC is notified on a quarterly basis on any expected shipments. Due to this setback, DESC is continuing a reduced meter deployment schedule until firm commitments are made on expected meter shipments. Currently, DESC is targeting approximately 1900 electric meter installations per week with hopes that the install rate can increase in Q1 2023. The meter shortage has extended the scheduled completion date for the AMI rollout to no sooner than January 2024. DESC is continuing to work closely with Itron to clarify delivery expectations and will increase the meter deployment rate as soon as possible.

Transmission Plans and Planning

DESCs constantly analyzes its transmission system to ensure the continued safe, reliable, and economical delivery of power to customers using the Reliability Standards for Transmission Planning (the "Reliability Standards") issued by the North American Electric Reliability Corporation ("NERC") in its capacity as the designated Electric Reliability Organization ("ERO") under the Federal Energy Policy Act of 2005. As ERO, NERC may recommend that FERC impose penalties of over $1.3 million per occurrence for any violation of mandatory planning or other reliability standards. FERC may also preempt action by state entities that compromises the reliability of the electrical system under its jurisdiction.

DESC's NERC authorized planning criteria[8] ensure that:

[T]he 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*

7 http://energy.sc.gov/node/3065. This is the most current year for which data was reported at the time of writing.

8 A copy of the NERC Reliability Standards is available at the NERC website www.nerc.com.

To assess transmission reliability, DESC applies reliability and protection criteria on an N+1 basis, meaning that the system must operate reliably if after grid operators have stabilized the system in response to any single event, a second event occurs.

Using these criteria, DESC evaluates each new generation interconnection agreement and each new or upgraded transmission asset over a ten-year planning horizon. DESC continuously updates its models to reflect planned additions and modifications to the transmission and generation system, changes in power flows from adjacent systems, general levels of forecasted demand growth and specific changes in loads from major new residential developments and commercial, industrial, or wholesale customers.

Regional Transmission Planning

DESC participates in assessment studies with neighboring transmission planners throughout the Southeast to assess the reliability of the Southeastern integrated transmission grid over the long-term horizon of up to 10 years and for upcoming summer and winter system conditions. In 2022, the Company participated in multiple near- and longer-term reliability studies under the aegis of the Southeastern Reliability Council ("SERC"), the Carolinas Transmission Coordination Arrangement.

Interconnection-Wide Planning

DESC is an active member of the Eastern Interconnection Planning Collaborative ("EIPC"), which seeks to identify projects that will increase reliability, reduce costs, and limit further reliance on renewable and intermittent resources by expanding the ability to transmit power between regions. EIPC was initiated by a coalition of NERC regional Planning Authorities that represent approximately 95% of the Eastern Interconnection from the maritime provinces of Canada through Florida and the mid-West.

EIPC builds upon the regional expansion plans developed each year by regional stakeholders to provide an interconnection-wide review of the existing regional plans. It assesses transmission options associated with the various policy options to maximize the potential of renewable and non-emitting resources.

Transmission Projects

During 2022, DESC invested a total of $134 million in capital additions and improvements to its transmission system and completed 15 major transmission projects representing $34 million of that amount. The following transmission projects were begun or completed in 2022. In all cases, rebuilds of current lines, the wooden structures were replaced with galvanized steel structures meeting all modern electric codes and providing increased reliability and resiliency.

Cainhoy-Mt. Pleasant 115kV Lines #1 & #2, Rebuild the Horlbeck Creek Crossing (Completed and in service January 2022). DESC rebuilt over three miles of the existing Cainhoy–Mt. Pleasant 115kV Lines #1 and #2, including the Horlbeck Creek. This project addressed end-of-life and reliability issues on these lines.

Bluffton-Santee 115kV Tie New Transmission Line (Completed and in service December 2022). This new 1.5-mile 115kV tie line from DESC's Bluffton Substation to South Carolina Public Service Authority's ("SCPSA") Bluffton Substation is required to reduce outage durations for planned outages and emergency situations for DESC's Bluffton, Hardeeville, and Pritchardville Substations, as well as, provide a secondary source of power to those substations.

Lake Murray-Harbison 115kV Rebuild and Saluda Hydro-Denny Terrace 115kV Transmission Line Construction (Completed and in service December 2022). DESC re-terminated the Saluda Hydro–Harbison 115kV line to Lake Murray Substation in preparation for the single-pole double-circuit rebuild of the Lake Murray–Harbison 115kV line, which will add an additional Saluda Hydro–Denny Terrace 115kV line. This project is needed to support system growth in the Irmo, Harbison, Piney Woods Road, and Kingswood areas, which require additional 115kV capacity and an additional transmission path to increase reliability.

Ward-Stevens Creek 115kV, Rebuild the 24+ mile Ward to Briggs Road Line Section (Completed and in service May 2022). The rebuild of this line was needed to replace aging infrastructure and is one of several projects needed to provide a tie line between the Aiken area and Columbia for power flows.

Lake Murray-Gilbert 115kV, Rebuild the 5-mile Lexington Westside to Gilbert Line Section (Completed and in service January 2022). The rebuild of this line was needed to replace aging infrastructure and is one of several projects needed to provide a tie line between the Aiken area and Columbia for increased transmission system flows.

Lake Murray-Gilbert 115kV, Rebuild the 4-mile Lexington Junction to Lexington Westside Line Section (Completed and in service August 2022). The rebuild of this line was needed to replace aging infrastructure and is one of several projects needed to provide a tie line between the Aiken area and Columbia for increased transmission system flows.

Denny Terrace-Craft Farrow & Denny Terrace-Dentsville Line #1 115kV, Rebuild 5+ mile Denny Terrace to Rader Line Section (Completed and in service August 2022). The rebuild of this line was needed to replace aging infrastructure.

Blackville West-Wagener 46kV, Rebuild the 23+ mile Line Section including North to LNG to Perry to Salley to Springfield (Completed and in service July 2022). The rebuild of this line was needed to replace aging infrastructure.

Calhoun County-St Matthews 46kV Rebuild (Completed and in service December 2022). The rebuild of this line was needed to replace aging infrastructure.

Park Street 115-13.8kV Substation and Williams Street-Park Street 115kV Construction (Completed and in service May 2022). These projects included rebuilding the Park Street Substation in Columbia and building a new 115kV line between Williams Street and Park Street Substations and are required to support load growth in the downtown Columbia area.

Cross County 115-23kV Substation and 115kV Transmission Line Tap Construction (Completed and in service June 2022). This project's scope was to build a new substation in the North Charleston area, which was needed due to increased load in the area.

May River 115-23kV Substation and 115kV Transmission Line Tap Construction (Completed and in service December 2022). This project's scope was to build the new substation in the Bluffton area, which was needed due to increased load in the area.

Smoaks 115-23kV Substation and 115kV Transmission Line Tap Construction (Completed and in service July 2022). The goal of this project was to build the new substation in the Smoaks area, between Canadys and Fairfax, which was needed due to increased load in the area and allowed for the retirement of an existing 46-12kV substation.

Queensboro – Johns Island & Church Creek – Queensboro Transmission Lines (In service expected December 2023). The rebuild of these two lines was needed to replace aging infrastructure which traverse difficult to access wetland and marsh environments.

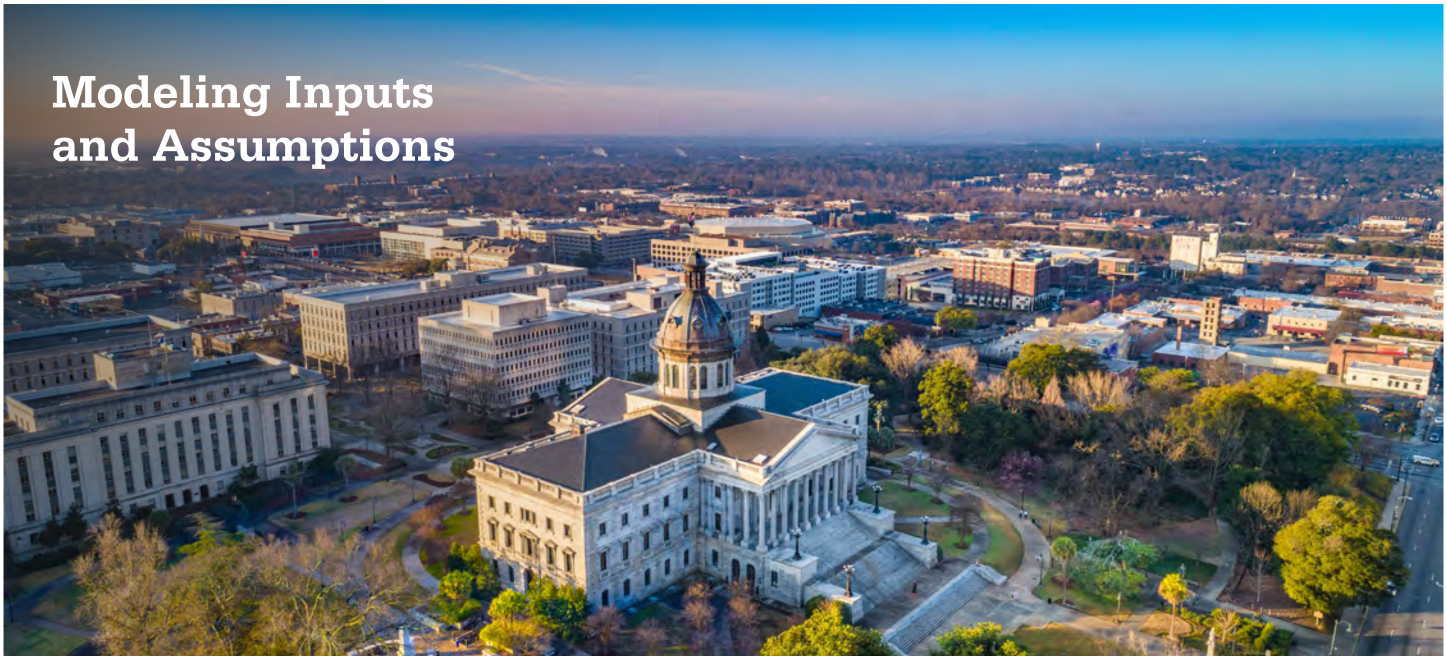
Whiskey Road 115kV-12kV Substation and 115kV Transmission Line Construction (In service expected August 2023). The goal of this project is to build a new substation and associated transmission line in the Aiken area, which is needed to provide decreased loading for other existing substations, as well as to support distribution reliability in contingency situations.

Jasper – Okatie 230kV #2, Okatie – Riverport 230kV, and other Associated Projects (In service expected December 2024). The Riverport series of projects includes constructing two new 230kV lines, totaling approximately 17 miles in length to support the growing load in the greater Hardeeville and Jasper County areas and growing power flow between utilities.

Ongoing and Planned Transmission Projects

As a result of its annual and ongoing transmission reliability assessments, DESC has identified twenty-four major electrical transmission projects that are either ongoing or planned within the next five years. A listing of these major transmission projects is found in **Appendix D**.

Modeling Inputs and Assumptions



State Capitol Building; Columbia, South Carolina

Load Growth Forecast

The reference load forecast used in this 2023 IRP incorporates the Company's 2023 annual Base Load Forecast of customers' future energy and demand needs across the planning horizon and reflects the updated forecast for expansion in demand for electric vehicles, as discussed in the section concerning Electric Vehicle Adoption, and base DSM assumptions. It anticipates a significant one-time reduction in peak electric demand in 2024, relative to 2023, due to the expected termination of the power supply agreement with the City of Orangeburg, South Carolina. Summer and winter peak demands then continue to grow at a relatively steady rate beginning in 2024. The compound average rate of growth in summer and winter demand over the planning horizon are 0.9% and 0.6% respectively.

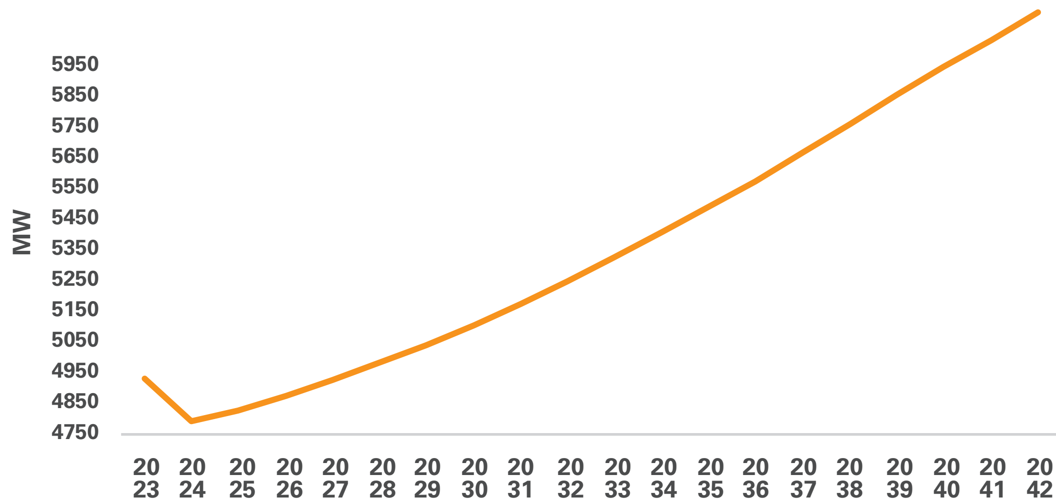
These peak demands reflect normal weather only and do not show the impact of the utility-scale solar contribution to meeting summer or winter peak or required reserve margins all of which are adjustments made later in the generation planning process. These growth rates do not include the potential demand reductions due to new DR programs, which are treated as generation resources in the PLEXOS model.

Table 12: 2023 Annual Energy and Peak Forecast

Year	Sales GWh	Peak Forecast	
		Summer MW	Winter MW
2023	23,941	4,921	4,902
2024	23,247	4,791	4,775
2025	23,361	4,825	4,813
2026	23,572	4,867	4,851
2027	23,789	4,915	4,891
2028	24,018	4,966	4,931
2029	24,288	5,021	4,971
2030	24,584	5,079	5,009
2031	24,890	5,142	5,048
2032	25,249	5,210	5,091
2033	25,614	5,281	5,133
2034	25,988	5,356	5,179
2035	26,370	5,433	5,228
2036	26,739	5,509	5,274
2037	27,157	5,595	5,332

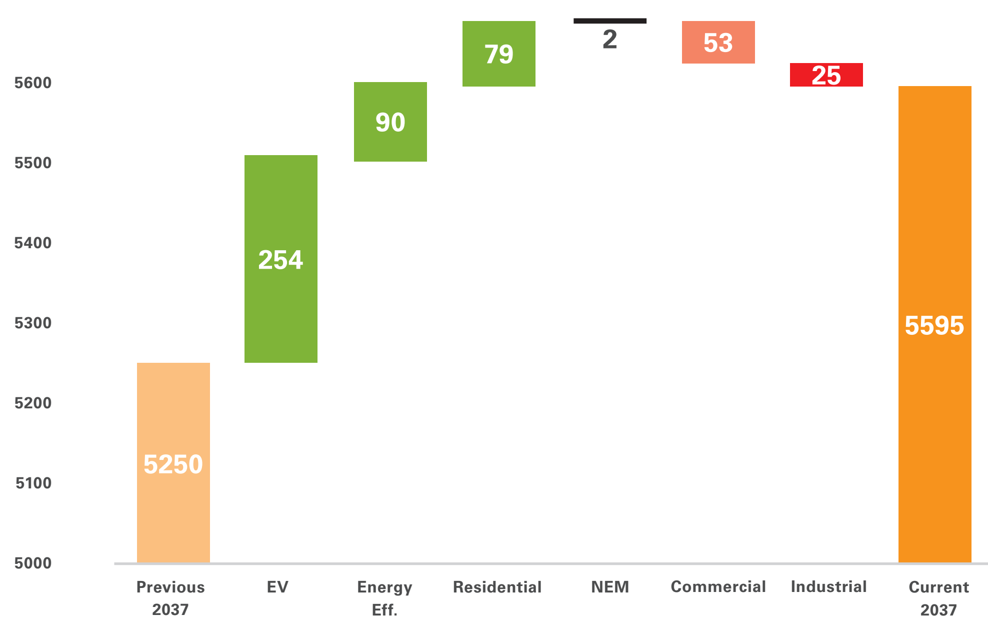
For the years 2025 and later, the 2023 peak demand forecast is generally higher than the similar forecast from 2022. This is due to higher assumed penetrations of EVs, lower assumed levels of demand reductions achievable through Company-sponsored DSM programs, and higher rates of demand growth for residential customers. These increases are offset in part by lower assumed rates of demand for commercial and industrial customers. Figure 12 shows the 2023 summer peak forecast.

Figure 12: 2023 Summer Peak Forecast (MW)



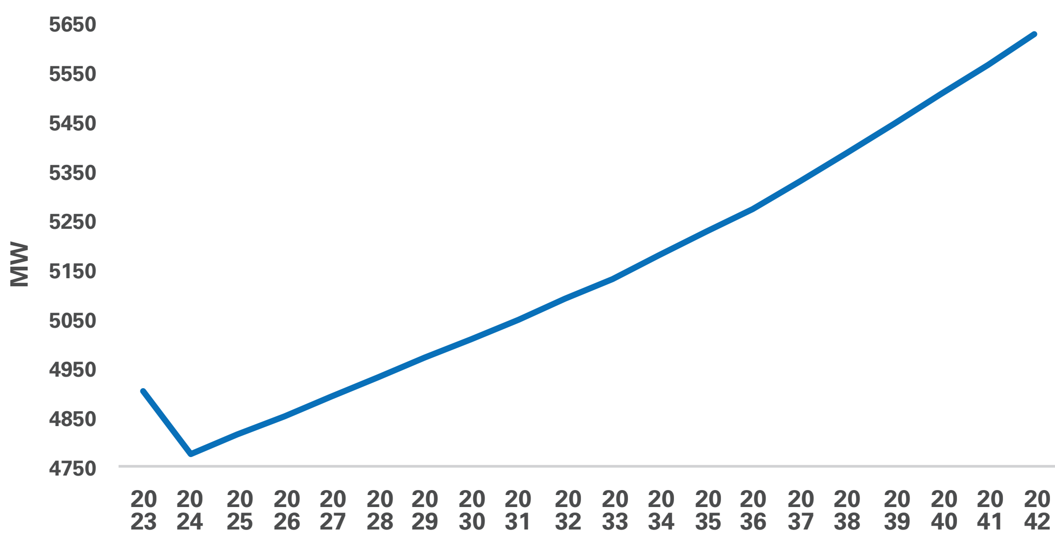
The factors contributing to the difference in summer peak demand forecasts for 2037 are shown in Figure 13 below.

Figure 13: The 2022 and 2023 Peak Demand Forecasts for 2037 Compared



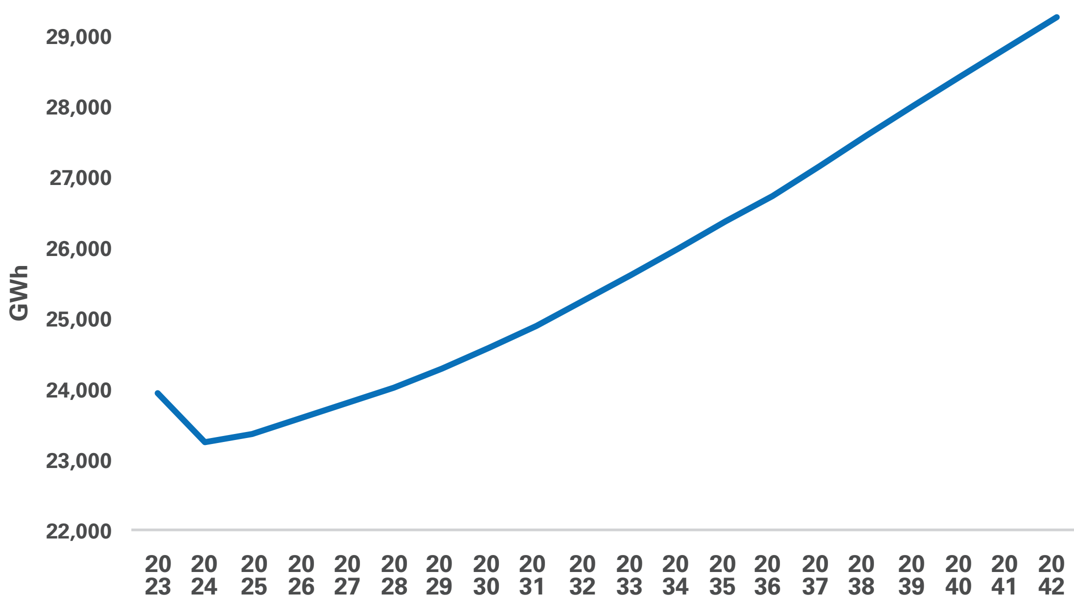
The 2023 forecasts of winter peak demands are somewhat lower but generally consistent with those from 2022. This is a result of the fact that most EV charging is anticipated to take place outside of peak demand periods in the winter.

Figure 14: 2023 Winter Peak Forecast (MW)



The 2023 energy forecast is slightly lower than the Reference Load Forecast for 2022 for the first several years and shows a dip in energy consumption between 2023 and 2024 driven by the loss of the wholesale customer. But thereafter the forecasted growth in consumption is faster than the growth in demand due to the energy demands that EV charging will place on the system, much of which will take place in off-peak hours. The forecasted compound average rate of growth energy demand over the planning horizon will be 0.9%.

Figure 15: 2023 Energy Forecast (GWh)



Analysis of Load Growth Rates under Alternative Economic Scenarios

As required by S.C. Code Ann. § 58-37-40(B)(1)(a), DESC has created high and low load growth rate scenarios to assess its generation planning under alternative economic scenarios. DESC has done so by increasing or decreasing growth in demand by 0.5% for the high and low load growth scenarios respectively. Historically, as measured over fifteen-year increments from 2001 to 2021, the compound annual growth in demand has varied between 0.778% and minus 0.372%, against a compound annual growth rate of 0.317% during that period. An assumed variation of 0.5% from the forecasted growth rate of 0.9% reasonably captures the range of expected variation in growth rates going forward as measured by historical data.

Given that the current reference forecast is for load growth of 0.9%, an increase or decrease of 0.5% represents a variation of more than 50% from the expected rate of growth. Of course, these variations in load expectations are compounded annually in a straight-line fashion over the course of the planning horizon and without allowance for low growth rates in one period being offset by high growth rates in another, or vice versa.

The reference demand forecast is 5,633 MW in 2042. Over 20 years, the high and low load growth assumptions create a band around the reference electrical demand forecast of 482 MW on the low case and 524 MW on the high case, or minus 8.6% and 9.3%, respectively. The band around the reference energy forecast is between 2,342 GWh on the low load case and 2,895 GWh on the high load case, or minus 8.0% and 9.9% of the reference forecast, respectively. This is a reasonably broad band.

Figure 16: Low, Reference and High Demand Forecasts

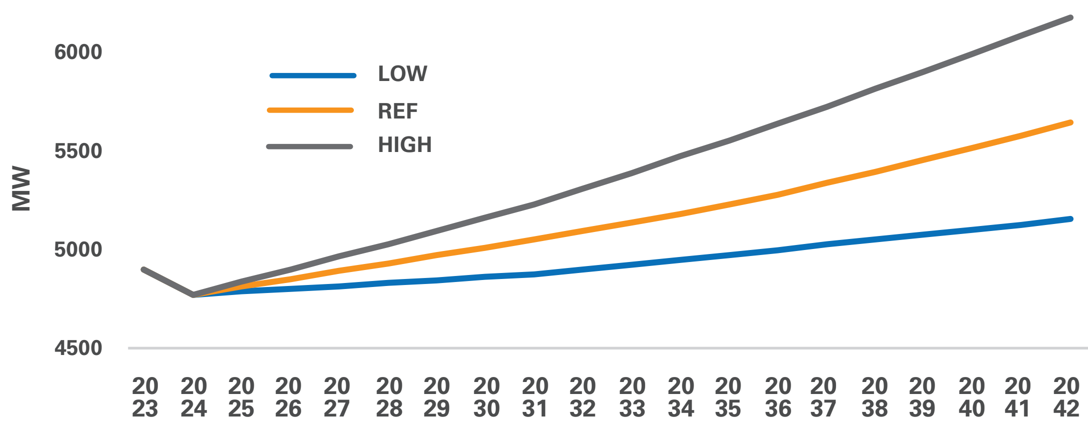
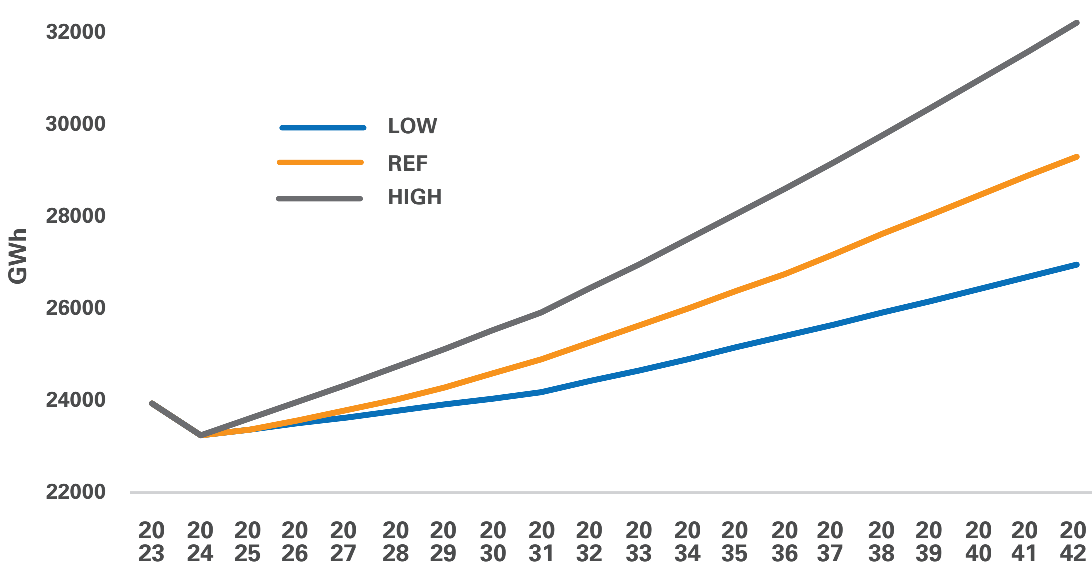


Figure 17: Low, Reference and High Energy Forecasts



Wholesale Sales

Wholesale energy sales currently represent about 3.7% 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 must compete with other power suppliers for the wholesale customers' business. The Company's largest wholesale customer currently is the City of Orangeburg, which has indicated that it will be served by an off-system wholesale supplier beginning on January 1, 2024, after which wholesale sales will represent approximately 0.3% of DESC's total sales.

DSM Assumptions

DESC modeled multiple assumptions concerning the effectiveness of DSM programs to limit load growth. The High DSM case assumes that DESC achieves a reduction in annual forecasted load growth (excluding opt-out customers) of 0.74% of gross sales, which is the maximum reduction determined in the 2023 DSM Potential Study to be achievable consistent with cost-effectiveness, aggressive but not unreasonable assumptions concerning customer participation and conditions fully supportive of effective program implementation. The Medium DSM case assumes that DESC can achieve a 0.51% energy sales reduction due to EE programs, which is the level the 2023 DSM Potential Study found to be most likely to be achieved assuming that DESC modifies and expands its existing DSM programs consistent with cost effectiveness and that customer participation follows reasonable assumptions concerning customer participation and conditions are generally supportive of effective program implementation. The Low DSM case assumes that DESC is only able to achieve 90% of the energy reductions assumed under the Medium DSM case or 0.46% due to factors that could include lower than anticipated levels of customer participation and conditions that hamper effective program implementation. All of DSM energy and demand values include marginal line losses. Each of these cases is described in more detail under the section concerning the 2023 DSM Potential Study.

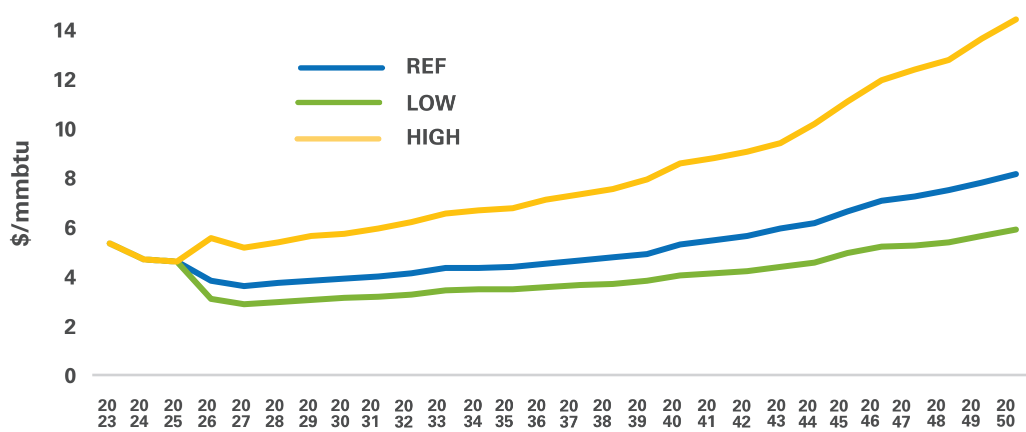
The PLEXOS model incorporates DR savings by treating two of the Residential ToU and Smart Thermostats Opt-In programs, as resources to call on to meet reserve requirements. These two DR programs were chosen because of their broad applicability, high cost-effectiveness, and high potential for reducing load growth. Specific DR programs have not yet been designed or approved but for planning purposes, it is reasonable to assume that these programs may form the core of DESC's expanded DR portfolio. For planning purposes, they serve as reasonable proxies for potential DR demand reduction investments over the planning horizon.

Fuel Price Forecasts

The base natural gas price forecast for the first three years of the planning horizon reflects the prices of publicly traded NYMEX Henry Hub contracts. DESC uses fuel forecasts based on market fundamentals for study inputs beyond three years.

For years 2026-2050, the forecast incorporates the IHS North American Power Market Outlook for natural gas at Henry Hub. IHS is a global forecasting and technology firm that is owned by S&P Global. To create the high and low natural gas price forecasts, DESC adjusted its base natural gas price forecast by the percentage difference each year between the reference natural gas price forecast and the high or low natural gas price forecast each as provided by the United States Energy Information Administration in its Annual Energy Outlook.

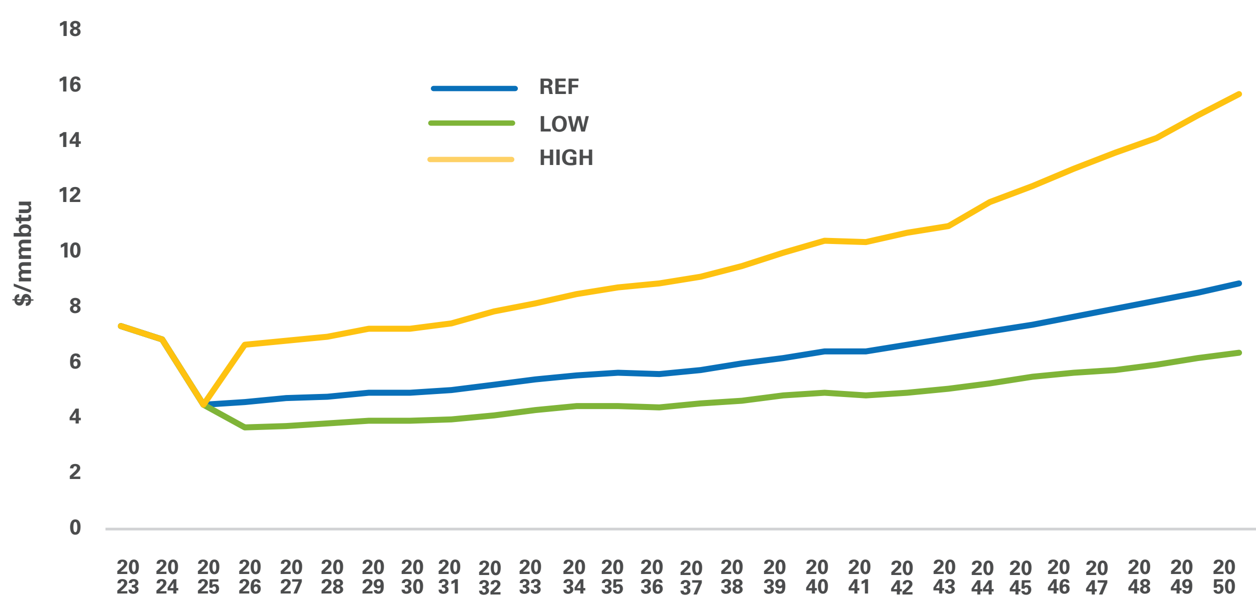
Figure 18: Gas Prices (Henry Hub)



The natural gas prices used in the PLEXOS model in include both Henry Hub commodity prices and costs to deliver the natural gas to each generating unit. Delivered costs include forecasts for delivery costs which include transportation costs on upstream pipelines, basis differential, allowance for fuel used by pipelines for compression and other purposes (commonly known as shrinkage) and all other natural gas transportation costs. Each generating unit has a different delivered cost of gas based on the upstream pipelines used to deliver gas to that generating unit, the tariffs or contracts under which that natural gas is delivered and the gas producing region supplying the commodity. The forecast of the future cost to deliver gas to each unit is based on the actual cost to deliver gas plus escalation. PLEXOS accounts for these costs on a unit by unit basis and the actual delivered price of natural gas varies from year to year and under each build plans. For new natural gas units, DESC uses prices for new gas supplies that have been provided by upstream natural gas pipelines for units on DESC's system.

DESC's forecasted coal prices are based on the Company's direct knowledge of Appalachian coal contract prices for the years 2023-2025 based on its coal purchasing activities and IHS forecasts for years 2026-2050. High and low coal price forecasts are based on the difference between the reference and the high or low coal price forecast provided by the United States Energy Information Administration in its Annual Energy Outlook.

Figure 19: 2023 Coal Price Forecasts



CO_2 Price Forecasts

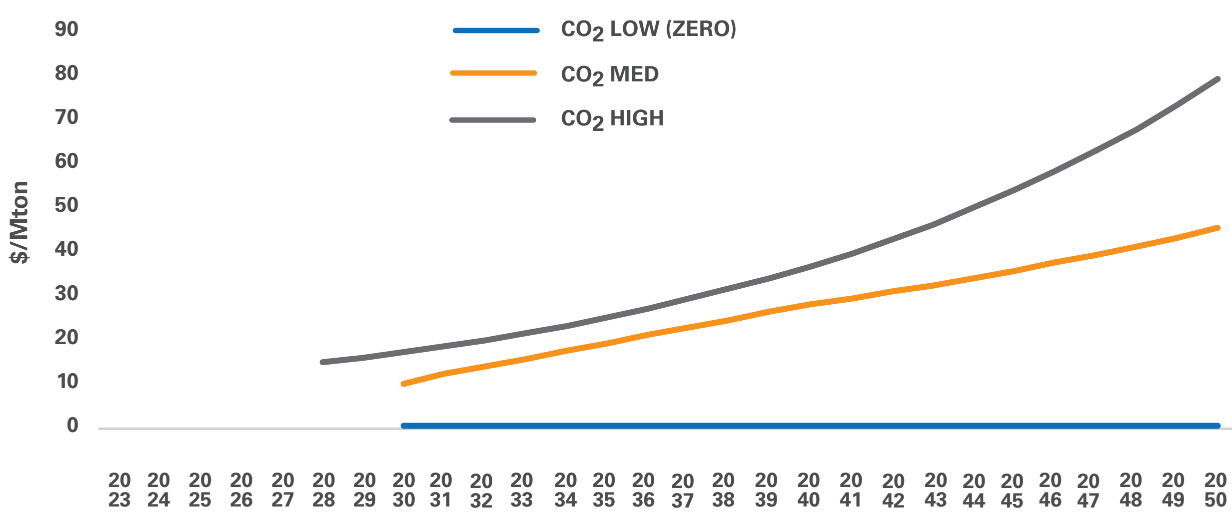
DESC developed three CO_2 pricing views for this IRP to reflect the range of possible emissions prices that are possible over the coming decades. DESC modeled five build plans using the medium CO_2 price assumption which is that a $9.62/Mton CO_2 price is imposed starting in 2030, and then escalates to more than $45/Mton by 2050. This is the IHS "US Power Sector" forecast for CO_2 prices, which is widely recognized in the industry.

For the high view of CO_2 prices, DESC assumed that CO_2 prices would start two years earlier in 2028 and would be 50% higher ($14.43/Mton) than the IHS forecast. The price escalates to $37/Mton by 2040 and $80/Mton by 2050. The low view of CO_2 prices assumes that they remain at zero.

Two build plans are based on the zero CO_2 price assumption which reflects a continuation of current state and federal policies that do not put any explicit price on CO_2 emissions.

This assumption creates a CO_2 sensitivity against which all other build plans can be evaluated and provides a consistent basis that is unaffected by CO_2 cost variables to assess the comparative impact of fuel and load growth variables across these build plans. The two build plans that use the zero CO_2 cost are the Zero Carbon Cost, and Electrification Build Plans.

Figure 20: CO_2 Price Forecasts



Reserve Margin Requirements

DESC instructed the PLEXOS model to maintain a single integrated minimum 20.1% winter reserve margin and a minimum 15% summer reserve margin based on the Reserve Margin Study. In all cases, meeting the winter reserve margin drove the addition of generation resources by PLEXOS.

Recently Added or Upgraded Generation Resources

The PLEXOS model includes as existing generation resources all binding solar PPAs whether already in place or contracted. They total 1,174 MW of capacity and include recent contracts for (i) paired solar and energy storage PPA with 73.6 MW of Solar and an 18 MW four-hour duration Battery and (ii) paired solar and energy storage PPA with 66 MW of Solar and a 66 MW three-hour duration Battery. The PLEXOS model also recognized as existing resources the planned replacement Bushy Park and Parr CT resources under construction and the existing Urquhart CT and gas steam unit resources pending completion of the Urquhart Replacements All Sources RFP. The existing CC units capacity reflects the full implementation of the AGP upgrades at Jasper Stations and Columbia Energy Center that increase the generating capacity and improve fuel efficiency of those units.

Resources Available to PLEXOS and Their Capital and Operating Costs

In consultation with Stakeholders, DESC identified twelve generating resources for PLEXOS to call on when optimizing generation plans to meet future demand. These resources included one configuration of Battery, one configuration of Solar, three configurations of CTs, four configurations of CCs, OSW, and SMRs. Solar resources are modeled as PPA resources in addition to utility-owned resources. The cost of Solar reflects IRA production tax credits for the duration of the programs under it and safe harbor extensions for uncompleted projects. These resources take the form of PPAs or utility-owned facilities. Battery resources reflect IRA investment tax credits on a similar basis and are modeled at an assumed energy availability of either 85% or 50% which means that the Battery is assumed to be able to use either 85% or 50% of its capacity to shift energy between periods of high and low energy costs during each day with the balance is available to meet system capacity needs. DR programs are modeled as a resource using cost and load reduction data provided by the 2023 DSM Potential Study.

The capital costs, escalation in capital cost, operating and maintenance ("O&M") costs, and other attributes of each of the eighteen resources available for selection by PLEXOS are listed in Table 13, below. These costs have been determined after consultation with Stakeholders. For candidate resources, the capital costs of the resources modeled in each plan have been escalated from 2023 to the year that the generator is installed.

Table 13: Generation Supply Technology Costs, Escalation and Capacity Units and Supply Technology Characteristics

Available Resources	Capital Cost ($2022/kW)	Escalation Rate	Capacity (MW)	Source Of Data
New 1x1 Combined Cycle	1,452	1.89%	650	Dominion Energy Services - Generation Construction Financial Management & Controls
New 2x1 Combined Cycle	1,163	1.89%	1325	Dominion Energy Services - Generation Construction Financial Management & Controls
New 2x1 Combined Cycle 50 Shared	1,163	1.89%	662	Dominion Energy Services - Generation Construction Financial Management & Controls
New 3x1 Combined Cycle	941	1.89%	1950	Dominion Energy Services - Generation Construction Financial Management & Controls
New CT Aero 2x	1,898	1.89%	114	Dominion Energy Services - Generation Construction Financial Management & Controls
New CT Frame 1x	1,402	1.89%	262	Dominion Energy Services - Generation Construction Financial Management & Controls
New CT Frame 2x	1,154	1.89%	523	Dominion Energy Services - Generation Construction Financial Management & Controls
New Small Modular Reactor	12,354	1.89%	274	Dominion Energy Services - Generation Construction Financial Management & Controls
New Solar	1,240	2.50%	75	NREL 2022 ATB
New Battery 4 hour	1,459	2.50%	37.5	NREL 2022 ATB
New OffShore Wind	4,323	2.50%	100	NREL 2022 ATB

All prices for renewables have been updated with nominal prices calculated from the NREL 2022 Annual Technology Baseline ("ATB"). DESC modeled the Solar Investment Tax Credit ("ITC") as provided in the ATB.

Through the Stakeholder process, DESC agreed to use NREL cost data for Solar. In working with that data, DESC determined that NREL embedded aggressive forecasts of future cost reductions for solar technology in it. These forecasted cost reductions are inconsistent with the recent trend of price increases for Solar, the overall maturing of the technology and the markets providing it, and the planning data used by other Dominion Energy companies. DESC is concerned that these aggressive forecasts of future price reductions may have increased the amount of Solar selected by PLEXOS to a level that will not be realized but these are long-term issues and are likely to have limited effects on the major resource procurement decisions that will be made on the basis of this 2023 IRP. Any inaccuracies in these forecasts will be corrected with time.

Build Plan Analysis

Springfield Solar Facility; Orangeburg, South Carolina

In preparing the 2023 IRP, DESC analyzed five Core Build Plans under a range of future conditions in the energy markets and policy considerations, resulting in the consideration of fifteen Core Cases. Each of the Core Build Plans represents a different generation supply plan that optimizes results for customers under the applicable assumptions concerning fuel costs, CO_2 costs, load growth, DSM results, and replacement resources for retired coal units. DESC quantified the costs, CO_2 emissions, and other impacts of these Core Build Plans by creating fifteen Core Cases to evaluate alternatives for meeting customers' energy needs reliably, affordably, and responsibly in the coming decades. It added to this analysis five Sensitivity Cases to assess the effect of alternative assumptions as future market conditions or load growth, as well as four Supplemental Cases to assess the relative cost and CO_2 impacts of alternative approaches to retiring and replacing Williams and Wateree.

The Eight Market Scenarios

DESC built the fourteen build plans around Market Scenarios that, with one exception, reflect an internally consistent narrative about future environmental policy choices, fossil fuel costs and availability, levels of economic development and load growth, and DSM program results. The exception is the Energy Conservation Market Scenario, which certain Stakeholders proposed. It assumes that the economy can absorb high costs imposed on fossil fuels without triggering a growth in electric demand as end users switch to electricity and that all future increases in electric demand, through development in the service territory or otherwise, will be offset through energy conservation. Collectively, the eight Market Scenarios encompass a broad spectrum of foreseeable future conditions on DESC's electric system.

Table 14: The Eight Market Scenarios

Market Scenario	Fuel Price	CO_2 Price	Load	DSM
1. Reference	Medium	Medium	Reference	Medium
This Market Scenario generally reflects a middle-of-the-road outlook and reasonably foreseeable values for key market drivers in general. While there is currently no explicit price on CO_2 and the design of future policies is uncertain, this Market Scenario assumes that a moderate CO_2 price is imposed on the electric sector as a proxy for future policy that increases the cost of fossil-fired resources. DSM programs are limited to achievable load reductions as determined in the 2023 DSM Potential Study.				
2. High Fossil Fuel Prices	High	Medium	Reference	Medium
This Market Scenario assumes that state and federal policies constrain investments in coal and natural gas supplies and in the expansion of natural gas pipelines resulting in high fossil fuel prices. Electrification of transportation and other end uses offset the effect of high prices and energy conservation on electric load growth. DSM programs are limited to achievable load reductions as determined in the 2023 DSM Potential Study. This Market Scenario represents a future in which high fossil fuel prices combine with moderate levels of electric demand growth.				
3. Zero Carbon Cost	Medium	Zero	Reference	Medium
This Market Scenario tests build plans against a future energy market in which CO_2 emissions remain unpriced and DSM programs are limited to their achievable potential. Electrification does not dramatically increase load growth and fossil fuel prices remain in a moderate range. This Market Scenario represents a future in which decarbonizing the energy sector is not prioritized.				
4. Electrification	Low	Zero	High	Medium
Under this Market Scenario, federal and state incentives and decarbonization mandates shift demand away from fossil fuels without imposing CO_2 costs directly on fossil fuels or limiting their availability. This results in lower demand for fossil fuels relative to supply and lower costs. Related policies supporting electrification of transportation and other sectors results in an increase in electric load growth. The result is a future energy market where fossil fuel costs are low but electric demand is high.				
5. Energy Conservation	High	Medium	Low	Medium
As in the High Fossil Fuel Prices Market Scenario, this Market Scenario assumes that state and federal policies constrain investments in coal and natural gas supplies and natural gas pipelines resulting in high fossil fuel prices. However, the Market Scenario also assumes that efficiency improvements and DSM programs more than fully offset the effects of end-use electrification and limit load growth. This Market Scenario is based on proposals from environmental and renewable energy Stakeholders and represents a future where high costs disfavor fossil fuel but load growth is low.				
6. Aggressive Regulation	High	High	High	Medium
Under this view, policymakers impose high CO_2 prices and also limit fossil fuel production increasing the cost of reliance on fossil fuels. Costs and policy mandates lead to high electric load growth through increased end-use electrification. The Market Scenario evaluates build plans where high fossil fuel cost, high CO_2 costs and high load conditions create a high-cost environment for the electric system.				
7. High DSM	Medium	Medium	Reference	High
This Market Scenario is a DSM sensitivity to meet Act No. 62 requirements. It incorporates Reference Case assumption for other items but assumes DSM programs achieve higher demand growth reductions than the most likely achievable levels found in the 2023 DSM Potential Study.				
8. Low DSM	Medium	Medium	Reference	Low
This Market Scenario is also a DSM sensitivity to meet Act No. 62 requirements. It incorporates Reference Case assumption for other items but assumes DSM programs achieve the reductions in future loads that are below those that the 2023 DSM Potential Study found to be reasonably achievable.				

The Reference Market Scenario includes DESC's assessment of the most likely and representative set of assumptions concerning future market conditions that collectively reflect a moderate position within the range of potential outcomes. It serves as a central point of reference in evaluating the Core Build Plans.

The Five Core Build Plans

DESC created eight of the fourteen build plans by using PLEXOS to optimize resource additions under each of the eight Market Scenarios. It created the additional six build plans by imposing specific constraints on Market Scenarios. DESC selected five build plans as Core Build Plans for detailed analysis that define a broad range of possible options for future planning, or in the case of the Reference Build Plan, represent most middle-of-the-road assumptions about the future of energy markets in South Carolina and the most likely and representative generation planning inputs. These five Core Build Plans are the Reference Build Plan, the Zero Carbon Cost Build Plan, the High Fossil Fuel Price Build Plan, the 70% CO_2 Reduction Build Plan and the 85% CO_2 Reduction Build Plan.

Table 15: The Five Core Build Plans

Build Plan	Market Scenario Used for Optimization	Additional Constraints	Notes
1. Reference Build Plan	Reference Market Scenario	None	PLEXOS crafted this build plan to perform best under the Reference Market Scenario, which generally reflects a middle-of-the-road outlook for key market drivers. It is the expected case for the 2023 IRP.
2. High Fossil Fuel Prices Build Plan Scenario	High Fossil Fuel Prices Market Scenario	None	This build plan optimizes resource additions under the High Fossil Fuel Prices Market Scenario, which assumes high fossil fuel prices, moderate levels of electric demand growth, and moderate CO_2 costs.
3. Zero Carbon Cost Build Plan	Zero Carbon Cost Market Scenario	None	PLEXOS created this build plan using the Zero Carbon Cost Market Scenario, which assumes future policy makers do not prioritize decarbonizing the energy sector. CO_2 prices remain at zero, fossil fuel prices are moderate, and electrification does not dramatically increase load growth.
4. 70% CO_2 Reduction Build Plan	Reference Market Scenario	Reduction of Carbon Emissions of approximately 70% by 2050	This build plan is based on the Reference Market Scenario but requires DSC to achieve a reduction in CO_2 emissions of 70% by 2050 to be accomplished in stages beginning in 2040.
5. 85% CO_2 Reduction Build Plan	Reference Market Scenario	Reduction of Carbon Emissions of approximately 85% by 2050	This build plan is also based on the Reference Market Scenario but requires DESC to achieve a reduction in CO_2 emissions of 85% by 2050 to be accomplished in stages beginning in 2040.

The Nine Non-Core Build Plans

The nine additional Non-Core Build Plans serve as sensitivities to evaluate options for Wateree or Williams retirements and replacements, to provide statutorily or Commission-mandated information or to measure how build plans vary depending on changes in fuel cost, CO_2 costs, load growth, and DSM effectiveness.

Table 16: The Nine Non-Core Build Plans

Build Plan	Market Scenario Used for Optimization	Additional Constraints	Notes
6. Electrification Build Plan	Electrification Market Scenario	None	PLEXOS optimized this build plan under the Electrification Market Scenario, which assumes that policy makers incentivize electrification while keeping fossil fuel costs low and CO_2 costs at zero.
7. Energy Conservation Build Plan	Energy Conservation Market Scenario	None	PLEXOS optimized this build plan under the Energy Conservation Market Scenario, which assumes future policies disfavor reliance on fossil fuel through constraints on production of fossil fuels and expansion gas pipelines, but also assumes that efficiency displaces load growth due to electrification and electric load growth is low.
8. Aggressive Regulation Build Plan	Aggressive Regulation Market Scenario	None	The Aggressive Regulation Market Scenario is the basis for this build plan and assumes high fossil fuel costs, high CO_2 costs, and high load growth rates. This creates strong cost pressures on fossil fuel resources while load growth puts a premium on capacity and capacity additions.
9. High DSM Build Plan	Reference Market Scenario	DSM Programs attain the Maximum Achievable Potential	This build plan assumes DSM programs are able to achieve their Maximum Potential as shown in the 2023 DSM Potential Study, not the Achievable Potential assumed in the Reference Market Scenario. It is otherwise optimized under the Reference Market Scenario.
10. Low DSM Build Plan	Reference Market Scenario	DSM Programs Do Not Achieve the Achievable Potential	This build plan assumes that DSM programs are only able to achieve 90% of thei Achievable Potential as shown in the 2023 DSM Potential Study and is otherwise optimized under the Reference Market Scenario.
11. Wateree Battery Build Plan	Reference Market Scenario	Wateree Capacity Is Replaced with Battery Capacity	This build plan evaluates the potential for replacing 300 500MW of Wateree capacity and associated energy with a combination of Battery Storage resources in 2028 located at the Wateree site. With that assumption, PLEXOS optimized the system under the Reference Market Scenario.
12. Wateree CT Build Plan	Reference Market Scenario	Wateree Capacity Is Replaced with a Frame CT	This build plan evaluates the potential for replacing 300-500 MW of Wateree capacity and associated energy by constructing a Frame CT at the Urquhart site and 100MW of storage at Wateree in 2028. With that assumption, PLEXOS optimized the system under the Reference Market Scenario.
13. Williams 2047 Build Plan	Reference Market Scenario	Williams Operates Until 2047	This build plan assesses the changes in costs and CO_2 emissions increases if Williams were kept in service until 2047, which is the end of its useful life. With that assumption, PLEXOS optimized the system under the Reference Market Scenario.
14. High Fuel Williams 2047 Build Plan	High Fossil Fuel Prices Market Scenario	Williams Operates Until 2047	This build plan assesses the changes in costs and CO_2 emissions increases if Williams were kept in service until 2047, under the High Fossil Fuel Prices Market Scenario.

Assumptions Common to the Build Plans

Each of the fourteen build plans assumes that DESC can retire Wateree in 2028. All but two assume that DESC retires Williams in 2030. The two exceptions are the Williams 2047 Build Plan and High Fuel Williams 2047 Build Plan, which provide a basis for comparing the cost and CO_2 emissions impacts of delaying the Williams retirement until the end of its useful life in 2047 instead of retiring it early.

In constructing these build plans, DESC informed the PLEXOS model to convert Cope Station ("Cope") to use only gas as a fuel in 2031. DESC remains committed to retiring coal-only units by the end of 2030 but decided for planning purposes to assume that

Cope remains dual-fuel capable until 2031. DESC based this decision on the likely schedule and complexity of assuring natural gas supply in the area where Cope is located as identified in preparing the Coal Plants Retirement Study, and it reflects the priority of retiring Williams as early as feasible. DESC will reassess this assumption as more information becomes available.

The Percentage of Renewable Resources Selected in Core Build Plans

Over the planning horizon, the Core Build Plans add non-emitting resources totaling between 80% and 87% of generation additions. The 85% CO_2 Reduction Build Plan adds the most non-emitting resources, 11,004 MW or 87%, and the Zero Carbon Cost Plan adds the least, 5,775 MW or 80%. The Reference Build Plan adds 6,625 MW of non-emitting resources or slightly more than 80% of the total MW added under that build plan.

All Core Build Plans envision DESC adding substantial quantities of Solar on a roughly annual basis beginning in 2026 and supplemented by Battery beginning in 2028. Solar and Battery are the principal non-emitting resources added under all Core Build Plans.

Only the 70% CO_2 Build Plan and the 85% CO_2 Build Plan envision adding OSW, which they add in the amounts of 800 MW and 1,100 MW respectively and do so in 100 MW stages beginning in 2040. The 85% CO_2 Reduction Build Plan is the only build plan that envisions adding SMR resources, which it adds in the amount of 804 MW in three stages beginning in 2040.

MWs Added by the Core Build Plans

For comparability purposes, DESC has based each of the Core Build Plans on the same load growth assumptions. This allows the levelized costs and CO_2 emissions of each Core Build Plan to be compared directly to the others. However, the total number of MW added under each build plan varies principally because of the intermittent nature of Solar and OSW and to a lesser degree, the cost of fuel avoided. Due to intermittency, adding Solar or OSW capacity displaces only a small amount of the need for non-intermittent capacity to meet peak winter demand. For this reason, there is a strong correlation between the percentage of Solar and OSW added under a build plan, and the fuel and CO_2 costs assumed in the Market Scenario, and the total amount of MW needed to meet customer demands.

Of the five Core Build Plans, the 85% CO_2 Reduction Build Plan adds the greatest amount of generating resources (12,591 MW) as well as the greatest amount of non-emitting resources (11,004 MW). The Zero Carbon Cost Build Plan adds the least amount of generating resources (7,222 MW) and the least amount of non-emitting resources (4,275 MW). The other Core Build Plans add between 8,333 MW (the Reference Plan) and 9,987 MW (the 70% CO_2 Reduction Build Plan) of total generating resources.

Fossil Fuel Resources Added by the Core Build Plans

Under each of the Core Build Plans, maintaining system reliability economically requires adding dispatchable natural gas-fired generation. The amount of natural gas-fired generation added is greatest in the Reference and High Fossil Fuel Prices Plans (1,708 MW each) and is least in the Zero Carbon Cost Plan (1,447 MW). Comparing the Core Build Plans shows that PLEXOS make very similar selections of natural gas-fired generators where Market Scenarios used similar load forecasts and made selections proportional to load growth in high and low load scenarios.

Retiring the Wateree and Williams coal units creates a planned deficit in the reserve margin, and under each Core Build Plan, an initial increment of gas-fired generation is needed in response. PLEXOS modeling shows that the most cost-effective resource mix to restore reserves above the planning reserve margin ("PRM") is a combination of natural gas-fired generation with some energy storage. In the Reference, High Fossil Fuel Prices and Zero Carbon Cost Build Plans, PLEXOS selected the Shared Resource (662 MW CC) to be constructed in 2031 and supplemented by Battery and Solar resources installed between 2026 and 2031. In the Zero Carbon Cost Build Plan, it supplemented the Shared Resource with a Frame CT resource in 2029. The 70% CO_2 Reduction Build Plan and the 85% CO_2 Reduction Build Plan envision DESC procuring a non-shared 1,325 MW CC 2 x 1 unit in 2031 and supplemented by a 262 MW Frame CT added in 2029.

The Specific Resources Added under Each Build Core Build Plan

The timing and nature of resource additions and the resulting capacities and winter reserve margins for each of the years of the model horizon are set forth in the full detail in the tables attached as **Appendix E & F** to this document.

The Reference Build Plan Resources

The Reference Build Plan builds a total of 8,333 MW of capacity over the planning horizon which puts it in the middle of the range of new capacity constructed under the Core Build Plans. It adds 5,025 MW of Solar supplemented by a total of 1,600 MW of Battery of which 400 MW is added in 2029 to support the Wateree and later Williams replacement. The annual Solar increments are between 150 and 300 MW beginning in 2026 and continue for each year thereafter until the final year of the plan. The Reference Build Plan selects the Shared Resource as the primary asset to provide 662 MW of new 2x1 CC to replace Wateree and Williams in 2031.

To support system reliability in later years, the Reference Build Plan adds 523 MW of new Frame CT capacity in 2040 and 2049. These additions are envisioned as a two dual-unit projects to reduce procurement and construction costs.

Table 17: The Reference Build Plan

Reference Build Plan									
Year	Peak (MW)	Firm Capacity (MW)	Winter Reserve Margin (%)	New Gas (MW)	New Solar (MW)	New Storage (MW)	New Wind (MW)	New SMR (MW)	Retirements (MW)
2023	4902	6305	28.6	0	0	0	0	0	0
2024	4775	6282	31.6	0	0	0	0	0	0
2025	4813	6277	30.4	0	0	0	0	0	0
2026	4851	6328	30.5	0	150	0	0	0	0
2027	4891	6339	29.6	0	225	0	0	0	0
2028	4931	6355	28.9	0	300	0	0	0	0
2029	4971	6032	21.4	0	300	400	0	0	-684
2030	5009	6057	20.9	0	300	0	0	0	0
2031	5048	6131	21.5	662	300	0	0	0	-610
2032	5091	6147	20.8	0	300	0	0	0	0
2033	5133	6206	20.9	0	300	100	0	0	0
2034	5179	6469	24.9	0	300	300	0	0	0
2035	5228	6475	23.9	0	300	0	0	0	0
2036	5274	6629	25.7	0	300	300	0	0	0
2037	5332	6631	24.4	0	150	0	0	0	0
2038	5390	6498	20.6	0	150	0	0	0	0
2039	5450	6598	21.1	0	150	200	0	0	0
2040	5509	7119	29.2	523	150	0	0	0	0
2041	5571	7117	27.8	0	150	0	0	0	0
2042	5633	7119	26.4	0	150	0	0	0	0
2043	5697	7119	25.0	0	150	0	0	0	0
2044	5761	7121	23.6	0	150	0	0	0	0
2045	5826	7123	22.3	0	150	0	0	0	0
2046	5892	7126	21.0	0	150	0	0	0	0
2047	5959	7177	20.5	0	150	100	0	0	0
2048	6026	7279	20.8	0	150	200	0	0	0
2049	6094	7464	22.5	523	150	0	0	0	0
2050	6163	7465	21.1	0	0	0	0	0	0

High Fossil Fuel Prices Build Plan Resources

The High Fossil Fuel Prices Build Plan adds a total of 9,908 MW over the planning horizon including 6,600 MW of new Solar supported by a total of 1,600 MW of new Battery. This build plan adds Solar in 300 MW increments beginning in 2026 and continuing through 2045 after which the increments are reduced to 150 MW. Like the Reference Build Plan, it replaces Wateree and Williams in part through 400 MW of Battery built in 2029 and 662 MW Shared Resource built in 2031. To ensure system reliability, it adds 523 MW of new CT Frame in years 2041 and 2049 as a dual unit projects.

Table 18: The High Fossil Fuel Prices Build Plan

High Fossil Fuel Prices Build Plan									
Year	Peak (MW)	Firm Capacity (MW)	Winter Reserve Margin (%)	New Gas (MW)	New Solar (MW)	New Storage (MW)	New Wind (MW)	New SMR (MW)	Retirements (MW)
2023	4902	6305	28.6	0	0	0	0	0	0
2024	4775	6282	31.6	0	0	0	0	0	0
2025	4813	6277	30.4	0	0	0	0	0	0
2026	4851	6329	30.5	0	300	0	0	0	0
2027	4891	6340	29.6	0	300	0	0	0	0
2028	4931	6356	28.9	0	300	0	0	0	0
2029	4971	6034	21.4	0	300	400	0	0	-684
2030	5009	6058	21.0	0	300	0	0	0	0
2031	5048	6132	21.5	662	300	0	0	0	-610
2032	5091	6148	20.8	0	300	0	0	0	0
2033	5133	6207	20.9	0	300	100	0	0	0
2034	5179	6470	24.9	0	300	300	0	0	0
2035	5228	6476	23.9	0	300	0	0	0	0
2036	5274	6630	25.7	0	300	300	0	0	0
2037	5332	6633	24.4	0	300	0	0	0	0
2038	5390	6500	20.6	0	300	0	0	0	0
2039	5450	6552	20.2	0	300	100	0	0	0
2040	5509	7073	28.4	523	300	0	0	0	0
2041	5571	7122	27.9	0	300	100	0	0	0
2042	5633	7124	26.5	0	300	0	0	0	0
2043	5697	7126	25.1	0	300	0	0	0	0
2044	5761	7178	24.6	0	300	100	0	0	0
2045	5826	7181	23.3	0	300	0	0	0	0
2046	5892	7234	22.8	0	300	100	0	0	0
2047	5959	7286	22.3	0	150	100	0	0	0
2048	6026	7288	21.0	0	150	0	0	0	0
2049	6094	7473	22.6	523	150	0	0	0	0
2050	6163	7474	21.3	0	0	0	0	0	0

The Zero Carbon Cost Build Plan Resources

The Zero Carbon Cost Build Plan adds a total of 7,222 MW of capacity to the system over the planning horizon including 4,275 MW of new Solar supported by 1,500 MW of new Battery. It is the least construction-intensive of the Core Build Plans. This build plan adds Solar on an annual basis beginning in 2026 but most annual increments are 150 MW and not 300 MW as in the Reference Build Plan and the High Fossil Fuel Prices Build Plan. In this build plan, Battery additions are weighted more toward the end of the planning period than in the other build plans. Like the Reference Build Plan and the High Fossil Fuel Prices Build Plan, this build plan adds the Shared Resource to provide 662 MW of new 2x1 CC capacity in 2031 to replace Wateree and Williams. But rather than adding 400 MW of Battery in 2029 as the other build plans do, it adds 100 MW of Battery and 262 MW of new Frame CT as a single unit project.

Table 19: The Zero Carbon Cost Build Plan

Zero Carbon Cost Build Plan									
Year	Peak (MW)	Firm Capacity (MW)	Winter Reserve Margin (%)	New Gas (MW)	New Solar (MW)	New Storage (MW)	New Wind (MW)	New SMR (MW)	Retirements (MW)
2023	4902	6305	28.6	0	0	0	0	0	0
2024	4775	6282	31.6	0	0	0	0	0	0
2025	4813	6277	30.4	0	0	0	0	0	0
2026	4851	6328	30.5	0	150	0	0	0	0
2027	4891	6338	29.6	0	150	0	0	0	0
2028	4931	6354	28.9	0	150	0	0	0	0
2029	4971	6038	21.5	262	225	100	0	0	-684
2030	5009	6062	21.0	0	300	0	0	0	0
2031	5048	6136	21.6	662	300	0	0	0	-610
2032	5091	6152	20.9	0	300	0	0	0	0
2033	5133	6212	21.0	0	300	100	0	0	0
2034	5179	6388	23.4	0	150	200	0	0	0
2035	5228	6734	28.8	0	150	400	0	0	0
2036	5274	6737	27.8	0	150	0	0	0	0
2037	5332	6740	26.4	0	150	0	0	0	0
2038	5390	6606	22.6	0	150	0	0	0	0
2039	5450	6607	21.2	0	150	0	0	0	0
2040	5509	6654	20.8	0	150	100	0	0	0
2041	5571	6702	20.3	0	150	100	0	0	0
2042	5633	7227	28.3	523	150	0	0	0	0
2043	5697	7228	26.9	0	150	0	0	0	0
2044	5761	7229	25.5	0	150	0	0	0	0
2045	5826	7231	24.1	0	150	0	0	0	0
2046	5892	7234	22.8	0	150	0	0	0	0
2047	5959	7236	21.4	0	150	0	0	0	0
2048	6026	7237	20.1	0	150	0	0	0	0
2049	6094	7354	20.7	0	150	400	0	0	0
2050	6163	7405	20.2	0	0	100	0	0	0

The 70% CO_2 Reduction Build Plan Resources

The 70% CO_2 Reduction Build Plan builds a total of 9,987 MW over the planning horizon including 6,000 MW of Solar and 1,600 MW of Battery, which makes it the second most construction intensive of the Core Build Plans. It adds 300 MW of new Solar each year from 2026 until 2045 and adds 1,600 MW of Storage concentrated in the period from 2029-2038 which is somewhat earlier than in other plans. To replace Wateree and Williams, it initially adds 100 MW of Storage and a single 262 MW Frame CT in 2029, then in 2031 it adds a 1,325 MW 2x1 CC, rather than the 662 MW Shared Resource which PLEXOS selected in the Reference Build Plan, the High Fossil Fuel Prices Build Plan and the Zero Carbon Cost Build Plan. This is the first build plan to select OSW which it does beginning in year 2040 for a total of 800 MW by year 2047.

Table 20: The 70% CO_2 Reduction Build Plan

70% CO_2 Reduction Build Plan									
Year	Peak (MW)	Firm Capacity (MW)	Winter Reserve Margin (%)	New Gas (MW)	New Solar (MW)	New Storage (MW)	New Wind (MW)	New SMR (MW)	Retirements (MW)
2023	4902	6305	28.6	0	0	0	0	0	0
2024	4775	6282	31.6	0	0	0	0	0	0
2025	4813	6277	30.4	0	0	0	0	0	0
2026	4851	6329	30.5	0	300	0	0	0	0
2027	4891	6340	29.6	0	300	0	0	0	0
2028	4931	6356	28.9	0	300	0	0	0	0
2029	4971	6041	21.5	262	300	100	0	0	-684
2030	5009	6065	21.1	0	300	0	0	0	0
2031	5048	6972	38.1	1325	300	200	0	0	-610
2032	5091	7073	38.9	0	300	100	0	0	0
2033	5133	7387	43.9	0	300	400	0	0	0
2034	5179	7445	43.8	0	300	100	0	0	0
2035	5228	7551	44.4	0	300	200	0	0	0
2036	5274	7655	45.2	0	300	200	0	0	0
2037	5332	7758	45.5	0	300	200	0	0	0
2038	5390	7675	42.4	0	300	100	0	0	0
2039	5450	7677	40.9	0	300	0	0	0	0
2040	5509	7715	40.1	0	300	0	100	0	0
2041	5571	7754	39.2	0	300	0	100	0	0
2042	5633	7796	38.4	0	300	0	100	0	0
2043	5697	7838	37.6	0	300	0	100	0	0
2044	5761	7880	36.8	0	300	0	100	0	0
2045	5826	7923	36.0	0	300	0	100	0	0
2046	5892	7965	35.2	0	0	0	100	0	0
2047	5959	8006	34.4	0	0	0	100	0	0
2048	6026	8007	32.9	0	0	0	0	0	0
2049	6094	7923	30.0	0	0	0	0	0	0
2050	6163	7924	28.6	0	0	0	0	0	0

The 85% CO_2 Reduction Build Plan Resources

The 85% CO_2 Reduction Build Plan builds 12,591 MW of capacity over the planning horizon making it the most construction-intensive of the Core Build Plans. From 2026 until 2050, it adds 300 MW of new Solar each year for a total of 7,500 MW. Like the 70% CO_2 Reduction Build Plan, it adds a total of 1,600 MW of Battery all during in the period from 2029-2038. Also, like the 70% CO_2 Reduction Build Plan, it replace Wateree and Williams with 100 MW of Storage and a single 262 MW Frame CT added in 2029, and then a 1,325 MW 2x1 CC, added in 2031. It envisions adding no gas-fired generation after 2031 and instead adds a total of 1,904 MW of OSW and SMRs beginning in 2040.

Table 21: The 85% CO_2 Reduction Build Plan

85% CO_2 Reduction Build Plan									
Year	Peak (MW)	Firm Capacity (MW)	Winter Reserve Margin (%)	New Gas (MW)	New Solar (MW)	New Storage (MW)	New Wind (MW)	New SMR (MW)	Retirements (MW)
2023	4902	6305	28.6	0	0	0	0	0	0
2024	4775	6282	31.6	0	0	0	0	0	0
2025	4813	6277	30.4	0	0	0	0	0	0
2026	4851	6329	30.5	0	300	0	0	0	0
2027	4891	6340	29.6	0	300	0	0	0	0
2028	4931	6356	28.9	0	300	0	0	0	0
2029	4971	6041	21.5	262	300	100	0	0	-684
2030	5009	6065	21.1	0	300	0	0	0	0
2031	5048	6972	38.1	1325	300	200	0	0	-610
2032	5091	7073	38.9	0	300	100	0	0	0
2033	5133	7387	43.9	0	300	400	0	0	0
2034	5179	7445	43.8	0	300	100	0	0	0
2035	5228	7551	44.4	0	300	200	0	0	0
2036	5274	7655	45.2	0	300	200	0	0	0
2037	5332	7758	45.5	0	300	200	0	0	0
2038	5390	7675	42.4	0	300	100	0	0	0
2039	5450	7677	40.9	0	300	0	0	0	0
2040	5509	7989	45.0	0	300	0	100	268	0
2041	5571	8028	44.1	0	300	0	100	0	0
2042	5633	8070	43.3	0	300	0	100	0	0
2043	5697	8112	42.4	0	300	0	100	0	0
2044	5761	8154	41.6	0	300	0	100	0	0
2045	5826	8471	45.4	0	300	0	100	268	0
2046	5892	8514	44.5	0	300	0	100	0	0
2047	5959	8557	43.6	0	300	0	100	0	0
2048	6026	8599	42.7	0	300	0	100	0	0
2049	6094	8557	40.4	0	300	0	100	0	0
2050	6163	8873	44.0	0	300	0	100	268	0

The Core Analysis

To create the Core Analysis, DESC modeled the five Core Build Plans under the three Core Market Scenarios to create fifteen Core Cases. To allow for costs and emissions to be compared on an equal basis, all three Core Market Scenarios assume Reference Load Growth and a medium level of cost-effective DSM.

The five Core Market Scenarios represent a range of assumptions for planning purposes that appropriately encompasses reasonable and foreseeable future conditions based on future regulatory policies, market conditions, and CO_2 emissions reduction goals. The Reference Market Scenario and the Zero Carbon Cost Market Scenario include medium expectations for fuel prices, while the High Fossil Fuel Prices Market Scenario assumes high fuel prices. The Reference Market Scenario and High Fossil Fuel Prices Market Scenario both assume medium expectations for CO_2 prices (a price of $10 per metric ton imposed in 2030 and escalating at 8%), while the Zero Carbon Cost Market Scenario assumes zero CO_2 prices.

The Core Build Plans reflect aggressive investment in non-emitting resources, market conditions and both favoring and disfavoring continued reliance on fossil fuels. Focusing the analysis on the Core Cases allows DESC to provide meaningful and confident recommendations about the most important elements of the path forward in the Preferred Plan.

The Core Analysis Results

The IRP Statute, Commission directives or both specify that DESC and the Commission should assess its build plans against eight specified metrics:

- Levelized Cost
- CO_2 Emissions
- Clean Energy
- Fuel Cost Resiliency
- Generation Diversity
- Reliability Factors
- Mini-Max Regret Analysis
- Cost Range Analysis

In fulfillment of these requirements, DESC has conducted the Core Analysis of the five Core Build Plans to show their relative performance in levelized cost, CO_2 emissions, incorporation of clean energy, fuel cost resiliency, generation diversity, reliability factors, mini-max regret factors, and a cost range analysis.

IRP Evaluation Standards and Metrics

Levelized Cost – Section 58-37-40(C)(2)(b) requires the Commission to consider, in its discretion, whether an IRP appropriately balances consumer affordability and least cost. Order No. 2020-832 also required the costs of all candidate resource plans be included.

CO_2 Emissions and Clean Energy – Section 58-37-40(C)(2)(c) requires the Commission to consider, in its discretion, whether an IRP appropriately balances compliance with applicable state and federal environmental regulations.

Fuel Cost Resiliency – Section 58-37-40(C)(2)(e) requires the Commission to consider, in its discretion, whether an IRP appropriately balances commodity price risks, which includes fuel cost resiliency.

Generation Diversity – Section 58-37-40(C)(2)(f) requires the Commission to consider, in its discretion, whether an IRP appropriately balances diversity of generation supply.

Reliability Factors – Section 58-37-40(C)(2)(d) requires the Commission to consider, in its discretion, whether an IRP appropriately balances power supply reliability.

Mini-Max Regret – Order No. 2020-832 required DESC to implement a Mini-Max regret analyses in the Modified 2020 IRP.

Cost Range Analysis – Section 58-37-40(C)(2)(b) requires the Commission to consider, in its discretion, whether an IRP appropriately balances consumer affordability and least cost. Order No. 2020-832 also required DESC to implement a Cost Range analysis in the Modified 2020 IRP.

Levelized Cost

The Levelized Cost metric measures the costs to customers of each of the Core Build Plans based on the thirty-year levelized net present value ("LNPV") of the incremental costs of each build plan. The incremental costs include incremental operating costs, capital costs for new generation, incremental costs for ongoing operation and maintenance, and DSM costs. The following table shows the Levelized Cost Comparison of the Core Build Plans. The Levelized Cost Comparison of all twenty-four cases is attached as **Appendix J**.

The following tables summarize rankings of the Core Build Plans. The results are color coded: 1. Green = Least Cost, 2. Light Green = Second, 3. Yellow = Third, 4. Orange = Fourth and 5. Red = Highest Cost.

Table 22: Levelized Cost Comparison of the Core Build Plans

(30-Year LNPV in Thousands of Dollars)

Core Build Plans 30 Yr Level NPV ($000)			
Market Scenarios	Reference	High Fossil Fuel Prices	Zero Carbon Cost
Reference	1,884	2,177	1,809
High Fossil Fuel Prices	1,954	2,200	1,838
Zero Carbon Cost	1,895	2,187	1,774
70% CO_2 Reduction	2,072	2,308	2,000
85% CO_2 Reduction	2,393	2,588	2,338

The LNPV cost rankings of the Core Build Plans are generally consistent across the Core Market Scenarios. The Reference Build Plan and the Zero Carbon Build Plan are either the first or second most cost-effective Core Build Plans. The High Fossil Fuel Prices Build Plan is the third lowest cost plan, and the 70% CO_2 and 85% CO_2 Build Plans are consistently the highest and second highest cost plans respectively across all Core Market Scenarios.

Table 23: Percentage Difference in NPV from Reference Build Plan

Core Build Plans Reference %			
Market Scenarios	Reference	High Fossil Fuel Prices	Zero Carbon Cost
Reference	0.0%	0.0%	0.0%
High Fossil Fuel Prices	3.7%	1.0%	1.6%
Zero Carbon Cost	0.6%	0.4%	-1.9%
70% CO_2 Reduction	10.0%	6.0%	10.6%
85% CO_2 Reduction	27.0%	18.8%	29.3%

The LNPV costs of the Reference, High Fossil Fuel Prices and Zero Carbon Cost Build Plans are closely bunched, with less than 2% variation between them in most comparisons. When compared with the Reference Build Plan under the Reference Market Scenario, the High Fossil Fuel Prices Build Plan is 3.7% higher.

The 85% CO_2 Build Plan and the 70% CO_2 Build Plan are the most expensive Core Build Plans with LNPV costs between 6% and 29.3% more than the Reference Build Plan, respectively.

Table 24: Levelized Cost Ranking of the Core Build Plans

Market Scenario 30 Yr LNPV			
Build Plans	Reference	High Fossil Fuel Prices	Zero Carbon Cost
Reference	1	1	2
High Fossil Fuel Prices	3	3	3
Zero Carbon Cost	2	2	1
70% CO_2 Reduction	4	4	4
85% CO_2 Reduction	5	5	5

CO_2 Emissions

The single most important long-term environmental challenge for electric generation will be limiting carbon emissions. Carbon emissions are a particularly important consideration for DESC's customers, for economic development in South Carolina and for achieving Dominion Energy's Net Zero carbon and methane emissions commitment.

Each build plan presented in this 2023 IRP complies with all current environmental regulations on air and climate emissions of electric generating stations, which are among the most stringent that apply to any industry in the United States. Each of them results in DESC reducing its CO_2 levels by at least 55% compared to emissions in 2005. This includes the offsetting of all increases in emissions that would otherwise have been caused by customer load growth since that date.

Under the Reference Market Scenario, the 85% CO_2 Reduction and 70% CO_2 Reduction Build Plans result in greatest reductions of CO_2 emissions 86.8% and 71.3% respectively compared to the 2005 levels. The other three build plans are relatively closely bunched with reductions between 55.2% and 63.3%.

Table 25: 2050 CO_2 Reductions for the Core Build Plans Compared to 2005 Levels

Core Build Plans 2050 CO_2 Reductions Compared to 2005 Levels			
Market Scenarios	Reference	High Fossil Fuel Prices	Zero Carbon Cost
Reference	59.1%	63.3%	55.2%
High Fossil Fuel Prices	59.2%	63.3%	56.4%
Zero Carbon Cost	56.9%	63.2%	56.3%
70% CO_2 Reduction	71.3%	71.3%	71.2%
85% CO_2 Reduction	86.8%	86.9%	86.8%

DESC also computed CO_2 levels in 2050, at the end of the planning horizon. The following table summarizes the CO_2 emissions of the Core Build Plans as forecasted at that time.

Table 26: 2050 CO_2 Emissions (Ktons) of the Core Build Plans

Core Build Plans 2050 CO_2 Emissions (Ktons) of the Core Build Plans			
Market Scenarios	Reference	High Fossil Fuel Prices	Zero Carbon Cost
Reference	7,758	6,968	8,497
High Fossil Fuel Prices	7,740	6,956	8,267
Zero Carbon Cost	8,170	6,975	8,297
70% CO_2 Reduction	5,446	5,443	5,457
85% CO_2 Reduction	2,498	2,489	2,499

As expected, under all Core Market Scenarios, the 85% CO_2 Reduction and 70% CO_2 Reduction Build Plans result in the greatest reduction in CO_2 emissions in 2050. The Reference Build Plan has the lowest or second to lowest reductions. The variation between the carbon constrained build plans, and the Reference Build Plan ranges between 21.8% and 70.6%.

The next table shows the percent variation in CO_2 emissions of the Core Build Plans as forecasted at the end of 2050 using the Reference Build Plan as the point of comparison.

Table 27: 2050 CO_2 Emissions Variation in the Core Build Plans from the Reference Case

Core Build Plans 2050 CO_2 Emissions Variation from the Reference Case			
Market Scenario	Reference	High Fossil Fuel Prices	Zero Carbon Cost
Reference	0.0%	0.0%	0.0%
High Fossil Fuel Prices	3.7%	1.0%	1.6%
Zero Carbon Cost	0.6%	0.4%	-1.9%
70% CO_2 Reduction	10.0%	6.0%	10.6%
85% CO_2 Reduction	27.0%	18.8%	29.3%

DESC has also compared the cumulative reduction in CO_2 emissions under the Core Build Plans over the planning horizon. The results are similar.

Table 28: Cumulative CO_2 Emissions (Ktons) of the Core Build Plans

Core Build Plans Cumulative CO_2 Emissions (Ktons)			
Market Scenario	Reference	High Fossil Fuel Prices	Zero Carbon Cost
Reference	202,714	190,900	218,036
High Fossil Fuel Prices	202,359	190,638	213,541
Zero Carbon Cost	210,270	191,511	214,402
70% CO_2 Reduction	170,724	170,640	171,629
85% CO_2 Reduction	154,049	154,270	155,250

The greatest reductions come under the 70% CO_2 Reduction Build Plan and the 85% CO_2 Reduction Build Plan. But due to the timing of resource additions, the scope of the variation in cumulative emissions is much less than the variation in 2050 emissions, with the 85% CO_2 Reduction Build Plan varying from the Reference Build Plan by only 26.2% compared to 70.6 % when considering emission in 2050 only.

Table 29: Variation from Reference in Cumulative CO_2 Emissions of the Core Build Plans

Core Build Plans Cumulative CO_2 Variation from the Reference Case			
Market Scenario	Reference	High Fossil Fuel Prices	Zero Carbon Cost
Reference	0.0%	0.0%	0.0%
High Fossil Fuel Prices	-0.2%	-0.1%	-2.1%
Zero Carbon Cost	3.7%	0.3%	-1.7%
70% CO_2 Reduction	-15.8%	-10.6%	-21.3%
85% CO_2 Reduction	-24.0%	-19.2%	-28.8%

CO_2 emissions data for all twenty-four cases is attached as **Appendix K**.

Clean Energy

The Clean Energy metric compares the Core Build Plans based on how much energy they produced with non-emitting generation. Clean Energy includes energy generated by nuclear, solar, and hydro facilities. The build plans with the largest Clean Energy generation over the planning horizon are the 70% CO_2 Reduction Build Plan and the 85% CO_2 Reduction Build Plan, at 57.8% and 78.6%, respectively, followed by the High Fossil Fuel Prices Build Plan at 52.1% and the Reference Build Plan at 46.1%. The Zero Carbon Cost Build Plan had the lowest component of Clean Energy in 2050 at 42.7%.

Measuring cumulative Clean Energy generated over the planning horizon shows a similar result, with 70% CO_2 Reduction Build Plan and the 85% CO_2 Reduction Build Plan having the highest levels of Clean Energy production, and the High Fossil Fuel Prices Build Plan taking the third place.

Table 30: Clean Energy Produced by the Core Build Plans

Core Build Plans Clean Energy					
Market Scenario	2050 Clean Energy (GWh)	Percentage of 2050 Clean Energy	Cumulative Clean Energy (GWh)	Percentage of Cumulative Clean Energy	2050 Clean Energy Rank
Reference	15,261	46.13%	338,247	43.54%	4
High Fossil Fuel Prices	17,134	51.54%	365,441	46.86%	3
Zero Carbon Cost	14,096	42.72%	311,693	40.23%	5
70% CO_2 Reduction	19,220	57.83%	384,881	49.40%	2
85% CO_2 Reduction	26,245	78.58%	402,706	51.64%	1

Fuel Cost Resiliency

Each of the Core Build Plans will result in a different mix of generating assets and fuel costs over the planning horizon. Fuel costs are considered along with other costs in the LNPV analysis, but variation in them is also a measure of the degree to which build plans are susceptible to fuel cost risk.

Table 31: Levelized Net Present Value of Fuel Costs

Core Build Plans Levelized Net Present Value of Fuel Costs ($000)			
Market Scenario	Reference	High Fossil Fuel Prices	Zero Carbon Cost
Reference	$669	$961	$690
High Fossil Fuel Prices	$660	$909	$639
Zero Carbon Cost	$712	$1,005	$697
70% CO_2 Reduction	$581	$815	$583
85% CO_2 Reduction	$537	$730	$540

Fuel costs closely track the percentage of non-emitting generation added by each build plan and the relative rankings do not vary across Market Scenarios. Given their high reliance on non-emitting generation, the 85% CO_2 Reduction Build Plan and the 70% CO_2 Reduction Build Plan produces the lowest fuel costs of the Core Build Plans across all three Core Market Scenarios and are 20% and 13% less, respectively, than the Reference Build Plan. These build plans are less susceptible to fuel cost risk, but their lower fuel costs are offset by higher capital costs, and the 85% CO_2 Reduction Build Plan and the 70% CO_2 Reduction Build Plan generate the highest overall cost of all Core Build Plans.

The High Fossil Fuel Prices Build Plan was optimized to perform well in a high fossil fuel cost environment and had the third lowest fuel cost of all the Core Build Plans. The Reference Build Plan was consistently ranked fourth and the Zero Carbon Cost Build Plan had the highest fuel costs due to its low percentage of non-emitting resources and its reliance on less fuel-efficient CTs.

Although all fuel costs are included in this fuel cost analysis, the only fuel prices that vary significantly among Market Scenarios are coal and natural gas prices. Nuclear fuel does not vary significantly due to the around-the-clock operation of nuclear generation and because fuel oil use is limited to the infrequent occasions when natural gas is not available.

Generation Diversity

Each of the Core Build Plans proposes a mix of generation resources which will result in a different level of generation diversity in the system at the end of the planning horizon. The following chart ranks the generation diversity of each of the Core Build Plans according to the concentration of its generation mix in any one type of generation asset. Under this analysis, a plan that leads to a generation system with a single type of generation asset representing 50% of its generation mix would have less generation diversity than a plan where no generation resource type represented more than 45% of its generation mix.

Table 32: Generation Diversity (Diversity Score and Rank Order)

Core Build Plans Generation Diversity			
Market Scenario	Highest Concentration	Most Concentrated Type of Generation	Ranking
Reference	44.40%	Solar	2
High Fuel	50.60%	Solar	5
Zero Carbon Cost	42.40%	Solar	1
Reference	45.90%	Solar	3
Reference	47.60%	Solar	4

In each case, because all build plans concentrate at least 42.4% of system assets in Solar resources the percentage of Solar added drives the diversity score. The highest concentration of Solar, and the lowest diversity score of 50.6%, is under the High Fossil Fuel Prices Build Plan where high fossil fuel costs have resulted in minimal natural gas generation being added to the system. The highest diversity score goes to the Zero Carbon Cost Build Plan which has the lowest concentration of Solar at 42.4%. This reflects the favorable conditions for natural gas generation under which PLEXOS optimized the Zero Carbon Cost Build Plan.

The MW of each generation type added by year for each build plan is provided in **Appendix F**.

Reliability Analysis

The IRP Statute[9] mandates consideration of power supply reliability. The PLEXOS model is configured to ensure that all build plans meet a common reliability standard and that the resources included in each build plan collectively meet the systems' seasonal PRM, including allowances for forced and scheduled outages and other reliability considerations. In addition, the DESC Transmission Planning Group considers coincident peak contribution, energy storage, limited energy storage, dispatchability, and secondary frequency response factors in its annual reliability planning. As a result, all Build Plans are designed with reliability as a priority. No plans are formulated to provide more resources or less resources than are necessary to meet the system reliability criteria.

To provide an additional measure of reliability, and to support comparative evaluation of build plans, DESC has devised a means of scoring the reliability contribution of each generation technology that is included in the build plans. To preclude double-counting, and in consultation with Stakeholders, DESC limited the reliability analysis to factors that are not otherwise considered, specifically black start, fast start, geographic diversity, and proximity in resource modeling to load factors.

Table 33: Reliability Factors Considered in the Metric

Reliability Factor	Able to generate or become a load , shift energy, and complement renewables.
Fast Start	The unit can respond from an offline condition and serve load in less than 10 minutes.
Geographic Diversity	The unit can be located in diverse locations and is not restricted by fuel infrastructure.
Proximity to Load	The unit has a compact footprint and low impact outside of the fence. It can often be sited near load centers.
Black Start	A generating unit which has the ability to be started without support from the system or is designed to remain energized without connection to the remainder of the system, with the ability to energize a bus, meeting the transmission operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that resource can be included in the transmission operator's restoration plan.

Under this analysis, the reliability contribution of each generation resource is as follows:

Table 34: Reliability Factors for Candidate and Retired Resources

Potential Reliability Attribute1	CC	Aero CT	Frame CT	PV Solar	Grid Storage	SMR	Offshore Wind	Coal Units
Black Start	No	Yes	Yes	No	No	No	No	No
Fast Start	No	Yes	Yes	No	Yes	No	No	No
Geographic Diversity	No	No	No	No	Yes	No	No	No
Proximity to Load	Yes	Yes	Yes	No	Yes	Yes	No	Yes[10]

9 S.C. Code Ann. § 58-37-40(C)(2)(d).

10 Williams's location is near a major load center and provides essential reliability attributes in the Charleston metroplex. Wateree is not credited for contributing to reliability in this analysis.

Each build plan has been scored based on the MWs that its resources contribute to fast start, geographic diversity, proximity to load, and black start. The score is based on the raw MW contribution and is not adjusted for abundance or scarcity of the attribute contributed on the system. The results show that each build plan make a positive contribution to system reliability.

Table 35: Reliability Scores

Build Plans	Total Change in Reliability Factor (MW equivalent)	Rank
Reference	7990	3
High Fossil Fuel Prices	7990	3
Zero Carbon Cost	6907	7
70% CO_2 Reduction	6301	9
85% CO_2 Reduction	7105	6
Electrification	7857	5
Energy Conservation	4552	10
Aggressive Regulation	8532	1
High DSM	6307	8
Low DSM	7990	3

Under this analysis, the Reference Build Plan and High Fossil Fuel Prices Build Plan scored highest, followed by the 85% CO_2 Reduction Build Plan. The 70% Reduction Build Plan scored lowest. The determining factor was the amount of CT capacity added under each build plan since CT capacity contributes both black start and fast start capabilities. Battery resources contributed to reliability scores at the same level as CT resources, but there was not enough MW of Battery resources in most build plans to match the reliability effect of CT resources. CC resources contributed to the system reliability scores but at a lower rate than CT resources.

Mini-Max Regret

The Mini-Max Regret metric assesses the potential under each Core Build Plan to incur higher costs that other build plans under the same Core Market Scenario. It does so by measuring the difference in levelized net present value cost between each Core Build Plan and the lowest cost Core Build Plan under that Market Scenario. The difference is called the regret potential associated with that plan.

In this analysis, the Zero Carbon Cost Build Plan received the best Mini-Max Regret score with a zero regrets score under one of the Core Market Scenarios and the second lowest regrets, $10 and $12 million, in the other two. The Reference Build Plan was second with zero regrets across two Core Market Scenarios and the second lowest regrets score, $35 million, in the third.

Table 36: Mini-Max Regret Comparison, Core Build Plans in $ Millions

Core Build Plans Mini-Max Regrets LNPV ($million)			
Build Plans	Reference	High Fossil Fuel Prices	Zero Carbon Cost
Reference	$0	$0	$35
High Fossil Fuel Prices	$70	$23	$64
Zero Carbon Cost	$12	$10	$0
70% CO_2 Reduction	$188	$130	$227
85% CO_2 Reduction	$509	$410	$564

The 85% CO_2 Reduction Build Plan presented the greatest financial risk to customers with the highest level of maximum regrets under each of the Core Market Scenarios. Its regret potential is an additional $509 million per year under the Reference Market Scenario, an amount that is approximately fifteen times greater than the maximum regret for the Reference Build Plan. The 70% CO_2 Reduction Build Plan had the second highest level of maximum regrets under each of the Core Market Scenario with a regret potential of $188 million per year under the Reference Market Scenario, an amount that is over five times greater than the maximum regret of the Reference Build Plan.

Table 37: Comparison of the Regret Levels of the Core Build Plans

Core Build Plans Mini_Max Regret Analysis			
Build Plans	Max Regret ($M)	Percent Greater than Reference	Ranking
Reference	$35	0%	2
High Fossil Fuel Prices	$70	99%	3
Zero Carbon Cost	$12	-67%	1
70% CO_2 Reduction	$227	546%	4
85% CO_2 Reduction	$564	1509%	5

Cost Range Analysis

The Cost Range Analysis calculates the spread between the lowest and highest cost for each build plan across the three Core Market Scenarios. It indicates the degree that a build plan is sensitive to changes in the assumptions that vary between each of the Core Market Scenarios but does not compare build plans against each other and so does not indicate whether a build plan is more or less cost effective or beneficial than any other.

This metric shows that the build plans with the highest renewables percentages, the 85% CO_2 Reduction Build Plan and the 70% CO_2 Reduction Build Plan received the best scores. This reflects the large percentage of non-emitting resources they add that are not subject to changing assumptions concerning CO_2 prices or fuel costs and, as a result, the costs of those build plans vary little when those assumptions are changed. But, given the high capital cost of non-emitting resources, these plans have the highest cost to customers across all Market Scenarios. The Zero CO_2 Cost Plan has the highest cost range reflecting the fact that it is optimized to generate low costs when no CO_2 cost is imposed but incurs higher costs under other assumptions.

Table 38: Cost Range Analysis

(Rank Order and Cost Spread, Minimum to Maximum)

Core Build Plans Cost Range Analysis		
	Max Difference Between Scenarios ($M)	Ranking
Reference	$368	4
High Fossil Fuel Prices	$362	3
Zero Carbon Cost	$413	5
70% CO_2 Reduction	$307	2
85% CO_2 Reduction	$249	1

Core Build Plans Ranked Across All Metrics

Ranking each of the Core Build Plans against all eight metrics shows that, as would be expected, the 85% CO_2 Reduction Build Plan and the 70% CO_2 Reduction Build Plan score well on measures related to environmental concerns, specifically 2050 CO_2 Emissions, Cumulative CO_2 Emissions, and 2050 Clean Energy. These build plans emphasize non-emitting resources which also garner them leadings scores for future Fuel Costs and Cost Range, indicating that their capital investment in non-emitting resources reduces future fossil fuel consumption and costs related to carbon emissions.

Table 39: Rankings of the Core Build Plans Against all Eight Metrics

Core Build Plans	Rankings within All Metrics, Reference Case Where Applicable							
Core Build Plans	30-Year LNPV	2050 CO_2	Cum. CO_2	2050 Clean Energy	Fuel Cost	Gen. Diversity	Reliability	Mini-Max Regret	Cost Range
Reference	1	4	4	4	4	2	1	2	4
High Fossil Fuel Prices	3	3	3	3	3	5	1	3	3
Zero Carbon Cost	2	5	5	5	5	1	4	1	5
70% CO_2 Reduction	4	2	2	1	2	3	5	4	2
85% CO_2 Reduction	5	1	1	2	1	4	3	5	1

The Reference Build Plan scores quite well in metrics related to costs to customers, specifically 30-Year LNPV of generation costs and Mini-Max Regrets, reflecting the fact that it is optimized to produce lowest cost for customers under the Reference Market Scenario. The Zero Carbon Cost Build Plan also scores well in cost related categories.

Although the 85% CO_2 Reduction Build Plan has the best ratings related to CO_2 emissions, fuel costs, clean energy, and cost range, it is also the most expensive build plan with an annual LNPV cost to customers that is between \$509 million and \$564 million more than the lowest cost plan under each Core Market Scenario. The 70% CO_2 Reduction Build Plan also scores well on CO_2 emissions, fuel costs, clean energy, and cost range, but is the second most expensive build plan with a levelized annual cost to customers that is between \$188 million and \$227 million more than the lowest cost plan under each Core Market Scenario.

The evaluation of the Core Build Plans across these eight metrics provides a systematic and quantitative assessment of the factors relevant to the selection of a preferred resource plan. Each of these metrics adds a specific insight to the analysis. But these calculations can never solely take the place of informed judgment and the appropriate balancing of multiple factors. In the current context, an important consideration in evaluating these Core Build Plans is the degree to which they diverge in how they would supply generation resources to replace Wateree and Williams, which represents the important practical planning decision that DESC must make based on this IRP.

Downtown Skyline; Columbia SC

Dominion Energy

The Wateree & Williams Replacement Plans

Williams Station; Goose Creek, SC

The Wateree Replacement Build Plans

In the near term, DESC must make an important decision about how to replace Wateree capacity to support its plan to retire that plant by December 31, 2028, to meet ELG deadlines. All Core Build Plans assume that DESC retires Wateree by that date provided that the Company can resolve all regulatory, procurement and construction related requirements in time to ensure reliable replacement generation capacity is available when required.

PLEXOS identified two possible approaches for replacing Wateree. In the Reference Build Plan and the High Fossil Fuel Prices Build Plan, the optimum replacement resource for Wateree would be 400 MW of Battery to be added in 2029. In the Zero Carbon Cost Build Plan, the 70% CO_2 Reduction Build Plan and the 85% CO_2 Reduction Build Plan, PLEXOS determined that the optimum replacement resource for Wateree would be a 262 MW Large Frame CT along with 100 MW of Battery added in 2029.

To assess the relative advantages and disadvantages of these replacement options, PLEXOS optimized two build plans, each adopting one of the alternative Wateree replacement options as a fixed assumption. The first of those build plans, the Wateree Battery Build Plan, assumes the addition of 400 MW of four-hour duration, standalone battery energy storage in 2029 and optimizes subsequent generation additions assuming the addition of that resource. Underlying this assumption is the understanding that this Battery resource would be located at the Wateree site to take advantage of existing electric transmission and other infrastructure to reduce interconnection, land acquisition, and other costs. The Wateree Battery Build Plan closely resembles the Reference Build Plan but includes less solar and storage as a result of the more precise optimization made possible by preselecting Battery as the replacement resource. (PLEXOS optimizations are more precise when there are fewer variables.)

The Wateree CT Build Plan assumes the addition of a 262 MW Large Frame CT and 100 MW energy storage facility in 2029 and optimizes subsequent generation additions assuming the addition of those resources. Underlying this build plan is the understanding that the Frame CT will be located at the DESC Urquhart Station site to take advantage of access to interstate natural gas pipeline transportation, existing electric transmission infrastructure, and other infrastructure that make the site attractive for natural gas generation resources. Preliminary results from the 2022 TIA were incorporated in this cost analysis to provide a preliminary location-specific estimate of the electric transmission upgrades needed to site a Large Frame CT resource such a unit at Urquhart ($180 million). Both build plans were optimized under the Reference Market Scenario and are not subject to carbon restraints. Both build plans both result in 900 MW of Solar added between 2026 and 2029.

The analysis shows that the Wateree Battery Build Plan is the lower cost of the two options, but the cost difference in terms of LNPV is relatively small, $23 million or 1.25%. The resulting difference in the compound annual growth rate ("CAGR") in retail rates is only 0.21% percentage points (a CAGR of 1.57% for the Wateree CT Build Plan compared to 1.36% for the Wateree Battery Build Plan).

Table 40: Wateree Replacement Plans, LNPV of Costs and Retail CAGR Compared

Wateree Replacement Build Plans LNPV ($M); CAGR %					
Wateree Replacement Build Plans	30-Year LNPV	Difference in NPV	Percentage Difference	Retail CAGR over 15 Years	Difference in CAGR
Wateree Battery	$1,876	$0	0%	1.36%	0%
Wateree CT	$1,900	$23	1.25%	1.57%	0.20%

The two build plans produce slightly different cumulative CO_2 emissions over the planning horizon. Counterintuitively, the Wateree Battery Build Plan has modestly higher cumulative CO_2 emissions than the Wateree CT Build Plan, primarily due to timing differences related to Battery and CT additions and the available system resources from which standalone battery energy storage would charge.

Table 41: Wateree Replacement Plans, Cumulative CO_2 Compared

Wateree Replacement Build Plans Cumulative CO_2 Emission (short tons M)			
Wateree Replacement Build Plans	Cumulative Emissions	Difference	Percentage
Wateree Battery	204,751	0	0%
Wateree CT	204,221	-530	-0.26%

At the end of the planning horizon the Wateree Battery Build Plan has higher 2050 CO_2 emissions, but the difference is still small, only 0.27%.

Table 42: Wateree Replacement Build Plans, 2050 CO_2 Emissions Compared

Wateree Replacement Build Plans 2050 CO_2 Emissions (short tons M)			
Wateree Replacement Build Plans	2050 Emissions	Difference	Percentage
Wateree Battery	7,813	0	0%
Wateree CT	7,792	-21	-0.27%

Both build plans ultimately add identical amounts of Solar (4,950 MW) and Battery (1,500 MW) over the planning horizon, but the Wateree CT Build Plan adds an additional 262 MW in CT capacity to support system reliability. The Wateree CT Build Plan produces a slightly higher level of clean energy capacity on the system in 2050 (51% vs. 50%) but the two build plans produce nearly identical percentages of clean energy over the planning horizon (42.93% vs 42.98%). Under both build plans, PLEXOS still selects the Shared Resource as the optimum replacement for Williams in 2031.

Given the similarities in these build plans, DESC proposes to issue an RFP to further refine cost estimates for replacement resources for Wateree. Design and issuance of this RFP should be informed by the results of the on-going Urquhart Replacements All Sources RFP process and DESC intends to begin this process later in 2023 to support Wateree retiring by December 31, 2028. Timing of this RFP process must account for the time required for development, permitting, procurement, and construction for any resources, particularly considering the on-going uncertainties and volatility in global supply chains. Replacing the Wateree capacity is critically necessary for DESC to maintain system reliability, and DESC cannot proceed with the retirement of the existing facility unless it has reasonable assurances that it can acquire a suitable replacement resource or set of resources in time.

DESC must make a formal regulatory commitment to either retire the plant or begin undertaking upgrades to meet the VIP provisions of the ELGs by December 31, 2025. If DESC decides not to proceed with ELG upgrades at Wateree, it may be forced to close the unit in 2028 regardless of whether replacement resources are available, and this could put system reliability at risk.

DESC has included the Wateree CT Build Plan in this analysis to emphasize the importance of competitively bidding alternative approaches for replacing Wateree rather than limiting the analysis to Battery resources at this stage of the process. The build plans that choose Battery do so based on NREL cost projections which assume significant (and potentially overly optimistic) on-going cost reductions in Battery technology. That may prove to be the case, but it is also possible that in procuring a 2029 resource, the Company may find that the costs are significantly more than the current 2022 NREL cost estimates. From a schedule perspective, supply chain disruptions and equipment delays could make Battery replacement impracticable on a timetable that allows DESC to avoid substantial ELG compliance costs at Wateree. By contrast, CT technology is mature, its costs and construction lead-times are well understood, and its supply chains are stable and well established. Allowing for both technologies to compete in a competitive procurement and to potentially create a blended portfolio of resources will ensure that the latest market pricing, equipment availability and construction timetables determine the cost and schedule for replacing Wateree.

The Williams Replacement Build Plans

Under most build plans, that retirement date for Williams by December 31, 2030 is assumed. But, as a sensitivity analysis, the Williams 2047 Build Plan and the High Fuel Williams 2047 Build Plan model the effects of keeping Williams in service until the end of its useful life in 2047.

PLEXOS modeled Williams 2047 Build Plan under the Reference Market Scenario, making it directly comparable to the Reference Build Plan. It modeled the High Fuel Williams 2047 Build Plan under the High Fossil Fuel Prices Market Scenario, making it directly comparable to the High Fossil Fuel Prices Build Plan.

Comparing the Williams 2047 Build Plan to the Reference Build Plan shows that retiring Williams by 2030 reduces the annual LNPV by approximately $25 million, or 1.32%, and results in a small reduction (0.14%), in the compound rate of growth in retail rates over the planning horizon.

Table 43: Williams Early Replacement, LNPV of Costs and Retail CAGR Compared Under the Reference Market Scenario

Williams 2047 Build Plan LNPV ($M); CAGR %					
Williams Replacement Build Plans	30-Year LNPV	Difference in 30 Year LNPV	Percentage Difference	Retail CAGR over 15 Years	Percentage Differene
Reference	$1,884	$0	0	1.47%	0
Williams 2047	$1,909	$25	1.32%	1.61%	0.15%

Retiring Williams early also reduces cumulative CO_2 emissions over the planning horizon by 3.26%. However, since Williams is assumed to retire before the end of the planning horizon in any case, the reduction in 2050 CO_2 emissions from retiring Williams early is only 0.44%.

Table 44: Williams Early Replacement, Cumulativ and 2050 CO_2 Emissions Compare Under the Reference Market Scenario

Williams 2047 Build Plan (M short tons)					
Williams Replacement Build Plans	30 -Year Cumulative Emissions	Difference	Percentage Difference	2050 Emissions	Percentage Difference
Reference	202,714	0	0	7,758	0
Williams 2047	209,556	6,842	3.38%	7,793	0.44%

The two approaches to retiring Williams result in identical amounts of Solar (5,025 MW) and gas-fired generation (1,708 MW) being added to the system, but the Williams 2047 Build Plan adds 100 MW less of Battery than the Reference Build Plan. For this reason, the Reference Build Plan has cumulative clean energy production that is 21,515 GWH or 6.2% greater than the Williams 2047 Build Plan over the planning horizon. While delaying Williams' retirement until 2047 increases the diversity and reliability of the system portfolio until that date, that advantage is lost in 2047, and from that point forward the two plans are roughly equivalent in their impact on generation diversity and reliability.

DESC also modeled both early and late retirement options under the High Fossil Fuel Prices Market Scenario to quantify the down-side cost and CO_2 risk of delaying Williams' retirement to 2047. Under those conditions, retiring Williams by 2030 generates an annual reduction in the LNPV of charges to customers of $3 million, or 1.68%, and a 0.21% reduction in compound annual retail rate increases over the planning horizon compared to the Williams 2047 High Fuel Build Plan.

Table 45: Williams Early Replacement, LNVP of Costs and Retail CAGR Compared Under the High Fuel Price Scenario

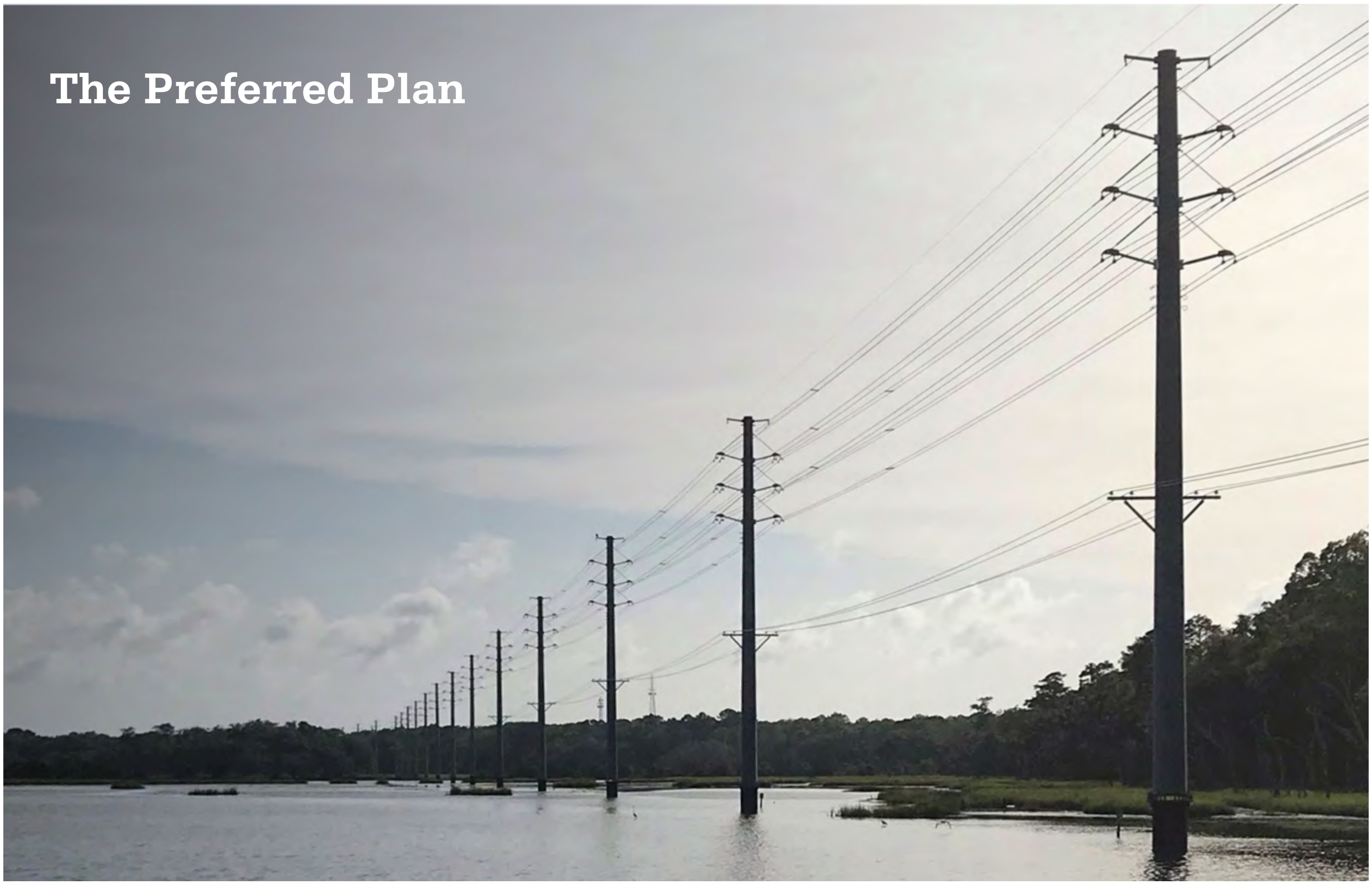
High Fuel Williams 2047 Build Plan LNPV ($M); CAGR %					
Williams Replacement Build Plans	**30-Year LNPV**	**Difference in 30 Year LNPV**	**Percentage Difference**	**Retail CAGR over 15 Years**	**Percentage Difference**
High Fossil Fuel Prices	$2,200	$0	0	2.16%	0
High Fuel Williams 2047	$2,237	$37	1.66%	2.37%	0.21%

Under the High Fossil Fuel Prices Market Scenario, retiring Williams early reduced cumulative CO_2 emissions by 10,054 million tons or 5.01% more than the High Fuel Williams 2047 Build Plan over the planning horizon. Retiring Williams early or not does not materially impact the amount of Solar, Battery or gas-fired generation added to the system, as both build plans result in nearly identical amounts of Solar (6,600 MW and 6,750 MW), with identical amounts of Battery (1,600 MW) and gas-fired generation (1,708 MW) being added to the system. Cumulative clean energy production over the course of the planning horizon is not materially impacted by the early retirement of Williams. Delaying Williams' retirement until 2047 increases the diversity and reliability of the generation system until that date, and the two plans are roughly equivalent in clean energy and CO_2 production in 2050 since Williams has been retired by that date.

Table 46: Williams Early Replacement, Cumulative and 2050 CO_2 Emissions Compared Under the High Fossil Fuel Prices Scenario

High Fuel Williams 2047 Build Plan (M short tons)					
Williams Replacement Build Plans	**30 -Year Cumulative Emissions**	**Difference**	**Percentage Difference**	**2050 Emissions**	**Percentage Differene**
High Fossil Fuel Prices	190,638	0	0	6,956	0
High Fuel Williams 2047	200,693	10,054	5.27%	6,989	0.47%

These facts support DESC's decision to continue to set December 31, 2030, as the assumed retirement date for Williams for planning purposes. That will also be the date by which resources to replace Williams' capacity would need to be completed and on line. It is worth noting that there are significant uncertainties surrounding the timing for a Williams replacement due to its role in supporting transmission system reliability and this in turn creates significant uncertainties concerning the achievability of the retirement date. However, for reasons discussed in the section concerning Coal Retirements, DESC must proceed with ELG compliance activities for Williams; doing so ensures that Williams remains available until suitable replacement resources are available.



The Preferred Plan

Based on its review of the needs of the system and the PLEXOS modeling contained in this 2023 IRP, DESC has determined that the Reference Build Plan is the preferred build plan to guide its planning decisions at this time. The Reference Build Plan is the lowest cost option with the lowest regrets score of any plan under Reference Market Scenario which represents DESC's assessment of the likely conditions to be encountered during the planning period. The only build plan that is comparable in terms of cost considerations under any of the three Core Market Scenarios is the Zero Carbon Cost Build Plan, which only out-performs the Reference Build Plan as to cost or regrets under the assumption that carbon emissions remain cost-free for the duration of the planning period. This is not an assumption on which DESC believes it should base its generation planning at this time.

The 85% CO_2 Reduction Build Plan and the 70% CO_2 Reduction Build Plan outperform the Reference Build Plan on most measures of CO_2 emissions reductions and clean energy. But their costs are significantly higher than the Reference Build Plan.

As a practical matter, the material differences at this time between pursuing the Reference Build Plan compared to the other plans relate to the decisions regarding the replacement of Wateree and Williams. As to these near-term decisions, the principal difference between the Reference Build Plan and the 85% CO_2 Reduction Build Plan or the 70% CO_2 Reduction Build Plan is that the Reference Build Plan replaces Wateree and Williams with 400 MW of Battery followed in 2031 by the 626 MW Shared Resource facility, while the two carbon constrained plans replace Wateree with 100 MW of Battery, and a 262 MW Frame CT in 2029 followed in 2031 by a 1,325 MW CC unit with no assumption of shared ownership. Adopting the Reference Build Plan as the preferred plan under this 2023 IRP does not foreclose either alternative. Conditional on regulatory and other matters, DESC intends to conduct a competitive procurement for resources reflecting these two plans, and through the 2023 TIA will continue to refine the calculation of transmission interconnection costs for both options as well as the cost of the Shared Resource and the 1,325 MW non-shared resource. DESC will make a choice between these options based on the information as it has developed at that time.

Dominion Energy

Forecast of Renewable Generation

All Core Build Plans include significant amounts of renewables energy resources—between 59% and 68% of total generation at the end of the forecast period in the Reference Market Scenario. As expected, the Zero Carbon Cost Build Plan adds the least amount of renewables under each market scenario. The 85% CO_2 and 75% CO_2 Reduction Build Plans contain the most renewables under each Market Scenario. The Reference Build Plan ranks fourth under each Market Scenario. The Zero Carbon Cost Market Scenario results in approximately the same amount of renewable generation as the High Fossil Fuel Prices Market Scenario in four out of the five Build Plans. The values in the table show the total renewable generation by resource plan by five-year period under three market scenarios for the Core Build Plans. Similar data for the sensitivity and supplemental cases are provided in **Appendix E**.

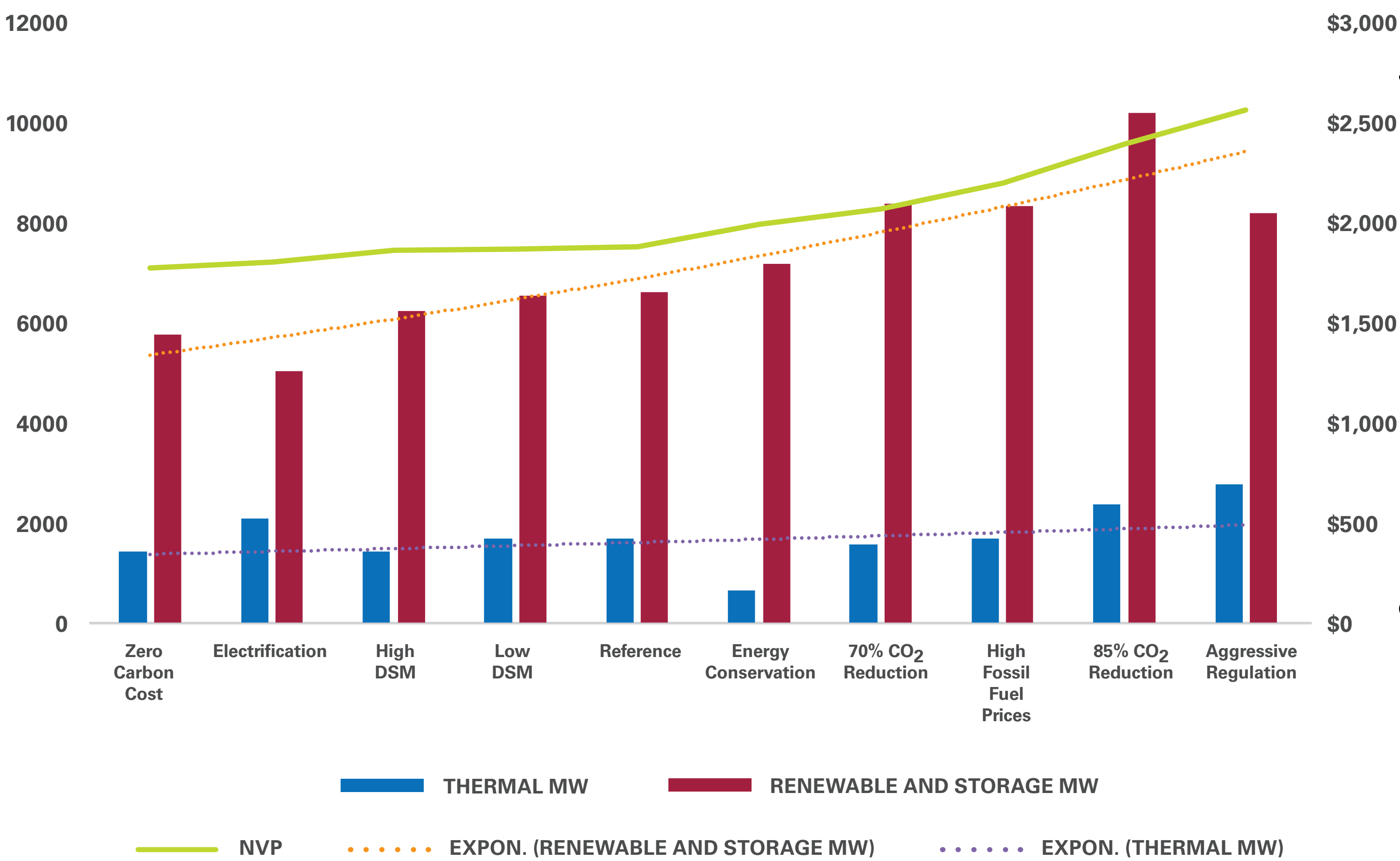
Table 47: Energy from Renewable Generation by Five-Year Period

Energy from Renewable Generation by Five-Year Period (GWh)							
Build Plan	**2023 - 2027**	**2028 - 2032**	**2033 - 2037**	**2038 - 2042**	**2043 - 2047**	**2048 - 2050**	**Total**
Reference Market Scenario							
Reference	13,467	24,350	24,935	40,841	46,632	30,793	181,019
High Fossil Fuel Prices	14,251	26,532	36,557	46,989	54,971	36,454	215,754
Zero Carbon Cost	13,315	20,879	28,124	32,944	40,412	26,294	161,968
70% CO_2 Reduction	14,252	20,187	45,934	67,714	82,840	66,318	297,245
85% CO_2 Reduction	5,451	19,212	33,530	54,029	72,831	49,893	234,945
High Fossil Fuel Prices Market Scenario							
Reference	13,467	24,361	34,392	40,889	47,089	30,863	191,060
High Fossil Fuel Prices	14,252	26,551	36,587	47,055	55,123	36,560	216,128
Zero Carbon Cost	13,311	21,415	28,807	33,668	41,403	27,127	165,731
70% CO_2 Reduction	14,249	26,494	37,051	50,195	63,432	42,875	234,295
85% CO_2 Reduction	5,471	19,252	33,387	53,757	200,992	49,957	362,816
Zero Carbon Cost Market Scenario							
Reference	13,314	23,649	32,460	37,698	44,080	28,606	179,807
High Fossil Fuel Prices	14,250	26,516	36,535	46,945	54,927	36,422	215,596
Zero Carbon Cost	13,310	21,404	28,784	33,595	41,297	27,058	165,448
70% CO_2 Reduction	14,253	26,448	37,019	50,135	63,366	42,828	234,048
85% CO_2 Reduction	5,465	19,177	33,324	53,675	200,910	49,876	362,426

cost of electricity with the addition of renewable energy resources as shown below in Figure 13. This is expected because PLEXOS selects resources based on which resources minimize cost under the given Market Scenario.

This indicates that the overall cost of energy, as determined by fuel costs and CO_2 costs, is a principal driver of the model choosing renewable energy resources.

Figure 21: Thermal, Renewable and Storage Build vs Increasing Scenario Cost Inputs



Insights from the Sensitivity Build Plans Optimized Under Alternative Market Scenarios

Cope Station; Cope, South Carolina

Data from supplemental build plans allows generation planners to identify the changes that would be required to respond effectively to Market Scenarios which are less likely or less representative of the range of possible conditions than Core Market Scenarios. Analyzing when and how supplemental build plans deviate from Core Build Plans can alert generation planners to the most relevant policy trends and market conditions to monitor and can identify the trigger points that may require a change in build plans should unlikely sets of conditions begin to emerge. In DESC's judgment, the Reference Build Plan is the suitable point of comparison for these supplemental build plans because it is optimized for the most likely set of future market conditions and it is the Preferred Plan as identified in this 2023 IRP.

The Electrification Build Plan and Market Scenario

The Electrification Market Scenario assumes that federal and state regulators promote electrification of transportation and other end uses for energy while expanding fossil fuel supplies and not imposing CO_2 costs on electricity. This build plan assumes that high electric demands result from the promotion of electrification, but abundant fuel supplies and zero CO_2 costs keep electric rates low.

The Electrification Build Plan adds 7,147 MW of new or replacement generation over the planning horizon which is 1,186 MW or 17% less than the Reference Build Plan. Even with this smaller portfolio of resources, the Electrification Build Plan can supply 6.8% more energy than the Reference Build Plan (829,632 GWh vs. 777,915 GWh) largely because it can intensively use low-fuel cost gas-fired generation to supply energy needs economically. It adds a total of 2,097 MW of gas generation which is 23% more gas-fired generation (389 MW) than the Reference Build Plan. Of that generation, 1,312 MW or 18% is high efficiency, low emissions CC generation. This compares to only 662 MW CC generation built under the Reference Build Plan which is only 7.9% of the generation built under that plan.

Inexpensive energy from gas generation limits the value of Solar which represents only 48% of the generation built under the Electrification Build Plan compared to 71% of the generation built under the Reference Build Plan (3,450 MW vs 5,025 MW). Both build plans add 1,600 MW of Battery and both add either 150 MW or 300 MW of Solar every year from 2026 to 2049.

Table 48: The Electrification Build Plan

Electrification Build Plan									
Year	**Peak (MW)**	**Firm Capacity (MW)**	**Winter Reserve Margin (%)**	**New Gas (MW)**	**New Solar (MW)**	**New Storage (MW)**	**New Wind (MW)**	**New SMR (MW)**	**Retirements (MW)**
2023	4902	6305	28.6	0	0	0	0	0	0
2024	4775	6282	31.6	0	0	0	0	0	0
2025	4836	6277	29.8	0	0	0	0	0	0
2026	4899	6328	29.2	0	150	0	0	0	0
2027	4963	6338	27.7	0	150	0	0	0	0
2028	5027	6354	26.4	0	150	0	0	0	0
2029	5092	6208	21.9	262	150	300	0	0	-684
2030	5159	6316	22.4	0	150	100	0	0	0
2031	5226	6390	22.3	662	150	0	0	0	-610
2032	5304	6405	20.8	0	150	0	0	0	0
2033	5384	6548	21.6	0	150	200	0	0	0
2034	5465	6640	21.5	0	150	100	0	0	0
2035	5547	6730	21.3	0	150	100	0	0	0
2036	5630	7134	26.7	0	150	800	0	0	0
2037	5714	7136	24.9	0	150	0	0	0	0
2038	5800	7002	20.7	0	150	0	0	0	0
2039	5887	8328	41.5	650	150	0	0	0	0
2040	5976	8325	39.3	0	150	0	0	0	0
2041	6066	8324	37.2	0	150	0	0	0	0
2042	6159	8326	35.2	0	150	0	0	0	0
2043	6254	8326	33.1	0	150	0	0	0	0
2044	6350	8328	31.2	0	150	0	0	0	0
2045	6448	8330	29.2	0	150	0	0	0	0
2046	6547	8333	27.3	0	150	0	0	0	0
2047	6648	8334	25.4	0	150	0	0	0	0
2048	6750	8336	23.5	0	150	0	0	0	0
2049	6854	8605	25.6	523	0	0	0	0	0
2050	6960	8521	22.4	0	0	0	0	0	0

The penalty for intensive reliance on natural gas is that the percentage of cumulative clean energy produced by the Electrification Build Plan is approximately one-third less than the Reference Build Plan (33.9% vs. 43.5%) and in 2050, the percentage of clean energy capacity on the Electrification Build Plan system is only 39% compared to 50% under the Reference Build Plan.

But despite these differences, in the near- to mid-term, the build plans are quite similar. With two exceptions from 2023 until 2029, the Reference Build Plan and the Electrification Build Plan envision adding the same resources, in the same quantities and at the same time. One exception is that that the Reference Build Plan adds 150 MW more Solar in 2028 than the Electrification Build Plan. The other is that to replace Wateree, the Electrification Build Plan adds a 262 MW Frame CT supplemented by 300 MW of Battery in 2029. It then adds another 100 MW of Battery in 2030. The Reference Build Plan, which assumes lower load growth, replaces Wateree with 400 MW of Battery in 2029, adds no CT capacity and no additional Battery until 2033. Both build plans replace Williams in 2031 with the 662 MW Shared Resource.

In this regard, IRPs are updated regularly, and a key function of a supplemental build plan is to show how Core Build Plans would need to change if the alternative Market Scenarios were to develop. In this case, the operative difference between the Electrification Build Plan and the Reference Build Plan in the 2023-2033 period is how it replaces Wateree in 2029.

In this regard, the Electrification Build Plan is not the only build plan that chooses Frame CT plus Battery resources to replace Wateree. Two of the five Core Build Plans do so as well. The other three select replacement by Battery resources and the amount varies based primarily on the load forecast. Thus, the Electrification Build Plan supports the representative nature of the Core Build Plans and does not identify a set of considerations related to the Wateree or Williams replacement that have not already been identified by Core Build Plans.

The Electrification Market Scenario highlights how high load growth and low costs fossil fuels could impact the Wateree replacement decision. It provides an important data point to guide the monitoring of trends in electricity demand and gas supply cost evaluations leading up to that decision. The information it provides is fully consistent with the approach DESC intends to pursue.

The Energy Conservation Build Plan and Market Scenario

The Energy Conservation Market Scenario assumes that policy makers limit investments in new fossil fuel supplies and pipeline capacity in a way that significantly increases fuel prices, but without also pressing for electrification of transportation and other end uses at a level that would overwhelm the ability of conservation efforts to forestall load growth. It assumes levels of energy efficiency in the economy generally and DSM savings levels specific to DESC's service territory that are sufficient to fully offset load growth. These are levels of DSM effectiveness that are greater than any that the 2023 DSM Potential Study determined to be obtainable and ignores the potential impact on demand of electrification of transportation and other end uses. It is based on the lowest load growth projection of any Market Scenario.

DESC agreed to model these assumptions when proposed by Stakeholders in the Stakeholder process. But DESC does not believe the policies and economic outcomes embedded in these assumptions are foreseeable or achievable.

Under these assumptions, the Energy Conservation Build Plan adds 7,862 MW of capacity which is 5.7% less than the Reference Build Plan. Of this amount, 5,700 MW or 73% is Solar capacity. The only gas-fired generation added under the Energy Conservation Build Plan is the 662 MW Shared Resource built to replace Williams and the total gas resources added are 61% less than under the Reference Build Plan. Both Plans involve adding substantial Battery resources, but the Energy Conservation Build Plan includes 100 MW less Battery than the Reference Plan reflecting lower assumptions concerning demand growth.

Table 49: The Energy Conservation Build Plan

Energy Conservation Build Plan									
Year	Peak (MW)	Firm Capacity (MW)	Winter Reserve Margin (%)	New Gas (MW)	New Solar (MW)	New Storage (MW)	New Wind (MW)	New SMR (MW)	Retirements (MW)
2023	4902	6305	28.6	0	0	0	0	0	0
2024	4775	6282	31.6	0	0	0	0	0	0
2025	4789	6277	31.1	0	0	0	0	0	0
2026	4803	6329	31.8	0	300	0	0	0	0
2027	4817	6340	31.6	0	300	0	0	0	0
2028	4832	6356	31.6	0	300	0	0	0	0
2029	4846	5864	21.0	0	300	200	0	0	-684
2030	4860	5888	21.2	0	300	0	0	0	0
2031	4875	5962	22.3	662	300	0	0	0	-610
2032	4899	5978	22.0	0	300	0	0	0	0
2033	4924	6037	22.6	0	300	100	0	0	0
2034	4949	6385	29.0	0	300	400	0	0	0
2035	4973	6391	28.5	0	300	0	0	0	0
2036	4998	6395	28.0	0	300	0	0	0	0
2037	5024	6397	27.4	0	150	0	0	0	0
2038	5049	6264	24.1	0	150	0	0	0	0
2039	5074	6264	23.5	0	150	0	0	0	0
2040	5100	6262	22.8	0	150	0	0	0	0
2041	5125	6261	22.2	0	300	0	0	0	0
2042	5150	6263	21.6	0	150	0	0	0	0
2043	5176	6263	21.0	0	150	0	0	0	0
2044	5202	6315	21.4	0	225	100	0	0	0
2045	5228	6368	21.8	0	300	100	0	0	0
2046	5254	6371	21.3	0	225	0	0	0	0
2047	5280	6423	21.7	0	150	100	0	0	0
2048	5306	6475	22.0	0	150	100	0	0	0
2049	5332	6506	22.0	0	150	400	0	0	0
2050	5359	6507	21.4	0	0	0	0	0	0

Despite these differences, the two build plans are quite similar during the period from 2023 until 2033. With only two exceptions, during that period the Reference Build Plan and the Electrification Build Plan envision adding the same resources, in the same quantities and at the same time.

One exception is that in 2026 and 2027, the Energy Conservation Build Plan adds 300 MW of Solar each year while the Reference Build Plan adds only 150 MW of Solar each year. The other is that in 2029 the Conservation Build Plan replaces Wateree with 200 MW of Battery while the Reference replaces it with 400 MW of Battery. Both build plans replace Williams in 2031 with the 662 MW Shared Resource.

The Energy Conservation Build Plan shows that a combination of high fuel prices and extraordinarily low demand growth could support adding 150 MW of additional Solar in 2026-2027 and could displace 200 MW of Battery resources that might otherwise be needed to replace Wateree. For near to mid-term planning purposes, those are the important conclusions that the Energy Conservation Build Plan supports. But even under extreme assumptions concerning energy efficiency, the Shared Resource will be needed to replace Williams and significant Battery resources will be needed to replace Wateree.

DESC will monitor the evolution of energy efficiency under its DSM programs and energy efficiency in the economy generally to determine what future projections of load growth should govern the decision concerning near term Solar procurements and the amount of Battery resources required to replace Wateree. But nothing in this sensitivity analysis provides a basis for departing from the Reference Build Plan at this time.

The Aggressive Regulation Build Plan and Market Scenario

The Aggressive Regulation Build Plan assumes that policy makers move aggressively to reduce CO_2 emissions by limiting fossil fuel supplies and pipeline access while imposing high costs on electric CO_2 emissions. At the same time, electric loads experience high growth as policy mandates and the high cost of alternative energy sources drive electrification.

The Aggressive Regulation Build Plan adds 10,972 MW of generation over the planning horizon which is 31% more than the Reference Build Plan and the highest amount of capacity added under any build plan. Of this amount, 6,600 MW or 60% is Solar capacity which is 31% more Solar than is added by the Reference Build Plan. Both Plans add 1,600 MW of Batteries, and both envision replacing Williams with the 662 MW Shared Resource.

High electric demand, high fossil fuel prices and high CO_2 emissions costs create a build plan that adds 2,772 MW of gas fired generation. This is 63% more generation than the Reference Plan adds, and crucially 71% of this generation, 1,978 MW, is high efficiency, low emissions CC natural gas generation which is 300% more CC capacity than the Reference Build Plan. This build plan adds the largest amount of CC generation of any build plan.

As a result of high fuel costs, the high number of MW added and the high capital costs of CC units, the Aggressive Regulation Build Plan has the highest retail rate impact of any build plan with a CAGR in retail rates that is 83% higher than the Reference Build Plan (2.69% vs, 1.47%). But aggressive regulation results in only a marginal increase in the cumulative percentage of clean energy generated over the planning horizon (44% vs 43%) and clean energy capacity in 2050 is only 2% higher (52% vs 50%) compared to the Reference Build Plan.

But for all their differences, during the period 2023-2033, the construction program under Aggressive Regulation Build Plan diverges from the Reference Build Plan in only two respects. Like the Energy Conservation Build Plan, it adds 300 MW of Solar in 2026 and 2027 not 150 MW as does the Reference Build Plan. Also like the Electrification Build Plan, the Aggressive Regulation Build Plan does not replace Wateree with Battery. Instead, like the Electrification Build Plan it adds a 262 MW Frame CT supplemented by 300 MW of Battery in 2029 and adds another 100 MW of Battery in 2030.

In the final analysis, the Aggressive Regulation Build Plan shows that in the near to middle term a combination of aggressive limitations on fossil fuels, high CO_2 costs, and aggressive electrification policies could support DESC adding 150 MW of additional Solar in 2026-2027 and replacing Wateree with both a 262 Frame CT and 400 MW of Battery installed in 2029 and 2030. It is otherwise consistent with the Core Build Plans and supports their representative nature. It does not provide a basis for departing from the Reference Build Plan at this time.

Table 50: The Aggressive Regulation Build Plan

Aggressive Regulation Build Plan									
Year	Peak (MW)	Firm Capacity (MW)	Winter Reserve Margin (%)	New Gas (MW)	New Solar (MW)	New Storage (MW)	New Wind (MW)	New SMR (MW)	Retirements (MW)
2023	4902	6305	28.6	0	0	0	0	0	0
2024	4775	6282	31.6	0	0	0	0	0	0
2025	4836	6277	29.8	0	0	0	0	0	0
2026	4899	6329	29.2	0	300	0	0	0	0
2027	4963	6340	27.8	0	300	0	0	0	0
2028	5027	6356	26.5	0	300	0	0	0	0
2029	5092	6211	22.0	262	300	300	0	0	-684
2030	5159	6320	22.5	0	300	100	0	0	0
2031	5226	6394	22.4	662	300	0	0	0	-610
2032	5304	6410	20.9	0	300	0	0	0	0
2033	5384	6469	20.2	0	300	100	0	0	0
2034	5465	6732	23.2	0	300	300	0	0	0
2035	5547	6738	21.5	0	300	0	0	0	0
2036	5630	6892	22.4	0	300	300	0	0	0
2037	5714	6895	20.7	0	300	0	0	0	0
2038	5800	8087	39.4	1325	300	0	0	0	0
2039	5887	8089	37.4	0	300	0	0	0	0
2040	5976	8087	35.3	0	300	0	0	0	0
2041	6066	8086	33.3	0	300	0	0	0	0
2042	6159	8088	31.3	0	300	0	0	0	0
2043	6254	8090	29.4	0	300	0	0	0	0
2044	6350	8092	27.5	0	300	0	0	0	0
2045	6448	8095	25.6	0	300	0	0	0	0
2046	6547	8098	23.7	0	150	0	0	0	0
2047	6648	8099	21.8	0	150	0	0	0	0
2048	6750	8201	21.5	0	150	200	0	0	0
2049	6854	8521	24.3	523	150	100	0	0	0
2050	6960	8537	22.7	0	0	200	0	0	0

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Rate and Bill Impacts

Levelized cost is one of the eight principal metrics against which the Core Build Plans are measured. To show the impact of changes in levelized cost on customers, DESC has taken the levelized cost for each Core Build Plan and combined it with rate data to show the resulting changes in retail rates ("Retail Rates"), and in the monthly bill of a typical residential customer ("Customer Bills"). The typical residential customer for DESC is a Rate 8 customer using 1,000 kWh per month.

This rate and bill impact analysis incorporates changes in fuel costs, including CO_2 and other emissions costs from burning fuel, and the capital and operating cost of generation assets but does not attempt to model other factors that would change Retail Rates or Customer Bills over time and so is not a forecast of future rates. It models changes in rates and bills resulting from changes in generation supply costs, all other things being equal, and is not a comprehensive rate forecast. It covers a fifteen-year period and incorporates the annual costs of generation supply for each year of that period.

Fuel costs, CO_2 costs, and load growth projects are important drivers of both Retail Rates and Customer Bills. Accordingly, in most cases, the changes in fuel costs and CO_2 costs between Market Scenarios drive Retail Rates and Customer Bills up or down in a consistent fashion, and build plans often maintain similar same relative positions across Market Scenarios. The factors that vary between Market Scenarios impact the cost to customers of build plans so strongly that comparing different build plans under different Market Scenarios does not provide meaningful information.

Under the Reference Market Scenario, the Reference Build Plan results in the lowest compound annual rate of growth in Customer Bills and the Zero Carbon Cost Build Plan is a close second with a CAGR that only is only 0.01 percentage points or 0.55% higher. Under the other two Core Market

Table 51: Compound Annual Growth Rate and Total Change in a Typical Customers' Bill Under the Core Analysis Due to Generation Costs

Typical Residential Bill @1000 kWh/month			
Market Sceanrio	**Build Plan**	**CAGR**	**Total Change**
Reference	Reference	1.63%	25.32%
Reference	High Fossil Fuel Prices	1.72%	26.91%
Reference	Zero Carbon Cost	1.63%	25.47%
Reference	70% CO_2 Reduction	2.36%	38.58%
Reference	85% CO_2 Reduction	2.35%	38.52%
High Fossil Fuel Prices	Reference	2.15%	34.66%
High Fossil Fuel Prices	High Fossil Fuel Prices	2.20%	35.65%
High Fossil Fuel Prices	Zero Carbon Cost	2.13%	34.39%
High Fossil Fuel Prices	70% CO_2 Reduction	2.76%	46.40%
High Fossil Fuel Prices	85% CO_2 Reduction	2.76%	46.41%
Zero Carbon Cost	Reference	1.43%	21.98%
Zero Carbon Cost	High Fossil Fuel Prices	1.51%	23.30%
Zero Carbon Cost	Zero Carbon Cost	1.34%	20.49%
Zero Carbon Cost	70% CO_2 Reduction	2.20%	35.69%
Zero Carbon Cost	85% CO_2 Reduction	2.20%	35.70%

Scenarios, the Zero Carbon Cost Build Plan has the lowest CAGR of all build plans and is between 0.02 percentage points (0.93%) and 0.09 percentage points (6.29%) lower than the Reference Build Plan. But the Reference Build Plan has the second lowest CAGR in those cases where the Zero Carbon Cost Build Plan is lowest.

The 85% CO_2 Reduction Build Plan or the 70% CO_2 Reduction Build Plan produce either the highest or the second highest CAGR under all Core Market Scenarios. The 85% CO_2 Reduction Build Plan results in CAGRs that are between 28.37% and 63.64% higher than the Reference Build Plan. The 70% CO_2 Reduction Build Plan produces CAGR that are between 28.37% and 57.34% higher than the Reference Build Plan.

Table 52: Variation in Compound Annual Growth Rate in a Typical Customers' Bill

CAGR and % Variation of the Typical Residential Bill @1000 kWh/month			
Market Sceanrio	Build Plan	CAGR Variation from the Reference Build Plan	Percentage Variation from the Reference Build Plan
Reference	Reference	0.00%	0.00%
Reference	High Fossil Fuel Prices	0.09%	5.63%
Reference	Zero Carbon Cost	0.01%	0.54%
Reference	70% CO_2 Reduction	0.73%	45.09%
Reference	85% CO_2 Reduction	0.73%	44.90%
High Fossil Fuel Prices	Reference	0.00%	0.00%
High Fossil Fuel Prices	High Fossil Fuel Prices	0.05%	2.50%
High Fossil Fuel Prices	Zero Carbon Cost	-0.01%	-0.67%
High Fossil Fuel Prices	70% CO_2 Reduction	0.61%	28.50%
High Fossil Fuel Prices	85% CO_2 Reduction	0.61%	28.51%
Zero Carbon Cost	Reference	0.00%	0.00%
Zero Carbon Cost	High Fossil Fuel Prices	0.08%	5.45%
Zero Carbon Cost	Zero Carbon Cost	-0.09%	-6.23%
Zero Carbon Cost	70% CO_2 Reduction	0.77%	54.18%
Zero Carbon Cost	85% CO_2 Reduction	0.77%	54.20%

The corresponding figures for Retail Rates show a similar pattern but higher impact due to how costs are allocated between customer classes based on cost of service data. A principal driver of these allocations is contribution to system peak demand, which varies among customer classes. The Reference Build Plan, not the Zero Carbon Cost Build Plan, has the lowest rate impact under the Reference and High Fossil Fuel Market Scenarios again due to how costs are allocated among residential customer classes and other customer classes. The carbon constrained cases have the highest rate impact across all Core Market Scenarios by a wide margin.

Table 53: Compound Annual Growth Rate and Total Change in a Retail Rates Under the Core Analysis Due to Generation Costs

CAGR and % Change in the Retail Rate			
Market Sceanrio	Build Plan	CAGR	Total Change
Reference	Reference	1.47%	22.64%
Reference	High Fossil Fuel Prices	1.55%	23.95%
Reference	Zero Carbon Cost	1.52%	23.57%
Reference	70% CO_2 Reduction	2.12%	34.11%
Reference	85% CO_2 Reduction	2.11%	34.04%
High Fossil Fuel Prices	Reference	2.13%	34.28%
High Fossil Fuel Prices	High Fossil Fuel Prices	2.16%	34.87%
High Fossil Fuel Prices	Zero Carbon Cost	2.15%	34.76%
High Fossil Fuel Prices	70% CO_2 Reduction	2.63%	43.90%
High Fossil Fuel Prices	85% CO_2 Reduction	2.63%	43.92%
Zero Carbon Cost	Reference	1.21%	18.36%
Zero Carbon Cost	High Fossil Fuel Prices	1.27%	19.36%
Zero Carbon Cost	Zero Carbon Cost	1.15%	17.30%
Zero Carbon Cost	70% CO_2 Reduction	1.92%	30.45%
Zero Carbon Cost	85% CO_2 Reduction	1.92%	30.45%

Retail rate impacts of the Core Build Plans are provided in Table 54 below in dollar terms. The retail rate impacts for the non-Core Build Plans are provided in **Appendix H**.

Table 54: Retail Rate Impact under Core Build Plans (Reference Market Scenario, dollars/kWh)

Retail Rate Impact (dollar/kWh)																
Market Sceanrio	**Build Plan**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Reference	Reference	0.10772	0.10215	0.10022	0.1029	0.10208	0.10343	0.10386	0.10842	0.10942	0.11657	0.11913	0.12317	0.12562	0.13001	0.13211
Reference	High Fossil Fuel Prices	0.10772	0.10235	0.1005	0.10351	0.10282	0.10419	0.10452	0.11024	0.11069	0.11693	0.12053	0.12392	0.127	0.13162	0.13352
Reference	Zero Carbon Cost	0.10772	0.10235	0.1005	0.10325	0.10216	0.10318	0.10493	0.11139	0.11142	0.11759	0.12136	0.1238	0.12971	0.13156	0.13311
Reference	70% CO_2 Reduction	0.10772	0.10215	0.10022	0.10315	0.10259	0.104	0.10541	0.11004	0.11862	0.12584	0.13079	0.1329	0.13738	0.14071	0.14446
Reference	85% CO_2 Reduction	0.10772	0.10214	0.10022	0.10316	0.1026	0.104	0.10541	0.11003	0.11862	0.12583	0.13078	0.13289	0.13736	0.14029	0.14439
High Fossil Fuel Prices	Reference	0.10772	0.10214	0.10021	0.11302	0.11098	0.11224	0.11352	0.11809	0.11822	0.12663	0.1297	0.13407	0.13694	0.14228	0.14465
High Fossil Fuel Prices	High Fossil Fuel Prices	0.10772	0.10215	0.10022	0.11311	0.11128	0.11256	0.11375	0.11824	0.1185	0.12684	0.12994	0.13428	0.13718	0.14246	0.14528
High Fossil Fuel Prices	Zero Carbon Cost	0.10772	0.10215	0.10022	0.11306	0.11093	0.11205	0.11421	0.11888	0.11916	0.12735	0.13074	0.13414	0.13969	0.14288	0.14516
High Fossil Fuel Prices	70% CO_2 Reduction	0.10772	0.10214	0.10021	0.11309	0.11126	0.11254	0.11467	0.11934	0.1264	0.13452	0.1401	0.14233	0.14748	0.15151	0.15501
High Fossil Fuel Prices	85% CO_2 Reduction	0.10772	0.10214	0.10022	0.1131	0.11128	0.11256	0.11471	0.11936	0.12642	0.13454	0.14013	0.14236	0.1475	0.15153	0.15503
Zero Carbon Cost	Reference	0.10772	0.10235	0.1005	0.10326	0.10254	0.10385	0.10419	0.10749	0.10798	0.11357	0.11664	0.11964	0.1225	0.12722	0.1275
Zero Carbon Cost	High Fossil Fuel Prices	0.10772	0.10212	0.10025	0.10317	0.10258	0.10398	0.10434	0.10624	0.10755	0.11405	0.11605	0.11975	0.12157	0.1261	0.12857
Zero Carbon Cost	Zero Carbon Cost	0.10772	0.10216	0.10022	0.10291	0.10192	0.10298	0.10429	0.10624	0.10745	0.11382	0.11604	0.11847	0.12282	0.12472	0.12636
Zero Carbon Cost	70% CO_2 Reduction	0.10772	0.10215	0.10021	0.10315	0.10259	0.10399	0.1054	0.10743	0.1166	0.12326	0.12781	0.12965	0.13357	0.13695	0.14052
Zero Carbon Cost	85% CO_2 Reduction	0.10772	0.10215	0.10022	0.10315	0.10259	0.10399	0.1054	0.10742	0.11659	0.12326	0.12781	0.12964	0.13355	0.13694	0.14052

Customer Bill impacts of the Core Build Plans are provided in Table 55 below in dollar terms. The bill impacts for the non-Core Build Plans are provided in **Appendix H**.

Table 55: Typical Residential Bill under Core Build Plans (Reference Market Scenario, 1000kWh/month)

Typical Residential Bill @1000 kWh/month																
Market Sceanrio	**Build Plan**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Reference	Reference	132.8	126.8	125.2	129.8	129.3	131.3	131.6	136.6	138.6	147.3	150.4	155.5	158.5	164.1	166.4
Reference	High Fossil Fuel Prices	132.8	127.0	125.5	130.6	130.5	132.4	132.6	138.8	140.3	148.1	152.2	156.7	160.2	166.0	168.5
Reference	Zero Carbon Cost	132.8	127.0	125.5	130.1	129.3	130.7	132.6	139.5	140.5	148.3	152.6	155.6	162.7	164.8	166.6
Reference	70% CO_2 Reduction	132.8	126.8	125.3	130.3	130.3	132.3	133.9	139.0	151.5	160.5	166.7	169.4	174.8	179.2	184.0
Reference	85% CO_2 Reduction	132.8	126.8	125.2	130.3	130.2	132.2	133.9	139.0	151.5	160.5	166.7	169.4	174.8	178.7	183.9
High Fossil Fuel Prices	Reference	132.8	126.8	125.2	139.8	138.2	140.0	141.1	146.2	147.4	157.3	160.9	166.3	169.7	176.2	178.8
High Fossil Fuel Prices	High Fossil Fuel Prices	132.8	126.8	125.2	140.2	138.9	140.7	141.8	146.7	148.0	157.9	161.5	166.9	170.3	176.8	180.1
High Fossil Fuel Prices	Zero Carbon Cost	132.8	126.8	125.2	139.8	138.0	139.5	141.8	146.9	148.2	157.9	161.9	165.8	172.5	175.9	178.5
High Fossil Fuel Prices	70% CO_2 Reduction	132.8	126.8	125.2	140.1	138.8	140.7	143.1	148.2	159.2	169.1	175.9	178.8	184.8	189.8	194.4
High Fossil Fuel Prices	85% CO_2 Reduction	132.8	126.8	125.2	140.1	138.9	140.7	143.1	148.2	159.3	169.1	175.9	178.8	184.8	189.8	194.4
Zero Carbon Cost	Reference	132.8	127.0	125.5	130.1	129.8	131.7	131.9	135.7	137.3	144.4	148.0	152.1	155.5	161.4	162.0
Zero Carbon Cost	High Fossil Fuel Prices	132.8	126.8	125.3	130.3	130.2	132.2	132.4	134.9	137.2	145.3	147.9	152.6	155.0	160.7	163.7
Zero Carbon Cost	Zero Carbon Cost	132.8	126.8	125.2	129.8	129.0	130.5	131.9	134.4	136.7	144.6	147.4	150.4	155.9	158.1	160.0
Zero Carbon Cost	70% CO_2 Reduction	132.8	126.8	125.2	130.3	130.2	132.2	133.9	136.5	149.6	158.0	163.8	166.3	171.1	175.5	180.2
Zero Carbon Cost	85% CO_2 Reduction	132.8	126.8	125.2	130.3	130.2	132.2	133.9	136.5	149.5	158.0	163.8	166.3	171.1	175.5	180.2

The DSM Build Plans

All Core Build Plans are based on the Medium DSM forecast which assumes that DESC can achieve 0.51% energy sales reduction through offering revised and expanded DSM portfolio of programs and marketing plans with the revised measures identified in the 2023 DSM Potential Study. To meet Act No. 62 requirements, DESC modeled two build plans as sensitivities to assess the impact of difference levels of assumed DSM impacts under otherwise similar market scenarios (the "DSM Sensitivities"). The High DSM Build Plan assumes DSM programs achieve their Maximum Achievable Potential as shown in the 2023 DSM Potential Study, which was determined by ICF to be 0.74% reduction in energy sales. That build plan is otherwise optimized under the Reference Market Scenario. The Low DSM Build Plan assumes that DSM programs are only able to achieve 90% of the Achievable Potential as shown in the 2023 DSM Potential Study, which was determined to be 0.46% reduction in energy sales but is otherwise optimized under the Reference Market Scenario.

The analysis shows that the Reference Build Plan is slightly higher in LNPV cost than the High DSM Build Plan and the Low DSM Build Plan, but only by 1% and 0.8%, respectively. The High DSM Build Plan is the lowest in LNPV cost of the three DSM Sensitivities. The resulting difference in the CAGR in retail rates among the DSM Sensitivities is only 0.01% and 0.19% as compared to the Reference Build Plan (a CAGR of 1.46% for the High DSM Build Plan and 1.28% for the Low DSM Build Plan compared to 1.47% for the Reference Build Plan).

Table 56: DSM Build Plan Sensitivities, LNPV of Costs and Retail CAGR Compared Under the Reference Market Scenario

DSM Sensitivities LNPV ($M); CAGR %					
DSM Sensitivity Build Plans	30-Year LNPV	Difference in 30 Year LNPV	Percentage Difference	Retail CAGR over 15 Years	Percentage Difference
Medium DSM	$1,884	$0	0	1.47%	0
High DSM	$1,863	($21)	-1.1%	1.46%	-0.01%
Low DSM	$1,868	($16)	-0.83%	1.28%	-0.19%

The DSM assumptions have little impact on carbon emissions over the planning horizon, both reducing 2050 CO_2 emissions only by an additional 0.02% and cumulative CO_2 emissions by an additional 0.01%.

Table 57: DSM Sensitivities, Cumulative and 2050 CO_2 Emissions Compared Under the Reference Market Scenario

DSM Sensitivity Build Plans (M short tons)					
DSM Sensitivity Build Plans	30-Year Cumulative Emissions	Difference from Reference	Percentage Difference	2050 Emissions	Percentage Difference
Medium DSM	202,714	0	0	7,758	0
High DSM	200,369	(2,346)	-1.16%	7,630	-1.66%
Low DSM	199,759	(2,955)	-1.46%	7,626	-1.71%

The High DSM Build Plan and the Low DSM Build Plan add the same amount of Solar (4,950 MW), but the Low DSM Build Plan adds slightly more Battery (1,600 MW versus 1,300 MW) and more Frame CT (1,046 MW versus 785 MW). All three build plans, including the Reference Build Plan, add the same amount of CC (662 MW). The Reference Build Plan adds slightly more Solar than the DSM Sensitivities (5,025 MW) but is otherwise identical to the Low DSM Build Plan.

These DSM Sensitivities show that the effective level of DSM programs over the planning horizon, from best to worst case scenario, will have very minor impacts on the costs, CO_2 emissions, and generation resources needed over the planning horizon. Each results in a similar approach to replacing Wateree and Williams.

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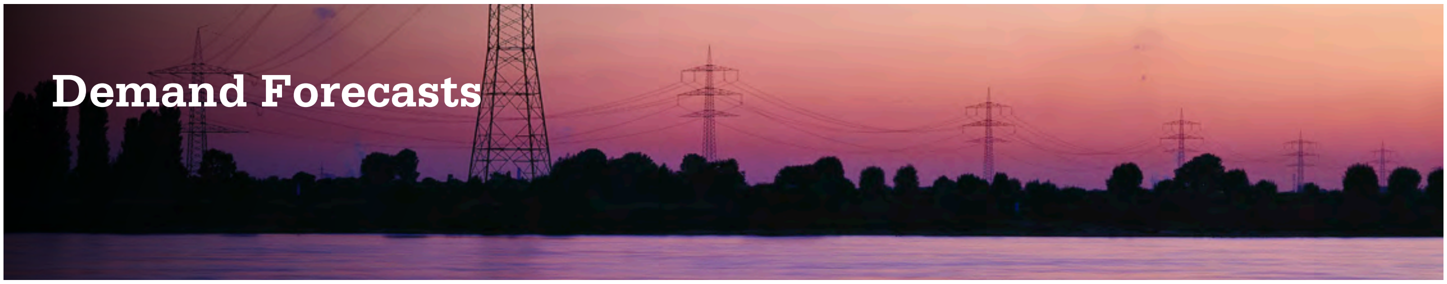
Demand Forecasts



The DSM analysis provides an important data point concerning how different assumptions about load growth affect the resulting build plans. In addition, the Reference, Electrification and Energy Conservation Build Plans provide three build plans incorporating the reference, high and low load growth forecast. These build plans assume different levels of fuel cost and CO_2 cost in addition to different assumptions as to base load growth since these factors are not independent variables but reflect certain policy choices and economic conditions that are to some degree interrelated. As discussed in the sections concerning Supplemental Build Plans, an analysis of these three build plans affirms that DESC's present approach to replacing the Wateree and Williams, capacity, and other near-term generation supply decisions including the amount of Solar capacity to add in 2026-2027, is sound and appropriate under a range of load growth assumptions. The variation that they reflect in short to near-term build plans is fully taken into account in this analysis.

Because the 2023 IRP is a planning document based on a snapshot in time, DESC will continue to evaluate these decisions as timely information concerning energy conservation generally and the scope and effectiveness of DSM programs become available.

The Dynamic Nature of Resource Planning

Resource planning is conducted throughout the year by the Company for multiple planning and resource procurement purposes. Given the pace of change in customer and other stakeholder expectations, technological advances, and environmental policies, it is important that the Company remain flexible with respect to build plans and asset procurements, retirements, up-ratings, and improvements. Resource plans will be updated to reflect current needs and the timing when future procurement or retirement decisions are considered based on these needs. The fact that DESC modeled the procurement or retirement of any resource in this 2023 IRP does not mean that DESC has made the decision to procure or retire any such resource or that such a decision has been approved by the Commission where such approval is required. These decisions will be presented to the Commission as appropriate at the time they are made or proposed, in accordance with the relevant aspects of the Siting Act.

Dominion Energy

Integration of the IRP into Utility Planning

Order No. 2020-832 requires the Company to outline how the IRP integrates into other planning at the Company. Each IRP identifies a preferred resource plan for planning purposes based on models run by the Resource Planning Department using inputs from the Forecasting group, the DSM group, the Load Research group, Power Generation Department, Nuclear Operations Department, the Fuel Procurement and Asset Management Department, Economic Resource Commitment Department, and the Dominion Energy Services - Project Construction Financial Management and Controls, among others. Changes in the IRP are communicated to these departments to ensure that their planning is based on current information.

In addition, as each IRP is approved, the preferred resource plan and its methodology are used by the Resource Planning Department for calculating avoided energy and capacity costs for projects that qualify as small renewable energy projects under the Federal Public Utilities Regulatory Policies Act, 16 U.S.C. 796 et seq., and the implementing FERC regulations, 18 C.F.R. §292.204. The results of these calculations are integrated into PPAs negotiated with renewable project developers by the Power Marketing Department. The resource planning model is also used by the Resource Planning Department and the Rates and Regulatory Department to prepare avoided cost filings presented to the Commission on a twenty-four-month cycle as required by S.C. Code Ann. § 58-41-20.

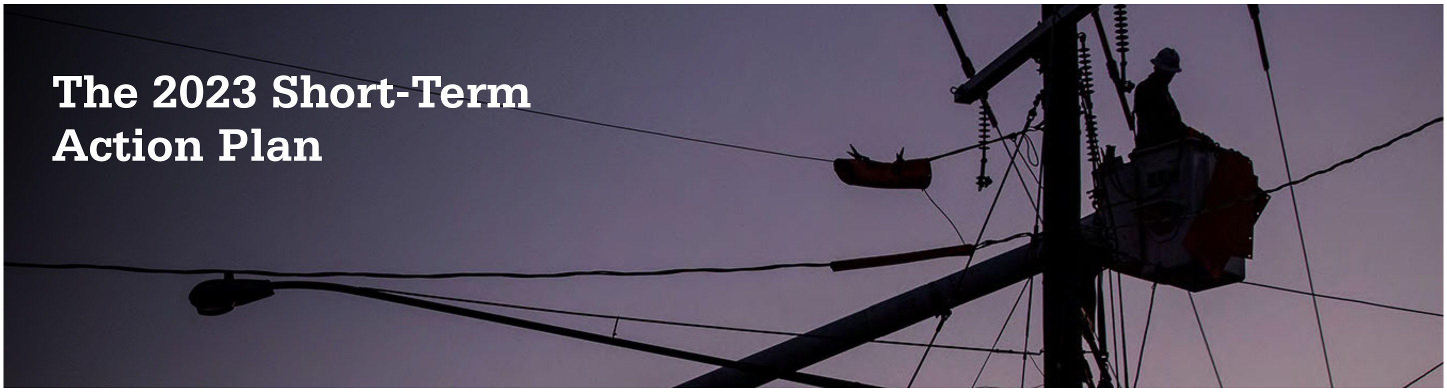
If the Company's preferred generation plan as identified through the IRP process shows that new generation resources are needed to meet customer load, the Resource Planning Department and Power Generation Operations Department will determine the lead time required to construct and permit those resources and any related fuel supply or transmission assets that are envisioned.

At this point, additional departments, including the DESC Transmission Planning Group, Power Delivery Business Unit and the Fuel Procurement and Asset Management Department, may be consulted. At the appropriate time, a tentative construction decision will be made establishing the size, technology and location of the required resources. The determination will then be made as to whether an all-source RFP for the new generation is required or advisable. The IRP will be updated to reflect these decisions in the next filing.

The decision to proceed with the project will be communicated to the DESC Transmission Planning Group by filing a formal interconnection application under DESC's FERC regulated Open Access Transmission Tariff. Any additional transmission resources required to support the generation plan will be identified by the DESC Transmission Planning Group, which will rely on the Electric Transmission Support Department in consultation with the Power Delivery Business Unit to determine the cost and schedule for construction of those transmission assets. The resulting costs and timelines will be communicated by the DESC Transmission Planning Group to the Resource Planning Department and Power Generation Operations Department for review and incorporation in future IRP filings.

At various stages in this process, the cost and justification for the generation and transmission assets would be reviewed by DESC senior leadership, and by the Investment Review Committee at Dominion Energy, Inc., and its CEO and board which must approve such significant capital expenditures. If a decision is made to construct the assets, those assets will be incorporated in the DESC Transmission Planning Group's reliability and interconnection models and in future IRP filings or annual updates.

The 2023 Short-Term Action Plan



Monitoring of Supply Side Decision Points

DESC's current generation reserves are sufficient to meet customers' demands under foreseeable conditions consistent with the planning criteria of not experiencing a generation-related loss of load event on the system more than once every ten years. That calculus changes dramatically with the retirement of Wateree and Williams and the loss to the system of approximately 1,294 of base load capacity. DESC remains committed to retiring Wateree in 2028 and Williams in 2030 if that can be done safely, reliably, and affordably.

In 2023, and with the support of this Commission and ORS, DESC will need to make critically important decisions concerning the replacement Wateree and Williams capacity. To support that decision making, the Company will carefully monitor changes affecting generation cost and needs including natural gas prices, regulatory and legislative requirements regarding CO_2 emissions, the costs of renewable and energy storage technologies, access to fuel supplies and delivery options, governmental incentives, changing environmental policies and the emergence of novel generating technologies. An important data point in this monitoring will the pricing data for generation resources discovered as a result of the bids made to replace the CT and fossil steam capacity at Urquhart which should be available in mid-2023.

At the core of this short-term action plan is the Company's intention to monitor changing market conditions and state or federal environmental laws and regulations and update its planning to reflect those changes. DESC will continue to pursue regular and meaningful dialogues with ORS and Stakeholders to receive comments and information and to work toward achieving as great a level of consensus around these matters as is possible given the divergent interests and perspectives of the parties. As always, DESC's guiding commitment is to provide safe, reliable, clean and affordable energy to its customers.

Generation Retirement Planning / Request for Proposals for Future Generation Procurement

Since 2002, DESC has retired or repowered eight coal units, and has reduced the percentage of coal-based energy it uses to serve its customers from 66% in 2005 to 24% in 2021. After discussions with the stakeholders, retirement studies for Wateree and Williams were completed and filed with Commission on May 16, 2022. The conclusions of the Coal Plants Retirement Study have been incorporated in this 2023 IRP.

As amended in 2019, the Siting Act authorizes the Commission, upon a showing of need, to require competitive bidding for major utility projects on a case by case basis considering the needs and circumstances of each case. DESC will use the framework established through the Urquhart RFP for future competitive procurement activities related to Wateree replacement as discussed above. Such RFPs require reasonable specificity concerning the nature and attributes of the resources required, and the timetable for procuring them.

The specific short-term actions that the Company intends to take in 2023 to accomplish its retirement planning goals and goals for competitive procurement are to:

- Complete the second and third TIA for the Wateree and Williams retirements.
- Design and conduct a competitive procurement activity to identify potential replacement resource(s) to support the retirement of Wateree by the end of 2028.
- Continue to evaluate the feasibility of planning assumptions as to retirement dates after being informed by competitive procurement and transmission impact analyses.

Peaking Modernization Program

The addition of approximately 1,000 MW of intermittent solar generation on the Company's system and normal operational contingencies have placed additional demands on its aging, outdated, fleet of simple cycle combustion turbines.

In November 2021, the Company entered into a Partial Settlement Agreement in Docket 2021-93-E that is allowing the retirement of nine of these CT units to proceed and for their replacements with three modern units at the Bushy Park and Parr sites. In accordance with the Partial Settlement, the Company is proceeding with the Urquhart RFP, which included a collaborative stakeholder process to design the first-of-its-kind all sources RFP process.

The specific short-term actions that the Company intends to take in 2023 to accomplish its peaking modernization goals are to:

- Continue to execute on the engineering and construction of the replacement units at Bushy Park and Parr.
- Retire the Parr CT units to support demolition and construction efforts at that site.
- Conclude Urquhart RFP activities, specifically, the evaluation of the bids received and selection of projects to proceed to contracting (as applicable) and transmission interconnection studies
- Filing supplemental testimony in accord with the Partial Settlement requirement outlining the results of the RFP process and any regulatory treatment or relief to be sought (including affirmation of like-facilities replacement under the Siting Act, if applicable and if a utility self-bid option is selected from the Urquhart RFP process).
- Proceed to engineering, procurement, and construction of the new units (for a utility self-build) or definitive contracting for third-party resources procured through the Urquhart RFP.

The 2023 DSM Potential Study

The specific short-term actions that the Company intends to take related to the 2023 DSM Potential Study results are to:

1. Begin working on modified DSM 5-Year EE Program Plans in collaboration with the EEAG which will include
    - Details of marketing efforts
    - Customer engagement techniques
    - Design of program delivery
    - Incentive/rebate amounts
2. Timely report any changes to the Commission on the development of EE program plans and provide updates on implementation timeline of new programs/measures within existing programs through Commission filings in 2023.

The AMI Roll-Out and Residential and Commercial Demand Reduction Programs

As discussed above, the AMI roll-out has been delayed due to supply chain issues related to the meters themselves. The Company expects to have completed the installation of sufficient AMI meters on its system in 2024 so that the 2023 DSM Potential Study can be used to further assess the development and implementation of new residential demand reduction programs.

The specific short-term actions that the Company intends to take to accomplish its AMI goals are to:

- Complete installation of AMI meters in 2024 if possible, considering supply chain issues.
- Collect data throughout 2023 to inform the demand response assessment of the 2023 DSM Potential Study and determine which DR programs should be offered to the DESC residential customers.
- Develop an implementation and Commission filing timeline to offer DR programs.
- Timely report the development of the DR programs to the EEAG.

Continue the IRP Stakeholder Advisory Group Process

DESC retained CRA to design and implement a robust IRP stakeholder advisory group process. The advisory group process has been used to consult on the selection and implementation of resource optimization software, on changes to model inputs, forecasts and assumptions, and on changes in DSM assumptions and programs. In the months prior to an IRP filing or update, this process is expected to involve meetings every six to eight weeks to review model inputs and scoping and draft model runs.

The specific short-term actions that the Company intends to take to accomplish its Stakeholder goals are to:

- Review the results of the 2023 IRP and inputs to the 2024 IRP Update with the advisory group after the conclusion of these proceedings.
- Conduct at least three advisory group meetings in 2023 and 2024 to follow up on the 2023 IRP and prepare for the 2024 and 2025 Update.
- Consider the recommendations of the ORS December 19, 2022 review of the DESC 2022 IRP Update and clarify or implement recommendations as appropriate.

This includes the ORS Commodity Forecast Recommendation #1 made in its 2022 IRP Update Report concerning the relationship between the natural gas price forecast and delivered gas pricing. DESC has and will continue to provide all elements of the gas forecast including the applied basis differential, shrinkage and other transport charges. In addition to the base commodity prices forecast, delivered pricing includes these additional factors, varies with supply point, transportation path, and point of delivery, and is specific to each delivery time frame. As DESC will detail in the Stakeholder process, the delivered cost can be calculated in all cases with the information DESC provides in the IRP filing.

Conclusion

In this 2023 IRP Update, DESC uses the PLEXOS resource optimization software to analyze five Core Build Plans, five Sensitivity Cases, and four Supplemental Build Plans to provide data to guide its future generation resource planning decisions. These build plans and the analysis of them examine a broad range of assumptions as to fuel costs, generation technologies, CO_2 costs and constraints, load growth and DSM forecasts. They are based on inputs that reasonably define a range of future market conditions and include a broad spectrum of potential future market conditions. The results of this modeling have been evaluated across a broad range of potential metrics that include all evaluation criteria required by the IRP Statute or Commission order.

The 2023 IRP appropriately identifies the Reference Build Plan as the preferred plan to guide DESC's generation planning for the next three years. It sets out a reasonable and prudent approach of planning for the next steps in the development of DESC's generation portfolio which includes the potential for adding additional Solar generation in 2026 and 2027 and for retiring and replacing Wateree in by December 31, 2028 and Williams by December 31, 2030.

DESC's fundamental objectives remain to protect safety, maintain reliability, and deliver clean, affordable energy to its customers. Achieving these objectives while transitioning to a Net Zero carbon future will require investment by the Company, support from the Commission, and coordination and consensus-building across all stakeholder groups. DESC submits that this IRP provides a sound and appropriate basis for investment evaluations by the Company, regulatory decision making and public engagement.

Appendix A: Cross Reference to the Requirements of the IRP Statute and Prior Commissions Orders

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 2023 IRP demonstrating compliance:

Act No. 62 58-37-40	Requirement	2023 IRP Section
(B)(1)(a)	a long-term forecast of the utility's sales and peak demand under various reasonable scenarios;	Load Forecasts (p. 45)
(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;	Technologies Considered (p. 11); Resources Available to PLEXOS (p. 51) Fuel Cost sensitivities (p.49)
(B)(1)(c)	projected energy purchased or produced by the utility from a renewable energy resource;	Forecast of Renewable Generation (p. 77) and Appendix E
(B)(1)(d)	a summary of the electrical transmission investments planned by the utility;	Transmission Plans and Planning (p. 42)
(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;	Build Plan Analysis (p. 53)
(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;	DESC's Current Generation (p. 35)
(B)(1)(g)	plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan;	Build Plan Analysis (p. 53); Levelized Cost (p. 64); Rate and Bill Impacts (p. 85); Appendix J; Appendix H
(B)(1)(h)	an analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs; and	Levelized Cost (p. 64); Reliability Analysis (p. 68)
(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.	Load Forecasts (p. 45); Build Plan Analysis (p. 53) DSM Assumptions (p. 49)
(B)(2)	An integrated resource plan may include distribution resource plans or integrated system operation plans.	Not Included

The requirements of this 2023 IRP pursuant to Orders Nos. 2020-832 and 2021-429 are shown in the following tables along with a reference to each section of the Company's 2023 IRP demonstrating compliance:

Order 2020-832 Page Number	Order Requirement	2023 IRP Section
16 (Finding of Fact 2)	It is reasonable that, at the time of the filing of Dominion's Modified IRP, Dominion shall be able [to] indicate to the Commission the composition of current and prospective stakeholders [for the IRP Stakeholder Process], and report on any stakeholder meetings that have occurred prior to the filing date.	Stakeholder Process Update (p. 14)
16 (Finding of Fact 3)	It is reasonable require DESC to adopt and implement the use of capacity expansion modeling software starting in the 2022 IRP Update, while requiring input from on [sic.] the selection and implementation of the software, and ensuring that the software meets the transparency requirements of Act 62.	Build Plan Analysis (p. 53); Stakeholder Process Update (p. 14); Modeling Inputs, Outputs and Other Data to Be Made Available at Filing; Software Licenses Are Being Made Available
29 (Commission Conclusion), 92 (Ordering Paragraph 8a.)	DESC is required to adopt and implement the use of capacity expansion software starting no later than with the development of the 2022 IRP Update. It is reasonable to require DESC to engage interested parties in this proceeding in a collaborative process to choose a capacity expansion model for the 2022 IRP Update and future IRP proceedings. DESC shall negotiate a discounted, project-based licensing fee that permits intervenors the ability to perform their own modeling runs in the same software package as DESC, and to direct DESC to absorb the cost of these licensing fees. Contemporaneously with the filing of each future IRP, DESC shall make available, without the need for a data request, the modeling inputs (including the settings) and outputs, assumptions, any post-processing spreadsheets (e.g. to create the revenue requirements) in electronic spreadsheet format, and the model manual.	
17 (Finding of Fact 5)	It is reasonable to require DESC to perform a comprehensive coal retirement analysis to inform development of its 2022 IRP Update and its 2023 IRP and to solicit parties' recommendations on guidelines for performing this analysis through the ongoing IRP Stakeholder Process. Upon completion of the coal retirement study—and targeting the 2023 IRP—DESC shall begin modeling coal retirement as an option in the various scenarios.	Coal Replacement Planning (p. 27); The Wateree and Williams Replacement Plans (p. 72)
40 (Commission Conclusion)	DESC is required to perform comprehensive coal retirement analysis to inform development of its 2022 IRP Update, and to solicit parties' recommendations on guidelines for performing this analysis and approve a set of guidelines prior to DESC's 2022 IRP Update development process via the ongoing IRP Stakeholder Process.	
17 (Finding of Fact 6)	DESC is required to include DSM and purchased power as resource options in its 2022 IRP Update and future IRPs	Modeling Inputs and Assumptions (p. 45)
44 (Commission Conclusion)	DESC is required to include DSM and purchased power as a resource option in the 2022 IRP Update and future IRPs	
46 (Commission Conclusion)	It is appropriate for DESC, starting with its 2021 IRP Update, to systematically compare resource options for meeting its peaking reserve margin increment, including all available resources, rather than limiting available resources to a narrow subset.	
	The Commission expects that reliability and resiliency considerations must be presented and such presentation must incorporate detailed discussion of the reserve requirements needed by the utility, including a traditional Loss of Load Expectation study.	DESC 2023 Reserve Margin Study (p. 24)
18-19 (Finding of Fact 11)	Cost range and minimax regret analyses are simple, appropriate methodologies that can feasibly be implemented in a Modified 2020 IRP. It is reasonable to require DESC to submit a Modified 2020 IRP including a comparison of candidate resource plans employing simple quantitative risk metrics, including cost ranges and regret scores, as recommended by SCSBA Witness Sercy in his direct and rebuttal testimony. DESC should also consider, with stakeholder input, implementation of more sophisticated risk-adjust metrics in the 2022 IRP Update.	The Core Analysis (p. 63)
64	The Commission will require DESC to implement the cost range and minimax regret analyses in the Modified 2020 IRP and subsequent updates and will consider more refined and sophisticated risk-adjusted metrics in its 2022 IRP Update.	
76	In its 2023 IRP, DESC must include comprehensive evaluation of the cost-effectiveness and achievability of higher levels of savings, including savings levels of 1.25%, 1.5%, 1.75% and 2%.	The 2023 DSM Potential Study (p. 14); DSM Assumptions (p. 49); Appendix C
20 (Finding of Fact 17)	It is reasonable to require DESC, starting in the 2022 IRP Update, to specifically consider and discuss diversity of its generation supply, and to (a) propose candidate resource plans designed to further diversity its generation supply and (b) include diversity of generation supply in the weighting of candidate resource plans.	The Core Analysis (p. 63, 67)

Order 2020-832 Page Number	Order Requirement	2023 IRP Section
21 (Finding of Fact 21)	The Proposed IRP does not provide sufficient information for the Commission to evaluate the plain in light of "power supply reliability." It is reasonable to require that DESC include recent generator performance and other reliability data in its Modified 2020 IRP and future IRPs.	Reliability Analysis (p. 68); Distribution Transmission Operating Report Update (p. 42); Appendix L
21-22 (Finding of Fact 23)	It is reasonable to require DESC to include a three-year Action Plan in its Modified 2020 IRP and in future IRPs. The three-year Action Plan should identify and describe the steps DESC will take to implement its IRP during that three-year period. This Action Plan should include a graphical representation of the planned sequence of actions.	The 2023 Short Term Action Plan (p. 92); Stakeholder Process Update (p. 14)
88	Accordingly, DESC shall include in its Modified 2020 IRP and in future IRPs a three-year Action Plan identifying and describing the steps it will take to implement its IRP during that three-year period, including but not limited to additional analyses, changes to its methodology, issuance of Requests for Proposals, modifications to its DSM portfolio, and applications for new generating facilities under the Siting Act. The Action Plan shall include a graphic representation of the sequencing of its actions. The Action Plan in the Modified 2020 IRP shall include, at a minimum, the DSM Action Plan discussed elsewhere in this Order; the Company's process for selecting a capacity expansion model, in collaboration with stakeholders; the Company's plans to conduct retirement studies required by this Order; as well as any actions related to competitive procurement of renewable energy resources that may be indicated based on the additional production cost modeling that the Commission is requiring in this Order.	
94 (Ordering Paragraph 11)	DESC shall include in its Modified 2020 IRP and in future IRPs a three-year Action Plan identifying and describing the steps it will take to implement its IRP during that three-year period, including but not limited to additional analyses, changes to its methodology, issuance of Requests for Proposals, modifications to its DSM portfolio, and applications for new generating facilities under the Siting Act. The Action Plan in the Modified 2020 IRP shall include, at a minimum, the DSM Action Plan discussed elsewhere in this Order; the Company's process for selecting a capacity expansion model, in collaboration with stakeholders; the Company's plans to conduct retirement studies required by this Order; as well as any actions related to competitive procurement of renewable energy resources that may be indicated based on the additional production cost modeling that the Commission is requiring in this Order.	
34, 50, 52 (Commission Conclusion)	DESC Shall be required to document how it is or is not prudent to take advantage of the solar ITC or implement a plant to take advantage of the solar ITC. This documentation shall be required beginning with its 2022 IRP Update.	Key Developments Since the 2022 IRP Update (p. 21)
52	Dominion shall work with stakeholders regarding fair inclusion of solar PV's winter capacity value in the 2022 IRP Update	Modeling Inputs and Assumptions (p. 45); Build Plan Analysis (p. 53); ELCC calculation (p. 24)
90 (Ordering Paragraph 6.b.ii)		Key Developments Since the 2022 IRP Update (p. 21)
71	The Commission will therefore direct DESC, in its Modified 2020 IRP and future updates, to use the AEO high CO_2 case described by Mr. Sercy in place of DESC's \$25 CO_2 case, in the revised cost analysis. . . .The Commission finds that it is prudent for Dominion to add at least one additional lower carbon option to the 2022 IRP Update for modeling incorporating additional solar and storage opportunities.	Modeling Inputs and Assumptions (p. 45); Build Plan Analysis (p. 53)
90 (Ordering Paragraph 6.b.vii)		
81	For that reason, the Commission adopts Witness Sommer's recommendation that DESC be required to calculate the rate and bill impacts of its various portfolios in the IRP, rather than just a levelized NPV of revenue requirements. DESC must include such an evaluation in its Modified 2020 IRP and in future IRPs and IRP Updates.	Rate and Bill Impacts (p. 85)
88	In addition to the Action Plan, Dominion shall explain how the IRP is integrated into other planning at the company by subdivision, division, and department within the Company.	Integration of the IRP into Utility Planning (p. 91)

Order 2020-832 Page Number	Order Requirement	2023 IRP Section
92 (Ordering Paragraph 8 b-i)	Starting in its 2022 IRP Update: b. DESC shall develop a wide but plausible range of load forecasts, and ensure that cost modeling captures each resource plan's capabilities to adapt to load that diverges from the base forecast, as suggested by SCSBA Witness Sercy. c. Use wide but plausible range of gas price projections form AEO or another public, credible fundamental gas supply-demand model, as suggested by SCSBA Witness Sercy. d. Use wide but plausible zero/medium/high CO_2 cost projections from AEO or other public sources, as suggested by SCSBA Witness Sercy. e. Include additional candidate resource plans including DSM and purchased power as resource options that are incorporated into candidate resource plans and evaluated across multiple scenarios. f. Include candidate resource plans to meet the Company's full peaking reserve margin target, and determine in its resource plan analysis what type of resources best meet the peaking increment. g. DESC should also consider, with stakeholder input, implementation of more sophisticated risk-adjusted metrics appropriate to consider sensitivities including but not limited to natural gas price risk, carbon price risk, and load forecast risk. h. Specifically consider and discuss diversity of its generation supply, propose candidate resource plans designed to further diversify its generation supply; and include contribution to diversity of generation supply in the evaluation of candidate resource plans. i. Incorporate the conclusions from the comprehensive coal retirement analysis.	Modeling Inputs and Assumptions (p. 45); Build Plan Analysis (p. 53)
93-94 (Ordering Paragraph 10)	In its 2020 Modified IRP, 2021 IRP Update, and subsequent annual Updates prepared pursuant to S.C. Code Ann. § 58-37-41(D)(1), DESC shall update its planning assumptions relating to the energy and demand forecast, commodity fuel price inputs, renewable energy forecast, energy efficiency and demand-side management forecasts, and changes to projected retirement dates of existing units.	Modeling Inputs and Assumptions (p. 45); Build Plan Analysis (p. 53)
18-19 (Order Paragraph 5)	DESC is ordered to adjust its Reliability Factors consistent with Appendix A of the filed "Joint Comments of South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, Carolinas Clean Energy Business Alliance and Sierra Club." DESC is required to adhere to Order No. 2020-832 in its application of the approved Minimax regrets and cost range analyses, as well as the plan selection criteria required by the Commission in its 2021 IRP Update as well as in all future IRPs. In its 2021 IRP Update as well as in all future IRPs, DESC shall use Dr. Sercy's Minimax Regrets and Cost Range methodologies in addition to using the "average ranking" approach in order to provide information related to risk using these various approaches.	Build Plan Analysis (p. 53)
19 (Ordering Paragraph 6)	DESC is ordered to develop and implement an All Source Procurement Plan in future IRPs which would offer independent power producers and developers to compete with DESC proposals in a technology-neutral process . . . Future DESC IRPs should recommend a portfolio of resources that best meet the needs of the DESC system using actual bid data.	Coal Replacement Planning (p. 27); Modeling Inputs and Assumptions (p. 45); Build Plan Analysis (p. 53); The 2023 Short Term Action Plan (p. 92)
19 (Ordering Paragraph 7)	DESC is directed to employ a reasonable levelized cost of saved energy (LCSE) which is comparable with industry standards in conducting its upcoming Market Potential Study and in developing future IRPs starting with the 2021 IRP Update.	The 2023 DSM Potential Study (p. 14); Modeling Inputs and Assumptions (p. 45); Build Plan Analysis (p. 53)
19 (Ordering Paragraph 8)	DESC is also ordered to include load forecasts and the integration of Energy Efficiency impacts with its stakeholders as part of the 2021 IRP Update. DESC is also required to present realistic and levelized DSM costs in all future IRPs starting with the 2021 IRP Update.	
19 (Ordering Paragraph 9)	DESC is directed to use marginal line losses in the calculation of avoided costs and in the translation of energy savings from the Market Potential Study to energy savings in future IRP modeling beginning with the 2021 IRP Update.	
20 (Ordering Paragraph 10)	DESC is required to use "cost effective, reasonable and achievable" as the standard going forward for evaluating the potential for higher savings portfolios in future IRPs and updates beginning with the 2021 IRP Update.	

Dominion Energy

Appendix B: Glossary of Terms

Table of Abbreviations	
Abbreviation	**Name**
ACE	Affordable Clean Energy
AEO	Annual Energy Outlook
Aero	Aeroderivative
AFR	Accident Frequency Rate
AGP	Advanced Gas Path
AMI	Advance Metering Infrastructure
ATB	Annual Technology Baseline
BAA	Balancing Authority Area
BOEM	Bureau of Ocean Energy Management
BSER	Best System of Emission Reduction
CAA	Clean Air Act
CAGR	Compound Annual Growth Rate
CASAC	Chartered Clean Air Scientific Advisory Committee
CC	Combined Cycle Power Plant
COD	Commercial Operation Date
CO	Carbon Dioxide
CPP	Clean Power Plan
CRA	Charles River Associates
CT	Combustion Turbine
CWA	Clean Water Act
DART	Days Away from Work Rate
DR	Demand Response
DSM	Demand Side Management
EE	Energy Efficiency
EEAG	Energy Efficiency Advisory Group
EIA	Energy Information Administration

Table of Abbreviations	
Abbreviation	**Name**
EIPC	Eastern Interconnection Planning Collaborative
ELCC	Effective Load Carrying Capacity
ELG	Effluent Limitation Guidelines
EM&V	Evaluation, Measurement, and Verification
EPA	Environmental Protection Agency
ERO	Electric Reliability Organization
ESS	Energy Storage System
EUE	Expected Unserved Energy
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulphurization
FOR	Forced Outage Rate
GWh	Gigawatt Hour
GHG	Greenhouse Gas
ICT	Internal Combustion Turbine
IIJA	Infrastructure Investment and Jobs Act
INPO	Institute of Nuclear Power Operations
IRA	Inflation Reduction Act of 2022
ITC	Investment Tax Credits
Ktons	Thousand Tons
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt Hour
LNPV	Levelized Net Present Value
LOLE	Loss of Load Event
LOLH	Loss of Load Hours

Dominion Energy

Table of Abbreviations	
Abbreviation	**Name**
MGD	Million Gallons Per Day
MMBtu	Metric Million British Thermal Unit
Mton	Metric Ton
MW	Megawatt
MW-ac	Megawatt, Alternating Current
MWh	Megawatt Hour
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NEPA	National Environmental Policy Act
NPV	Net Present Value
NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NSPS	New Source Performance Standards
O&M	Operation and Maintenance
ODC	Opinion Dynamics Corporation
O	Original Equipment Manufacturer
ORS	South Carolina Office of Regulatory Staff
OSW	Offshore Wind
PM	Particulate Matter
PPA	Power Purchase Agreement
PRM	Planning Reserve Margin
PSD	Prevention of Significant Deterioration
PTC	Production Tax Credit
PURPA	Public Utility Regulatory Policies Act of 1978
PV	Photovoltaic
RF	Reliability Factor
RFP	Request for Proposal
SAIDI	System Average Interruption Duration Index

Table of Abbreviations	
Abbreviation	**Name**
SAM	System Advisor Model
SCPSA	South Carolina Public Service Authority
SEE	Southeastern Electric Exchange
SEEM	Southeast Energy Exchange Market
SERC	Southeastern Reliability Council
SERVM	Strategic Energy & Risk Valuation Model
SLR	Subsequent License Renewal
SMR	Small Modular Reactor
STAP	Short-Term Action Plan
TIA	Transmission Impact Analysis
ToU	Time of Use
TWh	Terawatt hour
μ/m	Micrograms Per Cubic Meter of Air
VACAR	Virginia-Carolinas Regional Reliability Group or Region
VIP	Voluntary Incentive Program

Table of Abbreviations	
Abbreviation	**Name**
Build Plan	A collection of resources used to meet customers' future energy needs.
Market Scenario	An outlook and expected values for key market drivers.
Resource Optimization	PLEXOS' selection of resources to most efficiently meet a given customers' future energy needs under a specific Market Scenario or set of constraints.
Cases	Build Plans evaluated across one or more Market Scenarios.
Core Build Plans	A selection representing the five most likely or representative Build Plans.
Core Market Scenarios	The three most likely or representative Market Scenarios.
Fifteen	The five Core Build Plans modeled across the three most likely Market Scenarios.
Sensitivity Cases	The five non-Core Build Plans modeled to fulfill requirements of the IRP Statute and Commission mandates.
Supplemental Cases	The Four additional non-Core Build plans modeled to test assumptions regarding Wateree and Williams.

Appendix C: Commission-Required EE Forecast Results

Commission-Required DSM Forecasts

This section is an excerpt from the 2023 DSM Potential Study Report that is filed separately with this docket. Specifically, this section summarizes the results of the commission-required forecasts that represent 1-2% annual incremental savings in 2024 relative to DESC's 2021 sales, excluding opt-out customers. As requested by the Commission, this includes scenarios 0.25% increments between 1-2%. As such, scenarios representing 1%, 1.25%, 1.5%, 1.75%, and 2% incremental annual savings were modeled. All these scenarios represent savings that are beyond the maximum (High) scenario, meaning that the Commission-required forecasts require participation that is beyond the maximum that can be reasonably achieved through DESC's DSM programs and would need to include measures and/or programs that are not cost-effective. Given this, ICF does not believe these scenarios are achievable, but has taken steps to model these theoretical scenarios.

Overall Results

This section provides an overview of the results at the sector and portfolio levels. Figure 1 and Figure 2 summarize the annual incremental energy and demand savings from each of the scenarios, providing a comparison of the results for 2024, 2030, and 2037. The figures show that savings later in the study period are lower. This is due to the program participation being so high in the early milestones that there are less energy efficiency opportunities in later years.

Figure 1: Annual Incremental Energy Savings (GWh) by Sector

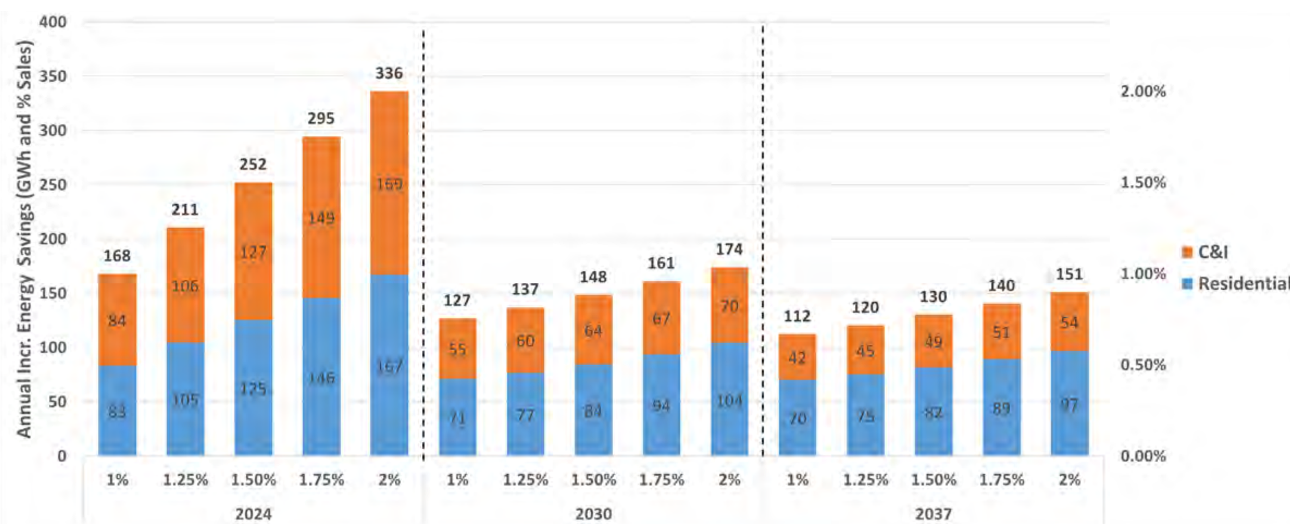


Figure 2: Annual Incremental Demand Savings (MW) by Sector

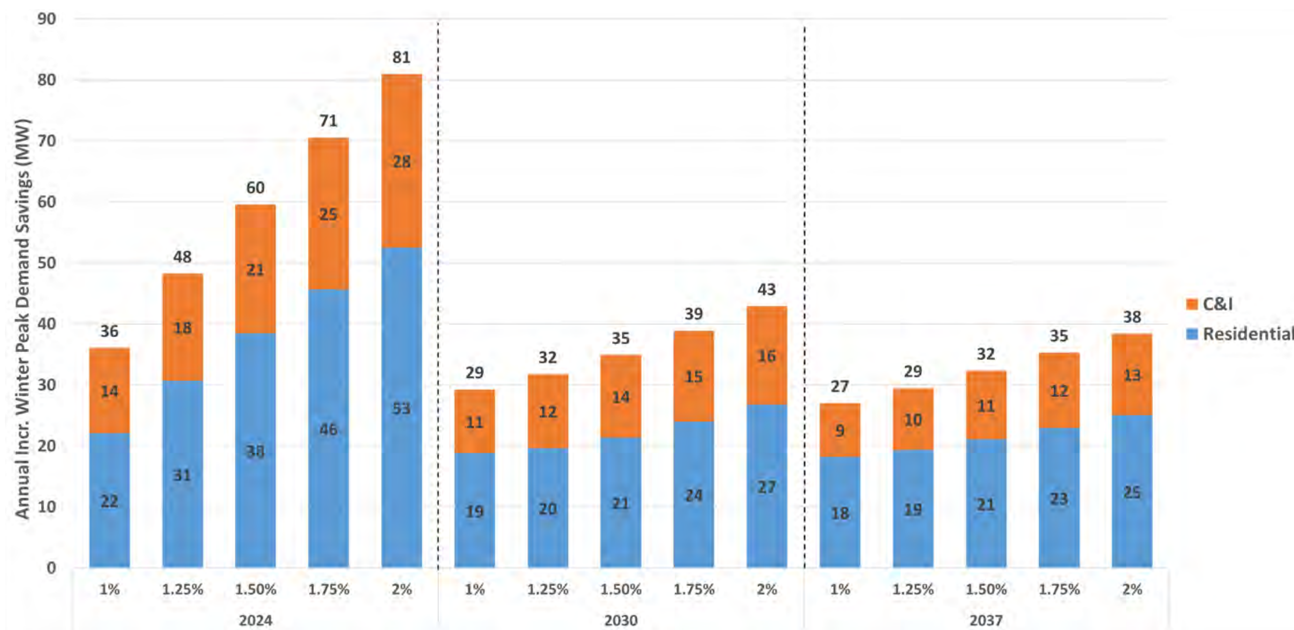


Figure 3 summarizes the annual incremental program costs by sector for each of the scenarios. Similar to the previous figures, program costs in later milestones are lower. The impact on reduced program costs in later milestones is more pronounced for C&I programs.

Figure 3: Annual Program Costs ($Millions) by Sector

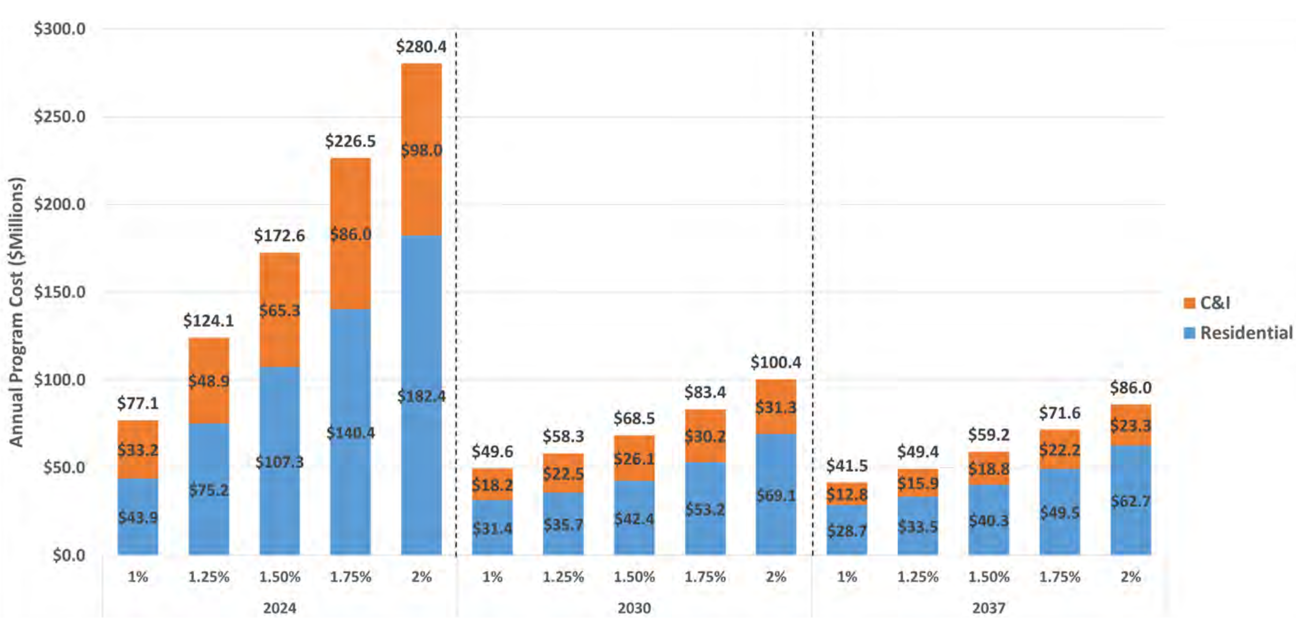


Figure 4 summarizes the results of the cost-effectiveness analysis by sector for each of the scenarios. The table also summarizes the overall portfolio-level results, showing that all of the scenarios are not cost-effective and that the program cost-effectiveness decreases for the scenarios with higher savings.

Figure 4: Cost-Effectiveness by Sector

Sector	1.00%	1.25%	1.50%	1.75%	2.00%
Residential	0.9	0 .8	0.8	0.8	0.7
C&I	1.0	0.9	0.9	0.8	0.8
Total	**0.9**	**0.8**	**0.8**	**0.8**	**0.7**

Residential Results

This section provides an overview of the residential sector results at the program level. Figure 5 and Figure 6 summarize the annual incremental energy and demand savings from each of the scenarios, providing a comparison of the results for 2024, 2030, and 2037.

Figure 5: Annual Incremental Energy Savings (GWh) by Residential Program

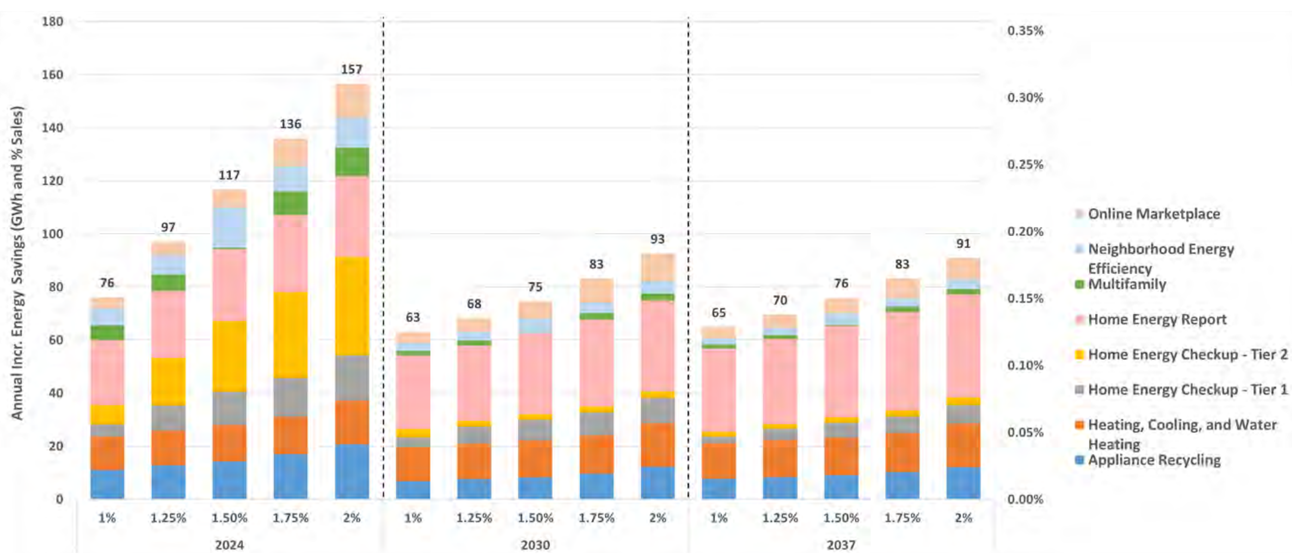


Figure 6: Annual Incremental Demand Savings (MW) by Residential Program

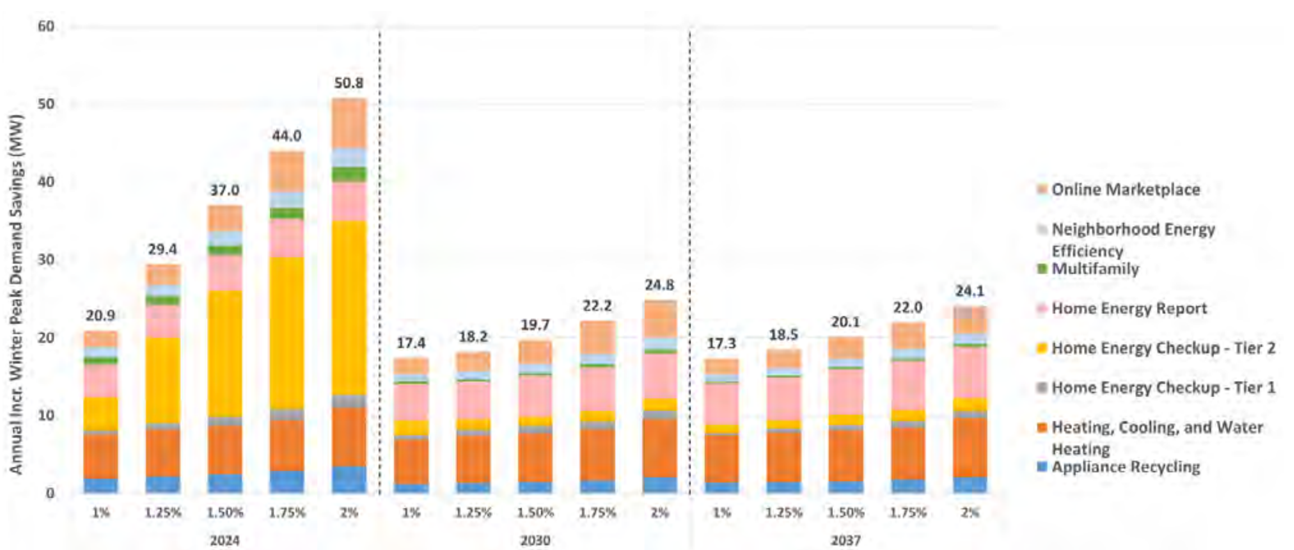


Figure 7 summarizes the program costs for each scenario, showing that overall program costs range from $43.9M to $182.4M in 2024. This compares to an estimated residential portfolio program cost of $14.2M in the Medium case.

Figure 7: Annual Residential Program Costs by Program

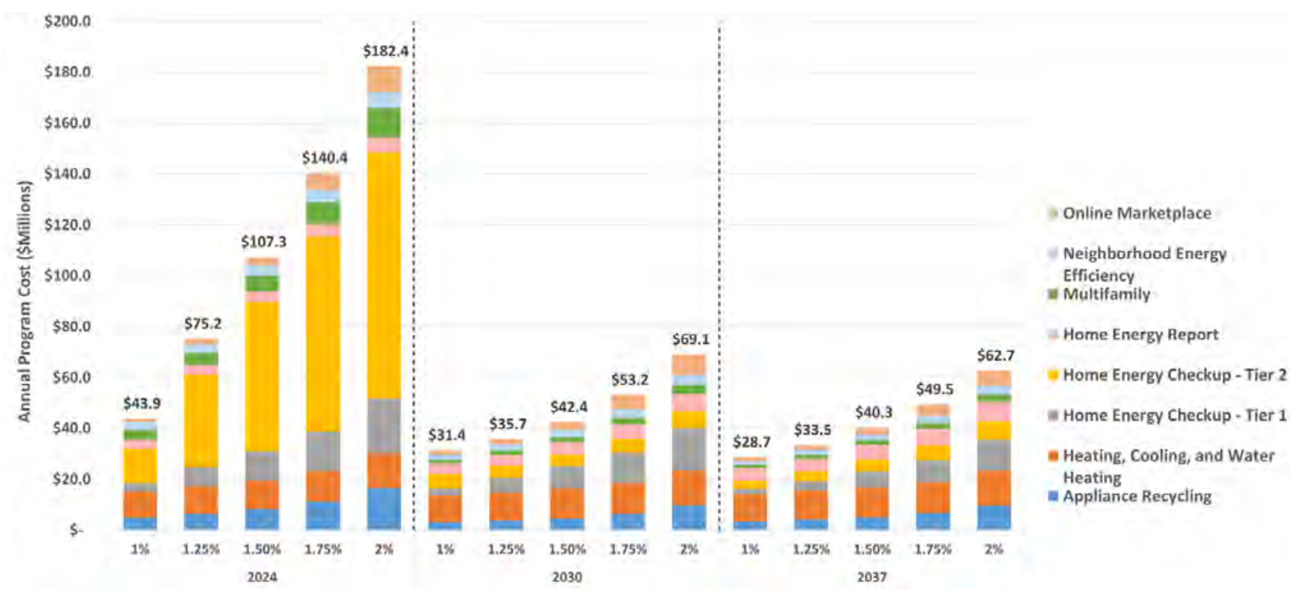


Table 1 summarizes the results of the cost-effectiveness analysis by residential sector program for each of the scenarios and the overall residential program portfolio, showing that all of the scenarios are not cost-effective and that the program cost-effectiveness decreases for the scenarios with higher savings.

Table 1: Residential Program Cost-Effectiveness (TRC)

Program	1.00%	1.25%	1.50%	1.75%	2.00%
Appliance Recycling	1.0	0.9	0.8	0.7	0.6
Heating, Cooling, and Water Heating	0.9	0.9	0.9	0.9	0.9
Home Energy Checkup - Tier 1	1.7	1.2	0.9	0.7	0.5
Home Energy Checkup - Tier 2	0.4	0.4	0.4	0.4	0.4
Home Energy Report	2.6	2.2	1.8	1.5	1.1
Multifamily	1.9	1.6	1.4	1.2	0.9
Neighborhood Energy Efficiency	1.2	1.2	1.1	1.1	1.0
Online Marketplace	2.4	2.2	1.9	1.5	1.2
Total (Residential Portfolio)	**0.9**	**0.8**	**0.8**	**0.8**	**0.7**

C&I Results

This section provides an overview of the residential sector results at the program level. Figure 8 and Figure 9 summarize the annual incremental energy and demand savings from each of the scenarios, providing a comparison of the results for 2024, 2030, and 2037.

Figure 8: Annual Incremental Energy Savings (GWh) by Commercial Program

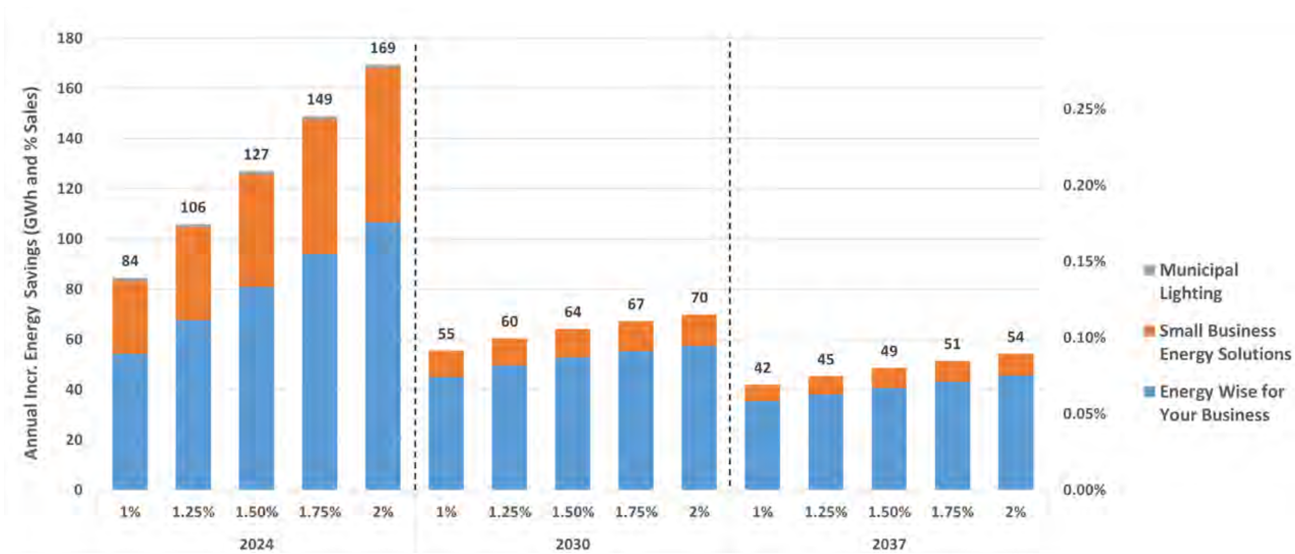


Figure 9: Annual Incremental Demand Savings (MW) by Commercial Program

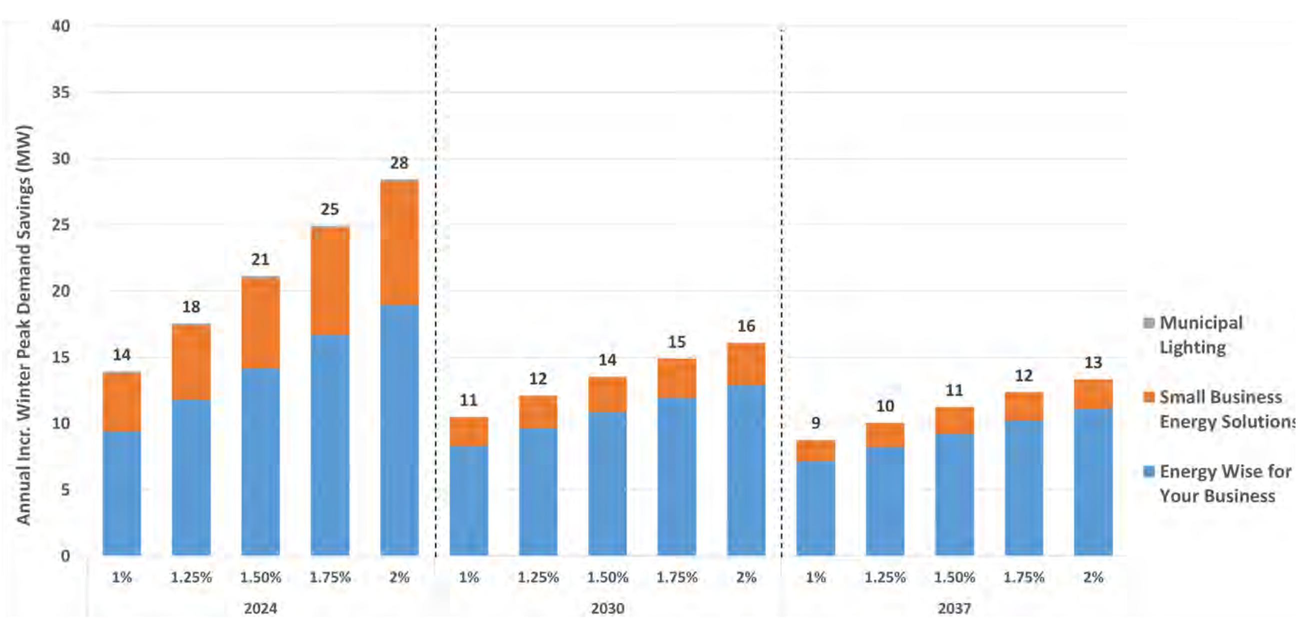


Figure 10 summarizes the program costs for each scenario, showing that overall program costs range from $33.2M to $98.0M in 2024. This compares to an estimated commercial portfolio program cost of $10.4M in the Medium case.

Figure 10: Annual Commercial Program Costs

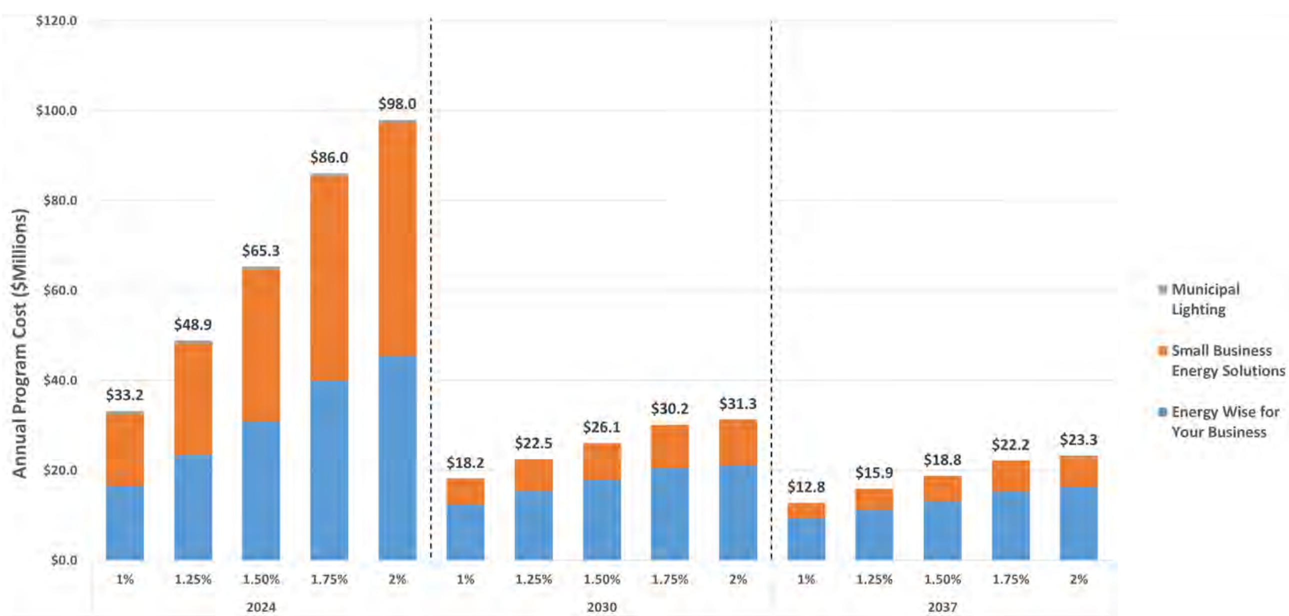


Table 2 summarizes the results of the cost-effectiveness analysis by C&I sector program for each of the scenarios and the overall C&I program portfolio, showing that all of the scenarios are not cost-effective and that the program cost-effectiveness decreases for the scenarios with higher savings.

Table 2: C&I Program Cost-Effectiveness (TRC)

Program	1.00%	1.25%	1.50%	1.75%	2.00%
Energy Wise for Your Business	0.9	0.9	0.9	0.8	0.8
Municipal Lighting	1.4	1.4	1.4	1.4	1.4
Small Business Energy Solutions	1.0	0.9	0.9	0.8	0.8
Total (C&I Portfolio)	**1.0**	**0.9**	**0.9**	**0.8**	**0.8**

Dominion Energy

Appendix D: Report on On-going, Completed, Deferred, and Cancelled Transmission Projects

Planned Project	Tentative Completion Date	Status Update	Explanation
Williams Street – Park Street 115kV: Construct	Jun-21	In Service May-22	
Saluda Hydro – Denny Terrace & Lake Murray – Harbison	Dec-22	Delayed to Completion Feb-23	Delayed due to substation outage constraints
Queensboro – Ft Johnson 115kV Tap	Dec-23	On Schedule	
Bluffton – (SCPSA) Santee 115kV Tie Line Construct	Dec-22	In Service Dec-22	
Whiskey Road 115kV-12kV Substation and 115kV Line: Construct	Aug-23	On Schedule	
Emory 230kV Distribution Sub: Construct	Dec-23	On Schedule	
Cainhoy – Mt. Pleasant 115kV #1 and #2 (Horlbeck Creek Crossing)	Dec-21	In Service Jan-22	
Queensboro – Johns Island 115kV Tie: Rebuild River and Marsh Crossing	Dec-22	Delayed to Completion Mar-23	Delayed due to construction schedule
Church Creek – Queensboro 115kV Phase 1: Construct	Dec-23	On Schedule	
Church Creek – Queensboro 115kV Phase 2: Stono River Crossing	Dec-23	On Schedule	
Edenwood Substation: Replace Switch House	Jun-22	In Service May-22	
Burton – Yemassee 115kV #2 Line Rebuild as Double Circuit	Dec-22	In Service Dec-22	
Denny Terrace – Crafts Farrow & Denny Terrace – Dentsville Line #1 115kV Rebuild	Dec-22	In Service Aug-22	
Wateree – Hopkins 230kV Line #2: Rebuild	Dec-23	Delayed to Completion Dec-24	Delayed due to budget constraints
Okatie – Bluffton 115kV: Rebuild	Dec-24	On Schedule	
Denny Terrace Substation: Replace Switch House	Dec-23	On Schedule	
Eastover – Square D 115kV: Rebuild	Dec-23	On Schedule	
Hopkins – Square D 115kV: Rebuild	Dec-23	Delayed to Completion Dec-24	Delayed due to budget constraints
Burton – St Helena 115kV: Rebuild **Burton – Frogmore Transmission Section**	Dec-24	On Schedule	
Burton – St Helena 115kV: Frogmore Distribution – St Helena	Dec-25	On Schedule	
Jasper – Okatie 230kV #2, Okatie – Riverport 230kV: Construct	Dec-24	On Schedule	

Planned Project	Tentative Completion Date	Status Update	Explanation
VCS1 – Denny Terrace 230kV & VCS1 – Pineland 230kV: Rebuild Double Circuit Section and Single Circuit Sections	Dec-26	On Schedule	Double circuit section In Service July 2022, single circuit sections delayed due to capital budget constraints
Wateree – Hopkins 230kV Line #1: Rebuild	Dec-26	On Schedule	
Coit – Gills Creek 115kV Line: Construct	Dec-24	On Schedule	
Union Pier 115–13.8kV Sub: Tap Construct	Dec-25	On Schedule	
Cainhoy – Hamlin 115kV: Rebuild Line and Cainhoy – Hamlin 115kV #2: Construct New 115kV Line	Dec-24	On Schedule	
Hopkins – CIP 230kV: Rebuild	Dec-24	Delayed to Completion Dec-25	Delayed due to capital budget constraints
Faber Place – Bayfront 115kV: Rebuild North Bridge Terrace to Bayfront Section	Dec-25	On Schedule	
Wateree – Killian 230kV: Rebuild	Dec-28	On Schedule	
Canadys – Ritter 115kV: Rebuild as 230/115kV Double Circuit	Jun-26	On Schedule	
Ritter – Yemassee 230kV and 115kV Transmission System Expansion	Jun-27	In Service Expected Jun-26	System Planning requested 2026, if possible, for reliability
Okatie 230–115kV Sub and the Jasper – Yemassee Fold In	Dec-26	In Service Expected Dec-24	System Planning requested 2024, if possible, for reliability
Clements Ferry 115–23kV Sub: Construct; Jack Primus–Cainhoy 115kV with Clements Ferry Tap Construct	Dec-27	On Schedule	
Blackville West-Wagener 46kV, Rebuild the 23+ mile Line section including North to LNG to Perry to Salley to Springfield	Jul-22	In Service Jul-22	
Calhoun County-St Matthews 46kV Rebuild	Dec-22	In Service Dec-22	
Cross County 115-23kV Substation and 115kV Transmission Line Tap Construction	Jun-22	In Service Jun-22	
May River 115-23kV Substation and 115kV Transmission Line Tap Construction	Dec-22	In Service Dec-22	
Smoaks 115-23kV Substation and 115kV Transmission Line Tap Construction	Jul-22	In Service Jul-22	
Ward – Stevens Creek 115kV: Ward – Trenton Section Rebuild	May-22	In Service May-22	
Lex Westside – Gilbert 115kV Line	Jan-22	In Service Jan-22	
Lake Murray-Gilbert 115kV, Rebuild the 4-mile Lexington Junction – Lexington Westside Line section	Aug-22	In Service Aug-22	
Lake Murray – Gilbert 115kV Line	Aug-22	In Service Aug-22	Combo designation of several projects above
Stevens Creek – Ward – Lake Murray Line and Associated System Hardening Construct	Aug-22	In Service Aug-22	Combo designation of several projects above

Appendix E: Timing and Nature of Resource Additions and Resulting Capacities and Reserve Margins

Reference Build Plan									
Year	Peak (MW)	Firm Capacity (MW)	Winter Reserve Margin (%)	New Gas (MW)	New Solar (MW)	New Storage (MW)	New Wind (MW)	New SMR (MW)	Retirements (MW)
2023	4902	6305	28.6	0	0	0	0	0	0
2024	4775	6282	31.6	0	0	0	0	0	0
2025	4813	6277	30.4	0	0	0	0	0	0
2026	4851	6328	30.5	0	150	0	0	0	0
2027	4891	6339	29.6	0	225	0	0	0	0
2028	4931	6355	28.9	0	300	0	0	0	0
2029	4971	6032	21.4	0	300	400	0	0	-684
2030	5009	6057	20.9	0	300	0	0	0	0
2031	5048	6131	21.5	662	300	0	0	0	-610
2032	5091	6147	20.8	0	300	0	0	0	0
2033	5133	6206	20.9	0	300	100	0	0	0
2034	5179	6469	24.9	0	300	300	0	0	0
2035	5228	6475	23.9	0	300	0	0	0	0
2036	5274	6629	25.7	0	300	300	0	0	0
2037	5332	6631	24.4	0	150	0	0	0	0
2038	5390	6498	20.6	0	150	0	0	0	0
2039	5450	6598	21.1	0	150	200	0	0	0
2040	5509	7119	29.2	523	150	0	0	0	0
2041	5571	7117	27.8	0	150	0	0	0	0
2042	5633	7119	26.4	0	150	0	0	0	0
2043	5697	7119	25.0	0	150	0	0	0	0
2044	5761	7121	23.6	0	150	0	0	0	0
2045	5826	7123	22.3	0	150	0	0	0	0
2046	5892	7126	21.0	0	150	0	0	0	0
2047	5959	7177	20.5	0	150	100	0	0	0
2048	6026	7279	20.8	0	150	200	0	0	0
2049	6094	7464	22.5	523	150	0	0	0	0
2050	6163	7465	21.1	0	0	0	0	0	0

High Fossil Fuel Prices Build Plan

Year	Peak (MW)	Firm Capacity (MW)	Winter Reserve Margin (%)	New Gas (MW)	New Solar (MW)	New Storage (MW)	New Wind (MW)	New SMR (MW)	Retirements (MW)
2023	4902	6305	28.6	0	0	0	0	0	0
2024	4775	6282	31.6	0	0	0	0	0	0
2025	4813	6277	30.4	0	0	0	0	0	0
2026	4851	6329	30.5	0	300	0	0	0	0
2027	4891	6340	29.6	0	300	0	0	0	0
2028	4931	6356	28.9	0	300	0	0	0	0
2029	4971	6034	21.4	0	300	400	0	0	-684
2030	5009	6058	21.0	0	300	0	0	0	0
2031	5048	6132	21.5	662	300	0	0	0	-610
2032	5091	6148	20.8	0	300	0	0	0	0
2033	5133	6207	20.9	0	300	100	0	0	0
2034	5179	6470	24.9	0	300	300	0	0	0
2035	5228	6476	23.9	0	300	0	0	0	0
2036	5274	6630	25.7	0	300	300	0	0	0
2037	5332	6633	24.4	0	300	0	0	0	0
2038	5390	6500	20.6	0	300	0	0	0	0
2039	5450	6552	20.2	0	300	100	0	0	0
2040	5509	7073	28.4	523	300	0	0	0	0
2041	5571	7122	27.9	0	300	100	0	0	0
2042	5633	7124	26.5	0	300	0	0	0	0
2043	5697	7126	25.1	0	300	0	0	0	0
2044	5761	7178	24.6	0	300	100	0	0	0
2045	5826	7181	23.3	0	300	0	0	0	0
2046	5892	7234	22.8	0	300	100	0	0	0
2047	5959	7286	22.3	0	150	100	0	0	0
2048	6026	7288	21.0	0	150	0	0	0	0
2049	6094	7473	22.6	523	150	0	0	0	0
2050	6163	7474	21.3	0	0	0	0	0	0

Zero Carbon Cost Build Plan									
Year	Peak (MW)	Firm Capacity (MW)	Winter Reserve Margin (%)	New Gas (MW)	New Solar (MW)	New Storage (MW)	New Wind (MW)	New SMR (MW)	Retirements (MW)
2023	4902	6305	28.6	0	0	0	0	0	0
2024	4775	6282	31.6	0	0	0	0	0	0
2025	4813	6277	30.4	0	0	0	0	0	0
2026	4851	6328	30.5	0	150	0	0	0	0
2027	4891	6338	29.6	0	150	0	0	0	0
2028	4931	6354	28.9	0	150	0	0	0	0
2029	4971	6038	21.5	262	225	100	0	0	-684
2030	5009	6062	21.0	0	300	0	0	0	0
2031	5048	6136	21.6	662	300	0	0	0	-610
2032	5091	6152	20.9	0	300	0	0	0	0
2033	5133	6212	21.0	0	300	100	0	0	0
2034	5179	6388	23.4	0	150	200	0	0	0
2035	5228	6734	28.8	0	150	400	0	0	0
2036	5274	6737	27.8	0	150	0	0	0	0
2037	5332	6740	26.4	0	150	0	0	0	0
2038	5390	6606	22.6	0	150	0	0	0	0
2039	5450	6607	21.2	0	150	0	0	0	0
2040	5509	6654	20.8	0	150	100	0	0	0
2041	5571	6702	20.3	0	150	100	0	0	0
2042	5633	7227	28.3	523	150	0	0	0	0
2043	5697	7228	26.9	0	150	0	0	0	0
2044	5761	7229	25.5	0	150	0	0	0	0
2045	5826	7231	24.1	0	150	0	0	0	0
2046	5892	7234	22.8	0	150	0	0	0	0
2047	5959	7236	21.4	0	150	0	0	0	0
2048	6026	7237	20.1	0	150	0	0	0	0
2049	6094	7354	20.7	0	150	400	0	0	0
2050	6163	7405	20.2	0	0	100	0	0	0

70% CO_2 Reduction Build Plan									
Year	Peak (MW)	Firm Capacity (MW)	Winter Reserve Margin (%)	New Gas (MW)	New Solar (MW)	New Storage (MW)	New Wind (MW)	New SMR (MW)	Retirements (MW)
2023	4902	6305	28.6	0	0	0	0	0	0
2024	4775	6282	31.6	0	0	0	0	0	0
2025	4813	6277	30.4	0	0	0	0	0	0
2026	4851	6329	30.5	0	300	0	0	0	0
2027	4891	6340	29.6	0	300	0	0	0	0
2028	4931	6356	28.9	0	300	0	0	0	0
2029	4971	6041	21.5	262	300	100	0	0	-684
2030	5009	6065	21.1	0	300	0	0	0	0
2031	5048	6972	38.1	1325	300	200	0	0	-610
2032	5091	7073	38.9	0	300	100	0	0	0
2033	5133	7387	43.9	0	300	400	0	0	0
2034	5179	7445	43.8	0	300	100	0	0	0
2035	5228	7551	44.4	0	300	200	0	0	0
2036	5274	7655	45.2	0	300	200	0	0	0
2037	5332	7758	45.5	0	300	200	0	0	0
2038	5390	7675	42.4	0	300	100	0	0	0
2039	5450	7677	40.9	0	300	0	0	0	0
2040	5509	7715	40.1	0	300	0	100	0	0
2041	5571	7754	39.2	0	300	0	100	0	0
2042	5633	7796	38.4	0	300	0	100	0	0
2043	5697	7838	37.6	0	300	0	100	0	0
2044	5761	7880	36.8	0	300	0	100	0	0
2045	5826	7923	36.0	0	300	0	100	0	0
2046	5892	7965	35.2	0	0	0	100	0	0
2047	5959	8006	34.4	0	0	0	100	0	0
2048	6026	8007	32.9	0	0	0	0	0	0
2049	6094	7923	30.0	0	0	0	0	0	0
2050	6163	7924	28.6	0	0	0	0	0	0

85% CO_2 Reduction Build Plan									
Year	Peak (MW)	Firm Capacity (MW)	Winter Reserve Margin (%)	New Gas (MW)	New Solar (MW)	New Storage (MW)	New Wind (MW)	New SMR (MW)	Retirements (MW)
2023	4902	6305	28.6	0	0	0	0	0	0
2024	4775	6282	31.6	0	0	0	0	0	0
2025	4813	6277	30.4	0	0	0	0	0	0
2026	4851	6329	30.5	0	300	0	0	0	0
2027	4891	6340	29.6	0	300	0	0	0	0
2028	4931	6356	28.9	0	300	0	0	0	0
2029	4971	6041	21.5	262	300	100	0	0	-684
2030	5009	6065	21.1	0	300	0	0	0	0
2031	5048	6972	38.1	1325	300	200	0	0	-610
2032	5091	7073	38.9	0	300	100	0	0	0
2033	5133	7387	43.9	0	300	400	0	0	0
2034	5179	7445	43.8	0	300	100	0	0	0
2035	5228	7551	44.4	0	300	200	0	0	0
2036	5274	7655	45.2	0	300	200	0	0	0
2037	5332	7758	45.5	0	300	200	0	0	0
2038	5390	7675	42.4	0	300	100	0	0	0
2039	5450	7677	40.9	0	300	0	0	0	0
2040	5509	7989	45.0	0	300	0	100	268	0
2041	5571	8028	44.1	0	300	0	100	0	0
2042	5633	8070	43.3	0	300	0	100	0	0
2043	5697	8112	42.4	0	300	0	100	0	0
2044	5761	8154	41.6	0	300	0	100	0	0
2045	5826	8471	45.4	0	300	0	100	268	0
2046	5892	8514	44.5	0	300	0	100	0	0
2047	5959	8557	43.6	0	300	0	100	0	0
2048	6026	8599	42.7	0	300	0	100	0	0
2049	6094	8557	40.4	0	300	0	100	0	0
2050	6163	8873	44.0	0	300	0	100	268	0

Electrification Build Plan									
Year	Peak (MW)	Firm Capacity (MW)	Winter Reserve Margin (%)	New Gas (MW)	New Solar (MW)	New Storage (MW)	New Wind (MW)	New SMR (MW)	Retirements (MW)
2023	4902	6305	28.6	0	0	0	0	0	0
2024	4775	6282	31.6	0	0	0	0	0	0
2025	4836	6277	29.8	0	0	0	0	0	0
2026	4899	6328	29.2	0	150	0	0	0	0
2027	4963	6338	27.7	0	150	0	0	0	0
2028	5027	6354	26.4	0	150	0	0	0	0
2029	5092	6208	21.9	262	150	300	0	0	-684
2030	5159	6316	22.4	0	150	100	0	0	0
2031	5226	6390	22.3	662	150	0	0	0	-610
2032	5304	6405	20.8	0	150	0	0	0	0
2033	5384	6548	21.6	0	150	200	0	0	0
2034	5465	6640	21.5	0	150	100	0	0	0
2035	5547	6730	21.3	0	150	100	0	0	0
2036	5630	7134	26.7	0	150	800	0	0	0
2037	5714	7136	24.9	0	150	0	0	0	0
2038	5800	7002	20.7	0	150	0	0	0	0
2039	5887	8328	41.5	650	150	0	0	0	0
2040	5976	8325	39.3	0	150	0	0	0	0
2041	6066	8324	37.2	0	150	0	0	0	0
2042	6159	8326	35.2	0	150	0	0	0	0
2043	6254	8326	33.1	0	150	0	0	0	0
2044	6350	8328	31.2	0	150	0	0	0	0
2045	6448	8330	29.2	0	150	0	0	0	0
2046	6547	8333	27.3	0	150	0	0	0	0
2047	6648	8334	25.4	0	150	0	0	0	0
2048	6750	8336	23.5	0	150	0	0	0	0
2049	6854	8605	25.6	523	0	0	0	0	0
2050	6960	8521	22.4	0	0	0	0	0	0

Energy Conservation Build Plan									
Year	**Peak (MW)**	**Firm Capacity (MW)**	**Winter Reserve Margin (%)**	**New Gas (MW)**	**New Solar (MW)**	**New Storage (MW)**	**New Wind (MW)**	**New SMR (MW)**	**Retirements (MW)**
2023	4902	6305	28.6	0	0	0	0	0	0
2024	4775	6282	31.6	0	0	0	0	0	0
2025	4789	6277	31.1	0	0	0	0	0	0
2026	4803	6329	31.8	0	300	0	0	0	0
2027	4817	6340	31.6	0	300	0	0	0	0
2028	4832	6356	31.6	0	300	0	0	0	0
2029	4846	5864	21.0	0	300	200	0	0	-684
2030	4860	5888	21.2	0	300	0	0	0	0
2031	4875	5962	22.3	662	300	0	0	0	-610
2032	4899	5978	22.0	0	300	0	0	0	0
2033	4924	6037	22.6	0	300	100	0	0	0
2034	4949	6385	29.0	0	300	400	0	0	0
2035	4973	6391	28.5	0	300	0	0	0	0
2036	4998	6395	28.0	0	300	0	0	0	0
2037	5024	6397	27.4	0	150	0	0	0	0
2038	5049	6264	24.1	0	150	0	0	0	0
2039	5074	6264	23.5	0	150	0	0	0	0
2040	5100	6262	22.8	0	150	0	0	0	0
2041	5125	6261	22.2	0	300	0	0	0	0
2042	5150	6263	21.6	0	150	0	0	0	0
2043	5176	6263	21.0	0	150	0	0	0	0
2044	5202	6315	21.4	0	225	100	0	0	0
2045	5228	6368	21.8	0	300	100	0	0	0
2046	5254	6371	21.3	0	225	0	0	0	0
2047	5280	6423	21.7	0	150	100	0	0	0
2048	5306	6475	22.0	0	150	100	0	0	0
2049	5332	6506	22.0	0	150	400	0	0	0
2050	5359	6507	21.4	0	0	0	0	0	0

Aggressive Regulation Build Plan

Year	Peak (MW)	Firm Capacity (MW)	Winter Reserve Margin (%)	New Gas (MW)	New Solar (MW)	New Storage (MW)	New Wind (MW)	New SMR (MW)	Retirements (MW)
2023	4902	6305	28.6	0	0	0	0	0	0
2024	4775	6282	31.6	0	0	0	0	0	0
2025	4836	6277	29.8	0	0	0	0	0	0
2026	4899	6329	29.2	0	300	0	0	0	0
2027	4963	6340	27.8	0	300	0	0	0	0
2028	5027	6356	26.5	0	300	0	0	0	0
2029	5092	6211	22.0	262	300	300	0	0	-684
2030	5159	6320	22.5	0	300	100	0	0	0
2031	5226	6394	22.4	662	300	0	0	0	-610
2032	5304	6410	20.9	0	300	0	0	0	0
2033	5384	6469	20.2	0	300	100	0	0	0
2034	5465	6732	23.2	0	300	300	0	0	0
2035	5547	6738	21.5	0	300	0	0	0	0
2036	5630	6892	22.4	0	300	300	0	0	0
2037	5714	6895	20.7	0	300	0	0	0	0
2038	5800	8087	39.4	1325	300	0	0	0	0
2039	5887	8089	37.4	0	300	0	0	0	0
2040	5976	8087	35.3	0	300	0	0	0	0
2041	6066	8086	33.3	0	300	0	0	0	0
2042	6159	8088	31.3	0	300	0	0	0	0
2043	6254	8090	29.4	0	300	0	0	0	0
2044	6350	8092	27.5	0	300	0	0	0	0
2045	6448	8095	25.6	0	300	0	0	0	0
2046	6547	8098	23.7	0	150	0	0	0	0
2047	6648	8099	21.8	0	150	0	0	0	0
2048	6750	8201	21.5	0	150	200	0	0	0
2049	6854	8521	24.3	523	150	100	0	0	0
2050	6960	8537	22.7	0	0	200	0	0	0

High DSM Build Plan									
Year	**Peak (MW)**	**Firm Capacity (MW)**	**Winter Reserve Margin (%)**	**New Gas (MW)**	**New Solar (MW)**	**New Storage (MW)**	**New Wind (MW)**	**New SMR (MW)**	**Retirements (MW)**
2023	4897	6305	28.8	0	0	0	0	0	0
2024	4768	6282	31.8	0	0	0	0	0	0
2025	4800	6277	30.8	0	0	0	0	0	0
2026	4835	6328	30.9	0	150	0	0	0	0
2027	4871	6338	30.1	0	150	0	0	0	0
2028	4907	6355	29.5	0	300	0	0	0	0
2029	4944	5954	20.4	262	300	0	0	0	-684
2030	4978	5978	20.1	0	300	0	0	0	0
2031	5012	6053	20.8	662	300	0	0	0	-610
2032	5052	6069	20.1	0	300	0	0	0	0
2033	5090	6128	20.4	0	300	100	0	0	0
2034	5132	6645	29.5	0	300	600	0	0	0
2035	5175	6651	28.5	0	300	0	0	0	0
2036	5219	6705	28.5	0	300	100	0	0	0
2037	5277	6708	27.1	0	150	0	0	0	0
2038	5334	6574	23.3	0	150	0	0	0	0
2039	5395	6575	21.9	0	150	0	0	0	0
2040	5453	6572	20.5	0	150	0	0	0	0
2041	5516	7094	28.6	523	150	0	0	0	0
2042	5578	7145	28.1	0	150	100	0	0	0
2043	5641	7146	26.7	0	150	0	0	0	0
2044	5705	7148	25.3	0	150	0	0	0	0
2045	5770	7150	23.9	0	150	0	0	0	0
2046	5835	7152	22.6	0	150	0	0	0	0
2047	5901	7154	21.2	0	150	0	0	0	0
2048	5968	7206	20.8	0	150	100	0	0	0
2049	6036	7358	21.9	0	150	300	0	0	0
2050	6104	7359	20.6	0	0	0	0	0	0

Low DSM Build Plan									
Year	Peak (MW)	Firm Capacity (MW)	Winter Reserve Margin (%)	New Gas (MW)	New Solar (MW)	New Storage (MW)	New Wind (MW)	New SMR (MW)	Retirements (MW)
2023	4903	6305	28.6	0	0	0	0	0	0
2024	4777	6282	31.5	0	0	0	0	0	0
2025	4816	6277	30.3	0	0	0	0	0	0
2026	4854	6328	30.4	0	150	0	0	0	0
2027	4896	6338	29.5	0	150	0	0	0	0
2028	4937	6355	28.7	0	300	0	0	0	0
2029	4978	6032	21.2	0	300	400	0	0	-684
2030	5018	6056	20.7	0	300	0	0	0	0
2031	5057	6131	21.2	662	300	0	0	0	-610
2032	5101	6147	20.5	0	300	0	0	0	0
2033	5144	6206	20.7	0	300	100	0	0	0
2034	5190	6468	24.6	0	300	300	0	0	0
2035	5239	6474	23.6	0	300	0	0	0	0
2036	5287	6728	27.3	0	300	500	0	0	0
2037	5346	6731	25.9	0	150	0	0	0	0
2038	5403	6597	22.1	0	150	0	0	0	0
2039	5463	6648	21.7	0	150	100	0	0	0
2040	5522	6645	20.4	0	150	0	0	0	0
2041	5584	7167	28.4	523	150	0	0	0	0
2042	5647	7168	27.0	0	150	0	0	0	0
2043	5711	7169	25.5	0	150	0	0	0	0
2044	5775	7171	24.2	0	150	0	0	0	0
2045	5840	7223	23.7	0	150	100	0	0	0
2046	5906	7225	22.4	0	150	0	0	0	0
2047	5973	7277	21.8	0	150	100	0	0	0
2048	6040	7279	20.5	0	150	0	0	0	0
2049	6108	7464	22.2	523	150	0	0	0	0
2050	6177	7465	20.9	0	0	0	0	0	0

Dominion Energy

Wateree Battery Build Plan									
Year	Peak (MW)	Firm Capacity (MW)	Winter Reserve Margin (%)	New Gas (MW)	New Solar (MW)	New Storage (MW)	New Wind (MW)	New SMR (MW)	Retirements (MW)
2023	4902	6305	28.6	0	0	0	0	0	0
2024	4775	6282	31.6	0	0	0	0	0	0
2025	4813	6277	30.4	0	0	0	0	0	0
2026	4851	6328	30.5	0	150	0	0	0	0
2027	4891	6338	29.6	0	150	0	0	0	0
2028	4931	6355	28.9	0	300	0	0	0	0
2029	4971	6032	21.4	0	300	400	0	0	-684
2030	5009	6056	20.9	0	300	0	0	0	0
2031	5048	6131	21.5	662	300	0	0	0	-610
2032	5091	6147	20.7	0	300	0	0	0	0
2033	5133	6206	20.9	0	300	100	0	0	0
2034	5179	6468	24.9	0	300	300	0	0	0
2035	5228	6474	23.9	0	300	0	0	0	0
2036	5274	6478	22.8	0	300	0	0	0	0
2037	5332	6481	21.6	0	150	0	0	0	0
2038	5390	6870	27.5	523	150	0	0	0	0
2039	5450	6871	26.1	0	150	0	0	0	0
2040	5509	6868	24.7	0	150	0	0	0	0
2041	5571	6867	23.3	0	150	0	0	0	0
2042	5633	6868	21.9	0	150	0	0	0	0
2043	5697	6869	20.6	0	150	0	0	0	0
2044	5761	6971	21.0	0	150	200	0	0	0
2045	5826	7023	20.6	0	150	100	0	0	0
2046	5892	7175	21.8	0	150	300	0	0	0
2047	5959	7177	20.5	0	150	0	0	0	0
2048	6026	7702	27.8	523	150	0	0	0	0
2049	6094	7414	21.7	0	150	100	0	0	0
2050	6163	7415	20.3	0	0	0	0	0	0

Wateree CT Build Plan									
Year	**Peak (MW)**	**Firm Capacity (MW)**	**Winter Reserve Margin (%)**	**New Gas (MW)**	**New Solar (MW)**	**New Storage (MW)**	**New Wind (MW)**	**New SMR (MW)**	**Retirements (MW)**
2023	4902	6305	28.6	0	0	0	0	0	0
2024	4775	6282	31.6	0	0	0	0	0	0
2025	4813	6277	30.4	0	0	0	0	0	0
2026	4851	6328	30.5	0	150	0	0	0	0
2027	4891	6338	29.6	0	150	0	0	0	0
2028	4931	6355	28.9	0	300	0	0	0	0
2029	4971	6039	21.5	262	300	100	0	0	-684
2030	5009	6063	21.1	0	300	0	0	0	0
2031	5048	6138	21.6	662	300	0	0	0	-610
2032	5091	6154	20.9	0	300	0	0	0	0
2033	5133	6213	21.1	0	300	100	0	0	0
2034	5179	6645	28.3	0	300	500	0	0	0
2035	5228	6736	28.9	0	300	100	0	0	0
2036	5274	6740	27.8	0	300	0	0	0	0
2037	5332	6743	26.5	0	150	0	0	0	0
2038	5390	6609	22.6	0	150	0	0	0	0
2039	5450	6610	21.3	0	150	0	0	0	0
2040	5509	6657	20.9	0	150	100	0	0	0
2041	5571	6706	20.4	0	150	100	0	0	0
2042	5633	7230	28.4	523	150	0	0	0	0
2043	5697	7231	26.9	0	150	0	0	0	0
2044	5761	7233	25.6	0	150	0	0	0	0
2045	5826	7235	24.2	0	150	0	0	0	0
2046	5892	7237	22.8	0	150	0	0	0	0
2047	5959	7239	21.5	0	150	0	0	0	0
2048	6026	7241	20.2	0	150	0	0	0	0
2049	6094	7358	20.7	0	150	400	0	0	0
2050	6163	7409	20.2	0	0	100	0	0	0

Williams 2047 Build Plan									
Year	Peak (MW)	Firm Capacity (MW)	Winter Reserve Margin (%)	New Gas (MW)	New Solar (MW)	New Storage (MW)	New Wind (MW)	New SMR (MW)	Retirements (MW)
2023	4902	6305	28.6	0	0	0	0	0	0
2024	4775	6282	31.6	0	0	0	0	0	0
2025	4813	6277	30.4	0	0	0	0	0	0
2026	4851	6328	30.5	0	150	0	0	0	0
2027	4891	6339	29.6	0	225	0	0	0	0
2028	4931	6355	28.9	0	300	0	0	0	0
2029	4971	6032	21.4	0	300	400	0	0	-684
2030	5009	6057	20.9	0	300	0	0	0	0
2031	5048	6741	33.6	662	300	0	0	0	0
2032	5091	6757	32.7	0	300	0	0	0	0
2033	5133	6731	31.2	0	300	0	0	0	0
2034	5179	7079	36.7	0	300	400	0	0	0
2035	5228	7085	35.5	0	300	0	0	0	0
2036	5274	7089	34.4	0	300	0	0	0	0
2037	5332	7091	33.0	0	150	0	0	0	0
2038	5390	6958	29.1	0	150	0	0	0	0
2039	5450	6958	27.7	0	150	0	0	0	0
2040	5509	6956	26.3	0	150	0	0	0	0
2041	5571	6954	24.8	0	150	0	0	0	0
2042	5633	6956	23.5	0	150	0	0	0	0
2043	5697	6956	22.1	0	150	0	0	0	0
2044	5761	6958	20.8	0	150	0	0	0	0
2045	5826	7483	28.5	523	150	0	0	0	0
2046	5892	7486	27.1	0	150	0	0	0	0
2047	5959	7487	25.7	0	150	0	0	0	-610
2048	6026	7402	22.9	523	150	0	0	0	0
2049	6094	7364	20.9	0	150	600	0	0	0
2050	6163	7415	20.3	0	0	100	0	0	0

Williams 2047 High Fossil Fuel Prices Build Plan									
Year	**Peak (MW)**	**Firm Capacity (MW)**	**Winter Reserve Margin (%)**	**New Gas (MW)**	**New Solar (MW)**	**New Storage (MW)**	**New Wind (MW)**	**New SMR (MW)**	**Retirements (MW)**
2023	4902	6305	28.6	0	0	0	0	0	0
2024	4775	6282	31.6	0	0	0	0	0	0
2025	4813	6277	30.4	0	0	0	0	0	0
2026	4851	6329	30.5	0	300	0	0	0	0
2027	4891	6340	29.6	0	300	0	0	0	0
2028	4931	6356	28.9	0	300	0	0	0	0
2029	4971	6034	21.4	0	300	400	0	0	-684
2030	5009	6058	21.0	0	300	0	0	0	0
2031	5048	6742	33.6	662	300	0	0	0	0
2032	5091	6758	32.8	0	300	0	0	0	0
2033	5133	6732	31.2	0	300	0	0	0	0
2034	5179	7080	36.7	0	300	400	0	0	0
2035	5228	7086	35.5	0	300	0	0	0	0
2036	5274	7090	34.4	0	300	0	0	0	0
2037	5332	7092	33.0	0	150	0	0	0	0
2038	5390	6959	29.1	0	225	0	0	0	0
2039	5450	6961	27.7	0	300	0	0	0	0
2040	5509	6959	26.3	0	300	0	0	0	0
2041	5571	6958	24.9	0	300	0	0	0	0
2042	5633	6960	23.6	0	300	0	0	0	0
2043	5697	6961	22.2	0	225	0	0	0	0
2044	5761	6964	20.9	0	300	0	0	0	0
2045	5826	7016	20.4	0	300	100	0	0	0
2046	5892	7120	20.9	0	300	200	0	0	0
2047	5959	7172	20.4	0	300	100	0	0	-610
2048	6026	7287	20.9	523	150	400	0	0	0
2049	6094	7472	22.6	523	150	0	0	0	0
2050	6163	7473	21.3	0	0	0	0	0	0

Appendix F: Generation Added by Type for each Resource Plan by Year

Reference Build Plan

Year	1x1 CC	2x1 CC 50% Shared	2x1 CC	3x1 CC	CT Aero 1x	CT Aero 2x	CT Frame 1x	CT Frame 2x	SMR	Solar	Solar IRA	Solar PPA	Solar PPA IRA	Off Shore Wind	Battery 85%	Battery 50%	Off Shore Wind
2023																	
2024																	
2025																	
2026													150				
2027											75		150				
2028											150		150				
2029											150		150		400		
2030											150		150				
2031		662									150		150				
2032											150		150				
2033											150		150		100		
2034											150		150		300		
2035											150		150				
2036										150		150				300	
2037												150					
2038												150					
2039												150				200	
2040								523				150					
2041												150					
2042												150					
2043												150					
2044												150					
2045												150					
2046												150					
2047												150				100	
2048												150				200	
2049								523				150					
2050																	
Total MW		662						1046		150	1275	2100	1500		800	800	

High Fossil Fuel Prices Build Plan

Year	1x1 CC	2x1 CC 50% Shared	2x1 CC	3x1 CC	CT Aero 1x	CT Aero 2x	CT Frame 1x	CT Frame 2x	SMR	Solar	Solar IRA	Solar PPA	Solar PPA IRA	Off Shore Wind	Battery 85%	Battery 50%	Off Shore Wind
2023																	
2024																	
2025																	
2026											150		150				
2027											150		150				
2028											150		150				
2029											150		150		400		
2030											150		150				
2031		662									150		150				
2032											150		150				
2033											150		150		100		
2034											150		150		300		
2035											150		150				
2036										150		150				300	
2037										150		150					
2038										150		150					
2039										150		150				100	
2040								523		150		150					
2041										150		150				100	
2042										150		150					
2043										150		150					
2044										150		150				100	
2045										150		150					
2046										150		150				100	
2047												150				100	
2048												150					
2049								523				150					
2050																	
Total MW		662						1046		1650	1500	2100	1500		800	800	

Zero Carbon Cost Build Plan

Year	1x1 CC	2x1 CC 50% Shared	2x1 CC	3x1 CC	CT Aero 1x	CT Aero 2x	CT Frame 1x	CT Frame 2x	SMR	Solar	Solar IRA	Solar PPA	Solar PPA IRA	Off Shore Wind	Battery 85%	Battery 50%	Off Shore Wind
2023																	
2024																	
2025																	
2026													150				
2027													150				
2028													150				
2029							262				75		150		100		
2030											150		150				
2031		662									150		150				
2032											150		150				
2033											150		150		100		
2034													150		200		
2035													150		400		
2036												150					
2037												150					
2038												150					
2039												150					
2040												150				100	
2041												150				100	
2042								523				150					
2043												150					
2044												150					
2045												150					
2046												150					
2047												150					
2048												150					
2049												150				400	
2050																100	
Total MW		662					262	523			675	2100	1500		800	700	

Dominion Energy

70% CO_2 Reduction Build Plan																	
Year	1x1 CC	2x1 CC 50% Shared	2x1 CC	3x1 CC	CT Aero 1x	CT Aero 2x	CT Frame 1x	CT Frame 2x	SMR	Solar	Solar IRA	Solar PPA	Solar PPA IRA	Off Shore Wind	Battery 85%	Battery 50%	Off Shore Wind
2023																	
2024																	
2025																	
2026										150		150					
2027										150		150					
2028										150		150					
2029							262			150		150			100		
2030										150		150					
2031			1325							150		150			200		
2032										150		150			100		
2033										150		150			400		
2034										150		150				100	
2035										150		150				200	
2036										150		150				200	
2037										150		150				200	
2038										150		150				100	
2039										150		150					
2040										150		150		100			100
2041										150		150		100			100
2042										150		150		100			100
2043										150		150		100			100
2044										150		150		100			100
2045										150		150		100			100
2046														100			100
2047														100			100
2048																	
2049																	
2050																	
Total MW			1325				262			3000		3000		800	800	800	800

85% CO_2 Reduction Build Plan																	
Year	**1x1 CC**	**2x1 CC 50% Shared**	**2x1 CC**	**3x1 CC**	**CT Aero 1x**	**CT Aero 2x**	**CT Frame 1x**	**CT Frame 2x**	**SMR**	**Solar**	**Solar IRA**	**Solar PPA**	**Solar PPA IRA**	**Off Shore Wind**	**Battery 85%**	**Battery 50%**	**Off Shore Wind**
2023																	
2024																	
2025																	
2026										150		150					
2027										150		150					
2028										150		150					
2029							262			150		150			100		
2030										150		150					
2031			1325							150		150			200		
2032										150		150			100		
2033										150		150			400		
2034										150		150				100	
2035										150		150				200	
2036										150		150				200	
2037										150		150				200	
2038										150		150				100	
2039										150		150					
2040									268	150		150		100			100
2041										150		150		100			100
2042										150		150		100			100
2043										150		150		100			100
2044										150		150		100			100
2045									268	150		150		100			100
2046										150		150		100			100
2047										150		150		100			100
2048										150		150		100			100
2049										150		150		100			100
2050									268	150		150		100			100
Total MW			1325				262		804	3750		3750		1100	800	800	1100

Dominion Energy

Electrification Build Plan																	
Year	1x1 CC	2x1 CC 50% Shared	2x1 CC	3x1 CC	CT Aero 1x	CT Aero 2x	CT Frame 1x	CT Frame 2x	SMR	Solar	Solar IRA	Solar PPA	Solar PPA IRA	Off Shore Wind	Battery 85%	Battery 50%	Off Shore Wind
2023																	
2024																	
2025																	
2026													150				
2027													150				
2028													150				
2029							262						150		300		
2030													150		100		
2031		662											150				
2032													150				
2033													150		200		
2034													150		100		
2035													150		100		
2036												150				800	
2037												150					
2038												150					
2039			650									150					
2040												150					
2041												150					
2042												150					
2043												150					
2044												150					
2045												150					
2046												150					
2047												150					
2048												150					
2049								523									
2050																	
Total MW		662	650				262	523				1950	1500		800	800	

Dominion Energy

Energy Conservation Build Plan

Year	1x1 CC	2x1 CC 50% Shared	2x1 CC	3x1 CC	CT Aero 1x	CT Aero 2x	CT Frame 1x	CT Frame 2x	SMR	Solar	Solar IRA	Solar PPA	Solar PPA IRA	Off Shore Wind	Battery 85%	Battery 50%	Off Shore Wind
2023																	
2024																	
2025																	
2026											150		150				
2027											150		150				
2028											150		150				
2029											150		150		200		
2030											150		150				
2031		662									150		150				
2032											150		150				
2033											150		150		100		
2034											150		150		400		
2035											150		150				
2036										150		150					
2037												150					
2038												150					
2039												150					
2040												150					
2041										150		150					
2042												150					
2043												150					
2044										75		150				100	
2045										150		150				100	
2046										75		150					
2047												150				100	
2048												150				100	
2049												150				400	
2050																	
Total MW		662								600	1500	2100	1500		700	800	

Dominion Energy

Aggressive Regulation Build Plan																	
Year	1x1 CC	2x1 CC 50% Shared	2x1 CC	3x1 CC	CT Aero 1x	CT Aero 2x	CT Frame 1x	CT Frame 2x	SMR	Solar	Solar IRA	Solar PPA	Solar PPA IRA	Off Shore Wind	Battery 85%	Battery 50%	Off Shore Wind
2023																	
2024																	
2025																	
2026											150		150				
2027											150		150				
2028											150		150				
2029							262				150		150		300		
2030											150		150		100		
2031		662									150		150				
2032											150		150				
2033											150		150		100		
2034											150		150		300		
2035											150		150				
2036										150		150				300	
2037										150		150					
2038			1325							150		150					
2039										150		150					
2040										150		150					
2041										150		150					
2042										150		150					
2043										150		150					
2044										150		150					
2045										150		150					
2046												150					
2047												150					
2048												150				200	
2049								523				150				100	
2050																200	
Total MW		662	1325				262	523		1500	1500	2100	1500		800	800	

Dominion Energy

High DSM Build Plan																	
Year	1x1 CC	2x1 CC 50% Shared	2x1 CC	3x1 CC	CT Aero 1x	CT Aero 2x	CT Frame 1x	CT Frame 2x	SMR	Solar	Solar IRA	Solar PPA	Solar PPA IRA	Off Shore Wind	Battery 85%	Battery 50%	Off Shore Wind
2023																	
2024																	
2025																	
2026													150				
2027													150				
2028											150		150				
2029							262				150		150				
2030											150		150				
2031		662									150		150				
2032											150		150				
2033											150		150		100		
2034											150		150		600		
2035											150		150				
2036										150		150				100	
2037												150					
2038												150					
2039												150					
2040												150					
2041								523				150					
2042												150				100	
2043												150					
2044												150					
2045												150					
2046												150					
2047												150					
2048												150				100	
2049												150				300	
2050																	
Total MW		662					262	523		150	1200	2100	1500		700	600	

Dominion Energy

Low DSM Build Plan

Year	1x1 CC	2x1 CC 50% Shared	2x1 CC	3x1 CC	CT Aero 1x	CT Aero 2x	CT Frame 1x	CT Frame 2x	SMR	Solar	Solar IRA	Solar PPA	Solar PPA IRA	Off Shore Wind	Battery 85%	Battery 50%	Off Shore Wind
2023																	
2024																	
2025																	
2026													150				
2027													150				
2028											150		150				
2029											150		150		400		
2030											150		150				
2031		662									150		150				
2032											150		150				
2033											150		150		100		
2034											150		150		300		
2035											150		150				
2036										150		150				500	
2037												150					
2038												150					
2039												150				100	
2040												150					
2041								523				150					
2042												150					
2043												150					
2044												150					
2045												150				100	
2046												150					
2047												150				100	
2048												150					
2049								523				150					
2050																	
Total MW		662						1046		150	1200	2100	1500		800	800	

Dominion Energy

Wateree Battery Build Plan																	
Year	1x1 CC	2x1 CC 50% Shared	2x1 CC	3x1 CC	CT Aero 1x	CT Aero 2x	CT Frame 1x	CT Frame 2x	SMR	Solar	Solar IRA	Solar PPA	Solar PPA IRA	Off Shore Wind	Battery 85%	Battery 50%	Off Shore Wind
2023																	
2024																	
2025																	
2026													150				
2027													150				
2028											150		150				
2029											150		150		400		
2030											150		150				
2031		662									150		150				
2032											150		150				
2033											150		150		100		
2034											150		150		300		
2035											150		150				
2036										150		150					
2037												150					
2038								523				150					
2039												150					
2040												150					
2041												150					
2042												150					
2043												150					
2044												150				200	
2045												150				100	
2046												150				300	
2047												150					
2048								523				150					
2049												150				100	
2050																	
Total MW		662						1046		150	1200	2100	1500		800	700	

Wateree CT Build Plan																	
Year	1x1 CC	2x1 CC 50% Shared	2x1 CC	3x1 CC	CT Aero 1x	CT Aero 2x	CT Frame 1x	CT Frame 2x	SMR	Solar	Solar IRA	Solar PPA	Solar PPA IRA	Off Shore Wind	Battery 85%	Battery 50%	Off Shore Wind
2023																	
2024																	
2025																	
2026													150				
2027													150				
2028											150		150				
2029							262				150		150		100		
2030											150		150				
2031		662									150		150				
2032											150		150				
2033											150		150		100		
2034											150		150		500		
2035											150		150		100		
2036										150		150					
2037												150					
2038												150					
2039												150					
2040												150				100	
2041												150				100	
2042								523				150					
2043												150					
2044												150					
2045												150					
2046												150					
2047												150					
2048												150					
2049												150				400	
2050																100	
Total MW		662					262	523		150	1200	2100	1500		800	700	

Williams 2047 Build Plan

Year	1x1 CC	2x1 CC 50% Shared	2x1 CC	3x1 CC	CT Aero 1x	CT Aero 2x	CT Frame 1x	CT Frame 2x	SMR	Solar	Solar IRA	Solar PPA	Solar PPA IRA	Off Shore Wind	Battery 85%	Battery 50%	Off Shore Wind
2023																	
2024																	
2025																	
2026													150				
2027											75		150				
2028											150		150				
2029											150		150		400		
2030											150		150				
2031		662									150		150				
2032											150		150				
2033											150		150				
2034											150		150		400		
2035											150		150				
2036										150		150					
2037												150					
2038												150					
2039												150					
2040												150					
2041												150					
2042												150					
2043												150					
2044												150					
2045								523				150					
2046												150					
2047												150					
2048								523				150					
2049												150				600	
2050																100	
Total MW		662						1046		150	1275	2100	1500		800	700	

High Fuel Williams 2047 Build Plan

Year	1x1 CC	2x1 CC 50% Shared	2x1 CC	3x1 CC	CT Aero 1x	CT Aero 2x	CT Frame 1x	CT Frame 2x	SMR	Solar	Solar IRA	Solar PPA	Solar PPA IRA	Off Shore Wind	Battery 85%	Battery 50%	Off Shore Wind
2023																	
2024																	
2025																	
2026											150		150				
2027											150		150				
2028											150		150				
2029											150		150		400		
2030											150		150				
2031		662									150		150				
2032											150		150				
2033											150		150				
2034											150		150		400		
2035											150		150				
2036										150		150					
2037												150					
2038										75		150					
2039										150		150					
2040										150		150					
2041										150		150					
2042										150		150					
2043										75		150					
2044										150		150					
2045										150		150				100	
2046										150		150				200	
2047										150		150				100	
2048								523				150				400	
2049								523				150					
2050																	
Total MW		662						1046		1500	1500	2100	1500		800	800	

Appendix G: Energy from Renewable Generation Summed by Five-year Period for the Twenty-Four Cases

Energy from Renewable Generation by Five-Year Period (GWh)							
Market Scenario	**Build Plan**	**2023- 2027**	**2028- 2032**	**2033- 2037**	**2038- 2042**	**2043- 2047**	**2048- 2050**
Reference	Reference	13,467	24,350	24,935	40,841	46,632	30,793
Reference	High Fossil Fuel Prices	40,215	53,159	62,343	65,685	349,421	42,360
Reference	Zero Carbon Cost	13,315	20,879	28,124	32,944	40,412	26,294
Reference	70% CO_2 Reduction	11,840	22,640	48,388	70,168	85,293	68,772
Reference	85% CO_2 Reduction	5,451	19,212	33,530	54,029	72,831	49,893
High Fossil Fuel Prices	Reference	13,467	24,361	34,392	40,889	47,089	30,863
High Fossil Fuel Prices	High Fossil Fuel Prices	14,252	26,551	36,587	47,055	55,123	36,560
High Fossil Fuel Prices	Zero Carbon Cost	13,311	21,415	28,807	33,668	41,403	27,127
High Fossil Fuel Prices	70% CO_2 Reduction	14,249	26,494	37,051	50,195	63,432	42,875
High Fossil Fuel Prices	85% CO_2 Reduction	5,471	19,252	33,387	53,757	200,992	49,957
Zero Carbon Cost	Reference	13,314	23,649	32,460	37,698	44,080	28,606
Zero Carbon Cost	High Fossil Fuel Prices	40,216	53,125	62,302	65,631	349,381	42,330
Zero Carbon Cost	Zero Carbon Cost	13,310	21,404	28,784	33,595	41,297	27,058
Zero Carbon Cost	70% CO_2 Reduction	14,253	26,448	37,019	50,135	63,366	42,828
Zero Carbon Cost	85% CO_2 Reduction	5,465	19,177	33,324	53,675	200,910	49,876
Sensitivity	Electrification	39,261	45,081	47,748	52,028	59,053	40,227
Sensitivity	Energy Conservation	57,131	60,770	59,999	62,415	65,849	42,537
Sensitivity	Aggressive Regulation	14,252	26,648	36,981	47,932	57,602	38,256
Sensitivity	High DSM	3,945	15,647	29,118	33,958	37,668	22,916
Sensitivity	Low DSM	3,526	8,184	15,663	24,063	31,928	22,688
Sensitivity	Wateree Battery	13,310	23,593	32,926	38,033	44,192	29,671
Sensitivity	Wateree CT	3,547	8,503	15,834	24,158	31,887	22,755
Sensitivity	Williams 2047	39,418	50,801	60,261	65,028	70,939	45,737
Sensitivity	High Fuel Williams 2047	40,249	53,201	62,335	65,369	67,533	43,367

Appendix H: Residential Bill Impacts for the Twenty-Four Cases

Typical Residential Bill @1000 kWh/month under Reference Market Scenario

Build Plan	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Reference	132.79	126.80	125.23	129.75	129.33	131.27	131.56	136.59	138.62	147.30	150.42	155.51	158.46	164.06	166.41
High Fossil Fuel Prices	132.79	127.00	125.51	130.63	130.46	132.42	132.60	138.76	140.26	148.06	152.19	156.65	160.20	166.02	168.52
Zero Carbon Cost	132.79	127.00	125.51	130.10	129.29	130.67	132.56	139.46	140.54	148.28	152.58	155.64	162.69	164.80	166.61
70% CO_2 Reduction	132.79	126.81	125.25	130.29	130.25	132.25	133.91	139.02	151.53	160.53	166.70	169.43	174.82	179.16	184.02
85% CO_2 Reduction	132.79	126.79	125.23	130.27	130.24	132.23	133.89	138.99	151.51	160.51	166.68	169.41	174.79	178.74	183.94

Typical Residential Bill @1000 kWh/month under High Fossil Fuel Market Scenario

Build Plan	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Reference	132.79	126.79	125.23	139.79	138.17	140.02	141.14	146.19	147.38	157.29	160.91	166.33	169.68	176.20	178.81
High Fossil Fuel Prices	132.79	126.80	125.24	140.15	138.86	140.73	141.76	146.73	148.04	157.88	161.53	166.91	170.29	176.75	180.13
Zero Carbon Cost	132.79	126.80	125.24	139.84	138.00	139.47	141.75	146.91	148.24	157.93	161.85	165.84	172.53	175.94	178.46
70% CO_2 Reduction	132.79	126.79	125.22	140.12	138.83	140.70	143.07	148.22	159.24	169.12	175.90	178.75	184.78	189.79	194.41
85% CO_2 Reduction	132.79	126.79	125.23	140.13	138.85	140.72	143.10	148.23	159.25	169.13	175.92	178.77	184.80	189.81	194.42

Typical Residential Bill @1000 kWh/month under Zero Carbon Cost Market Scenario

Build Plan	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Reference	132.79	127.00	125.51	130.11	129.79	131.70	131.90	135.71	137.25	144.42	148.04	152.13	155.47	161.39	161.98
High Fossil Fuel Prices	132.79	126.77	125.26	130.29	130.23	132.22	132.43	134.87	137.21	145.27	147.85	152.61	154.95	160.69	163.73
Zero Carbon Cost	132.79	126.81	125.23	129.76	129.04	130.46	131.91	134.42	136.65	144.58	147.37	150.41	155.94	158.10	160.00
70% CO_2 Reduction	132.79	126.80	125.23	130.27	130.24	132.23	133.89	136.47	149.55	158.01	163.79	166.26	171.10	175.49	180.18
85% CO_2 Reduction	132.79	126.80	125.23	130.27	130.24	132.23	133.89	136.46	149.54	158.01	163.79	166.25	171.09	175.49	180.19

Typical Residential Bill @1000 kWh/month under Reference Market Scenario

Build Plan	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Electrification	132.79	126.79	125.70	126.06	125.58	127.25	130.25	133.31	135.41	142.94	146.45	149.17	151.69	161.98	164.07
Energy Conservation	132.79	126.79	125.25	139.96	138.46	140.17	139.02	143.57	144.64	153.85	157.30	162.88	165.84	169.45	171.37
Aggressive Regulation	132.79	126.80	125.71	141.19	140.08	146.90	151.37	155.72	156.29	166.57	170.94	176.29	180.29	188.02	192.05
High DSM	132.79	126.81	125.08	129.53	128.80	130.73	131.45	136.53	138.67	147.07	150.39	157.67	160.67	164.38	166.60
Low DSM	132.79	127.00	125.35	129.91	129.07	130.92	131.07	137.33	138.47	146.37	150.32	153.88	156.71	160.01	161.72
Wateree Battery	132.79	126.79	125.23	129.75	129.02	130.98	131.42	136.47	138.49	147.19	150.30	155.41	158.34	161.26	163.71
Wateree CT	132.79	126.80	125.22	129.75	129.04	130.98	134.01	139.11	141.28	149.76	153.14	159.69	163.65	166.52	168.80
Williams 2047	132.79	126.80	125.23	129.75	129.33	131.28	131.57	136.60	146.34	152.25	155.18	160.90	164.38	167.56	170.01
High Fuel Williams 2047	132.79	126.79	125.24	140.14	138.87	140.73	141.78	146.73	155.72	165.35	168.99	174.79	178.74	182.93	185.60

Dominion Energy

Appendix I: Retail Rate Impacts for the Twenty-Four Cases

Retail Rate Impacts (dollars/kWh) under Reference Market Scenario															
Build Plan	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Reference	0.10772	0.10215	0.10022	0.10290	0.10208	0.10343	0.10386	0.10842	0.10942	0.11657	0.11913	0.12317	0.12562	0.13001	0.13211
High Fossil Fuel Prices	0.10772	0.10235	0.10050	0.10351	0.10282	0.10419	0.10452	0.11024	0.11069	0.11693	0.12053	0.12392	0.12700	0.13162	0.13352
Zero Carbon Cost	0.10772	0.10235	0.10050	0.10325	0.10216	0.10318	0.10493	0.11139	0.11142	0.11759	0.12136	0.12380	0.12971	0.13156	0.13311
70% CO_2 Reduction	0.10772	0.10215	0.10022	0.10315	0.10259	0.10400	0.10541	0.11004	0.11862	0.12584	0.13079	0.13290	0.13738	0.14071	0.14446
85% CO_2 Reduction	0.10772	0.10214	0.10022	0.10316	0.10260	0.10400	0.10541	0.11003	0.11862	0.12583	0.13078	0.13289	0.13736	0.14029	0.14439

Retail Rate Impacts (dollars/kWh) under High Fossil Fuel Market Scenario															
Build Plan	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Reference	0.10772	0.10214	0.10021	0.11302	0.11098	0.11224	0.11352	0.11809	0.11822	0.12663	0.12970	0.13407	0.13694	0.14228	0.14465
High Fossil Fuel Prices	0.10772	0.10215	0.10022	0.11311	0.11128	0.11256	0.11375	0.11824	0.11850	0.12684	0.12994	0.13428	0.13718	0.14246	0.14528
Zero Carbon Cost	0.10772	0.10215	0.10022	0.11306	0.11093	0.11205	0.11421	0.11888	0.11916	0.12735	0.13074	0.13414	0.13969	0.14288	0.14516
70% CO_2 Reduction	0.10772	0.10214	0.10021	0.11309	0.11126	0.11254	0.11467	0.11934	0.12640	0.13452	0.14010	0.14233	0.14748	0.15151	0.15501
85% CO_2 Reduction	0.10772	0.10214	0.10022	0.11310	0.11128	0.11256	0.11471	0.11936	0.12642	0.13454	0.14013	0.14236	0.14750	0.15153	0.15503

Retail Rate Impacts (dollars/kWh) under Zero Carbon Cost Market Scenario															
Build Plan	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Reference	0.10772	0.10235	0.10050	0.10326	0.10254	0.10385	0.10419	0.10749	0.10798	0.11357	0.11664	0.11964	0.12250	0.12722	0.12750
High Fossil Fuel Prices	0.10772	0.10212	0.10025	0.10317	0.10258	0.10398	0.10434	0.10624	0.10755	0.11405	0.11605	0.11975	0.12157	0.12610	0.12857
Zero Carbon Cost	0.10772	0.10216	0.10022	0.10291	0.10192	0.10298	0.10429	0.10624	0.10745	0.11382	0.11604	0.11847	0.12282	0.12472	0.12636
70% CO_2 Reduction	0.10772	0.10215	0.10021	0.10315	0.10259	0.10399	0.10540	0.10743	0.11660	0.12326	0.12781	0.12965	0.13357	0.13695	0.14052
85% CO_2 Reduction	0.10772	0.10215	0.10022	0.10315	0.10259	0.10399	0.10540	0.10742	0.11659	0.12326	0.12781	0.12964	0.13355	0.13694	0.14052

Retail Rate Impacts (dollars/kWh) under Senstivity Cases															
Build Plan	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Electrification	0.10772	0.10214	0.10069	0.09917	0.09842	0.09973	0.10222	0.10471	0.10600	0.11219	0.11513	0.11748	0.11952	0.12775	0.12959
Energy Conservation	0.10772	0.10214	0.10023	0.11292	0.11087	0.11199	0.11147	0.11553	0.11554	0.12323	0.12613	0.13042	0.13289	0.13600	0.13766
Aggressive Regulation	0.10772	0.10215	0.10070	0.11417	0.11252	0.11884	0.12261	0.12621	0.12571	0.13450	0.13834	0.14264	0.14617	0.15275	0.15623
High DSM	0.10772	0.10215	0.10005	0.10266	0.10165	0.10299	0.10369	0.10828	0.10939	0.11625	0.11901	0.12456	0.12706	0.13001	0.13197
Low DSM	0.10772	0.10235	0.10033	0.10305	0.10193	0.10319	0.10348	0.10930	0.10938	0.11572	0.11913	0.12184	0.12446	0.12726	0.12870
Wateree Battery	0.10772	0.10214	0.10022	0.10289	0.10189	0.10326	0.10381	0.10838	0.10936	0.11653	0.11908	0.12314	0.12557	0.12797	0.13017
Wateree CT	0.10772	0.10215	0.10021	0.10289	0.10191	0.10326	0.10572	0.11033	0.11147	0.11841	0.12124	0.12628	0.12951	0.13186	0.13389
Williams 2047	0.10772	0.10215	0.10022	0.10290	0.10208	0.10344	0.10387	0.10843	0.11525	0.12019	0.12275	0.12712	0.13005	0.13264	0.13478
High Fuel Williams 2047	0.10772	0.10214	0.10022	0.11310	0.11129	0.11256	0.11378	0.11825	0.12429	0.13234	0.13562	0.14007	0.14349	0.14713	0.14950

Appendix J: CO_2 Cost, Fuel Cost, and Levelized Cost Comparison for the Twenty-Four Cases

Market Scenario	Build Plan	Fuel ($000)	CO_2 ($000)	LNPV ($000)
Reference	Reference	$669,402	$95,884	$1,883,717
Reference	High Fossil Fuel Prices	$659,896	$94,353	$1,953,582
Reference	Zero Carbon Cost	$712,430	$105,289	$1,895,375
Reference	70% CO_2 Reduction	$580,586	$73,523	$2,071,839
Reference	85% CO_2 Reduction	$536,656	$56,826	$2,392,627
High Fossil Fuel Prices	Reference	$961,250	$95,718	$2,177,480
High Fossil Fuel Prices	High Fossil Fuel Prices	$909,445	$88,021	$2,200,304
High Fossil Fuel Prices	Zero Carbon Cost	$1,004,641	$102,792	$2,187,001
High Fossil Fuel Prices	70% CO_2 Reduction	$815,324	$73,489	$2,307,940
High Fossil Fuel Prices	85% CO_2 Reduction	$730,439	$56,937	$2,587,568
Zero Carbon Cost	Reference	$689,718	$0	$1,809,067
Zero Carbon Cost	High Fossil Fuel Prices	$639,139	$0	$1,837,964
Zero Carbon Cost	Zero Carbon Cost	$696,761	$0	$1,773,982
Zero Carbon Cost	70% CO_2 Reduction	$582,856	$0	$2,000,495
Zero Carbon Cost	85% CO_2 Reduction	$539,521	$0	$2,338,430
Senstivity Case	Electrification	$628,823	$0	$1,805,958
Senstivity Case	Energy Conservation	$852,740	$79,425	$1,996,645
Senstivity Case	Aggressive Regulation	$1,062,356	$175,571	$2,565,891
Senstivity Case	High DSM	$658,857	$94,552	$1,862,858
Senstivity Case	Low DSM	$678,573	$98,400	$1,868,130
Senstivity Case	Wateree Battery	$673,419	$96,975	$1,876,177
Senstivity Case	Wateree CT	$670,479	$96,756	$1,899,583
Senstivity Case	Williams 2047	$665,713	$99,630	$1,908,602
Senstivity Case	High Fuel Williams 2047	$913,460	$93,447	$2,236,860

Appendix K: Summary of CO_2 emissions (000's Tons) for the Twenty-Four Cases

Market Scenario	Build Plan	2050 CO_2 Emissions	2050 Reduction from 2005 CO_2	2050 Cumulative CO_2 (2023-2050)
Reference	Reference	7,758	59.1%	202,714
Reference	High Fossil Fuel Prices	6,968	63.3%	190,900
Reference	Zero Carbon Cost	8,497	55.2%	218,036
Reference	70% CO_2 Reduction	5,446	71.3%	170,724
Reference	85% CO_2 Reduction	2,498	86.8%	154,049
High Fossil Fuel Prices	Reference	7,740	59.2%	202,359
High Fossil Fuel Prices	High Fossil Fuel Prices	6,956	63.3%	190,638
High Fossil Fuel Prices	Zero Carbon Cost	8,267	56.4%	213,541
High Fossil Fuel Prices	70% CO_2 Reduction	5,443	71.3%	170,640
High Fossil Fuel Prices	85% CO_2 Reduction	2,489	86.9%	154,270
Zero Carbon Cost	Reference	8,170	56.9%	210,270
Zero Carbon Cost	High Fossil Fuel Prices	6,975	63.2%	191,511
Zero Carbon Cost	Zero Carbon Cost	8,297	56.3%	214,402
Zero Carbon Cost	70% CO_2 Reduction	5,457	71.2%	171,629
Zero Carbon Cost	85% CO_2 Reduction	2,499	86.8%	155,250
Senstivity Case	Electrification	9,897	47.8%	240,169
Senstivity Case	Energy Conservation	5,861	69.1%	179,434
Senstivity Case	Aggressive Regulation	9,101	52.0%	218,088
Senstivity Case	High DSM	7,630	59.8%	200,369
Senstivity Case	Low DSM	7,626	59.8%	199,759
Senstivity Case	Wateree Battery	7,813	58.8%	204,751
Senstivity Case	Wateree CT	7,792	58.9%	204,221
Senstivity Case	Williams 2047	7,793	58.9%	209,556
Senstivity Case	High Fuel Williams 2047	6,989	63.2%	200,693

Appendix L: Generator Level Performance Data

Availability Factor					
Generator	**2018**	**2019**	**2020**	**2021**	**2022**
Columbia Energy Center CT 1	87.22%	90.60%	78.15%	86.15%	64.70%
Columbia Energy Center CT 2	82.79%	88.89%	77.29%	72.90%	89.00%
Columbia Energy Center ST 3	87.30%	91.40%	80.13%	88.57%	89.50%
Cope	77.34%	92.33%	47.50%	92.53%	81.40%
Fairfield Pumped Storage 1	84.18%	96.44%	90.53%	98.65%	77.80%
Fairfield Pumped Storage 2	84.25%	96.25%	90.52%	98.84%	77.60%
Fairfield Pumped Storage 3	89.58%	97.12%	88.40%	99.47%	92.40%
Fairfield Pumped Storage 4	89.96%	97.06%	88.11%	99.40%	92.10%
Fairfield Pumped Storage 5	93.06%	90.68%	99.76%	94.23%	96.40%
Fairfield Pumped Storage 6	92.51%	89.70%	99.71%	94.27%	97.00%
Fairfield Pumped Storage 7	92.99%	88.39%	97.58%	92.41%	84.40%
Fairfield Pumped Storage 8	92.93%	88.39%	97.59%	91.71%	86.20%
Hagood CT 4	99.83%	98.70%	94.76%	97.37%	98.80%
Hagood CT 5	92.45%	96.83%	99.21%	80.78%	99.60%
Hagood CT 6	95.89%	99.07%	99.84%	98.77%	99.60%
Jasper CT 1	88.62%	91.83%	92.17%	86.27%	83.30%
Jasper CT 2	87.91%	90.83%	89.49%	81.71%	87.30%
Jasper CT 3	88.99%	90.87%	89.38%	78.63%	87.50%
Jasper ST 4	90.48%	92.31%	94.01%	88.28%	86.10%
McMeekin 1	93.82%	85.24%	96.21%	82.65%	81.40%
McMeekin 2	94.02%	82.58%	89.98%	87.90%	87.10%
Parr CT 3	98.36%	87.71%	99.68%	97.93%	97.90%
Parr CT 4	93.81%	90.16%	99.99%	96.98%	100.00%
Saluda Hydro 1	61.71%	93.48%	68.79%	98.81%	18.20%
Saluda Hydro 2	73.99%	74.94%	98.06%	100.00%	86.50%
Saluda Hydro 3	14.69%	82.71%	98.85%	100.00%	89.80%
Saluda Hydro 4	98.22%	79.03%	95.34%	94.52%	85.40%
Saluda Hydro 5	97.96%	62.60%	95.58%	91.25%	93.00%
Urquhart ST 1	82.73%	92.37%	87.89%	96.62%	88.80%
Urquhart ST 2	83.01%	92.64%	84.50%	81.15%	89.50%
Urquhart ST 3	43.25%	78.61%	94.63%	92.13%	98.60%
Urquhart CT 5	82.96%	92.57%	87.90%	96.72%	88.80%
Urquhart CT 6	83.23%	92.68%	87.22%	81.53%	89.80%
Urquhart CT 4	85.13%	94.33%	97.98%	89.85%	89.10%
V.C. Summer 1	86.07%	95.92%	91.11%	82.33%	99.43%
Wateree 1	91.01%	61.27%	73.50%	81.48%	76.40%
Wateree 2	91.24%	61.58%	10.79%	0.00%	58.30%
Williams	83.69%	74.83%	84.57%	72.23%	72.50%
Bushy Park CT A	93.29%	76.50%	0.00%	0.00%	0.00%
Bushy Park CT B	73.23%	99.95%	99.76%	99.62%	88.70%

Annual Forced Outage Rate					
Generator	**2018**	**2019**	**2020**	**2021**	**2022**
Columbia Energy Center CT 1	0.03%	0.15%	0.45%	8.02%	3.90%
Columbia Energy Center CT 2	0.71%	0.78%	1.25%	8.01%	0.85%
Columbia Energy Center ST 3	0.04%	0.11%	0.12%	7.67%	0.43%
Cope	3.35%	0.20%	1.20%	0.26%	11.38%
Fairfield Pumped Storage 1	0.78%	0.35%	0.08%	0.03%	0.00%
Fairfield Pumped Storage 2	0.21%	0.55%	0.08%	0.00%	0.00%
Fairfield Pumped Storage 3	0.09%	0.01%	0.00%	0.00%	0.16%
Fairfield Pumped Storage 4	0.09%	0.03%	0.30%	0.05%	0.16%
Fairfield Pumped Storage 5	0.20%	0.00%	0.00%	0.04%	0.43%
Fairfield Pumped Storage 6	0.79%	1.04%	0.00%	0.00%	0.51%
Fairfield Pumped Storage 7	0.00%	0.00%	1.46%	0.00%	0.66%
Fairfield Pumped Storage 8	0.09%	0.00%	1.46%	0.00%	0.63%
Hagood CT 4	0.03%	0.06%	0.12%	0.16%	4.39%
Hagood CT 5	7.55%	1.14%	0.12%	1.11%	1.58%
Hagood CT 6	4.11%	0.03%	0.07%	0.90%	1.23%
Jasper CT 1	0.41%	0.05%	0.00%	0.00%	0.22%
Jasper CT 2	0.00%	0.11%	0.01%	0.14%	0.03%
Jasper CT 3	0.00%	0.08%	0.02%	0.03%	0.54%
Jasper ST 4	0.04%	0.11%	0.00%	0.00%	2.04%
McMeekin 1	0.05%	3.45%	0.00%	0.00%	6.45%
McMeekin 2	0.00%	0.00%	2.97%	0.06%	1.62%
Parr CT 3	1.64%	2.71%	0.32%	0.00%	75.30%
Parr CT 4	6.19%	0.00%	0.01%	0.95%	0.00%
Saluda Hydro 1	16.63%	3.05%	31.09%	0.00%	0.00%
Saluda Hydro 2	0.23%	0.00%	1.79%	0.00%	0.00%
Saluda Hydro 3	79.01%	0.00%	0.51%	0.00%	0.00%
Saluda Hydro 4	0.46%	4.42%	4.20%	0.00%	0.00%
Saluda Hydro 5	0.98%	5.82%	4.35%	0.00%	5.60%
Urquhart ST 1	0.35%	0.40%	0.28%	0.80%	1.03%
Urquhart ST 2	0.34%	1.89%	3.43%	4.33%	2.09%
Urquhart ST 3	0.39%	3.56%	2.43%	0.01%	4.59%
Urquhart CT 5	0.22%	0.33%	0.25%	0.76%	0.97%
Urquhart CT 6	0.26%	1.86%	0.84%	4.09%	1.75%
Urquhart CT 4	0.51%	0.48%	0.37%	8.93%	65.35%
V.C. Summer 1	0.00%	4.08%	0.67%	7.53%	0.00%
Wateree 1	1.43%	0.21%	0.10%	0.36%	4.34%
Wateree 2	1.26%	0.94%	88.06%	100.00%	47.73%
Williams	0.16%	1.81%	0.11%	0.08%	0.73%
Bushy Park CT A	0.00%	23.47%	100.00%	N/A	N/A
Bushy Park CT B	21.14%	0.02%	0.24%	0.01%	N/A

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Annual Capacity Factor					
Generator	**2018**	**2019**	**2020**	**2021**	**2022**
Columbia Energy Center CT 1	59.74%	79.88%	68.56%	76.65%	48.08%
Columbia Energy Center CT 2	44.96%	77.69%	66.19%	55.17%	70.97%
Columbia Energy Center ST 3	38.35%	57.93%	49.27%	44.14%	43.72%
Cope	47.29%	50.93%	26.48%	43.87%	47.38%
Fairfield Pumped Storage 1	8.43%	9.28%	8.88%	9.45%	3.22%
Fairfield Pumped Storage 2	8.52%	9.43%	8.36%	9.06%	8.86%
Fairfield Pumped Storage 3	8.52%	9.21%	8.04%	4.52%	10.27%
Fairfield Pumped Storage 4	8.97%	9.31%	8.65%	5.34%	10.41%
Fairfield Pumped Storage 5	8.59%	9.43%	8.28%	8.36%	11.93%
Fairfield Pumped Storage 6	8.39%	9.36%	8.13%	6.55%	8.20%
Fairfield Pumped Storage 7	8.76%	9.62%	8.55%	8.44%	7.57%
Fairfield Pumped Storage 8	8.73%	9.49%	8.65%	6.68%	8.26%
Hagood CT 4	1.92%	0.91%	2.10%	2.25%	2.29%
Hagood CT 5	1.65%	1.41%	2.13%	3.01%	2.38%
Hagood CT 6	2.58%	1.69%	2.63%	3.71%	2.79%
Jasper CT 1	73.22%	72.22%	74.10%	69.70%	64.48%
Jasper CT 2	72.93%	75.01%	74.39%	66.89%	68.87%
Jasper CT 3	73.29%	75.19%	74.27%	67.17%	64.94%
Jasper ST 4	54.96%	57.27%	58.75%	52.30%	54.09%
McMeekin 1	29.66%	35.05%	45.45%	40.21%	34.97%
McMeekin 2	25.56%	33.70%	47.52%	43.84%	34.07%
Parr CT 3	1.13%	0.27%	0.91%	0.57%	0.55%
Parr CT 4	1.14%	0.41%	0.96%	0.49%	0.95%
Saluda Hydro 1	14.42%	14.70%	3.88%	3.17%	3.33%
Saluda Hydro 2	3.30%	3.63%	8.32%	4.13%	2.16%
Saluda Hydro 3	8.39%	13.50%	24.18%	12.97%	10.49%
Saluda Hydro 4	15.34%	9.00%	25.80%	12.80%	4.50%
Saluda Hydro 5	17.44%	4.28%	17.76%	6.65%	9.95%
Urquhart ST 1	64.41%	51.01%	56.88%	63.71%	53.50%
Urquhart ST 2	51.94%	44.97%	48.21%	52.40%	55.72%
Urquhart ST 3	9.58%	5.45%	5.61%	11.16%	5.02%
Urquhart CT 5	52.19%	41.85%	46.50%	52.78%	41.68%
Urquhart CT 6	41.53%	36.11%	38.25%	43.55%	44.23%
Urquhart CT 4	3.93%	2.56%	5.16%	6.84%	4.52%
V.C. Summer 1	84.87%	94.97%	89.06%	82.69%	101.52%
Wateree 1	59.16%	37.36%	27.02%	50.36%	34.59%
Wateree 2	67.68%	31.44%	0.84%	0.00%	39.38%
Williams	55.64%	48.05%	50.25%	45.72%	32.60%
Bushy Park CT A	0.52%	0.05%	0.00%	N/A	N/A
Bushy Park CT B	0.47%	0.10%	0.07%	0.05%	N/A

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APPENDIX H 2

TRANSMISSION SYSTEM MAP

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APPENDIX H 3

REQUIRED SAFETY TRAINING

EXHIBIT H-3

REQUIRED SAFETY TRAINING

Training Topic	Training Required For	Applicable Standard and/or SCE&G Safety Procedure	Training Frequency*	Saluda Hydro Requirement
Ladder Safety	Employees who use ladders	29CFR1910.25-27 & 1926.1060 (OSHA)	Initially	**YES**
Emergency Plans	Employees who are expected to take action, such as evacuating a facility, in the event of an emergency	1910.38 (OSHA) SD-301	Initially	**YES**
Respiratory Protection	Employees who use respirators	1910.134 (OSHA) SD-204	Initially & Annually	**YES**
Hearing Conservation	Employees exposed to noise at or above an 8 hour TWA of 85 db	1910.95 (OSHA) SD-203	Initially & Annually	**YES**
Emergency Response to Hazardous Material Incidents (HAZMAT)	Employees who are expected to respond to emergencies involving uncontrolled releases of hazardous materials	1910.120 (OSHA)	Initially & Annually	**YES**
Personal Protective Equipment	Employees who wear personal protective equipment	1910.132 (OSHA) SD-202; SD-203; SD-204; SD-205; SD-210; SD-213; SD-501	Initially	**YES**
Confined Spaces	Employees who supervise, monitor, or enter confined spaces	1910.146 (OSHA)	Initially	**YES**
Confined Space Rescue	Employees who are on confined space rescue teams	1910.146 (OSHA) SD-300	Initially & Annually	**YES**
Control of Hazardous Energy (Lockout/Tagout)	Employees who work in power generating plants, and other areas, where equipment is locked or tagged during maintenance work	1910.147 (OSHA) SD-306	Initially & Annually	**YES**
First Aid & CPR	Employees who are expected to perform first aid or CPR duties	1910.151 (OSHA)	Initially & Every Three Years	**YES**
Fire Extinguishers	Employees who are expected to use fire extinguishers	1910.157 (OSHA) SD-303	Initially & Annually	**YES**
Fixed Fire Extinguishing Systems	Employees who inspect, maintain, or repair fixed fire extinguishing systems	1910.160 (OSHA)	Initially & Annually	**YES**
Powered Industrial Trucks (including Fork Lifts)	Employees who operate powered industrial trucks, such as forklifts or hand trucks.	1910.178 (OSHA) SD-307	Initially & Every Three Years	**YES**
Arc Welding and Cutting	Employees who operate arc welding equipment	1910.254 & 1926.351 (OSHA)	Initially	**YES**
Resistance Welding	Employees who operate resistance welding equipment	1910.255 (OSHA)	Initially	**YES**
Electrical Safety - Qualified Person	Employees who work near energized electrical parts or equipment	1910.332/269 (OSHA) SD-500	Initially	**YES**
Electrical Safety - Apparel	Employees who are exposed to electrical arcs or flames	1910.269 (OSHA) SD-500; SD-501; SD-502; SD-503; SD-504	Initially	**YES**
Access to Employee Exposure & Medical Records	Employees who have medical records or exposure records	1910.1020 (OSHA) SD-103	Initially & Annually	**YES**
Bloodborne Pathogens	Employees who are reasonably expected to be exposed to blood, body fluids, or other infectious materials	1910.1030 (OSHA) SD-206	Initially & Annually	**YES**

EXHIBIT H-3

REQUIRED SAFETY TRAINING

Training Topic	Training Required For	Applicable Standard and/or SCE&G Safety Procedure	Training Frequency*	Saluda Hydro Requirement
Hazard Communication (HAZCOM)	Employees who work with hazardous chemicals	1910.1200 (OSHA) SD-207	Initially & whenever a new hazard is introduced	**YES**
Heat Stress	Employees who work in a hot environment (temperature > 95 ^{o})	SCE&G SD-209	Initially & Annually	**YES**
Switching & Tagging	Employees who perform switching and tagging on the transmission or distribution electrical system	SCE&G SD-504	Initially	**YES**
Driver & Vehicle Safety	Employees who operate a Company vehicle	SCE&G SD-400	Initially	**YES**
Powder Actuated Tools	Employees who use powder actuated tools.	1926.302 (OSHA)	Initially	**YES**
Fall Protection	Employees who work at elevated locations and use fall protective equipment.	1926.503 (OSHA) SD-210	Initially	**YES**
Lead	Employees who work with or are exposed to lead.	1926.1025 (OSHA) SD-304	Initially & Annually	**YES**
Asbestos	Employees who work with or are exposed to asbestos.	1926.1101 (OSHA) SD-308	Initially & Annually	**YES**
Commercial Motor Vehicle Operation (Federal Motor Carrier Safety Regulations)	Employees who drive commercial motor vehicles.	49CFR383-399 (DOT) CSHD-2000	Initially	**YES**

OSHA - Occupational Safety and Health Administration
DOT - Department of Transportation
DOE - Department of Energy

* Unless specified otherwise, retraining is required whenever (1) there is a change in any condition which renders the previous training obsolete, (2) an employee demonstrates non compliance or incompetence in a subject, (3) a safety related task has not been performed in the past year, or (4) there is evidence that indicates that the previous training is not effective.

Training is to be documented and include the training topic, the date of the training, the name of the individual that received the training, and the name of the person who provided the training.

APPENDIX H 4

REQUIRED OPERATOR TRAINING

EXHIBIT H-4

REQUIRED OPERATOR/REPAIRMAN TRAINING

	OPERATOR/REPAIRMAN COURSE REQUIREMENTS	NCCER Hours	**NCCER Earned Courses**	**NCCER Written Test** (Grade)	(Date)	**Lab Perform Complete** (Date)	**All Training Completed** (Date)	**NCCER Earned Hours**
1	**SAFETY TRAINING (ON-SITE)**							
	Plant Safety Training (Plant T/C)	25	Non-NCCER					
2	**BASIC SAFETY (ON-SITE)**							
	Basic Safety	12.5	00101-09					
3	**POWER PLANT FUNDAMENTALS (ON-SITE)**							
	PPF/Walkdown/Time with APOs	40	Non-NCCER					
4	**POWER INDUSTRY**							
	Introduction to the Power Industyry	12.5	49101-10					
5	**BASIC MATH (ON-SITE AND CLASS)**							
	Intro to Construction Math	10	00102-09					
	Craft-Related Mathematics	15	40106-07					
6	**FORKLIFTS (ON-SITE)**							
	Intro to Materials Handling	5	00109-09					
	Mobile & Support Equipment	10	40112-07					
7	**HAND & POWER TOOLS**							
	Intro to Hand Tools	10	00103-09					
	Intro to Power Tools	10	00104-09					
8	**INTERMEDIATE RIGGING**							
	Intermediate Rigging	40	00106-09		**NACB-VENDOR**			
8	**MATERIAL HANDLING & HAND RIGGING**							
	Material Handling & Hand Rigging	15	40111-07					
9	**GASKETS & PACKING**							
	Gaskets and Packing	10	40105-07					
10	**LUBRICATION**							
	Lubrication	12.5	40113-07					
11	**PREVENTIVE AND PREDICTIVE MAINTENANCE**							
	Preventive and Predictive Maintenance	10	40401-09					
12	**PUMPS & DRIVERS/ INTRODUCTION TO VALVES**							
	Pumps and Drivers	5	40108-07					
	Introduction to Valves	5	40109-07					
13	**FLAME CUTTING**							
	Oxyfuel Cutting	17.5	40104-07					
14	**SHIELDED METAL ARC WELDING SETUP**							
	SMAW Equipment and Setup	5	29107-09					
15	**HAZARDOUS LOCATIONS**							
	Hazardous Locations	10	40301-08					
16	**HYDRAULICS**							
	Hydraulic Controls	15	40311-08					
17	**PNEUMATICS**							
	Pneumatic Controls	15	40312-08					
18	**PROGRAMMABLE LOGIC CONTROLLERS**							
	Programmable Logic Controllers	17.5	40409-09					
19	**BLUEPRINTS AND DOCUMENTS**							
	Intro to Construction Drawings	10	00105-09					
	Construction Drawings	12.5	40107-07					
	Instrument Drawings & Documents Part One	15	40211-08					
	E & I Drawings	10	40303-08					
20	**ELECTRICAL SAFETY AND TEST EQUIPMENT**							
	Electrical Safety							

EXHIBIT H-4

REQUIRED OPERATOR/REPAIRMAN TRAINING

	OPERATOR/REPAIRMAN COURSE REQUIREMENTS	NCCER Hours	NCCER Earned Courses	NCCER Written Test (Grade)	(Date)	Lab Perform Complete (Date)	All Training Completed (Date)	NCCER Earned Hours
	Industrial Safety for E & I Technicians	12.5	40201-08					
	Managing Electrical Hazards	12.5	26501-09					
	Introduction to the *National Electrical Code* ®	5	40202-08					
	Electrical Test Equipment							
	Introduction to Test Instruments	7.5	40110-07					
	E & I Test Equipment	10	40205-08					
21	**ELECTRICAL WIRING / NATIONAL ELECTRIC CODE**							
	Conductor Installations	10	26206-08					
22	**CONDUCTOR SELECTION, RACEWAYS/BOX/FITTING FILL**							
	Conductor Selection and Calculation	15	40307-08					
23	**CONDUCTOR INSTALL, TERMINATIONS/SPLICES**							
	Conductors and Cables	10	40212-08					
	Conductor Terminations and Splices	10	40213-08					
24	**CONDUIT BENDING AND INSTALLATION**							
	Hand Bending	10	40208-08					
	Machine Bending of Conduit	15	40310-08					
	Medium Voltage Terminations and Splices	10	26411-08					
25	**FASTENERS/ANCHORS, BOXES/FITTINGS, CABLE TRAY**							
	Fasteners and Anchors	5	40103-07					
	Tools of the Trade	5	40102-07					
	Cable Tray	7.5	26207-08					
26	**ELECTRICAL THEORY**							
	Electrical Theory	15	40203-08					
	Alternating Current	20	40204-08					
27	**MOTOR THEORY**							
	Motors: Theory and Application	20	26202-08					
	Motor Calculations	12.5	26309-08					
28	**MOTORS**							
	Motor Operation and Maintenance	10	26410-08					
29	**MOTOR CONTROLS AND ADVANCED MOTOR CONTROLS**							
	Motor Controls	15	40304-08					
	Advanced Motor Controls	20	26407-08					
30	**MOTOR OPERATED VALVES**							
	Motor-Operated Valves	15	40313-08					
31	**ELECTRICAL SERVICES, CKT BKRS, FUSES AND RELAYS**							
	Circuit Breakers and Fuses	12.5	26210-08					
	Control Systems and Fundamental Concepts	12.5	26211-08					
	Load Calculations-Branch and Feeder Ckts	17.5	26301-08					
	Overcurrent Protection	25	26305-08					
32	**CIRCUIT BREAKERS, PROTECTION, DISTRIBUTION**							
	Switchgear and Breaker Maintenance	25	50402-10					
	Power Plant Electrical Systems	12.5	50301-11					
33	**LIGHTING**							
	Electric Lighting	15	26203-08					
	Practical Applications of Lighting	12.5	26303-08					
34	**TRANSFORMERS**							
	Distribution Equipment	17.5	40305-08					
	Transformer Applications	7.5	40306-08					
	Specialty Transformers	10	26406-08					
35	**GROUNDING**							
	Temporary Grounding	15	40308-08					

EXHIBIT H-4

REQUIRED OPERATOR/REPAIRMAN TRAINING

	OPERATOR/REPAIRMAN COURSE REQUIREMENTS	**NCCER Hours**	**NCCER Earned Courses**	**NCCER Written Test** (Grade)	(Date)	**Lab Perform Complete** (Date)	**All Training Completed** (Date)	**NCCER Earned Hours**
	Grounding and Bonding	15	26209-08					
36	**MAIN GENERATOR / BUSSES**							
	Generator Maintenance	20	50401-10					
37	**BATTERIES, CHARGERS, STANDBY/EMERG. SYSTEMS**							
	Standby and Emergency Systems	12.5	40401-09					
38	**HEAT TRACING AND FREEZE PROTECTION**							
	Heat Tracing	10	26409-08					
39	**FLOW,PRESSURE,LEVEL AND TEMPERATURE**							
	Flow,Pressure,Level and Temperature	15	40206-08					
40	**PROCESS MATHEMATICS**							
	Process Mathematics	15	40207-08					
41	**TUBING**							
	Tubing	15	40209-08					
	Clean,Purge & Test Tubing & Piping Systems	7.5	40210-08					
42	**LAYOUT TUBING**							
	Layout & Installation of Tubing & Piping Systems	22.5	40309-08					
43	**ELECTRONIC COMPONENTS**							
	Electronic Components	10	40302-08					
44	**BASIC PROCESS CONTROL ELEMENTS**							
	Basic Process Control Elements,Transducers & Transmitters	15	40402-09					
45	**INSTRUMENT CALIBRATION**							
	Instrument Calibration & Configuration	10	40403-09					
46	**PNEUMATIC VALVES**							
	Pneumatic Control Valves,Actuators & Positioners (includes REM vendor)	40	40404-09					
47	**PERFORMING LOOP CHECKS**							
	Performing Loop Checks	7.5	40405-09					
48	**TROUBLESHOOTING & COMMISSIONING A LOOP**							
	Troubleshooting & Commissioning a Loop	10	40406-09					
49	**PROCESS CONTROL LOOPS & TUNING**							
	Process Control Loops & Tuning	20	40407-09					
50	**DATA NETWORKS**							
	Data Networks	15	40408-09					
51	**DISTRIBUTED CONTROL SYSTEMS**							
	Distributed Control Systems	17.5	40410-09					
	TOTAL	1108						