GENERATION, TRANSMISSION, AND DISTRIBUTION REPORT

I. PURPOSE OF THE REPORT

The purpose of this report is to supplement the information contained in the May 1, 2026 management Request to Adopt Retail Rate Adjustment Process and Recommendation to Adjust 2027 and 2028 Retail Rates (the "Management Recommendation") and the 2026 Electric System Cost of Service and Rate Design Study being provided to the Authority's Board of Directors (the "Board") in support of the recommended rate adjustment by providing an overview of the Santee Cooper (the "Authority") system (generation, transmission, and distribution) and explain the capital investments needed to serve, directly or indirectly, the growing number of South Carolinians in all 46 counties of the State.

II. SUMMARY OF THE REPORT

The Authority provides electric service to over two million South Carolinians through its vertically integrated generation, transmission, and distribution systems. The Authority serves its customers through a reliable generation portfolio, which includes a variety of resources geographically dispersed throughout South Carolina totaling approximately 5,163 megawatts ("MW") of capacity in the summer and approximately 5,388 MW in the winter, and through various power purchase arrangements. The Authority also maintains a distribution system that serves over 219,000 residential, commercial, and small industrial customers.

The Authority set seven new peak power demand records in 2025, evidencing the impact of load growth on our electric system. To support this load growth, the Board of Directors voted at the October 2025 meeting to advance capacity projects that will significantly increase system generating capacity.

In addition to the investments in new capacity needed to support load growth, the Authority carries out a well-established maintenance program to ensure that existing generation is highly reliable and operates efficiently when called upon. The Authority continues to undertake good utility practices and maintenance programs and has been able to maintain the reliability of its system. Continued and growing external forces including inflation, regional system growth, and regulatory costs, are increasing the cost to maintain the system in a reliable manner.

III. DISCUSSION

A. SYSTEM DESCRIPTION

The Authority is South Carolina's state-owned, not-for-profit electric utility and owns and operates over 40 miles of dams and dikes, several large generating facilities, a high voltage transmission network of 5,277 miles, and 3,237 miles of distribution lines and associated facilities. The Authority is statutorily authorized to, among other things, produce, transmit, and distribute electricity at wholesale and retail, and uses its robust system to serve over two million people across South Carolina. Of those over two million people the Authority

directly serves over 219,000 retail customers in Berkeley, Georgetown, and Horry counties, including 27 large industrial retail customers, and the remainder are served indirectly through its wholesale contracts with Central Electric Cooperative and the cities of Bamberg, Georgetown, and Seneca. The Authority also serves power to Piedmont Municipal Power Agency and the Town of Waynesville, North Carolina.

1. Generation and Power Purchase Arrangements

The Authority currently serves its customers through a reliable generation portfolio that includes a variety of resources geographically dispersed throughout South Carolina, including: two natural gas combined-cycle units; simple-cycle combustion turbines; six hydro units located on Lakes Moultrie and Marion; five landfill gas-to-energy biomass facilities; three solar PV sites; two coal-fired generating stations; and, through a partnership with Dominion Energy South Carolina, Inc. ("DESC"), a one-third ownership interest in the V.C. Summer Nuclear Station Unit 1. The capacity of these generating units totals approximately 5,163 MW, based on peak output ratings under summer conditions, and approximately 5,388 MW during the winter, as shown in Table 1 on the following page.

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Table 1 – Authority Electric System Facility Information

	AUTHORITY ELECTRIC SYSTEM GENERATING FACILITY INFORMATION			
		IN-SERVICE	PEAK CAPABILITY (MW) [1]		ENERGY
	FACILITY	DATE	WINTER	SUMMER	SOURCE
	EXISTING:				
1.	JEFFERIES HYDROELECTRIC GENERATING	1942	140	140	HYDRO
2.	WILSON DAM GENERATING STATION	1950	2	2	HYDRO
			142	142	
3.	MYRTLE BEACH COMBUSTION TURBINES[2]				
	NOS. 1 AND 2	1962	20	16	OIL
	NOS. 3	1972	20	19	OIL
	NO. 5	1976	25	21	OIL
4.	HILTON HEAD COMBUSTION TURBINES				
	NO. 1	1973	20	16	OIL
	NO. 2	1974	20	16	OIL
	NO. 3	1979	60	52	OIL
			165	140	
5.	WINYAH GENERATING STATION				
	NO. 1	1975	280	275	COAL
	NO. 2	1977	290	285	COAL
	NO. 3	1980	290	285	COAL
	NO. 4	1981	290	285	COAL
6.	CROSS GENERATING STATION				
	NO. 1	1995	585	580	COAL
	NO. 2	1983	570	565	COAL
	NO. 3	2007	580	585	COAL
	NO. 4	2008	595	605	COAL
			3,480	3,465	
7.	SUMMER NUCLEAR STATION[3]	1983	322	322	NUCLEAR
8.	LANDFILL GAS (VARIOUS SITES)	2001 - 2011	26	26	METHANE GAS
9.	J.S. RAINEY GENERATING STATION				
	COMBINED CYCLE NO. 1	2002	520	460	GAS
	COMBUSTION TURBINE NO. 2A	2002	180	146	GAS
	COMBUSTION TURBINE NO. 2B	2002	180	146	GAS
	COMBUSTION TURBINE NO. 3, 4, & 5	2004	270	225	GAS
10.	CHEROKEE	1998	98	86	GAS
			1,248	1,063	
11.	SOLAR (VARIOUS SITES)[4]	2006-2019	5	5	SOLAR
	TOTAL EXISTING CAPABILITY		**5,388**	**5,163**	

Notes:

[1] Capacity represented by Net Dependable Capacity (NDC).

[2] Myrtle Beach 4 Unavailable Winter (20 MW) Summer (19 MW) until further notice and is not included above.

[3] Represents The Authority's one-third ownership interest in Summer Nuclear Unit 1.

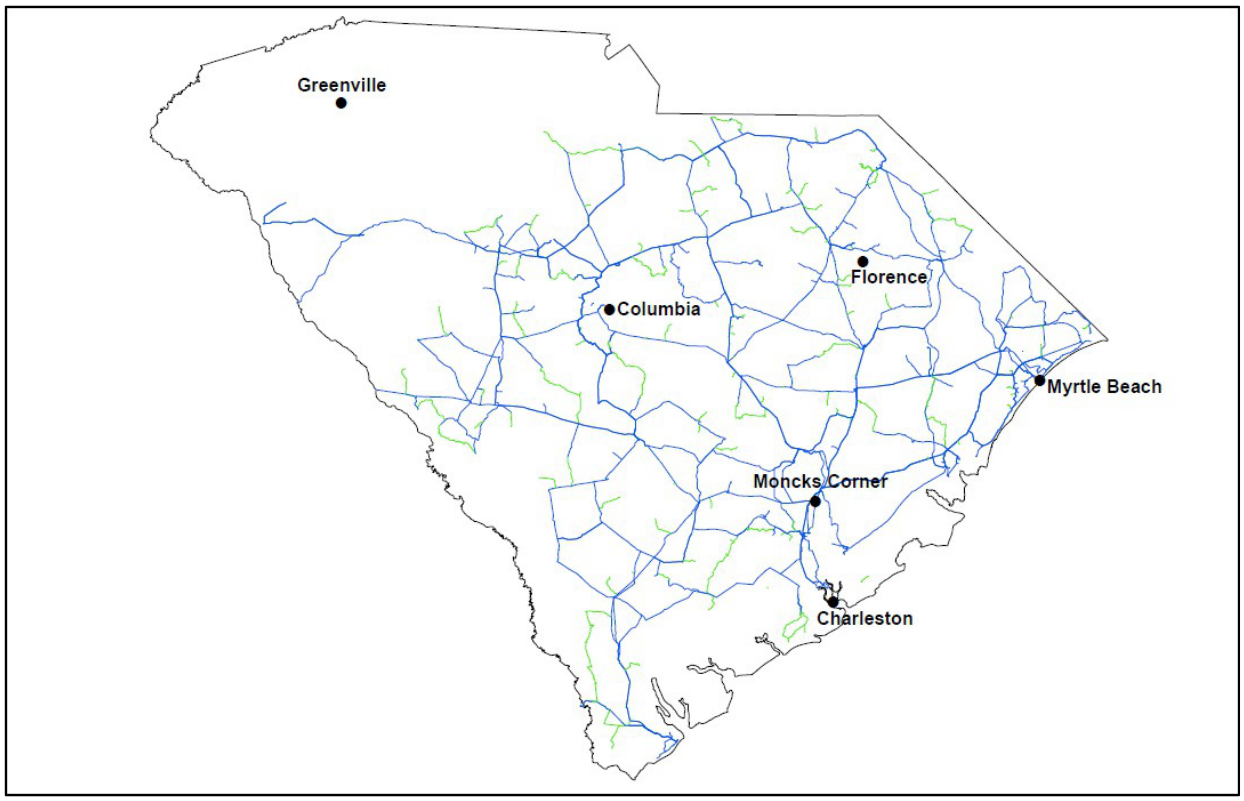
[4] Capacity values for solar reflect nameplate capacity. The Authority owns approximately 5 MW of solar capacity.

The Authority also currently purchases approximately 1,350 MW of nameplate capacity and associated energy and 883 MW in winter capacity through power purchase arrangements with third-parties.

2. Transmission

The Authority operates an integrated transmission system, illustrated in Figure 1 below, which consists of lines The Authority owns and lines that Central owns and the Authority maintains. The transmission system includes approximately 5,277 miles[1] of overhead and underground lines which are primarily rated between 69 kV and 230 kV. Additionally, the system includes 94 transmission substations and switching stations serving delivery point substations that the Authority and Central own. The Authority plans the transmission system to operate during normal and contingency conditions in compliance with mandatory North American Electric Reliability Corporation ("NERC") electric system reliability standards ("Reliability Standards").

Figure 1 – The Authority Transmission System



[1] Includes Central-owned transmission lines

The Authority's transmission system is interconnected with neighboring electric utilities in the region. It is directly interconnected with DESC at 12 locations; with Duke Energy Progress, LLC ("DEP"), at eight locations; with Duke Energy Carolinas, LLC ("DEC"), at two locations; and with Southern Company Services, Inc. ("Southern Company"), at one location. The Authority is also interconnected with DESC, DEC, Southern Company, and the Southeastern Power Administration ("SEPA") through a five-way interconnection at the SEPA J. Strom Thurmond Hydroelectric Project and with Southern Company and SEPA through a three-way interconnection at the SEPA R. B. Russell Hydroelectric Project.

Through these interconnections, the Authority transmission system is integrated into the regional transmission system serving the Southeastern region of the United States and the Eastern Interconnection (one of the three major electrical grids in the continental U.S. power transmission grid). The Authority has separate interchange agreements with each of the companies with which it is interconnected to provide for mutual exchanges of power.

3. Distribution

The Authority distribution system serves over 219,000 residential, commercial, lighting, and small industrial customers in two service areas: (1) the Berkeley District, which serves retail customers in St. Stephen, Bonneau Beach, Moncks Corner, Pinopolis, some unincorporated and rural areas in Berkeley County, and a small parcel in Charleston County; and (2) the Horry-Georgetown Division, which serves retail customers in Conway, Myrtle Beach, North Myrtle Beach, Garden City, Loris, Briarcliffe, Surfside Beach, Atlantic Beach, Pawleys Island, unincorporated areas along the Grand Strand, and portions of rural Georgetown and Horry Counties.

To deliver power safely and reliably to its directly served retail customers, the Authority distribution system is comprised of 3,237 miles of 12 kV and 34 kV primary lines. The primary distribution system is 43% overhead and 57% underground. The distribution system is served from 61[2] substations (of which 56 are 12 kV and five are 34 kV), including 89 power transformers (of which 80 are 12 kV and nine are 34 KV), 306 breakers and 290 loaded feeders. The distribution system also includes: 3,622 miles of secondary distribution lines; 111,048 poles; 45,093 distribution transformers; 4,113 switches; 10,901 fuse protective devices; 52,499 underground enclosures; 882 regulators; 400 distribution line capacitors; and 221,605 network devices, including 220,810 AMI meters, 787 mesh devices, and eight cellular collectors.

B. SAFETY AND RELIABILITY

1. Safety

Safety is the cornerstone in everything the Authority does to serve South Carolina. The Authority continuously utilizes good utility practices and industry-wide engineering and

[2] Total substations include the addition of a new substation planned to be in service second quarter 2026.

management best practices to assess and implement safety improvements to its facilities and processes.

The Authority's safety commitment has long-been recognized by the American Public Power Association, which awards members for maintaining safety. The Authority's employees earned the utility first place, i.e., a Diamond Award, in its group for the 2025 American Public Power Association's ("APPA") Safety Award of Excellence program, which honored safe operating practices in 2025.

The Recordable Incident Rate ("RIR") is a calculation used by the Occupational Safety and Health Administration ("OSHA") to describe the number of employees per one hundred full-time employees that have been involved in an OSHA-recordable injury or illness. The Authority's RIR for 2025 was 0.53. As the Authority's load grows and places increasing requirements on employees and assets, it will continue to invest in the safety of its employees and customers and to employ industry best practices.

2. Reliability

Maintaining optimum performance and reliability is of utmost importance to the Authority. In fact, system reliability is essential to the Authority's core mission and responsibilities, and it continually works to maintain, promptly restore, and improve its system, including its generation, transmission, and distribution assets.

a. Generation

To maintain low-cost, reliable power, the Authority continues to invest in its generation resources through capital replacements, major component maintenance, efficiency improvement projects, and control system upgrades. As a result of these investments, along with the efforts of a talented and engaged team, the Authority maintains a high level of reliability for its fleet of generators. The Authority uses widely available industry standards to measure the reliability of its generation system. Generation's key performance metrics include weighted forced outage rate ("WFOR"). The Authority's WFOR for its largest assets (Cross, Winyah, Cherokee, and Rainey) was 3.7% over the five-year period of 2020-2024, which was 61% lower than the industry average of 9.6%.

b. Transmission

The Authority measures the reliability of its transmission system with several metrics that are benchmarked internally and externally against similar utilities in the industry.

For internal benchmarking of reliability, the Authority uses the Average Customer Interruption Time ("ACIT"), which represents the average unexpected interruption time (in minutes) to customer delivery point substation. The Authority's annual goal is to have an ACIT of 15.77 outage minutes (or less) per customer delivery point. In 2025, the Authority's transmission system availability exceeded the internal ACIT goal, ending the year with

7.18 minutes of outage time per customer delivery point.

The Authority also considers Average Outage Duration, or the length of time a transmission facility is out of service for unplanned outages. This metric is also benchmarked with transmission utilities participating in the same industry peer group. This metric will differ from ACIT due to the networked nature of the Authority's transmission system, i.e., customers can often be served by multiple delivery paths in the event of unplanned system events. In 2025, the Authority's transmission system finished the year with an Average Outage Duration of 3.82 hours, yielding a best-in-class finish.

c. Distribution

The Authority's distribution system also continues to provide high-quality service due to the investments made in the system. The Authority evaluates the performance of its system based on System Average Interruption Duration Index ("SAIDI"), among other metrics. Based on benchmark data, the Authority targets a SAIDI of less than 25 minutes per year. In 2025, the Authority accomplished this goal with an annual SAIDI of 22.96 minutes. These SAIDI results continue to place the Authority amongst the top companies according to the Energy Information Administration. This top-tier distribution reliability ranking demonstrates the Authority's commitment and ability to deliver the reliable service its customers require and expect.

C. SYSTEM INVESTMENTS

System investments, as explained more fully below, are critical to the Authority's mission to provide reliable and efficient service to its growing customer base and to comply with regulatory requirements. The Authority has a significant 10-year investment plan to meet the needs of the growing system.

1. Generation

For existing generation assets, the Authority determines its investments through good utility practice and industry-wide engineering and management best practices. Management and staff continuously evaluate a wide range of potential capital projects related to corporate and operational objectives such as safety, environmental stewardship, reliability, and efficiency to develop annual budgets and long-term capital plans. For new or planned generation additions, the Authority has a robust integrated resource planning process that is reviewed by the South Carolina Office of Regulatory Staff ("ORS") and regulated by the South Carolina Public Service Commission ("SCPSC"). Additionally, for those resources at or above 75 MWs, the Authority seeks regulatory approval to constructure pursuant to the Utility Facility Siting and Environmental Protection Act, S.C. Code Ann. § 58-33-10 et seq., (the "Siting Act").

The Authority's 2025 Integrated Resource Plan ("IRP") Update[3], which was accepted by

[3] At least every three years, Santee Cooper develops a comprehensive IRP for review by the SCPSC

the SCPSC on February 5, 2026, confirmed prior IRP updates that indicated a number of resource additions needed to support load growth, including:

- **Canadys Joint Resource** (Docket pending; Docket No. 2025-323-E; hearing held April 14 - 16, 2026). The project, jointly developed with DESC, is an advanced class natural gas fired combined cycle ("NGCC") facility in Colleton County designed to provide approximately 1,090 MW by 2033. The additional NGCC capacity is needed to meet load growth identified in the Authority's 2025 IRP Update and to replace capacity associated with the planned retirement of the Winyah Generating Station. While a final order remains pending following the conclusion of the evidentiary hearing, ORS reviewed the Canadys Joint Resource application for a Certificate of Environmental Compliance and Public Convenience and Necessity ("CECPCN Application") and found it to be in compliance with the Siting Act;

- **Rainey Combined Cycle Conversion** (Docket No. 2024-264-E; Order No. 2025-137). The project converts existing simple-cycle Units 2A and 2B at the Rainey Generating Station, near Iva, South Carolina, to combined-cycle operation through the addition of an approximately 178 MW steam turbine generator, two heat recovery steam generators, a condenser, and a cooling tower, all within the existing station footprint. The Authority demonstrated a need for the additional capacity based on its 2024 System Load Forecast, which projected an approximately 1,000 MW increase in system demand by 2030 and identified a need for additional capacity beginning Winter 2027, ultimately growing to roughly 2,150 MW by 2031 upon retirement of the Winyah Generating Station. On March 4, 2025, the SCPSC granted the Authority a CECPCN for the project, finding that the facilities will serve the interests of system economy and reliability and that public convenience and necessity require their construction, and that the construction and operation of the facilities is in the public interest;

- **Winyah LM6000 Aeroderivative Combustion Turbines** (Docket No. 2025 246 E; Order No. 2026-74). The project consists of the construction and operation of two GE Vernova LM6000 dual fuel aeroderivative combustion turbine generators and associated facilities at a brownfield site at the existing Winyah Generating Station in Georgetown County, providing up to 107 MW of winter net dependable, quick start peaking capacity. The project is needed to help meet near term capacity and energy shortfalls identified in the Authority's 2025 System Load Forecast, which projects a need for almost 250 MW of additional capacity in Winter 2028 and an ultimate need of approximately 2,000 MW upon the future retirement of Winyah's coal fired units, and is supported by the Authority's 2025 IRP Update. On February 6, 2026, the SCPSC granted the Authority a CECPCN

pursuant to S.C. Code Ann. § 58-37-40. An IRP analyzes system needs and generation options to meet those needs in terms of cost, reliability, and the other criteria set forth in S.C. Code Ann. § 58-33-10(8). Additionally, as required by S.C. Code Ann. § 58-37-40 (D)(1), electrical utilities must submit annual updates to their IRPs.

for the project, finding that it will serve the interests of system economy and reliability, that public convenience and necessity require its construction and operation, and that the construction and operation of the project is in the public interest; the SCPSC separately determined, by Order No. 2025 644 dated October 10, 2025, that the related 230 kV interconnection facilities qualify as a "like facility" replacement; and

- The addition of 300 MW of battery energy storage capacity by 2029. In November 2025, the Authority selected AYPA Power Development LLC to build, own, and operate 300 MW of battery energy storage systems on property leased at the existing Jefferies Generating Station under a 20-year services agreement.

These generation investments in both the existing assets and new capacity needs provide the best energy mix to reliably and efficiently address growth, to support current and future economic development, and to replace existing facilities that approach the end of their economic lives.

2. Transmission

The Authority plans its transmission system to (1) operate within the applicable facility ratings during normal conditions as well as single and other selected contingency conditions and (2) maintain system voltages which are consistent with good utility practice. The transmission system is planned to provide voltage at the delivery point connection to a customer during normal conditions as well as single and other selected contingency conditions. No transmission facilities may operate outside of their continuous ratings during normal conditions or outside their emergency ratings during selected contingency conditions.

The primary concerns on the transmission system are that: (1) all facilities remain within their continuous ratings during normal operating conditions; (2) all facilities remain within their emergency ratings during selected contingency conditions; (3) the voltage on the transmission system remains within the ratings of the facilities on the system; and (4) the voltage at the delivery point connection to each customer is within the operating range of standard equipment for the voltage class of the delivery point connection. The guidelines for testing the transmission system are categorized by thermal loading contingency criteria and bus voltage criteria.

In addition to the Authority's Corporate Transmission System Planning Reliability Criteria, the Authority transmission system is planned to meet the requirements of all approved NERC Reliability and SERC Regional Standards that are applicable to the Authority.[4]

NERC Standard TPL-001 establishes transmission system performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies.

[4] These Standards can be found at www.nerc.com and www.serc1.org.

This standard requires that an annual assessment be conducted, and corrective action plans are identified where analyses indicate an inability of the system to meet performance requirements. These plans may include installation or modification of transmission or generation facilities, protection systems, use of operating procedures, etc.

Investments are being made to maintain the reliability of the transmission system and to improve grid security and resiliency. These investments include new substations, switching stations, and additional high-voltage lines to improve the ability of the system to support added generation across the State and customer growth. Investments also include equipment replacements and improvements to ensure reliability, such as condition-based replacements, the addition of fault indicator technology, the installation of automatic sectionalizing equipment, and investments to maintain compliance with NERC standards.

Recently, the Authority has received SCPSC CECPCN approvals including:

- **Wassamassaw to Indian Field 230 kV Line** (Docket No. 2025-177-E; Order No. 2025-692). The project consists of the construction and operation of a new Wassamassaw–Indian Field 230 kV transmission line and associated facilities, extending approximately 21.5 miles from the Wassamassaw 230/115 kV substation in Berkeley County to the planned Indian Field 230/115 kV substation in Dorchester County, primarily within or parallel to existing rights-of-way. The Line is needed to provide an initial 230 kV source to the Indian Field substation, to support significant industrial, commercial, and residential load growth in the Charleston, Dorchester, and Berkeley County areas, to facilitate transfer capability with neighboring utilities, and to mitigate impacts associated with the future retirement of the Winyah Generating Station. On November 7, 2025, the SCPSC granted the Authority a CECPCN for the project, finding that the project will serve the interests of system economy and reliability, that public convenience and necessity require its construction, and that the construction and operation of the project is in the public interest;

- **Kingstree to Hemingway 230/115 kV Lines** (Docket No. 2025-300-E; Order No. 2026-206). The project consists of rebuilding approximately 22.6 miles of the existing Kingstree–Hemingway 115 kV line as new double circuit Kingstree-Hemingway 230/115 kV transmission lines and associated facilities between the Hemingway substation and the 230 kV Kingstree substation in Williamsburg County. The project is needed to provide additional electrical capacity to reliably serve the region's load demands, to provide thermal loading relief and voltage support necessary for compliance with NERC Transmission Planning Standards, and to provide additional network support to a highly concentrated and growing load area in Horry and Georgetown Counties. On April 10, 2026, the SCPSC approved the Authority's Application and granted a Certificate, finding that the project will serve the interests of system economy and reliability, that public convenience and necessity require its construction,

and that the construction and operation of the project is in the public interest;

- **Indian Field–Sugar Hill #1 and #2 230 kV Lines** (Docket No. 2025-274-E; Order No. 2026-83). The project consists of the construction and operation of the Indian Field–Sugar Hill #1 and #2 230 kV transmission lines and associated facilities, including a new Sugar Hill 230 kV Substation, in Dorchester County, to provide service to an industrial data center consumer of Edisto Electric Cooperative ("EEC," a Central Electric Power Cooperative member). The project is needed to satisfy the reliability requirements and demand of the consumer's data center under a construction agreement among Central, EEC, and the consumer, and provides the most direct transmission interconnection with sufficient capacity to serve that load. On February 13, 2026, the SCPSC granted the Authority a CECPCN for the project, finding that the project will serve the interests of system economy and reliability, that public convenience and necessity require its construction and operation, and that the construction and operation of the project is in the public interest; and

- **Cross to Wassamassaw #2 230 kV Line** (Docket pending; Docket No. 2025-334-E; hearing scheduled May 5, 2026). The project involves retrofitting approximately 14.8 miles of the existing Cross–Jefferies 230 kV Line with a new 230 kV circuit, rebuilding 3.7 miles of the existing Jefferies–Wassamassaw 115 kV line as a new 230/115 kV double circuit, and rebuilding 0.4 miles of the existing Wassamassaw–Carnes #1 230 kV Line, primarily within existing right of way in Berkeley County. The project is needed to provide additional network support to a highly concentrated and growing load area in Berkeley and Dorchester Counties, to provide necessary thermal loading relief required for compliance with NERC Transmission Planning Standards, and to enhance resiliency to delivery points in the area. The SCPSC's evidentiary hearing on the application is scheduled for May 5, 2026.

3. Distribution

The Authority's distribution system investments are primarily related to new construction to serve new customers. In addition to the lines necessary to serve the new customers, the load growth prompts new substation additions along with feeder exits and line upgrades. Other significant investments are guided by the municipalities that the Authority serves. A municipality may commit a portion of their franchise fees, which the Authority will match, to convert existing overhead lines to more resilient underground lines.

The Authority also plans to upgrade its existing OMS system to an Advanced Distribution Management System ("ADMS"). That will allow better integration with the Authority's SCADA system, grant distribution controllers greater oversight of the distribution system, and enable more timely responses to outages. An ADMS will also allow the Authority to consider adding automation, such as FLISR (fault location, isolation, and service restoration) to reduce outage times and customer interruptions. Other upgrades include continuing to upgrade

electromechanical relays to microprocessor relays. The Authority further plans software upgrades to enhance and support its distribution operations, such as a work management upgrade and replacement and a GIS upgrade.

The Authority's distribution investments will help it achieve its goal of continuing to operate a highly reliable distribution system at the level its customers have come to expect. New customers will benefit by having the necessary infrastructure to connect them to the Authority's distribution grid; existing customers will benefit from a more aesthetic and resilient underground system; and all customers will benefit from the Authority's addition of sufficient capacity to serve the system and provide redundancy for N-1 failures, which helps maintain the distribution system's excellent reliability.

IV. CONCLUSION

The Authority operates and maintains its electric generation, transmission, and distribution facilities as a fully integrated electric system to provide reliable and affordable electric service to over two million South Carolinians. This system is vital for ensuring essential power for homes, schools, and hospitals. It is also a key driver in retaining current industrial customers and attracting new industry to the State.

As its system continues to grow, the Authority is making investments consistent with the preferred portfolio identified in the 2025 IRP Update. The investments identified by the 2025 IRP Update are targeted to prevent or mitigate unexpected costly repairs and comply with regulatory requirements pertaining to reliability and security. These investments will also ensure that the Authority's integrated electric system is able to respond to recent growth on its system, accommodate economic growth, and invest in areas to provide enhanced grid reliability and resilience — all while ensuring the Authority continues to maintain the high level of reliable service its customers expect.