Matthew W. Gissendanner
Assistant General Counsel

matthew.gissendanner@scana.com

February 8, 2019

VIA ELECTRONIC FILING

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

RE: South Carolina Electric & Gas Company's 2019 Integrated Resource Plan
Docket No. 2019-__-E

Dear Ms. Boyd:

In accordance with S.C. Code Ann. § 58-37-40 (2015) and Order No. 98-502 enclosed you will find the 2019 Integrated Resource Plan of South Carolina Electric & Gas Company ("SCE&G 2019 IRP"). This filing also serves to satisfy the annual reporting requirements of the Utility Facility Siting and Environmental Protection Act, S.C. Code Ann. § 58-33-430.

By copy of this letter, we are also serving the South Carolina Office of Regulatory Staff and the South Carolina Energy Office with a copy of the SCE&G 2019 IRP and attach a certificate of service to that effect.

If you have any questions or concerns, please do not hesitate to contact us.

Very truly yours,

Matthew W. Gissendanner

Matthew W. Gissendanner

MWG/kms
Enclosures

cc: Dawn Hipp
Jeffrey M. Nelson, Esquire
M. Anthony James
(both via electronic mail and U.S. First-Class Mail w/enclosure)

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2019-__-E

IN RE:

South Carolina Electric & Gas Company's 2019 Integrated Resource Plan	))))	**CERTIFICATE OF SERVICE**

This is to certify that I have caused to be served this day one (1) copy of the **2019 Integrated Resource Plan of South Carolina Electric & Gas Company** via electronic mail and U.S. First Class Mail to the persons named below at the address set forth:

Jeffrey M. Nelson, Esquire
Office of Regulatory Staff
1401 Main Street, Suite 900
Columbia, SC 29201
jnelson@ors.sc.gov

Dawn Hipp
Office of Regulatory Staff
1401 Main Street, Suite 900
Columbia, SC 29201
dhipp@ors.sc.gov

M. Anthony James
Office of Regulatory Staff
1401 Main Street, Suite 900
Columbia, SC 29201
ajames@ors.sc.gov

Karen M. Scruggs

Karen M. Scruggs

Cayce, South Carolina
This 8th day of February, 2019

2019

Integrated

Resource

Plan

SCE&G is becoming Dominion Energy®

February 8, 2019

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Introduction

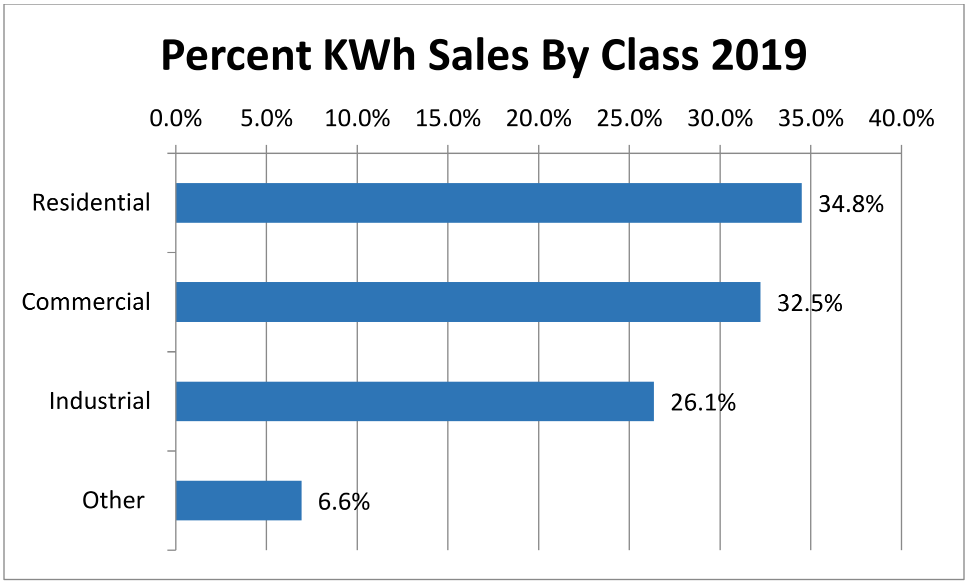
This document presents South Carolina Electric & Gas Company's ("SCE&G" or "Company") Integrated Resource Plan ("IRP") for meeting the energy needs of its customers over the next fifteen years, 2019 through 2033. This document is filed with the Public Service Commission of South Carolina ("Commission") in accordance with S.C. Code Ann. § 58-37-40 (2015) and Order No. 98-502 and also serves to satisfy the annual reporting requirements of the Utility Facility Siting and Environmental Protection Act, S.C. Code Ann. § 58-33-430 (2015). The objective of the Company's IRP is to develop a resource plan that will provide reliable and economically priced energy to the Company's customers while complying with all environmental laws and regulations.

I. Demand and Energy Forecast for the Fifteen-Year Period Ending 2033

Total territorial energy sales on SCE&G's system are expected to grow at an average rate of 0.9% per year over the next 15 years, while both firm territorial summer peak demand and winter peak demand will increase at 0.8% per year over the same forecast horizon. The table below contains these projected loads. By utility industry convention the winter period follows the summer period, so the 2019 winter refers to the 2019-2020 winter season.

	Summer Peak (MW)	Winter Peak (MW)	Energy Sales (GWh)
2019	4,639	4,749	22,654
2020	4,688	4,792	22,828
2021	4,733	4,822	23,014
2022	4,772	4,860	23,153
2023	4,810	4,882	23,331
2024	4,835	4,921	23,461
2025	4,874	4,963	23,649
2026	4,919	5,007	23,879
2027	4,961	5,046	24,123
2028	5,003	5,085	24,353
2029	5,042	5,124	24,581
2030	5,084	5,166	24,807
2031	5,125	5,208	25,061
2032	5,168	5,248	25,310
2033	5,208	5,290	25,563

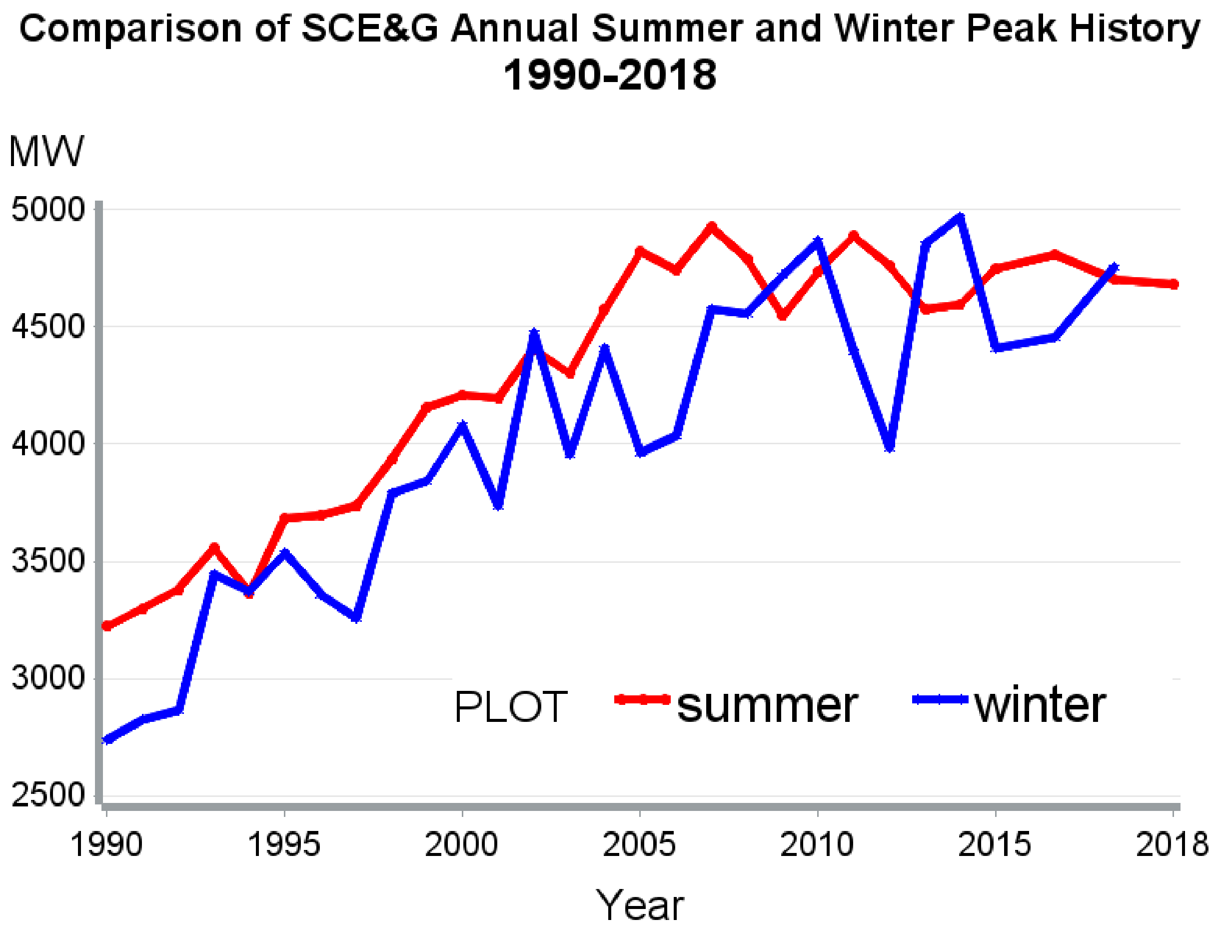
The energy sales forecast for SCE&G is made for over 30 individual categories. The categories are subgroups of the Company's six classes of customers. The three primary customer classes - residential, commercial, and industrial - comprise just over 93% of sales. The following bar chart shows the relative contribution to territorial sales made by each class. The "Other" class in the chart below includes public street lighting, other public authorities, and municipalities.



SCE&G's forecasting process is divided into two parts: development of the baseline forecast, followed by adjustments for large customer expansions, new large customers and energy efficiency impacts. A detailed description of the short-range baseline forecasting process and statistical models is contained in Appendix A. Short-range is defined as the next two years. Appendix B contains similar information for the long-range methodology. Long range is defined as beyond two years. Sales projections for each group are based on statistical and econometric models derived from historical relationships, which are then adjusted for factors not captured in the models.

A. System Peak Demand: Summer vs. Winter

The following chart shows SCE&G's experience with summer versus winter peaking. By utility industry convention, the winter period is assumed to follow the summer period. In 7 of the past 29 years (5 of which occurred within the last 10 years), SCE&G peaked in the winter. One other notable feature of the peak demand chart is the greater variability in winter peak demand.

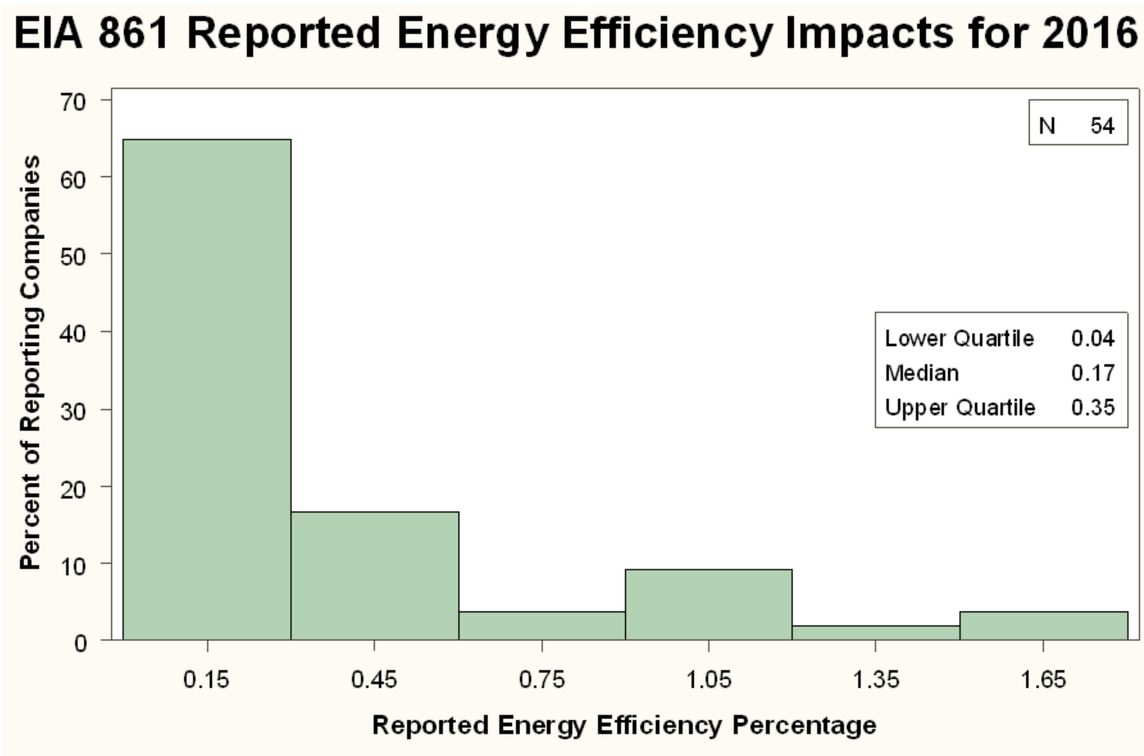


The forecasts of summer peak demand and winter peak demand are developed by combining the load profile characteristics of each customer class collected in the Company's Load Research Program with forecasted energy.

B. Demand Side Management (DSM) Impact on Forecast

SCE&G anticipates that its energy efficiency ("EE") programs will reduce retail sales in 2019 by 71,739 MWh or approximately 72 GWh. Retail sales after this EE impact are expected to be 21,753 GWh. Retail sales equals territorial load minus company use, unaccounted use, and municipal sales. Therefore, the EE programs are expected to reduce retail sales by about 0.33% from what they would have been. To gauge how SCE&G's EE programs compared to other companies in the Southeast, the Company analyzed the EE impacts filed with the U.S. Energy Information Administration ("EIA") in 2016, the latest year available. There were 57 companies filing from the Southeast, in particular from SERC Reliability Corporation (SERC) and the Florida Reliability Coordinating Council (FRCC) regions of the North American Electric

Reliability Corporation (NERC). Three companies were dropped from the analysis. The chart below shows graphically the distribution of reported results. The median EE impact was 0.17%. Thus, half the companies reported results higher and half lower than this median value. SCE&G's expectation for 2019 places it in the top half of the distribution. Clearly, SCE&G's EE programs compare favorably with other companies in the Southeast.



As part of the forecast development, the 0.33% EE savings was divided into a residential and commercial component. In addition, savings due to lighting efficiencies were removed from the class numbers and combined with lighting efficiency effects due to federally mandated measures. This was necessary to produce a consistent forecast of lighting efficiency effects. After this adjustment, the annual EE percentages used to produce the forecast were determined to be 0.27% and 0.10% for the residential and commercial sectors, respectively. The table below illustrates the calculation of the EE reductions. The far right-hand column labeled "Total Cumulative Reductions" is the sum of the residential and commercial cumulative reductions and represents the "SCE&G DSM Programs" column shown in a subsequent forecast summary table.

Derivation of Annual EE Savings									
	Baseline Residential (GWh)	**Cumulative Reductions (GWh)**	**Incremental Reductions (GWh)**	**Inc. %**	**Baseline Commercial (GWh)**	**Cumulative Reductions (GWh)**	**Incremental Reductions (GWh)**	**Inc. %**	**Total Cumulative Reductions (GWh)**
2019	8,019	-	-	-	7,378	-	-	-	-
2020	8,103	-	-	-	7,438	-	-	-	-
2021	8,266	-22	-22	-0.27	7,516	-7	-7	-0.10	-29
2022	8,409	-45	-23	-0.27	7,586	-14	-7	-0.10	-59
2023	8,548	-68	-23	-0.27	7,656	-22	-8	-0.10	-90
2024	8,686	-91	-23	-0.27	7,726	-29	-7	-0.10	-120
2025	8,827	-115	-24	-0.27	7,797	-37	-7	-0.10	-152
2026	8,983	-139	-24	-0.27	7,880	-44	-8	-0.10	-183
2027	9,142	-164	-25	-0.27	7,963	-52	-8	-0.10	-215
2028	9,310	-189	-25	-0.27	8,049	-59	-7	-0.10	-248
2029	9,477	-214	-25	-0.27	8,134	-67	-8	-0.10	-281
2030	9,641	-240	-26	-0.27	8,219	-75	-8	-0.10	-315
2031	9,820	-267	-27	-0.27	8,312	-83	-8	-0.10	-350
2032	9,997	-294	-27	-0.27	8,406	-91	-8	-0.10	-385
2033	10,178	-321	-27	-0.27	8,500	-99	-8	-0.10	-420

C. Energy Efficiency Adjustments

Several adjustments were made to the baseline projections to incorporate significant factors not reflected in historical experience. These were increased air-conditioning, heat pump, and water heater efficiency standards, plus improved lighting efficiencies, all mandated by federal law. The addition of SCE&G’s energy efficiency and solar programs were also significant factors that were incorporated. The following table shows the baseline projection, solar and energy efficiency adjustments, and the resulting forecast of territorial energy sales.

	Baseline Sales (GWh)	SCE&G Solar Programs (GWh)	SCE&G DSM Programs (GWh)	Federal Mandates (GWh)	Total Impact (GWh)	Territorial Sales (GWh)
2019	22,801	-45	0	-102	-147	22,654
2020	23,023	-54	0	-141	-195	22,828
2021	23,336	-58	-29	-235	-322	23,014
2022	23,609	-58	-59	-339	-456	23,153
2023	23,880	-58	-90	-401	-549	23,331
2024	24,143	-59	-120	-503	-682	23,461
2025	24,411	-59	-152	-551	-762	23,649
2026	24,711	-59	-183	-590	-832	23,879
2027	25,018	-59	-215	-621	-895	24,123
2028	25,342	-60	-248	-681	-989	24,353
2029	25,664	-60	-281	-742	-1,083	24,581
2030	25,979	-60	-315	-797	-1,172	24,807
2031	26,319	-60	-350	-848	-1,258	25,061
2032	26,655	-61	-385	-899	-1,345	25,310
2033	26,995	-61	-420	-951	-1,432	25,563

Baseline sales are projected to grow at the rate of 1.2% per year. The impact of energy efficiency, both from SCE&G's DSM and solar programs, plus savings from federal mandates, causes the ultimate territorial sales growth to fall to 0.9% per year as reported earlier.

Since the baseline forecast utilizes historical relationships between energy use and driver variables such as weather, economics, and customer behavior, it embodies changes which have occurred over time. For example, construction techniques which result in better insulated houses have a dampening effect on energy use. Because this process happens with the addition of new houses and/or extensive home renovations, it occurs gradually. Over time this factor and others are captured in the forecast methodology. However, when significant events occur which impact energy use but are not captured in the historical relationships, they must be accounted for outside the traditional model structure.

The first adjustment relates to federal mandates for air-conditioning units and heat pumps. In 2015 the minimum Seasonal Energy Efficiency Ratio ("SEER") increased from 13 to 14 for South Carolina and other regions of the United States. This was the first change in SEER ratings since 2006, when the minimum SEER for newly manufactured appliances was raised from 10 to 13. The cooling load for a house that replaced a 10 SEER unit with a 13 SEER unit would decrease by 30% assuming no change in other factors. The first mandated change to efficiencies took place in 1992, when the minimum SEER was raised from 8 to 10, a 25% increase in energy efficiency. Since then air-conditioner and heat pump manufacturers introduced much higher-efficiency units, and models are now available with SEERs over 20. However, overall market production of heat pumps and air-conditioners is concentrated at the lower end of the SEER mandate. The 2015 minimum SEER rating represented another significant change in energy use which would not be fully captured by statistical forecasting techniques based on historical relationships. For this reason an adjustment to the baseline was warranted. Finally, a 2016 DOE Notice of Proposed Rulemaking (NOPR) stipulated a further increase of central air-conditioners manufactured for use in the Southeast from 14 to 15 SEER beginning in January 2023. This was also incorporated into the forecast.

All electric water heaters manufactured after April 2015 will be subject to higher efficiency standards. The level of increase varies according to the size of the water heater, but for a 40-gallon water heater the energy factor will rise by 3.4%. While high-efficiency water heaters have been available in the market for some time, it is still expected that a considerable percentage of residential customers will be impacted by the new standards. Therefore, reductions were made to the baseline energy projections to incorporate this effect.

A third reduction was made to the baseline energy projections beginning in 2013 for savings related to lighting. Mandated federal efficiencies as a result of the Energy Independence and Security Act of 2007 took effect in 2012 and were phased in through 2014. Standard incandescent light bulbs are inexpensive and provide good illumination, but are extremely inefficient. Compact fluorescent light bulbs ("CFLs") have become increasingly popular over the past several years as substitutes. CFLs last much longer and generally use about one-fourth the energy that incandescent light bulbs use. However, CFLs are more expensive and have some unpopular lighting characteristics, so their large-scale use as a result of market forces was not guaranteed. The new mandates will not force a complete switchover to CFLs, but they do impose efficiency standards that can only be met by CFLs, Light Emitting Diode ("LED") bulbs or newly developed high-efficiency incandescent light bulbs. Again, this shift in lighting represents a change in energy use which was not fully reflected in the historical data.

The final adjustment to the baseline forecast was to account for SCE&G's set of energy efficiency and new solar programs. These energy efficiency programs along with the others in SCE&G's existing DSM portfolio are discussed later in the IRP. In developing the forecast it was assumed that the impacts of these programs were captured in the baseline forecast for the next two years but thereafter had to be reflected in the forecast on an incremental basis.

D. Load Impact of Energy Efficiency and Demand Response Programs

There are two common subsets of Demand Side Management: Energy Efficiency and Load Management (also known as Demand Response). The Company's energy efficiency programs ("EE") and its demand response programs ("DR") will reduce the need for additional generating capacity on the system. The EE programs implemented by SCE&G's customers should lower not only their overall energy needs but also their power needs during peak periods. The DR programs serve more directly as a substitute for peaking capacity. The Company has two DR programs: an interruptible program for large customers and a standby generator program. These programs represent over 200 megawatts ("MW") on SCE&G's system. The following table shows the impacts of EE from the Company's DSM programs and from federal mandates as well as the impact from the Company's DR programs on the firm peak demand projections.

Territorial Peak Demands (MWs)							
		Energy Efficiency					
Year	Baseline Trend	SCE&G Programs	Federal Mandates	Total EE Impact	System Peak Demand	Demand Response	Firm Peak Demand
2019	4,999	0	-35	-35	4,964	-215	4,749
2020	5,069	-7	-54	-61	5,008	-216	4,792
2021	5,129	-14	-76	-90	5,039	-217	4,822
2022	5,187	-22	-87	-109	5,078	-218	4,860
2023	5,243	-29	-114	-143	5,100	-218	4,882
2024	5,301	-36	-125	-161	5,140	-219	4,921
2025	5,360	-43	-134	-177	5,183	-220	4,963
2026	5,420	-50	-142	-192	5,228	-221	5,007
2027	5,482	-59	-155	-214	5,268	-222	5,046
2028	5,544	-67	-169	-236	5,308	-223	5,085
2029	5,602	-74	-180	-254	5,348	-224	5,124
2030	5,663	-83	-189	-272	5,391	-225	5,166
2031	5,724	-91	-199	-290	5,434	-226	5,208
2032	5,783	-99	-209	-308	5,475	-227	5,248
2033	5,845	-107	-220	-327	5,518	-228	5,290

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

A. Demand Side Management

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

1. Energy Efficiency

SCE&G's Energy Efficiency programs include Customer Education and Outreach, Energy Conservation and the Demand Side Management Programs. A description of each follows:

a. **Customer Education and Outreach:** SCE&G's customer education and outreach includes a wide variety of communication tactics and channels to increase customer awareness and to help customers become more energy efficient in their homes and businesses. Two key components of customer education and outreach are summarized below:

    i. **Customer Insights and Analysis:** SCE&G continues to educate customers by leveraging insights from ongoing research, voice of the customer panels, demographics data and other customer segmentation data. These learnings are used to understand and reach customers through optimized messaging, collateral development and channel placement.

    ii. **Media/Channel Placement:** SCE&G is committed to customer education on available programs and services designed to help them be more energy efficient. To reach as many customers as possible, a diverse mix of channels is used, including both paid and earned media. Direct mail, bill inserts, internet radio, online strategies and community events continue to prove successful in reaching and engaging most customers. Extensive outreach via social media continues to optimize coverage and increase the opportunity to inform customers. Year-round news coverage is equally important and is consistently integrated into the media mix, particularly during peak winter and summer months when usage is high.

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

i. **Energy Saver / Conservation Rate**: Rate 6 (Energy Saver/ Conservation) rewards homeowners and homebuilders with a reduced electric rate when they upgrade existing homes or build new homes to a high level of energy efficiency. This reduced rate, combined with a significant reduction in energy usage, provides for considerable savings to customers. Participation in the program is easy as the requirements are prescriptive which is beneficial to all customers and trade allies.

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

c. Demand Side Management Programs: In 2018, the Demand Side Management portfolio of programs included six (6) programs targeting SCE&G's residential customer classes and two (2) programs targeting commercial and industrial customer classes that have not opted out of the DSM rider. With each program, considerable effort is made to cross-sell and promote other DSM offers, as appropriate, to help ensure customers are consistently informed of all available incentives. A description of each program follows:

i. **Residential Home Energy Reports** provides customers with monthly/bi-monthly reports comparing their energy usage to a peer group and providing household information to help identify, analyze and act upon potential energy efficiency measures and behaviors.

ii. **Residential Home Energy Check-up** provides customers with a visual energy assessment performed by SCE&G staff at the customer's home. At the completion of the visit, customers are offered an energy efficiency kit containing simple energy conservation measures, such as energy efficient bulbs, water heater wraps and/or pipe insulation. The Home Energy Check-up is provided at no additional cost to all residential customers who elect to participate.

iii. **Residential ENERGY STAR® Lighting** incentivizes residential customers to purchase and install high-efficiency ENERGY STAR® qualified lighting products by providing deep discounts directly to customers. In 2018, SCE&G continued to offer lighting incentives via an online store, in addition to providing energy efficiency lighting kits to customers at various business office locations and via direct mail.

iv. **Residential Heating & Cooling Program** provides incentives to customers for purchasing and installing high efficiency HVAC equipment in existing homes. Additionally, the program provides residential customers with incentives to improve the efficiency of existing AC and heat pump systems through complete duct replacements, duct insulation and duct sealing.

v. **Neighborhood Energy Efficiency Program** provides income-qualified customers with energy efficiency education and direct installation of multiple low-cost energy conservation measures as part of a neighborhood door-to-door sweep approach to reach customers. In 2018, neighborhoods in North Charleston, Blackville, Williston, Elko, Barnwell and Walterboro participated in the program. Additionally, the Neighborhood Energy Efficiency Program continued offerings to mobile and manufactured homes to include additional measures specific to this housing stock.

vi. **Appliance Recycling Program** provides incentives to residential customers for allowing SCE&G to collect and recycle less-efficient, but operable, secondary refrigerators, and/or standalone freezers, permanently removing the units from service.

vii. **EnergyWise for Your Business Program** provides incentives to non-residential customers (who have not opted out of the DSM rider) to invest in high-efficiency lighting and fixtures, high efficiency motors and other equipment. To ensure simplicity, the program includes a master list of prescriptive measures and incentive levels that are easily accessible to commercial and industrial customers on SCE&G's website. Additionally, a custom path provides incentives to commercial and industrial customers based on the calculated efficiency benefits of their particular energy efficiency plans or new construction proposals. This program applies to technologies and applications that are more complex and customer-specific. All aspects of this program fit within the parameters of retrofits, building tune-ups and new construction projects.

viii. **Small Business Energy Solutions Program** is a turnkey program, tailored to help owners of small businesses manage energy costs by providing incentives for energy efficiency lighting and refrigeration upgrades. The program is available to SCE&G's small business and small nonprofit customers with an annual energy usage of 350,000 kWh or less, and five or fewer SCE&G electric accounts.

2. Load Management Programs

The primary goal of SCE&G's load management programs is to reduce the need for additional generating capacity. There are four load management programs: Standby Generator Program, Interruptible Load Program, Real Time Pricing Rate and the Time of Use Rates. In addition, SCE&G plans to evaluate the creation of a winter peak clipping program. A description of each follows:

a. **Standby Generator Program:** The Standby Generator Program for wholesale customers provides about 25 megawatts of peaking capacity that can be called upon when reserve capacity is low on the system. This capacity is owned by SCE&G's wholesale customers and through a contractual arrangement is made available to SCE&G System Controllers. SCE&G has a retail version of its standby generator program in which SCE&G can call on participants to run their emergency generators. This retail program provides approximately 10 megawatts of additional capacity when called upon.

b. **Interruptible Load Program:** SCE&G has over 200 megawatts of interruptible customer load under contract. Participating industrial customers receive a discount on their demand charges for shedding load when SCE&G is short of capacity.

c. **Real Time Pricing ("RTP") Rate:** A number of customers receive power under SCE&G's real time pricing rate. During peak usage periods throughout the year when capacity availability is low in the market, the RTP program sends a high price signal to participating customers which encourages conservation and load shifting. Alternatively, during high capacity availability periods, prices are lower.

d. **Time of Use Rates:** SCE&G's time of use rates contain higher charges during the peak usage periods of the day and lower charges during off-peak periods. This encourages customers to conserve energy during peak periods and to shift energy consumption to off-peak periods. All SCE&G customers have the option of purchasing electricity under a time of use rate.

e. **Winter Peak Clipping Program:** Over the next few years SCE&G will evaluate several ways of reducing its winter peak demands. These peaks are infrequent and of short duration. SCE&G will consider the following types of programs: direct load control, voltage conservation, a winter only interruptible load program, a critical peak pricing program and perhaps others.

B. Supply Side Management

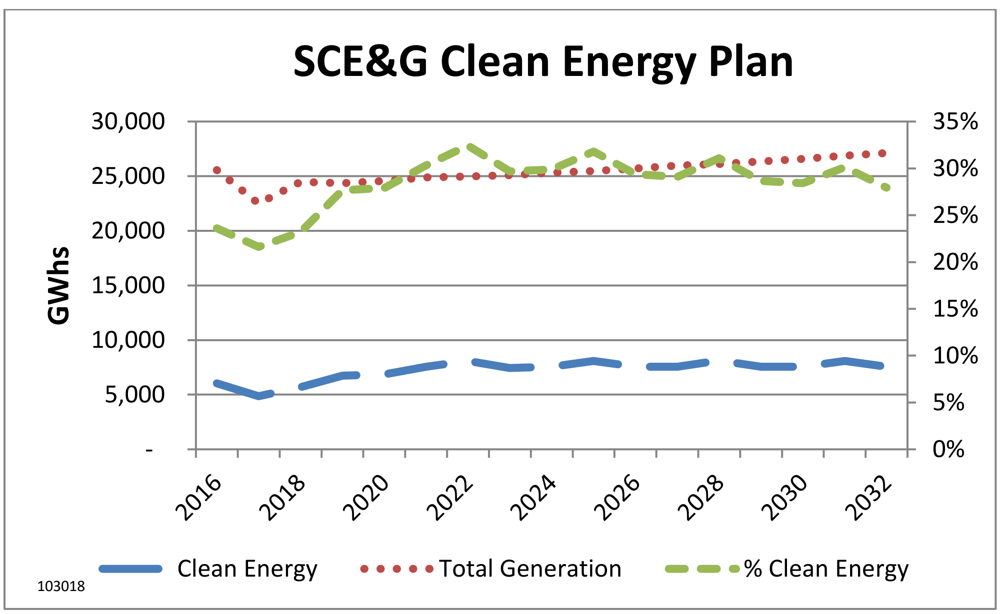
Clean Energy at SCE&G

Clean energy includes energy efficiency and clean energy supply options such as nuclear power, hydro power, combined heat and power, and renewable energy.

1. Existing Sources of Clean Energy

SCE&G is committed to generating more of its power from clean energy sources. This commitment is reflected in the amount of current and projected generation coming from clean sources, in the certified renewable energy credits that the Company generates each year, and in the Company's distributed energy resource program. Below is a discussion of each of these topics.

a. **Current Generation:** SCE&G generates clean energy from hydro, nuclear and solar. The following chart shows the current and projected amounts of clean energy in GWh and as a percentage of total generation.



As seen in the chart above, SCE&G expects to produce around 30% of its total generation from clean energy sources in the future.

b. Net Energy Metering, PR-1 and PR-2 Rates: Protecting the environment includes encouraging and helping customers to take steps to do the same. Net Energy Metering (NEM) provides a way for residential, commercial and industrial customers interested in generating their own renewable electricity to partially power their homes or businesses and sell the excess energy back to SCE&G. For residential customers, the generator output capacity cannot exceed the annual maximum household energy requirements or 20 kilowatts alternating current (kW AC), whichever is less. For commercial and industrial customers, the generator output capacity cannot exceed the annual maximum energy requirements of the business, the contract demand, or 1,000 kW AC, whichever is less. The total customer generator capacity under the NEM program is limited to 2% of the Company's previous five-year average retail peak demand. For SCE&G, this capacity limit is 84.5 MW AC. As of 12/31/18, SCE&G was at 82% (68.9 MW) of the 84.5 MW cap.

Under Commission Order 2015-194, a Net Energy Metering Methodology ("NEM 2.0") was approved whereby a value per kWh will be calculated annually for distributed energy resources. This value will be the basis upon which the Company will continue to provide customers a retail NEM incentive and have the difference funded through the Distributed Energy Resource Program Act. Provided the total customer generator capacity cap has not been met, customers will be offered the NEM rate until January 1, 2021, and those customers taking service under the NEM rate will receive the Net Metering Incentive described above through December 31, 2025, or until they take service under a different rate, whichever occurs first.

The Company also offers Qualifying Facilities as defined by the Federal Energy Regulatory Commission Order No. 70 under Docket No. RM 79-54 payments for power generated and transmitted to the SCE&G system. For Qualifying Facilities no greater than 100 kW, the PR-1 rates (one for solar and one for other qualifying facilities) are available for these energy payments. For Qualifying Facilities greater than 100 kW but no greater than 80 megawatts (MW), the PR-2 rate is available for these energy payments. Both the PR-1 and PR-2 rates are developed using SCE&G's avoided costs.

c. Distributed Energy Resource ("DER") Program:

Since 2015, SCE&G has exceeded the renewable resource goals established by the Legislature in Act 236 and by the Commission in Order No. 2015-512. SCE&G was the first investor owned utility in South Carolina to the meet its statutory goal for interconnected customer-sited distributed energy resources (42 MW as of June 2017) and was also the first to meet its utility scale goal (48 MW as of 2017) with nine utility-scale solar farms online. SCE&G continues to manage the DER Customer Scale programs to include the approval and interconnection of systems under the NEM 2.0 rate. SCE&G completed interconnection of the remaining. Commercial and Industrial Bill Credit Agreement systems for a total of 109 systems with a total capacity of 19.2 MW. SCE&G also has one of the nation's largest utility sponsored community solar programs with 16 MW of capacity across three solar farms completely sold-out. A total of 14 MW is already online, providing benefits to schools, churches, municipalities, and both residential and low-to-moderate income customers.

Springfield Solar Farm, located in Orangeburg County, consists of nearly 65,000 panels, each providing 120 watts of DC power for SCE&G's community solar program.

Nimitz Solar Farm, located in Jasper County, consists of more than 89,000 panels, each providing up to 120 watts of DC power for SCE&G's community solar program.

Below is a list of Community Solar farms planned or currently in operation on SCE&G's system.

Community Solar	Nameplate Capacity (MW-AC)
Nimitz	8.0
Springfield	6.0
Curie (expected commercial operation Feb 2019)	2.0
	16.0

Below is a list of DER utility scale solar farms currently in operation on SCE&G's system.

DER Utility Scale PPAs	Nameplate Capacity (MW-AC)
TIG Sun Energy III, LLC (Leeds Avenue Site)	0.50
Saluda Solar I, LLC	6.80
Ridgeland Solar Farm I, LLC	10.0
Saluda Solar II, LLC	3.40
Cameron Solar II, LLC	4.08
Barnwell Solar, LLC	5.44
Odyssey Solar, LLC (Pelion, Lexington County)	8.16
TIG Sun Energy IV, LLC (Otarre Site)	1.62
Haley Solar, LLC (Allendale County)	8.16
	48.16

d. Non-DER Utility Scale Solar: Beginning in 2017 and continuing through 2018, the Company experienced a significant increase in interest for independent power producer ("IPP") photovoltaic generator interconnections with respect to non-DER solar projects. These utility scale solar farms are contracted according to the PURPA avoided cost approved methodology and are currently producing clean power on the SCE&G system. Below is a list of non-DER utility scale solar farms currently in operation on SCE&G's system.

PURPA Utility Scale PPAs	Nameplate Capacity (MW-AC)
Hampton Solar I, LLC	6.8
St. Matthews Solar, LLC	10.2
Moffett Solar I, LLC (Jasper County)	71.4
Champion Solar, LLC (Pelion, Lexington County)	10.88
Swamp Fox Solar, LLC (Pelion, Lexington County)	10.88
Cameron Solar, LLC	20
Estill Solar I, LLC	20.4
Hampton Solar II, LLC	20
Estill Solar II, LLC	10.2
Gaston Solar I, LLC	10.2
Southern Current One (Brunson, Hampton County)	10.2
Peony Solar, LLC (Orangeburg County)	39.0
Gaston Solar II, LLC	7.48
Diamond Solar, LLC (Lexington County)	8.16
Edison Solar, LLC (Barnwell County) *	4.76
Blackville Solar, LLC (Barnwell County) *	20.0
	280.56

* Are generating test power, have not entered commercial operation

e. Nuclear Power: Unit 1 at the Summer Nuclear Station produces a substantial amount of clean energy and has a significant beneficial impact on the environment. The Unit came online in January 1984 and has a capacity of 966 MW with SCE&G owning 647 MW (two-thirds) and Santee Cooper owning the balance. In 2018, Unit 1 produced 4,911 gigawatt-hours ("GWh") of clean energy for SCE&G's customers. This represented 20% of SCE&G's generation mix. Over the last 35 years of operation, Unit 1 has produced 163,922 GWhs for SCE&G's customers. SCE&G received an extension to its original operating license in April 2004 and the Unit is now licensed to operate until August 2042. Over these next 25 years Unit 1 should produce another 124,283 GWhs of clean energy for SCE&G. If SCE&G were to generate this 60-years' worth of energy with fossil fuels, it would result in approximately 212 million more tons of CO_2 emitted to the atmosphere. This amount represents only SCE&G's two-thirds share of the Unit; when Santee Cooper's share is also considered, the full impact of the unit to the environment is 50% greater.

f. **Renewable Energy Credits:** The electric generator, located at the KapStone Charleston Kraft LLC facility, which was owned by SCE&G, until December 31, 2018, generates electricity using a mixture of coal and biomass. KapStone Charleston Kraft LLC produces black liquor through its Kraft pulping process and produces and purchases biomass fuels. These fuels are used to produce renewable energy which qualifies for Renewable Energy Certificates ("REC"). SCE&G has also begun generating RECs from solar generation. The table below shows the MWh of renewable energy generated by the KapStone biomass (prior to the change in ownership) plus various solar generators.

Year	Kapstone MWh	Solar MWh	% of Retail Sales
2007	371,573		1.7%
2008	369,780		1.7%
2009	351,614		1.7%
2010	346,190		1.5%
2011	336,604		1.5%
2012	414,047		1.9%
2013	385,202		1.8%
2014	404,526		1.8%
2015	385,470	22	1.8%
2016	394,814	1,005	1.8%
2017	382,696	90,234	2.1%
2018	349,419	533,271	4.1%

g. **Hydro-Power:** SCE&G owns five hydroelectric generating plants, one of which is a pumped storage facility, that combine for a total of 802 MW of clean capacity in the winter and 794 MW in the summer. The Saluda Hydro plant in Irmo, SC has a generating capacity of 198 MW. Saluda Hydro was put in service in 1930 and in August 2008 SCE&G filed an application requesting a new fifty-year license with the Federal Energy Regulatory Commission ("FERC"). The Company is still waiting for the issuance of this new license. In June 2018, SCE&G filed an application with the FERC requesting a new fifty-year license for the Parr Hydroelectric Project, which consists of the Parr Shoals Development and Fairfield Pumped Storage Development. The current license expires in June 2020. This project is critical for the future of SCE&G's

generation portfolio. With the increased adoption rate of non-dispatchable solar generation on the SCE&G system, Fairfield Pumped Storage is an important asset for grid stability, reliability and power quality for SCE&G customers. In 2018, SCE&G's hydroelectric plants produced 361.5 gigawatt-hours ("GWh") of clean energy for SC customers. SCE&G's pumped storage facility, Fairfield Pumped Storage, has a net dependable generating capacity of 576 MW and is a valuable asset to the SCE&G generation fleet. Fairfield Pumped Storage contributed 434.5 gigawatt-hours ("GWh") in 2018 and has been a reliable resource for responding to rapid load changes on the SCE&G system. In 2018, the Company started the process of relicensing the Stevens Creek Hydroelectric Project. SCE&G will file an application with the FERC by October 2023 requesting a new fifty-year license for this Project. The current license expires in October 2025. This project provides fairly constant generation as it re-regulates the releases from the US Army Corps of Engineers J. Strom Thurmond Hydroelectric Project.21

2. Future Clean Energy

SCE&G is participating in activities seeking to advance clean energy technologies in the future. Specifically, the Company is involved with a) utility scale non-DER Solar b) off-shore wind activities in the state, c) smart grid opportunities, d) environmental mitigation activities, e) small modular new nuclear power and f) hydro relicensing. These activities are set forth in more detail below.

a. Utility Scale Non-DER Solar: The company gauges the future of utility scale solar based on the current volume of interconnection applications in the Company's interconnection queue. As of December 27, 2018, across the Company's State and FERC interconnection queues, there were 5,103 MW of "In-Progress" and "Suspended" projects and 3,465 MW of "Withdrawn" projects logged.

b. Off-Shore Wind Activities: SCANA/SCE&G is a founding member of the Southeastern Wind Coalition and participates in the Utility Advisory Group of that organization. The mission of the Southeastern Wind Coalition is to advance the wind industry in ways that result in net economic benefits to industry, utilities, ratepayers, and citizens of the Southeast. The focus is threefold:

i. Research and Analysis – objective, transparent, data-driven, and focused on economics.

ii. Policy / Market Making – exploring multistate collaborative efforts and working with utilities, not against them.

iii. Education and Outreach – website, communications, and targeted outreach.

SCE&G participated in the Regulatory Task Force for Coastal Clean Energy. This task force was established with a 2008 grant from the U.S. Department of Energy. The goal was to identify and overcome existing barriers for coastal clean energy development for wind, wave and tidal energy projects in South Carolina. Efforts included an offshore wind transmission study; a wind, wave and ocean current study; and creation of a Regulatory Task Force. The mission of the Regulatory Task Force was to foster a regulatory environment conducive to wind, wave and tidal energy development in state waters. The Regulatory Task Force was comprised of state and federal regulatory and resource protection agencies, universities, private industry and utility companies.

SCANA/SCE&G participated in discussions to locate a 40 MW demonstration wind farm off the coast of Georgetown. This effort, known as Palmetto Wind, included Clemson University's Restoration Institute, Coastal Carolina University, Santee Cooper, the S.C. Energy Office and various utilities. Palmetto Wind has been put on hold due to the high cost of the project.

In an effort to promote wind turbine research, SCE&G invested $3.5 million in the Clemson University Restoration Institute's wind turbine drive train testing facility at the Clemson campus in North Charleston. This new facility is dedicated to groundbreaking research, education, and innovation with the world's most advanced wind turbine drive train testing facility capable of full-scale highly accelerated mechanical and electrical testing of advanced drive train systems for wind turbines.

c. Smart Grid Activities:

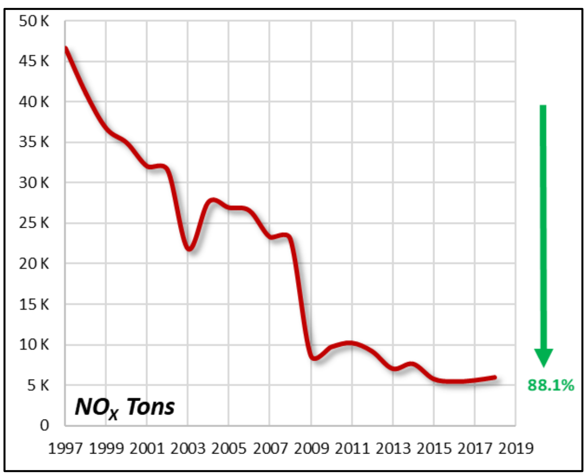
AMI (Advanced Metering Infrastructure): SCE&G currently has approximately 26,000 AMI meters that are installed predominately on medium and large commercial and industrial customers. Other applications where this technology is deployed include all time-of-use accounts and all accounts with customer generation (net metering). These meters utilize public wireless networks as the communication backbone and have full two-way communication capability. Register readings and load profile interval data are remotely collected daily from all AMI meters. In addition to traditional metering functions, the technology also provides real-time monitoring capability including power outage/restoration, meter/site diagnostics, and power quality monitoring. Load profile data is made available to customers daily via web applications enabling these customers to have quick access to energy usage allowing better management of their energy consumption. SCE&G is in the planning stages for deploying mass AMI technology for all electric meters.

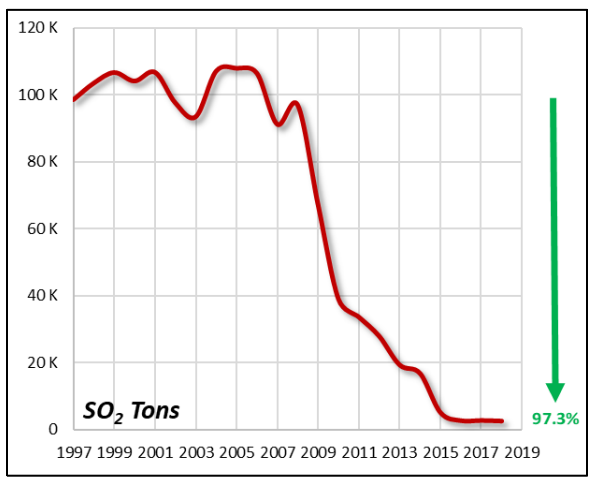
Distribution Automation: SCE&G is continuing to expand Supervisory Control and Data Acquisition ("SCADA") switching and other intelligent devices throughout the system. SCE&G has approximately 1,100 SCADA switches and reclosers, most of which can detect system outages and operate automatically to isolate sections of line with problems thereby minimizing outage times to affected customers. Some of these isolating switches can communicate with each other to determine the optimal configuration to restore service to as many customers as possible without operator intervention. SCE&G continues to evaluate systems that will further enable these automated devices to communicate with each other and safely reconfigure the system in a fully automated fashion, let operators know exactly where the faulted section of a line is, and monitor the status of the system as it is affected by outages, switching, and customer generation (solar).

d. Environmental Mitigation Activities: The Cross-State Air Pollution Rule (CSAPR) Update that became effective on December 27, 2016 removed South Carolina from the emissions monitoring and reporting requirements for ozone season Nitrogen Oxides (NOx), although obligations continue under the NOx and Sulfur Dioxide (SO_2)

Annual Emission Allowances Trading Program. The longstanding Acid Rain Program (ARP) contemporaneously governs NOx and SO_2 by way of an emission allowances construct. Obligations under the 1998 NOx SIP Call for certain generating units within the SCE&G fleet also remain. The NOx control strategy executed by SCE&G (and GENCO) entails the operation of Selective Catalytic Reduction equipment (SCRs) at Columbia Energy Center and Cope, Jasper, Wateree, and Williams Stations. Investment in low NOx burners at the coal and major natural gas fired units also contributes to the overall strategy. To meet the compliance requirements for SO_2, Williams and Wateree Stations have installed Flue Gas Desulfurization (FGD) equipment, commonly known as "wet scrubbers." Cope Station operates FGD equipment in the form of a "dry scrubber," as well as the ability to primary fire and co-fire its main boiler on natural gas. Natural gas conversions over the past several years for former coal units at McMeekin Station and Urquhart Station also lend to the overall SO_2 control strategy.

The two charts below illustrate the significant NOx and SO_2 emission reductions realized by SCE&G from 1997 to present.





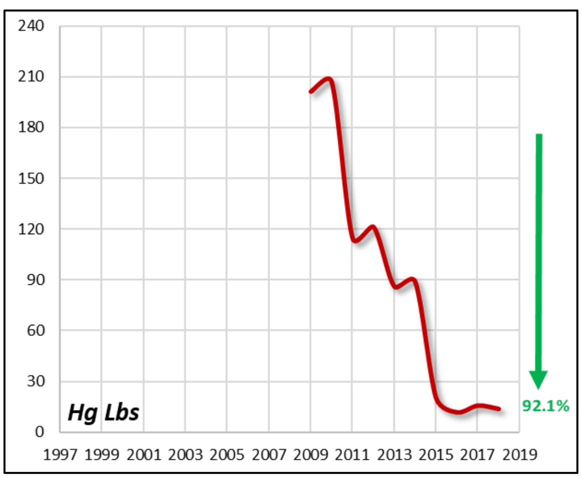
The compliance requirements of the US EPA's Mercury and Air Toxics Standard (MATS) became effective for SCE&G's regulated units at Cope, Wateree and Williams Station on April 16, 2016. Previously described emission control strategies for NOx and SO_2 control yielded notable co-benefits relating to SCE&G's MATS compliance strategy through the operation of SCRs and FGD scrubbers at these generating stations.

The Chem-Mod™ fuel additive used at Cope and Williams Stations similarly contributes to SCE&G's efforts to control mercury emissions, as well as for NO_X and

SO_2. As a result of the MATS regulations for mercury, the company has also installed carbon injection systems that are available for rapid deployment at Williams, Wateree and Cope Stations if needed to comply with the MATS requirements, as well as wet scrubber re-emission control reagent for Wateree and Williams Stations. At the time of this writing, SCE&G has filed for "Low Emitting Electric Generating Unit" (LEE) status for Mercury at Cope and Williams Stations with the SC Department of Health and Environmental Control (SCDHEC), presently awaiting issuance of SCDHEC's written concurrence of our demonstration submissions. Additional LEE filings for other MATS parameters that require longer operating eligibility periods by regulation are projected in 2019.

In response to the EPA MATS regulations, the last coal-fired boiler at Urquhart Station, Unit 3, was converted to natural gas. Decommissioning of the plant's former coal handling facilities was completed in 2014. Also in response to MATS, Canadys Station ceased operations on November 6, 2013, and the plant infrastructure was decommissioned in 2015. McMeekin Units 1 & 2 were fully converted to gas in April 2016 and removal of the coal handling facilities was completed in 2017.

The chart below illustrates the significant mercury emission reduction accomplished by SCE&G from 2009 to present.



SCE&G continues to monitor for developments with the USEPA's Steam Electric Effluent Limitation Guidelines (ELGs) following the agency's action after the 2015 final rule was published. More specifically, the regulated community awaits an impending proposed rule that may change the prior requirements for Flue Gas Desulfurization (FGD) wastewater and bottom ash transport water. Of note, SCE&G's prior investment to cease bottom ash sluicing to the Wateree Station's ash ponds has contributed to a proactive compliance posture in relation to the Steam Electric ELGs. Two remote submerged flight conveyors were installed at Wateree Station that dewater boiler bottom ash sluice and recycle the overflow back for boiler reuse. This retrofit was completed for Units 1 and 2 during October 2012. The bottom ash is then beneficially used as an ingredient in the manufacture of pre-stressed concrete products. In April 2016, Wateree Station completed construction of dry fly ash handling systems and discontinued sluicing ash to ponds - all fly ash is now managed dry. Closure of the former Wateree Station ash pond is also progressing on schedule. Fly ash at Williams and Cope Stations has been handled dry since those plants were constructed.

e. Nuclear Power in the Future – Small and Modular: Small Modular Reactor ("SMR") technology continues to be developed. DOE has awarded several grants to support the development of the SMR technology. At about a third, or less, of the size of current nuclear power plants, SMRs could make available, for a smaller capital investment, a modular design for specific generation needs. Multiple modules could be incrementally added to match load growth depending on the design. Modules are factory built for easy transportation and are installed below-grade in a seismically robust facility. SMR designs consider a smaller emergency planning zone and a reduced site boundary due to design enhancements in safety.

The process of licensing these reactors through the Nuclear Regulatory Commission ("NRC") is underway. NuScale's design is the most developed SMR design, completing their design certification application at the end of 2016 and being subsequently accepted for docketing in March of 2017. In December of 2017, the NRC approved NuScale's "Safety Classification of the Passive Nuclear Power Plant Electrical Systems" Licensing Topical Report, which establishes the bases of how a design can be safe without reliance on any safety-related electrical power. Utah Associated Municipal Power Systems (UAMPS) Carbon Free Power Project (CFPP) will be the first planned NuScale SMR deployment with a 12-module (600 MWe gross) on the Idaho National Laboratory site. The expected commercial operation date of 2026 is dependent on federal production tax credits being extended.

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

3. Summary of Proposed and Recently Finalized Environmental Regulations

The EPA has recently enacted a number of regulations with significant potential to impact SCE&G operations. These are: a) Cross-State Air Pollution Rule (CSAPR); b) Mercury and Air Toxics Standards (MATS): c) Affordable Clean Energy (ACE) rule to replace the Clean Power Plan; d) Cooling Water Intake Structures Rule; e) Coal Combustion Residuals (CCR) Rule; and f) Effluent Limitation Guidelines. A discussion of these proposed and finalized regulations follows.

a. Cross-State Air Pollution Rule (CSAPR): On July 6, 2011, the EPA issued the Cross-State Air Pollution Rule to reduce emissions of SO_2 and NO_X from power plants in the eastern half of the United States. A series of court actions stayed this rule until October 23, 2014. CSAPR requires a total of 28 states to reduce annual SO_2 emissions, annual NO_X emissions and/or ozone season NO_X emissions to assist in attaining the 1997 ozone and fine particle and 2006 fine particle National Ambient Air Quality Standards (NAAQS). The rule establishes an emissions cap for SO_2 and NO_X and limits the trading region for emission allowances by separating affected states into two groups with no trading between the groups.

On July 28, 2015, the Court of Appeals held that Phase 2 emissions budgets for certain states, including South Carolina, required reductions in emissions beyond the point necessary to achieve downwind attainment and were, therefore, invalid. The State of South Carolina has chosen to remain in the CSAPR program, even though this recent court ruling exempted the state. This allows the state to remain compliant with regional haze standards.

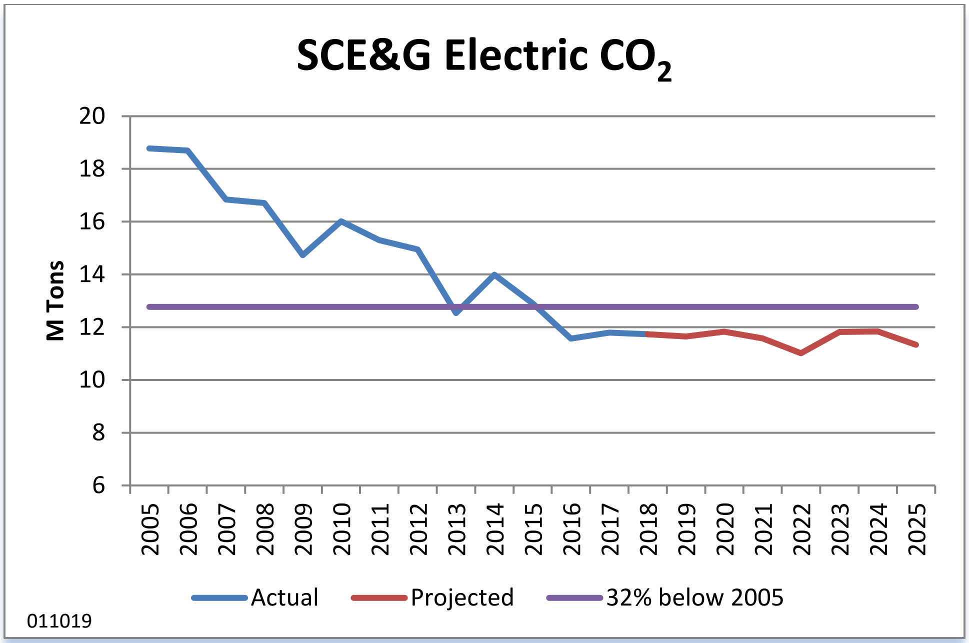
SCE&G generation is in compliance with the allowances set by CSAPR. Air quality control installations that SCE&G has already completed have positioned the Company to comply with the rule.

b. Mercury and Air Toxics Standards ("MATS"): The MATS rule set numeric emission limits for mercury, particulate matter as a surrogate for toxic metals, and hydrogen chloride as a surrogate for acid gases. MATS became effective on April 16, 2012, and compliance with MATS was required by April 2015. SCE&G and GENCO were granted a one-year extension (through April 2016) to comply with MATS at Cope, McMeekin, Wateree and Williams Stations. These extensions allowed time to convert McMeekin Station to burn natural gas and to install additional pollution control devices at the other plants to enhance the control of certain MATS-regulated pollutants. In addition, SCE&G retired certain other coal-fired units during this time frame. The MATS rule has been the subject of ongoing litigation even while it remains in effect. SCE&G and GENCO are in compliance with the MATS rule and expect to remain in compliance.

c. Clean Power Plan and its replacement - Affordable Clean Energy: In August 2015, the EPA issued two rules addressing the emission of greenhouse gases from electric generating units (EGU), one for existing units and one for new or modified units.

The first of these rules amends the new source performance standards (NSPS) for EGUs and establishes the first NSPS for greenhouse gas (GHG) emissions. Carbon dioxide emissions from natural gas-fired EGUs are limited to 1000 lbs. CO_2/MWh. Coal-fired EGUs carbon dioxide emissions are limited to 1400 lbs. CO_2/MWh. In December 2018, the EPA proposed to revise the standard for newly constructed large coal-fired units to 1,900 pounds of CO_2/MWh and for small units to 2,000 pounds CO_2/MWh. The Company currently has no plans to add new coal-fired generation.

The second rule published in August 2015, was issued under the authority of Section 111(d) of the Clean Air Act and governs existing power plants. The EPA determined a "Best System of Emissions Reduction" (BSER) for these existing plants. The BSER included three "Building Blocks," including heat rate reduction at coal-fired plants; re-dispatch of electric generation from coal to natural gas plants; and substituting zero-emission generation for existing coal-fired plants. Using this BSER, the EPA established targets for each state covered by the 111(d) rule and has proposed various pathways for each state to comply with those targets.



However, on February 9, 2016, the Supreme Court stayed the rule pending disposition of a petition of review of the rule in the Court of Appeals. As a result of an Executive Order on March 28, 2017, the EPA placed the rule under review and the Court of Appeals agreed to hold the case in abeyance. On October 10, 2017, the Administrator of the EPA signed a notice proposing to repeal the rule on the grounds that it exceeds the EPA's statutory authority. In a separate but related action, EPA issued an Advance Notice of Proposed Rulemaking (ANPRM) on December 18, 2017, to solicit information from the public about a potential future rulemaking to limit greenhouse gas emissions from existing units. EPA has more recently stated its understanding that the best system of emission reduction for a source should be based only on measures that can be applied to or at the source (facility-specific measures).

As a result, on August 21, 2018, the EPA proposed the Affordable Clean Energy (ACE) rule which would replace the 2015 Clean Power Plan (CPP). The proposed ACE rule has several components: Defines the BSER for GHG emissions from existing power plants as on-site, heat-rate efficiency improvements; Provides states with a list of "candidate technologies" that can be used to establish standards of performance and incorporated into their state plans; Updates EPA's New Source Review Permitting program to incentivize efficiency improvements at existing power plants; and Aligns Clean Air Act section 111(d) general implementing regulations to give states adequate time and flexibility to develop their state plans. Comments were due on October 31, 2018 and EPA has yet to issue the final rule. SCE&G is currently evaluating the rule for potential impact at its remaining coal fired units.

Although SCE&G agrees that the proposed ACE rule is more consistent with the statutory authority of the Clean Air Act, specifically with inside-the-fence measures, the rule as proposed will create challenges with its implementation and compliance measurement. First, the heat rate improvements anticipated under this rule may amount to only 2 to 4% cumulatively. Given that most of the heat rate improvements sought through 'boiler process' changes would be small, they will be difficult at best to measure and report. Additionally, SCE&G anticipates that its coal-fired EGUs will be dispatched in a different manner in the near future. In the past, coal-fired units have been generally "base loaded" -- that is they are fired at a relatively constant load throughout a day, week, or other period. Other electric generation output is then varied to "follow" the electric load on a given electric utility. In the future, coal-fired generating units are expected to be increasingly used to follow the load. This is due to several reasons, including increased capacity of residential and utility-scale solar generation which is prone to fluctuations caused by weather; and using more efficient natural gas combined cycle (NGCC) units for base loading. When SCANA's coal-fired units follow load, the units are fired at lower rates during certain periods of the day. During these periods of lower load, the heat rate of the units typically increases (performance is lower). For SCANA's three coal-fired EGUs, the average heat rate difference between full load and the lowest available load is 12%. Thus, the coal-fired EGU may be as much as 12% less efficient when operated in the load follow mode; however, because the electricity is now being generated by natural gas or solar or other renewables, the system-wide emissions will be significantly lower. It is not yet clear if the final ACE rule will recognize that this loss of coal-fire EGU performance due to load following will actually result in a reduction in fleet CO_2 emissions. However, as noted previously, this will place a substantial burden on States to understand and create compliance mechanisms that account for this change in coal-fired EGU dispatch.

What's more, SCE&G has steadily reduced its carbon emissions over 38% since 2005. This has been achieved through retirements of older coal-fired units, fuel switching to natural gas use at other units, the addition of solar, and most recently with the purchase of a merchant NGCC EGU. Significant emission reductions have also been achieved for all other emissions, including sulfur dioxide (SO_2) and nitrogen oxides (NOx).

SCANA has remained committed to improving air quality by reducing emissions over the years, including CO_2 emissions, well before this proposal was issued. The company has done so by investing in clean air technologies such as flue gas desulfurization controls and selective catalytic reduction and by diversifying fuels (i.e. more natural gas) to introduce lower-emitting electric generation. Two of SCANA's remaining coal-fired EGUs have been named as top twenty heat rate performers in the past few years, as reported by *ELP* (e-magazine *ELP- Electric Light & Power*). Because these EGUs are top performers, very little heat rate improvement is available to the units. To pursue additional heat rate improvements would come at a high cost.

Once the ACE rule becomes final and as SC DHEC develops a State Implementation plan (which may take up to 3 years) SCE&G will continue to evaluate and implement compliance measures that will be required at its remaining coal fired units.

d. Cooling Water Intake Structures: The Clean Water Act Section 316(b) Existing Facilities Rule became effective on October 14, 2014. This rule is intended to reduce impacts to fish and shellfish due to impingement, when organisms are trapped against inlet screens, and entrainment, when small organisms are drawn through the screens into the facility's cooling water system. Facilities capable of withdrawing at least 2 million gallons per day are generally subject to the rule. Facilities that are subject to the rule must, at a minimum, submit a series of reports which describe the design and operation of the cooling water intake, as well as physical and biological characteristics of the cooling water source waterbody. For some facilities, operational or design changes will be necessary to meet the requirements of the rule. Potential design changes range from enhanced screening and reconfiguration of water intake systems to installation of closed-cycle cooling towers to reduce flow rates.   Of the SCE&G generating facilities potentially subject to the rule, two stations, Wateree and Cope Stations, currently meet Best Technology Available (BTA) requirements for impingement mortality and entrainment. Two other stations, McMeekin and Jasper Stations, have been determined to be not-in-scope of the rule. SCE&G has conducted entrainment studies that demonstrate that Summer Station's existing intake structure fully complies with the rule. A one-year entrainment study, which would evaluate current impacts to fish, is underway at Urquhart Station. The results of this and other studies will be used to determine what modifications to the Urquhart intake structure, if any, are required. A two-year entrainment study is now underway at Williams Station. Modifications to the Williams Station intake structure, if any, may be delayed due to interferences of this intake with the Charleston Water Service intake for drinking water supplied to the Charleston Metro area.

e. **Coal Combustion Residuals:** The coal combustion residual (CCR) rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The rule became effective on October 19, 2015, and requires certain several activities be conducted over several years beginning in 2016, including publishing information on the Company website, assessing the structural integrity of pond dikes, and additional monitoring of environmental conditions at each landfill and pond.

The rule acknowledges that CCR can be safely reused in encapsulated products such as cement, concrete and wallboard. SCE&G has long provided CCR as a useful raw material to those industries and expects to continue to do so.

CCR landfills at Cope, Wateree, and Williams Station are subject to the rule. Ponds at Wateree and Williams station are also covered by the rule. An August 2018 decision by the United States Court of Appeals for the DC Court also imposed the rule requirements on CCR ponds at the closed Canadys generating station. Notwithstanding this new CCR rule, SCE&G has already closed its ash storage ponds or has begun the process of ash pond closure at all of its operating facilities, including those at Canadys Station. Those ash storage ponds that are still open are subjected to a rigorous inspection and maintenance program to ensure the safe management of those units. SCE&G will continue to operate ponds for flue-gas desulfurization (FGD) solids for the foreseeable future, and will continue to operate CCR landfills.

SCE&G has been conducting compliance activities required by this rule, including, but not limited to: studies and monitoring of pond dikes; increased inspections of CCR units; additional groundwater monitoring; and publication on the internet of certain data required by the rule.

f. Effluent Limitation Guidelines: On September 30, 2015, the EPA amended the Effluent Limitation Guideline for Steam Electric Power Generators also referred to as the ELG Rule. The standards under this rule were set to match the "Best Available Technology" for wastewaters produced at this type of electric generating facilities. Although several types of wastewaters were given new discharge standards under this rule, the most significant and difficult water to treat is flue-gas desulfurization (FGD) wastewater. FGD wastewater is generated at Wateree and Williams Stations.

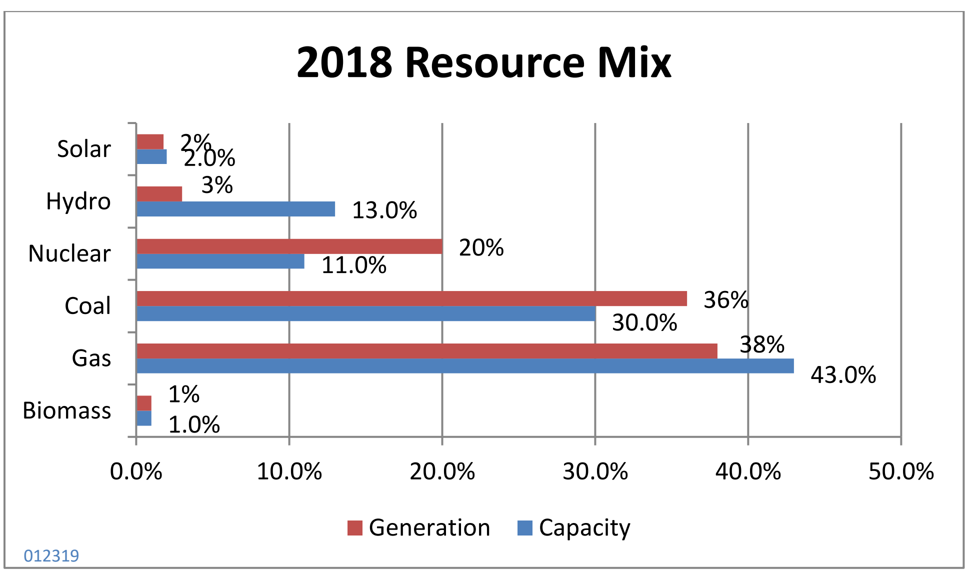
Under the Clean Water Act, compliance with applicable limitations is achieved under State-issued National Permit Discharge Elimination System (NPDES) permits. As a facility's NPDES permit is renewed (every 5 years) any new effluent limitations are incorporated. State environmental regulators will modify each renewed NPDES permit to match more restrictive standards, thus requiring utilities to retrofit affected facilities with new wastewater treatment technologies. Compliance dates will vary by type of wastewater and some will be based on a plant's 5-year permit renewal cycle and thus may range from 2020 to 2023. Based on the proposed rule, SCE&G expects that wastewater treatment technology retrofits will be required at Williams and Wateree at a minimum.

The ELG Rule is under reconsideration by the EPA and has been stayed administratively. The EPA has decided to conduct a new rulemaking that could result in revisions to certain flue gas desulfurization wastewater and bottom ash transport water requirements. Accordingly, in September 2017, the EPA finalized a rule that resets compliance dates under the ELG Rule to a range from November 1, 2020, to December 31, 2023. The EPA indicates that the new rulemaking process may take up to three years to complete, such that any revisions to the ELG Rule likely would not be final until the summer of 2020.

4. Supply Side Resources at SCE&G

a. Existing Supply Resources: In 2018 SCE&G owned and operated three (3) coal-fired fossil fuel plants, two (2) gas-fired steam plants, three (3) combined cycle gas turbine/steam generator plants (gas/oil fired), seven (7) peaking turbine plants, four (4) hydroelectric generating plants, and one Pumped Storage Facility. In addition, SCE&G received the output of 85 MW from a cogeneration facility. The total fossil-hydro generating capability rating of these facilities is 5,055 MW in summer and 5,294 MW in winter. These ratings, which are updated at least on an annual basis, reflect the expectation for the coming summer and winter seasons. When SCE&G's nuclear capacity (647 MW in summer and 661 MW in winter), a long term capacity purchase (25 MW), additional capacity (20 MW) provided through a contract with the Southeastern Power Administration and 263.16 MW of summer only utility scale solar are added with a firm capacity value of 121 MW, SCE&G's total supply capacity was 5,868 MW in summer and 6,000 MW in winter. This is summarized in the table on the following page. For 2019 Saluda's capacity will be 198 MW, Kapstone will not be a SCE&G resource and solar capacity will increase to 419.53 MW with a firm capacity of 193 MW for a summer 2019 total of 5,879 MW and winter 2019 capacity of 5,939 MW.

The bar chart below shows SCE&G's actual 2018 relative energy generation and relative capacity by fuel source.



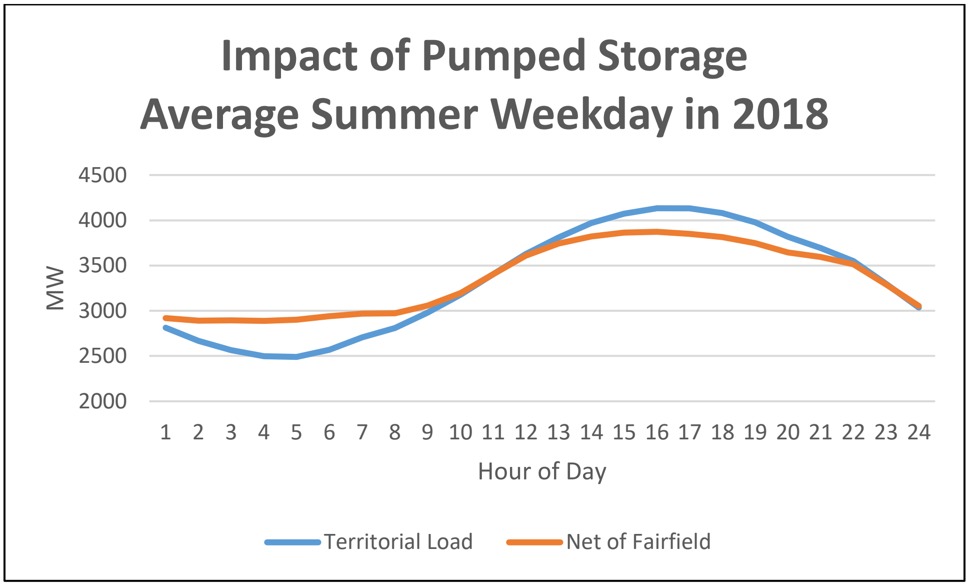
Existing Long Term Supply Resources

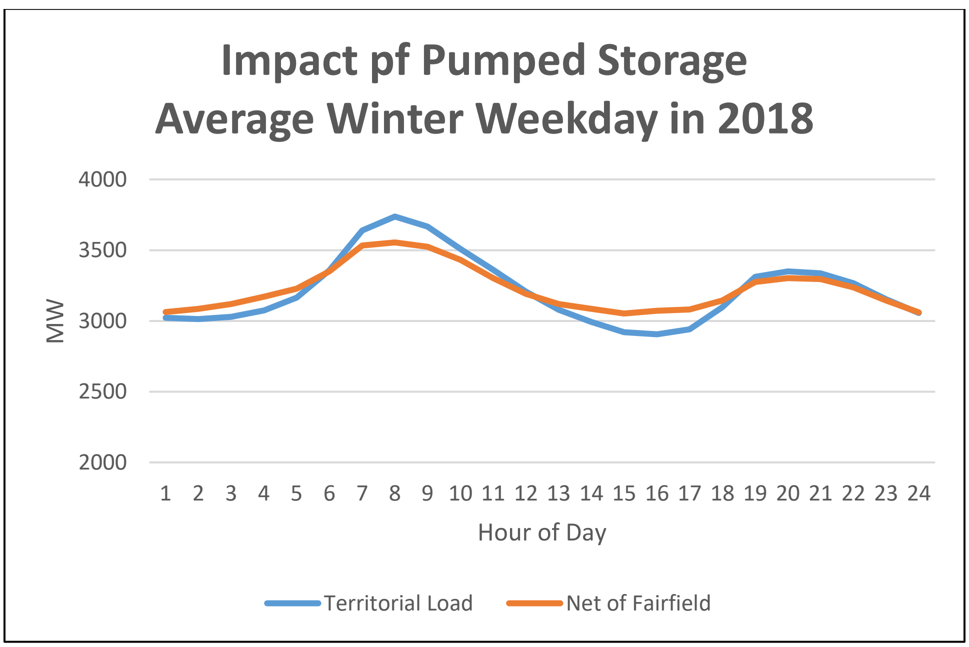
The following table shows the SCE&G available generating capacity in 2018 and in 2019.

	In-Service Date	Summer 2018 (MW)	Winter 2018 (MW)	Summer 2019 (MW)	Winter 2019 (MW)
Coal-Fired Steam:					
Wateree – Eastover, SC	1970	684	684	684	684
Williams – Goose Creek, SC*	1973	605	610	605	610
Cope - Cope, SC	1996	415	415	415	415
KapStone – Charleston, SC	1999	85	85	0	0
Total Coal-Fired Steam Capacity		1,789	1,794	1,704	1,709
Gas-Fired Steam:					
McMeekin – Irmo, SC	1958	250	250	250	250
Urquhart – Beech Island, SC	1955	95	96	95	96
Total Gas-Fired Steam Capacity		345	346	345	346
Nuclear:					
V. C. Summer - Parr, SC	1984	647	661	647	661
Gas Turbines:					
Hardeeville, SC	1968	9	9	0	0
Urquhart – Beech Island, SC	1969	39	48	39	48
Coit – Columbia, SC	1969	26	36	26	36
Parr, SC	1970	60	73	60	73
Williams – Goose Creek, SC	1972	40	52	40	52
Hagood – Charleston, SC	1991	126	141	126	141
Urquhart No. 4 – Beech Island, SC	1999	48	49	48	49
Urquhart Combined Cycle – Beech Island, SC	2002	458	484	458	484
Jasper Combined Cycle – Jasper, SC	2004	852	924	852	924
Columbia Energy Center Combined Cycle	2004	504	571	504	571
Total I. C. Turbines Capacity		2,162	2,387	2,153	2,378
Hydro:					
Neal Shoals – Carlisle, SC	1905	3	4	3	4
Parr Shoals – Parr, SC	1914	7	12	7	12
Stevens Creek - Near Martinez, GA	1914	8	10	8	10
Saluda - Irmo, SC	1930	165	165	198	198
Fairfield Pumped Storage - Parr, SC	1978	576	576	576	576
Total Hydro Capacity		759	767	792	800
Solar:	2015-2019	121	0	193	0
Other: Long-Term Purchases		25	25	25	25
Southeastern Power Administration (SEPA)		20	20	20	20
Grand Total:		5,868	6,000	5,879	5,939

* Williams Station is owned by GENCO, a wholly owned subsidiary of SCANA and is operated by SCE&G.

b. DSM from the Supply Side: SCE&G is able to achieve a DSM-like impact from the supply side using its Fairfield Pumped Storage Plant. The Company uses off-peak energy to pump water uphill into the Monticello Reservoir and then displaces on-peak generation by releasing the water and generating power. This accomplishes the same goal as many DSM programs, namely, shifting use to off-peak periods and lowering demands during high cost, on-peak periods. The following graph shows the impact that Fairfield Pumped Storage had on a typical summer and winter weekday.





In effect, the Fairfield Pumped Storage Plant was used to shave an average of 254 MW from the daily peak times of 2:00 p.m. through 6:00 p.m. in the summer and to move about 2% of customer's daily summer energy needs off peak. Fairfield Pumped Storage Plant was used to shave an average of 162 MW from the daily peak times of 7:00 a.m. through 9:00 a.m. in the winter and to move about 1% of customer's daily winter energy needs off peak. Because of this valuable supply side capability, a similar capability on the demand side, such as a time of use rate, would be less valuable on SCE&G's system than on many other utility systems.

c. Planning Reserve Margin: Summer and Winter: All electric utilities require supply reserves to mitigate the risk of not being able to serve their load requirement because of demand-side related risk and supply-side related risk. Demand-side risk results from uncertainty in the level of demand which can increase because of abnormal weather or other unforeseen circumstances. Supply-side risk results from the possibility of supply resources either not being available at all or their capacity being reduced because of mechanical, fuel, weather or other circumstances. SCE&G is also required to carry operating reserves sufficient to meet its VACAR reserve sharing agreement. While SCE&G's share of the VACAR reserves can change each year, it is typically within a few megawatts of 200 MW which is the amount SCE&G uses in its planning.

In determining its required reserve margin, SCE&G finds it necessary to analyze the need separately for the cooling season and the heating season. Additionally within each season it is necessary to distinguish between a peaking need and a base need. There are at least two reasons for this dichotomy. First very cold weather can make SCE&G's winter peak spike for an hour or two. A peak clipping resource or dispatchable energy storage device available for a few hours may be better suited to address this risk than a generating unit. Secondly, SCE&G anticipates a significant amount of solar capacity in its resource portfolio and the ability of solar to serve load can be substantially different during peak summer conditions, peak winter conditions and other times during the year.

For the summer months which include May through October, SCE&G requires base reserves in the amount of 12% of the summer peak load to operate the system reliably and 14% of summer peak load during the peak load periods. For the winter months of November through April, SCE&G requires 14% of the winter peak load forecast in base reserves to operate the system reliably and 21% for the peak load periods. The peak load period is the 10-20 days of highest demand on the system while the base period is the balance of the year. The following table summarizes SCE&G's reserve margin policy.

SCE&G's Reserve Margin Target		
	Summer	**Winter**
Base Reserves	**12%**	**14%**
Peaking Reserves	**14%**	**21%**
Increment for Peaking	**2%**	**7%**

d. Electric Vehicles: Electric Vehicles: Electric vehicles represent the potential for the addition of electrical load on SCE&G's system. An electric car will go about 4 miles per kWh. Some cars will get more miles and some less but the figure is about right for both a Battery Electric Vehicle ("BEV") which is all electric and a Plug-in Hybrid Electric Vehicle ("PHEV") which operates on electricity as a BEV until the battery is depleted and then switches to the internal combustion gasoline engine (ICE). Although it varies, an ICE vehicle might get 30 miles to the gallon. If the cost of electricity is $0.14 per kWh and the cost of gasoline is $2.40 per gallon; an electric car can go about 28.6 miles per dollar compared to a gasoline vehicle that will go about 12.5 miles per dollar. Assuming the need to drive 15,000 miles per year, the annual fuel cost of the electric car will be about $525 while the annual fuel cost for the gasoline car will be about $1,200. Thus the more efficient electric car will save a driver about $675 per year in fuel costs. BEV's and PHEV's also provides the convenience of re-fueling (charging) at home or work. To counterbalance the better economics of operating an electric vehicle, the downsides include a larger capital outlay to purchase, a reduced driving range although the gap has closed, and fewer, less convenient opportunities to re-fuel on the road. All these dynamics continue to change and SCE&G will continue to monitor developments in the electric vehicle market.

In 2015 South Carolina had 1,784,004 vehicles. Assuming that 25% of those vehicles were in SCE&G's territory then we can determine the impact to SCE&G's load from an increase in the number of electric vehicles. The above analysis assumes 3,750 kWh/year per electric vehicle. If 50% of the vehicles in SCE&G's territory were electric then an additional 836 GWh of load would be added or about 3.5% of the current 2025 territorial load forecast. A reasonable estimate for electric vehicles would be 3% of automobiles by 2025. An additional 3% of electric vehicles would add 50.2 GWh or 0.212% of the current 2025 territorial load forecast. There is significant opportunity that a majority of the new load could be achieved off-peak.

e. Battery Storage on the Grid and in the Home: Battery storage systems are likely to play a significant role in the future, both on the grid and in the home. The cost of battery storage has been decreasing consistently over the last several years and the technology continues to improve. Today battery storage can be cost effective in select grid integrations when supplying necessary stabilization services such as frequency response and voltage regulation. Batteries may also offer solutions to system integration challenges associated with intermittent renewable generation. Often these applications require specific, real-time analysis by the utility in examining the available battery storage solutions and the impact they have to the utility's transmission and distribution systems. This analysis is especially important in determining the potential for cost effectively storing and shifting large amounts of renewable energy. The dominant technologies currently are lithium-ion and a variety of flow batteries. Lithium-ion batteries have a high density storage coupled with a quick response time while flow batteries are better able to store energy for longer periods of time, hours to days. SCE&G will continue to monitor developments in battery storage technologies and their cost, and look for ways to improve the economics and reliability of service to our customers.

f. Projected Loads and Resources: SCE&G is providing two expansion plans based on economic studies of nineteen scenarios. The nineteen scenarios are listed then described below.

Scenario Number	Scenario
1	Battery-1
2	Battery-1 w/ Solar Ownership
3	Battery-2
4	Battery-2 w/ Solar Ownership
5	CC 1081 MW
6	CC 540 MW + Retire Coal
7	CC 540 MW x 2
8	CC 540 MW w/ Battery-1
9	CC 540 MW w/ Battery-2
10	CC 540 MW w/ ICT 337 MW
11	CC 540 MW w/ ICT 93 MW
12	ICT 337 MW
13	ICT 93 MW
14	Solar Ownership w/ ICT 93 MW
15	Solar Ownership w/ ICT 93 MW + Retire Gas
16	Solar PPA 200 MW w/ ICT 93 MW, $30/MWh
17	Solar PPA 400 MW w/ ICT 93 MW, $30/MWh
18	Solar PPA 400 MW w/ ICT 93 MW, $35/MWh
19	Solar PPA 400 MW w/ ICT 93 MW, $40/MWh

Scenario 1: In this scenario 1,000 MW of battery capacity is added in 100 MW increments in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2043, 2045, and 2047. Each battery installation has 100 MW of capacity and 400 MWh of energy. The battery construction cost is $2,126/kW ($2017) but there is no annual operating cost.

Scenario 2 In this scenario 1,000 MW of battery capacity is added in 100 MW increments in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2043, 2045, and 2047. Each battery installation has 100 MW of capacity and 400 MWh of energy. The construction cost is $2,126/kW ($2017) with no annual cost. In this scenario 1,000 MW of solar generation is also added between 2028 and 2047. The solar generators have no energy cost but a construction cost of $1,762/kW ($2017).

Scenario 3: In this scenario 1,000 MW of battery capacity is added in 100 MW increments in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2043, 2045, and 2047. Each battery installation has 100 MW of capacity and 400 MWh of energy.

The construction cost is $1,350/kW ($2017) with an annual cost of $1.65M per year.

Scenario 4: In this scenario 1,000 MW of battery capacity is added in 100 MW increments in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2043, 2045, and 2047. Each battery installation has 100 MW of capacity and 400 MWh of energy. The construction cost is $1,350/kW ($2017) with an annual cost of $1.65M per year. In this scenario 1,000 MW of solar generation is added in 100 MW increments in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2043, 2045, and 2047. The solar generators have no energy cost but a construction cost of $1,762/kW ($2017).

Scenario 5: In this scenario one 1,081 MW 2-on-1 combined cycle (CC) gas generating plant is added in the winter of 2029. This combined cycle generator has a full load heat rate of 6,203 Btu/kWh and an estimated construction cost of $876/kW ($2017).

Scenario 6: In this scenario three 540 MW 1-on-1 combined cycle (CC) gas generating plants are added in the winter of 2029, 2033 and 2044. This scenario also includes the retirement of one 342 MW coal plant in the winter of 2029. These combined cycle generators have a full load heat rate of 6,276 Btu/kWh and an estimated construction cost of $938/kW ($2017).

Scenario 7: In this scenario two 540 MW 1-on-1 combined cycle (CC) gas generating plants are added in the winters of 2029 and the winter of 2040. These combined cycle generators have a full load heat rate of 6,276 Btu/kWh and an estimated construction cost of $938/kW ($2017).

Scenario 8: In this scenario 100 MW of battery capacity is added in 2029 with two 540 MW 1-on-1 combined cycle (CC) gas generating plants are added in the winters of 2031 and the winter of 2042. These combined cycle generators have a full load heat rate of 6,276 Btu/kWh and an estimated construction cost of $938/kW ($2017). The battery construction cost is $2,126/kW ($2017) but there is no annual operating cost.

Scenario 9: In this scenario 100 MW of battery capacity is added in 2029 with two 540 MW 1-on-1 combined cycle (CC) gas generating plants added in the winters of 2031 and the winter of 2042. These combined cycle generators have a full load heat rate of 6,276 Btu/kWh and an estimated construction cost of $938/kW ($2017). Each battery installation has 100 MW of capacity and 400 MWh of energy. The construction cost is $1,350/kW with an annual cost of $1.65M per year.

Scenario 10: In this scenario one 540 MW 1-on-1 CC gas generating plant is added in the winter of 2029. The rest of the expansion plan is filled out with two 337 MW ICT generators added in the winters of 2040 and 2047. The combined cycle generator has a full load heat rate of 6,276 Btu/kWh and an estimated construction cost of $938/kW ($2017). The 337 MW turbines have a full load heat rate of 9,091 Btu/kWh and an estimated construction cost of $647/kW ($2017).

Scenario 11: In this scenario one 540 MW 1-on-1 CC gas generating plant is added in the winter of 2029. The rest of the expansion plan is filled out with five 93 MW ICT generators added in the winters of 2040, 2042, 2044, 2046 and 2047. The combined cycle generator has a full load heat rate of 6,276 Btu/kWh and an estimated construction cost of $938/kW ($2017). The 93 MW turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017).

Scenario 12: In this scenario three 337 MW internal combustion turbines (ICT) are added in the winters of 2029, 2036 and 2043. These turbines have a full load winter heat rate of 9,091 Btu/kWh and an estimated construction cost of $647/kW ($2017).

Scenario 13: In this scenario ten 93 MW internal combustion turbines (ICT) are added in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2042, 2044, and 2046. These turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017).

Scenario 14: In this scenario 1,000 MW of solar generation and 930 MW of ICTs are added in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2043, 2045, and 2047. The 93 MW turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017). The solar generators have no energy cost but a construction cost of $1,762/kW ($2017).

Scenario 15: In this scenario 1,000 MW of solar generation and 1,302 MW of ICT are added in years 2028(4), 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2043, 2045, and 2046. Three gas fired steam plants are retired in the winter of 2028 with a combined capacity of 346 MW. The 93 MW turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017). The solar generators have no energy cost but a construction cost of $1,762/kW ($2017).

Scenario 16: In this scenario 200 MW of solar PPAs are added in 2026 which have no winter capacity. The energy of these PPAs are prices at $30/MWh in 2018 and growing at 2% per year. This scenario includes ten 93 MW ICTs added in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2042, 2044, and 2046. These turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017).

Scenario 17: In this scenario 400 MW of solar PPAs are added in 2026 which have no winter capacity. The energy of these PPAs is priced at $30/MWh in 2018 and growing at 2% per year. This scenario includes ten 93 MW ICTs added in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2042, 2044, and 2046. These turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017).

Scenario 18: In this scenario 400 MW of solar PPAs are added in 2026 which have no winter capacity. The energy of these PPAs is priced at $35/MWh in 2018 and growing at 2% per year. This scenario includes ten 93 MW ICTs added in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2042, 2044, and 2046. These turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017).

Scenario 19: In this scenario 400 MW of solar PPAs are added in 2026 which have no winter capacity. The energy of these PPAs are priced at $40/MWh in 2018 and growing at 2% per year. This scenario includes ten 93 MW ICTs added in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2042, 2044, and 2046. These turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017).

These nineteen scenarios were modeled under four different assumptions. The four assumptions are 1) $0/ton CO_2 and base gas prices, 2) $15/ton CO_2 and high gas prices, 3) $0/ton CO_2 and high gas prices, and 4) $15/ton CO_2 and base gas prices. A ranking of the forty-year NPV cost results are shown in the following table. A ranking of 1 is the least cost option for the given assumptions. CO_2 costs begin at $15/ton in 2025 and grow at 5% per year. Base gas prices are based on NYMEX Henry Hub prices through 2020 then growing at 4.82% until 2031 then growing at 3.9% thereafter. High gas prices are double the NYMEX Henry Hub prices through 2020 then grow at the same rate as the base gas.

		Scenario Ranking			
Scenario Number	Scenario	$0 CO_2 Base gas	$15 CO_2 High gas	$0 CO_2 High gas	$15 CO_2 Base gas
1	Battery-1	16	17	16	17
2	Battery-1 w/ Solar Ownership	19	18	19	19
3	Battery-2	11	13	12	15
4	Battery-2 w/ Solar Ownership	18	16	15	18
5	CC 1081 MW	14	14	14	11
6	CC 540 MW + Retire Coal	12	15	17	4
7	CC 540 MW x2	1	10	10	6
8	CC 540 MW w/ Battery-1	17	19	18	16
9	CC 540 MW w/ Battery-2	13	12	13	13
10	CC 540 MW w/ ICT 337 MW	8	9	8	8
11	CC 540 MW w/ ICT 93 MW	6	7	6	2
12	ICT 337 MW	9	11	9	10
13	ICT 93 MW	2	5	5	7
14	Solar Ownership w/ ICT 93 MW	10	6	7	12
15	Solar Ownership w/ ICT 93 MW + Retire Gas	15	8	11	14
16	Solar PPA 200 MW w/ ICT 93 MW ($30)	3	4	3	3
17	Solar PPA 400 MW w/ ICT 93 MW ($30)	4	1	1	1
18	Solar PPA 400 MW w/ ICT 93 MW ($35)	5	2	2	5
19	Solar PPA 400 MW w/ ICT 93 MW ($40)	7	3	4	9

We are providing two resource plans, one for each of the least cost scenarios that were modeled. The resource plans show the need for additional capacity during the next fifteen years and identify, on a preliminary basis, whether the need is for summer or winter capacity.

Line 4 shows the amount of capacity available at the beginning of each summer and winter season. On line 7 the resource plan shows the amount of firm solar capacity expected to be added to serve the system summer peak. As shown on line 5, by 2020 this solar capacity accumulates to 1048 MW of solar capacity but only 46% of this capacity is assumed firm in the summer and therefore reflected in the resource plan. Also embedded in the peak demand forecast is the projected Net Energy Metering (NEM) solar capacity, i.e., behind the customer's meter, which is projected to increase to about 84 MW by 2020.

By the winter of 2029 the system will be short of base capacity and capacity is added. On line 10 the resource plans show a decrease in capacity of 85 MW in 2019 and another decrease of 25 MW in 2020. The reduction of 85 MW represents the loss of the Kapstone generator and the 25 MW is the expiration of a power purchase contract with Santee Cooper. The resource plans thus constructed represent four possible ways to reliably meet the increasing demand of our customers. As we get closer to the need we will refine the plan.

The Company believes that its supply plans, summarized in the following tables, will be as benign to the environment as possible because of the Company's continuing efforts to utilize state-of-the-art emission reduction technology in compliance with state and federal laws and regulations. The supply plan will also help SCE&G keep its cost of energy service at a minimum since the generating units being added are competitive with alternatives in the market.

Resource Plan – Scenario 7 (Combined Cycle)

SCE&G Forecast of Summer and Winter Loads and Resources - 2019 IRP Update

(MW)

	YEAR	2019		2020		2021		2022		2023		2024		2025		2026		2027		2028		2029		2030		2031		2032		2033	
		S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W
Load Forecast																															
1	Baseline Trend	4911	4999	4965	5069	5028	5129	5087	5187	5144	5243	5200	5301	5255	5360	5315	5420	5372	5482	5433	5544	5492	5602	5551	5663	5609	5724	5669	5783	5726	5845
2	EE/Renewables Impact	-28	-35	-32	-61	-49	-90	-68	-109	-86	-143	-116	-161	-131	-177	-145	-192	-159	-214	-176	-236	-195	-254	-211	-272	-227	-290	-243	-308	-259	-327
3	Gross Territorial Peak	4883	4964	4933	5008	4979	5039	5019	5078	5058	5100	5084	5140	5124	5183	5170	5228	5213	5268	5257	5308	5297	5348	5340	5391	5382	5434	5426	5475	5467	5518
System Capacity																															
4	Existing	5780	5948	5780	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	6295	6463	6295	6463	6295	6463	6295	6463
5	Existing Solar	121.1	0	193	0	379.8	0	482	0	482	0	482	0	482	0	482	0	482	0	482	0	482	0	482	0	482	0	482	0	482	0
6	Demand Response	244	215	245	216	246	217	247	218	248	218	249	219	250	220	251	221	252	222	254	223	255	224	256	225	257	226	258	227	259	228
	Additions:																														
7	Solar Plant	71.93	0	186.8	0	102.1	0																								
8	Peaking/Intermediate																						540								
9	Baseload																														
10	Retirements	-85		-25																											
11	Total System Capacity	6132	6163	6380	6139	6483	6140	6484	6141	6485	6141	6486	6142	6487	6143	6488	6144	6489	6145	6491	6146	6492	6687	7033	6688	7034	6689	7035	6690	7036	6691
12	Winter Deficit		0		0		0		3		30		77		128		182		229		277		0		0		0		0		0
13	Total Production Capability	6132	6163	6380	6139	6483	6140	6484	6144	6485	6171	6486	6219	6487	6271	6488	6326	6489	6374	6491	6423	6492	6687	7033	6688	7034	6689	7035	6690	7036	6691
Reserves																															
14	Margin (L13-L3)	1249	1199	1447	1131	1504	1101	1465	1066	1427	1071	1402	1079	1363	1088	1318	1098	1276	1106	1234	1115	1195	1339	1693	1297	1652	1255	1609	1215	1569	1173
15	% Reserve Margin (L14/L3)	25.6%	24.2%	29.3%	22.6%	30.2%	21.8%	29.2%	21.0%	28.2%	21.0%	27.6%	21.0%	26.6%	21.0%	25.5%	21.0%	24.5%	21.0%	23.5%	21.0%	22.6%	25.0%	31.7%	24.1%	30.7%	23.1%	29.7%	22.2%	28.7%	21.3%

Resource Plan – Scenario 17 (Solar)

SCE&G Forecast of Summer and Winter Loads and Resources - 2019 IRP Update (MW)

	YEAR	2019		2020		2021		2022		2023		2024		2025		2026		2027		2028		2029		2030		2031		2032		2033	
		S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W
Load Forecast																															
1	Baseline Trend	4911	4999	4965	5069	5028	5129	5087	5187	5144	5243	5200	5301	5255	5360	5315	5420	5372	5482	5433	5544	5492	5602	5551	5663	5609	5724	5669	5783	5726	5845
2	EE/Renewables Impact	-28	-35	-32	-61	-49	-90	-68	-109	-86	-143	-116	-161	-131	-177	-145	-192	-159	-214	-176	-236	-195	-254	-211	-272	-227	-290	-243	-308	-259	-327
3	Gross Territorial Peak	4883	4964	4933	5008	4979	5039	5019	5078	5058	5100	5084	5140	5124	5183	5170	5228	5213	5268	5257	5308	5297	5348	5340	5391	5382	5434	5426	5475	5467	5518
System Capacity																															
4	Existing	5780	5948	5780	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	5848	6016	5848	6016	5941	6109	5941	6109
5	Existing Solar	121.1	0	193	0	379.8	0	482	0	482	0	482	0	482	0	482	0	666	0	666	0	666	0	666	0	666	0	666	0	666	0
6	Demand Response	244	215	245	216	246	217	247	218	248	218	249	219	250	220	251	221	252	222	254	223	255	224	256	225	257	226	258	227	259	228
	Additions:																														
7	Solar Plant	71.93	0	186.8	0	102.1	0									184															
8	Peaking/Intermediate																						93				93				93
9	Baseload																														
10	Retirements	-85		-25																											
11	Total System Capacity	6132	6163	6380	6139	6483	6140	6484	6141	6485	6141	6486	6142	6487	6143	6672	6144	6673	6145	6675	6146	6676	6240	6770	6241	6771	6335	6865	6336	6866	6430
12	Winter Deficit		0		0		0		3		30		77		128		182		229		277		231		282		240		289		247
13	Total Production Capability	6132	6163	6380	6139	6483	6140	6484	6144	6485	6171	6486	6219	6487	6271	6672	6326	6673	6374	6675	6423	6676	6471	6770	6523	6771	6575	6865	6625	6866	6677
Reserves																															
14	Margin (L13-L3)	1249	1199	1447	1131	1504	1101	1465	1066	1427	1071	1402	1079	1363	1088	1502	1098	1460	1106	1418	1115	1379	1123	1430	1132	1389	1141	1439	1150	1399	1159
15	% Reserve Margin (L14/L3)	25.6%	24.2%	29.3%	22.6%	30.2%	21.8%	29.2%	21.0%	28.2%	21.0%	27.6%	21.0%	26.6%	21.0%	29.1%	21.0%	28.0%	21.0%	27.0%	21.0%	26.0%	21.0%	26.8%	21.0%	25.8%	21.0%	26.5%	21.0%	25.6%	21.0%

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III. Transmission System Assessment and Planning

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

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

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

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

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

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

Furthermore, SCE&G subscribes to the set of mandatory Electric Reliability Organization ("ERO"), also known as the North American Electric Reliability Corporation ("NERC") Reliability Standards for Transmission Planning, as approved by the NERC Board of Trustees and the Federal Energy Regulatory Commission ("FERC").

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

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

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

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

1. SERC NTWG Reliability 2018 Summer Study
2. SERC NTWG Reliability 2018/2019 Winter Study
3. SERC NTWG OASIS 2018 January Studies (18Q1)
4. SERC NTWG OASIS 2018 April Studies (18Q2)
5. SERC NTWG OASIS 2018 July Studies (18Q3)
6. SERC NTWG OASIS 2018 October Studies (18Q4)
7. SERC LTWG 2023 Summer Peak Transfer Study
8. SERC LTWG 2022 Winter Peak Renewables Impact Study
9. CTCA 2019 Summer Peak, 2019 Daytime Minimum, 2023 Summer Peak, 2023 Daytime Minimum – Reliability and Transfer Capability Studies
10. SCRTP 2022 Summer Transfer Studies

The acronyms used above have the following reference:

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

These activities, as discussed above, provide for a reliable and cost effective transmission system for SCE&G customers.

Eastern Interconnection Planning Collaborative (EIPC)

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

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

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

Appendix A

Short Range Methodology

This section presents the development of the short-range electric sales forecasts for the Company. Two years of monthly forecasts for electric customers, average usage, and total usage were developed according to Company class and rate structures, with industrial customers further categorized individually or into SIC (Standard Industrial Classification) codes. Residential customers were classified by housing type (single family, multi-family, and mobile homes), rate, and by a statistical estimate of weather sensitivity. For each forecasting group, the number of customers and either total usage or average usage was estimated for each month of the forecast period.

The short-range methodologies used to develop these models were determined primarily by available data, both historical and forecast. Monthly sales data by class and rate are generally available historically. Daily heating and cooling degree data for Columbia and Charleston are also available historically, and were projected using a 15-out-of-17-year average of the daily values, after dropping the high and low values for each day. Industrial production indices are also available by SIC on a quarterly basis and can be transformed to a monthly series. Therefore, sales, weather, industrial production indices, and time dependent variables were used in the short range forecast. In general, the forecast groups fall into two classifications, weather sensitive and non-weather sensitive. For the weather sensitive classes, regression analysis was the methodology used, while for the non-weather sensitive classes regression analysis or time series models based on the autoregressive integrated moving average (ARIMA) approach of Box-Jenkins were used.

The short range forecast developed from these methodologies was also adjusted for federally mandated lighting programs, net energy metering solar, new industrial loads, terminated contracts, or economic factors as discussed in Section 3.

Regression Models

Regression analysis is a method of developing an equation which relates one variable, such as usage, to one or more other variables which help explain fluctuations and trends in the first. This method is mathematically constructed so that the resulting combination of explanatory variables produces the smallest squared error between the historic actual values and those estimated by the regression. The output of the regression analysis provides an equation for the variable being explained. Several statistics which indicate the success of the regression analysis fit are shown for each model. Several of these indicators are R^2, Root Mean Squared Error, Durbin-Watson Statistic, F-Statistic, and the T-Statistics of the Coefficient. PROC REG of SAS was used to estimate all regression models. PROC AUTOREG of SAS was used if significant autocorrelation, as indicated by the Durbin-Watson statistic, was present in the model.

Two variables were used extensively in developing weather sensitive average use models: heating degree days ("HDD") and cooling degree days ("CDD"). The values for HDD and CDD are the average of the values for Charleston and Columbia. The base for HDD was 60^{o} and for CDD was 75^{o}. In order to account for cycle billing, the degree day values for each day were weighted by the number of billing cycles which included that day for the current month's billing. The daily weighted degree day values were summed to obtain monthly degree day values. Billing sales for a calendar month may actually reflect consumption that occurred in the previous month based on weather conditions in that period and also consumption occurring in the current month. Therefore, this method more accurately reflects the impact of weather variations on the consumption data.

The development of average use models began with plots of the HDD and CDD data versus average use by month. This process led to the grouping of months with similar average use patterns. Summer and winter groups were chosen, with the summer models including the months of May through October, and the winter models including the months of November through April. For each of the groups, an average use model was developed. Total usage models were developed with a similar methodology for the municipal customers. For these customers, HDD and CDD were weighted based on monthly calendar weather. Simple plots of average use over time revealed significant changes in average use for some customer groups. Three types of variables were used to measure the effect of time on average use:

1. Number of months since a base period;
2. Dummy variable indicating before or after a specific point in time; and,
3. Dummy variable for a specific month or months.

Some models revealed a decreasing trend in average use, which is consistent with conservation efforts and improvements in energy efficiency. However, other models showed an increasing average use over time. This could be the result of larger houses, increasing appliance saturations, lower real electricity prices, and/or higher real incomes.

ARIMA Models

Autoregressive integrated moving average ("ARIMA") procedures were also used in developing the short range forecasts. For various class/rate groups, they were used to develop customer estimates, average use estimates, or total use estimates.

ARIMA procedures were developed for the analysis of time series data, i.e., sets of observations generated sequentially in time. This Box-Jenkins approach is based on the assumption that the behavior of a time series is due to one or more identifiable influences. This method recognizes three effects that a particular observation may have on subsequent values in the series:

1. A decaying effect leads to the inclusion of autoregressive (AR) terms;
2. A long-term or permanent effect leads to integrated (I) terms; and,
3. A temporary or limited effect leads to moving average (MA) terms.

Seasonal effects may also be explained by adding additional terms of each type (AR, I, or MA).

The ARIMA procedure models the behavior of a variable that forms an equally spaced time series with no missing values. The mathematical model is written:

$$Z_t = u + Y_i \ (B)\ X_{i,t} \ + \ q\ (B) \,/\, f\ (B)\ a_t$$

This model expresses the data as a combination of past values of the random shocks and past values of the other series, where:

t	indexes time
B	is the backshift operator, that is $B\ (X_t) = X_{t-1}$
Z_t	is the original data or a difference of the original data
f(B)	is the autoregressive operator, $f(B) = 1 – f_1 B - \dots - f_1 B^p$
u	is the constant term
q(B)	is the moving average operator, $q\ (B) = 1 - q_1 B - ... - q_q B^q$
a_t	is the independent disturbance, also called the random error
$X_{i,t}$	is the ith input time series
$y_i(B)$	is the transfer function weights for the ith input series (modeled as a ratio of polynomials)
$y_i(B)$	is equal to $w_i\ (B)/\ d_i\ (B)$, where $w_i\ (B)$ and $d_i\ (B)$ are polynomials in B.

The Box-Jenkins approach is most noted for its three-step iterative process of identification, estimation, and diagnostic checking to determine the order of a time series. The autocorrelation and partial autocorrelation functions are used to identify a tentative model for univariate time series. This tentative model is estimated. After the tentative model has been fitted to the data, various checks are performed to see if the model is appropriate. These checks involve analysis of the residual series created by the estimation process and often lead to refinements in the tentative model. The iterative process is repeated until a satisfactory model is found.

Many computer packages perform this iterative analysis. PROC ARIMA of (SAS/ETS)[2] was used in developing the ARIMA models contained herein. The attractiveness of ARIMA models comes from data requirements. ARIMA models utilize data about past energy use or customers to forecast future energy use or customers. Past history on energy use and customers serves as a proxy for all the measures of factors underlying energy use and customers when other variables were not available. Univariate ARIMA models were used to forecast average use or total usage when weather-related variables did not significantly affect energy use or alternative independent explanatory variables were not available.

Electric Sales Assumptions

For short-term forecasting, over 30 forecasting groups were defined using the Company's customer class and rate structures. Industrial (Class 30) Rate 23 was further divided using SIC codes. In addition, thirty-seven large industrial customers were individually projected. The residential class was disaggregated into several sub-groups, starting first with rate. Next, a regression analysis was done to separate customers into two categories, “more weather-sensitive” and “less weather sensitive”. Generally speaking, the former group is associated with higher average use per customer in winter months relative to the latter group. Finally, these categories were divided by housing type (single family, multi-family, and mobile homes). Each municipal account represents a forecasting group and was also individually forecast. Discussions were held with Industrial Marketing and Economic Development representatives within the Company regarding prospects for industrial expansions or new customers, and adjustments made to customer, rate, or account projections where appropriate. Table 1 contains the definition for each group and Table 2 identifies the methodology used and the values forecasted by forecasting groups.

The forecast for Company Use is based on historic trends and adjusted for Summer 1 nuclear plant outages. Unaccounted energy, which is the difference between generation and sales and represents for the most part system losses, is usually between 4-5% of total territorial sales. The average annual loss for the three previous years was 4.7%, and this value was assumed throughout the forecast. The monthly allocations for unaccounted use were based on a regression model using normal total degree-days for the calendar month and total degree-days weighted by cycle billing. Adding Company Use and unaccounted energy to monthly territorial sales produces electric generation requirements.

1. TABLE 1 Short-Term Forecasting Groups

A. Class Number	Class Name	Rate/SIC Designation	Comment
10	Residential Less Weather-Sensitive	Single Family	Rates 1, 2, 5, 6, 8, 18, 25, 26, 62, 64
		Multi Family	67, 68, 69
910	Residential More Weather-Sensitive	Mobile Homes	
20	Commercial Less Weather-Sensitive	Rate 9	Small General Service
		Rate 12	Churches
		Rate 20, 21	Medium General Service
		Rate 22	Schools
		Rate 24	Large General Service
		Other Rates	3, 10, 11, 14, 16, 18, 25, 26 29, 62, 67, 69
920	Commercial Space Heating More Weather-Sensitive	Rate 9	Small General Service
30	Industrial Non-Space Heating	Rate 9	Small General Service
		Rate 20, 21	Medium General Service
		Rate 23, SIC 22	Textile Mill Products
		Rate 23, SIC 24	Lumber, Wood Products, Furniture and Fixtures (SIC Codes 24 and 25)
		Rate 23, SIC 26	Paper and Allied Products
		Rate 23, SIC 28	Chemical and Allied Products
		Rate 23, SIC 30	Rubber and Miscellaneous Products
		Rate 23, SIC 32	Stone, Clay, Glass, and Concrete
		Rate 23, SIC 33	Primary Metal Industries; Fabricated Metal Products; Machinery; Electric and Electronic Machinery, Equipment and Supplies; and Transportation Equipment (SIC Codes 33-37)
		Rate 23, SIC 99	Other or Unknown SIC Code*
		Rate 27, 60	Large General Service
		Other	Rates 18, 25, and 26
60	Street Lighting	Rates 3, 9, 13, 17, 18, 25, 26, 29, and 69	
70	Other Public Authority	Rates 3, 9, 20, 21, 25, 26, 29, 65 and 66	
92	Municipal	Rate 60, 61	Three Individual Accounts

*Includes small industrial customers from all SIC classifications that were not previously forecasted individually. Industrial Rate 23 also includes Rate 24. Commercial Rate 24 also includes Rate 23.

TABLE 2

Summary of Methodologies Used To Produce
The Short Range Forecast

Value Forecasted	Methodology	Forecasting Groups
Average Use	Regression	Class 10, All Groups Class 910, All Groups Class 20, Rates 9, 12, 20, 22, 24, 99 Class 920, Rate 9 Class 70, Rate 3
Total Usage	ARIMA/ Regression	Class 30, Rates 9, 20, 99, and 23, for SIC = 91 and 99 Class 930, Rate 9 Class 60 Class 70, Rates 65, 66
	Regression	Class 92, All Accounts Class 97, One Account
Customers	ARIMA	Class 10, All Groups Class 910, All Groups Class 20, All Rates Class 920, Rate 9 Class 30, All Rates Except 60, 99, and 23 for SIC = 22, 24, 26, 28, 30, 32, 33, and 91 Class 930, Rate 9 Class 60 Class 70, Rate

Appendix B

Long Range Sales Forecast

Electric Sales Forecast

This section presents the development of the long-range electric sales forecast for the Company. The long-range electric sales forecast was developed for six classes of service: residential, commercial, industrial, street lighting, other public authorities, and municipals. These classes were disaggregated into appropriate subgroups where data was available and there were notable differences in the data patterns. The residential, commercial, and industrial classes are considered the major classes of service and account for over 93% of total territorial sales. A customer forecast was also developed for each major class of service.

For the residential class, forecasts were produced for those customers categorized into two groups, more and less weather-sensitive. They were further disaggregated into housing types of single family, multi-family and mobile homes. Residential street lighting was also evaluated separately. These subgroups were chosen based on available data and differences in the average usage levels and/or data patterns. Commercial sales were estimated for four subgroups within this sector: small, medium, large, and “other”. Small commercial sales were limited to Rate 9 usage; medium was based on Rates 12, 20, 21, and 22; large was Rate 24, and other consisted of the special rates shown in Table 1 in Appendix A. Average use and customer equations were developed for each commercial subgroup, with the resulting sales projections combined to create the total commercial sales forecast. The industrial class was disaggregated into two digit SIC code classification for the large general service customers, while smaller industrial customers were grouped into an "other" category. These subgroups were chosen to account for the differences in the industrial mix in the service territory. With the exception of the residential group, the forecast for sales was estimated based on total usage in that class of service. The number of residential customers and average usage per customer were estimated separately and total sales were calculated as a product of the two.

The forecast for each class of service was developed utilizing an econometric approach. The structure of the econometric model was based upon the relationship between the variable to be forecasted and the economic environment, weather, conservation, and/or price.

Forecast Methodology

Development of the models for long-term forecasting was econometric in approach and used the technique of regression analysis. Regression analysis is a method of developing an equation which relates one variable, such as sales or customers, to one or more other variables that are statistically correlated with the first, such as weather, personal income or population growth. Generally, the goal is to find the combination of explanatory variables producing the smallest error between the historic actual values and those estimated by the regression. The output of the regression analysis provides an equation for the variable being explained. In the equation, the variable being explained equals the sum of the explanatory variables each multiplied by an estimated coefficient. Various statistics, which indicate the success of the regression analysis fit, were used to evaluate each model. The indicators were R^2, mean squared Error of the Regression, Durbin-Watson Statistic and the T-Statistics of the Coefficient. PROC REG and PROC AUTOREG of SAS were used to estimate all regression models. PROC REG was used for preliminary model specification, elimination of insignificant variables, and also for the final model specifications. Model development also included residual analysis for incorporating dummy variables and an analysis of how well the models fit the historical data, plus checks for any statistical problems such as autocorrelation or multicollinearity. PROC AUTOREG was used if autocorrelation was present as indicated by the Durbin-Watson statistic.

Prior to developing the long-range models, certain design decisions were made:

- The multiplicative or double log model form was chosen. This form allows forecasting based on growth rates, since elasticities with respect to each explanatory variable are given directly by their respective regression coefficients. Elasticity explains the responsiveness of changes in one variable (e.g. sales) to changes in any other variable (e.g. price). Thus, the elasticity coefficient can be applied to the forecasted growth rate of the explanatory variable to obtain a forecasted growth rate for a dependent variable. These projected growth rates were then applied to the last year of the short range forecast to obtain the forecast level for customers or sales for the long range forecast. This is a constant elasticity model, therefore, it is important to evaluate the reasonableness of the model coefficients.
- One way to incorporate conservation effects on electricity is through real prices or time trend variables. Models selected for the major classes would include these variables, if they were statistically significant.

- The remaining variables to be included in the models for the major classes would come from four categories:
  1. Demographic variables - Population.
  2. Measures of economic well-being or activity: real personal income, real per capita income, employment variables, and industrial production indices.
  3. Weather variables - average summer/winter temperature or heating and cooling degree-days.
  4. Variables identified through residual analysis or knowledge of political changes, major economics events, etc. (e.g., the gas price spike in 2005 attributable to Hurricane Katrina and recession versus non-recession years).

Standard statistical procedures were used to obtain preliminary specifications for the models. Model parameters were then estimated using historical data and competitive models were evaluated on the basis of:

- Residual analysis and traditional "goodness of fit" measures to determine how well these models fit the historical data and whether there were any statistical problems such as autocorrelation or multicollinearity.
- An examination of the model results for the most recently completed full year.
- An analysis of the reasonableness of the long-term trend generated by the models. The major criteria here was the presence of any obvious problems, such as the forecasts exceeding all rational expectations based on historical trends and current industry expectations.
- An analysis of the reasonableness of the elasticity coefficient for each explanatory variable. Over the years a host of studies have been conducted on various elasticities relating to electricity sales. Therefore, one check was to see if the estimated coefficients from Company models were in-line with other studies. As a result of the evaluative procedure, final models were obtained for each class.
- The drivers for the long-range electric forecast included the following variables.

Service Area Housing Starts
Service Area Real Per Capita Income
Service Area Real Personal Income
State Industrial Production Indices
Real Price of Electricity

Average Summer Temperature
Average Winter Temperature
Heating Degree Days
Cooling Degree Days

The service area data included Richland, Lexington, Berkeley, Dorchester, Charleston, Aiken and Beaufort counties, which account for the vast majority of total territorial electric sales. Service area historic data and projections were used for all classes with the exception of the industrial class. Industrial productions indices were only available on a statewide basis, so forecasting relationships were developed using that data. Since industry patterns are generally based on regional and national economic patterns, this linking of Company industrial sales to a larger geographic index was appropriate.

Economic Assumptions

In order to generate the electric sales forecast, forecasts must be available for the independent variables. The forecasts for the economic and demographic variables were obtained from Global Insight, Inc. and the forecasts for the price and weather variables were based on historical data. The trend projection developed by Global Insight is characterized by slow, steady growth, representing the mean of all possible paths that the economy could follow if subject to no major disruptions, such as substantial oil price shocks, untoward swings in policy, or excessively rapid increases in demand.

Average summer temperature (average of June, July, and August temperature) or CDD , and average winter temperature (average of December (previous year), January and February temperature) or HDD were assumed to be equal to the normal values used in the short range forecast.

After the trend econometric forecasts were completed, reductions were made to account for higher air-conditioning and water-heater efficiencies, DSM programs, net energy metering solar, and the replacement of incandescent light bulbs with more efficient CFL or LED light bulbs. Industrial sales were increased if new customers are anticipated or if there are expansions among existing customers not contained in the short-term projections.

Peak Demand Forecast

A demand forecast is made for the summer peak, the winter peak and then for each of the remaining ten months of the year. The summer peak demand forecast and the winter peak demand forecast is made for each of the six major classes of customers. Customer load research data is summarized for each of these major customer classes to derive load characteristics that are combined with the energy forecast to produce the projection of future peak demands on the system. Interruptible loads and standby generator capacity is captured and used in the peak forecast to develop a firm level of demand. By utility convention the winter season follows the summer season. The territorial peak demands in the other ten months are projected based on historical ratios by season. The months of May through October are grouped as the summer season and projected based on the average historical ratio to the summer peak demand. The other months of the year are similarly projected with reference to the winter peak demand.