STATE OF SOUTH CAROLINA **South Carolina Electric & Gas Company's Integrated Resource Plan (IRP)**	**BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA** **COVER SHEET** **DOCKET NUMBER:** 2016 - ____ - E

(Please type or print)

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DOCKETING INFORMATION (Check all that apply)

☐ **Emergency Relief demanded in petition** ☐ **Request for item to be placed on Commission's Agenda expeditiously**

☐ **Other:**

INDUSTRY (Check one)	**NATURE OF ACTION (Check all that apply)**		
☒ Electric	☐ Affidavit	☐ Letter	☐ Request
☐ Electric/Gas	☐ Agreement	☐ Memorandum	☐ Request for Certification
☐ Electric/Telecommunications	☐ Answer	☐ Motion	☐ Request for Investigation
☐ Electric/Water	☐ Appellate Review	☐ Objection	☐ Resale Agreement
☐ Electric/Water/Telecom.	☐ Application	☐ Petition	☐ Resale Amendment
☐ Electric/Water/Sewer	☐ Brief	☐ Petition for Reconsideration	☐ Reservation Letter
☐ Gas	☐ Certificate	☐ Petition for Rulemaking	☐ Response
☐ Railroad	☐ Comments	☐ Petition for Rule to Show Cause	☐ Response to Discovery
☐ Sewer	☐ Complaint	☐ Petition to Intervene	☐ Return to Petition
☐ Telecommunications	☐ Consent Order	☐ Petition to Intervene Out of Time	☐ Stipulation
☐ Transportation	☐ Discovery	☐ Prefiled Testimony	☐ Subpoena
☐ Water	☐ Exhibit	☐ Promotion	☒ Other:
☐ Water/Sewer	☐ Expedited Consideration	☐ Proposed Order	Integrated Resource Plan
☐ Administrative Matter	☐ Interconnection Agreement	☐ Protest	
☐ Other:	☐ Interconnection Amendment	☐ Publisher's Affidavit	
	☐ Late-Filed Exhibit	☐ Report	

Matthew W. Gissendanner
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February 26, 2016

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 2016 Integrated Resource Plan
Docket No. 2016-____-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 2016 Integrated Resource Plan of South Carolina Electric & Gas Company ("SCE&G 2016 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 2016 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: John W. Flitter
Jeffrey M. Nelson, Esquire
M. Anthony James
(all via electronic and U.S. First-Class Mail)

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2016-___-E

IN RE:

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

This is the certify that I have caused to be served this day one (1) copy of the **2016 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:

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Karen M. Scruggs

Karen M. Scruggs

Cayce, South Carolina

This 26th day of February 2016

2016

Integrated

Resource

Plan

SCE&G®
A SCANA COMPANY

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Introduction

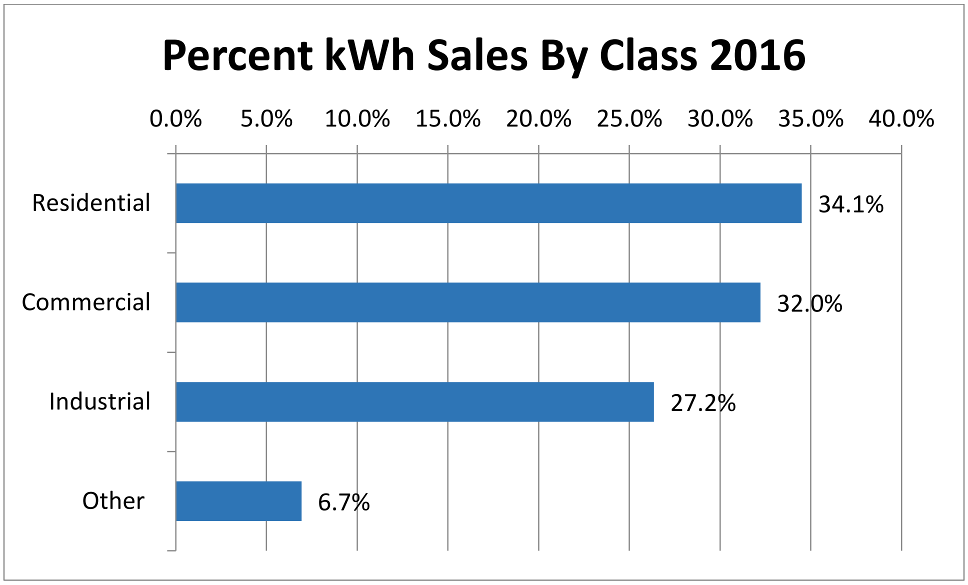
This document presents South Carolina Electric & Gas Company's ("SCE&G" or "Company") Integrated Resource Plan ("IRP") for meeting the energy needs of its customers over the next fifteen years, 2016 through 2030. This document is filed with the Public Service Commission of South Carolina ("Commission") in accordance with S.C. Code Ann. § 58-37-40 (Supp. 2014) 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 (Supp. 2014). The objective of the Company's IRP is to develop a resource plan that will provide reliable and economically priced energy to its customers while complying with all environmental laws and regulations.

I. Demand and Energy Forecast for the Fifteen-Year Period Ending 2030

Total territorial energy sales on SCE&G's system are expected to grow at an average rate of 1.3% per year over the next 15 years, while firm territorial summer peak demand and winter peak demand will increase at 1.7% and 1.2% per year, respectively, over this forecast horizon. The table below contains these projected loads. Note that by utility convention winter follows summer so that the 2016 winter refers to the 2016-2017 winter season.

	Summer Peak (MW)	**Winter Peak (MW)**	**Energy Sales (GWh)**
2016	4,766	4,531	22,970
2017	4,860	4,586	23,178
2018	4,999	4,659	23,605
2019	5,114	4,767	23,861
2020	5,245	4,827	24,153
2021	5,362	4,885	24,399
2022	5,457	4,945	24,623
2023	5,547	4,998	24,966
2024	5,623	5,050	25,311
2025	5,690	5,100	25,656
2026	5,761	5,146	26,012
2027	5,826	5,195	26,357
2028	5,886	5,241	26,711
2029	5,954	5,287	27,073
2030	6,019	5,335	27,434

The energy sales forecast for SCE&G is made for over 30 individual categories. The categories are subgroups of our six classes of customers. The three primary customer classes - residential, commercial, and industrial - comprise just over 93% of our 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.

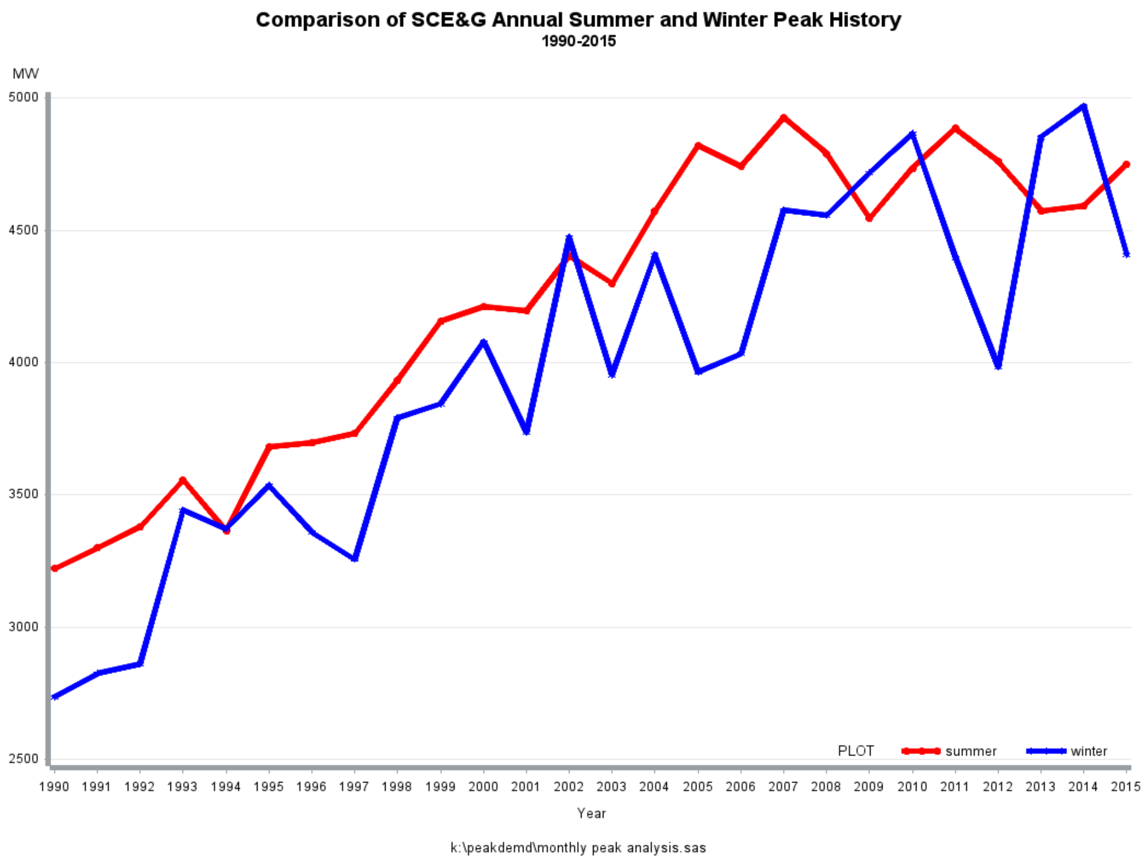


SCE&G’s forecasting process is divided into two parts: development of the baseline forecast, followed by adjustments for energy efficiency impacts. A detailed description of the short-range baseline forecasting process and statistical models is contained in Appendix A of this report. Short-range is defined 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.

1. System Peak Demand: Summer vs. Winter

SCE&G usually peaks in the summer as seen in the following chart. This is reasonable for several factors. First, the climate in SCE&G’s service area is generally hotter in the summer than colder in the winter in the sense that kWh sales are about 15% higher in the summer than winter. Second, the penetration of air-conditioners among SCE&G’s customers approaches 100% since there are no real substitutes for electric air-conditioners at present. Finally, a large number of electric customers heat their homes and/or businesses with natural gas. Results of the peak demand forecast methodology used herein show that the general pattern of higher summer peaks relative to winter peaks will continue.

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 6 of the past 25 years, SCE&G peaked in the winter. One other notable feature of the peak demand chart is the greater variability in winter peak demand.

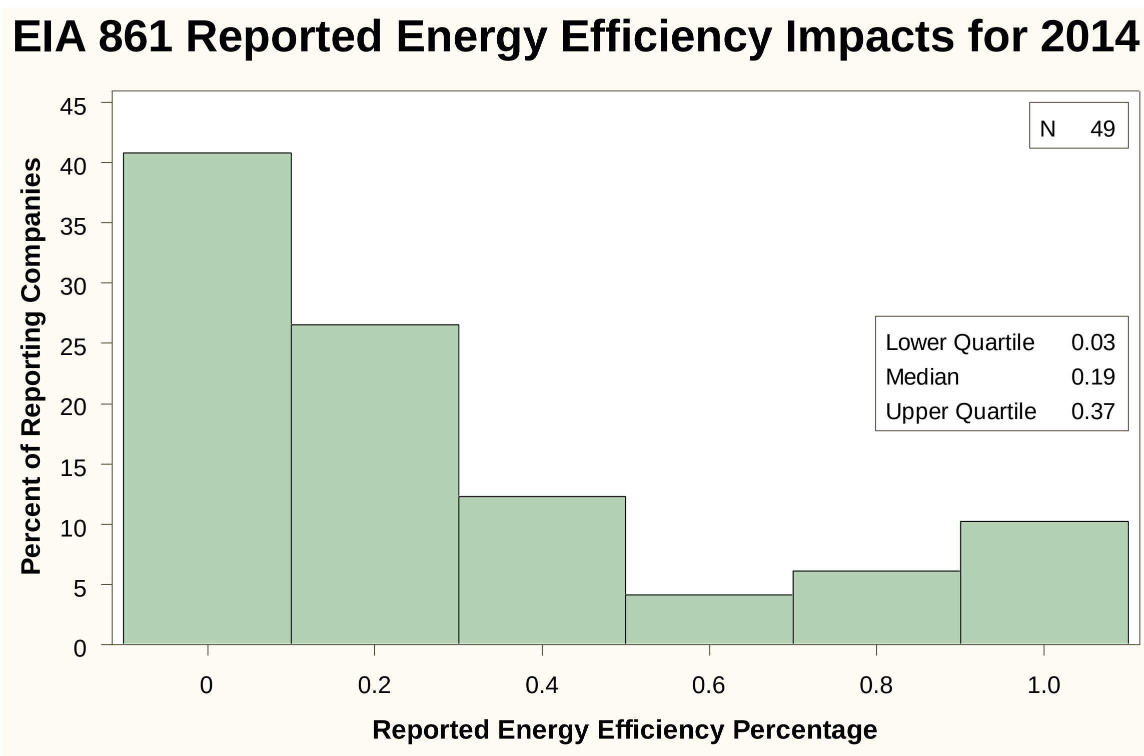


The forecast of summer peak demand is developed by combining the load profile characteristics of each customer class collected in the Company's Load Research Program with forecasted energy. The winter peak demand is projected through customer class equations which relate class winter peaks with weather variables and growth factors.

2. DSM Impact on Forecast

SCE&G anticipates that its energy efficiency ("EE") programs will reduce retail sales in 2016 by 71,307 MWH or approximately 71 GWH. Retail sales after this EE impact are expected to be 22,166 GWH. Therefore, the EE programs are expected to reduce retail sales by about

0.32% from what they would have been. To gauge how its EE programs compared to other companies in the Southeast, SCE&G analyzed the EE impacts filed with the U.S. Energy Information Administration ("EIA") in 2014, the latest year available. There were 54 companies filing from the Southeast, in particular, from the North American Electric Reliability Corporation (NERC) regions of the SERC Reliability Corporation (SERC) and the Florida Reliability Coordinating Council (FRCC). One company was dropped from the analysis for bad data, and the Tennessee Valley Authority reporting in four states was dropped as well. The chart below shows graphically the distribution of reported results. The median EE impact was 0.19%. Thus, half the companies reported results higher and half lower than this median value. SCE&G's expectation for 2016 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 0.32% 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 0.28% and 0.10% for the residential and commercial sectors, respectively. The table below

	Baseline Sales (GWH)	SCE&G Solar Programs (GWH)	SCE&G DSM Programs (GWH)	Federal Mandates (GWH)	Total EE Impact (GWH)	Territorial Sales (GWH)
2016	23,045	-6	0	-69	-75	22,970
2017	23,307	-9	0	-120	-129	23,178
2018	23,816	-12	-30	-169	-211	23,605
2019	24,157	-14	-61	-221	-296	23,861
2020	24,539	-17	-92	-277	-386	24,153
2021	24,872	-18	-124	-331	-473	24,399
2022	25,181	-19	-155	-384	-558	24,623
2023	25,611	-20	-188	-437	-645	24,966
2024	26,043	-21	-221	-490	-732	25,311
2025	26,480	-22	-255	-547	-824	25,656
2026	26,929	-23	-289	-605	-917	26,012
2027	27,367	-24	-324	-662	-1,010	26,357
2028	27,818	-26	-360	-721	-1,107	26,711
2029	28,277	-27	-397	-780	-1,204	27,073
2030	28,732	-28	-434	-836	-1,298	27,434

Baseline sales are projected to grow at the rate of 1.6% 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 1.3% 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 between them over time. For example, construction techniques which result in better insulated houses have had 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

	Baseline Sales (GWH)	SCE&G Solar Programs (GWH)	SCE&G DSM Programs (GWH)	Federal Mandates (GWH)	Total EE Impact (GWH)	Territorial Sales (GWH)
2016	23,046	-6	-63	-69	-75	22,970
2017	23,307	-9	-111	-120	-129	23,178
2018	23,815	-12	-157	-169	-181	23,605
2019	24,158	-14	-207	-221	-235	23,861
2020	24,539	-17	-260	-277	-294	24,153
2021	24,872	-18	-313	-331	-349	24,399
2022	25,181	-19	-365	-384	-403	24,623
2023	25,611	-20	-417	-437	-457	24,966
2024	26,044	-21	-469	-490	-511	25,311
2025	26,480	-22	-525	-547	-569	25,656
2026	26,929	-23	-582	-605	-628	26,012
2027	27,368	-24	-638	-662	-686	26,357
2028	27,818	-26	-695	-721	-747	26,711
2029	28,276	-27	-753	-780	-807	27,073
2030	28,732	-28	-808	-836	-864	27,434

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All electric water heaters manufactured after April 2015 will also 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 they are extremely inefficient. Compact fluorescent light bulbs (“CFLs”) have become increasingly popular over the past several years as substitutes. They last much longer and generally use about one-fourth the energy that incandescent light bulbs use. However, CFLs are more expensive and still 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 will impose efficiency standards that can only be met by them 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.

4. Load Impact of Energy Efficiency and Demand Response Programs

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 our 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 250 megawatts ("MW") on our 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
2016	5,031	-2	-6	-8	5,023	-257	4,766
2017	5,133	-3	-10	-13	5,120	-260	4,860
2018	5,293	-13	-13	-27	5,267	-268	4,998
2019	5,431	-25	-21	-45	5,385	-272	5,114
2020	5,582	-36	-28	-63	5,519	-274	5,245
2021	5,721	-45	-37	-82	5,640	-277	5,363
2022	5,837	-56	-45	-100	5,736	-279	5,458
2023	5,948	-66	-54	-120	5,828	-281	5,547
2024	6,047	-76	-63	-140	5,907	-284	5,623
2025	6,136	-87	-72	-160	5,976	-286	5,690
2026	6,230	-98	-82	-180	6,050	-289	5,761
2027	6,318	-110	-91	-201	6,117	-291	5,826
2028	6,403	-121	-101	-222	6,181	-294	5,887
2029	6,495	-133	-111	-244	6,251	-297	5,954
2030	6,583	-146	-119	-265	6,319	-299	6,019

5. Potential for New Solar Generation

SCE&G began actively signing up customers for rooftop solar systems in 2015. Under one arrangement, net-metering, solar generation offsets consumption by the customer, so it acts as a reduction to sales. This is different than a buy-all sell-all configuration, in which all of the customer's solar generation enters the grid and is metered and paid for separately from consumption. Under the buy-all sell-all arrangement there is no impact upon the company's sales, unlike net-metering, which is a direct reduction in consumption. Therefore the only solar impacts considered in SCE&G's territorial load projection are those attributable to a net-metering arrangement.

The accompanying table shows the energy reductions to the baseline forecast for net-metering. While these numbers might appear small relative to SCE&G's customer base, it is important to keep in mind that this group represents only a very specific type of solar power use and sales. The bulk of solar generation is expected to come in different configurations such as buy-all sell-all or community solar. There are also limitations on the suitability of a great number of houses for economic installation of solar generation, because homes in the South are generally constructed to minimize the amount of solar radiation reaching the rooftop. Ranges of rooftop area suitable for solar generation vary wildly in studies from 15%-65% on a national basis, so it is safe to say that a large number of residential customers would not benefit from solar panels, thereby implying that net-metering customer growth will be somewhat constrained.

Impact of Rooftop Solar on SCE&G Territorial Sales

Year	Solar Customers	GWh Reduction
2016	1,215	-6
2017	1,710	-9
2018	2,205	-12
2019	2,745	-14
2020	3,285	-17
2021	3,449	-18
2022	3,621	-19
2023	3,802	-20
2024	3,992	-21
2025	4,192	-22
2026	4,402	-23
2027	4,622	-24
2028	4,853	-26
2029	5,096	-27
2030	5,351	-28

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 vehicles to increase customer awareness and to help customers become more energy efficient. Two key components, customer insights/analysis and media/channel placement, are summarized below:

   i. **Customer Insights and Analysis:** In 2015, SCE&G conducted a follow-up Voice of the Customer (VOC) panel survey to gain additional insight about energy efficiency and engagement with Demand Side Management residential programs. Over 3,200 SCE&G residential customers were solicited with a 55% completion rate.

   ii. **Media/Channel Placement:** SCE&G is committed to customer education about 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, radio, online and community events continue to prove successful with engaging customers. Extensive outreach via social media continues to provide maximum coverage and the opportunity to inform customers. A steady increase in customer engagement with social media networks, Facebook and Twitter, has resulted in nearly 31,500 likes and about 7,230 followers respectively. 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 2015, the Demand Side Management portfolio of programs included seven (7) programs targeting SCE&G's residential customer classes and two programs targeting commercial and industrial customer classes. 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 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 measures, such as compact fluorescent light bulbs ("CFL"), 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 2015, SCE&G offered incentives via an online store, in addition to providing energy efficiency lighting kits at various business office locations.

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. **Residential ENERGY STAR® New Homes** provides incentives to customers and builders who are willing to commit to ENERGY STAR® standards in new home construction.

vi. **Neighborhood Energy Efficiency Program (NEEP**) provides income qualified customers with energy efficiency education, an in-home energy assessment and direct installation of low-cost energy saving measures as part of a neighborhood door-to-door sweep approach. In 2015, neighborhoods in Charleston, West Columbia, Johnston, Ridgeland, Hardeeville and Columbia participated in the program.

vii. **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.

viii. **EnergyWise for Your Business Program** provides incentives to non-residential customers 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 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 both retrofit and new construction projects.

ix. **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, electric water heaters and refrigeration upgrades. The program is available to SCE&G's small business and small nonprofit customers with an annual energy use of 250,000 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. 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 our wholesale customers and through a contractual arrangement is made available to SCE&G dispatchers. 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 about 9 megawatts of additional capacity as needed.

b. **Interruptible Load Program:** SCE&G has over 200 megawatts of interruptible customer load under contract. Participating 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 our real time pricing rate. During peak usage periods throughout the year when capacity is low in the market, the RTP program sends a high price signal to participating customers which encourages conservation and load shifting. Of course during low usage periods, prices are lower.

d. **Time of Use Rates:** Our 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.

B. Supply Side Management

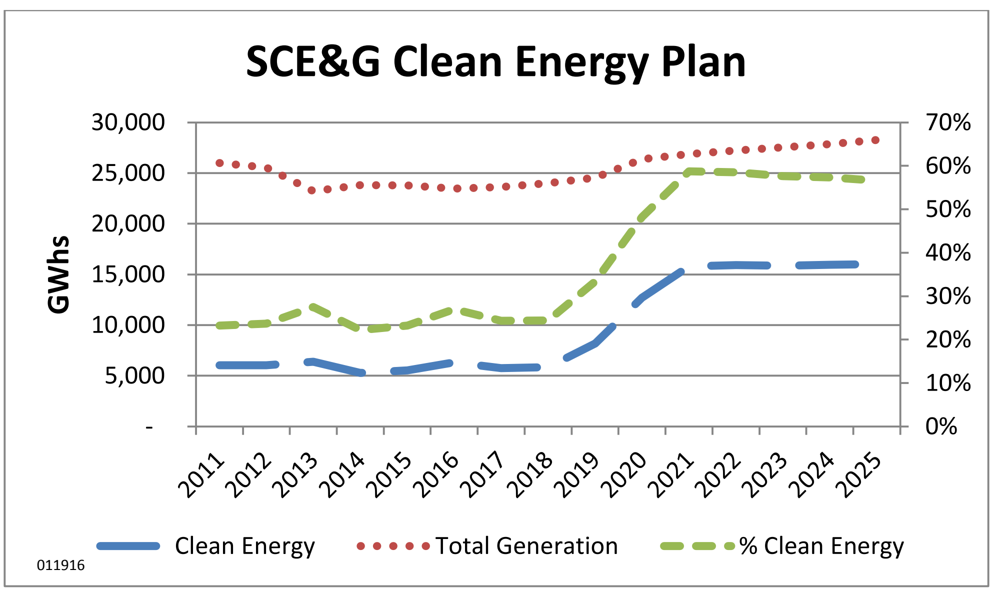
Clean Energy at SCE&G

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

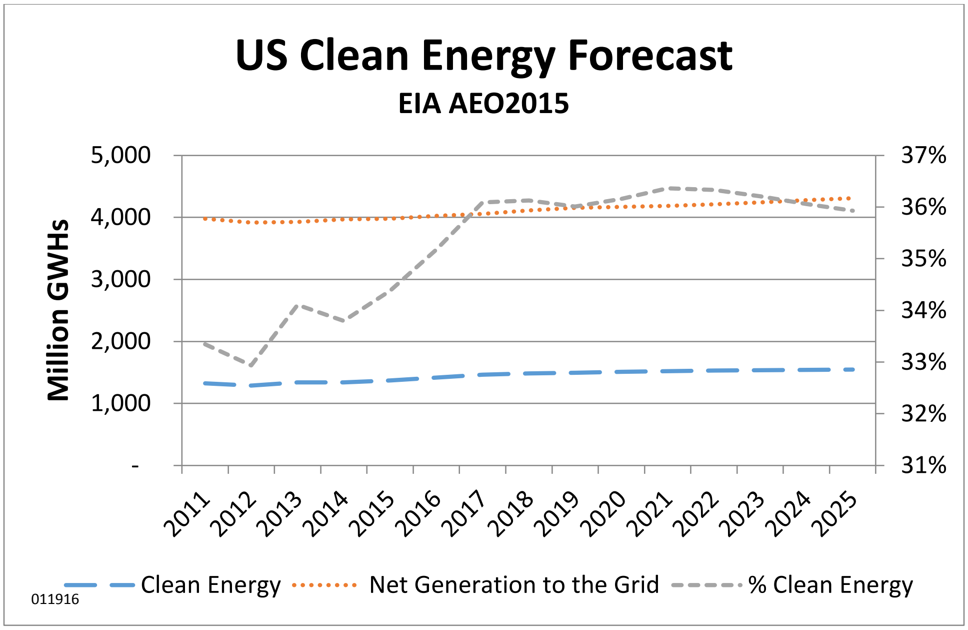
1. Existing Sources of Clean Energy

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, in the Company's distributed energy resource program, and in the Company's support for Palmetto Clean Energy, Inc. Below is a discussion of each of these topics.

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



As seen in the chart above, SCE&G currently produces approximately 25% of its total generation from clean energy sources but by 2021 it expects to generate about 60% from clean energy. According to the EIA, the U.S. as a nation currently produces about 34% of its total generation from clean sources and it expects this percentage to increase slightly over the next ten years or so. The following chart graphs EIA's forecast for US clean energy.



SCE&G compares favorably to the nation in its clean energy plans. By 2021 it should be producing almost twice as much of its generation with clean energy on a relative basis compared to the nation.

b. 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 MWs with SCE&G owning 647 MWs (two-thirds) and Santee Cooper owning the balance. In 2015 Unit 1 produced 4,744 gigawatt-hours ("GWH") of clean energy for SCE&G's customers. This represented 20% of our customers' need. Over the last 33 years of operation, Unit 1 has produced 148,629 GWHs for SCE&G's customers. SCE&G received an extension to its original operating license in April 2004 and the Unit is now expected to operate until August 2042. Over these next 27 years Unit 1 should produce another 134,665 GWHs of clean energy for SCE&G. If SCE&G were to generate this 60-years' worth of energy with fossil fuels, it would mean about 212 million more tons of CO_2 emitted to the atmosphere. And this 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.

c. Renewable Energy Credits: The SCE&G owned electric generator, located at the KapStone Charleston Kraft LLC facility, 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"). The nearby table shows the MWhs of renewable energy generated by the KapStone generator, formerly known as the Cogen South generator.

Year	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	1.8%

d. Boeing Solar Generator: In 2011, SCE&G installed approximately 10 acres of thin-film laminate panels (18,095 individual panels) on the roof of Boeing's North Charleston assembly plant. The PV system with a nameplate rating of 2.6 MW DC began generating in October 2011 and has a peak output of about 2.35 MW AC. All RECs and energy generated by the roof top solar system are provided to Boeing for onsite use. At the time of completion this was the largest roof-top solar generator in the Southeast. Over the last four years the Boeing solar plant has generated the following amounts of energy:

Year	MWh
2012	3,513
2013	3,410
2014	3,337
2015	3,267

e. Net Energy Metering ("NEM") Rates and the PR-1 Rate: Protecting the environment includes encouraging and helping our customers to take steps to do the same. Net metering provides a way for residential and commercial 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 under the NEM rider, the generator output capacity cannot exceed the annual maximum household energy requirements or 20 KW, 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, whichever is less. The NEM rider provides that each kWh generated by the customer will offset one kWh of consumption by the customer. This is referred to as 1:1 (one for one) net energy metering. Customer generator capacity under the current NEM program is limited to 2% of the Company's previous five-year average retail peak demand.

Under Commission Order 2015-194, a Net Energy Metering Methodology 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 1:1 NEM incentive and have the difference funded through the Distributed Energy Resource Program Act. Customers will be offered the NEM rate until January 1, 2021, and those customers taking service under the new NEM rate will receive the Net Metering Incentive described above until December 31, 2025, or until they take service under a different rate, whichever occurs first.

Under its PR-1 rate for qualifying facilities, the Company will pay the qualifying customer for any power generated and transmitted to the SCE&G system. The PR-1 rate is developed using SCE&G's avoided costs.

f. Palmetto Clean Energy, Inc.: Palmetto Clean Energy, Inc. ("PaCE") is a non-profit, tax exempt organization formed in 2007 by SCE&G, Duke Energy, Progress Energy, the South Carolina Office of Regulatory Staff ("ORS") and the S.C. Energy Office for the purpose of promoting the development of renewable power in South Carolina. Customers voluntarily make a tax deductible contribution to PaCE and PaCE uses the funds collected to pay renewable generators a financial incentive for their power.

2. Future Clean Energy

SCE&G is participating in activities seeking to advance renewable technologies in the future. Specifically the Company is involved with a) distributed energy resources, b) off-shore wind activities in the state, c) co-firing with biomass fuels, d) smart grid opportunities, e) distribution automation, f) environmental mitigation activities, and g) nuclear power in the future. These activities are set forth in more detail below.

a. Distributed Energy Resource ("DER") Program: SCE&G's customers and other South Carolina stakeholders have expressed a desire for solar energy in the State, and SCE&G is looking for ways to integrate additional solar into the system in the most economical way possible while beginning to grow a new clean energy economy in South Carolina based on a diverse portfolio of generation. SCE&G currently has approximately 6 megawatts of solar generation on the system. As part of its new DER Programs which were approved by the Commission in July 2015 under Order 2015-512, SCE&G plans to add up to 100 megawatts of renewable energy to its system by 2021. SCE&G's DER programs became available to customers in October of 2015 and these programs offer incentives through simple, customer centric offerings with a variety of customer choices. Customer feedback has been positive and participation levels have been increasing. In 2015, SCE&G contracted for a 500 kW utility scale solar farm at its Leeds Avenue site in North Charleston. This farm became commercially operational on December 22, 2015. See picture below. SCE&G also interconnected three large customer scale projects in the Columbia area totaling approximately 1 MW. In 2016, SCE&G plans to install over 30 MWs of solar generation on its system. As part of this, SCE&G plans to install a 2 MW solar farm along Saxe Gotha Road in Cayce, adjacent to SCE&G's corporate headquarters. SCE&G has assembled an experienced team focused on research, design, and implementation of renewable energy resources.

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

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: SCE&G currently has approximately 9,600 AMI (Advanced Metering Infrastructure) meters that are installed predominately on our medium to large commercial customers as well as our smaller 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 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 provided to customers daily via web applications enabling these customers to have quick access to energy usage allowing better management of their energy consumption.

d. Distribution Automation: SCE&G is continuing to expand the penetration of automated Supervisory Control and Data Acquisition ("SCADA") switching and other intelligent devices throughout the system. We have approximately 1000 SCADA switches and reclosers, most of which can detect system outages and operate automatically to isolate sections of line with problems thereby minimizing the number of 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. We are continuing to evaluate systems that will 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).

e. Environmental Mitigation Activities: On January 1, 2015, the Clean Air Interstate Rule (CAIR) was replaced by the Cross State Air Pollution Rule (CSAPR), which set new emission limits for Annual and Seasonal NO_X and also for Annual SO_2. In addition the existing Acid Rain Program (ARP) continues in effect for annual SO_2 emissions.

To meet the compliance requirements for NO_X, SCE&G (& GENCO) has installed Selective Catalytic Reduction equipment (SCRs) at Wateree, Cope and Williams Stations. Also all coal fired units have previously installed low NO_X burners.

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 has FGD equipment in the form of a dry scrubber, which was part of the original equipment of that plant.

Mercury emission control has also been realized in the industry via the operation of FGD equipment. Consequently, the continued operation of the FGD equipment will contribute to SCE&G's strategy for meeting the impending requirements of the US EPA's Mercury and Air Toxics Standard ("MATS") that became effective on April 16, 2015. The Chem-Mod fuel additive being used at McMeekin, Cope, and Williams Stations will similarly contribute to SCE&G's efforts in stack emission control for mercury, 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 at Williams, Wateree and Cope. This will allow for additional control of mercury emissions if needed to comply with MATS requirements.

In response to the EPA's impending MATS, 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 decommissioning efforts are still in progress. McMeekin Units 1 & 2 will be fully converted to gas by April 2016 with no coal to be utilized after that date.

In an effort to cease bottom ash sluicing to the Wateree Station's ash ponds, SCE&G installed two remote submerged flight conveyors that dewater boiler bottom ash sluice and recycle the overflow back to the boiler for reuse. This retrofit was completed for Units 1 and 2 during October 2012. The bottom ash is then marketed as an ingredient in the manufacture of pre-stressed concrete products.

f. 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. In 2015 SCE&G assisted an SMR vendor with a feasibility study for replacement of coal generation with the SMR technology. However SCE&G has no current plans for SMR on its system but will continue to evaluate this technology as it develops.

3. Summary of Proposed and Recently Finalized Environmental Regulations

The EPA has either proposed or recently finalized six regulations and modified one additional regulation. These are: a) Cross-State Air Pollution Rule (CSAPR); b) Mercury and Air Toxics Standards (MATS): c) Clean Power Plan; d) Cooling Water Intake Structures; e) Coal Combustion Residuals; f) Effluent Limitation Guidelines; and g) a 1-hour sulfur dioxide National Ambient Air Quality Standard (NAAQS). 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, when the U.S. Court of Appeals for the D.C. Circuit issued an order granting a motion to lift the stay. On December 3, 2014, the EPA published an interim final rule that aligns the dates in the CSAPR rule text with the revised court-ordered schedule, thus delaying the implementation dates to 2015 for Phase 1 implementation and to 2017 for Phase 2. SC is not a Phase 2 state.

CSAPR, replaces the Clean Air Interstate Rule (CAIR), and 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.

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 is required by April 2015. After receiving numerous petitions for reconsideration of this rule, on November 19, 2014, the EPA modified the MATS provisions applicable during startup and shutdown. On June 29, 2015, the U.S. Supreme Court ruled that the EPA unreasonably failed to consider costs in its decision to regulate, and remanded a case challenging the regulation on that basis to the Court of Appeals. The Court noted during remand that EPA has said that I is on track to issue a revised "appropriate and necessary" finding by April 15, 2016.

SCE&G initially applied for and received a 1-year extension of the compliance deadline from the SC Department of Health and Environmental Control (SCDHEC) for both McMeekin and Canadys. Canadys retired in the 4th quarter of 2013 and McMeekin will cease the use of coal by April 2016. Due to the additional requirements of the reconsideration rule issued in late 2014, extensions were also obtained from SCDHEC for Cope, Wateree, and Williams Stations. These extensions, which also expire in April 2016, allow time to install and test additional pollution control devices that will enhance the control of certain MATS-regulated pollutants. SCE&G and GENCO are in compliance with the MATS rule and expect to remain in compliance.

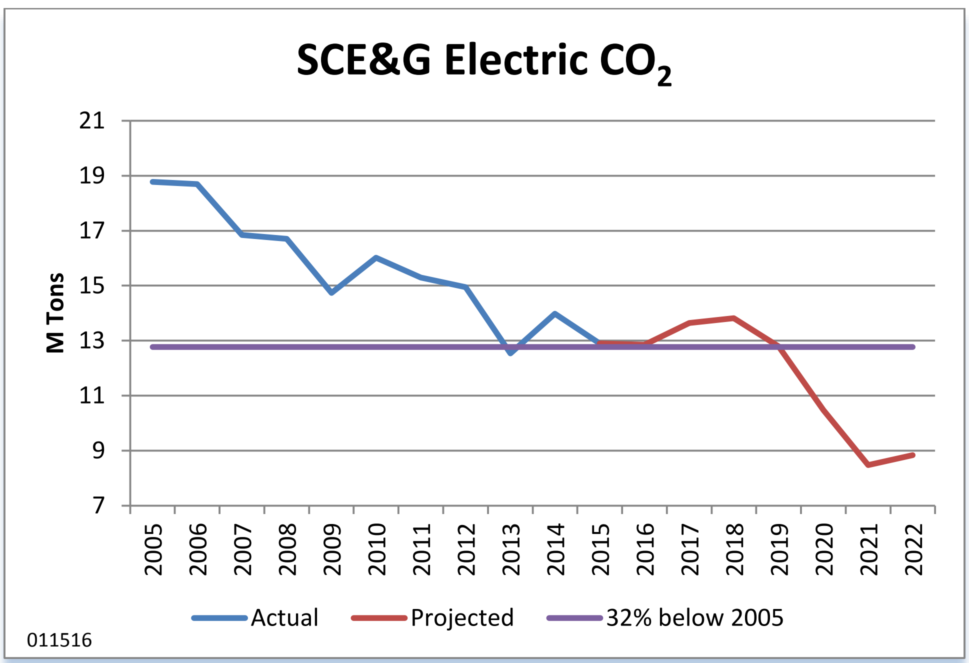
c. Clean Power Plan: In August 2015, the EPA issued two rules addressing the emission of greenhouse gases from electric generating units (EGU), one for existing units and one for new or modified units. These rules were issued in response to the President's June 2013 Climate Action Plan.

The first of these rules amends the new source performance standards ("NSPS") for EGUs and will establish 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. The Company 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 has determined a "Best System of Emissions Reduction" (BSER) for these existing plants. The BSER includes three "Building Blocks," including heat rate reduction at coal-fired plants; redispatch of electric generation from coal to natural gas plants; and substituting zero-emission generation for existing coal-fired plants. The final rule differs from the 2014 proposed rule, which did not give proper credit to new nuclear units being constructed in South Carolina and several other states. The August 2015 final rule does give proper credit to those nuclear units.

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. Those pathways include rate-based compliance plans, wherein each EGU would be required to meet an emission rate target. Alternatively, a state may select a mass-based compliance plan, in which an EGU would be allocated a CO_2 emission (in short tons) cap. In both the rate and mass-based plans, EGUs would have the opportunity to trade credits or allocations to assist in meeting those targets.

The Company has no plans to add new coal-fired generation but is currently constructing two new nuclear generation units (see Section 4d, "New Nuclear Capacity"). The new nuclear credit in addition to the Company's plans to add renewables and energy efficiency measures are expected to help it achieve compliance with the Clean Power Plan. However, it is not known what specific measures and requirements may be promulgated in the final State Implementation Plan which was expected to be completed in September 2018. If the Clean Power Plan is implemented, the EPA anticipates that CO2 emissions will be 32% below 2005 levels by the year 2030. The following chart shows that SCE&G's CO_2 emissions will fall well below the "32% below 2005" emission level after new nuclear begins generating.



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. Although the order of the Supreme Court has no immediate impact on SCE&G and GENCO or their generation operations, it is generally expected that the stay will delay the implementation dates of the rule on a day for day basis just as it has done during litigation of other environmental rules (e.g. the Cross State Air Pollution Rule or CSAPR).

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 damage 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, Wateree and Cope Stations, currently meet Best Technology Available (BTA) requirements for impingement mortality and entrainment. Two others, McMeekin and Jasper Stations, have been determined to be not-in-scope of the rule. An entrainment study is currently ongoing at Summer Station Unit 1 and will be completed in 2016. The Company is currently in discussions with the SCDHEC regarding compliance requirements for Urquhart Station and Williams Station. A biological study plan, which would evaluate current impacts to fish and shellfish, is being developed for Urquhart Station.

e. Coal Combustion Residuals: In response to concerns over the potential structural failure of coal ash impoundment facilities, EPA has elected to further regulate coal combustion residual (CCR or ash) management in landfills and surface impoundments (ponds). On April 17, 2015, the EPA issued a final CCR management rule. The 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 the phase-in of several activities including making information accessible on the Company website, additional structural integrity assessments 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 uses such as cement and wallboard manufacture. 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. 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. 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.

f. Effluent Limitation Guidelines: On September 30, 2015, the EPA amended the Effluent Limitation Guideline for Steam Electric Power Generators. 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 CWA, 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 would be incorporated. Now that the rule is effective, the State environmental regulators will modify the NPDES permits to match more restrictive standards thus requiring utilities to retrofit each facility 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 2018 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.

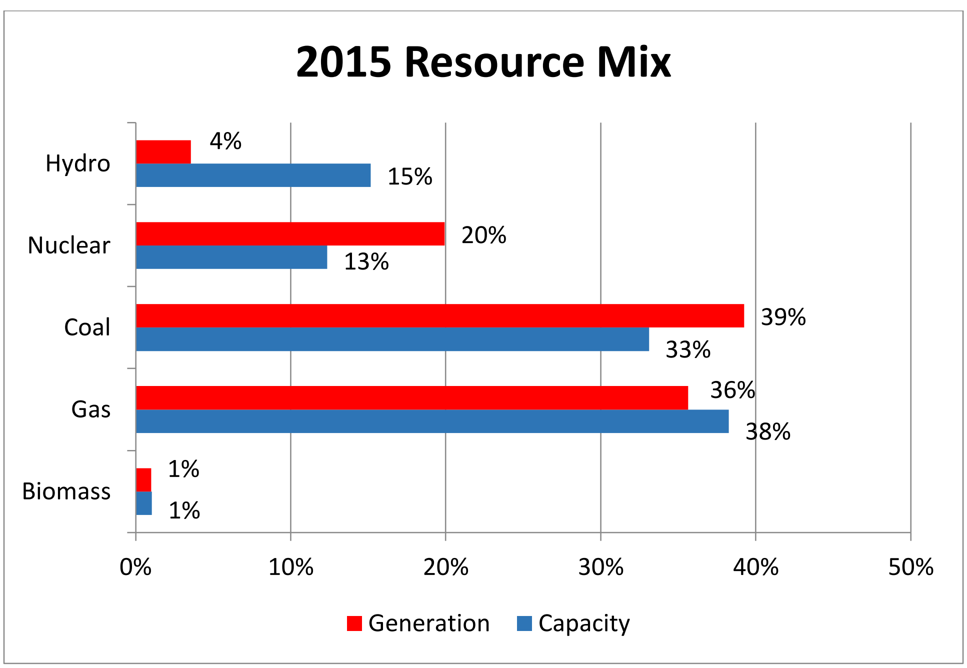
g. NAAQS 1-hour SO_2: In June 2010, EPA revised the primary SO_2 standard by establishing a new 1-hour standard at a level of 75 parts per billion ("ppb"). The EPA revoked the two existing primary standards of 140 ppb evaluated over 24-hours, and 30 ppb per hour averaged over an entire year. The new form is the 3-year average of the 99th percentile of the annual distribution of daily maximum 1-hour average concentrations.

In August 2015, the EPA issued additional rules (the Data Requirements Rule) clarifying that only facilities emitting more than 2000 tons per year of SO_2 are required to demonstrate compliance. For SCE&G, only Wateree Station exceeds that threshold. Compliance can be demonstrated using computer-based dispersion models; however, compliance may also be demonstrated using a series of ambient SO_2 monitors. The details of this dispersion modeling are currently being discussed with SCDHEC and modeling is expected to be submitted in 2016 or early 2017.

4. Supply Side Resources at SCE&G

a. Existing Supply Resources: SCE&G owns and operates three (3) coal-fired fossil fuel plants, two (2) gas-fired steam plants, two (2) 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 receives the output of 85 MWs from a cogeneration facility. The total net non-nuclear summer generating capability rating of these facilities is 4,587 MWs in summer and 4,758 MWs 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 MWs in summer and 661 MWs in winter), a long term capacity purchase (25 MWs) and additional capacity (20 MWs) provided through a contract with the Southeastern Power Administration are added, SCE&G's total supply capacity is 5,279 MWs in summer and 5,464 MWs in winter. This is summarized in the table on the following page.

The bar chart below shows SCE&G's actual 2015 relative energy generation and relative capacity by fuel source.



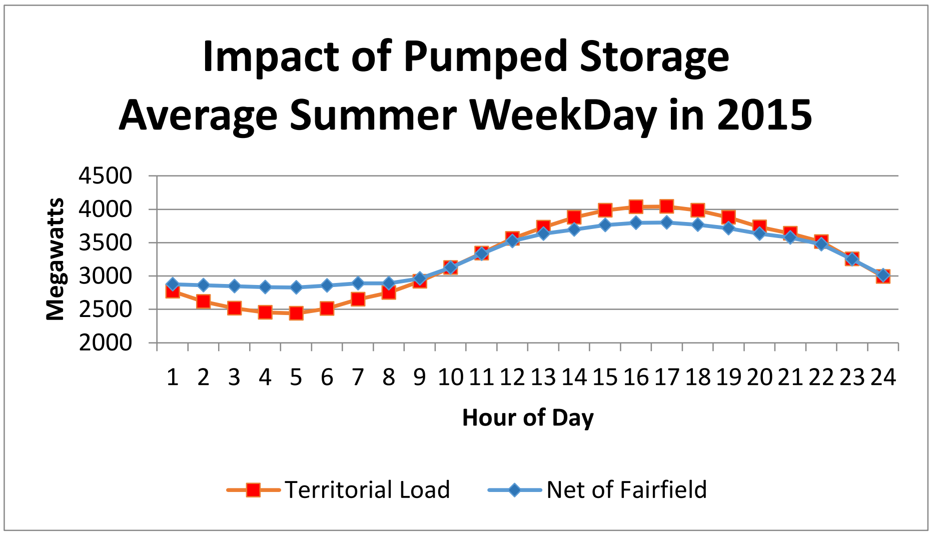
Existing Long Term Supply Resources

The following table shows the generating capacity that is available to SCE&G in 2016.

	In-Service Date	Summer (MW)	Winter (MW)
Coal-Fired Steam:			
Wateree – Eastover, SC	1970	684	684
Williams – Goose Creek, SC*	1973	605	610
Cope - Cope, SC	1996	415	415
KapStone – Charleston, SC	1999	85	85
Total Coal-Fired Steam Capacity		1,789	1,794
Gas-Fired Steam:			
McMeekin – Irmo, SC	1958	250	250
Urquhart – Beech Island, SC	1955	95	96
Total Gas-Fired Steam Capacity		345	346
Nuclear:			
V. C. Summer - Parr, SC	1984	647	661
I. C. Turbines:			
Hardeeville, SC	1968	9	9
Urquhart – Beech Island, SC	1969	39	48
Coit – Columbia, SC	1969	26	36
Parr, SC	1970	60	73
Williams – Goose Creek, SC	1972	40	52
Hagood – Charleston, SC	1991	127	141
Urquhart No. 4 – Beech Island, SC	1999	48	49
Urquhart Combined Cycle – Beech Island, SC	2002	458	484
Jasper Combined Cycle – Jasper, SC	2004	852	924
Total I. C. Turbines Capacity		1,659	1,816
Hydro:			
Neal Shoals – Carlisle, SC	1905	3	4
Parr Shoals – Parr, SC	1914	7	12
Stevens Creek - Near Martinez, GA	1914	8	10
Saluda - Irmo, SC	1930	200	200
Fairfield Pumped Storage - Parr, SC	1978	576	576
Total Hydro Capacity		794	802
Other: Long-Term Purchases		25	25
Southeastern Power Administration (SEPA)		20	20
Grand Total:		5,279	5,464

* Williams Station is owned by GENCO, a wholly owned subsidiary of SCANA and is operated by SCE&G.
* Not reflected in the table is a solar PV generator owned by SCE&G with a nominal direct current rating of 2.6 MWs, nor off-system purchases totaling 300 MWs of firm capacity for the years 2016-2017.
* The Leeds Avenue solar farm (North Charleston, SC), a 0.50 MW project, is also not reflected in the table.

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 weekday.



In effect the Fairfield Pumped Storage Plant was used to shave about 229 MWs from the daily peak times of 2:00 p.m. through 6:00 p.m. and to move about 2.8% of customer's daily 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 and Operating Reserves: The Company provides for the reliability of its electric service by maintaining an adequate reserve margin of supply capacity. The appropriate level of reserve capacity for SCE&G is in the range of 14 to 20 percent of its firm peak demand. This range of reserves will allow SCE&G to have adequate daily operating reserves and to have reserves to cover two primary sources of risk: supply risk and demand risk.

Supply reserves are needed to balance the "supply risk" that some SCE&G generation capacity may be forced out of service or its capacity reduced on any particular day because of mechanical failures, fuel related problems, environmental limitations or other force majeure/unforeseen events. The amount of capacity forced-out or down-rated will vary from day-to-day. SCE&G's reserve margin range is designed to cover most of these days as well as the outage of any one of our generating units.

Another component of reserve margin is the demand reserve. This is needed to cover "demand risk" related to unexpected increases in customer load above our peak demand forecast. This can be the result of extreme weather conditions or other unexpected events.

The level of daily operating reserves required by the SCE&G system is dictated by operating agreements with other VACAR companies. VACAR is the organization of utilities serving customers in the Virginia-Carolinas region of the country who have entered into a reserve sharing agreement. These utilities are members of the SERC Reliability Corporation, a nonprofit corporation responsible for promoting and improving the reliability of the bulk power transmission system in much of the southeastern United States. While it can vary by a few megawatts each year, SCE&G's pro-rata share of this capacity is always around 200 megawatts.

To analyze these three components of reserve and establish a reserve margin target range, SCE&G employs three methodologies: 1) the component method which analyzes separately each of the three components mentioned above; 2) the traditional and industry standard technique of "Loss of Load Probability," or LOLP, using a range of LOLP from 1 day per year to 1 day in 10 years; and 3) the largest unit out method. The results of this analysis are summarized in the following table and support a reserve margin target range of 14% to 20%.

	Low MWs	Low %	High MWs	High %
Component Method	656	13.7%	1144	24.0%
LOLP	710	14.9%	1110	23.3%
Largest Unit	647	13.6%	971	20.4%
	671		1075	
Reserve Margin Range		14.1%		22.6%

By maintaining a reserve margin in the 14 to 20 percent range, the Company addresses the uncertainties related to load and to the availability of generation on its system. It also allows the Company to meet its VACAR obligation. SCE&G will monitor its reserve margin policy in light of the changing power markets and its system needs and will make changes to the policy as warranted.

d. New Nuclear Capacity: On May 30, 2008, SCE&G filed with the Commission a Combined Application for a Certificate of Environmental Compatibility and Public Convenience and Necessity and for a Base Load Review Order for the construction and operation of two 1,117 net MW nuclear units to be located at the V.C. Summer Nuclear Station near Jenkinsville, South Carolina. Following a full hearing on the Combined Application, the Commission issued Order No. 2009-104(A) granting SCE&G, among other things, a Certificate of Environmental Compatibility and Public Convenience and Necessity.

On March 30, 2012, the United States Nuclear Regulatory Commission issued a combined Construction and Operation License ("COL") to SCE&G for each unit. Both units will have the Westinghouse AP1000 design and use passive safety systems to enhance the safety of the units.

On January 27, 2014, SCE&G and Santee Cooper agreed to increase SCE&G's ownership share from 55% to 60% in three stages. SCE&G will acquire an additional 1% of the 2,234 MWs of capacity when Unit #2 achieves commercial operation. An additional 2% will go to SCE&G one year later, and another 2% one year after that. SCE&G's purchase of the additional 5% ownership will require approval of the South Carolina Public Service Commission.

On October 27, 2015, SCE&G and Westinghouse agreed to amend the Engineering, Procurement and Construction ("EPC") agreement. The amendment clears substantially all existing disputes among parties to the project and provides better protection against future cost increases for SCE&G's customers. The amended agreement revises the Guaranteed Substantial Completion Dates for Units 2 and 3 to August 31, 2019 and 2020 respectively. By the end of 2021, SCE&G expects to own 60% of both units (about 670 MWs each) while Santee Cooper will own 40%.

e. Retirement of Coal Plants: When the EPA promulgated its Mercury and Air Toxics Standards ("MATS") on December 21, 2011, SCE&G had six small coal-fired units in its fleet totaling 730 MWs ranging in age from 45 to 57 years that could not meet the emission standards without further modifications to the units. Those six units are displayed in the following table.

Plant Name	Capacity (MW)	Commercialization Date
Canadys 1	90	1962
Canadys 2	115	1964
Canadys 3	180	1967
Urquhart 3	95	1955
McMeekin 1	125	1958
McMeekin 2	125	1958
Total	730	

After a thorough retirement analysis, the Company decided that these six units would be retired when the addition of new nuclear capacity was available as a replacement.[1] As part of this retirement plan the Company has retired Canadys' Units #1, 2 and 3 and has converted Urquhart Unit 3 to be fired with natural gas while dismantling the coal handling facilities at this unit. The capacity (250 MWs) of the remaining two coal-fired units, McMeekin Units 1 and 2, is required to maintain system reliability until the new nuclear capacity is available. Under the MATS regulations but with a one year waiver granted by DHEC these units cannot run on coal after April 15, 2016. The Company expects to bridge the gap between the MATS compliance date and the availability of the new nuclear capacity by firing McMeekin Units 1 and 2 on natural gas and purchasing the balance of needed capacity. McMeekin Units 1 and 2 have been running well on natural gas primarily during the last several months confirming that this option will definitely work.

Since the 2011 retirement study reported in the Company's 2012 IRP, natural gas prices have gone down and the U.S. Environmental Protection Agency has issued its Clean Power Plan providing more certainty about the future cost of emitting CO_2. With expectation of lower natural gas prices in the future and zero cost of emitting CO_2, it was important for the Company to update its retirement study regarding Urquhart 3 and McMeekin 1 and 2. The following table compares the annual levelized revenue requirements between the base case of retiring all three units and each alternative change case.

[1] In announcing its plans to retire the units in its 2012 Integrated Resource Plan, the Company was careful to note that its retirement plans were subject to change if circumstances changed. See SCE&G's 2012 Integrated Resource Plan, at 29 (May 30, 2012) ("Although today's reference resource plan calls for the plant retirements, the Company will continue to monitor, among other things, developments in environmental regulations and will continue to analyze its options and modify the plan as needed to benefit its customers.").

Scenario	Retire/Mothball	Return to Service	Levelized Present Worth Cost Relative to the Base Case-Scenario ($000)
0	Base Case: Retire URQ3, MCM1 and MCM2 in 2020		
1	Mothball URQ3 and retire MCM1, MCM2 in 2020	URQ3 2023	($5,095)
2	Mothball MCM1 and retire MCM2, URQ3 in 2020	MCM1 2024	($2,629)
3	Mothball MCM1, MCM2, and retire URQ3 in 2020	MCM1 2024, MCM2 2025	($8,087)
4	Mothball all in 2020	URQ3 2024, MCM1 2025, MCM2 2026	($11,412)
5	Retire URQ3 and MCM2 in 2020	MCM1 doesn't retire or Mothball	($2,321)
6	Retire URQ3 in 2020	MCM1 & MCM2 don't retire or Mothball	($6,985)
7	None	MCM1,MCM2, URQ3 don't retire or Mothball	($10,354)
8	None	MCM1,MCM2, URQ3 don't retire or Mothball, 50% Higher gas	($6,105)
9	None	MCM1,MCM2, URQ3 don't retire or Mothball, 100% Higher gas	($2,742)

Scenario 7 which assumes no retirements will save our customers about $10.354 million per year. Scenario 4 will save a little more but it involves placing the units in mothball status for several years and then returning them to service. The mothball scenario may not be feasible. It would present large manpower and equipment maintenance challenges and just may not be practical. Based on these results the Company will plan on keeping these units operating but will continue to monitor the direction of natural gas prices, environmental regulations and any other factors that might affect the value of these units in serving our customers.

f. Electric Vehicles: Electric vehicles represent the potential for the addition of a large electrical load on SCE&G's system but at present the economics favors gasoline powered cars. Using electricity a car will go about 3 miles per kWh. Some cars will get more miles, 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 runs partly on electricity and partly on gasoline. On gasoline, a car might get 30 miles to the gallon. Again naturally it varies. Assuming the need to drive 15,000 miles per year, a cost of electricity of $0.14 per kWh, and the average miles per unit of fuel just discussed, a table showing the electric driving advantage can be constructed.

Fuel Cost Advantage of Electricity		
Cost of Gasoline $ per Gallon	**All Electric (BEV) $ per Year**	**50% Electric (PHEV) $ per Year**
2.00	$300	$150
3.00	$800	$400
4.00	$1,300	$650
5.00	$1,800	$900

The fuel cost advantage of driving on electricity must be balanced against the capital cost disadvantage. An electric powered car can cost $10,000 to $20,000 more than a similar gasoline powered car. For example the Chevy Volt (PHEV) will cost about $34,000 today. The Toyota Prius (PHEV) and the Nissan Leaf (BEV) both cost about the same. A comparable gasoline powered car such as a Nissan Versa will cost about $15,000. The federal investment tax credit of $7,500 will certainly help close the gap but not completely. A capital cost disadvantage table can be constructed assuming a 5-year load at 2.5%. Below is such a table.

Capital Cost Disadvantage of Electricity	
Added Capital Cost for Electric	**Added Financing Cost $ per Year for 5 Years**
$5,000	$1,065
$10,000	$2,130
$15,000	$3,195
$20,000	$4,260

Today the capital cost disadvantage of an electric car seems to outweigh its fuel cost advantage. For example, at $2.00 per gallon for gasoline, an all-electric car will save about $300 per year in fuel but with a $10,000 premium on the purchase price, it will add $2,130 per year to the financing costs resulting in a net cost increase of $1,830 per year for 5 years. SCE&G will continue to monitor the market for electric cars and analyze their economics for the consumer. With gasoline prices almost certain to rise and the purchase price of electric cars expected to decrease, an economic crossover point should be reached in the future.

Currently there are over 26,000 commercial charging locations in the United States, according to Chargepoint.com, and electric vehicle charging times vary depending on the voltage and amperage levels of the charger and the kW of the onboard vehicle charger. Typically charging times are between 3-7 hours for a full battery charge on BEVs. While costs of batteries are an impediment to lower costs, battery ranges are definitely an impediment to driving distances for most current driving habits. Mileages range from about 10 miles on some PHEVs to over 250 miles on more expensive BEVs. Again, once the economics are more favorable to drive EVs the infrastructure of chargers will grow and therefore make driving an EV cheaper and more driver-friendly.

g. 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. Often these applications require specific, real-time experience by the utility in examining the available battery storage solutions and impact they have to the utility’s transmission and distribution systems. This experience is especially important in determining the potential for cost effectively storing and shifting large amounts of renewable energy generation when coupled together. 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.

h. Projected Loads and Resources: SCE&G’s resource plan for the next 15 years is shown in the table labeled “SCE&G Forecast Loads and Resources – 2016 IRP Plan A” on a subsequent page. To acknowledge some uncertainty about retiring certain units, a Plan B is also documented but Plan A is considered SCE&G’s “Resource Plan”. The resource plan shows the need for additional capacity and identifies, on a preliminary basis, whether the need is for peaking/intermediate capacity or base load capacity.

Line 6 shows the amount of capacity available at the beginning of each summer. On line 7 the resource plan shows the amount of firm solar capacity expected to be available on the system peak hour. This solar capacity includes 82 MWs of DER solar and 196 MWs of non-DER solar. Only 50% of this capacity is assumed firm 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 15 MWs by 2030, the end of the planning horizon.

Line 8 shows the amount of peaking capacity needed. Solar capacity is rated at 50% of installed capacity for planning purposes. The capacity related to the two nuclear units under construction is shown on line 9. On line 10 the resource plan shows decreases in capacity which relate to the retirement of generating units as previously discussed. The need for any firm one year capacity purchases is shown on line 12. The Company has secured the purchase of 300 MWs in the year 2016. Capacity is added to maintain the SCE&G's planning reserve margin above a minimum of 14%. The resource plan thus constructed represents one possible way to reliably meet the increasing demand of our customers. Before the Company commits to adding a new resource, it will perform a study to determine what type resource will best serve our customers.

The Company believes that its supply plan, summarized in the following table, 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.

SCE&G Forecast of Summer Loads and Resources - 2016 IRP Plan A
(MW)

	YEAR	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load Forecast																
1	Baseline Trend	5031	5133	5293	5431	5582	5721	5837	5948	6047	6136	6230	6318	6403	6495	6583
2	EE Impact	-8	-13	-26	-45	-63	-82	-101	-120	-140	-160	-180	-201	-223	-244	-265
3	Gross Territorial Peak	5023	5120	5267	5386	5519	5639	5736	5828	5907	5976	6050	6117	6180	6251	6318
4	Demand Response	-257	-260	-268	-272	-274	-277	-279	-281	-284	-286	-289	-291	-294	-297	-299
5	Net Territorial Peak	4766	4860	4999	5114	5245	5362	5457	5547	5623	5690	5761	5826	5886	5954	6019
System Capacity																
6	Existing	5282	5307	5336	5376	5421	6047	6717	6761	6761	6761	6761	6761	6761	6761	6854
	Additions:															
7	Solar Plant	25	29	40	45											
8	Peaking/Intermediate														93	93
9	Baseload					626	670	44								
10	Retirements															
11	Total System Capacity	5307	5336	5376	5421	6047	6717	6761	6761	6761	6761	6761	6761	6761	6854	6947
12	Firm Annual Purchase	300	225	325	425											
13	Total Production Capability	5607	5561	5701	5846	6047	6717	6761	6761	6761	6761	6761	6761	6761	6854	6947
Reserves																
14	Margin (L13-L5)	841	701	702	732	802	1355	1304	1214	1138	1071	1000	935	875	900	928
15	% Reserve Margin (L14/L5)	17.6%	14.4%	14.0%	14.3%	15.3%	25.3%	23.9%	21.9%	20.2%	18.8%	17.4%	16.0%	14.9%	15.1%	15.4%

SCE&G Forecast of Summer Loads and Resources - 2016 IRP Plan B
(MW)

	YEAR	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load Forecast																
1	Baseline Trend	5031	5133	5293	5431	5582	5721	5837	5948	6047	6136	6230	6318	6403	6495	6583
2	EE Impact	-8	-13	-26	-45	-63	-82	-101	-120	-140	-160	-180	-201	-223	-244	-265
3	Gross Territorial Peak	5023	5120	5267	5386	5519	5639	5736	5828	5907	5976	6050	6117	6180	6251	6318
4	Demand Response	-257	-260	-268	-272	-274	-277	-279	-281	-284	-286	-289	-291	-294	-297	-299
5	Net Territorial Peak	4766	4860	4999	5114	5245	5362	5457	5547	5623	5690	5761	5826	5886	5954	6019
System Capacity																
6	Existing	5282	5307	5336	5376	5421	6047	6372	6416	6416	6416	6509	6602	6695	6788	6788
	Additions:															
7	Solar Plant	25	29	40	45											
8	Peaking/Intermediate										93	93	93	93		93
9	Baseload					626	670	44								
10	Retirements						-345									
11	Total System Capacity	5307	5336	5376	5421	6047	6372	6416	6416	6416	6509	6602	6695	6788	6788	6881
12	Firm Annual Purchase	300	225	325	425											
13	Total Production Capability	5607	5561	5701	5846	6047	6372	6416	6416	6416	6509	6602	6695	6788	6788	6881
Reserves																
14	Margin (L13-L5)	841	701	702	732	802	1010	959	869	793	819	841	869	902	834	862
15	% Reserve Margin (L14/L5)	17.6%	14.4%	14.0%	14.3%	15.3%	18.8%	17.6%	15.7%	14.1%	14.4%	14.6%	14.9%	15.3%	14.0%	14.3%

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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 our 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 our customers. These needs include: 1) distributed load growth of existing residential, commercial, industrial, and wholesale customers, 2) new residential, commercial, industrial, and wholesale customers and 3) customers who use only transmission services on the SCE&G system.

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 more severe 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 short circuit, power flow and stability 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 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 owners completed over the past year:

1. SERC NTSG Reliability 2015 Summer Study
2. SERC NTSG Reliability 2015/2016 Winter Study
3. SERC LTSG 2020 Summer Peak Study
4. SERC NTSG OASIS 2015 January Studies (15Q1)
5. SERC NTSG OASIS 2015 April Studies (15Q2)
6. SERC NTSG OASIS 2015 July Studies (15Q3)
7. SERC NTSG OASIS 2015 October Studies (15Q4)
8. ERAG 2015 Summer Transmission System Assessment
9. CTCA 2020 Summer, 2026 Summer Peak Reliability Study
10. SCRTP 2018 Summer Peak, 2016/17 Winter, and 2018/19 Winter Transfer Studies
11. ERAG 2015 Special Transmission Assessment Weather Based Transfer Analysis (cases are 2015 Summer and 2015/16 Winter)

The acronyms used above have the following reference:

SERC – SERC Reliability Corporation
NTSG – Near Term Study Group
LTSG – Long Term Study Group
OASIS – Open Access Same-time Information System
ERAG – Eastern Interconnection Reliability Assessment 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. These Planning Authorities are entities listed on the NERC compliance registry as Planning Authorities and represent the entire Eastern Interconnection. The EIPC was founded to be a broad-based, transparent collaborative process among all interested stakeholders:

- State and Federal policy makers
- Consumer and environmental interests
- Transmission Planning Authorities
- Market participants generating, transmitting or consuming electricity within 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 guided by the consensus input of an open and transparent stakeholder process.

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.

FERC Order 1000 – Transmission Planning and Cost Allocation

On July 21, 2011, the FERC issued Order 1000 – Transmission Planning and Cost Allocation by Transmission Owning and Operating Utilities. With respect to transmission planning, this Final Rule: (1) requires that each public utility transmission provider participate in a regional transmission planning process that produces a regional transmission plan; (2) requires that each public utility transmission provider amend its OATT to describe procedures that provide for the consideration of transmission needs driven by public policy requirements in the local and regional transmission planning processes; (3) removes from Commission-approved tariffs and agreements a federal right of first refusal for certain new transmission facilities; and (4) improves coordination between neighboring transmission planning regions for new interregional transmission facilities. Also, this Final Rule requires that each public utility transmission provider must participate in a regional transmission planning process that has: (1) a regional cost allocation method for the cost of new transmission facilities selected in a regional transmission plan for purposes of cost allocation; and (2) an interregional cost allocation method for the cost of certain new transmission facilities that are located in two or more neighboring transmission planning regions and are jointly evaluated by the regions in the interregional transmission coordination procedures required by this Final Rule. Each cost allocation method must satisfy six cost allocation principles.

Regional milestones: On October 11, 2012, SCE&G filed with the FERC its proposed actions to achieve compliance with the Regional requirements of Order 1000. On April 18, 2013, FERC conditionally accepted SCE&G's regional filing subject to SCE&G providing more clarity and adding greater detail to SCE&G's compliance plans. On October 15, 2013, SCE&G submitted a second regional filing addressing these points. On May 14, 2014, FERC conditionally accepted SCE&G's regional filing subject to SCE&G providing additional clarity to SCE&G's compliance plans. On July 14, 2014, SCE&G submitted an additional regional filing addressing these points. On January 22, 2015, FERC conditionally accepted SCE&G's regional filing subject to SCE&G providing additional clarity to SCE&G's compliance plans. On February 23, 2015, SCE&G submitted an additional regional filing addressing these points. On June 3, 2015, FERC conditionally accepted SCE&G's regional filing subject to SCE&G providing additional clarity to SCE&G's compliance plans. On July 6, 2015, SCE&G submitted an additional regional filing addressing these points. On August 3, 2015, FERC accepted

SCE&G's regional filing and SCE&G is currently implementing the required practices and procedures.

Interregional milestones: SCE&G worked with its neighboring planning region (Southeastern Regional Transmission Planning "SERTP") to develop actions to achieve compliance with the interregional requirements of Order 1000. On July 10, 2013, SCE&G filed with the FERC its proposed actions to achieve compliance with the interregional requirements of Order 1000. On January 22, 2015, FERC conditionally accepted SCE&G's interregional filing subject to SCE&G providing more clarity and adding greater detail to SCE&G's compliance plans. On March 24, 2015, SCE&G submitted an additional interregional filing addressing these points. On July 30, 2015, FERC accepted SCE&G's interregional filing and SCE&G is currently implementing the required practices and procedures.

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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-year average of the daily values. 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, 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, $f(B) = 1 – f_1\ B - \ldots - f_1\ B^p$

u is the constant term

$q(B)$ is the moving average operator, $q\ (B) = 1 - q_1\ B - \ldots - q_q\ B^q$

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-five 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 4.6%, 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 developed for each major class of service. For the residential class, forecasts were also 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. 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 others. 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, 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 seven 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.