STATE OF SOUTH CAROLINA

South Carolina Electric & Gas Company's Integrated Resource Plan

BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

COVER SHEET

DOCKET NUMBER: 2013 - ____ - 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 Certificatio
☐ Electric/Telecommunications	☐ Answer	☐ Motion	☐ Request for Investigatior
☐ 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	☐ Tariff
☐ Water/Sewer	☐ Expedited Consideration	☐ Proposed Order	☒ Other:
☐ Administrative Matter	☐ Interconnection Agreement	☐ Protest	Integrated Resource Plan
☐ Other:	☐ Interconnection Amendment	☐ Publisher's Affidavit	
	☐ Late-Filed Exhibit	☐ Report	

Matthew W. Gissendanner
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February 28, 2013

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 2013 Integrated Resource Plan
Docket No. 2013-___-E

Dear Ms. Boyd:

In accordance with S.C. Code Ann. § 58-37-40 (Supp. 2012) and Order No. 98-502 enclosed you will find the 2013 Integrated Resource Plan of South Carolina Electric & Gas Company ("SCE&G 2013 IRP"). This filing also serves to satisfy the annual reporting requirements of the Utility Facility Siting and Environmental Protection Act, S.C. Code Ann § 58-33-340.

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 2013 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/mcs

cc: John W. Flitter
Jeffrey M. Nelson, Esquire
Ashlie Lancaster
(all via electronic mail and U.S. First Class Mail w/enclosure)

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2013 -___- E

IN RE:

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

This is to certify that I have caused to be served this day one (1) copy of the **2013 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 addresses set forth:

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Mary C. Salane-Walker

Cayce, South Carolina
This 28th day of February, 2013

2013

Integrated

Resource

Plan

SCE&G®
A SCANA COMPANY

Introduction

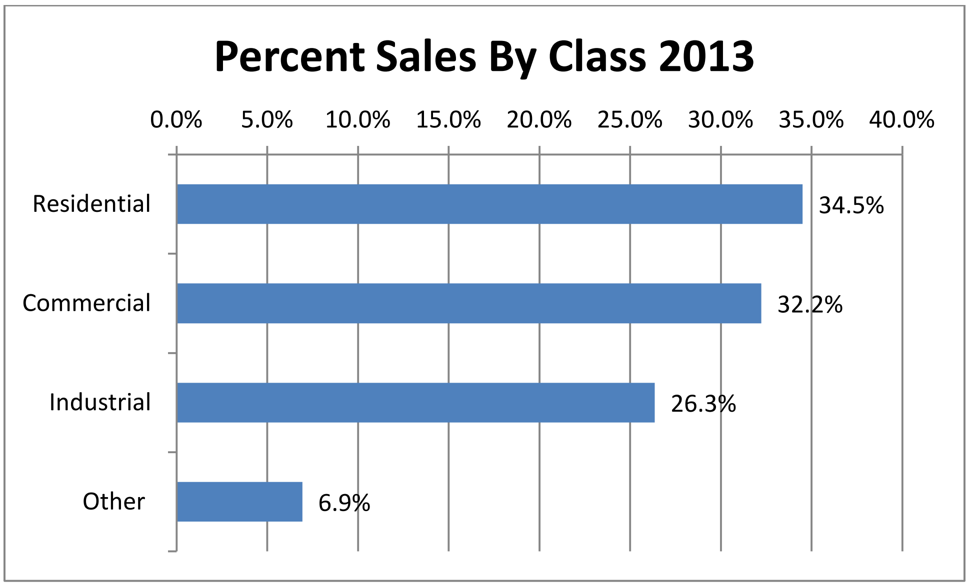
This document presents South Carolina Electric & Gas Company's ("SCE&G" or "Company") Integrated Resource Plan ("IRP") for meeting the energy needs of its customers over the next fifteen years, 2013 through 2027. This document is filed with the Public Service Commission of South Carolina ("Commission") in accordance with S.C. Code Ann. § 58-37-40 (Supp. 2012) 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. 2012). The objective of the Company's IRP is to develop a resource plan that will provide reliable and economically priced energy to its customers.

I. Demand and Energy Forecast for the Fifteen-Year Period Ending 2027

Total territorial energy sales on SCE&G's system are expected to grow at an average rate of 1.1% per year over the next 15 years, while firm territorial summer peak demand and winter peak demand will increase at 1.4% and 1.1% per year, respectively, over this forecast horizon. The table below contains these projected loads.

	Summer Peak (MW)	Winter Peak (MW)	Energy Sales (GWH)
2013	4,778	4,491	22,889
2014	4,868	4,495	23,016
2015	4,909	4,530	23,203
2016	5,034	4,561	23,545
2017	5,096	4,625	23,792
2018	5,161	4,688	24,040
2019	5,248	4,759	24,390
2020	5,325	4,820	24,674
2021	5,388	4,874	24,918
2022	5,463	4,939	25,260
2023	5,545	5,010	25,605
2024	5,614	5,077	25,924
2025	5,680	5,144	26,236
2026	5,741	5,207	26,506
2027	5,793	5,257	26,748

The energy sales forecast for SCE&G is made for over 30 individual categories. The categories are subgroups of our seven classes of customers. The three primary customer classes - residential, commercial, and industrial - comprise more than 90% 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 street lighting, other public authorities, municipalities and electric cooperatives.



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 to each group are based on statistical and econometric models derived from historical relationships.

Energy Efficiency Adjustments

Several adjustments were made to the baseline projections to incorporate significant impacts not reflected in historical experience. These were increased air-conditioning and heat pump efficiency standards and improved lighting efficiencies, both mandated by federal law, and the addition of SCE&G's energy efficiency programs.

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. Since 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 will 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 2006, the minimum Seasonal Energy Efficiency Ratio ("SEER") for newly manufactured appliances was raised from 10 to 13, which means that cooling loads for a house that replaced a 10 SEER unit with a 13 SEER unit would decrease by 30% assuming no change in other factors. The last mandated change to efficiencies like this took place in 1992, when the minimum SEER was raised from 8 to 10, a 25% increase in energy efficiency. Since then air-conditioner and heat pump manufacturers introduced much higher-efficiency units, and models are now available with SEERs over 20. However, overall market production of heat pumps and air-conditioners is concentrated at the lower end of the SEER mandate. The 2006 minimum SEER rating represented a significant change in energy use which would not be fully captured by statistical forecasting techniques based on historical relationships. For this reason an adjustment to the baseline was warranted.

A second 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 take effect in 2013 and will be phased in through 2015. 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 new set of energy efficiency 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.

The following table shows the baseline projection, the energy efficiency adjustments and the resulting forecast of territorial energy sales.

		Energy Efficiency			
	Baseline Sales (GWH)	SCE&G DSM Programs (GWH)	Federal Mandates (GWH)	Total EE Impact (GWH)	Territorial Sales (GWH)
2013	23,017	0	-128	-128	22,889
2014	23,278	0	-262	-262	23,016
2015	23,769	-93	-473	-566	23,203
2016	24,252	-194	-513	-707	23,545
2017	24,633	-290	-551	-841	23,792
2018	25,025	-395	-590	-985	24,040
2019	25,534	-509	-635	-1,144	24,390
2020	26,058	-633	-751	-1,384	24,674
2021	26,553	-767	-868	-1,635	24,918
2022	27,052	-901	-891	-1,792	25,260
2023	27,567	-1,048	-914	-1,962	25,605
2024	28,053	-1,194	-935	-2,129	25,924
2025	28,546	-1,353	-957	-2,310	26,236
2026	29,003	-1,522	-975	-2,497	26,506
2027	29,453	-1,711	-994	-2,705	26,748

Baseline sales are projected to grow at the rate of 1.8% per year. The impact of energy efficiency, both from SCE&G's DSM programs and from federal mandates, causes the ultimate territorial sales growth to fall to 1.1% per year as reported earlier.

The forecast of summer peak demand is developed using a load factor methodology. Load factors for each class of customer are associated with the corresponding forecasted energy to project a contribution to summer peak. The winter peak demand is projected through its correlation with annual energy sales and winter degree-day departures from normal. By industry convention, the winter period is assumed to follow the summer period.

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 200 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
2013	5,016	0	0	0	5,016	-238	4,778
2014	5,111	0	0	0	5,111	-243	4,868
2015	5,210	-19	-31	-50	5,160	-251	4,909
2016	5,369	-37	-42	-79	5,290	-256	5,034
2017	5,470	-61	-54	-115	5,355	-259	5,096
2018	5,571	-84	-65	-149	5,422	-261	5,161
2019	5,697	-108	-77	-185	5,512	-264	5,248
2020	5,819	-135	-93	-228	5,591	-266	5,325
2021	5,929	-164	-108	-272	5,657	-269	5,388
2022	6,040	-193	-112	-305	5,735	-272	5,463
2023	6,159	-223	-116	-339	5,820	-275	5,545
2024	6,267	-256	-119	-375	5,892	-278	5,614
2025	6,375	-291	-123	-414	5,961	-281	5,680
2026	6,481	-329	-127	-456	6,025	-284	5,741
2027	6,581	-372	-130	-502	6,079	-286	5,793

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.

Energy Efficiency

SCE&G's Energy Efficiency programs include Customer Information Programs, Web-Based Information and Services Programs, Energy Conservation and the Demand Side Management Programs. A description of each follows:

1. **Customer Information Programs:** SCE&G's customer information programs fall under two headings: the **Annual Energy Efficiency Campaigns** and **Web-based Information Initiatives**. The following is an overview of each.

   Annual Energy Efficiency Campaigns

   a. **Customer Insights and Analysis:** In 2012, SCE&G continued to proactively educate its customers and create awareness on issues related to energy efficiency and conservation. To help maximize the effectiveness of our campaigns, ongoing customer feedback is used to ensure marketing and communications efforts are consistent with what customers value most. Key insights gained through SCE&G's Brand Health Study and Voice of the Customer Panels are integrated to ensure we are communicating in a consistent manner that customers will understand.

      As a result, SCE&G continues to highlight programs/services that reflect three main categories identified by our customers as offering the best opportunity to save energy and money. These areas include rebates and incentives, in-home services and education.

b. **Media/Channel Preferences:** Placement of all marketing and advertising is carefully considered, taking into the customers' preferred methods of communicating information about SCE&G's energy efficiency programs and services. Priority channels include television (local news and select cable stations); online banner advertising, radio, electronic/print newsletters, direct mail, bill inserts and newspaper (major dailies and weekly minority publications). SCE&G's statewide business office locations also serve as a distribution point for sharing information with customers. In addition, SCE&G has also incorporated social media, e.g. Twitter and Facebook, into its communications strategy. Key South Carolina markets covered with all marketing communications include Columbia, Charleston, Aiken and Beaufort.

c. **Public Affairs/News Media/Speakers Bureau:** Furthermore, SCE&G understands the value of public affairs as an integral part of well-rounded energy efficiency, communication strategy and actively engages news media (broadcast and print) for coverage with key programs and services that will benefit our customers now and in the future. Public Affairs and Marketing staff also provide support with securing company experts to address a variety of organizations through a formal Speakers' Bureau, extending our outreach to church groups, senior citizen and low-income housing communities, civic organizations, builder groups and homeowner associations.

d. **Special Events:** Another key component to SCE&G's annual marketing initiatives include participation in a variety of events that offer the opportunity to further extend customer education and outreach for energy information. SCE&G's 2012 schedule included a solid mix of special events to include the Home Builders Association ("HBA") Home Improvement Show and Tour of Homes in Columbia and Black Expos in Columbia and Charleston. The Company also organized an Energy Day sponsorship with the University of South Carolina.

e. **EnergyWise Communications:** Brand positioning of SCE&G's energy efficiency programs and services with all marketing and advertising initiatives falls under the EnergyWise umbrella – an SCE&G registered trademark in South

Carolina and encompassing **general awareness education** as well as **program specific offerings**.

General Awareness Education: Last year's advertising included messaging on a wide range of topics such as year-round and seasonal energy efficiency tips that are practical for customers to manage on their own or that have a no-cost, low-cost factor to them. Examples include thermostat settings, checking air filters monthly, water heater settings and unplugging appliances that are sometimes perceived to be "energy vampires" (lights, TV's, computers, cell phone chargers, etc.).

Program Specific Offerings: In 2012, SCE&G continued to heavily promote its portfolio of residential electric rebate/incentive programs under its Demand Side Management (DSM) department – many of which were featured in our general awareness advertising schedule. Specific programs included ENERGY STAR Lighting, our free Home Energy Check-up, Home Performance with ENERGY STAR and Residential Heating & Cooling and Water Heater Equipment.

2. **Web-Based Information and Services Programs:** SCE&G's online offerings can be broken into four components: Customer Awareness Information, the Energy Analyzer, free online Energy Audit and EnergyWise e-newsletter. Altogether, there have been more than 4.1 million visits to SCE&G's website in 2012. Customers must be registered to use the interactive tools: Energy Analyzer and Energy Audit. There are over 325,000 customers registered for this access. Descriptions of the four categories listed above follows:

    a. **Customer Awareness Information:** The SCE&G website supports all communication efforts to promote energy savings information – both general awareness tips and program-specific profiles, tools and resources – all through a section called "Be EnergyWise and Save". Energy savings information includes detailed information on each of the Demand Side Management programs for residential and commercial/industrial customers, as well as how-to videos on insulation, thermostats and door and windows. Details on the latest tax credits offered by the American Recovery and Reinvestment Act of

2009 are also available, including links to help customers explore and learn how they can take advantage of these credits.

b. **Energy Analyzer:** The Energy Analyzer, in use since 2004, is a 24-month bill analysis tool. It uses complex analytics to identify a customer's seasonal usages and target the best ways to reduce demand. This Web-based tool allows customers to access their current and historical consumption data and compare their energy usage month-to-month and year-to-year -- noting trends, temperature impact and spikes in their consumption. There were a little over 101,705 visits to the Energy Analyzer tool in 2012.

c. **Online Energy Audit:** The Online Energy Audit tool leads customers through the process of creating a complete inventory of their home's insulation and appliance efficiency. The tool allows customers to see the energy and financial savings of upgrades before making an investment. There were 6,579 customers who used the Energy Audit tool in 2012.

d. **SCE&G EnergyWise E-Newsletter:** SCE&G's web-based information and services included ongoing management of its EnergyWise e-newsletter to support customer demand for additional information on ways to help them save energy. A total of 2,346 customers are registered for the e-newsletters distributed in 2012.

3. 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:

a. **Energy Saver / Conservation Rate**: The Rate 6 (Energy Saver / Conservation) rewards homeowners and homebuilders who upgrade their existing homes or build their new homes to a high level of energy efficiency with a reduced electric rate. This reduced rate, combined with a significant reduction in energy usage, provides for considerable savings for our customers. Participation in the program is very easy as the requirements are prescriptive which is beneficial to all of our customers and trade allies. Homes built to this standard have improved comfort levels and increased resale value over homes built to the minimum building code standard, which is also a significant benefit to participants. Information on this program is available on our website and by brochure.

b. **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.

4. Demand Side Management Programs

In 2012, the Demand Side Management portfolio included nine programs, seven targeting SCE&G's residential customer classes and two targeting SCE&G's commercial and industrial customer classes. A description of each program follows:

a. **Residential Home Energy Reports** provides customers with comparisons of their monthly energy consumption with benchmarks showing average energy consumption by similarly situated energy users. The monthly benchmarking information is provided free of charge to customers who elect to participate in the program.

b. **Residential Energy Information Display** provides customers with an in-home display that shows information from the customer's meter regarding a home's current energy use and cost, and the use and cost to date for the month. The displays were distributed to targeted customers at a discounted price.

c. **Residential Home Energy Check-up and Home Performance with ENERGY STAR®** encourages customers to have an assessment done of the energy efficiency of their homes. It included two tiers of home energy review and assessment.

   i. As a first tier, the **Home Energy Check-up** program was offered to customers. This visual checkup and "check-off" audit was performed by SCE&G staff at the customer's home. As a direct incentive for customers to participate in the program, customers were 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 free of charge to all residential customers who elect to participate.

ii. The **Home Performance with ENERGY STAR®** program goes a step further and provides a comprehensive audit with diagnostic testing of the energy efficiency of the home by trained contractors. SCE&G promotes these audits by independent providers and subsidizes the cost of the audit and specific measures undertaken by customers based on the audit findings.

d. **Residential ENERGY STAR® Lighting** program provides residential customers with incentives for purchasing and installing high-efficiency and ENERGY STAR® qualified lighting.

e. The **Residential Heating & Cooling and Water Heating Equipment** program provides incentives for high efficiency HVAC units and water heaters installed in new and existing homes.

f. The **Residential Heating & Cooling Efficiency Improvements** program provides residential customers with incentives for investing in a comprehensive system optimization and other improvements to their HVAC systems.

g. Customers and builders willing to commit to overall high standards of energy efficiency in new construction may receive incentives under the **Residential ENERGY STAR® New Homes** program. This program provides incentives based on a comprehensive analysis of the energy efficiency of new homes reflecting both the construction techniques used and the appliances installed.

h. The **Commercial and Industrial Prescriptive** program provides lighting 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 measures and incentive levels that are easily accessible to commercial and industrial customers on the website.

i. **Commercial and Industrial Custom** program provides tailored 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.

5. 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 but because of recent environmental regulations, it is unclear whether this program can survive. On March 3, 2010, the United States Environmental Protection Agency ("EPA") published regulations restricting the operation of certain reciprocating internal combustion engines ("RICE"). These RICE regulations restrict the operation of the generators in our retail standby generator program and require that a system emergency be declared before they operate. SCE&G is working with customers who participate in this program to see if the program can be continued. Until there is a resolution the approximately 16 megawatts of capacity in the program has been removed from the Company's resource plan

b. **Interruptible Load Program:** SCE&G has over 150 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.

e. **Demand Response Technologies:** With the retirement of coal capacity and the increased reserve margin target, both discussed later in this document, the Company's resource plan reflects that SCE&G will require additional capacity in order to continue providing reliable electric service to its customers. As SCE&G evaluates how to satisfy this need, the Company will consider, among other things, demand response technologies.

B. Supply Side Management

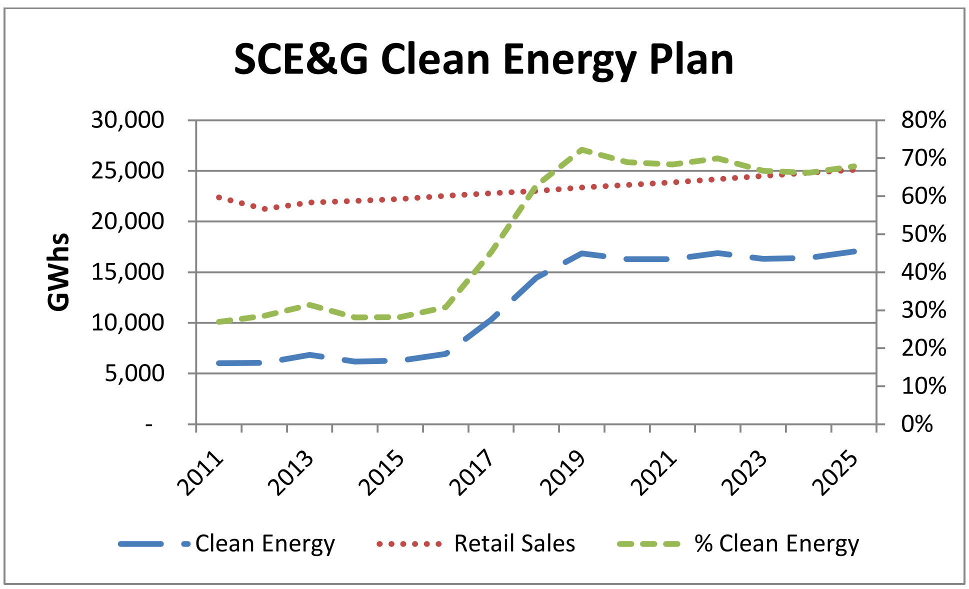
Clean Energy at SCE&G

Clean energy includes energy efficiency and clean energy supply options like nuclear power, hydro power, combined heat and power as well as 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 net metering 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 by GWH and as a percentage of retail sales.



As seen in the chart, SCE&G currently generates nearly 30% of its retail sales from clean energy sources and by 2019 expects to generate about 72%.

b. 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 which are used to produce renewable energy and the electricity generated qualify for Renewable Energy Certificates ("REC") as approved by Green-e Energy, a leading national independent certification and verification program for renewable energy administered by the Center for Resource Solutions, a nonprofit company based in San Francisco, California. Over the last few years SCE&G generated the following amounts of renewable energy from 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%

c. 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, having an alternating current peak output of 2.35 MW, began generating in October 2011. 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. The 2012 solar generation from this facility was 3513 MWHs.

d. Net Metering 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 power their homes or businesses and sell the excess energy back to SCE&G. For residential customers, the generator output capacity cannot exceed the annual maximum household demand or 20 KW, whichever is less. For small commercial customers, the generator output capacity cannot exceed the annual maximum demand of the business or 100 KW, whichever is less. 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.

e. Palmetto Clean Energy, Inc.: Palmetto Clean Energy, Inc. (“PaCE”) is a non-profit, tax exempt organization formed 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 subsidizing renewable power in South Carolina. Customers make a tax deductible payment to PaCE and PaCE uses the funds collected to pay renewable generators a supplemental fee 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 off-shore wind activities in the state, co-firing with biomass fuels, studying smart grid opportunities and distribution automation. These activities are set forth in more detail below.

a. Off-Shore Wind Activities: SCE&G currently participates 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 is to identify and overcome existing barriers for coastal clean energy development for wind, wave and tidal energy projects in South Carolina. Efforts include 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 is to foster a regulatory environment conducive to wind, wave and tidal energy development in state waters. The Regulatory Task Force is comprised of state and federal regulatory and resource protection agencies, universities, private industry and utility companies.

SCANA/SCE&G also participated in discussions to locate a 40 MW demonstration wind farm off the coast of Georgetown. This effort, known as Palmetto Wind, includes 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.

SCANA/SCE&G is a founding member of the Southeastern Coastal Wind Coalition and will be participating 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 will be three fold:

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

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

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

b. Co-firing with Biomass: In 2010, SCE&G began a project to investigate and evaluate the co-firing of biomass and other engineered waste products in our existing coal burning facilities. The goal of the project is to determine the operational practicality as well as the economic and fuel supply implications of co-firing in existing coal units. Co-firing of biomass fuel in our existing units represents an opportunity to include additional renewable fuels in our production mix without having to build new facilities or spend significant capital on existing facilities.

The Company has purchased and set up mobile fuel handling equipment to facilitate testing of different types of biomass and other waste materials at multiple facilities. Tests with different forms of biomass material are ongoing and the results are being evaluated by the Fossil Hydro department to determine a future course of action.

c. New Renewable Projects: SCE&G has met with several companies that are considering developing renewable facilities in South Carolina and who wish to sell power to SCE&G through a long term purchased power agreement. SCE&G evaluates all power proposals to determine if the power is needed and can be supplied at a price that is competitive with other supply alternatives. The Company will continue to evaluate opportunities in the renewable market sector, but the power must be economical for our customers.

SCE&G also continues to monitor state and federal bills that, if enacted, would mandate a federal or state renewable portfolio standard ("RPS"). One of the primary purposes of an RPS is to increase the amount of clean energy produced in the U.S. The bills proposed, but not passed, in 2010 required 15-20% of utilities' retail sales to come from renewable sources by year 2020. Qualified renewable sources include wind, solar, geothermal, biomass, qualified hydro-power, and marine and hydrokinetic renewable energy. The most viable renewable energy source in S.C. is woody biomass. Off-shore wind energy and solar energy are available but are uneconomic today. SCE&G will follow the development of these technologies and will include them in its resource mix when appropriate.

d. Smart Grid Activities: SCE&G currently has approximately 9,000 AMI 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 application enabling these customers to have quick access to energy usage allowing better management of their energy consumption. Moving forward, this technology will also enable more sophisticated DSM offerings that may be attractive to a variety of customer classes.

e. 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 over 800 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 help these automated devices communicate with each other and safely reconfigure the system in a fully automated fashion.

f. Environmental Mitigation Activities: In order to reduce NO_X emissions and to meet compliance requirements, SCE&G installed Selective Catalytic Reduction ("SCR") equipment at Cope Station in the fall of 2008. The SCR began full time operation on January 1, 2009, and has run well since that time. It is capable of reducing NO_X emissions at Cope Station by approximately 90%. SCE&G is also utilizing the existing SCRs at Williams and Wateree Station along with previously installed low NO_X burners at the other coal-fired units to meet the Clean Air Interstate Rule ("CAIR") requirements for NO_X which are in effect while the Cross State Air Pollution Rule is under a court-ordered stay. Additionally, SCE&G has installed flue gas desulfurization ("FGD") equipment, commonly known as wet scrubbers, at Williams and

Wateree Station to reduce SO_2 emissions. The in-service date for Williams and Wateree Stations were February 25, 2010, and October 12, 2010, respectively. Scrubber performance tests at both stations met the SO_2 designed removal rate of 98%.

During 2010, SCE&G worked with a contractor to test a Chem-Mod fuel additive that was expected to reduce SO_2, NO_X and mercury at Urquhart 3, Canadys, and McMeekin units. Test results through a third party indicate emissions reductions of more than 30% mercury, more than 7% NO_X, and a 2 – 3% SO_2 reduction. SCE&G recently received a SCDHEC permit for on-going use of Chem-Mod at McMeekin, Canadys and Urquhart Stations.

Through recent testing, reduction in mercury is occurring as a result of the scrubber installations. SCE&G is currently quantifying the removal efficiency of mercury through third party testing. Any reductions in emissions resulting from the use of the Chem-Mod fuel additive will be a benefit to the environment of South Carolina.

g. Nuclear Power in the Future – Small and Modular: Small Modular Reactor ("SMR") technology continues to be developed. 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. SCE&G is positioned to support continuing development of SMR technology.

3. Summary of Proposed and Recently Finalized Regulations

The EPA has either proposed or recently finalized 6 regulations and modified one additional regulation. These are Cross-State Air Pollution Rule ("CSAPR"), Mercury and Air Toxics Standards ("MATS"), Greenhouse Gases, Cooling Water Intake Structures, Coal Combustion Residuals, Effluent Limitation Guidelines, and a new 1-hour sulfur dioxide National Ambient Air Quality Standard ("NAAQS").

a. Cross-State Air Pollution Rule ("CSAPR")

On December 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit issued a stay delaying implementation of CSAPR pending the outcome of a legal appeal. On August 21, 2012, the U.S. Court of Appeals for the D.C. Circuit vacated CSAPR and left CAIR in place. The federal court ordered the EPA to continue administering the previously promulgated CAIR. On October 5, 2012, the EPA filed a petition for rehearing of the order. On

January 24, 2013, the United States Court of Appeals for the D.C. Circuit denied EPA's petition for rehearing. The Court ordered EPA to continue to enforce the 2005 CAIR until CSAPR could be re-issued. EPA may ask the Supreme Court to consider the case.

CSAPR, which was intended to replace CAIR, was initially finalized in July 2011 under the Clean Air Act and would affect 27 states including South Carolina, requiring reductions in sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emissions beginning in 2012, with stricter reductions in 2014. The rule established an emissions cap for SO_2 and NO_X and limited the trading region for emission allowances by separating affected states into two groups with no trading between the groups.

SCE&G Fossil Hydro generation is in compliance with emission limits set by CSAPR and CAIR.

b. Mercury and Air Toxics Standards ("MATS")

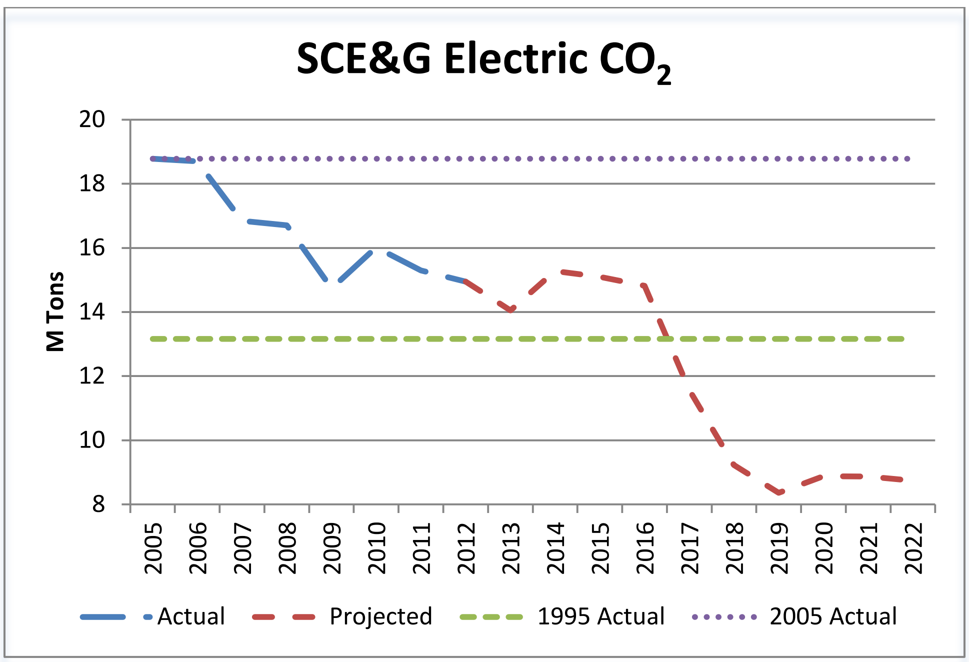
Proposed under the Clean Air Act, this rule sets numeric emission limits for mercury, particulate matter as a surrogate for toxic metals, and hydrogen chloride as a surrogate for acid gases. The final rule also revises new source performance standards for power plants to address emissions of particulate matter, sulfur dioxide and nitrogen oxides. The rule would replace the court-vacated Clean Air Mercury Rule. MATS was proposed in May 2011, and the final rule was issued on December 21, 2011.

The rule became effective on April 16, 2012. Compliance with MATS is required within three years. A 1-year extension may be granted by the state permitting authorities if additional time is needed for units that are required to run for reliability purposes which would otherwise be deactivated, or which, due to factors beyond the control of the owner/operator, have a delay in installation of controls or need to operate because another unit has had such a delay. It is expected that coal-fired generators will need to have a combination of flue gas desulfurization, selective catalytic reduction and fabric filters in order to comply with the standards. A second year of extension may also be possible for reliability critical units that qualify for an Administrative Order at the end of the 1-year extension. All extension requests must be supported by the written concurrence of the appropriate Planning Authority and will be considered by EPA on a case-by-case basis, supplemented by consultation with FERC and/or other entities with relevant reliability expertise as appropriate.

c. Greenhouse Gases

This rule, proposed under the Clean Air Act, would establish performance standards for new and modified generating units, along with emissions guidelines for existing generating units. This action will amend the new source performance standards ("NSPS") for electric generating units ("EGU") and will establish the first NSPS for greenhouse gas ("GHG") emissions. The Rule essentially requires all new fossil fuel-fired power plants to meet the carbon dioxide ("CO_2") emissions profile of a combined cycle natural gas plant. While most new natural gas plants will not be required to include any new technologies, no new coal plants can be constructed without carbon capture and sequestration ("CCS") capabilities. The first part of this rule, related to new generation sources, was released in April 2012 and is expected to become final in March 2013. The part related to existing generation sources is expected later.

SCE&G's new nuclear generation will minimize CO_2 concerns going forward.



d. Cooling Water Intake Structures

Proposed under section §316(b) of the Clean Water Act, this rule is intended to reduce damage to aquatic life through impingement, when organisms are trapped against inlet screens, or entrainment, when they are drawn into the generator's cooling water system. Facilities that withdraw at least 2 million gallons per day would be subject to a limit on the number of fish that can be killed through impingement. Facilities that withdraw at least 125 million gallons per day and new units at existing facilities may be subject to more stringent restrictions. The rule was proposed in April 2011, and a final rule is expected in June 2013.

There is considerable uncertainty regarding when the regulations would be effective and the steps that would have to be taken in order to meet them. Facilities must comply with Best Available Technology Standards within 8 years, but many required submittals are due much earlier, as early as six months after rule promulgation. Compliance actions range from enhanced screening and reconfiguration of water intake systems to installation of cooling towers to reduce the flow rate. On SCE&G's system, Jasper, Cope, Canadys and Wateree Stations have closed cycle cooling towers installed and should not be significantly affected by these regulations.

e. Coal Combustion Residuals

In response to concerns over the potential structural failure of coal ash impoundment facilities instigated by the December 2008 failure that occurred at a Tennessee Valley Authority facility, EPA has proposed changing the classification of coal combustion residuals from its current status of an exempt waste. Two options were proposed under the Resource Conservation and Recovery Act: (1) list residuals as special hazardous wastes when destined for disposal in landfills or surface impoundments or (2) regulate as a non-hazardous waste. The proposed rule was released in June 2010 and comments were received through November 2010. EPA did not issue the rule during 2012 as indicated and has not specified when a final rule will be issued. The effective date is believed to be dependent on which option is selected. If coal combustion residuals are classified as non-hazardous wastes, the compliance date is expected to be around 2018. A special hazardous waste designation would likely push compliance out until about 2020. On January 18, 2012, several environmental groups, led by Earthjustice, filed a notice of intent to sue the EPA to force the agency to finalize its proposed rule determining how coal combustion residuals (commonly referred to as "coal ash") will be categorized. On January 22, 2013, the Court in the coal combustion residuals ("CCR") deadline litigation postponed the status conference in the case until April 26, 2013.

f. Effluent Limitation Guidelines

The Clean Water Act ("CWA") establishes the basic structure for regulating discharges of pollutants into the waters of the United States. It provides EPA and the States with a variety of programs and tools to protect and restore the nation's waters. These programs and tools generally rely either on water quality-based controls, such as water quality standards and water quality-based permit limitations, or technology-based controls such as effluent guidelines and technology-based permit limitations. The EPA is currently developing a proposed rule to amend the effluent guidelines and standards for the Steam Electric Power Generating category. Once issued, the Steam Electric effluent guidelines and standards will be incorporated into State administered wastewater permits known as National Pollutant Discharge Elimination System ("NPDES") permits. EPA's decision to proceed with a rulemaking was announced on September 15, 2009, following completion of a preliminary study. EPA reviewed wastewater discharges from power plants and the treatment technologies available to reduce pollutant discharges, which demonstrated the need to update the current effluent guidelines. EPA believes that the current regulations, which were last updated in 1982, do not adequately address the pollutants being discharged and have not kept pace with changes that have occurred in the electric power industry over the last three decades. EPA's main reason for this concern is that the air pollution control technologies that have been retrofitted to power plants in order to reduce air emissions put a majority of those contaminants into the wastewater discharge. In 2010, EPA submitted an Information Collection Request ("ICR") to all electric utilities to aid in their review of plant operations, pollution control technologies, and current wastewater discharges. Consequently, SCE&G expended considerable time and resources to answer a 213-page questionnaire for each of its electric generating facilities.

The next step is for EPA to sign a notice of proposed rulemaking which is expected by April 19, 2013, and to then sign a decision taking final action by May 22, 2014. When this happens, 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.

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. EPA also required states to install new monitors by

January 1, 2013. Compliance requires both monitoring and refined dispersion modeling of SO_2 sources to meet the new standard.

The new 1-hour national ambient air quality standard ("NAAQS") for SO_2 presents new challenges and is driving strategic planning for large SO_2 emitters around the country. For this new standard, EPA is requiring the unusual step of using air quality modeling for criteria pollutant attainment designations. EPA released its draft guidance for this State Implementation Plan ("SIP") modeling and now the states are gearing up for their designation modeling efforts. However, later guidance issued during June 2012 indicates that they intend to back off of the modeling requirement.

Historically, ambient air monitoring data has provided the basis for attainment designations. The shift to using models instead of ambient data poses significant challenges. For example, due to the stringent nature of the short term SO_2 standards, the conservative nature of the models and use of conservative inputs in the model (short-term emission limits), the results can significantly overstate reality. Also there are likely to be surprises for historically grandfathered sources or even new well-controlled sources.

4. Supply Side Resources at SCE&G

a. Existing Supply Resources

SCE&G owns and operates eight (8) coal-fired fossil fuel units (2,249 MW), one (1) gas-fired steam unit (95 MW), eight (8) combined cycle gas turbine/steam generator units (gas/oil fired, 1,310 MW), sixteen (16) peaking turbine units (352 MW), four (4) hydroelectric generating plants (218 MW), and one Pumped Storage Facility (576 MW). 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 4,885 MW. These ratings, which are updated at least on an annual basis, reflect the expectation for the coming summer season. When SCE&G's nuclear capacity (648 MW), a long term capacity purchase (25 MW) and additional capacity (22 MW) provided through a contract with the Southeastern Power Administration are added, SCE&G's total supply capacity is 5,580 MW. This is summarized in the table on the following page.

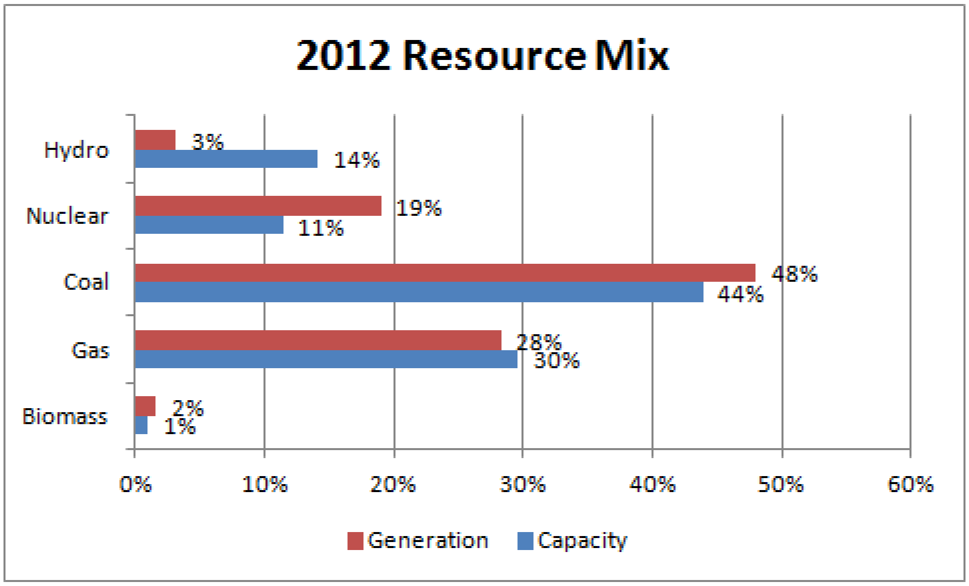
Existing Long Term Supply Resources

The following table shows the generating capacity that is available to SCE&G in the summer of 2013.

	In-Service Date	Summer (MW)
Coal-Fired Steam:		
McMeekin – Near Irmo, SC	1958	250
Canadys - Canadys, SC	1962	295
Wateree – Eastover, SC	1970	684
*Williams – Goose Creek, SC	1973	605
Cope - Cope, SC	1996	415
Kapstone – Charleston, SC	1999	85
Total Coal-Fired Steam Capacity		2,334
Gas-Fired Steam:		
Urquhart – Beech Island, SC	1953	95
Nuclear:		
V. C. Summer - Parr, SC	1984	648
I. C. Turbines:		
Hardeeville, SC	1968	9
Urquhart – Beech Island, SC	1969	39
Coit – Columbia, SC	1969	28
Parr, SC	1970	60
Williams – Goose Creek, SC	1972	40
Hagood – Charleston, SC	1991	128
Urquhart No. 4 – Beech Island, SC	1999	48
Urquhart Combined Cycle – Beech Island, SC	2002	458
Jasper Combined Cycle – Jasper, SC	2004	852
Total I. C. Turbines Capacity		1,662
Hydro:		
Neal Shoals – Carlisle, SC	1905	3
Parr Shoals – Parr, SC	1914	7
Stevens Creek - Near Martinez, GA	1914	8
Saluda - Near Irmo, SC	1930	200
Fairfield Pumped Storage - Parr, SC	1978	576
Total Hydro Capacity		794
Other: Long-Term Purchases		25
SEPA		22
Grand Total:		5,580

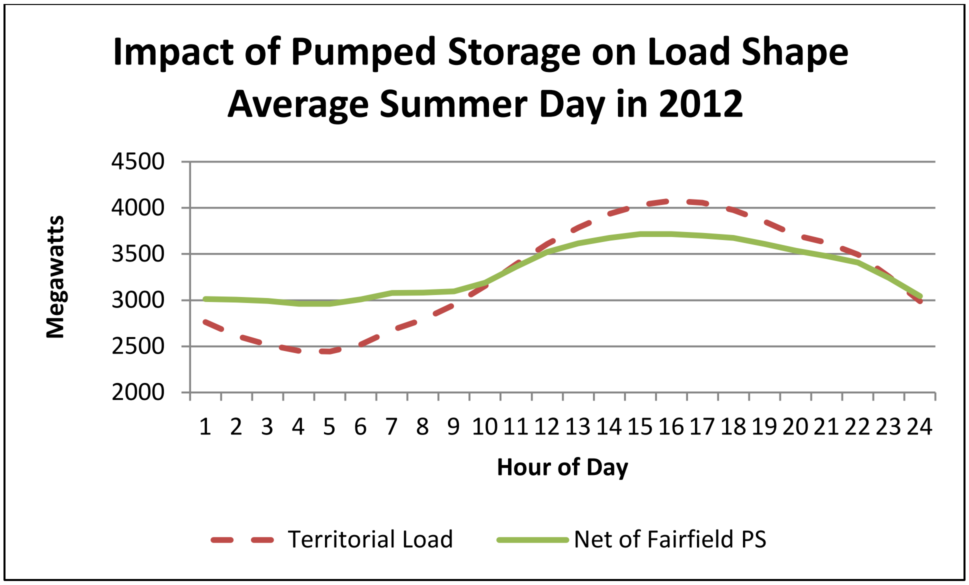
* Williams Station is owned by GENCO, a wholly owned subsidiary of SCANA and is operated by SCE&G. Not reflected in the table is a solar PV generator owned by SCE&G with a nominal direct current rating of 2.6 MWs.

The bar chart below shows the actual 2012 relative energy generation and the relative capacity by fuel source.



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 330 MWs from the daily peak times of 2:00pm through 6:00pm and to move about 3.3% 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	766	16.0%	1016	21.3%
LOLP	721	14.4%	1171	23.5%
Largest Unit	644	13.5%	966	20.2%
	644		1171	
Reserve Policy		14.0%		20.0%

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. The first unit is expected to come online in March 2017 and the second in May 2018. SCE&G will own 55% of the units (614 MWs each) while Santee Cooper will own 45%.

e. Retirement of Coal Plants

SCE&G has six small coal-fired units in its fleet totaling 730 MWs that range in age from 45 to 57 years that cannot meet the emission standards set by the EPA's Mercury and Air Toxics Standards ("MATS") 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

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 #1 and has converted Urquhart #3 to be fired with natural gas while dismantling the coal handling facilities at this unit. The capacity of the remaining four coal-fired units (545 MW) is required to maintain system reliability until the new nuclear capacity is available. Under the MATS regulations they cannot run after April 15, 2015.

[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 retirement of the six coal-fired units, the Company will continue to monitor, among other things, developments in environmental regulation and will continue to analyze its options and modify the plan as needed to benefit its customers.").

The Company is currently looking at ways to bridge the gap between the MATS compliance date and the availability of the new nuclear capacity.

f. Scenario Planning and Risk

There is considerable uncertainty associated with planning for the future. To help understand some of the related risk, the Company analyzed three alternate scenarios: 1) an increased level of energy efficiency in our programs; 2) an increase in load perhaps caused by improved economic conditions; and 3) the addition of more renewable power in the generation portfolio with the goal of offsetting about 5% of retail sales.

1. Increased Energy Efficiency Scenario:

A scenario based on an increased level of energy efficiency was considered in the resource planning process. To measure the system benefit it was assumed that a level of energy efficiency could be achieved to eliminate the last peaking turbine in the resource plan, that is, that the incremental impact of increased energy efficiency would be a reduction in peak demand of 93 megawatts in 2026. If a linear progression to this end is assumed, the result is an increasing peak reduction of 7.75 megawatts each year starting in 2015. Based on a load factor of 54% for this new energy efficiency program, there is an associated reduction in energy of about 440 GWHs by 2026.

The table below shows the accumulated effect in the peak forecast.

		Resource Plan			Capacity Change	
Year	Firm Peak	One Year Purchase	Long Term Capacity	Incremental Peak Impact	One Year Purchase	Long Term Capacity
2013	4778			0		
2014	4868			0		
2015	4909	25		8		
2016	5034	175		16		
2017	5096		319	23		
2018	5161		274	31		
2019	5248			39		
2020	5325			47		
2021	5388			54		
2022	5463		93	62		-93
2023	5545		93	70		
2024	5614		93	78		
2025	5680		93	85		
2026	5741		93	93		-93
2027	5793			101		93

In the last two columns of the table, it can be seen that 93 megawatts was removed from the 15-year planning horizon, and an additional 93 megawatts was delayed within the planning horizon. Over the 30 year study period and assuming that the displaced megawatts were combustion turbines, the value of the reduced energy in terms of reduced revenue requirements was $0.092 per kWh on a levelized basis. On an economic basis, i.e., escalating the value at an inflation rate of 2%, the value is $0.072 per kWh. The cost of CO_2 emissions is assumed to be $30 per ton beginning in 2017 and escalating at 5% per year. If the cost of CO_2 were set to $0 per ton, then the levelized value would be $0.075 per kWh and the economic value would be $0.059 per kWh.

2**. High Load Growth Scenario:**

A scenario with higher load growth was studied. In this scenario it was assumed that the peak demand and sales grew at a rate similar to what SCE&G experienced prior to the last recession, i.e., the peak demand is assumed to grow at 2.2% per year instead of 1.4% in the base case. The following table shows the higher peak demands and what it implies in the need for additional capacity.

	Resource Plan				Changed Capacity	
Year	Firm Peak	One Year Purchase	Long Term Capacity	High Load Peak	One Year Purchase	Long Term Capacity
2013	4778			4778		
2014	4868			4868		
2015	4909	25		5009	125	
2016	5034	175		5195	200	
2017	5096		319	5312	175	
2018	5161		274	5430	50	
2019	5248			5564		186
2020	5325			5700		186
2021	5388			5826		186
2022	5463		93	5949		
2023	5545		93	6083		93
2024	5614		93	6206		
2025	5680		93	6327		93
2026	5741		93	6426		
2027	5793			6514		93

In the last columns of the table it can be seen that by 2027, this increased load would require 837 megawatts of additional capacity to maintain a minimum reserve margin of 14%. Over the 30 year study period and assuming the displaced capacity was from combustion turbines, the cost of the increased energy in terms of additional revenue requirements was \$0.108 per kWh on a levelized basis. On an economic basis, i.e., escalating the value at an inflation rate of 2%, the value is \$0.081 per kWh. The cost of CO_2 emissions is assumed to be \$30 per ton escalating at 5%. If the cost of CO_2 were set to \$0 per ton, then the levelized value would be \$0.081 and the economic value would be \$0.061 per kWh.

3**. Renewable Power Scenario:**

Three sources of renewable power were considered separately: i) solar power, ii) off-shore wind power and iii) biomass power. Each was assumed to provide approximately 5% of retail sales starting in 2015. The following table summarizes the key assumptions about each.

Technology	Energy (GWH)	Capacity (MW)	Capacity Factor	Firm Capacity (MW)	Overnight Cost* (2013$/kW)
Solar	1,015	700	17%	427	3,959
Wind	1,143	350	37%	0	6,368
Biomass	1,439	200	82%	200	4,204
*Overnight construction costs are based on the EIA's Annual Energy Outlook for 2013. Two percent escalation is assumed.					

i) Solar Scenario Results:

The following table shows how the addition of this solar power affected the resource plan.

		Resource Plan			Capacity Change	
Year	Firm Peak	One Year Purchase	Long Term Capacity	Firm Solar Capacity	One Year Purchase	Long Term Capacity
2013	4778					
2014	4868					
2015	4909	25		427	-25	
2016	5034	175			-175	
2017	5096		319			
2018	5161		274			
2019	5248					
2020	5325					
2021	5388					
2022	5463		93			-93
2023	5545		93			-93
2024	5614		93			-93
2025	5680		93			-93
2026	5741		93			-93
2027	5793					93

Adding 700 megawatts of solar capacity in 2015 with 427 megawatts coincidental with the system peak eliminates the one year purchases of 25 and 175 megawatts occurring in 2015 and 2016 as well as removing 372 megawatts from the 15 year planning horizon and delaying the need for another 93 megawatts. Over the 30 year study period and assuming the displaced capacity comes from combustion turbines, the value of the solar energy to the system ignoring its cost was $0.073 per kWh on a levelized basis. On an economic basis, i.e., escalating the value at an inflation rate of 2%, the value is $0.060 per kWh. Removing the cost of CO_2 emissions of $30 per ton the levelized value becomes $0.066 and the economic value $0.054. If SCE&G built and owned the solar generators at a construction cost of $3,959 per kW, the levelized cost of the power to our customers over the same 30-year period would be $0.292 per kWh. If the construction cost of solar power drops to $2,000 per kW, then the levelized cost would be $0.148 per kWh.

ii) Off Shore Wind Scenario Results:

The following table shows how the addition of this off shore wind power affected the resource plan.

Year	Firm Peak	Resource Plan: One Year Purchase	Resource Plan: Long Term Capacity	Firm Wind Capacity	Capacity Change: One Year Purchase	Capacity Change: Long Term Capacity
2013	4778					
2014	4868					
2015	4909	25		0		
2016	5034	175				
2017	5096		319			
2018	5161		274			
2019	5248					
2020	5325					
2021	5388					
2022	5463		93			
2023	5545		93			
2024	5614		93			
2025	5680		93			
2026	5741		93			
2027	5793					

Adding 350 megawatts of off shore wind capacity in 2015 does not displace any capacity in our resource plan because the output of wind turbines is too intermittent and cannot be depended on to serve the system peak. Over the 30 year study period, the value of the off shore wind energy to the system ignoring its cost was $0.066 per kWh on a levelized basis. On an economic basis, i.e., escalating the value at an inflation rate of 2%, the value is $0.055 per kWh. Removing the cost of CO_2 emissions of $30 per ton the levelized value becomes $0.046 per kWh and the economic value $0.038 per kWh. If SCE&G built and owned the off shore wind generators at a construction cost of $6,368 per kWh, the levelized cost of the power to our customers over the same 30-year period would be $0.297 per kWh.

iii) Biomass Scenario Results:

The following table shows how the addition of this biomass power affected the resource plan.

Year	Firm Peak	Resource Plan One Year Purchase	Resource Plan Long Term Capacity	Firm Biomass Capacity	Capacity Change One Year Purchase	Capacity Change Long Term Capacity
2013	4778					
2014	4868					
2015	4909	25		200	-25	
2016	5034	175			-175	
2017	5096		319			
2018	5161		274			
2019	5248					
2020	5325					
2021	5388					
2022	5463		93			-93
2023	5545		93			-93
2024	5614		93			
2025	5680		93			
2026	5741		93			-93
2027	5793					93

Adding 200 megawatts of biomass capacity in 2015 eliminates the one year purchases of 25 and 175 megawatts occurring in 2015 and 2016 as well as removing 186 megawatts from the 15 year planning horizon and delaying another 93 megawatts. Over the 30 year study period and assuming the displaced capacity comes from combustion turbines, the value of the biomass energy to the system ignoring its cost was $0.073 per kWh on a levelized basis. On an economic basis, i.e. escalating the value at an inflation rate of 2%, the value is $0.061 per kWh. Removing the cost of CO_2 emissions of $30 per ton the levelized value becomes $0.056 per kWh and the economic value $0.046. If SCE&G built and owned the biomass generators at a construction cost of $4,204 per kW, the levelized cost of the power to our customers over the same 30-year period would be $0.094 per kWh.

Scenario Planning and Risk – Summary and Conclusions

SCE&G considered five different future scenarios and measured the impact of each on the revenue required to serve our customers. The results are summarized in the following table:

30-Year Levelized and Economic Values $/KWH				
	CO2@$30		CO2@$0	
	Levelized	Economic	Levelized	Economic
Higher Energy Efficiency	$0.092	$0.072	$0.075	$0.059
Higher Load Growth	$0.108	$0.081	$0.081	$0.061
Renewable Power Scenarios				
Solar	$0.073	$0.060	$0.066	$0.054
Off Shore Wind	$0.066	$0.055	$0.046	$0.038
Biomass	$0.073	$0.061	$0.056	$0.046

Since the values in this table are based on generic load profiles and unspecified projects and since they span a 30 year planning horizon, they should be considered as only indicative of the relevant values. For the short term, the best results to use to value the relevant energy are in the last column of the table, i.e., the economic values with CO_2 set to $0 per ton. Using this column will mitigate some of the distortion caused by 30 years of escalating prices and will recognize that for the present there is no cost associated with emitting CO_2. The two scenarios of higher energy efficiency and higher load growth have approximately the same value for the change in energy—about 6 cents per KWH. This result reflects a utility valuation. SCE&G, however, relies heavily on the Total Resource Cost (“TRC”) test to value its DSM programs and relies less on a utility cost analysis. Regarding the renewable power scenarios, again referring to the last column in the table, it is seen that the energy from a solar plant has a greater value to the system than either that of off shore wind or biomass and that off shore wind energy has the least value. This is the result of their hourly profiles. Solar provides energy during sunlight hours which is for the most part peak periods on the system while off shore wind provides much of its energy at night and receives a much reduced value. Biomass is a base load resource running almost all the time, and its value falls in between solar and off shore wind. Unfortunately on a per KW basis solar provides the least amount of energy—about one half that of wind and about one fifth that of biomass.

g. 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 – 2013 IRP ” on a subsequent page. 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.

On line 11 the resource plan shows decreases in capacity which relate to the retirement of coal units as previously discussed. The resource plan shows the addition of peaking capacity on line 9 and the need for any firm one year capacity purchases on line 13. Capacity is added to maintain the SCE&G's planning reserve margin within the target range. The resource plan thus constructed represents one possible way to 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 is best to 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 - 2013 IRP

	YEAR	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Load Forecast																
1	Baseline Trend	5016	5111	5211	5374	5470	5571	5698	5819	5930	6040	6159	6267	6375	6480	6580
2	EE Impact	0	0	-51	-84	-115	-149	-186	-228	-273	-305	-339	-375	-414	-455	-501
3	Gross Territorial Peak	5016	5111	5160	5290	5355	5422	5512	5591	5657	5735	5820	5892	5961	6025	6079
4	Demand Response	-238	-243	-251	-256	-259	-261	-264	-266	-269	-272	-275	-278	-281	-284	-286
5	Net Territorial Peak	4778	4868	4909	5034	5096	5161	5248	5325	5388	5463	5545	5614	5680	5741	5793
6	Firm Contract Sales															
7	Total Firm Obligation	4778	4868	4909	5034	5096	5161	5248	5325	5388	5463	5545	5614	5680	5741	5793
System Capacity																
8	Existing	5580	5580	5580	5580	5580	5899	6168	6168	6168	6168	6261	6354	6447	6540	6633
	Additions															
9	Peaking/Intermediate										93	93	93	93	93	
10	Baseload					614	614									
11	Retirements					-295	-345									
12	Total System Capacity	5580	5580	5580	5580	5899	6168	6168	6168	6168	6261	6354	6447	6540	6633	6633
13	Firm Annual Purchase			25	175											
14	Total Production Capability	5580	5580	5605	5755	5899	6168	6168	6168	6168	6261	6354	6447	6540	6633	6633
Reserves																
15	Margin (L14-L7)	802	712	696	721	803	1007	920	843	780	798	809	833	860	892	840
16	% Reserve Margin (L15/L7)	16.8%	14.6%	14.2%	14.3%	15.8%	19.5%	17.5%	15.8%	14.5%	14.6%	14.6%	14.8%	15.1%	15.5%	14.5%
17	% NERC Res.Mrgn L15/(L7-L4)	16.0%	13.9%	13.5%	13.6%	15.0%	18.6%	16.7%	15.1%	13.8%	13.9%	13.9%	14.1%	14.4%	14.8%	13.8%

Note: L17 shows the reserve margin calculated according to NERC's new definition. See the following link for details:
http://www.nerc.com/docs/pc/ris/RIS_Report_on_Reserve_Margin_Treatment_of_CCDR_%2006.01.10.pdf

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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 Progress Energy – Carolinas, Duke Energy, South Carolina Public Service Authority ("Santee Cooper"), Georgia Power ("Southern Company") and the Southeastern Electric Power Administration ("SEPA") systems. Because of these interconnections with neighboring systems, system conditions on other systems can affect the capabilities of the SCE&G transmission system and also system conditions on the SCE&G transmission system can affect other systems. SCE&G participates with other transmission planners throughout the southeast to develop current and future power flow 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 2012 Summer Study
2. SERC NTSG Reliability 2012/2013 Winter Study
3. SERC LTSG 2016 Summer Future Year Study
4. CTCA 2016 Summer Peak/Shoulder Reliability Study
5. ERAG 2012 Summer Transmission System Assessment
6. ERAG 2012/13 Winter Transmission System Assessment
7. SCE&G-Duke Tie Line Study
8. SCE&G-Santee Cooper-Southern Tie Line Study
9. 2012 January OASIS Study (12Q1)

10. 2012 April OASIS Study (12Q2)
11. 2012 July OASIS Study (12Q3)
12. 2012 October OASIS Study (12Q4)

where the acronyms used above have the following reference:

SERC – SERC Reliability Corporation
NTSG – Near Term Study Group of SERC
LTSG – Long Term Study Group of SERC
CTCA – Carolinas Transmission Coordination Arrangement
ERAG – Eastern Interconnection Reliability Assessment Group
OASIS – Open Access Same-time Information System

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 represents a first-of-its-kind effort, to involve Planning Authorities in the Eastern Interconnection 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.

SCE&G filed with the FERC its proposed actions to achieve compliance with the Regional requirements of Order 1000 on October 11, 2012. FERC is currently reviewing SCE&G's filing. SCE&G is working with neighboring planning regions (Southeastern Regional Transmission Planning "SERTP" and North Carolina Transmission Planning Collaborative "NCTPC") to develop actions to achieve compliance with the interregional requirements of Order 1000. Proposed Interregional requirements must be filed with the FERC in April 2013.

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 classified 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[1] 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 should more accurately reflect 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 and cooperative customers. For these customers, HDD and CDD were weighted based on Cycle 20 distributions. This is the last reading date for bills in any given month, and is generally used for larger customers.

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 used in developing the short range forecasts. For various class/rate groups, they were used to develop customer estimates, average use estimates, or total use estimates.

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

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

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

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

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

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

t indexes time

B is the backshift operator, that is $B\ (X_t) = X_{t-1}$

Z_t is the original data or a difference of the original data

f(B) is the autoregressive operator, $f(B) = 1 – f_1\,B - \dots - f_1\ B^p$

u is the constant term

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

a_t is the independent disturbance, also called the random error

$X_{i,t}$ is the ith input time series

$y_i(B)$ is the transfer function weights for the ith input series (modeled as a ratio of polynomials)

$y_i(B)$ is equal to $w_i\,(B)/\ d_i\,(B)$, where $w_i\,(B)$ and $d_i\,(B)$ are polynomials in B.

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

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

Footnotes

1. SAS Institute, Inc., SAS/STAT[tm] Guide for Personal Computers, Version 6 Edition. Cary, NC: SAS Institute, Inc., 1987.

2. SAS Institute, Inc., SAS/ETS User's Guide, Version 6, First Edition. Cary, NC: SAS Institute, Inc., 1988.

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, twenty-eight 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 and cooperative 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 nuclear plant outages. Unaccounted energy, which is the difference between generation and sales and represents for the most part system losses, is usually about 4.4% of total territorial sales. The monthly allocations for unaccounted for 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.

TABLE 1
Short-Term Forecasting Groups

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
97	Cooperative	Rate 60	One Account

*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 3

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 seven classes of service: residential, commercial, industrial, street lighting, other public authorities, municipal and cooperatives. 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. In addition, two residential classes and residential street lighting were 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 forecasted 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., gas price spike in 2005 and recession versus non-recession years).

Standard statistical procedures (all possible regressions, stepwise regression) 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 Population
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 or CDD (Average of June, July, and August temperature) and average winter temperature or HDD (Average of December (previous year), January and February temperature) 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 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

This section describes the procedures used to create the long-range summer and winter peak demand forecasts. It also describes the methodology used to forecast monthly peak demands. Development of summer peak demands will be discussed initially, followed by the construction of winter peaks.

Summer Peak Demand

The forecast of summer peak demands was developed with a load factor methodology. This methodology may be characterized as a building-block approach because class, rate, and some individual customer peaks are separately determined and then summed to derive the territorial peak.

Briefly, the following steps were used to develop the summer peak demand projections. Load factors for selected classes and rates were first calculated from historical data and then used to estimate peak demands from the projected energy consumption among these categories. Next, planning peaks were determined for a number of large industrial customers. The demands of these customers were forecasted individually. Summing these class, rate, and individual customer demands provided the forecast of summer territorial peak demand. Next, savings identified from SCE&G's demand-side management programs were removed. Finally, the incremental reductions in demand resulting from the Company's standby generator and interruptible programs were subtracted from the peak demand forecast. This calculation gave the firm summer territorial peak demand, which was used for planning purposes.

Load Factor Development

As mentioned above, load factors are required to calculate KW demands from KWH energy. This can be seen from the following equation, which shows the relationship between annual load factors, energy, and demand:

$$\textit{Load Factor} = \textit{Energy}/(\textit{Demand} \times 8760)$$

The load factor is thus seen to be a ratio of total energy consumption relative to what it might have been if the customer had maintained demand at its peak level throughout the year. The value of a system coincident load factor will usually range between 0 and 1, with lower values indicating more variation in a customer's consumption patterns, as typified by residential users with relatively large space-conditioning loads. Conversely, higher values result from more level demand patterns throughout the year, such as those seen in the industrial sector.

Rearrangement of the above equation makes it possible to calculate peak demand, given energy and a corresponding load factor. This form of the equation is used to project peak demand herein. The question then becomes one of determining an appropriate load factor to apply to projected energy sales.

The load factors used for the peak demand forecast were not based on one-hour coincident peaks. Instead, it was determined that use of a 4-hour average class peak was more appropriate for forecasting purposes. This was true for two primary reasons. First, analysis of territorial peaks showed that all of the summer peaks had occurred between the hours of 2 and 6 PM. However, the distribution of these peaks between those four hours was fairly evenly spread. It was thus concluded that while the annual peak would occur during the 4-hour band, it would not be possible to say with a high degree of confidence during which hour it would happen.

Second, the coincident peak demand of the residential and commercial classes depended on the hour of the peak's occurrence. This was due to the former tending to increase over the 4-hour band, while the latter declined. Thus, load factors based on peaks occurring at, say, 2 PM, would be quite different from those developed for a 5 PM peak. It should also be noted that the class contribution to peak is quite stable for groups other than residential and commercial. This means that the 4-hour average class demand, for say, municipals, was within 2% of the 1-hour coincident peak. Consequently, since the hourly probability of occurrence was roughly equal for peak demand, it was decided that a 4-hour average demand was most appropriate for forecasting purposes.

The effect of system line losses were embedded into the class load factors so they could be applied directly to customer level sales and produce generation level demands. This was a convenient way of incorporating line losses into the peak demand projections.

Energy Projections

For those categories whose peak demand was to be projected from KWH sales, the next requirement was a forecast of applicable sales on an annual basis. These projections were utilized in the peak demand forecast construction. In addition, street light sales were excluded from forecast sales levels when required, since there is no contribution to peak demand from this type of sale.

Combining load factors and energy sales resulted in a preliminary, or unadjusted peak demand forecast by class and/or rate. The large industrial customers whose peak demands were developed separately were also added to this forecast.

Derivation of the planning peak required that the impact of demand reduction programs be subtracted from the unadjusted peak demand forecast. This is true because the capacity expansion plan is sized to meet the firm peak demand, which includes the reductions attributable to such programs.

Winter Peak Demand

To project winter peaks actual winter peak demands were correlated with three primary explanatory variables, total territorial energy, customers, and weather during the day of the winter peak's occurrence. Other dummy variables were also tested for inclusion in the model to account for unusual events, such as recessions or extremely cold winters, but the final model utilized the two variables named above.

The logic behind the choice of these variables as determinants of winter peak demand is straightforward. Over time, growth in total territorial load is correlated with economic growth and activity in SCE&G's service area, and as such may be used as a proxy variable for those economic factors, which cause winter peak demand to change. It should be noted that the winter peak for any given year by industry convention is defined as occurring after the summer peak for that year. The winter period for each year is December of that year, along with January and February of the following year. For example, the winter peak in 1968 of 962 MW occurred on December 11, 1968, while the winter peak for 1969 of 1,126 MW took place on January 8, 1970. In addition to economic factors, weather also causes winter peak demand to fluctuate, so the impact of this element was measured by two variables: the average of heating degree days (HDD) experienced on the winter peak day in Columbia and Charleston and the minimum temperature on the peak day. The presence of a weather variable reduces the bias which would exist in the other explanatory variables' coefficients if weather were excluded from the regression model, given that the weather variable should be included. When the actual forecast of winter peak demand was calculated, the normal value of heating degree-days over the sample period was used. Although the ratio of winter to summer peak demands fluctuated over the sample period, it did show an increase over time. A primary cause for this increasing ratio was growth in the number of electric space heating customers. Due to the introduction and rapid acceptance of heat pumps over the past three decades, space-heating residential customers increased from less than 5,000 in 1965 to almost 217,000 in 2004, a 10.2% annual growth rate. However, this growth slowed dramatically in the 1990’s, so the expectation is that the ratio of summer to winter peaks will change slowly in the future.