

STATE OF SOUTH CAROLINA

South Carolina Electric & Gas Company's Integrated
Resource Plan from 2006 - Present

**BEFORE THE
PUBLIC SERVICE COMMISSION
OF SOUTH CAROLINA**

COVER SHEET

DOCKET

NUMBER: 2006 - 103 - E

(Please type or print)

Submitted by: K. Chad Burgess

SC Bar Number: 69456

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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)			
<input checked="" type="checkbox"/> Electric	<input type="checkbox"/> Affidavit	<input checked="" type="checkbox"/> Letter	<input type="checkbox"/> Request	
<input type="checkbox"/> Electric/Gas	<input type="checkbox"/> Agreement	<input type="checkbox"/> Memorandum	<input type="checkbox"/> Request for Certification	
<input type="checkbox"/> Electric/Telecommunications	<input type="checkbox"/> Answer	<input type="checkbox"/> Motion	<input type="checkbox"/> Request for Investigation	
<input type="checkbox"/> Electric/Water	<input type="checkbox"/> Appellate Review	<input type="checkbox"/> Objection	<input type="checkbox"/> Resale Agreement	
<input type="checkbox"/> Electric/Water/Telecom.	<input type="checkbox"/> Application	<input type="checkbox"/> Petition	<input type="checkbox"/> Resale Amendment	
<input type="checkbox"/> Electric/Water/Sewer	<input type="checkbox"/> Brief	<input type="checkbox"/> Petition for Reconsideration	<input type="checkbox"/> Reservation Letter	
<input type="checkbox"/> Gas	<input type="checkbox"/> Certificate	<input type="checkbox"/> Petition for Rulemaking	<input type="checkbox"/> Response	
<input type="checkbox"/> Railroad	<input type="checkbox"/> Comments	<input type="checkbox"/> Petition for Rule to Show Cause	<input type="checkbox"/> Response to Discovery	
<input type="checkbox"/> Sewer	<input type="checkbox"/> Complaint	<input type="checkbox"/> Petition to Intervene	<input type="checkbox"/> Return to Petition	
<input type="checkbox"/> Telecommunications	<input type="checkbox"/> Consent Order	<input type="checkbox"/> Petition to Intervene Out of Time	<input type="checkbox"/> Stipulation	
<input type="checkbox"/> Transportation	<input type="checkbox"/> Discovery	<input type="checkbox"/> Prefiled Testimony	<input type="checkbox"/> Subpoena	
<input type="checkbox"/> Water	<input type="checkbox"/> Exhibit	<input type="checkbox"/> Promotion	<input type="checkbox"/> Tariff	
<input type="checkbox"/> Water/Sewer	<input type="checkbox"/> Expedited Consideration	<input type="checkbox"/> Proposed Order	<input type="checkbox"/> Other:	
<input type="checkbox"/> Administrative Matter	<input type="checkbox"/> Interconnection Agreement	<input type="checkbox"/> Protest		
<input type="checkbox"/> Other:	<input type="checkbox"/> Interconnection Amendment	<input type="checkbox"/> Publisher's Affidavit		
	<input type="checkbox"/> Late-Filed Exhibit	<input type="checkbox"/> Report		



May 28, 2008

VIA ELECTRONIC FILING

The Honorable Charles Terreni
Chief Clerk/Administrator
Public Service Commission of South Carolina
101 Executive Center Drive (29210)
Post Office Drawer 11649
Columbia, South Carolina 29211

RE: South Carolina Electric & Gas Company's Integrated Resource Plan from 2006 -
Present
Docket No. 2006-103-E

Dear Mr. Terreni:

By letter dated February 28, 2008, and in accordance with S.C. Code Ann. § 58-37-40 (1976, as amended), § 58-33-430 (1976, as amended), and Commission Order No. 98-502, South Carolina Electric & Gas Company ("SCE&G" or "Company") filed its 2008 Integrated Resource Plan ("2008 IRP") with the Public Service Commission of South Carolina ("Commission"). The purpose of this letter is to inform the Commission that SCE&G has revised its 2008 IRP and submits for filing the Company's updated 2008 IRP.

SCE&G continuously evaluates and analyzes its need for capacity to meet the growing demand for electric power by SCE&G's customers and to maintain the reliability of the Company's electric system. Since filing its 2008 IRP in February 2008, the Company has made certain revisions to its integrated resource plan to reflect the latest and most accurate planning information. More specifically, SCE&G has revised its 2008 IRP to include the projected effects of the Energy Independence and Security Act, which was enacted into law in December 2007. Further, SCE&G anticipates that the South Carolina Climate, Energy & Commerce Advisory Committee formed by the Governor's Office will recommend to the State of South Carolina the increased usage of renewable generation and energy efficiency. In response, SCE&G has revised its 2008 IRP to reflect that the Company's immediate need for additional capacity in the 2008 - 2015 time period will be supplied by purchased power rather than by self-building generation as originally forecasted by the Company in its 2008 IRP. Finally, SCE&G has revised its 2008 IRP to include the most current forecasts and plans which take into consideration matters not known to SCE&G at the time it filed its 2008 IRP in February 2008.

Enclosed for filing is an electronic copy of SCE&G's 2008 IRP (updated as of May 28, 2008), which reflects the revisions discussed above. By copy of this letter we are also serving counsel for the South Carolina Office of Regulatory Staff with a copy of SCE&G's updated 2008 IRP and attach a certificate of service to that effect.

(Continued . . .)


The Honorable Charles Terreni

May 28, 2008

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If you have any questions or need additional information, please do not hesitate to contact us.

Very truly yours,

A handwritten signature in black ink, appearing to read "K. Chad Burgess". The signature is fluid and cursive, with a large, stylized "B" at the end.

K. Chad Burgess

KCB/kms

Enclosures

cc: Shannon Bowyer Hudson, Esquire

BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA
DOCKET NO. 2006-103-E

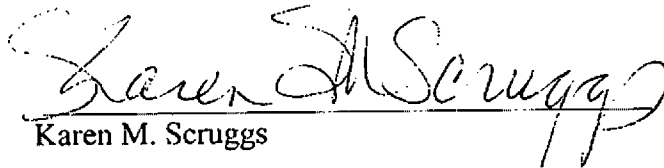
IN RE:

South Carolina Electric & Gas Company's)
Integrated Resource Plan from 2006 -)
Present)
_____)

**CERTIFICATE OF
SERVICE**

This is to certify that I have caused to be served this day one (1) copy of the
**2008 Integrated Resource Plan (May 2008 Update) of South Carolina Electric &
Gas Company** via hand delivery to the person named below at the address set forth:

Shannon Bowyer Hudson, Esquire
Office of Regulatory Staff
1441 Main Street, Suite 300
Columbia, SC 29201


Karen M. Scruggs

Columbia, South Carolina
This 28th day of May 2008

2008

Integrated

Resource

Plan

May 2008 Update



Introduction

This document presents South Carolina Electric & Gas Company's (SCE&G) Integrated Resource Plan (IRP) for meeting the energy needs of its customers over the next fifteen years, 2008 through 2022. The Company's objective is to provide reliable and economically priced energy to its customers.

This document updates the 2008 IRP that was filed on February 28, 2008. It was necessary to update that filing so that the latest and most accurate planning information would be available. This update reflects the following changes:

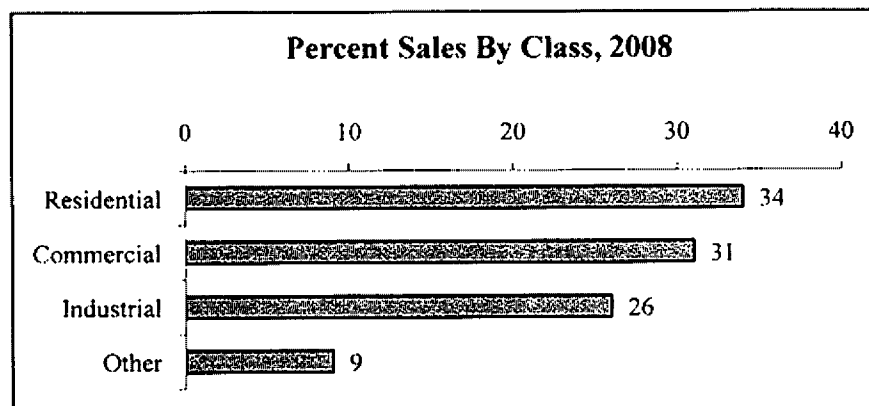
- The IRP filed on February 28, 2008 was based on the Company's forecasts and plans developed during the summer of 2007. Every summer the Company goes through another planning cycle and all forecasts and plans are updated. The Company has started this process and is aware of certain large customer expansions not previously reflected.
- In December of 2007 the president of the United States signed into law the Energy Independence and Security Act of 2007. This act mandates increased levels of efficiency in lighting. The impact of this is expected to be significant and needed to be reflected in the Company's plans.
- On February 16, 2007 the governor of South Carolina established the South Carolina Climate, Energy & Commerce Advisory Committee (CECAC). This group has met several times and is likely to recommend a goal for the state of increasing use of renewable generation and energy efficiency. The Company therefore removed the 2011 self-build option of two peaking turbines from its expansion plan and instead is showing more reliance on power purchases to meet the growing customer demand. This will allow the Company more flexibility in responding to any legislation that may result from the CECAC recommendation.

The Load Forecast

Total territorial energy sales on the SCE&G system are expected to grow at an average rate of 1.3% per year over the next 15 years. The firm territorial summer peak demand and winter peak demand will increase at 1.7% per year over this forecast horizon. The table below contains these projected loads.

	Summer	Winter	Energy
	Peak	Peak	Sales
	(MW)	(MW)	(GWH)
2008	4,931	4,385	24,286
2009	4,873	4,390	24,113
2010	4,931	4,392	24,133
2011	5,047	4,503	24,657
2012	5,166	4,588	24,386
2013	5,262	4,674	24,673
2014	5,367	4,764	24,981
2015	5,472	4,863	25,471
2016	5,582	4,957	25,987
2017	5,697	5,058	26,514
2018	5,811	5,160	27,046
2019	5,924	5,264	27,586
2020	6,037	5,363	28,011
2021	6,146	5,462	28,528
2022	6,258	5,565	29,066

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 about 91% of our sales. The following bar chart shows the relative contribution to territorial sales of each class in 2008.



The “other” classes are street lighting, other public authorities, municipalities and cooperatives.

The forecasting process can be divided into two parts: development of the baseline forecast, followed by non-model adjustments. 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. Sales projections to each group are based on statistical and econometric models derived from historical relationships.

Non-model Adjustments

Several adjustments were made to the baseline projections to incorporate substantive events not considered in the forecast methodology. These were increased air-conditioning and heat pump efficiency standards, improved lighting efficiencies, and the addition of several large industrial loads. The first two of these represent reductions to the forecast while the latter is additional load from the baseline.

Since the baseline forecast is based on 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 tighter new houses have caused energy use as a result of the infiltration of unheated or uncooled air to decrease. 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 current forecast has three “non-model” adjustments of this nature, two being reductions to projected loads and the third an increase.

The first adjustment relates to federal mandates for air-conditioning units and heat pumps. In 2006 the minimum SEER (Seasonal Energy Efficiency Ratio) 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%. The last mandated change to efficiencies like this took place in 1992, when the minimum SEER was raised from 8 to 10. Since then air-conditioner and heat pump manufacturers introduced much higher-efficiency units, and models are now available with SEERs up to 19. However, overall market production of heat pumps and air-conditioners is concentrated at the lower end of the SEER mandate, so the new ruling represented a significant change in energy use which was not captured in the current forecast. For this reason a non-model adjustment was warranted.

A second reduction was made to the baseline energy projections beginning in 2012 for savings related to lighting. Mandated federal efficiencies as a result of the Energy Independence

and Security Act of 2007 will take effect that year, and be phased in through 2014. Standard incandescent light bulbs are inexpensive and provide good illumination, but they are extremely inefficient. Compact fluorescent light bulbs (CFLs) have become increasingly popular over the past several years as substitutes. They last much longer and generally use about one-fourth the energy as that of standard light bulbs. 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 present in the historic data, so it too was modeled as a non-model adjustment.

The final adjustment to the baseline forecast was to account for new industrial growth on SCEG's system. Industrial use generally tracks economic indicators. However, when a large customer begins operations or a significant expansion occurs they should be treated independently of the normal baseline forecasting process. Discussions with industrial and economic development representatives within the company identified several expansions which justified individual handling.

The following table provides the annual reductions in territorial energy attributable to these non-model adjustments.

	Baseline Forecast	Large Customer Change	Interim Forecast (GWH)	% Efficiency Impact	Adjusted Forecast (GWH)
2008	24286	0	24,286	0.0	24,286
2009	24113	0	24,113	0.0	24,113
2010	23967	202	24,169	-0.1	24,133
2011	24472	258	24,730	-0.3	24,657
2012	24945	377	25,322	-3.7	24,386
2013	25418	377	25,795	-4.4	24,673
2014	25920	377	26,297	-5.0	24,981
2015	26435	377	26,813	-5.0	25,471
2016	26980	377	27,357	-5.0	25,987
2017	27534	377	27,911	-5.0	26,514
2018	28094	377	28,471	-5.0	27,046
2019	28663	377	29,040	-5.0	27,586
2020	29211	377	29,588	-5.3	28,011
2021	29757	377	30,134	-5.3	28,528
2022	30324	377	30,701	-5.3	29,066

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.

Demand-Side Management at SCE&G

The Demand-Side Management Programs at SCE&G can be divided into three major categories: Customer Information Programs, Energy Conservation Programs and Load Management Programs.

CUSTOMER INFORMATION PROGRAMS

SCE&G's customer information programs fall under two headings: the annual energy campaigns and the web-based information initiative. Following is a brief description of each.

1. The 2007 Energy Campaigns: In 2007 SCE&G continued to proactively educate its customers and create awareness of issues related to energy efficiency and conservation.

- Weatherline -- energy saving tips promoted on the Weatherline.
- Bill Inserts -- bill insert issued to targeted customers promoting the Low-Income Home Energy Assistance Program (LIHEAP).
- Brochures/Printed Materials -- energy saving tips available on various printed materials in business offices.
- News Releases -- distributed to print and broadcast media throughout SCE&G's service territory.
- Featured News Guests -- SCE&G energy experts conducted several interviews with the media regarding energy conservation and useful tips.
- Web site -- energy saving tips and other conservation information placed on the company's Web site. The address for the Web site was promoted in most of the communication channels mentioned above.
- Weatherization Project -- SCE&G partners targeted low-income homes in Florence, Myrtle Beach, Bluffton and Columbia for weatherization. SCE&G employees volunteer their time to assist the effort.
- Speakers Bureau -- Representatives from SCE&G talked to local organizations about energy conservation.
- Energy Awareness Month -- company used the month as an opportunity to send information to the media discussing energy costs and savings tips.
- Energy Wise Newsletter -- provides energy conservation information for all customer classifications. Direct mailed to more than 500,000 customers in November 2007.

2. WEB-Based Information and Services Programs: SCE&G has available a Web-based tool which 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. Feedback on this tool has been positive, with almost 200,000

customers registered for internet access and 1.8 million visits received in 2007. The SCE&G Web site supports all communication efforts to promote energy savings tips. The "Energy Analyzer" tool on the SCE&G Web site, which allows customers to analyze their bills and usage, received almost 97,000 visits in 2007. For business customers, online information includes: power quality technical assistance, conversion assistance, new construction information, expert energy assistance and more.

ENERGY CONSERVATION PROGRAMS

There are three energy conservation programs: the Value Visit Program, the Conservation Rate and our use of seasonal rate structures. A description of each follows:

1. **Value Visit Program:** The Value Visit Program is designed to assist residential electric customers who are considering an investment in upgrading their home's energy efficiency. We speak with the customer either by phone, through email or by visiting the customer's home and guide them in their purchase of energy related equipment and materials such as heating and cooling systems, duct insulation, attic insulation, storm windows, etc. Our representative explains the benefits of upgrading different areas of the home and what affect upgrading these areas will have on energy bills and comfort levels as well as informing the customer on the many rebates we offer for upgrading certain areas of the home (see rebate schedule below). We also offer financing for qualified customers which makes upgrading to a higher energy efficiency level even easier. There is a \$25 charge for the program, but this charge is reimbursed if the customer implements any suggested upgrade within 90 days of the visit. Information on this program is available on our website and by brochure.

0 to R30 attic insulation - \$6.00 per 100 sq. ft.
R11 to R30 attic insulation - \$3.00 per 100 sq. ft.
Storm windows - \$30.00 per house
Duct insulation - \$60.00 per house
Wall Insulation - \$80.00 per house

2. **Rate 6 Energy Saver / Energy Conservation Program:** The Rate 6 Energy Saver / Energy Conservation Program rewards homeowners and home builders 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, provide for considerable savings for our customers. Participation in the program is very easy as the requirements are prescriptive and do not require a large monetary investment which is beneficial to all of our customers and trade allies. Homes built to this standard also have improved comfort levels and increased re-sale value over homes built to the minimum building code standards which are also a significant benefit to our customers. Information on this program is available on our website and by brochure.

3. 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.

LOAD MANAGEMENT PROGRAMS

SCE&G's load management programs have as their primary goal the reduction of 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:

1. Standby Generator Program: The Standby Generator I Program for retail customers was introduced in 1990 to serve as a load management tool. General guidelines authorize SCE&G to initiate a standby generator run request when reserve margins are stressed due to a temporary reduction in system generating capability or high customer demand. The Standby Generator II Program for retail customers was developed in 2000, authorizing standby generator runs both when reserve margins are stressed and when market prices are very high. Through consumption avoidance, customers who own generators release capacity back to SCE&G where it is then used to satisfy system demand. Qualifying customers (able to defer a minimum of 200 kW) receive financial credits determined initially by recording the customer's demand during a load test. Future demand credits are based on what the customer actually delivers when SCE&G requests them to run their generator(s). This program allows customers to reduce their monthly operating costs, as well as earn a return on their generating equipment investment. There is also a wholesale standby generator program that is similar to the retail programs.

2. Interruptible Load Program: SCE&G has over 200 megawatts of interruptible customer load under contract. Participating customers receive a discount on their demand charges for shedding load when SCE&G is short of capacity.
3. 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.
4. Time of Use Rates: Our time of use rates contain higher charges during the peak usage periods of the day and discounted charges during off-peak periods. This encourages customers to conserve energy during peak periods and to shift energy consumption to off-peak periods. All our customers have the option of a time of use rate.

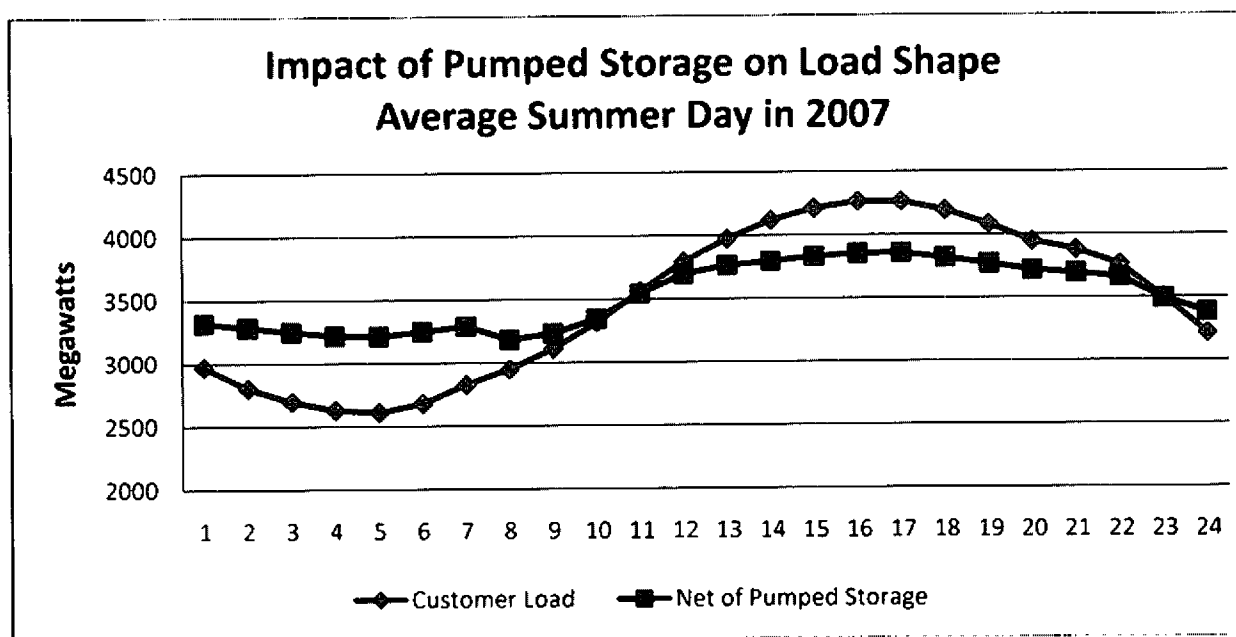
Load Impact of Load Management Programs

The Company relies on the standby generator program and the interruptible service program to help maintain the reliability of its electrical system. There are currently 234 megawatts of capacity made available to the system through these programs. This load management capacity is expected to decrease to 209 megawatts in 2009. The table on the right shows the peak demand on the system with and without these programs. The firm peak demand is the load level that results when the DSM is used to lower the system peak demand.

	System Peak (MW)	DSM Impact (MW)	Firm Peak (MW)
2008	5,165	234	4,931
2009	5,082	209	4,873
2010	5,127	209	4,918
2011	5,234	209	5,025
2012	5,333	209	5,124
2013	5,429	209	5,220
2014	5,534	209	5,325
2015	5,639	209	5,430
2016	5,744	209	5,535
2017	5,859	209	5,650
2018	5,973	209	5,764
2019	6,086	209	5,877
2020	6,199	209	5,990
2021	6,308	209	6,099
2022	6,420	209	6,211

DSM From the Supply Side

SCE&G is able to achieve a DSM 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 during 2007.



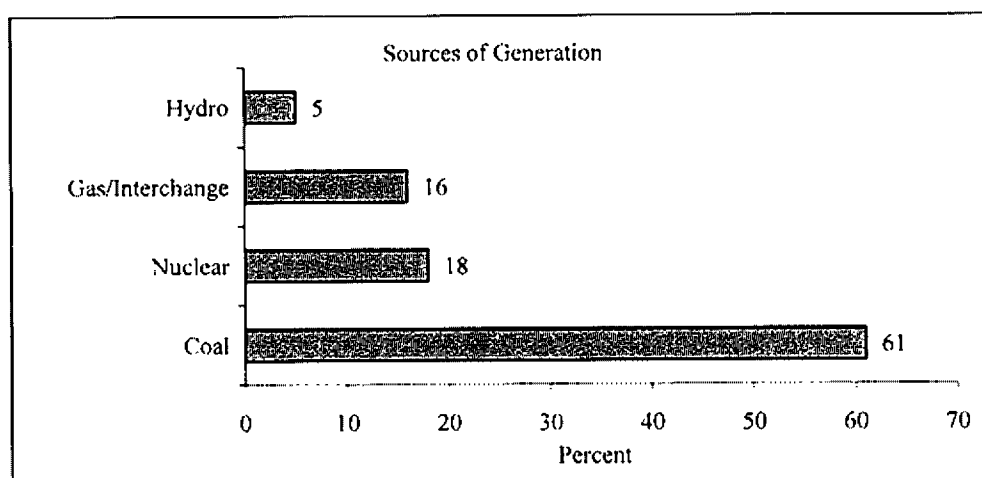
In effect the Fairfield Pumped Storage Plant shaved about 400MWs from the daily peak times of 2:00pm through 6:00pm and moved almost 4% of customer's daily energy needs to the off peak. Because of this valuable supply side capability, a similar capability on the demand side, such as a time of use rate, would be less valuable on the SCE&G system than on many other utility systems.

Existing Long Term Supply Resources

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

	In-Service Date	Summer (MW)
Coal-Fired Steam:		
Urquhart – Beech Island, SC	1953	94
McMeekin – Near Irmo, SC	1958	250
Canadys - Canadys, SC	1962	405
Wateree – Eastover, SC	1970	700
*Williams – Goose Creek, SC	1973	615
Cope - Cope, SC	1996	420
Cogen South – Charleston, SC	1999	90
Total Coal-Fired Steam Capacity		<u>2,574</u>
Nuclear:		
V. C. Summer - Parr, SC	1984	644
I. C. Turbines:		
**Burton, SC	1961	0
**Faber Place – Charleston, SC	1961	0
Hardeeville, SC	1968	11
Urquhart – Beech Island, SC	1969	37
Coit – Columbia, SC	1969	30
Parr, SC	1970	60
Williams – Goose Creek, SC	1972	40
Hagood – Charleston, SC	1991	88
Urquhart No. 4 – Beech Island, SC	1999	47
**Un-sited ICTs	2008	34
Urquhart Combined Cycle – Beech Island, SC	2002	467
Jasper Combined Cycle – Jasper, SC	2004	<u>852</u>
Total I. C. Turbines Capacity		<u>1666</u>
Hydro:		
Neal Shoals – Carlisle, SC	1905	2
Parr Shoals – Parr, SC	1914	7
Stevens Creek - Near Martinez, GA	1914	9
*Columbia Canal - Columbia, SC	1927	3
Saluda - Near Irmo, SC	1930	206
Fairfield Pumped Storage - Parr, SC	1978	<u>576</u>
Total Hydro Capacity		<u>803</u>
Other: Long-Term Purchases		25
SEPA		33
Grand Total:		<u>5,745</u>
<p>* Williams Station is owned by GENCO, a wholly owned subsidiary of SCANA and Columbia Canal is owned by the City of Columbia. This capacity is operated by SCE&G. ** Burton (27MW) and Faber Place (8 MW) gas turbine units are currently in non-run status and will be unavailable indefinitely. Two 17 MW un-sited ICTs will replace this lost capacity.</p>		

The bar chart below shows the projected 2008 relative energy generation by fuel source. SCE&G generates the majority of its energy from coal and nuclear fuel.



Supply 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 12 to 18 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. Mitigation of these two types of risk is discussed below.

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, wet coal 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 except the two largest: Summer Station and Williams Station.

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 forecast error.

The level of daily operating reserves required by the SCE&G system is dictated by operating agreements with other VACAR companies. VACAR has set the region’s reserve

needs at 150% of the largest unit in the region. While it varies by a megawatt or two each year, SCE&G's pro-rata share of this capacity is always around 200 megawatts.

By maintaining a reserve margin in the 12 to 18 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.

The Need for Base Load Capacity

As our customers' need for energy continues to grow, so does the need for generating capacity to serve those customers. In particular SCE&G projects the need for additional baseload capacity around the year 2016. Currently about 56% of the Company's generation fleet is baseload. When the last coal plant, Cope Station, came online in 1996, the percentage of baseload capacity was about 74%. The choice among baseload, intermediate and peaking capacity is an economic one and depends on how much energy the new capacity will need to generate. Base load capacity typically dispatches at a capacity factor in excess of 70%.

Nuclear Capacity and Fuel Diversity

SCE&G has entered into an Engineering, Procurement and Construction (EPC) agreement with Westinghouse Electric Co. and Stone & Webster Inc. to construct two 1,117 net megawatt nuclear facilities. SCE&G will own 55% of these units i.e. 614 MWs of each. Santee Cooper will own the remaining 45%. Both units will have the Westinghouse AP1000 design and use passive safety systems to enhance the safety of the unit. The first unit is planned for 2016 and the second 2019. In addition to the environmental benefits, the nuclear option will also offer an opportunity to diversify our capacity. SCE&G's current capacity is about 43% coal fired, 30% gas fired, and 11% nuclear (See page 9 for the generated energy distribution). Adding more nuclear capacity can provide a better balance among fuel types.

Role of Purchased Power

SCE&G constantly monitors the markets for electric energy and capacity and at times is an active purchaser and seller in those markets. When it appears that market resources may be able to meet supply needs for its system appropriately, SCE&G polls the market, in some cases

informally, and in other cases through the issuance of formal RFPs. In cases where the market resources can be an appropriate part of SCE&G's supply mix, SCE&G includes those resources in its comparative analysis of alternative supply options.

On December 8, 2006 SCE&G issued an RFP to purchase capacity over several years. As responses were being received, a number of uncertainties in our resource plan arose making it impractical for the company to commit to a multi-year capacity purchase. As a result the RFP process was closed. The company has made a 100 MW capacity purchase for the summer of 2008. Another multi-year RFP is likely to be issued within the next 12 months.

Non-Traditional Generation Sources

SCE&G considers non-traditional sources of generation in its planning. In fact it depends on 90 MWs of co-generation capacity in its Cogen South facility. This facility co-fires with coal the biomass waste from a paper manufacturing plant. Also, SCE&G is increasing its attention on renewable sources of generation while at the same time policy makers are considering new energy efficiency standards and renewable portfolio standards. Some proposed bills in congress have defined renewable as: geothermal, hydro, wind, solar and biomass. Unfortunately there are no sites for geothermal generation available in South Carolina. SCE&G generates about 5% of its energy from hydro power. The Company has invested in its existing hydro sites and increased hydro output as a result and will continue to pursue other such economic opportunities but no sites have been identified for a new hydro facility. Both wind and solar have been considered but because of the high capital costs and the limited energy production caused by low wind speeds and insufficient solar radiation, these generation sources are not economical within the SCE&G service territory. SCE&G has also evaluated potential biomass applications in recent years, but none have proven economically feasible and operationally practical yet, but we continue to examine proposals and opportunities as they are identified.

Projected Loads and Resources

The table on the following page shows SCE&G's projected loads and resources for the next 15 years. The resource plan shows the need for additional capacity and identifies, at least, on a preliminary basis whether the need is for peaking/intermediate capacity or baseload capacity.

The resource plan shows the need for the addition of more than 400 MWs of peaking/intermediate capacity in the 2009 - 2015 timeframe. Some or all of this capacity may be supplied as purchased power. As discussed previously the plan also calls for nuclear base load capacity in 2016 and 2019.

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 other units being added in the market.

SCE&G Forecast of Summer Loads and Resources - 2008 COL

YEAR		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Load Forecast																
1	Gross Territorial Peak	5165	5082	5140	5256	5375	5471	5576	5681	5791	5906	6020	6133	6246	6355	6467
2	Less: DSM	234	209	209	209	209	209	209	209	209	209	209	209	209	209	209
3	Net Territorial Peak	4931	4873	4931	5047	5166	5262	5367	5472	5582	5697	5811	5924	6037	6146	6258
4	Firm Contract Sales	250	250	250	250	250										
5	Total Firm Obligation	5181	5123	5181	5297	5416	5262	5367	5472	5582	5697	5811	5924	6037	6146	6258
System Capacity																
6	Existing	5745	5745	5726	5692	5692	5692	5692	5692	5692	6306	6306	6306	6920	6920	6920
	Additions															93
7	Peaking/Intermediate															
8	Baseload									614			614			
9	Other		-19	-34												
10	Total System Capacity	5745	5726	5692	5692	5692	5692	5692	5692	6306	6306	6306	6920	6920	6920	7013
11	Firm Annual Purchase	100	25	125	250	375	225	325	450		75	225				
12	Total Production Capability	5845	5751	5817	5942	6067	5917	6017	6142	6306	6381	6531	6920	6920	6920	7013
Reserves With DSM																
13	Margin	664	628	636	645	651	655	650	670	724	684	720	996	883	774	755
14	% Reserve Margin	12.8%	12.3%	12.3%	12.2%	12.0%	12.4%	12.1%	12.2%	13.0%	12.0%	12.4%	16.8%	14.6%	12.6%	12.1%
15	% Capacity Margin	11.4%	10.9%	10.9%	10.9%	10.7%	11.1%	10.8%	10.9%	11.5%	10.7%	11.0%	14.4%	12.8%	11.2%	10.8%
Reserves Without DSM																
16	Margin	430	419	427	436	442	446	441	461	515	475	511	787	674	565	546
17	% Reserve Margin	7.9%	7.9%	7.9%	7.9%	7.9%	8.2%	7.9%	8.1%	8.9%	8.0%	8.5%	12.8%	10.8%	8.9%	8.4%
18	% Capacity Margin	7.4%	7.3%	7.3%	7.3%	7.3%	7.5%	7.3%	7.5%	8.2%	7.4%	7.8%	11.4%	9.7%	8.2%	7.8%

Transmission 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 network. 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 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) transmission only customers.

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 is an active member of the Southeastern Electric Reliability Council (SERC), which has adopted the North American Electric Reliability Corporation (NERC) Reliability Standards as approved by the NERC Board of Trustees. SCE&G tests 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/>.

As a member of the Virginia-Carolinas (VACAR) Reliability Group, SCE&G participates in joint studies with other utilities to determine the reliability of the integrated systems throughout Virginia, North Carolina and South Carolina. As a member of the SERC Reliability Corporation, SCE&G participates with other utilities in the SERC Regional Studies Process, including the SERC Regional Studies Executive Committee, the SERC Long-Term Power Flow Study Group, the SERC Near-Term Power Flow Study Group, the SERC Dynamics Study Group, the SERC Short Circuit Database Working Group and the SERC Inter-regional studies efforts.

SCE&G also participates in the SERC power flow database development efforts and the NERC Multi-area Modeling Working Group (MMWG) annual model development process. These processes develop computer models of the transmission grid across the VACAR area, SERC area, and other portions of 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.

The SCE&G transmission system is interconnected with Progress Energy -- Carolinas, Duke Energy, South Carolina Public Service Authority (Santee Cooper), Georgia Power Company, Savannah Electric Power Company, and the Southeastern Electric Power Administration (SEPA) systems.

The following is a list of regional and sub-regional studies completed over the past year:

1. SERC NTSG 2007 Summer Reliability Study
2. SERC NTSG 2007/2008 Winter Reliability Study
3. SERC LTSG 2011 Summer Future Year Study
4. SERC East -- RFC 2007 Summer Reliability Study
5. SERC East -- RFC 2007/2008 Winter Reliability Study
6. 2007 January-March OASIS Study
7. 2007 April-June OASIS Study
8. 2007 July-September OASIS Study
9. 2007 October-December OASIS Study
10. VACAR Stability Study of Projected 2010 Summer Peak Conditions
11. Evaluation of the Under-Frequency Load Shedding (UFLS) Program of the SERC Region

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

FERC Order 890 – Attachment K (Transmission Planning)

On March 15, 2007 the Federal Energy Regulatory Commission (FERC) published in the Federal Register a final rule reforming the 1996 open-access transmission regulatory framework rules in Orders No. 888 and 889. This final rule, called FERC Order No. 890, was adopted by FERC on February 15, 2007 and is designed to "prevent undue discrimination and preference in transmission service". Among other requirements, this order requires transmission providers to establish an open, transparent and coordinated transmission planning process that includes FERC jurisdictional stakeholder involvement. SCE&G and the South Carolina Public Service Authority (Santee Cooper) have jointly established the South Carolina Regional Transmission Planning (SCRTP) process to meet the requirements of FERC Order No. 890. Documentation of this process was filed with the FERC on December 7, 2007 in the form of Attachment K to the SCE&G Open Access Transmission Tariff (OATT). Activities associated with this process can be reviewed and followed at the SCRTP website (www.scrtp.com).

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) and by whether or not they use electric space heating. 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. Monthly heating and cooling degree data for Columbia and Charleston are also available historically, and may be forecast using averages based on NOAA normals¹. 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 marketing 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 SAS² 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° and for CDD was 75°. 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.

The plots also revealed significant changes in average use over time. 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:

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

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, $q(B) = 1 - q_1 B - \dots - q_q B^q$

a_t is the independent disturbance, also called the random error

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

$y_i(B)$ is the transfer function weights for the i th 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)³ 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. The 15-year average daily weather “normals” were based on data from 1992 to 2006 published by the National Oceanic and Atmospheric Association.
2. SAS Institute, Inc., SAS/STAT[™] Guide for Personal Computers, Version 6 Edition. Cary, NC: SAS Institute, Inc., 1987.
3. 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-seven large industrial customers were individually projected. The residential class was disaggregated into those customers with electric space heating and those without electric space heating and by housing type (single family, multi-family, and mobile homes). Each municipal and cooperative account represents a forecasting group and were 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 for 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 for to monthly territorial sales produces electric generation requirements

TABLE 1
Short-Term Forecasting Groups

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

<u>Value Forecasted</u>	<u>Methodology</u>	<u>Forecasting Groups</u>
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, All Accounts
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 90% 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 with electric space heating and for those without electric space heating. 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 STEPWISE, PROC REG, and PROC AUTOREG of SAS were used to estimate all regression models. PROC STEPWISE was used for preliminary model specification and elimination of insignificant variables. PROC REG was used 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., foreign oil price increases in 1979 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., (formerly DRI-WEFA) 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.

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, 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:

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

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 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 two primary explanatory variables, total territorial energy 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 variable was measured by the average of heating degree days (HDD) experienced on the winter peak day in Columbia and Charleston. 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. Finally, 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.