



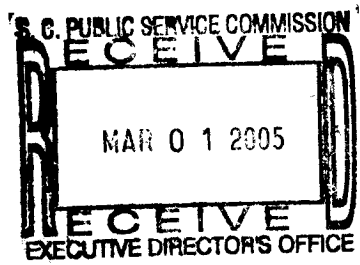
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ACCEPTED
Legal 202 3-2-05

Catherine D. Taylor
Associate General Counsel
cdtaylor@scana.com

February 28, 2005

The Honorable Charles L.A. Terreni
Chief Clerk & Administrator
Public Service Commission of South Carolina
ATTN: Docketing Department
101 Executive Center Drive
Columbia, South Carolina 29210

2005-36E



RE: South Carolina Electric and Gas Company's 2005 Integrated Resource Plan

Dear Mr. Terreni:

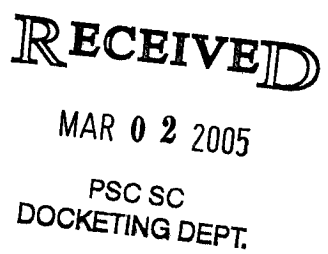
In accordance with Order No. 98-502 issued in Docket No. 87-223-E and dated July 2, 1998, enclosed are ten (10) copies of South Carolina Electric & Gas Company's 2005 Integrated Resource Plan. This filing also serves to satisfy the annual reporting requirements of the Utility Facility Siting and Environmental Protection Act, S.C Code § 58-33-430. SCE&G is also serving copies upon the Office Regulatory Staff.

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

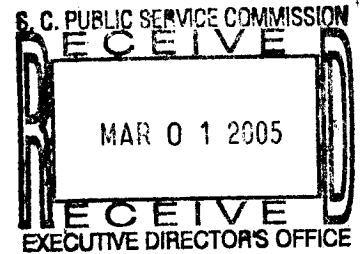
Sincerely,
Catherine D. Taylor/kms
Catherine D. Taylor

CDT/kms
Enclosures

cc: Dan Arnett, Chief of Staff
John Flitter, Director of Electric and Gas Regulation



2005



Integrated

Resource

Plan



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, 2005 through 2019. The Company's objective is to provide reliable and economically priced energy to its customers.

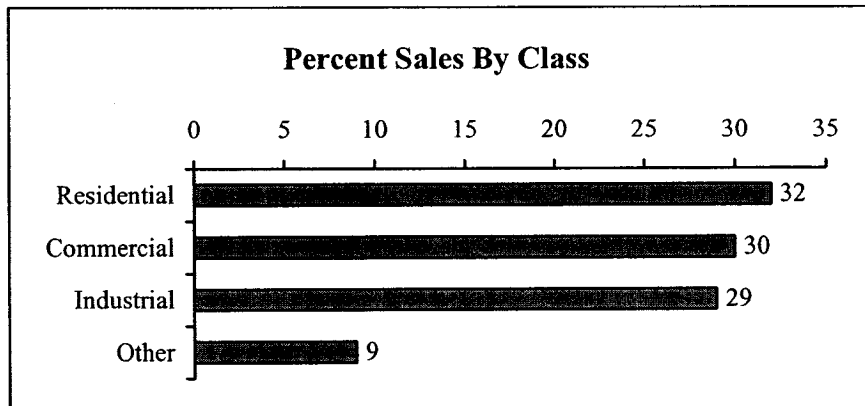
The Load Forecast

Total territorial energy sales on the SCE&G system are expected to grow at an average rate of 2.2% per year over the next 15 years. The summer peak demand and winter peak demand will increase at 2.2% and 2.3% per year respectively over this forecast horizon. The table below contains the projected loads.

	Summer Peak (MW)	Winter Peak (MW)	Energy Sales (GWH)
2005	4,641	4,240	23,473
2006	4,725	4,314	23,922
2007	4,828	4,412	24,414
2008	4,934	4,508	24,898
2009	5,038	4,605	25,386
2010	5,143	4,705	25,889
2011	5,261	4,815	26,441
2012	5,380	4,929	27,013
2013	5,512	5,056	27,650
2014	5,651	5,186	28,306
2015	5,779	5,309	28,924
2016	5,901	5,426	29,510
2017	6,042	5,563	30,197
2018	6,181	5,701	30,891
2019	6,327	5,847	31,624

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 90% of our sales. The following bar

chart shows the relative contribution to territorial sales of each class in 2005. The other classes are street lighting, other public authorities, municipalities and cooperatives. A detailed description of the short-range 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.



The forecast of summer peak demand is developed using a load factor methodology. Load factors for each class of customers 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

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.

- The 2004 Energy Campaigns: In 2004 as in the past, SCE&G continued to proactively educate its customers and create awareness of issues related to energy and conservation management. The summer & winter campaign consisted of several different strategies in communicating to our customers. Following are the strategies implemented:
 - Radio & Newspaper – two-week radio and newspaper campaigns were conducted in early July & October in all the major service areas. The spots featured energy savings tips, online energy management tools, and energy savings clinics.
 - Weatherline – energy saving tips on the Weatherline promoted.
 - “Energy Wise” newsletter – energy saving tips featured in the SCE&G “Energy Wise” newsletter distributed to customers in July via their bills.
 - Bill Inserts – a 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.
 - On-hold Messaging – key energy messages developed for SCE&G call centers for customers placed on hold.
 - 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.
 - Project Cool Breeze – SCE&G was a sponsor of this program in Charleston that provided fans and/or air conditioners to lower income persons in the Lowcountry.
 - 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 Beaufort and Sumter for weatherization. SCE&G employees volunteer their time to assist the effort.
 - Speakers Bureau – Representatives from SCE&G talk to local organizations about energy conservation. Also use company-produced video that highlights energy conservation.

- Energy Awareness Month – company used the month as an opportunity to send information to the media discussing energy costs and savings tips.
- Lowe’s Partnership – SCE&G partnered with Lowe’s to conduct energy saving seminars at Lowe’s stores throughout SCE&G’s service territory in October, Energy Awareness Month.
- WEB-Based Information and Services Programs: In addition to energy savings tips and conservation information placed on the Company’s website, SCE&G now has available a Web-based tool which allows customers to access current and historical consumption data and compare their energy usage month-to-month and year-to-year, noting trends and spikes in their consumption. Feedback on this tool has been positive and nearly 100,000 customers have registered to access this tool as well as other account related information. The SCE&G Web site supports all communication efforts to promote energy savings tips and provides video instruction on weatherization as well as other useful content. For our business customers, online information includes: retro-fit and conversion assistance, standby generator program, 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:

- Value Visit Program: The Value Visit Program is designed to assist residential electric customers that are considering an investment in upgrading their home's energy efficiency. We visit 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 attached rebate schedule). We also offer financing for qualified customers which makes upgrading to a higher energy efficiency level even easier. The Value Visit Program is often used in conjunction with our Rate 6 Program to achieve the maximum benefit for customers wanting to reduce their energy

usage, make their homes more comfortable and to increase their home's overall value. 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 or 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

- 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 is also a significant benefit to our customers. Information on this program is available on our website and by brochure.
- 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

SCEG's load management programs have as their primary goal the reduction of the need for additional generating capacity. There are five load management programs: Standby Generator Program, Wholesale Standby Generator Program, Interruptible Load Program, Real Time Pricing Rate and the Time of Use Rates. A description of each follows.

- Standby Generator Program: The Standby Generator I Program 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 was developed in 2000, authorizing standby generator runs for revenue producing opportunities during times of high market prices. Through consumption avoidance, generator customers 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.

- Wholesale Standby Generator Program: The Company will work with wholesale customers to utilize their generation in a manner that will be mutually beneficial. Instead of the wholesale customer running his generation when his system is peaking, the generation is dispatched when the Company needs it with the wholesale customer receiving credit in terms of a lower bill. There are currently about 23 MWs under contract through this program.
- 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 SCEG is short of capacity.
- 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 rate sends a high price signal to participating customers which encourages conservation and load shifting. Of course during low usage periods, prices are lower.
- Time of Use Rates: Our time of use rates contain higher charges during the peak usage periods of the day to encourage conservation and load shifting during these periods.

Load Impact of Load Management Programs

There are two primary load management programs at SCE&G: the standby generator program and the interruptible service program. The Company relies on these programs to help maintain the reliability of its electrical system. There are 262 megawatts of capacity made available to the system through these programs. The table below 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)
2005	4887	246	4641
2006	4987	262	4725
2007	5090	262	4828
2008	5196	262	4934
2009	5300	262	5038
2010	5405	262	5143
2011	5523	262	5261
2012	5642	262	5380
2013	5774	262	5512
2014	5913	262	5651
2015	6041	262	5779
2016	6163	262	5901
2017	6304	262	6042
2018	6443	262	6181
2019	6589	262	6327

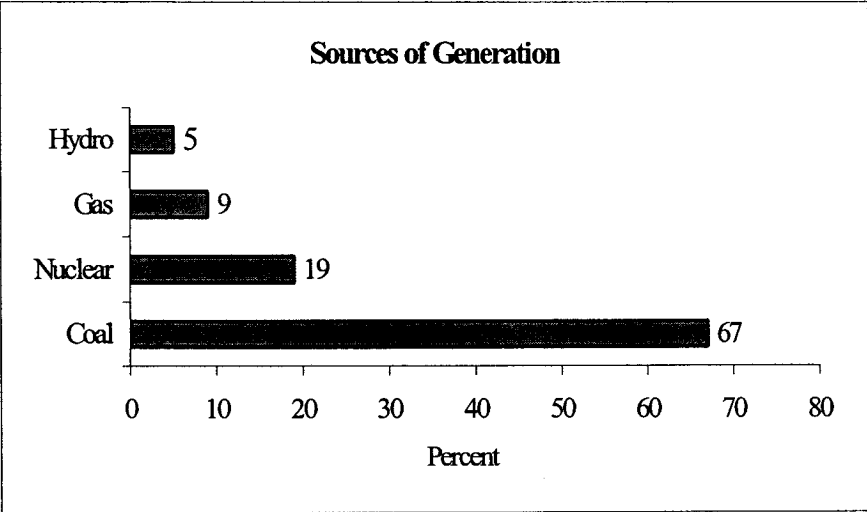
Existing Supply Capacity Existing Supply Capacity

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

2004 Existing Capacity		
	In-Service <u>Date</u>	Summer <u>(MW)</u>
Coal-Fired Steam:		
Urquhart – Beech Island, SC	1953	94
McMeekin – Near Irmo, SC	1958	250
Canadys - Canadys, SC	1962	396
Wateree – Eastover, SC	1970	700
Williams – Goose Creek, SC	1973	615
*D-Area – USDOE Savannah River Site	1995	35
Cope - Cope, SC	1996	410
Cogen South – Charleston, SC	1999	<u>90</u>
Total Coal-Fired Steam Capacity		<u>2,590</u>
Nuclear:		
V. C. Summer - Parr, SC	1984	644
I. C. Turbines:		
Burton, SC	1961	27
Faber Place – Charleston, SC	1961	8
Hardeeville, SC	1968	12
Urquhart – Beech Island, SC	1969	40
Coit – Columbia, SC	1969	32
Parr, SC	1970	69
*Williams – Goose Creek, SC	1972	40
Hagood – Charleston, SC	1991	86
Urquhart No. 4 – Beech Island, SC	1999	51
Urquhart Combined Cycle – Beech Island, SC	2002	474
Jasper Combined Cycle – Jasper, SC	2004	<u>880</u>
Total I. C. Turbines Capacity		<u>1719</u>
Hydro:		
Neal Shoals – Carlisle, SC	1905	5
Parr Shoals – Parr, SC	1914	15
Stevens Creek - Near Martinez, GA	1914	12
*Columbia Canal - Columbia, SC	1927	9
Saluda - Near Irmo, SC	1930	206
Fairfield Pumped Storage - Parr, SC	1978	<u>576</u>
Total Hydro Capacity		<u>823</u>
Other: Long-Term Purchases		
SEPA		33
Grand Total:		<u>5,834</u>

* D-Area is leased from the U.S. DOE; Williams Station is owned by GENCO, a wholly owned subsidiary of SCANA and Columbia Canal is owned by the City of Columbia. All of this capacity is operated by SCE&G to meet its load obligations.

The bar chart below shows the projected 2005 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.

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. SCE&G’s prorata share of this capacity for 2005 is 198 megawatts.

Supply reserves are needed to balance the “supply risk” that some SCE&G generation capacity may be forced out 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 a hotter than normal summer or forecast error.

By maintaining a reserve margin in the 12% – 18% range, the Company addresses the uncertainties related to load and to the availability of generation on its system, as well as 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.

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 but at this time the Company has not determined how it will meet that need. This capacity is specified as “Undecided” in the resource planning table.

There are two significant updates to make since filing the last IRP. SCE&G has received a 20-year extension to its operating license for the Summer Plant from the NRC. The plant is now licensed to operate until 2042. Also construction of the Jasper Plant, a gas-fired combined cycle plant in Jasper county was completed. The plant was placed into commercial service on May 10, 2004.

The Company believes that its supply plan, summarized in the following table, will be as benign to the environment as possible because of its reliance on efficient, gas fired generation, as well as 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 to 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's Forecast of Summer Loads and Resources – 15 Years

	<u>YEAR</u>	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Load Forecast																
1	Gross Territorial Peak	4887	4987	5090	5196	5300	5405	5523	5642	5774	5913	6041	6163	6304	6443	6589
2	Less: DSM	246	262	262	262	262	262	262	262	262	262	262	262	262	262	262
3	Net Territorial Peak	4641	4725	4828	4934	5038	5143	5261	5380	5512	5651	5779	5901	6042	6181	6327
4	Firm Contract Sales	350	250	250	250	250	250	250	250							
5	Total Firm Obligation	4991	4975	5078	5184	5288	5393	5511	5630	5512	5651	5779	5901	6042	6181	6327
System Capacity																
6	Existing	5834	5834	5834	5834	5834	5934	6084	6184	6334	6334	6334	6484	6634	6784	6934
Additions																
7	Fairfield P.S.															
8	Jasper Combined Cycle					100	150	100	150			150	150	150	150	150
9	Undecided															
10	Total System Capacity	5834	5834	5834	5834	5934	6084	6184	6334	6334	6334	6484	6634	6784	6934	7084
11	Firm Annual Purchase															
12	Total Production Capability	5834	5834	5834	5834	5934	6084	6184	6334	6334	6334	6484	6634	6784	6934	7084
Reserves With DSM																
13	Margin	843	859	756	650	646	691	673	704	822	683	705	733	742	753	757
14	% Reserve Margin	16.9%	17.3%	14.9%	12.5%	12.2%	12.8%	12.2%	12.5%	14.9%	12.1%	12.2%	12.4%	12.3%	12.2%	12.0%
15	% Capacity Margin	14.4%	14.7%	13.0%	11.1%	10.9%	11.4%	10.9%	11.1%	13.0%	10.8%	10.9%	11.0%	10.9%	10.9%	10.7%
Reserves Without DSM																
16	Margin	597	597	494	388	384	429	411	442	560	421	443	471	480	491	495
17	% Reserve Margin	11.4%	11.4%	9.3%	7.1%	6.9%	7.6%	7.1%	7.5%	9.7%	7.1%	7.3%	7.6%	7.6%	7.6%	7.5%
18	% Capacity Margin	10.2%	10.2%	8.5%	6.7%	6.5%	7.1%	6.6%	7.0%	8.8%	6.6%	6.8%	7.1%	7.1%	7.1%	7.0%

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 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, including: load growth in existing retail customers (residential, commercial, and industrial), new residential, commercial, and industrial customers, wholesale customers, and transmission only customers.

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

It is recognized that the reliability of power supply in local areas is the responsibility of the individual systems and that each system has internal criteria relating to the more common contingencies. It is further recognized that there are severe contingencies, which are credible, but of a low probability of occurrence, which may result in conditions such as islanding and/or loss of load. Such conditions are considered acceptable as long as they are controlled so as to limit the adverse impact of the disturbance and so as to leave the system or systems in such condition as to permit rapid load restoration and/or reconnection.

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 new NERC Planning Standards as approved by the NERC Board of Trustees in September 1997 and subsequently amended. SCE&G tests and designs its transmission system to be compliant with the requirements as set forth in these standards and guides. A copy of the NERC Planning Standards document is available at the NERC homepage <http://www.nerc.com/>.

As a member of the Virginia-Carolinas (VACAR) Reliability Group, the Southeastern Electric Reliability Council (SERC), and the North American Electric Reliability Council (NERC), SCE&G participates in the VST (VACAR-Southern-TVA-Entergy) and NERC Multi-area Modeling Working Group (MMWG) annual model development process. This process develops 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 NERC Planning Standards and the SCE&G Long Range Planning Criteria. Also, SCE&G participates in regional studies of the electrical network to determine its' existing and future capabilities and to ensure compliance of the regional grid with the NERC Planning Standards.

The SCE&G transmission system is interconnected with the Progress Energy – Carolina, Duke Power, South Carolina Public Service Authority, Georgia Power Company, Savannah Electric Power Company, and the Southeastern Electric Power Administration systems. These interconnections consist of 22 active interties and 3 normally opened interties. The 3 normally opened interties are used only to restore service following local area outages.

SCE&G participates in a number of regional and sub-regional studies designed to evaluate the performance of the integrated transmission system. These studies include both near-term and long-term reliability studies. The following is a list of regional and sub-regional studies conducted over the past year:

1. VACAR 2009 Summer Study
2. VAST 2004 Summer Reliability Study
3. VAST 2004/2005 Winter Reliability Study
4. VST 2011 Summer Future Year Study
5. VEM 2004 Summer Reliability Study
6. VEM 2004/2005 Winter Reliability Study
7. VSWG 2003 Stability Study of Projected 2004/05 Winter Peak Conditions
8. VST-SSG UVLS Assessment
9. 2004 April-June OASIS Study
10. 2004 July-September OASIS Study
11. 2004 October-December OASIS Study
12. 2005 January-March OASIS Study

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

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 to 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:

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

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, $f(B) = 1 - f_1 B - \dots - f_p B^p$

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 1989 to 2003 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, 31 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, nineteen 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 is usually about 4.5% 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, 2004 – 2005

<u>Class Number</u>	<u>Class Name</u>	<u>Rate/SIC Designation</u>	<u>Comment</u>
		Single Family	Rates 1, 2, 5, 6, 8, 18, 25, 26, 62, 64
10	Residential Non-Space Heating	Multi Family	Rates 67, 68, 69
910	Residential Space Heating	Mobile Homes	Rates 1, 2, 5, 7, 8
20	Commercial Non-Space Heating	Rate 9	Small General Service
		Rate 12	Churches
		Rate 20, 21	Medium General Service
		Rate 22	Schools
		Rate 24	Large General Service
		Other	Rates 10, 11, 14, 16, 17, 18, 24, 25, 26, 29, 60, 62, 64, 67, 68, 69
920	Commercial Space Heating	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 91	Executive, Legislative and General Government (except Finance)
		Rate 23, SIC 99	Other or Unknown SIC Code*
		Rate 27, 60	Large General Service
		Other	Rates 25 and 26
930	Industrial Space Heating	Rate 9	Small General Service
60	Street Lighting	Rates 3, 9, 13, 17, 25, 26, 29, and 69	
70	Other Public Authority	Rate 3 and 29	
		Rates 65 and 66	
92	Municipal	Rate 60, 61	Four Individual Accounts
97	Cooperative	Rate 60, 61	Three Individual Accounts

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

TABLE 2

Summary of Methodologies Used To Produce
2004 and 2005 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. Several other dummy variables were also included in the model to account for recessions, two extreme winters, and the higher than average growth experienced on the system over the past decade.

The logic behind the choice of these variables as determinants of winter peak demand is straightforward. Over time, growth in total territorial load 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 occurs by definition 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.