SOUTH CAROLINA ELECTRIC & GAS COMPANY

COLUMBIA, SOUTH CAROLINA

SALUDA HYDROELECTRIC PROJECT

FERC PROJECT NO. 516

ADDITIONAL INFORMATION

EXHIBIT H

AUGUST 2008

Prepared by:

Kleinschmidt

Energy & Water Resource Consultants

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Information Required from All Applicants

1. The Applicant intends to continue to operate and maintain the Project to provide efficient and reliable electric service.

    a. The Applicant provides for the reliability of its electric system by maintaining an adequate reserve margin of supply capacity, and by maintaining daily operating reserves to balance the risk that some of the Applicant's generation capacity may be forced offline on any given day because of mechanical failures, wet coal problems, environmental limitations, or other unforeseen events. The Applicant is a member of the Virginia-Carolinas Electric Reliability Council (VACAR), an organization which coordinates a regional reserve sharing system allowing its members to pool their reserve generation resources on a prorated basis. This VACAR Reserve Sharing Arrangement (VRSA) provides a formal mechanism for VACAR members to share reserve capacity.

    b. Saluda Hydro will continue to operate primarily as a reserve generation facility in the SCE&G system. In the event of a loss of generation elsewhere in the Applicant's system, the Project units can be started and brought to full load within 15 minutes. This allows a rapid response to emergencies on SCE&G's system, and also fulfills all or part of SCE&G's reserve share obligation as a member of VACAR. Providing rapid response to emergencies on SCE&G's system and those to which SCE&G is interconnected helps to insure reliability of electrical service both locally and area-wide. The use of Saluda Hydro for reserve generation is more efficient and reliable than other reserve alternatives such as combustion turbines or diesel powered generators.

    c. Saluda Hydro provides "black start" capability[1] for a portion of the Applicant's system, including the V. C. Summer Nuclear Station in Fairfield County, and serves

[1] "Black start" refers to the ability to start a generating unit or plant with no external power supplied from the transmission and distribution system, using the power plant's own internal power sources such as batteries or stored compressed air or water. Black start capability may be required to restore the electric power system in the event of widespread damage to the

as a backup source of station service power for the nearby McMeekin steam-electric station. Both of these roles enhance the reliability of the Applicant's system.

d. Plans for increasing capacity and generation at Saluda Hydro are limited to replacement of turbine runners with more efficient modern designs and generator rewinds. Significantly increasing the hydraulic capacity of the Project is not considered feasible at Saluda Hydro, based on a Resource Utilization Study prepared in 2005. Potential equipment upgrades were evaluated in a Saluda Hydroelectric Project Upgrade Study (Kleinschmidt 2007). The results of both studies are summarized in Exhibit B, and detailed cost information for the proposed upgrades is given in Exhibit D.

e. The Applicant intends to continue to operate the Project in coordination with upstream and downstream water resource projects in all conditions from droughts to extreme floods. Operations at Saluda Hydro will continue to be coordinated with upstream Buzzards Roost Hydroelectric Project (P-1267) in order to utilize the flows in the Saluda River efficiently.

f. The Applicant's plans to continue to operate the Project within its own system, and in coordination with others, as described above, will help to minimize the cost of production by providing economical reserve generation capacity.

2. The Applicant's need over short and long term for power generated from this project is described as follows:

a. Saluda Hydro's primary function will continue to be reserve generation to fulfill the Applicant's own system reserve requirements, as well as reserve obligations under the existing VRSA. VACAR has set the regional reserve requirement at 150 percent of the largest unit in the region. The Applicant's prorated share of this reserve requirement is approximately 200 MW. Currently, reserve generation on the Applicant's system is provided by a mix of conventional hydro (non-run of river), pumped storage, and combustion turbine assets. Of these, only Saluda

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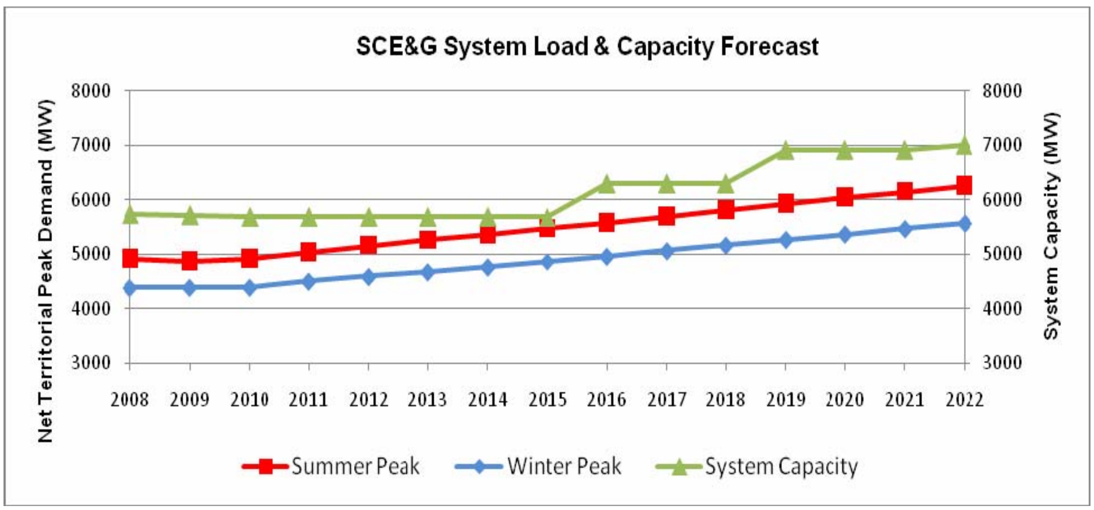
transmission and distribution system. Hydroelectric plants need very little power to start generating, and are often utilized as black start resources.

b. The graph below shows that total summer and winter peak electric demand on the Applicant's system is forecast to increase by approximately 1.7 percent per year during the period 2008 – 2022. The Applicant's system generation capacity is planned to increase by 614 MW of new baseload generation in both 2016 and 2019 due to planned additional nuclear units on the existing V. C. Summer Station site. Based on the forecast, the continued availability of Saluda Hydro for reserve generation will be critical to maintaining the reliability of the Applicant's system.



Source: Integrated Resource Plan, SCE&G May 2008.

c. Discussion of increase in fuel, capital, and O&M costs if license is not granted: Saluda Hydro provides rapid-start reserve generation capacity for the Applicant's system and to meet the Applicant's reserve share obligation under the VRSA. This reserve generation capacity is critical to maintaining the reliability of the Applicant's system as well as contributing to the reliability of the regional transmission grid. Should a new license for Saluda Hydro not be granted, the Project's reserve generation capacity would have to be replaced by constructing new rapid-start generation facilities, most likely aero-derivative combustion turbines. The cost of financing, constructing, operating, and maintaining such facilities would increase the cost of power to the Applicant's wholesale, residential, commercial, military, and industrial customers.

The loss of license for Saluda Hydro through a takeover by the Federal Government or through the decommissioning of the Project would result in a loss of tax revenues. The Project annually contributes approximately $6.1 million in property taxes and approximately $3.5 million in income taxes. The governmental entities affected by this loss in revenue would ultimately have to seek a reduction in expenses or an increase in other sources of revenue.

d. Effect of each alternative source of power on customers, operation and load characteristics, and communities: New rapid start reserve generation facilities would require a sizable site to accommodate the generating units, approximately 1,000,000 gallons of fuel, and ancillary equipment. The large quantity of fuel stored would present potential environmental and safety concerns. The site would have to be chosen with regard to permitting constraints for air, water, and noise emissions; water availability; and the availability of interconnections with the electric transmission system. The cost of financing, constructing, operating, and maintaining such facilities would increase the cost of power to the Applicant's wholesale, residential, commercial, military, and industrial customers. The effect on operation and load characteristics would vary with the site(s) selected and their proximity to load centers on the Applicant's system.

3. Data showing need, reasonable cost and availability of alternate source of power:

a. The average annual cost of power produced by the Project in 2007 was $15.60 per net MWH (FERC Form 1).

b. Projected resources required to meet short and long term capacity and energy requirements are presented in Exhibit H-1, <u>2008 Integrated Resource Plan (IRP).</u> The Applicant files a copy of its IRP with the SCPSC in accordance with S.C. Code Ann. § 58-37-40 (1976, as amended), § 58-33-430 (1976, as amended), and

SCPSC Order No. 98-502. This Plan was filed with the South Carolina Public Service Commission on May 28, 2008.

c. Costs associated with alternative sources of power:

i. Generation of additional power at existing facilities: Since Saluda Hydro is a reserve generation facility, the plant's rapid start capability is critical to its function. The Applicant currently has no other rapid-start generation units at existing facilities which could be utilized to replace the Project's reserve capacity in the long term.

ii. Restarting deactivated units: SCE&G has no deactivated generation facilities capable of being restarted at this time.

iii. Purchase of power off-system: It is not practical to purchase rapid start reserve capacity off-system. Having an on-system, rapid-start reserve generation asset under the direct control of the Applicant's system operators is essential to maintaining reliability under adverse system conditions.

iv. Construction or purchase and operation of a new power plant: New on-system, rapid-start reserve generation plants to replace Saluda Hydro would be either diesel generator sets (80 to 100 units would be required), or aero-derivative combustion turbines (4 units would be required). Capital construction costs in 2010 dollars associated with each alternative are estimated to be:

1. Diesel Generator Sets:

LAND	$108,668
PERMITTING	$173,869
EQUIPMENT	$44,010,671
BALANCE OF PLANT	$41,293,963
ENGINEERING	$543,342
CONSTRUCTION	$7,606,783
START-UP	$271,671
PROJECT MGMT	$271,671
TOTAL	**$94,280,638**

2. Aero-Derivative Combustion Turbines:

LAND	$108,668
PERMITTING	$173,869
EQUIPMENT	$63,896,974
BALANCE OF PLANT	$20,407,911
ENGINEERING	$652,010
CONSTRUCTION	$12,388,189
START-UP	$217,337
PROJECT MGMT	$326,005
TOTAL	**$98,170,964**

The above costs are based on budget level estimates from equipment vendors and suppliers, and estimates developed by the Applicant based on typical construction costs for these types of facilities.

[It should be noted that the Applicant's Generation Planning Group has estimated the installed cost of aero-derivative combustion turbines in 2007 dollars is $697 per installed KW of capacity. Based on that estimate, the cost of replacing Saluda Hydro with 206 MW of aero-derivative combustion turbines would be $143 million.]

The estimated increase in annualized 30 year life cycle costs in 2010 dollars (including capital cost from the tables above, operation and maintenance costs, and fuel costs) for replacing Saluda Hydro with these two alternatives are estimated to be:

1. Diesel Generator Sets: $23,500,000 per year.

2. Aero-Derivative Combustion Turbines: $16,941,000 per year.

v. Discussion of the relative merits of each alternative:

1. Diesel generator sets have an overall efficiency of about 37%, and an estimated equivalent availability of about 90%. 80 to 100 individual engine-generator sets would be required to replace the 206 MW of reserve capacity currently provided by the Saluda Hydro Project. This would require a sizable site to accommodate the generating units, approximately 1,000,000 gallons of fuel, and ancillary equipment. The large quantity of

fuel stored would present potential safety and environmental hazards. The site would have to be chosen with regard to permitting constraints for air, water, and noise emissions; water availability; and the availability of interconnections with the electric transmission system.

2. Aero-derivative combustion turbines have an overall efficiency of about 40%, and an estimated equivalent availability of about 90%. Four to five individual turbine-generator sets would be required to replace the 206 MW of reserve capacity currently provided by the Saluda Hydro Project. This would require a sizable site to accommodate the generating units, approximately 1,000,000 gallons of fuel, and ancillary equipment. The large quantity of fuel stored would present potential safety and environmental hazards. The site would have to be chosen with regard to permitting constraints for air, water, and noise emissions; water availability; and the availability of interconnections with the electric transmission system.

d. Load management measures such as conservation: The Applicant's Demand Side Management programs are described in Section 10 below.

4. Effect on direct providers and their customers of alternate sources: If any of the alternative sources of rapid start reserve capacity discussed above were to be constructed, the cost of financing, constructing, operating, and maintaining such facilities would increase the cost of power to the Applicant's wholesale, residential, commercial, military, and industrial customers.

5. Use of power for Applicant's own industrial facilities: The Applicant is an investor-owned utility, and has no non-utility industrial facilities to be affected by loss of electricity from the Saluda Hydroelectric Project. Saluda Hydro is capable of providing backup station service power to the adjacent McMeekin steam-electric generating station. Saluda Hydro also provides "black start" capability for a portion of the Applicant's system as described above.

6. Need for Project to foster the purpose of an Indian Tribal Reservation: The Applicant is not an Indian Tribe, and does not use the electricity generated by Saluda Hydro to foster the purposes of a reservation.

7. Impact on the operation and planning of transmission system of receiving or not receiving license: The Saluda Hydroelectric Project is an important resource for meeting the Reliability Standards of the North American Electric Reliability Corporation (NERC) for interconnected-systems operation, in particular Standard BAL-001 - Real Power Balancing Control Performance and Standard BAL-002 – Disturbance Control Performance. These Standards provide recommended practices for maintaining steady-state frequency within defined limits and to provide for operating reserves and frequency regulation to address the resolution of inadvertent interchange between electric systems or conditions of insufficient generation resources. Over many years, NERC has developed and adopted these Standards for the planning and operation of the bulk electric system through the cooperative efforts of its member utilities. NERC has recently begun to change from voluntary to mandatory Standards for system reliability management. NERC's Regional Entities have initiated requirements to assess and enforce compliance with NERC Reliability Standards. A Compliance Program designed to implement the Standards set forth by NERC has been adopted by the SERC Reliability Corporation (SERC). The Applicant is an active participant in the Compliance Program within SERC.

   The Applicant utilizes the Saluda Hydroelectric Project to comply with these NERC Standards. The Project is located in the Columbia metropolitan area, which is a major load center on the Applicant's system. The Project is also located adjacent to McMeekin Station, a combined 250 MW coal fired baseload generating facility. Interconnections with the Applicant's 115 KV and 230 KV systems are available at this location, making the current location beneficial to the Project's primary role as reserve generation in the Applicant's system. If hydroelectric operations at this facility were to be discontinued, in the short term the Applicant would be required to utilize other generation sources to maintain these and other related operational Standards specified by NERC. The effect on the Applicant's transmission system operation and planning would vary depending upon the generation sources available and their proximity to load centers on the Applicant's system. In the long term, it is likely that construction of other reserve generation facilities would be required. New reserve generation sources would best be located near one or both of the two principal load centers in the Applicant's system, namely the Columbia and Charleston metropolitan areas, and would most likely be in the form of either aero-derivative combustion turbines (at least 4 units), or diesel engine-generator sets (80 to 100 units). Depending upon siting constraints, it may not be possible to locate all of the new reserve units reasonably close to either major load center. In that case, there is the potential for negative impacts to the Applicant's transmission system in the form of inefficient redistribution of power flow in the system when reserve generation is required. It is also likely that new transmission facilities would need to be constructed to integrate the new reserve units into the Applicant's system. The potential cost impact of these system modifications would depend on the particular site(s) chosen and their proximity to load centers and system interconnection points. Transmission costs associated with new rapid start generation has been estimated by the Applicant's Generation Planning group to be $10.75 per installed KW of capacity, or approximately $2.2 million to replace Saluda Hydro with 206 MW of new rapid start generation on the Applicant's system.

An additional consideration in this discussion is the Saluda Hydroelectric Project's role as a "black start" resource in the Applicant's system, as previously described in general terms in Section 1 of this Exhibit. The Project is a key resource, along with the Applicant's Parr Shoals Hydroelectric development, in providing black start capability for the V. C. Summer Nuclear Station, which is located in Fairfield County and is owned (in part) and operated by the Applicant.

A detailed map of the Applicant's transmission facilities is included as Exhibit H-2.

8. Need for, or usefulness of, modifications to existing Project facilities or operations: A detailed discussion of proposed modifications to the existing turbo-generating equipment is presented in Exhibit B, Section 4.0. The proposed equipment modifications will increase the installed generation capacity at the Project, in order to maintain adequate reserve generation capability in the future. The proposed modifications will also increase dissolved oxygen (DO) uptake in the water passing through the turbines, which is anticipated to enhance water quality in the lower Saluda River during the summer and fall, when reservoir stratification reduces DO levels in the Project forebay. Maintaining

9. The Applicant's financial resources to meet its obligations under a new license are as follows:

   a. The Applicant has adequate personnel resources to continue to operate and maintain the Saluda Hydroelectric Project in accordance with the provisions of the license. The permanent staff at the plant consists of four operator-repairmen, who are on site eight hours per day, five days per week, and perform plant checks on weekends and holidays. In addition, the Applicant can provide additional personnel from its other electric generating facilities in the event of emergencies or major maintenance outages. An organization chart for the Project is provided as Exhibit H-3. Saluda Hydro personnel receive on-the-job and other in-house training programs to prepare them to safely operate and maintain the plant, including training for response to environmental and other emergencies. A list of required training programs is included as Exhibit H-4, and a list of required Operator/Repairman Training programs is included as Exhibit H-5.

10. The Applicant proposes to extend the Project to encompass certain additional lands for existing and/or future recreation sites. All of the proposed expansion property is already owned in fee by the Applicant, therefore notification of the owners of such property for this purpose is not required. Details on these properties will be included in the Recreation Plan currently being developed in consultation with Project stakeholders as described more fully in Exhibit E.

11. Statement of energy conservation programs and measures: The Applicant is actively involved in a number of Demand Side Management Programs to improve the efficiency of electricity generation and consumption on its power system. These programs can be divided into three major categories: Customer Information Programs, Energy Conservation Programs, and Load Management Programs. These programs in combination are expected to reduce peak system load by 209 MW each year during the period 2008 – 2022.

Customer Information Programs

These programs include annual energy campaigns and a Web-based information initiative. The 2007 Energy Campaign consisted of:

- Weatherline: Provided call-in access to energy saving tips.
- Targeted bill inserts promoting the Low Income Home Energy Assistance Program (LIHEAP).
- Brochures and other printed material containing energy saving tips, available at the Applicant's business offices.
- News releases distributed to print and broadcast media throughout the Applicant's service area.
- Applicant's in-house energy experts conducted several interviews with local media regarding energy conservation.
- Web site link to energy saving tips and other conservation information was included in most of the communication channels mentioned above.
- Weatherization project: Applicant's partners and employee volunteers provided weatherization to low income homes in the service area.
- Speakers Bureau: Applicant's representatives talked to local organizations about energy conservation, and also provided videos produced by the Applicant that highlight energy conservation.
- Energy Awareness Month: The Applicant used the month as an opportunity to promote energy conservation via the local media.
- Energy Wise Newsletter – Provides energy conservation information for all customer classifications. Direct mailed to more than 500,000 customers in November, 2007.

Web-based Information and Services Programs allow 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 more than 97,000 visits received in 2007. The SCE&G Web site supports all communication efforts to promote energy savings tips. The "Manage Energy Use" section of the SCE&G Web site, which features an interactive bill estimator tool, video instruction on weatherization and other useful content, is currently averaging more than 9,000 visits per year. For business customers, online information includes: power quality technical assistance, conversion assistance, new construction information, expert energy assistance and more.

Energy Conservation Programs

The Applicant currently has three energy conservation programs:

- **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.
- **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.
- **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

The Applicant maintains four load management programs:

- 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.
- 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.
- 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.
- 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.

<u>Load Impact of Load Management Programs</u>

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 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)
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

As a corporation organized and existing under the laws of the State of South Carolina, the Applicant must comply with the policies of the South Carolina Public Service Commission (SCPSC) regarding energy conservation. The Applicant files a copy of its Integrated Resource Plan (IRP) with the SCPSC in accordance with S.C. Code Ann. § 58-37-40 (1976, as amended), § 58-33-430 (1976, as amended), and SCPSC Order No. 98-502. The section of the IRP titled "Demand-side Management at SCE&G" describes many of the Applicant's programs as well as the methodology used by the Applicant to choose cost effective programs that promote energy conservation and load management by the Applicant's customers. A copy of the most recent IRP filing (May 28, 2008) is included as Exhibit H-1.

12. Indian tribes with land on the Project or who would be affected by the Project:

a. There are no Indian tribes with land within the Saluda Hydroelectric Project boundary. However, during November 2004 through January 2005, 17 federally-recognized Indian Tribes were contacted by mail to see if they wished to be consulting parties for the Saluda Hydroelectric Project. The list of potentially interested tribes was obtained from the State Historic Preservation Office (SHPO). In March 2007, follow up phone calls and faxes were made to tribes that had not responded to the initial contact letter. Contact information for the two consulting party tribes is contained in the Historic Properties Management Plan (S&ME 2007), which is included as an Appendix to Exhibit E in this Application. The responses of the tribes who were contacted are summarized below.

Indian Tribe	***Response/Stat*****us**
Absentee-Shawnee Tribe	No Response
Catawba Indian Nation	Consulting Party
Cherokee Nation	No Response
Chickasaw Nation	No Response
Choctaw Nation of Oklahoma	No Response
Eastern Band of Cherokee Indians	Consulting Party
Eastern Shawnee Tribe of Oklahoma	Not interested in being a consulting party; however, notify if human remains or funerary objects are found.
Jena Band of Choctaw Indians	No Response
Miccosukee Tribe of Indians of Florida	Not interested in being a consulting party
Mississippi Band of Choctaw	Not interested in being a consulting party
Muscogee (Creek) Nation	Not interested in being a consulting party; however, notify of inadvertent discoveries.
Poarch Band of Creek Indians	No Response
Santee Sioux Tribe of Nebraska	No Response
Seminole Indian Tribe	Not interested in being a consulting party; however, they want a copy of final archaeology report.
Seminole Nation of Oklahoma	No Response
Tuscarora Nation	Not interested in being a consulting party; however, notify of any inadvertent discoveries.
United Keetoowah Band of Cherokee	Not interested in being a consulting party; however, notify if human remains or funerary objects are found.

Information Required from Existing Licensees

1. The Applicant has taken measures to ensure safe management, operation, and maintenance of the Saluda Hydroelectric Project, and will continue to do so in the future, as described below.

   a. Operation During Flood Conditions: The Applicant has developed a computer based Flow Forecasting Model (FFM), which is used to predict inflow to the Project, using real-time data provided by the U.S. Geological Survey (USGS) and the National Weather Service (NWS). FFM simulations are run when flood conditions are expected in the Project drainage basin, and the results are used to determine what measures should be taken to accommodate the predicted inflow. Such measures include generation in advance of the arrival of high inflow in order to lower the reservoir level to allow storage of the flood flow and, in extremely large floods, operation of one or more spillway gates to allow passage of inflow which cannot be stored. Based on the annual flow duration curves presented in Exhibit B, the hydraulic capacity of the powerhouse corresponds to approximately the 1 percent exceeds flow. This makes operation of the spillway extremely infrequent, except for annual testing as required by the FERC.

The primary method of operating the spill gates is by electric drive motors for each gate. The electrical power source for the spillway gates is a power line connected to the local area distribution system. The back-up power supply is a diesel generator located near the gate operating house. The existing electrical service is sufficient to raise or lower two gates at one time; however the two gates cannot start simultaneously, but can be started within a few seconds of one another. All six gates can be opened from a full closed position to a 10 foot opening in approximately 60 minutes. Raising or lowering Gates 1 - 4 averages 56 seconds per foot of travel. Raising or lowering Gates 5 or 6 averages 58 seconds per foot of travel. In the event that electrical power is not available to operate the spill gate drive motors, the gates can be opened or closed using an air-drive motor. The air supply for this type of operation would come from a portable air compressor (gas or diesel fueled). It would take four to six hours to open all six gates using compressed air.

During high tailwater conditions, the Saluda Hydro powerhouse would be subject to flooding through the work bay roll-up door and personnel doors at the northeast wall of the work bay, and through the seven large ventilation louvers located on the east side of the turbine level at el. 192.5’ NAVD[2].

Flood protection of the work bay roll-up and personnel doors is accomplished by installation of stop logs in steel channels outside the work bay door alcove. The stop logs are stored beneath the work bay floor under removable floor sections. The stop logs can be put in place using the work bay crane and forklift.

[2] Unless otherwise noted, all elevation references in Exhibit H are given in North American Vertical Datum 1988 (NAVD 88); conversion to traditional plant datum (PD, used in numerous supporting studies for this license application and often erroneously referred to as MSL) requires the addition of 1.50 feet.

Flood protection of the ventilation louvers is accomplished by installing rubber seals around the perimeter of each louver. The seal material is stored on-site in the plant warehouse. The seal material must be cut to fit the louvers, and attached to the louvers with silicone adhesive/sealant, which is also kept on site. The louvers are to be maintained in the closed position after installation of the seal material, until the tailwater level has receded to below elevation 190.0 NAVD.

b. <u>Emergency Action Plan</u>: The Applicant maintains an up to date Emergency Action Plan (EAP) in accordance with FERC requirements. This plan defines responsibilities and provides procedures designed to identify unusual and unlikely conditions that may endanger either the original Saluda Dam or the newly completed back-up dam in time to take mitigating action and to notify the appropriate emergency management officials of possible, impending, or actual failure of either dam. The plan may also be used to provide notification when spillway flood releases create major flooding.

Annual EAP training of Project personnel is performed (beginning in 2006, the annual training includes emergency response agency personnel, as required by the FERC Atlanta Regional Office.) An annual EAP drill is conducted which consists of contacting each local emergency responder by telephone to confirm that the notification procedures and contact information are valid. Every five years, a tabletop and functional exercise are conducted at one of the Applicant's high hazard projects, including Saluda, which is intended to mimic in real time the activation of the EAP, with full participation of the emergency responders.

To assist the State and Counties with the notification process during possible impending or actual failure of either dam, the Applicant has installed a siren system for early warning of the downstream residents. The siren coverage area includes the one-hour inundation zone and 1500 feet on both sides of the river from the one-hour boundary to the Columbia Canal diversion dam on the Broad River and Granby Park on the Congaree River. The siren system will be activated by the Applicant after consultation and coordination with the local responder agencies. The Applicant also maintains an emergency information brochure on its company website. This brochure provides evacuation routes, emergency shelter locations, and directions for tuning to radio and television stations for emergency service announcements for those in the siren coverage area.

c. Monitoring Devices: The Project structures are monitored using instrumentation (including piezometers, inclinometers, tilt meters, seepage measurement points, and survey monuments) which is read periodically by personnel familiar with the structures and instruments. The applicant maintains a Surveillance and Monitoring Program for the Project, and files annual Surveillance Reports with the FERC Atlanta Regional Office. Plant maintenance personnel staff the plant five days a week, and are also present for brief surveillance periods on weekend days and holidays. This group performs routine daily surveillance of the dam. Detailed monthly, quarterly, semi-annual, and annual surveillance and reading of instrumentation are done by SCE&G Fossil/Hydro engineering personnel, and maintenance of the dam is performed by SCE&G parks and dams maintenance personnel from another location. All of these groups are responsible for observation and reporting of any problems noticed during their surveillance.

d. Employee and Public Safety: The Saluda Hydroelectric Project has a good employee safety record. During the period since the current license was issued, there have been 5 work related injuries at the Project, one each in 1986, 1987, 2002, 2003, and 2007. All of the injuries were minor, three requiring first aid only, and the other two requiring only minor medical attention.

The Applicant maintains a Public Safety Plan (PSP) for the Project, which includes warning and caution devices of various types and at various locations at the public access facilities on the reservoir and downstream of the dam in the lower Saluda River. The Applicant maintains a system of operational sirens and strobe lights along the lower Saluda River to warn recreational users of rising water levels. The Applicant has consulted with the Safety and Recreation Resource Conservation Groups, and will install additional sirens, strobe lights, and signage in areas identified as more frequented by recreational users. Any new sirens, strobes, and signage installed will be included in a revised PSP, which will be filed with the FERC Atlanta Regional Office.

As a result of recommendations from the Safety Resource Conservation Group, the Applicant has implemented a public website (http://www.sceg.com/en/my-community/lower-saluda-river/), which provides information on current and planned generation at Saluda Hydro. This allows recreational users of the lower Saluda River to be better informed about river conditions when using the river.

In response to another recommendation from the Safety Resource Conservation Group, the Applicant has implemented an automatic notification (ring-down) system which allows individuals who are registered for the service to be called by phone when generation is increased at Saluda Hydro. A message is played and the recipient must confirm receipt of the message by pressing a key on their phone. This system also provides e-mail notification to registered users.

In addition to the Applicant's measures to maintain and improve public safety, the S.C. Department of Natural Resources maintains navigational aids on the reservoir, and conducts law enforcement patrols by boat on the reservoir. The four counties surrounding the Project also patrol the reservoir by boat under a multi-county agreement.

There have been at least 74 incidents involving accidental or criminal death or injury to 83 members of the public within the Saluda Hydroelectric Project during the period since the present license was issued through the end of 2007.

The following table lists the number of incidents by year since 1987.

Year	Number of Incidents
1987	2
1990	6
1991	2
1992	4
1993	1
1994	1
1995	5
1996	6
1997	10
1998	5
1999	2
2000	4
2001	5
2002	4
2003	6
2004	3
2005	4
2006	3
2007	1

Of the 83 people involved in incidents since 1987, 50 drowned in the reservoir or Saluda River; 20 died or were injured as a result of boat or watercraft accidents; 5 were involved in 2 plane crashes; 3 were homicides or apparent suicides; 2 were electrocutions (1 fatal); 1 died for medical reasons while boating, and 2 were found dead of undetermined cause.

2. Description of Current Operation of the Project:

Saluda Hydro is operated primarily as a reserve generation facility in the SCE&G system. The plant normally operates with one unit on line at minimum gate to provide downstream flow in the Saluda River. In the event of a loss of generation, the remaining Saluda Hydroelectric Project units can be started and brought to full load within 15 minutes. This allows a rapid response to emergencies on the Applicant's system, and also fulfills the Applicant's reserve share obligation under the VRSA. It should be noted that, in order to be considered a reserve generation asset at any given time, Saluda Hydro units must remain on standby and cannot be providing generation for other purposes.

Saluda Hydro is also operated to manage the reservoir elevation on a seasonal basis. Under the current license, the Applicant has managed the reservoir using monthly target elevations, which are subject to revision by the Applicant's management based on climatic conditions, reservoir level at the time, dam and reservoir maintenance requirements, or operational considerations. Historically, the reservoir has been maintained between El. 348.5' (winter) and El. 356.5' (summer). Occasional drawdowns to El. 343.5' have occurred for Project maintenance work or control of aquatic vegetation (primarily hydrilla) in the reservoir. The current license allows a maximum operating water surface elevation of 358.5'. Saluda Hydro units are occasionally dispatched on an economic basis when it is necessary to release water from the reservoir for seasonal or other drawdowns, or to pass inflow from precipitation in the drainage basin. During the relatively infrequent periods when Saluda Hydro is being utilized for reservoir management, the units being so utilized are not available for reserve generation, and other generation assets must be made available to meet the Applicant's obligation under the VRSA.

3. Discussion of history of Project and record of programs to upgrade operation and maintenance of Project:

The Saluda Hydroelectric Project was constructed between 1927 and 1930 by the Lexington Water Power Company, which merged in 1943 with SCE&G. When the hydro plant was completed it had four turbines, each capable of producing 32,500 kilowatts (KW). When the original dam was built, provisions were made to later add fifth and sixth turbines. The intake tower and the associated tunnels to carry reservoir water under the dam to the future unit were constructed when the dam was originally built. The following modifications have been made to the Project since its original construction:

1943 – 1946: Two additional spillway gates added, spillway discharge channel enlarged and partially rerouted, dam crest elevation raised by 3 feet, rock excavated from the spillway channel added to the downstream face of the dam. Added flood walls around the butterfly valve actuators, watertight doors at several locations, and provisions for stop logs at the work bay roll-up door to protect from high tailwater conditions.

1957 – 1958: Added cooling water piping connected to two penstocks for the McMeekin steam electric generating plant. At this time Saluda Hydro was automated, giving the system dispatcher operational control of the plant.

1966: Replaced unit 3 generator original asphaltic base coils for the stator with class B insulated coils. Generator capacity increased to 47,000 KVA (up from 40,625 KVA), power factor changed from 0.80 to 0.90, generator capacity increased to 42.3 MW.   Unit 3 is limited by turbine horsepower to 32.5 MW.

1968 – 1971: Construction of fifth unit rated at 67.5 MW. Unit 5 was put into commercial operation during the summer of 1971, making the total generator capacity of the Saluda Hydro Plant 207.3 MW.

1975: Replaced upstream riprap armor between original dam stations 63+50 and 77+00 by placing new filter, bedding, and a 30 inch layer of armor stone. Spot repairs to the remainder of the upstream armor were made in October 1977.

1975 - 1976: S.C. Department of Transportation (SCDOT) widened the crest of the original dam to 36 feet, in order to improve driver safety on SC Rt. 6.

1977: 81 stator coils were replaced by General Electric on the Unit 4 generator.

1985: 5 stator coils on the Unit 2 generator were replaced by Westinghouse.

1983 - 1995: All of the main step-up transformers were replaced with new or refurbished units.

1989: Installed sheet pile wall with top elevation 375.5’ on the crest of the dam at the upstream side of SC Highway 6, to protect the dam from overtopping in the event of a new, larger PMF. A computer based Flow Forecasting Model (FFM) was developed and is used to predict inflow to the Project, using real-time data provided by the U.S. Geological Survey (USGS) and the National Weather Service (NWS). The development of the FFM in combination with the sheet pile crest wall allowed the Project to meet current hydrologic safety requirements of the FERC, and raising the embankment further was not required.

1990: Epoxy grouting of cracks in the concrete walls of the five intake towers between elevations 343.5’ and 358.5’. Also, Spillway Gates 5 and 6 were painted, gate seals were replaced, and damaged structural members of Gate No. 6 were replaced.

1991: Unit 1 and 3 surge tanks were removed and the wicket gate closure timing on these units was slowed down to about 25 seconds.

1991 – 1992: Installation of post-tensioned anchors in the south abutment wall of the spillway to stop rotation of the wall.

1994: Replaced the four original riveted steel spillway gates (Gate Nos. 1 - 4), which were badly deteriorated, with new welded steel gates of similar design.

2002 – 2005: Constructed a rock fill and roller-compacted concrete backup dam immediately downstream of the original dam. Additional material was added to the downstream side of the original dam to provide a base for two additional lanes of SC Highway 6. The SCDOT subsequently added pavement, guardrail, and markings to complete these traffic lanes.

2006: Repaired 3,000 linear feet of the upstream face riprap armor on the southern portion of the original dam, between original dam stations 45+00 and 75+00. A 200 linear foot section between stations 53+00 and 55+00 was completely excavated and new filter, bedding, and armor stone placed.

2006 - 2008: The SCDOT widened the crest of approximately 4,750 linear feet of the original dam to a maximum of approximately 50 feet, to accommodate additional travel lanes, pedestrian and bicycle lanes, and wider shoulders.

4. Summary of unscheduled outages over the last 5 years:

YEAR	DATE	UNIT	PROBLEM	DURATION
2003	3-25	2	REPLACEMENT OF BROKEN WICKET GATE ARM	2 WEEKS 3 DAYS
2003	5-16	2	REPAIR TURBINE GUIDE BEARING	3 WEEKS
2003	9-1	5	REPAIR BEARING COOLER	2 DAYS
2004	8-3	1	REPAIR VOLTAGE REGULATOR TRANSFORMER	7 DAYS
2005	3-29	2	REPAIR BEARING TEMPERTURE PROBLEM	9 DAYS
2005	4-20	3	REPAIR BELT DRIVEN OIL PUMP	2.5 DAYS
2005	5-21	3	REPAIR PIT DRAIN PIPING	1.5 DAYS
2005	5-30	3	REPAIR BROKEN HEADGATE CABLE	25 DAYS
2005	8-26	4	REPAIR COMMUTATOR	80 DAYS
2005	10-8	3	REPAIR VOLTAGE REGULATOR TRANSFORMER	2 DAYS
2005	10-9	2	REPAIR HOLE IN PENSTOCK	9 DAYS
2005	11-14	2	REPAIR LEAKING OIL COOLER	2 DAYS
2006	NO FORCED OUTAGES >1 DAY			
2007	3-26	3	REPAIR BELT DRIVEN OIL PUMP	25.5 HOURS
2008	3-4	3	INVESTIGATE GENERATOR COOLING WATER	42 HOURS

Estimating the generation lost due to forced outages is impractical, since the Project is utilized primarily for reserve generation on an as-needed basis.

5. Discussion of record of compliance with terms and conditions of existing license, including list of all incidents of non-compliance, their disposition, and documentation relating to each incident:

a. The Applicant has made a significant effort to comply with all articles in the existing license, as well as with the FERC's Rules and Regulations, and any directives from the Atlanta Regional Office. When necessary, the Applicant has requested additional time to complete work in progress. The Applicant has not been cited for non-compliance during the term of the current license. The following items provide specific compliance information for several key license articles.

b. Article 5 (Within 5 years of license issuance, acquire title in fee or the right to use in perpetuity all lands necessary for the Project operation): The conditions of this article have been met.

c. Article 8 (Install stream flow and water level gages): The Applicant compensates the USGS to maintain the following gages:

- 02166501 - Saluda River at Lake Greenwood tailrace
- 02167000 - Saluda River at Chappells
- 02167450 - Little River near Silverstreet
- 02167582 - Bush River near Prosperity
- 021677037 - Little Saluda River at Saluda
- 02168500 - Lake Murray near Columbia
- 02168504 - Saluda River below Lake Murray
- 02169000 - Saluda River near Columbia
- 02169500 - Congaree River at Columbia.

d. Article 13 (Other uses of Project property and water): The Applicant has water withdrawal agreements in place with the municipal water users listed in Exhibit C.

e. Article 17 (Construct and maintain recreational facilities): All recreational facilities required in the current license have been constructed and maintained in good order.

f. Article 18 (Provide public access to Project water and lands for recreational use): The Applicant has provided public access to Project lands and waters as required.

g. Article 19 (Take reasonable measures to prevent soil erosion): The Applicant has obtained all required Federal, State, and local permits, including sediment and erosion control permits, when performing construction, maintenance, or operation of the Project.

h. Article 20 (Clearing of land and disposal of material): The Applicant has complied with the requirements of this article.

i. Article 24 (Consultation with SHPO Prior to Future Construction): Prior to the construction of the Saluda backup dam in 2002 -2005, the Applicant conducted a cultural resources survey of the Project area, and entered into a programmatic agreement with the SHPO and the FERC. All requirements of the programmatic agreement have been fulfilled.

j. Article 25 (Tailrace fishing facility study): This study was filed with the FERC as required. A tailrace fishing platform was not required. Access to the lower Saluda River for boating and fishing has been made available to the public.

k. Article 26 (Perform new Probable Maximum Flood study): This study was filed with the FERC as required. A sheet pile crest wall was added to the dam, and a computer based Flow Forecasting Model was developed and implemented.

l. Article 27 (Perform seismic hazard study): This study was performed as required, and led to the construction of the Saluda backup dam.

m. Article 28 (Annual charges): The Applicant pays annual charges for the Project as stipulated.

n. Article 29 (Project amortization reserve account): The requirements of this article have been met.

o. Article 30 (Use and occupancy of Project lands and waters): The Applicant has a Land Use and Shoreline Management Plan in place, and has granted permission for use of certain Project property for non-Project uses, such as docks and easements. Applicant annually files documentation with the Commission regarding easements and land sales from the previous year.

p. Article 31 (Develop and file annual operating plan to enhance water quality in the lower Saluda River): This article was amended to the license by FERC order dated July 15, 2004. The Applicant has entered into a settlement agreement with two non-governmental organizations (NGOs) which requires the Applicant to take action to improve water quality (specifically dissolved oxygen) in the Project tailrace and lower Saluda River. The Applicant files annual reports by June 30 of each year as required by this Article.

q. The Commission issued an Order dated June 23, 2004 [107 FERC ¶62,273] approving the Applicant's update of the Saluda Project's Land Use and Shoreline Management Plan, with modifications. On October 28, 2004, the Commission issued an Order Clarifying and Modifying the June 23, 2004 Order [109 FERC ¶61,083]. In the October 23, 2004 Order, the Commission ordered the Applicant to *"…inventory all developed shoreline within the project boundary for structural encroachments and determine if this property is still needed to serve a project purpose, during pre-filing consultation in its relicensing proceeding. Any property within the project boundary that is no longer needed to serve a project purpose should be removed from the project boundary in the licensee's application for a new license."*

After consultation with legal counsel, and performing the required inventory of the developed shoreline properties, the Applicant has determined that removing shoreline properties which have been sold from the Project boundary may detrimentally affect the Applicant's flowage rights on some or all of the properties in question, and could expose the Applicant to additional liability should the reservoir surcharge at some future time due to flood conditions beyond the control of the Applicant. A letter dated April 24, 2008 from John B. McArthur, Attorney, to Patricia B. Morrison of the Applicant's Legal Department outlines the issues and is attached as Exhibit H-6.

The Applicant submits that retaining the subject property within the Project boundary is supported by previous Commission action denying a request to modify a Project boundary line at another FERC licensed project to exclude private residential properties where such lands might be required to meet the reservoir's surcharge or backwater needs [Public Utility District No. 2 of Grant County, Washington, 88 FERC ¶61,012, 89 FERC ¶61,177]. The Commission premised its rejection of the proposal to exclude the subject properties on the need for flowage and the associated maintenance of the surcharge capacity of the reservoir, which the Commission defined as being the capacity of the reservoir to accommodate the volume of water between the normal full pond elevation and the maximum water surface elevation for which the Project is designed [88 FERC ¶61,032 n.20].

6. Discussion of any actions taken that affect the public:

   a. Backup Dam Construction in 2002 – 2005: As part of a seismic remediation of the Saluda Dam, a backup dam was constructed during 2002 – 2005. To maintain normal safety factors of the original embankment dam during the backup dam construction, the FERC ordered that Lake Murray be drawn down to El. 343.5' (345.0' PD) until all foundation excavations were complete and backfilled to original grade or higher. This drawdown began in the fall of 2002 and lasted until May 2004, and resulted in limited impact to recreational access to Lake Murray during that period. The Applicant extended some boat ramps, and made special provisions allowing private and commercial docks to be extended to reach the water during the construction period.

7. Ownership and operating expenses that would be reduced if Project license were transferred are as shown in Exhibit D in detail.

8. Statement of annual fees paid under Part I of the Federal Power Act for use of Federal or Indian lands within the Project boundary: There are no Federal or Indian lands located within the Saluda Hydroelectric Project boundary, therefore no annual fees are paid for such.

9. The Applicant requests a 50 year license term based on the proposed unit upgrade costs estimated to be as much as $25.3 million, the potential costs associated with protection, mitigation, and enhancement measures (to be provided later), lost generation (to be provided later), loss of real estate related revenue opportunities due to land rebalancing (to be provided later), and estimated cost to develop the new license application of $12 million. Further, Applicant submits that the Commission, in establishing the appropriate term of the new license, should give considerable weight to the fact that just three years prior to the filing of this application, Applicant had completed the construction of the back-up dam as the integral part of remediating the seismic risks

associated with the original dam, an undertaking requiring the expenditure of some $319,000,000. Although Applicant recognizes that the Commission generally does not look to expenditures incurred under a prior license as a factor in determining the term of a new license, *see El Dorado Irrigation District*, 117 FERC ¶ 61,284 at P 5 (2006); *Georgia Power Company,* 111 FERC ¶ 61,183 at PP 9-15 (2005); *Ford Motor Company*, 110 FERC ¶ 61,236 at PP 6-8 (2005), the selection of an appropriate license term does remain a matter within the Commission's discretion. *See FPL Energy Main Hydro LLC*, 88 FERC ¶ 61,116 at 61,272 (1999). Such discretion allows the Commission, in particular or extraordinary circumstances, to step away from its general policy and to take into consideration expenditures incurred under a prior license. Indeed, when a new license was issued for the 12-MW Bond Falls Project (FERC Project No. 1864); lying between Michigan and Wisconsin, expenditures under a prior license were explicitly taken into consideration in determining the length of the license term. *See Upper Peninsula Power Company*, 104 FERC ¶ 62,217 (2003). The size of the capital costs incurred by Applicant in constructing the back-up dam, which was made entirely to protect public safety and with no economic benefit to the Project whatsoever, as compared to the depreciated investment of the Project just prior to the construction of the new dam, approximately $24.5 million, amply justifies the consideration of those construction expenditures, along with all the other costs associated with the new license, in setting the term of this new license at 50 years.

EXHIBIT H-1

Saluda Hydroelectric Project P-516

2008 Integrated Resource Plan, May 2008 Update

(Filed with South Carolina Public Service Commission May 28, 2008)

2008

Integrated

Resource

Plan

May 2008 Update

A SCANA COMPANY

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:

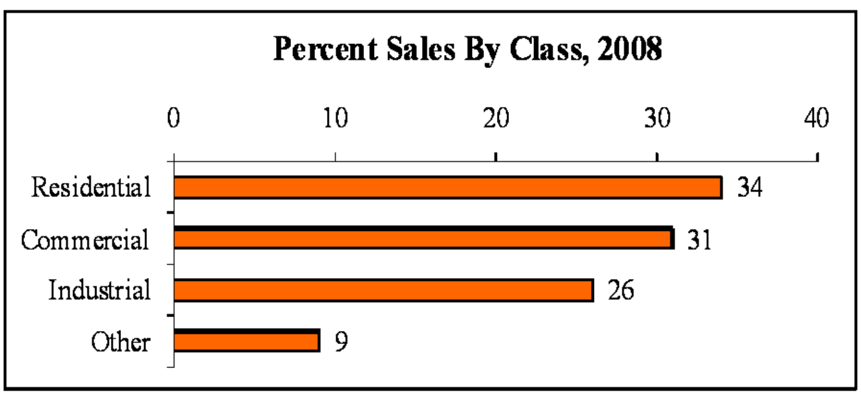
- The IRP filed on February 28, 2008 was based on the Company's forecasts and plans developed during the summer of 2007. Every summer the Company goes through another planning cycle and all forecasts and plans are updated. The Company has started this process and is aware of certain large customer expansions 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 Peak (MW)	**Winter Peak (MW)**	**Energy Sales (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.

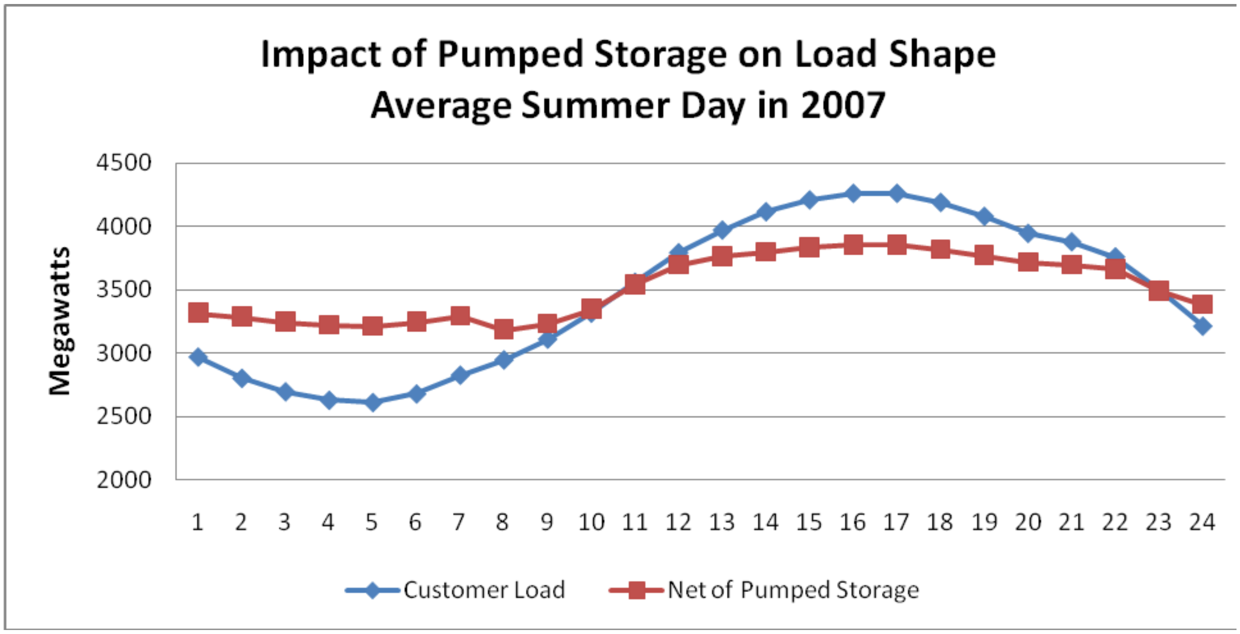
Load Impact of Load Management Programs

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.

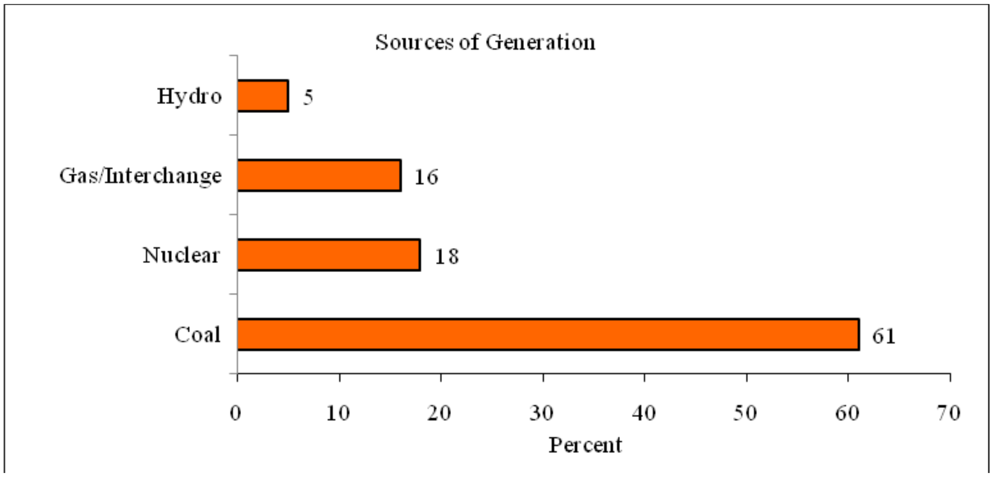
Existing Long Term Supply Resources

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		2,574
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	852
Total I. C. Turbines Capacity		1666
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	576
Total Hydro Capacity		803
Other: Long-Term Purchases		25
SEPA		33
Grand Total:		5,745

* 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.

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 normals[1]. 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 SAS[2] was used to estimate all regression models. PROC AUTOREG of SAS was used if significant autocorrelation, as indicated by the Durbin-Watson statistic, was present in the model.

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

The development of average use models began with plots of the HDD and CDD data versus average use by month. This process led to the grouping of months with similar average use patterns. Summer and winter groups were chosen, with the summer models including the months of May through October, and the winter models including the months of November through April. For each of the groups, an average use model was developed. Total usage models were developed with a similar methodology for the municipal and cooperative customers. For these customers, HDD and CDD were weighted based on Cycle 20 distributions. This is the last reading date for bills in any given month, and is generally used for larger customers.

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, $f(B) = 1 – f_1\,B - \ldots - f_1\,B^p$

u is the constant term

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

a_t is the independent disturbance, also called the random error

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

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

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

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

Many computer packages perform this iterative analysis. PROC ARIMA of (SAS/ETS)[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[tm] 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

Class Number	Class Name	Rate/SIC Designation	Comment
10	Residential Non-Space Heating	Single Family	Rates 1, 2, 5, 6, 8, 18, 25, 26, 62, 64
		Multi Family	67, 68, 69
910	Residential Space Heating	Mobile Homes	
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, 27, 29, 62, 64, 67, 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 99	Other or Unknown SIC Code*
		Rate 24, 27, 60	Large General Service
		Other	Rates 18, 25, and 26
60	Street Lighting	Rates 3, 9, 13, 17, 18, 25, 26, 29, and 69	
70	Other Public Authority	Rates 3, 9, 20, 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

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

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

The load factor is thus seen to be a ratio of total energy consumption relative to what it might have been if the customer had maintained demand at its peak level throughout the year. The value of a 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 occuring 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.

EXHIBIT H-2

Saluda Hydroelectric Project P-516

Map of Electric Transmission System, Rev. 48

CEII – (Not Available on Public Version)

EXHIBIT H-3

SALUDA HYDROELECTRIC PROJECT NO. 516

PROJECT PERSONNEL ORGANIZATION CHART

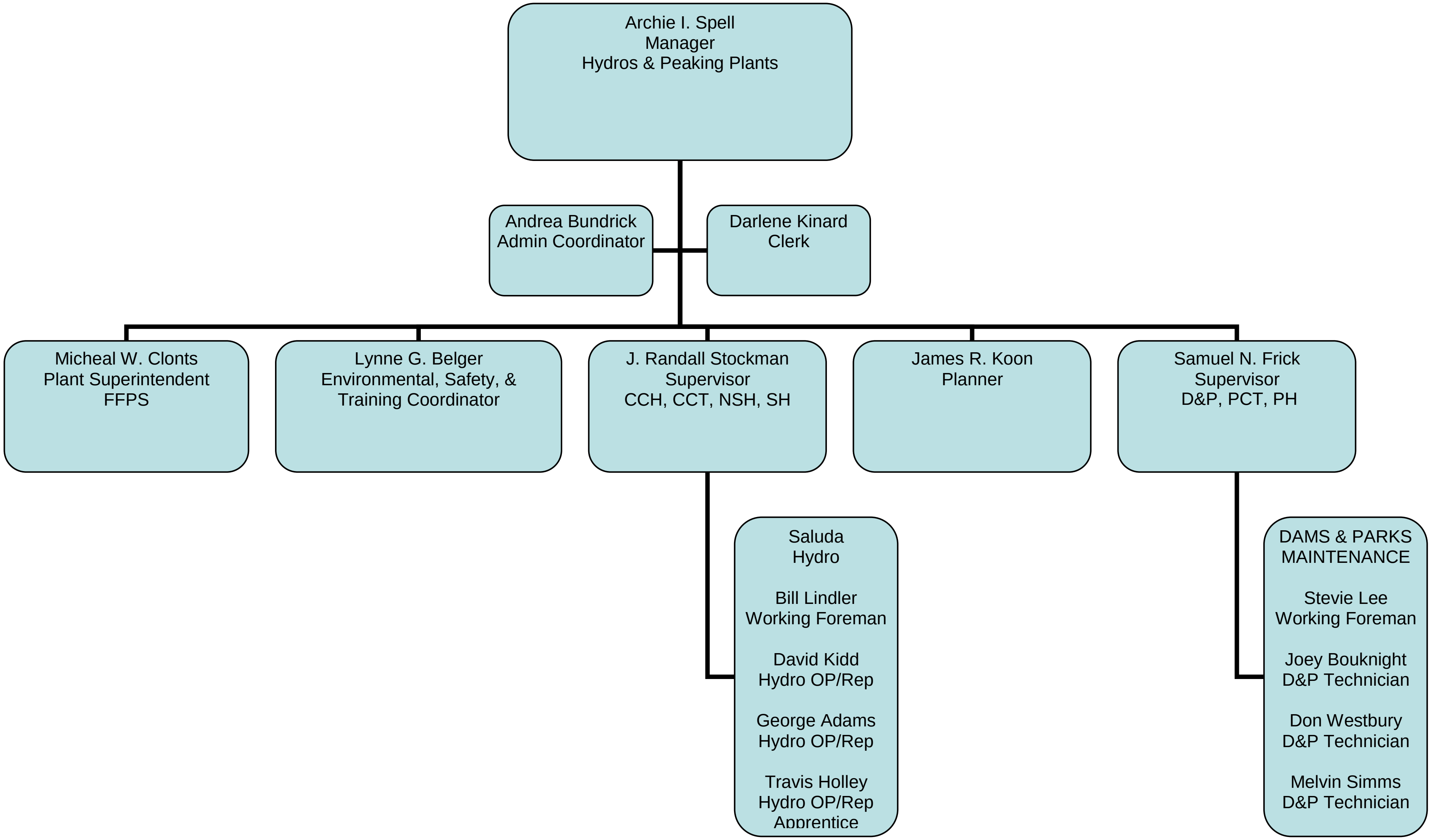


EXHIBIT H-4

SALUDA HYDROELECTRIC PROJECT NO. 516

REQUIRED SAFETY TRAINING

Training Topic	Training Required For	Applicable Standard and/or SCE&G Safety Procedure	Training Frequency*	Saluda Hydro Requirement
Ladder Safety	Employees who use ladders	29CFR1910.25-27 & 1926.1060 (OSHA)	Initially	**YES**
Scaffold Safety	Employees who build or use scaffolds	1910.28-29 & 1926.450-453 (OSHA) SD-305	Initially	**YES**
Emergency Plans	Employees who are expected to take action, such as evacuating a facility, in the event of an emergency	1910.38 (OSHA) SD-301	Initially	**YES**
Vehicle-Mounted Elevating and Rotating Work Platforms (Aerial Lifts)	Employees who operate vehicle-mounted elevating and rotating work platforms, such as bucket trucks and aerial lifts	1910.67 (OSHA)	Initially	**YES**
Respiratory Protection	Employees who use respirators	1910.134 (OSHA) SD-204	Initially & Annually	**YES**
Hearing Conservation	Employees exposed to noise at or above an 8 hour TWA of 85 db	1910.95 (OSHA) SD-203	Initially & Annually	**YES**
Emergency Response to Hazardous Material Incidents (HAZMAT)	Employees who are expected to respond to emergencies involving uncontrolled releases of hazardous materials	1910.120 (OSHA)	Initially & Annually	**YES**
Personal Protective Equipment	Employees who wear personal protective equipment	1910.132 (OSHA) SD-202; SD-203; SD-204; SD-205; SD-210; SD-213; SD-501	Initially	**YES**
Confined Spaces	Employees who supervise, monitor, or enter confined spaces	1910.146 (OSHA)	Initially	**YES**
Confined Space Rescue	Employees who are on confined space rescue teams	1910.146 (OSHA) SD-300	Initially & Annually	**YES**
Control of Hazardous Energy (Lockout/Tagout)	Employees who work in power generating plants, and other areas, where equipment is locked or tagged during maintenance work	1910.147 (OSHA) SD-306	Initially & Annually	**YES**
First Aid & CPR	Employees who are expected to perform first aid or CPR duties	1910.151 (OSHA)	Initially & Every Three Years	**YES**
Fire Extinguishers	Employees who are expected to use fire extinguishers	1910.157 (OSHA) SD-303	Initially & Annually	**YES**
Fixed Fire Extinguishing Systems	Employees who inspect, maintain, or repair fixed fire extinguishing systems	1910.160 (OSHA)	Initially & Annually	**YES**
Powered Industrial Trucks (including Fork Lifts)	Employees who operate powered industrial trucks, such as forklifts or hand trucks.	1910.178 (OSHA) SD-307	Initially & Every Three Years	**YES**
Arc Welding and Cutting	Employees who operate arc welding equipment	1910.254 & 1926.351 (OSHA)	Initially	**YES**
Resistance Welding	Employees who operate resistance welding equipment	1910.255 (OSHA)	Initially	**YES**
Electrical Safety - Qualified Person	Employees who work near energized electrical parts or equipment	1910.332/269 (OSHA) SD-500	Initially	**YES**

EXHIBIT H-4

SALUDA HYDROELECTRIC PROJECT NO. 516

REQUIRED SAFETY TRAINING

Training Topic	Training Required For	Applicable Standard and/or SCE&G Safety Procedure	Training Frequency*	Saluda Hydro Requirement
Electrical Safety - Apparel	Employees who are exposed to electrical arcs or flames	1910.269 (OSHA) SD-500; SD-501; SD-502; SD-503; SD-504	Initially	**YES**
Access to Employee Exposure & Medical Records	Employees who have medical records or exposure records	1910.1020 (OSHA) SD-103	Initially & Annually	**YES**
Bloodborne Pathogens	Employees who are reasonably expected to be exposed to blood, body fluids, or other infectious materials	1910.1030 (OSHA) SD-206	Initially & Annually	**YES**
Hazard Communication (HAZCOM)	Employees who work with hazardous chemicals	1910.1200 (OSHA) SD-207	Initially & whenever a new hazard is introduced	**YES**
Heat Stress	Employees who work in a hot environment (temperature > 95 ^{o})	SCE&G SD-209	Initially & Annually	**YES**
Switching & Tagging	Employees who perform switching and tagging on the transmission or distribution electrical system	SCE&G SD-504	Initially	**YES**
Driver & Vehicle Safety	Employees who operate a Company vehicle	SCE&G SD-400	Initially	**YES**
Powder Actuated Tools	Employees who use powder actuated tools.	1926.302 (OSHA)	Initially	**YES**
Fall Protection	Employees who work at elevated locations and use fall protective equipment.	1926.503 (OSHA) SD-210	Initially	**YES**
Lead	Employees who work with or are exposed to lead.	1926.1025 (OSHA) SD-304	Initially & Annually	**YES**
Asbestos	Employees who work with or are exposed to asbestos.	1926.1101 (OSHA) SD-308	Initially & Annually	**YES**
Commercial Motor Vehicle Operation (Federal Motor Carrier Safety Regulations)	Employees who drive commercial motor vehicles.	49CFR383-399 (DOT) CSHD-2000	Initially	**YES**

OSHA - Occupational Safety and Health Administration
DOT - Department of Transportation
DOE - Department of Energy

* Unless specified otherwise, retraining is required whenever (1) there is a change in any condition which renders the previous training obsolete, (2) an employee demonstrates non compliance or incompetence in a subject, (3) a safety related task has not been performed in the past year, or (4) there is evidence that indicates that the previous training is not effective.

Training is to be documented and include the training topic, the date of the training, the name of the individual that received the training, and the name of the person who provided the training.

EXHIBIT H-5

SALUDA HYDROELECTRIC PROJECT NO. 516

OPERATOR REPAIRMAN TRAINING PROGRAM

	FIRST YEAR - OR (E&I) Course Description	OCTC Days	NCCER Hours
1	**SAFETY TRAINING (ON-SITE): *M/E/I*** Primedia CDs as required by plant	**0**	25
2	**POWER PLANT FUNDAMENTALS (ON-SITE): *M/E/I*** 40 Primedia PPR Ops CDs (see listing) Two Weeks w/ APOs	**0**	80
3	**BASIC SAFETY (ON-SITE): *M/E/I*** Basic Safety CD **AMSBA** (NCCER Core) Safety - Chemical Health Hazards CD **AMSHS** (NCCER Core)	**0**	15
4	**BASIC MATH (ON-SITE): *M/E/I*** Basic Math CD **AMMBA** (NCCER Core)	**0**	15
5	**FORKLIFTS (ON-SITE): *M/E/I*** Forklifts - Operation CD **AMFOO** Other Training Requirements (determined by plant)	**0**	10
6	**HAND & POWER TOOLS: *M/E/I*** Introduction to Hand Tools CD **AMTIH** (NCCER Core) Introduction to Power Tools CD **AMTIP** (NCCER Core)	**1**	15
7	**LADDERS, SCAFFOLDS & FALL PROTECTION: *M/E/I*** Rigging-Ladders and Scaffolds CD **AMRLS** (NCCER Core)	**1**	15
8	**BASIC RIGGING: *M/E/I*** Basic Rigging CD **AMROV** (NCCER Core) Rigging- Basic Lifting CD **AMRLL** (NCCER Core) Rigging-Heavy Lifting CD **AMRL** (NCCER Core)	**2**	20
	Site-Specific Practical(s) on Crane/Rigging		
9	**BLUEPRINTS AND DOCUMENTS (E&I): *E/I*** Introduction to Blueprints CD **AEDBL** Diagrams - Electrical CD **AEDEL** Bill Metz - Document Control (opt.)	**1** **( )**	15
10	**ELECTRICAL SAFETY AND TEST EQUIPMENT: *E/I*** Safety-Electrical CD **AMSEL** Understanding Electricity CD (Safety) **BBUEL** Elect. Safety for All Workers CD (Safety) **BBEAW** Elect. Safety for Elect. Workers CD (Safety) **BBEEW** Electrical Maintenance - Test Equipment CD **AEETE** Dig/Analog O-scopes CD (Controls-Found.) **ACCDA** Electrical Maint - Troubleshoot Electrical CD **AEETA**	**2**	28

EXHIBIT H-5

SALUDA HYDROELECTRIC PROJECT NO. 516

OPERATOR REPAIRMAN TRAINING PROGRAM

	SECOND YEAR - OR (E&I) Course Description	OCTC Days	NCCER Hours
11	**ELECTRICAL THEORY**	**2**	15
	Electrical Theory - Basic Electr Review CD **AEBER**		
	Electrical Theory - AC Circuits CD **AEEAC*		
12	**FLAME CUTTING: *M/E/I***	**1**	17.5
	Welding-Oxyfuel Gas Welding CD **AWTMI**		
13	**CONTROLS - FOUNDATION**	**2**	26
	Introduction CD **ACCIN **		
	Principles of Control CD **ACCCO **		
	Principles of Calibration CD **ACCCA **		
	Introduction to Control and Data Systems CD ** ACCIC **		
	The Human- Machine Interface CD **ACCHM **		
14	**CONTROLS - CONTINUOUS PROCESS PT 1**	**2**	24
	Principles (Continuous Process) CD **ACPCR **		
	Pneumatic Controls CD **ACPPC **		
	Field Devices : Temp., Press. & Weight CD **ACPPT **		
	Field Devices: Level & Flow CD **ACPLF **		
15	**CONTROLS - CONTINUOUS PROCESS PT 2**	**2**	24
	Field Devices: Analog Configuration CD **ACPAF **		
	Field Devices: Using Field Communicators CD **ACPCA **		
	Field Devices: Analytical CD **ACPAF **		
	Field Devices: Configuration with a Laptop PC CD **ACPCL **		
16	**ELECTRICAL WIRING / NATIONAL ELECTRIC CODE**	**3**	52.5
	Intro to the National Electric Code CD **AEEIN**		
	Raceways, Boxes and Fittings CD **AEERA**		
	Conductors CD **AEECO**		
	Wiring: Commerical and Industrial CD **AEECW**		
	Wiring: Residential CD **AEERW**		
17	**MOTORS**	**2**	20
	Electric Motors - DC Motors CD **AEEDM**		
	Electric Motors - Three Phase Motors CD **AEETP**		
	Electric Motors - Motor Branch Ckt Prot CD **AEEMB**		
18	**GROUNDING: *E/I***	**1**	12.5
	Grounding CD **AEEGD**		
19	**CONDUIT BENDING AND INSTALLATION**	**1**	30
	Hand Bending CD **AEEHB**		
	Electrical Wiring - Conduit Installation CD **AEECI**		
	Conduit Bending CD **AEECB**		

EXHIBIT H-5

SALUDA HYDROELECTRIC PROJECT NO. 516

OPERATOR REPAIRMAN TRAINING PROGRAM

	THIRD YEAR - OR (E&I) Course Description	OCTC Days	NCCER Hours
20	**DISTRIBUTED CONTROL SYSTEMS** Introduction to DCS CD ** ACPID ** Field Devices: Digital Config w/ a DCS CD **ACPCD ** Troubleshooting DCS I/O's Procedures CD **ACPTD ** Troubleshooting DCS I/O's Practices CD **ACPTP **	**2**	24
21	**PROCESS CONTROL LOOPS** Single Loop Control CD ** ACPSL ** Smart Controllers CD ** ACPSC ** Troubleshooting Loops ** ACPTS ** Tuning Loops CD ** ACPTL **	**3**	32
22	**TUBING** Tubing (no CD) *Swagelock Vendor Course may be Substituted*	**1**	12.5
23	**CONTROL VALVES, ACTUATORS & POSITIONERS** Use and Repair of Control Valves, Actuators & Positioners (Non-NCCER - no CD) *Robert E. Mason Vendor Course may be Substituted*	**3**	24
24	**CALIBRATE FOR VIBRATION** Calibrate for Vibration (no CD) *Bentley/Nevada Vendor Course may be Substituted*	**1**	5
25	**MAIN GENERATOR / BUSSES** Non-NCCER Course (no CD)	**2**	16
26	**CONDUCTOR INSTALL, TERMINATIONS/SPLICES** Electrical Wiring - Cables & Conductors CD **AEECC** Conductor Installations CD **AEECD** Conductor Terminations CD **AEETS** High Voltage Terminations & Splices (no CD)	**2**	35
27	**ELECTRICAL SERVICES, CKT BKRS, FUSES AND RELAYS** Installation of Electrical Services CD **AEEIS** Circuit Breakers and Fuses CD **AEECF** Switching Devices and Timers (no CD) Contactors and Relays CD **AEECR**	**3**	47.5
28	**LIGHTING** Electric Lighting CD **AEEEL** Lamps, Ballasts, and Components (no CD) Practical Applications of Lighting (no CD)	**2**	25
29	**MOTOR CONTROLS AND ADVANCED MOTOR CONTROLS** Elect Motors - AC Motor Controllers 1 CD **AEEA1** Elect Motors - AC Motor Controllers 2 CD **AEEA2** Advanced Motor Controls (no CD)	**3**	52.5

EXHIBIT H-5

SALUDA HYDROELECTRIC PROJECT NO. 516

OPERATOR REPAIRMAN TRAINING PROGRAM

	FOURTH YEAR - OR (E&I) **Course Description**	**OCTC Days**	**NCCER Hours**
30	**CIRCUIT BREAKERS, PROTECTION, DISTRIBUTION** Circuit Bkrs - Bkrs and Switchgear 1 CD **AECLV** Circuit Bkrs - Bkrs and Switchgear 2 CD **AECHV**	**2**	25
31	**BATTERIES, CHARGERS, STANDBY/EMERG. SYSTEMS** Battery Systems CD **AEETM** Inverters & UPS's (no CD)	**2**	20
32	**MOTOR OPERATED VALVES** Pipes and Valves - Motor Operators CD **AMPMO**	**3**	24
33	**HYDRAULICS 1: *M/E/I*** Principles and Circuits CD **AHHPC** Pumps CD **AHHPU** Actuators CD **AHHAC** Valves 1 CD **AHHV1** Valves 2 CD **AHHV2**	**2**	20
34	**HYDRAULICS 2: *M/E/I*** Fluids and Resevoirs CD **AHHFS** Diagrams CD **AHHDI** Routine Maintenance CD **AHHRM** Component Inspection & Replacement CD **AHHCI** Troubleshooting CD **AHHTR**	**2**	20
35	**PROGRAMMABLE LOGIC CONTROLLERS 1: *E/I*** Architecture, Types & Networks CD **ACLAT** Numerics CD **ACLNU** Ladder Logic and Symbology CD **ACLLL** I/O Communication CD **ACLIO** Introduction to Programming CD **ACLIP** Installing & Maintaining CD **ACLIM ** Programmable Logic Controllers (no CD)	**3**	38
36	**PROGRAMMABLE LOGIC CONTROLLERS 2: *E/I*** Program Entry, Testing & Modification CD **ACLPE** Programming Common Functions CD **ACLCF** HMI's & Troubleshooting CD **ACLMT** Troubleshooting Hardware CD **ACLTH** Troubleshooting Software & Networks CD **ACLSN**	**2**	26

EXHIBIT H-5

SALUDA HYDROELECTRIC PROJECT NO. 516

OPERATOR REPAIRMAN TRAINING PROGRAM

	FOURTH YEAR - INSTRUMENTATION (cont.) **Course Description**	OCTC Days	NCCER Hours
37	**PERFORMANCE MEASUREMENT** Air/Fuel Flow Testing, Heat Rate Calc., Flue Gas Anal. *Taught By SCE&G Performance Group (Non-NCCER)*	**1**	8
38	**VARIABLE SPEED DRIVES: *E/I*** Introduction to VSD's CD **ACVSD** Applications CD **ACVDA** System Integration CD **ACVSI** Programming Controllers CD **ACVPC** Controllers & Troubleshooting CD **ACVCT** System Troubleshooting CD **ACVST**	**3**	36

EXHIBIT H-6

Saluda Hydroelectric Project P-516

Letter Dated April 24, 2008 Concerning Relocation of Project Boundary Line

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April 24, 2008

Patricia Banks Morrison
SCANA Legal Department
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Re: Relocation of FERC Project Boundary Line – Impact on SCE&G's Rights Under Recorded Deeds and Easements With Respect to Flood Event

Dear Patricia:

SCE&G has indicated that the Federal Energy Regulatory Commission ("FERC") has proposed moving the FERC Project Boundary Line (the "PBL") at Lake Murray to the 360-foot Plant Datum (PD) contour of Lake Murray or 75-foot set back, for those parcels no longer owned in fee by the Company. This proposal raises a number of business and legal issues. SCE&G has asked that we review a specific legal issue: in the context of a flood event that requires raising the level of the lake, would relocation of the PBL have an adverse impact on the property rights and liabilities of SCE&G with respect to landowners adjoining Lake Murray.

SCE&G has indicated that the PBL in some instances is located substantially above the reservoir's maximum pool elevation of 360 PD (the "360 Contour"), and extends into the property of adjoining landowners. Reducing the PBL to the 360-Contour or 75-foot setback would essentially move the PBL down to the shoreline.

Our conclusion is that relocation of the PBL would detrimentally affect SCE&G's rights with respect to many adjoining landowners. SCE&G would lose the right to flood water on some of the surrounding lands and would be exposed to additional liability should such flooding occur. SCE&G would also lose access rights on some lands.

<u>Severe Rainfall Situation</u>.

For the purpose of this letter we are assuming the hypothetical set of facts which we discussed at a recent meeting at SCE&G. SCE&G has indicated that the high water line of Lake Murray has typically been around 358-foot PD, and rarely exceeds 360 Contour. SCE&G has indicated that the height and engineering of the Lake Murray Dam would potentially allow increasing the elevation of the lake to more than 370-foot PD.

For the purpose of this letter, we are assuming a catastrophic weather event, such as a severe hurricane-related rain that settles over the upper part of the state and causes substantial rainfall in the upstate region feeding the Saluda River. An example of this type of weather event is Hurricane Floyd, which in 1999 resulted in many river basins in eastern North Carolina exceeding 500-year flood levels. A rain event like Hurricane Floyd would create substantial flooding in the Saluda River basin.

In the above scenario, SCE&G could be faced with the lake level rising substantially above the 360 Contour even with generation and opening of the spillway gates. As the lake water level continues to rise there may be flood damage to houses, commercial facilities, outbuildings and yards along the lake that are above the 360 Contour, but are not above the top of dam elevation of 377-foot PD.

There might be considerable pressure from government officials for SCE&G not to release flood waters, and to raise the level of the lake. Although perhaps not part of SCE&G's core mission, government officials probably consider the Lake Murray dam as a flood control device.

Flooding Rights, Liability Releases and Access Rights in Title Documents.

SCE&G has provided us with samples of deeds and easements by which SCE&G obtained title or flowage rights for the construction of what was then called the Dreher Shoals Dam and for the creation of Lake Murray. These documents were granted in the 1920s to Lexington Water Power Company, now SCE&G. The deeds in to Lexington Water Power Company contain language allowing flooding of adjoining land and releasing Lexington Water Power Company (now SCE&G) from liability for damages caused by erection and maintenance of the dam and the creation of a reservoir of water "of any height and size." An excerpt of the typical flooding rights and liability release provisions in deeds in to Lexington Water Power Company is attached as Exhibit A.

Although most of Lake Murray is owned in fee simple by SCE&G, Lexington Water Power Company also obtained easements for flowage (flooding) rights, rather than fee simple title, with respect to some land. These flowage easements contain the same flooding rights and liability release provisions. An excerpt of the provisions found in typical flowage easements granted to Lexington Water Power Company is attached as Exhibit B.

SCE&G has also used a number of forms of deeds over the years in conveying property to landowners around the lake. All of these deeds contain some form of reserved flooding rights, release of liability and access rights. An excerpt of the flooding rights, liability release and access rights provisions in typical deeds out is attached hereto as Exhibit C. Some more recent deeds also contain specific provisions regarding shoreline management.

Limitation of Flooding Rights, Liability Releases and Access Rights to Property Within the PBL.

A number of the sample deeds out granted by SCE&G for lands adjoining Lake Murray specifically limit the reserved flooding rights, liability release and access rights to land within the PBL. Some deeds state that the flooding rights, liability releases and access rights only apply to land within the PBL. See an excerpt of typical language in the attached Exhibit D. Other deeds state that upon a relocation of the PBL, SCE&G will execute a release of rights outside the PBL. See an excerpt of typical language in attached Exhibit E.

Analysis and Conclusion.

If the PBL is reduced (moved closer to the 360 Contour), SCE&G will be releasing its flooding rights, liability releases and access rights with respect to land above the level of the relocated PBL for all properties conveyed out by SCE&G using deeds that included the language in Exhibit D or Exhibit E. In addition, for those deeds out that do not reference the PBL and for those deeds in and flowage rights easements by which Lexington Water Power Company obtained title that do not reference the PBL, the adjoining landowners may argue that SCE&G's flooding and liability release rights are implicitly limited to land within the PBL.

In the case of a catastrophic rain event like the hypothetical described above, SCE&G may be faced with the prospect of backing up water on property above the relocated PBL. Property owners who suffer losses as a result of flooding likely will seek damages from SCE&G based on theories such as trespass, nuisance, temporary taking, negligence and possibly strict liability. SCE&G currently would have the basis for a defense against some of these claims based on the flooding rights and liability releases contained in the various title documents described above. If the PBL is relocated, such defense will not be available for adjoining properties governed by the language in Exhibit D or Exhibit E, and the defense may be weakened for other adjoining properties.

Accordingly, with respect to the backing up of water on adjoining lands, SCE&G will be exposed to the potential of a significant increase in liability if the PBL is moved closer to the shoreline.

We also note that SCE&G will lose its access and clearing rights on all property outside the PBL covered by the language in Exhibit D and Exhibit E, and may also lose some shoreline area management rights. There may be cases where such rights are still useful to SCE&G in order to maintain their Shoreline Management Plan.

Please note that SCE&G has asked that we look only at the specific issue discussed above. We have not addressed in this letter any other policy, legal or business issues that might also be affected by the relocation of the PBL.

Please feel free to call me with any questions.

Very truly yours,

John B. McArthur

JBM:jpr

EXHIBIT A

Flooding and Liability Release Language Contained in Deeds In (1920s Conveyances)

Together with all and singular, the rights, members, hereditaments and appurtenances to the said premises belonging or in anywise incident or appertaining; including specifically all claims, rights or demands for damages, or otherwise, which may hereafter, in law or equity, accrue to [the Grantor] arising from or caused directly, indirectly or incidentally by the erection and maintenance by the grantee herein, its successors and assigns, of a dam and reservoir of water of any height and size whatsoever on Saluda River at or near Dreher Shoals, or above it; to have and to hold all and singular the premises before mentioned unto the said Lexington Water Power Company, its successors and assigns forever.

Some Deeds In Also Include the Following Access and Clearing Rights

It is further understood and agreed that Lexington Water Power Company, its successors and assigns, has the right to clear and to keep cleared all of the above tract of land. . .

EXHIBIT B

Flooding, Liability Release and Access Rights Language in Flowage Easements Granted to Lexington Water Power Company (1920s)

> [Grantors] . . . have granted, bargained, sold and released and by these presents do grant, bargain, sell and release under the sale of Lexington Water Power Company, its successors and assigns; the easement, privilege, franchise and right to turn water on, to back water over, and to flood in perpetuity [followed by description of property]. . .
>
> It is understood and agreed that by this conveyance the grantor for himself and for his heirs and assigns hereby releases Lexington Water Power Company, its successors and assigns, from any and all damages that may be caused directly or indirectly by the erection, construction, operation and maintenance of a dam or dams, and reservoir of water of any size and height and necessary spillway on the Saluda River at or near Dreher's Shoals, whether such damage is caused by the flooding of said [tract], or injury to the drainage thereof, or by storage of water, or from any other cause whatsoever.
>
> It is further understood and agreed that in case any part of [said tract of land] ever becomes flooded, and if for that reason or for any other reason the Federal Power Commission or the State Board of Health requires the same to be cleared, or any part thereof to be cleared and to be kept cleared, that the grantee, its successors and assigns, shall have the right to enter upon the same at any and all times for the purposes of clearing and keeping so much of said land cleared as required by the said Federal Power Commission or the State Board of Health.

EXHIBIT C

Flooding, Release of Liability and Access Provisions in Deeds Out for Land Adjoining Lake Murray

[Grantor] does grant, bargain, sell and release, unto the said [Grantee] subject to the right of the Grantor, its successors and assigns, through its servants or agents, to have the right of ingress, egress and access in, to, over, across and out of the property herein conveyed for malaria control and other corporate purposes, and subject also to all damages that may be caused to said parcel or tract of land by reason of the erection, construction, operation and maintenance by the Grantor, its successors and assigns, of a dam or dams and reservoir of water of any height and size and necessary spillways on the Saluda River at or near Dreher's Shoals, whether such damage is caused by the flooding of the lands or injury to the drainage thereof, or by storage of water, or for any other reason whatsoever, and the Grantee herein, for himself and for his heirs and assigns, hereby expressly releases the Grantor, its successors and assigns, from any and all liability for any and all damages that may be caused to said parcel or tract of land as aforesaid. [followed by property description of parcel conveyed out]

EXHIBIT D

Language in Deeds Out Restricting Flooding Rights, Liability Release and Access Rights to Property Within PBL

The portions of the property conveyed herein which are within the Project Boundary Line of the hydroelectric project designated in the Files of the Federal Energy Regulatory Commission ("FERC") as Project 516 (the "Project") are conveyed herein subject to any and all easements or servitudes which now exist, inchoate or perfected, and reserving to the Grantor, its successors and assigns, the right of ingress, egress and access in, to, over, across and out of such property for malaria control; subject further to all damages that may be caused to said parcel or tract of land by reason of the erection, construction, presence, operation and maintenance by Grantor, its successors and assigns, of a dam or dams and reservoir of water of any height or size and necessary spillways on the Saluda River at or near Dreher Shoals, whether such damage is caused by flooding of the property or injury to the drainage thereof, or by storage of water, or for any reason whatsoever, and the Grantee, by acceptance of this deed, for Grantee and for Grantee's heirs, successors and assigns, hereby expressly releases the Grantor, its successors and assigns, from any and all liability for any and all damages that may be caused to said property as aforesaid. **[Emphasis Added]**

EXHIBIT E

Deed Out Language Requiring Release of Reserved Rights Upon Reduction of PBL

Should any portion of the premises being conveyed hereby lie outside the boundary lines of FERC Project 516 and be burdened with covenants and restrictions in favor of Grantor granting to Grantor the right to flood or flow water upon and/or the right to clear and keep clear such property, Grantor covenants that it will, upon request by Grantee, release those properties outside the PBL from such covenants and restrictions.