EXHIBIT H

ADDITIONAL INFORMATION

Information Required from All Applicants

1. South Carolina Electric & Gas Company (SCE&G) ("Licensee" or "Applicant") intends to continue to operate and maintain the Project to provide efficient and reliable electric service as described below.

   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. Fairfield Pumped Storage Development will continue to serve as a peaking and reserve generation facility in the Applicant's system, as well as serving a critical role in storing off peak energy. As a peaking power generator, up to 3,960 MWh of energy can be dispatched rapidly and flexibly to follow system load on a daily basis. During the pumping portion of the cycle, up to 5,760 MWh of off peak energy can be utilized for pumping. At maximum utilization, Fairfield Pumped Storage allows the Applicant approximately 1,100 MW[1] of "swing" between generation and load absorption on a daily basis. While generation flexibility is critical in providing on-peak generation, its energy storage capability allows baseload plants to remain on line during periods of minimum customer load, thereby avoiding additional fuel and O&M costs associated with repeated shutdown and startup of baseload units. By shifting some of the system load from peak to off peak periods, the Fairfield Development allows more efficient use of baseload plants.

[1] Based on generating capacity and pumping load use estimated at median net head.

c. As a reserve asset, in the event of a loss of generation elsewhere in the Applicant's system, the Fairfield Development units not being used for peaking power generation 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 VACAR member. 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. The Fairfield Development usually has some reserve availability even during peak demand periods, with correspondingly greater reserve availability during off peak periods when not being utilized for pumping. 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 Fairfield Pumped Storage for both peaking and reserve generation is more efficient and reliable than other potential alternatives such as combustion turbines or diesel powered generators.

   Monticello Reservoir (part of the Fairfield Development) also serves as a cooling and service water source for the Applicant's V. C. Summer Nuclear Station (VCSNS), and continued operation of the Parr Project is and will remain critical to continued operation of VCSNS. The operation of the Fairfield Development in both pumping and generating modes will also serve to balance the baseload generation of the VCSNS, which will continue to be critical to safe, reliable, and efficient operation of the Applicant's system.

d. The Parr Shoals Development provides low cost baseload generation as well as "black start" capability[2] for a portion of the Applicant's system, including the VCSNS in Fairfield County. This enhances the reliability of the Applicant's system.

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

e. The Applicant's System Control and Hydro Compliance departments coordinate the operation of the Project with the downstream hydroelectric project and operate the hydroelectric project immediately upstream.

f. Plans for increasing capacity and generation at the Parr Hydroelectric Project are limited to replacement of generators at the Parr Shoals Development to allow use of full available project head. Potential equipment upgrades were evaluated in a Parr Hydroelectric Project Resource Utilization Study (Kleinschmidt 2015), and a Generation Capacity Increase Review (Kleinschmidt 2017). The results of this study are summarized in Exhibit B.

g. 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 baseload, peaking, and reserve generation capacity. Continued operation of the Project is also critical to the Applicant's short and long term plans for their baseload generation fleet of scrubbed coal, gas (both conventional steam and combined cycle), and nuclear assets. Conventional hydro, pumped storage, and simple cycle gas turbine assets will serve peaking and reserve functions, with solar generation also being integrated into the Applicant's system as it comes on line.

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

a. <u>Reasonable costs and availability of alternate sources of power</u>: The U.S. Energy Information Administration (EIA) has provided an estimate of the capital, fixed O&M, variable O&M cost and heat rate of the following potential replacements. All values listed in Table 2-1 are given in 2016 dollars since that was the latest data available on the EIA website. Fuel costs in $/MWh are determined by the heat rate and an estimate of delivered fuel prices. The delivered fuel prices assumed are:

Combined Cycle - $3.36/mmbtu[3]
Combustion Turbine - $4.44/mmbtu

[3] One million British Thermal Units

Biomass - $1.87/mmbtu

New on-system, generation to replace the Parr Project could be one of the following technologies.

Table 2-1

Technology	**Total overnight cost ($/KW)**	**Fixed Costs ($/KW-yr)**	**Variable O&M ($/MWh)**	**Fuel Costs ($/MWh)**	**Emissions Cost ($/MWh)**	**Heat rate in (Btu/kWh)**
Advanced Gas/Oil Combined Cycle	$1,094	$9.94	$1.99	$21.17	$0.0073	6,300
Advanced Combustion Turbine	$672	$6.76	$10.63	$43.51	$0.041	9,800
Biomass	$3,790	$110.34	$5.49	$25.25	$0.143	13,500
Photovoltaic	$2,277	$21.66	$0.00	$0.00	$0.00	na

The estimated increase in annual costs (including capital cost, operation and maintenance costs, and fuel costs from Table 2-1) for replacing the Parr Project with these four alternatives are estimated to be as shown in Table 2-2 (all cost references going forward in this Exhibit are based on 2018 dollars, unless specifically referenced to another year):

Table 2-2

Technology	Levelized Total Costs ($/MWh)	Estimated increase in Annual Cost ($/Yr)
Advanced Gas/Oil Combined Cycle	$180.71	$107,442,591
Advanced Combustion Turbine	$160.46	$92,933,972
Biomass	$639.33	$436,032,356
Photovoltaic	$318.34	$206,051,045

These calculations use the existing Parr Hydroelectric Project levelized generation costs of $30.75/MWh and assume an average of 716,475 MWhs are generated annually.

Estimated increase in annual cost = (levelized total costs – levelized existing generation cost) x 716,475.

Levelized cost are calculated over 30 years with 8.14% discount rate and 2% escalation.

Other possible sources of replacement power include the following two purchase options as shown in Table 2-3.

Table 2-3

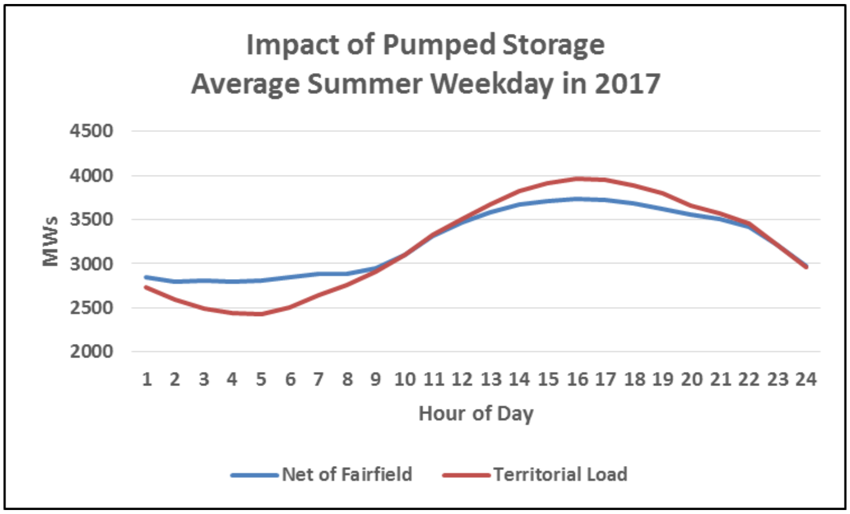
Description	Levelized Purchase Costs ($/MWH)	Estimated increase in Annual Cost ($/Yr)
Purchase of off-system energy and capacity	$128.71	$70,185,891
Increased generation at existing facilities with off-system capacity purchase	$50.75	$14,329,500

Estimated increase in annual cost = (levelized purchase cost – levelized existing generation cost) x 716,475 MWhs.

Energy Storage Function

The energy storage function served by the Fairfield Development due to pumping during off peak periods is also critical to the operation of the Applicant's system and would be extremely costly to replace. For example, the installed cost of storage batteries and ancillary equipment to replace the 3,960 MWh of energy stored in Monticello Reservoir would cost approximately $2 billion in 2018 dollars, based on an installed cost of $1,000 per KW for two hours of battery storage. IHS Markit estimates battery storage costs to be $700 per KW for two hours of battery storage in 2020. This would still mean $1.4B to replace the storage benefit provided by the Fairfield Pumped Storage facility. Assuming a 25 year life and 8.14% weighted average cost of capital, the annual costs would be approximately $205,380,000 per year.

SCE&G is able to achieve a Demand Side Management (DSM)-like impact from the supply side using its Fairfield Development. 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 Development had on a typical summer weekday.



In effect, the Fairfield Pumped Storage Plant was used to shave an average of 233 MWs from the daily peak times of 2:00 p.m. through 6:00 p.m. and to move about 2% of customer's daily energy needs off peak. This is an extremely valuable supply side resource that can't be easily replaced or duplicated.

b. <u>A discussion of the increase in fuel, capital, and O&M costs if the license is not granted</u>: The Parr Project provides flexible peaking power generation and rapid-start reserve generation capacity for the Applicant's system and to meet the Applicant's reserve share obligation under the VACAR Reserve Sharing Agreement (VRSA). Both energy and capacity are 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 the Parr Project not be granted, the Project's generation and capacity would have to be replaced by 1) off system power purchases, 2) constructing new generation facilities, 3) an increase in existing generation or 4) a combination of these options. All of these options would increase the cost of power to the Applicant's wholesale, residential, commercial, military, and industrial customers.

c. <u>Effect of each alternative source of power on customers, operation and load characteristics, and communities</u>: New peaking and reserve generation facilities would require a sizable site to accommodate the generating units, fuel storage, 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.

d. The table below shows that total summer and winter peak electric demand on the Applicant's system is forecast to increase by approximately 1.2 percent and 0.8 percent per year, respectively, during the period 2018 – 2032. Based on the forecast, the continued availability of the Fairfield Development for peaking and reserve generation will be critical to maintaining the reliability of the Applicant's system.

	Summer Peak (MW)	Winter Peak (MW)	Energy Sales (GWh)
2018	4,803	4,802	23,234
2019	4,836	4,848	23,140
2020	4,904	4,893	23,385
2021	4,976	4,961	23,802
2022	5,081	5,002	24,068
2023	5,160	5,030	24,373
2024	5,220	5,071	24,635
2025	5,287	5,118	24,958
2026	5,353	5,161	25,305
2027	5,410	5,201	25,636
2028	5,464	5,241	25,973
2029	5,514	5,277	26,310
2030	5,559	5,319	26,530
2031	5,609	5,360	26,765
2032	5,657	5,402	26,995

Source: Exhibit H-1 - Integrated Resource Plan, SCE&G February 2018.

e. Parr Shoals Development's primary function will be to supply baseload power to fulfill the Applicant's own system requirements. The Parr Shoals Development is also crucial to the operation of the Fairfield Pumped Storage Development, since Parr Reservoir acts as the lower reservoir for the pumped storage system, and Parr Hydro and the spillway crest gates on Parr Shoals Dam are used to modulate discharges from the lower reservoir to balance the overall storage in the pumped storage complex.

f. Fairfield Development's primary function will be to supply peaking power and reserve generation to fulfill the Applicant's own system requirements, as well as reserve obligations under the existing VRSA. The Fairfield Development is one of the Applicant's primary peaking power generation assets, and is used nearly every day of the year to some extent in this capacity.

g. Loss of use of the Project would require that Monticello Reservoir become a dedicated cooling water source for VCSNS. If the Fairfield Development were no longer in operation, an alternative means to pump water into the reservoir to make up for evaporative and other losses would need to be developed, because the watershed draining to the reservoir is too small to rely on runoff as a makeup source. This would require modifications to the operating licenses for VCSNS.

   The growth of solar generation facilities on the Applicant's system is projected to require increased use of the Fairfield Development to balance system generation on a daily basis as solar generation varies during each day. Fairfield can generate early and late in the day when solar generation is not available, and can reduce generation through the middle of the day when solar generation is at its maximum.

h. The loss of license for the Project would result in a loss of tax revenues to the federal, state and local governments. 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. For example, the Applicant currently pays approximately $5.85 million annually in property taxes on Project property and assets.

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

   a. The average annual cost of power produced by the Parr Shoals and Fairfield Developments in 2017 were $14.20 and $8.24 per net MWH respectively (2017 FERC Form 1 filed with the FERC on April 16, 2018).

   b. Projected resources required to meet short and long term capacity and energy requirements are presented in Exhibit H-1, <u>2018 Integrated Resource Plan (IRP).</u> The Applicant files a copy of its IRP with the South Carolina Public Service Commission (SCPSC) in accordance with S.C. Code Ann. § 58-37-40 (2015), § 58-33-430, and SCPSC Order No. 98-502. This Plan was filed with SCPSC on February 28, 2018.

   c. Costs associated with alternative sources of power:

i. Generation of additional power at existing facilities: The baseload power produced by the Parr Shoals Development could be replaced by dispatching coal or gas fired units, or by purchasing the power off system. The Applicant currently has no generation units at existing facilities which could be utilized to replace the Fairfield Development's peaking power and energy storage capacity.

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

iii. Purchase of power off-system: The least cost alternative for replacing the capacity and generation produced by the Parr Hydroelectric Project would result in an annual cost increase of approximately $14,330,204 based on the average annual generation of 716,475 MWh provided in Exhibit B-1. Replacing the storage component would add an additional $205,380,000 per year.

iv. Construction or purchase and operation of a new power plant: The following annual cost calculations assume that the 586 MW of Parr Hydroelectric Project with an annual generation of 716,475 MWh given in Exhibit B-1 is replaced with the described resources:

The total annual cost of each alternative:

Table 3-1

Technology	**Levelized Annual Capital ($/Yr)**	**Annual Fixed Costs ($/Yr)**	**Annual Variable Costs ($/Yr)**	**Total Annual Costs ($/Yr)**
Advanced Gas/Oil Combined Cycle	$90,843,193	$6,060,164	$16,654,960	$113,558,316
Advanced Combustion Turbine	$55,801,303	$4,043,400	$39,128,457	$98,973,160
Biomass	$314,712,706	$67,271,473	$22,280,940	$404,265,119
Photovoltaic	$189,076,737	$13,026,780	$0	$202,103,517
Purchase of off-system energy and capacity	$0	$29,830,854	$58,571,369	$88,402,223
Increased generation at existing facilities with off-system capacity purchase	$0	$29,830,854	$6,530,956	$36,361,811

v. The basis for the determination of projected annual cost:

For the new plant alternatives:

- Annual Capital Costs are determined using the Overnight Costs in Table 2-1 assuming a plant size of 586 MWs and a levelized fixed charge rate of 13.62%.
- Fixed Costs are determined using Fixed Costs in Table 2-1 and assuming a plant size of 586 MWs.
- Variable Costs are determined using Variable O&M Costs, Fuel Costs, and Emissions Cost from Table 2-1 and assuming 716,475 MWhs/Year (average annual generation provided in Exhibit B-1).
- Total Annual Costs is the sum of Annual Capital Costs, Annual Fixed Costs and Annual Variable Costs.

For the purchase power alternatives:

- Annual Fixed Costs are determined using the levelized cost of off-system peaking capacity of $50.906/Kw-yr x 586 MWs
- Off-system energy Annual Variable Costs are determined using the levelized energy cost from an advanced combustion turbine using values from Table 2-1

- Increased generation Annual Variable Costs are determined by running the hourly dispatch model with and without the Parr Project then creating a levelized difference in operating costs.

vi. Discussion of the relative merits of each alternative:

- Advanced Gas/Oil Combined Cycle (CC) – Although the size of a Combined Cycle is approximately the same as the Parr Project, this would be a very expensive solution. A Combined Cycle typically needs to run at higher capacity factors in order to be economical. This solution doesn't provide the load shifting and storage currently available with the Project's pumped storage system.

- Advanced Combustion Turbine (CT) – This is the best alternative for a new power plant. The total costs as well as additional costs are lower than the other three power plants evaluated. The typical capacity factor is approximately equal to that of the Project's facilities. This is still a very expensive option. This solution doesn't provide the load shifting and storage currently available with the existing pumped storage system.

- Biomass – The biomass plant is the most expensive of the power plant options evaluated. A biomass plant is typically about 50 MWs, much smaller than the 586 MWs of the Project's facilities. The large amount of biomass material required to generate 586 MWs of power make this an unworkable solution. This solution doesn't provide the load shifting and storage currently available with the Project's pumped storage system.

- Photovoltaic (PV) – Due to the high costs and lack of dispatchability this option is not good for replacing the existing facilities. Large amounts of PV can negatively impact the reliability of the Applicant's system and the lack of dispatchability can negatively impact the cost of operating other plants on the system. This solution doesn't provide the load shifting and storage currently available with the Project's pumped storage system.

- Purchase of off-system energy and capacity – This is a reasonable alternative because the energy and capacity could be designed to meet the system needs. The cost of this alternative is much higher than maintaining the Project's existing facilities and more than twice as expensive as the least cost option considered. Purchasing transmission to get 586 MWs to the applicant's system may create reliability issues and the cost was not included in the analysis. This solution doesn't provide the load shifting and storage currently available with the Project's pumped storage system.

- Increased generation at existing facilities with off-system capacity purchase – This is the least cost alternative considered but would still increase the annual cost by approximately $14,330,204 per year. About half of the increase would come from higher fuel and operating costs at existing facilities and half would come from off-system capacity purchases. Purchasing transmission to get 586 MWs to the applicant's system may create reliability issues and the cost was not included in the analysis. This solution doesn't provide the load shifting and storage currently available with the Project's pumped storage system.

d. Load management measures such as conservation: The Applicant's Demand Side Management programs are described in Section 11 of this Exhibit.

e. Effect on direct providers and their customers of alternate sources: If any of the alternative sources of peaking and 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.

4. 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 Parr Hydroelectric Project. The Parr Shoals Development provides "black start" capability for a portion of the Applicant's system as described above.

5. 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 the Parr Hydroelectric Project to foster the purposes of a reservation.

6. Impact on the operation and planning of transmission system of receiving or not receiving license: The Parr 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 include requirements for balancing load and generation, maintaining steady-state frequency and provide for operating reserves and frequency

regulation to address the resolution of inadvertent interchange between electric systems or conditions of insufficient generation resources. 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's Regional Entities have initiated requirements to assess and enforce compliance with NERC Reliability Standards. Enforcement of the Standards developed by NERC has been assigned to the SERC Reliability Corporation (SERC), a Regional Entity of NERC. The Applicant is a registered entity of SERC.

The Applicant utilizes the Parr Hydroelectric Project to comply with these NERC Standards in the most cost effective manner. This includes Fairfield Pumped Storage Development which is operated as a generator to support system loads and operated as a pump to balance the system during light load conditions to maintain the stability of the transmission system and comply with the NERC Standards. The Project is located near the Columbia metropolitan area, which is a major load center on the Applicant's system. The Project is also located adjacent to the VCSNS. 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. In addition, these generating facilities provide support to meet the requirements of the Nuclear Regulatory Commission for the 115kV and 230kV offsite power sources for the VCSNS nuclear facility. The absence of the support provided by these generating facilities would negatively impact our ability to meet the Nuclear Regulatory Commission requirements. Further study would be required to determine the magnitude of these impacts which could be significant. 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 peaking and 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 a technology referenced in

Table 3-1 of this Exhibit. Depending upon siting constraints, it may not be possible to locate all of the new reserve units reasonably close to either major load center. This would result in a change in transmission line flows and could result in transmission system changes. 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 generation has been estimated by the Applicant's Transmission Planning group to be $15.73 per installed KW of capacity, or approximately $9.3 million in transmission costs associated with replacing the Fairfield Development with new peaking and reserve generation and Parr Shoals Development with new base load generation on the Applicant's system based on 591 MW (576 MW at Fairfield and 15 MW at Parr Shoals). This cost per installed KW is an estimate and made without knowing where any future replacement generation would be located or how it would be connected to the Applicant's existing system.

An additional consideration in this discussion is the Parr 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 Development, in providing black start capability for the VCSNS, 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. (Note this item is CEII and will be provided with the Final License Application).

7. <u>Proposed changes to the Project facilities or operations</u>: The Applicant has plans to modify the existing Project facilities and operations in order to reduce downstream flow fluctuations year round which will potentially reduce the frequency of spillage at Parr Shoals Dam. Need for, or usefulness of, modifications to existing Project facilities are described in more detail in Section 3.2.1 of Exhibit E and Section 4.0 of Exhibit B of this application and its consistency with comprehensive plans for improving the waterway and other beneficial public uses as defined in section 10(a) of the Federal Power Act can

be found in Section 6.3 of Exhibit E of this application. The projected costs of this proposed plan to modify existing Project facilities can be found in Exhibit D of this application.

8. The Applicant has plans for modifying the Project facilities, so this paragraph does not apply. Please refer to Paragraph 7 above.

9. The Applicant's financial and personnel resources to meet its obligations under a new license are as follows: The Applicant has adequate personnel resources to continue to operate and maintain the Parr Hydroelectric Project in accordance with the provisions of the license. The permanent staff at the Parr Shoals Development 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. The permanent staff at the Fairfield Development consists of 21 personnel who are on site eight hours per day, five days per week. The Fairfield Development control room is staffed continuously by an Operator and a Station Attendant. 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. The Parr Project 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 safety training programs is included as Exhibit H-4, and a list of required Operator/Repairman training programs is included as Exhibit H-5. The Applicant's financial resources to meet its obligations under the new license can be found in the Section titled "Sources of Financing" in Exhibit D of this application.

10. Proposed changes to the Project boundary: 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 are included in the Recreation Plan in Exhibit E-8 of this application. Consultation with governmental agencies and other stakeholders regarding the Project encompassing additional lands was conducted throughout the relicensing

process. Documentation of this consultation can be found in the process and correspondence information of this application (Exhibit E-1).

11. Statement of energy conservation programs and measures and compliance with applicable regulatory requirements: The Applicant is actively involved in a number of programs to improve the efficiency of electricity generation and consumption on its power system. These programs can be divided into two major categories: Energy Efficiency (EE) Programs (include Customer Education and Outreach, Energy Conservation and Demand Side Management (DSM)), and Load Management Programs (also known as Demand Response (DR), which include Standby Generator, Interruptible Load, Real Time Pricing Rate, Time of Use Rates and Winter Peak Clipping programs). The Company's EE programs and its DR programs will reduce the need for additional generating capacity on the system. The EE programs implemented by the Applicant's customers should lower not only their overall energy needs but also their power needs during peak periods. The DR programs serve more directly as a substitute for peaking capacity. The DR programs represent over 270 MW on the Applicant's system.

    As a corporation organized and existing under the laws of the State of South Carolina, the Applicant must comply with the policies of the 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 (2015), § 58-33-430, and SCPSC Order No. 98-502. The section of the 2018 IRP titled "Demand Side Management" describes 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. The table on Page 11 of the 2018 IRP shows projected impacts over the next 15 years of EE from the Company's DSM programs and from federal mandates as well as the impact from the Company's DR programs on the firm peak demand projections. A copy of the 2018 IRP filed on February 28, 2018 with the SCPSC is included as Exhibit H-1.

12. Indian tribes with land on the Project or who would be affected by the Project: There are no Indian tribes with land within the Parr Hydroelectric Project boundary. However, in July 2013, 17 federally-recognized Indian Tribes were contacted by mail to see if they wished to be consulting parties for the Parr Hydroelectric Project. The list of potentially

interested tribes was obtained from the State Historic Preservation Office (SHPO). Contact information for the two consulting party tribes is contained in the Historic Properties Management Plan (Terracon 2016), which is included in Exhibit E-9. 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	Not interested in being a consulting party
Choctaw Nation of Oklahoma	Not interested in being a consulting party
Eastern Band of Cherokee Indians	No Response
Eastern Shawnee Tribe of Oklahoma	No Response.
Jena Band of Choctaw Indians	No Response
Miccosukee Tribe of Indians of Florida	No Response
Mississippi Band of Choctaw	No Response
Muscogee (Creek) Nation	Not interested in being a consulting party; however, notify if human remains or cultural material are found.
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, notify if human remains or cultural material are found.
Seminole Nation of Oklahoma	No Response
Tuscarora Nation	No Response
United Keetoowah Band of Cherokee	Consulting Party

Information Required from Existing Licensees

1. Responses to the information specified in 18 CFR §16.10(a) has been provided in the preceding paragraphs.

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

    a. Operation During Flood Conditions: Article 39 of the current Project license issued August 28, 1974 states, *"The Licensee shall operate the project reservoirs in such a manner that releases from the lower reservoir during flood flows shall be no greater than flows which would have occurred in the absence of the project."* During the design and construction of the Fairfield Development and the concurrent installation of the bascule crest gates on Parr Dam, the Applicant determined that a river flow in excess of 40,000 CFS downstream of Parr Dam would cause the river to begin to inundate low lying areas outside the main river channel. Since the Project Boundary does not extend downstream of Parr Dam, the Applicant operates the Project so as to never exceed 40,000 CFS downstream when the Fairfield Development is operating in generating mode. As inflow begins to increase beyond the hydraulic capacity of Parr Hydro, the operators begin to lower the Parr Dam crest gates in order to pass the excess inflow over the spillway. When the Fairfield Development is generating and the Parr crest gates are not fully raised, the discharge from Fairfield is added to the natural river flow, resulting in a higher flow downstream of Parr Dam than would occur without Fairfield's discharge. As the inflow to Parr Reservoir increases further, and the crest gates continue to be lowered to pass the flow, Fairfield generation is gradually curtailed until it completely ceases prior to the flow downstream of Parr Dam reaching 40,000 CFS, at which point all the crest gates have been lowered to the fully down position. At this point, Parr Dam is passing all inflow either through the Parr Hydro powerhouse, or over the dam crest, and the flow downstream of Parr Dam is not greater than the flow which would have occurred in the absence of the Project, i.e. the natural flow in the river. The Applicant proposes to continue operating in this manner in the future during high inflows to the Project.

b. Limitation of Upstream Backwatering: A second constraint imposed on the Project during high inflow periods is the need to limit the reservoir water surface elevation upstream of Parr Dam due to the backwater profile resulting from the presence of Parr Dam. A backwater study performed by the United States Geological Survey (USGS) during the design of the Fairfield Development and Parr crest gates determined that a critical cross section exists at USGS study cross section 13 (“Section 13”), located approximately 5 miles upstream of Parr Dam. At this location, the Norfolk Southern Railroad track runs on an embankment across a portion of Parr Reservoir, which can be inundated during high flow events if the Parr Dam crest gates are not lowered as inflow increases in order to reduce the maximum water surface elevation of Parr Reservoir, as measured at Parr Dam. A table was developed which gives maximum Parr Reservoir water elevations (measured at Parr Shoals Dam) which are allowed at various inflow values, and is provided as Exhibit H-6. The Applicant proposes to continue to observe this restriction in the future.

c. Warning Devices Used to Ensure Public Safety: The Parr Shoals Development utilizes a warning siren to alert anyone in the river immediately downstream of the dam of when the crest gates are lowered to spill water over the dam.

d. Emergency Action Plan: The Applicant maintains up to date Emergency Action Plans (EAPs) for both the Parr Shoals and Fairfield Developments in accordance with FERC requirements. These plans define responsibilities and provide procedures designed to identify unusual and unlikely conditions that may endanger Project water retaining structures in time to take mitigating action and to notify the appropriate emergency management officials of possible, impending, or actual dam failure. 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. Prior to 2015, every five years, a tabletop and functional exercise are conducted at one of the Applicant’s high hazard projects, which is intended to mimic in real time the activation of the EAP, with full participation of the emergency responders. Starting in 2015, FERC Atlanta Regional Office required Licensees to conduct a tabletop and functional exercise every five years for each high hazard dam. Therefore, a tabletop and functional exercise were conducted for Parr and Fairfield Developments in 2011 and again in 2016. The next exercise is currently scheduled for 2021.

e. Monitoring Devices: The Project structures are monitored using instrumentation (including piezometers, inclinometers, tilt meters, seepage measurement points, and survey monuments) which are read periodically by personnel familiar with the structures and instruments. The Applicant maintains a Surveillance and Monitoring Program for both developments of the Project, and files annual Dam Safety Surveillance and Monitoring Reports (DSSMRs) with the FERC Atlanta Regional Office. The Fairfield Development is staffed by operators at all times, and by maintenance and engineering personnel 5 days per week. These groups perform routine daily visual surveillance of the Fairfield Development. At Parr Shoals, plant operators 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 visual surveillance of the Parr Shoals dam. Detailed monthly, quarterly, semi-annual, and annual surveillance and reading of instrumentation are done by SCE&G Fossil/Hydro Dam Safety personnel, and maintenance of the dams and instrumentation is performed by SCE&G parks and dams maintenance personnel. SCE&G surveyors perform annual crest monument monitoring of the Parr and Fairfield dams and intake and penstock slope monitoring at the Fairfield Development. All of these groups are responsible for observation and reporting of any problems noticed during their surveillance.

f. Employee and Public Safety: During the period since the current license was issued until the end of 2017, there have been 30 OSHA recordable work related injuries at the Project, and 26 first aid cases:

Year	Recordable	First Aid
1977	1	
1979	1	1
1980	4	
1981	3	1
1982		1

(Continued)

Year	Recordable	First Aid
1984		1
1986		1
1988	2	
1989	1	2
1990	4	
1993	2	
1994	2	
1996	1	
1997	2	
1998	1	
1999	2	
2001	1	3
2003	1	
2004	1	1
2007		2
2009		2
2011		1
2012		7
2013	1	
2014		1
2016		1
2017		1

g. Public Safety Plan: The Applicant maintains a Public Safety Plan (PSP) for the Project, which includes warning, caution, and information signs and devices of various types and at various locations at the public access facilities on the reservoirs.

In addition to the Applicant's measures to maintain and improve public safety, the S.C. Department of Natural Resources maintains navigational aids on Monticello Reservoir, and conducts law enforcement patrols by boat on both reservoirs.

There have been at least 16 incidents involving accidental or criminal death or injury to 17 members of the public within the Parr Hydroelectric Project during the period since the present license was issued through the end of 2017. The following table lists the number of incidents by year:

Year	Number of Incidents
1987	1
1989	1 (2 people died)
1992	1
1996	1
1998	2
2004	1
2008	1
2009	1
2011	2
2012	1
2013	4
2015	0
2016	0
2017	0

Of the 17 people involved in incidents since 1987, 11 drowned and two were presumed drowned in Monticello Reservoir, and three drowned and one attempted suicide occurred in Parr Reservoir.

3. Description of Current Operation of the Project:

The Project is configured and operated as a modified run of river conventional hydro (the Parr Development) with a superimposed pumped storage system (the Fairfield Development). Prior to the Fairfield Development, the Parr Development operated in a manner more closely approximating a true run of river plant. Under the current license issued August 28, 1974, during periods when the natural inflow to Parr Reservoir is within the hydraulic capacity of the Parr Hydro turbines, the Parr Dam crest gates are maintained in the fully raised position, allowing retention of the maximum active storage available in Parr Reservoir. The Fairfield Development is dispatched almost on a daily basis in both pumping and generating modes in order to meet the peak demands of the Applicant's interconnected system, and to a lesser extent to fulfill the reserve requirements of the Applicant's system and the aforementioned VACAR Reserve Sharing Agreement (VRSA). During Fairfield's operating cycle, some or all of the 29,000 acre-feet of active storage available within the allowable operating ranges of the Project reservoirs are exchanged, resulting in fluctuating reservoir water surface elevations in both Parr and Monticello Reservoirs almost on a daily basis. The operating range for Parr Reservoir can be up to 10 feet between a minimum of el. 255.3 ft. and maximum controlled elevation 265.3 ft. (which would only be exceeded as a result of a very large flood, and not by action of the Applicant). The operating range for Monticello Reservoir can be up to 4.5 feet between a minimum of el. 419.8 ft. and a maximum of el. 424.3 ft. In a letter dated February 22, 1979 (provided as Exhibit H-7), the Commission's Regional Engineer agreed that the Applicant would be allowed to draw Monticello Reservoir down to el. 417.3 during emergency situations, with a requirement that the Applicant notify the Atlanta Regional Office each time this is implemented. In a September 7, 1984 meeting with the Commission's Regional Engineer in Atlanta, the Regional Engineer agreed that the Applicant would be allowed to draw Monticello Reservoir down to el. 419.3 on an occasional basis without notifying the Commission's Atlanta Regional Office. This agreement is documented by letter dated December 19, 1984 from the Applicant to the Regional Engineer (provided as Exhibit H-8). The Applicant proposes to continue operation under these guidelines.

Other restrictions on the current operation of the Project exist for high inflows and floods, as described in part 2.a and 2.b of this "Information Required from Existing Licensees" section of Exhibit H.

4. <u>Discussion of history of Project and record of programs to upgrade operation and maintenance of Project</u>:

Parr Hydro Plant was constructed 1912-1914 by J. G. White Engineering Corporation for Parr Shoals Power Company, a subsidiary of Columbia Railway Gas and Electric Company. Initially constructed with five main turbine-generators, with a sixth installed in 1921. As of July 1, 1925, the Parr Shoals Power Company was transferred to Broad River Power Company, now South Carolina Electric and Gas Company (SCE&G). In the early 1960s, automatic control equipment was installed at Parr Hydro giving the system dispatcher operational control over the generating units through the use of remote means from the central dispatching office in then located in Columbia.

On August 28, 1974, the Federal Power Commission (later renamed Federal Energy Regulatory Commission, or "FERC") issued a new license to SCE&G to permit continued operation of the Parr Shoals Hydroelectric Project. The new license authorized construction of the Fairfield Pumped Storage Development and modifications to the Parr

Shoals Development, with both developments constituting the redeveloped Parr Shoals Hydroelectric Project. As part of the redevelopment, between 1975 and 1977 the spillway section of the Parr Shoals Dam was raised 9 feet by the addition of ten hydraulically-operated, bottom hinged bascule-type spillway crest gates. Two rows of post-tensioned rock anchors were installed during gate installation to increase dam stability under the higher reservoir load conditions. These modifications were undertaken in conjunction with the construction of the Fairfield Pumped Storage Development, to allow Parr Reservoir to serve as the pumped storage development's lower reservoir.

Construction of Fairfield Pumped Storage Development began on September 3, 1974 and was completed on December 22, 1978. The first four units of the Development (Units 1 through 4) began commercial operation on June 15, 1978 and the last four units (Units 5 through 8) began commercial operation on December 22, 1978. Between 2000 and 2005, new stainless steel turbine runners were installed, generators were re-wedged, rotor poles were replaced, controls and governors were upgraded, and excitation were replaced on all units at Fairfield. Servo systems were replaced on units 5 and 6, and tailrace trash racks were replaced on Units 1, 2, 7 and 8.

In 2007, an automated trash rake system was installed at the Parr Shoals powerhouse, which resulted in improved operation of the units and less intake loss due to rack obstruction.

Between 2011 and 2017, the hydraulic actuating cylinders for Parr Dam crest gates 1, 2, 4, 5, 6, 7, and 8 were replaced along with the hydraulic power unit (HPU) for the crest gates. In 2012-13, the Parr Hydro plant control system was upgraded to a PLC based system.

Additional information can be found in Exhibit C of this application.

5. Summary of generation lost due to unscheduled outages: Below is a summary of unscheduled outages over the last 5 years at Parr Shoals and Fairfield Pumped Storage developments:

Estimating the generation lost due to unscheduled outages is impractical. At Parr Shoals Development lost generation would only occur when flows in the river were greater than the available units and at Fairfield Development since the Project is utilized for reserve and peaking generation on an as-needed basis unscheduled outages may not result in lost generation.

Parr Shoals Development

YEAR	**DATE**	**UNIT**	**PROBLEM**	**DURATION (Hours)**
2013	3/6	1, 4, 5 & 6	Plant Trip - High Winds	6.08
2013	3/18	3	Oil Pump Bearing Failure	48.00
2013	5/7	1 - 6	High Water from Excessive Rain	48.00
2013	12/24	4	Trash Rake Differential	40.17
2013	12/31	4	Hydraulic Servo Issues	8.83
2014	1/1	4	Unit Failed to Stop	255.00
2014	1/12	3	Trash Rake Differential	22.10
2014	1/12	4	Trash Rake Differential	23.10
2014	3/10	3 & 4	Trash Different due Heavy Rain	24.00
2014	3/31	3	HPU Tripped due to High Temp	6.48
2014	4/1	3	HPU High Temp	14.50
2014	4/30	1 - 6	13721 Breaker Open Due to Ground	6.42
2014	6/14	4	Failed Power Supply HPU	40.00
2014	10/1	1, 3 & 4	Battery Charger Failure	1.67
2015	1/31	5	Oil Pump Failure	14.00
2015	2/1	5	Oil Pump Shaft Failure	248.00
2016	6/14	5	Lower Guide Bearing Failure	4,813.50
2016	7/18	1	DESC 400 EPROM Failure	582.50
2016	10/14	1	Shorted Stator Leads	424.50
2016	11/1	1	Shorted Stator Leads	231.00
2017	1/1	5	Lower Guide Bearing Failure	7,102.00

Fairfield Pumped Storage Development

YEAR	DATE	UNIT	PROBLEM	DURATION (Hours)
2013	1/1	5	Exciter Problem	61.5
2013	3/8	8	Varcontrol Indication Light Out	5.92
2013	3/16	2	A stator cooler was leaking water in the air housing.	2.08
2013	3/22	3	The exciter field breaker was opening and closing instead of staying closed.	239.92
2013	3/27	5	The cooling water strainer shaft packing was worn allowing water to blow by.	1.50
2013	3/27	8	The gates would close while the unit was generating this was believed to be tied to the speed sensor in the governor cabinet.	0.50
2013	4/8	5	This was due to the governor oil pressure tank not regulating the oil pressure properly. This was not while the unit was running.	1.35
2013	4/9	5	This was a problem with the governor pressure tank not regulating the oil pressure allowing too much oil into the governor sump tank.	34.23

2013	4/11	3	There was an arc on the B phase of the motor run breaker.	14.03
2013	4/11	4	The transformer motor operated disconnect had to be opened for the work on #3.	8.92
2013	5/23	1 - 4	The drainage and dewatering sump room was flooded causing the drainage pumps to short out. The plant was taken off line the cleanup and motor repair.	50.50
2013	5/23	5	The drainage and dewatering sump room was flooded causing the drainage pumps to short out. The plant was taken off line the cleanup and motor repair.	50.50
2013	5/23	6	The drainage and dewatering sump room was flooded causing the drainage pumps to short out. The plant was taken off line the cleanup and motor repair.	51.00
2013	6/18	1 - 8	The OCB 8942 in Summer Station switch yard tripped open.	3.08
2013	7/12	5 - 8	Load circuit breaker 8912 at V C Summer station switch yard tripped open.	3.43
2013	7/18	1 & 2	There were traces of gases in the oil sample. This was caused by the	319.17

			heating of crimped leads inside the transformer.	
2013	7/19	5 - 8	OCB 8912 tripped due to a bad vacuum bottle in #6 Motor Run Breaker going phase to phase causing a fault.	5.25
2013	8/1	1 & 2	There were traces of gases in the oil sample. This was caused by the heating of crimped leads inside the transformer.	24.00
2013	8/14	5 & 6	It was determined that there was a fault on #6's lighting arrestor that had to be replaced. Units 5 & 6 share the same transformer so while 6 was out of service 5 was out also.	163.62
2013	8/14	7 & 8	Generator Breaker Problem - #6	4.62
2013	8/18	3 & 4	The relay and alarm for indication of temperature cooling and oil pump operation wiring was burnt due to arcing.	13.33
2013	8/25	5	Unit #5 was taken offline to repair a generator/motor breaker issue on Unit #6. Unit #5 and #6 share a common transformer.	159.87
2013	8/25	6	The 8912 switch tripped due to two broken vacuum bottles in the	168.00

			generator/motor breaker lineup.	
2013	8/25	7 & 8	Generator Breaker Problem - #6	4.37
2013	8/28	3	Would not Synchronize. This was caused by contractors removing wiring underneath 1&2 control board for controls upgrades on units 1&2.Units 1, 2, 3, & 4 share a synchronous relay.	18.5
2013	8/28	4	Would not Synchronize. This was caused by contractors removing wiring underneath the control board for the controls upgrades on units 1 & 2.Units 1, 2, 3 & 4 share a synchronous relay.	16.25
2013	9/1	5	Unit #5 was taken offline to repair a generator/motor breaker issue on Unit #6. Unit #5 and #6 share a common transformer.	231.75
2013	9/1	6	The 8912 switch tripped due to two broken vacuum bottles in the generator/motor breaker lineup.	231.75
2013	9/23	7	While removing wiring on MCC #9 a contractor accidentally cut the wiring to #7 thrust bearing oil lift pump. This prevents the unit starting.	13.83
2013	11/12	5 &	This was caused by a failure of the	2.75

		6	emergency station service 23 kv line feeding the 5 - 8 side of Fairfield due to the motor operated disconnect being open for the work on units 7 & 8 transformer.	
2014	4/14	1	Manual disconnect 15912 was locked out while L&S worked on the tie in for controls upgrades.	3.50
2014	4/14	2	Power circuit breaker 8942 was tripped.	3.50
2014	4/14	5	Power circuit breaker 8916 was tripped.	3.50
2014	4/14	6 - 8	Power circuit breaker 8912 was tripped.	3.50
2014	5/20	4	Several wicket gates had end seals leaking oil.	3.25
2014	6/21	5	There was a cooler leaking in the upper guide bearing the oil had to be pulled out the cleaned. Then the motor start and generator breakers failed to rack back up the motor operated disconnect 8914 had to be opened.	42.10
2014	6/23	6	The work on #5 breakers required that the motor operated disconnect 8914 be opened units 54&6 share	3.02

			the same MODS.	
2014	8/25	5	#7 MR Overload. Unit #5 was not running at the time the capacitor failed but it was in outage while the relays were checked.	6.17
2014	8/25	7	#7 MR Overload. When the capacitor in the VC Summer 2 & 3 switchyard failed, it caused a surge on the 230 kv line switch 8912. All 3 breakers were tested and checked for faults.	6.17
2014	8/25	8	When the capacitor failed in V.C. Summer Stations 2 & 3 switchyard, unit #8 was operating as a pump. All three breakers were tested for faults.	23.50
2014	9/18	4	The unit was running with 30 mils vibration while pumping. The turbine guide bearing shoes were adjusted.	93.08
2014	11/3	4	Unit tripped due to a ground in faulty cable. Cable replaced.	47.92
2015	2/13	1 & 2	The generator control cabinet had a power supply module that failed.	3.00
2015	8/1	6	A brake pad was broken during an upper guide bearing inspection.	1.92
2015	8/14	4	One of the stator coolers was leaking water and had to be replaced.	6.50

2015	8/17	7 & 8	There was a questionable read out on the relay panel.	1.63
2015	12/16/	7 & 8	CT Transformer Repair	16.17
2015	12/30	1 & 2	Oil circuit breaker tripped due to water in switchgear for unit 3. Switch gear repaired and OCB reset.	15.67
2015	12/30	3 & 4	Oil circuit breaker tripped due to water in switchgear for unit 3. Switch gear repaired and OCB reset.	33.15
2016	1/1	3 & 4	Rain ran into the #3 generator buss causing a fault to the generator breaker and the buss works.	184.50
2016	3/18	3 & 4	While pulling cables on the #1 & #2 transformer, a contractor dropped a board on a relay housing. This gave a sudden pressure alarm to activate in turn this caused OCB 8942 to open tripping unit #3.	2.90
2016	5/16	5	This outage was caused by a weak spring on the breaker indication to the relay. The relay indicated the amps increasing as if there was a fault or arcing in the breaker.	10.00
2016	5/17	3	The thrust bearing oil lift pump tripped at shut down it was	4.00

			determined that the oil lift pump needed replacing.	
2016	7/30	5	The unit was pumping when it tripped with an E1 & E2 relay lock out due to amps and voltage going high.	28.33
2016	8/1	5	This was to replace a switch in the M/S cubical.	14.25
2016	10/18	6	A relay problem was causing a megawatt reading on the HMI Screen as well as the System Control.	1.20
2016	12/15	2	This outage was due to the motor start breaker motor kept charging.	19.67
2017	3/16	3	E&I had to adjust 52 plunger switch to make unit #3 gen run breaker close.	3.92
2017	5/25	1	MOD 8944 Opened for Unit 2 Work	24.80
2017	5/25	2	Replace Burnt Grounding Wire	28.55
2017	9/5	2	Brk. Tripped on High Vibration	74.58
2017	9/11	8	Storm Forced Outage	15.38
2017	11/24	2	E-1 & E-2 Lockouts	100.78

6. 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:

   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.

7. Discussion of any actions taken that affect the public: No actions affecting the public have been taken.

8. Ownership and operating expenses that would be reduced if Project license were transferred: The costs are as shown in detail in Exhibit D of this application.

9. 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 162.61 acres of Federal lands owned by the U.S. Forest Service which are part of the Parr Hydroelectric Project. Exhibit A-3 contains a tabulation of Federal Lands within the Project Boundary, by tract number, along with a designation as to which Exhibit G map sheet each tract is shown on. In 2017, the Applicant paid $11,729.81 in fees for Federal lands occupied by the Project. There are no Indian lands within the Project.

EXHIBIT H-1

Parr Hydroelectric Project P-1894

2018 Integrated Resource Plan
(Filed with South Carolina Public Service Commission February 28, 2018)

Matthew W. Gissendanner
Assistant General Counsel

matthew.gissendanner@scana.com

February 28, 2018

VIA ELECTRONIC FILING

The Honorable Jocelyn G. Boyd
Chief Clerk/Administrator
Public Service Commission of South Carolina
101 Executive Center Drive
Columbia, South Carolina 29210

RE: South Carolina Electric & Gas Company's 2018 Integrated Resource Plan
Docket No. 2018-____-E

Dear Ms. Boyd:

In accordance with S.C. Code Ann. § 58-37-40 (2015) and Order No. 98-502 enclosed you will find the 2018 Integrated Resource Plan of South Carolina Electric & Gas Company ("SCE&G 2018 IRP"). This filing also serves to satisfy the annual reporting requirements of the Utility Facility Siting and Environmental Protection Act, S.C. Code Ann § 58-33-430.

By copy of this letter, we are also serving the South Carolina Office of Regulatory Staff and the South Carolina Energy Office with a copy of the SCE&G 2018 IRP and attach a certificate of service to that effect.

If you have any questions or concerns, please do not hesitate to contact us.

Very truly yours,

Matthew W. Gissendanner

Matthew W. Gissendanner

MWG/kms
Enclosures
cc: Dawn Hipp
Jeffrey M. Nelson, Esquire
M. Anthony James
(all via electronic and U.S. First-Class Mail w/enclosures)

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2018-___-E

IN RE:

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

This is the certify that I have caused to be served this day one (1) copy of the **2018 Integrated Resource Plan of South Carolina Electric & Gas Company** via electronic mail and U.S. First Class Mail to the persons named below at the address set forth:

Jeffrey Nelson, Esquire
Office of Regulatory Staff
1401 Main Street, Suite 900
Columbia, SC 29201
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Karen M. Scruggs

Karen M. Scruggs

Cayce, South Carolina

This 28th day of February 2018

2018

Integrated

Resource

Plan

SCE&G®
A SCANA COMPANY

Table of Contents

Table of Contents

Introduction

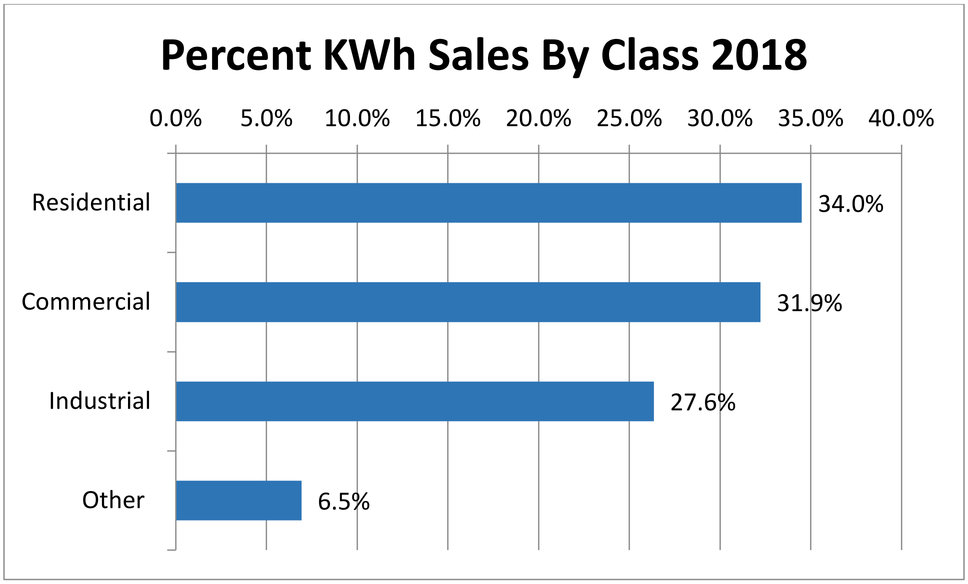
This document presents South Carolina Electric & Gas Company's ("SCE&G" or "Company") Integrated Resource Plan ("IRP") for meeting the energy needs of its customers over the next fifteen years, 2018 through 2032. This document is filed with the Public Service Commission of South Carolina ("Commission") in accordance with S.C. Code Ann. § 58-37-40 (2015) and Order No. 98-502 and also serves to satisfy the annual reporting requirements of the Utility Facility Siting and Environmental Protection Act, S.C. Code Ann. § 58-33-430 (2015). The objective of the Company's IRP is to develop a resource plan that will provide reliable and economically priced energy to the Company's customers while complying with all environmental laws and regulations.

I. Demand and Energy Forecast for the Fifteen-Year Period Ending 2032

Total territorial energy sales on SCE&G's system are expected to grow at an average rate of 1.1% per year over the next 15 years, while firm territorial summer peak demand and winter peak demand will increase at 1.2% and 0.8% per year, respectively, over the same forecast horizon. The table below contains these projected loads. By utility industry convention the winter period follows the summer period so that the 2018 winter refers to the 2018-2019 winter season.

	Summer Peak (MW)	Winter Peak (MW)	Energy Sales (GWh)
2018	4,803	4,802	23,234
2019	4,836	4,848	23,140
2020	4,904	4,893	23,385
2021	4,976	4,961	23,802
2022	5,081	5,002	24,068
2023	5,160	5,030	24,373
2024	5,220	5,071	24,635
2025	5,287	5,118	24,958
2026	5,353	5,161	25,305
2027	5,410	5,201	25,636
2028	5,464	5,241	25,973
2029	5,514	5,277	26,310
2030	5,559	5,319	26,530
2031	5,609	5,360	26,765
2032	5,657	5,402	26,995

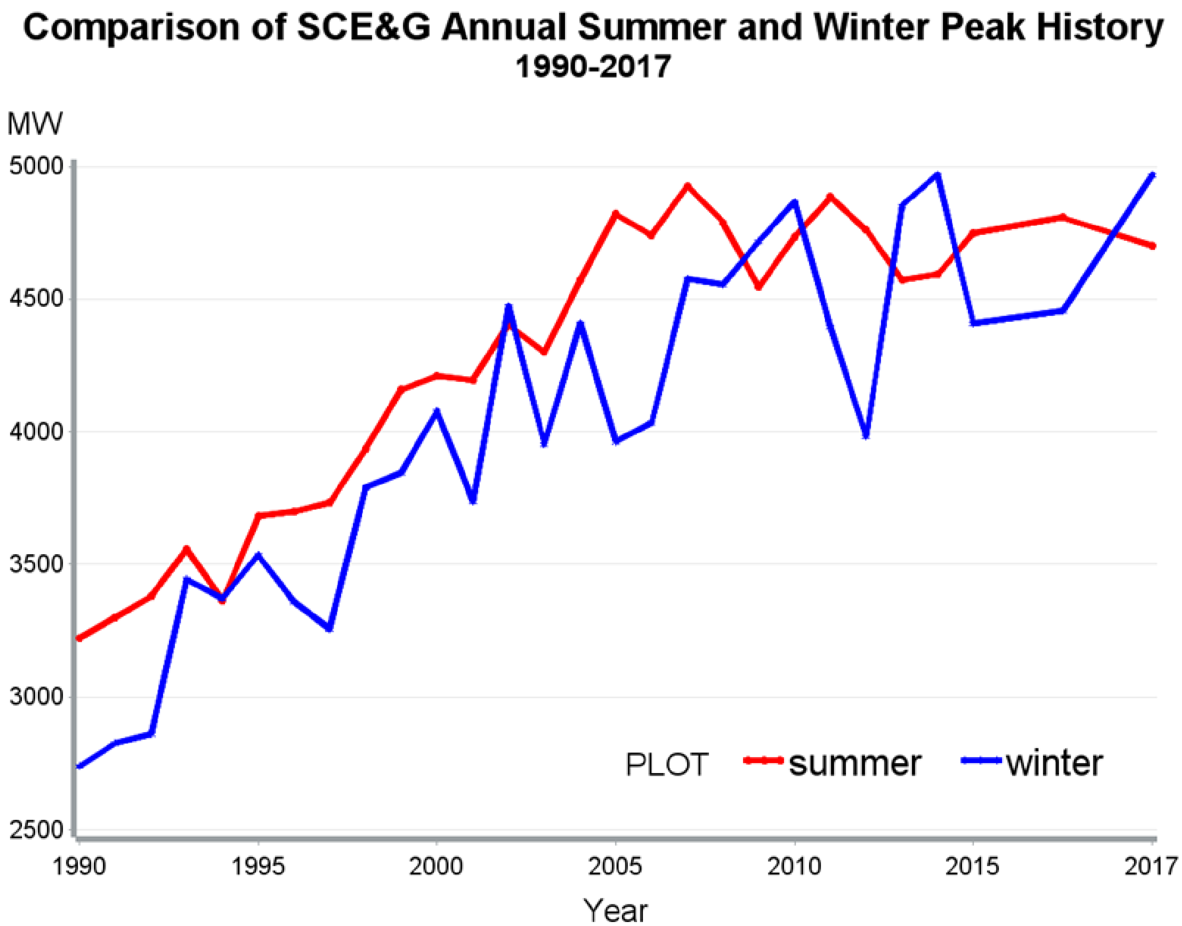
The energy sales forecast for SCE&G is made for over 30 individual categories. The categories are subgroups of the Company's six classes of customers. The three primary customer classes - residential, commercial, and industrial - comprise just over 93% of sales. The following bar chart shows the relative contribution to territorial sales made by each class. The "Other" class in the chart below includes public street lighting, other public authorities, and municipalities.



SCE&G's forecasting process is divided into two parts: development of the baseline forecast, followed by adjustments for large customer expansions, new large customers and energy efficiency impacts. A detailed description of the short-range baseline forecasting process and statistical models is contained in Appendix A. Short-range is defined as the next two years. Appendix B contains similar information for the long-range methodology. Long range is defined as beyond two years. Sales projections for each group are based on statistical and econometric models derived from historical relationships, which are then adjusted for factors not captured in the models.

A. System Peak Demand: Summer vs. Winter

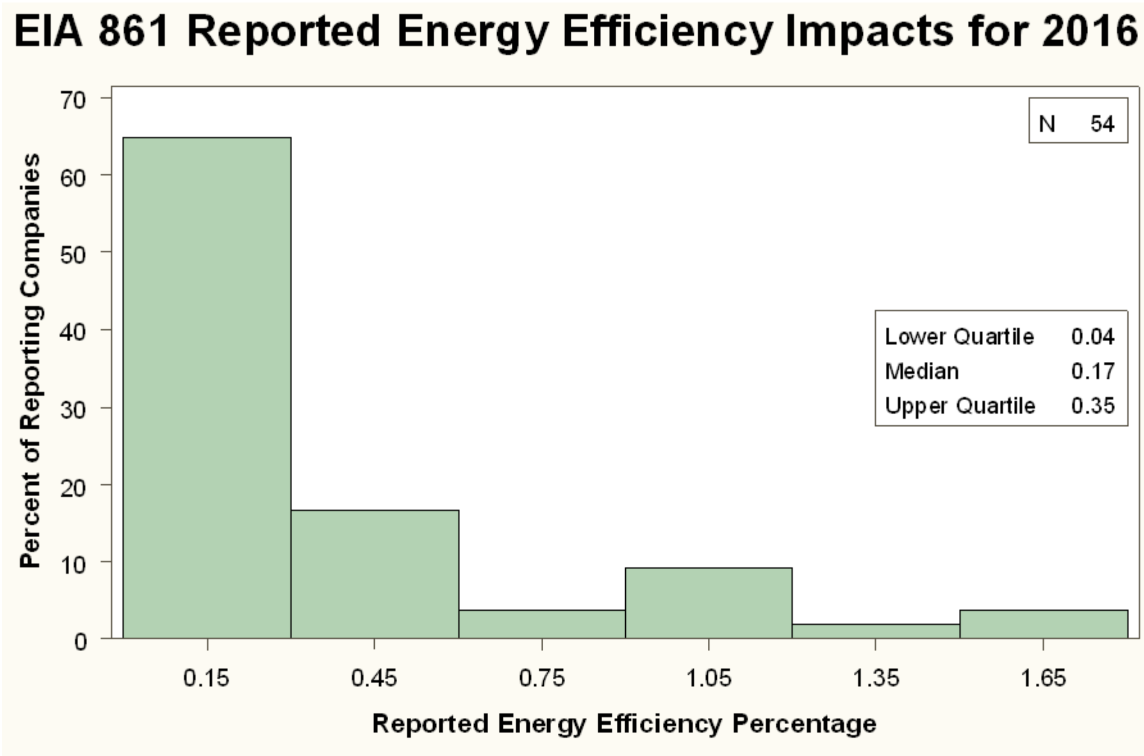
The following chart shows SCE&G's experience with summer versus winter peaking. By utility industry convention, the winter period is assumed to follow the summer period. In 7 of the past 28 years (5 of which occurred within the last 10 years), SCE&G peaked in the winter. One other notable feature of the peak demand chart is the greater variability in winter peak demand.



The forecasts of summer peak demand and winter peak demand are developed by combining the load profile characteristics of each customer class collected in the Company's Load Research Program with forecasted energy.

B. Demand Side Management (DSM) Impact on Forecast

SCE&G anticipates that its energy efficiency ("EE") programs will reduce retail sales in 2019 by 71,739 MWh or approximately 72 GWh. Retail sales after this EE impact are expected to be 21,902 GWh. Therefore, the EE programs are expected to reduce retail sales by about 0.33% from what they would have been. To gauge how SCE&G's EE programs compared to other companies in the Southeast, the Company analyzed the EE impacts filed with the U.S. Energy Information Administration ("EIA") in 2016, the latest year available. There were 57 companies filing from the Southeast, in particular, from SERC Reliability Corporation (SERC) and the Florida Reliability Coordinating Council (FRCC) regions of the North American Electric Reliability Corporation (NERC). Three companies were dropped from the analysis. The chart below shows graphically the distribution of reported results. The median EE impact was 0.17%. Thus, half the companies reported results higher and half lower than this median value. SCE&G's expectation for 2019 places it in the top half of the distribution. Clearly, SCE&G's EE programs compare favorably with other companies in the Southeast.



As part of the forecast development, the 0.33% EE savings was divided into a residential and commercial component. In addition, savings due to lighting efficiencies were removed from the class numbers and combined with lighting efficiency effects due to federally mandated measures. This was necessary to produce a consistent forecast of lighting efficiency effects. After this adjustment, the annual EE percentages used to produce the forecast were determined to be 0.27% and 0.10% for the residential and commercial sectors, respectively. The table below illustrates the calculation of the EE reductions. The far right-hand column labeled "Total Cumulative Reductions" is the sum of the residential and commercial cumulative reductions and represents the "SCE&G DSM Programs" column shown in a subsequent forecast summary table.

Derivation of Annual EE Savings									
	Baseline Residential (GWh)	**Cumulative Reductions (GWh)**	**Incremental Reductions (GWh)**	**Inc. %**	**Baseline Commercial (GWh)**	**Cumulative Reductions (GWh)**	**Incremental Reductions (GWh)**	**Inc. %**	**Total Cumulative Reductions (GWh)**
2018	8,011	-	-	-	7,435	-	-	-	-
2019	8,083	-	-	-	7,506	-	-	-	-
2020	8,251	-22	-22	-0.27	7,628	-7	-7	-0.10	-29
2021	8,390	-45	-23	-0.27	7,799	-14	-7	-0.10	-59
2022	8,518	-68	-23	-0.27	7,970	-22	-7	-0.10	-90
2023	8,671	-91	-23	-0.27	8,144	-30	-8	-0.10	-121
2024	8,826	-115	-24	-0.27	8,322	-38	-8	-0.10	-153
2025	8,995	-139	-24	-0.27	8,496	-46	-8	-0.10	-185
2026	9,171	-164	-25	-0.27	8,673	-54	-8	-0.10	-218
2027	9,349	-189	-25	-0.27	8,854	-63	-9	-0.10	-252
2028	9,531	-215	-26	-0.27	9,038	-71	-8	-0.10	-286
2029	9,711	-241	-26	-0.27	9,226	-80	-9	-0.10	-321
2030	9,811	-267	-26	-0.27	9,377	-89	-9	-0.10	-356
2031	9,918	-294	-27	-0.27	9,533	-98	-9	-0.10	-392
2032	10,020	-321	-27	-0.27	9,689	-107	-9	-0.10	-428

C. Energy Efficiency Adjustments

Several adjustments were made to the baseline projections to incorporate significant factors not reflected in historical experience. These were increased air-conditioning, heat pump, and water heater efficiency standards, plus improved lighting efficiencies, all mandated by federal law. The addition of SCE&G's energy efficiency and solar programs were also significant factors that were incorporated. The following table shows the baseline projection, solar and energy efficiency adjustments, and the resulting forecast of territorial energy sales.

	Baseline Sales (GWh)	SCE&G Solar Programs (GWh)	SCE&G DSM Programs (GWh)	Federal Mandates (GWh)	Total EE Impact (GWh)	Territorial Sales (GWh)
2018	23,369	-42	0	-93	-135	23,234
2019	23,341	-65	0	-136	-201	23,140
2020	23,709	-82	-29	-213	-324	23,385
2021	24,235	-82	-59	-292	-433	23,802
2022	24,600	-83	-90	-359	-532	24,068
2023	24,993	-83	-121	-416	-620	24,373
2024	25,386	-83	-153	-515	-751	24,635
2025	25,788	-84	-185	-561	-830	24,958
2026	26,204	-84	-218	-597	-899	25,305
2027	26,630	-84	-252	-658	-994	25,636
2028	27,069	-85	-286	-725	-1,096	25,973
2029	27,510	-86	-321	-793	-1,200	26,310
2030	27,829	-86	-356	-857	-1,299	26,530
2031	28,161	-86	-392	-918	-1,396	26,765
2032	28,488	-87	-428	-978	-1,493	26,995

Baseline sales are projected to grow at the rate of 1.4% per year. The impact of energy efficiency, both from SCE&G's DSM and solar programs, plus savings from federal mandates, causes the ultimate territorial sales growth to fall to 1.1% per year as reported earlier.

Since the baseline forecast utilizes historical relationships between energy use and driver variables such as weather, economics, and customer behavior, it embodies changes which have occurred over time. For example, construction techniques which result in better insulated houses have a dampening effect on energy use. Because this process happens with the addition of new houses and/or extensive home renovations, it occurs gradually. Over time this factor and others are captured in the forecast methodology. However, when significant events occur which impact energy use but are not captured in the historical relationships, they must be accounted for outside the traditional model structure.

The first adjustment relates to federal mandates for air-conditioning units and heat pumps. In 2015 the minimum Seasonal Energy Efficiency Ratio ("SEER") increased from 13 to 14 for South Carolina and other regions of the United States. This was the first change in SEER ratings since 2006, when the minimum SEER for newly manufactured appliances was raised from 10 to 13. The cooling load for a house that replaced a 10 SEER unit with a 13 SEER unit would decrease by 30% assuming no change in other factors. The first mandated change to efficiencies took place in 1992, when the minimum SEER was raised from 8 to 10, a 25% increase in energy efficiency. Since then air-conditioner and heat pump manufacturers introduced much higher-efficiency units, and models are now available with SEERs over 20. However, overall market production of heat pumps and air-conditioners is concentrated at the lower end of the SEER mandate. The 2015 minimum SEER rating represented another significant change in energy use which would not be fully captured by statistical forecasting techniques based on historical relationships. For this reason an adjustment to the baseline was warranted. Finally, a 2016 DOE Notice of Proposed Rulemaking (NOPR) stipulated a further increase of central air-conditioners manufactured for use in the Southeast from 14 to 15 SEER beginning in January 2023. This was also incorporated into the forecast.

All electric water heaters manufactured after April 2015 will be subject to higher efficiency standards. The level of increase varies according to the size of the water heater, but for a 40-gallon water heater the energy factor will rise by 3.4%. While high-efficiency water heaters have been available in the market for some time, it is still expected that a considerable percentage of residential customers will be impacted by the new standards. Therefore, reductions were made to the baseline energy projections to incorporate this effect.

A third reduction was made to the baseline energy projections beginning in 2013 for savings related to lighting. Mandated federal efficiencies as a result of the Energy Independence and Security Act of 2007 took effect in 2012 and were phased in through 2014. Standard incandescent light bulbs are inexpensive and provide good illumination, but are extremely inefficient. Compact fluorescent light bulbs ("CFLs") have become increasingly popular over the past several years as substitutes. CFLs last much longer and generally use about one-fourth the energy that incandescent light bulbs use. However, CFLs are more expensive and 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 do impose efficiency standards that can only be met by CFLs, Light Emitting Diode ("LED") bulbs or newly developed high-efficiency incandescent light bulbs. Again, this shift in lighting represents a change in energy use which was not fully reflected in the historical data.

The final adjustment to the baseline forecast was to account for SCE&G's set of energy efficiency and new solar programs. These energy efficiency programs along with the others in SCE&G's existing DSM portfolio are discussed later in the IRP. In developing the forecast it was assumed that the impacts of these programs were captured in the baseline forecast for the next two years but thereafter had to be reflected in the forecast on an incremental basis.

D. Load Impact of Energy Efficiency and Demand Response Programs

There are two common subsets of Demand Side Management: Energy Efficiency and Load Management (also known as Demand Response). The Company's energy efficiency programs ("EE") and its demand response programs ("DR") will reduce the need for additional generating capacity on the system. The EE programs implemented by SCE&G's customers should lower not only their overall energy needs but also their power needs during peak periods. The DR programs serve more directly as a substitute for peaking capacity. The Company has two DR programs: an interruptible program for large customers and a standby generator program. These programs represent over 270 megawatts ("MW") on SCE&G's system. The following table shows the impacts of EE from the Company's DSM programs and from federal mandates as well as the impact from the Company's DR programs on the firm peak demand projections.

Territorial Peak Demands (MWs)

		Energy Efficiency					
Year	Baseline Trend	SCE&G Programs	Federal Mandates	Total EE Impact	System Peak Demand	Demand Response	Firm Peak Demand
2018	5,103	-16	-10	-26	5,077	-274	4,803
2019	5,148	-25	-12	-37	5,111	-275	4,836
2020	5,239	-40	-19	-59	5,180	-276	4,904
2021	5,333	-50	-30	-80	5,253	-277	4,976
2022	5,459	-60	-40	-100	5,359	-278	5,081
2023	5,559	-70	-49	-119	5,440	-280	5,160
2024	5,652	-79	-72	-151	5,501	-281	5,220
2025	5,738	-90	-79	-169	5,569	-282	5,287
2026	5,820	-100	-84	-184	5,636	-283	5,353
2027	5,900	-111	-94	-205	5,695	-285	5,410
2028	5,976	-122	-104	-226	5,750	-286	5,464
2029	6,049	-132	-116	-248	5,801	-287	5,517
2030	6,116	-144	-125	-269	5,847	-288	5,559
2031	6,186	-155	-132	-287	5,899	-290	5,609
2032	6,254	-166	-140	-306	5,948	-291	5,657

II. SCE&G's Program for Meeting Its Demand and Energy Forecasts in an Economic and Reliable Manner

A. Demand Side Management

Demand Side Management ("DSM") can be broadly defined as the set of actions that can be taken to influence the level and timing of the consumption of energy. There are two common subsets of Demand Side Management: Energy Efficiency and Load Management (also known as Demand Response). Energy Efficiency typically includes actions designed to increase efficiency by maintaining the same level of production or comfort, but using less energy input in an economically efficient way. Load Management typically includes actions specifically designed to encourage customers to reduce usage during peak times or shift that usage to other times.

1. Energy Efficiency

SCE&G's Energy Efficiency programs include Customer Education and Outreach, Energy Conservation and the Demand Side Management Programs. A description of each follows:

a. **Customer Education and Outreach:** SCE&G's customer education and outreach includes a wide variety of communication tactics and channels to increase customer awareness and to help customers become more energy efficient in their homes and businesses. Two key components of customer education and outreach are summarized below:

    i. **Customer Insights and Analysis:** SCE&G continues to educate customers by leveraging insights from ongoing research, voice of the customer panels, demographics data and other customer segmentation data. These learnings are used to understand and reach customers through optimized messaging, collateral development and channel placement.

    ii. **Media/Channel Placement:** SCE&G is committed to customer education on available programs and services designed to help them be more energy efficient. To reach as many customers as possible, a diverse mix of channels is used, including both paid and earned media. Direct mail, bill inserts, internet radio, online strategies and community events continue to prove successful in reaching and engaging most customers. Extensive outreach via social media continues to optimize coverage and increase the opportunity to inform customers. Year-round news coverage is equally important and is consistently integrated into the media mix, particularly during peak winter and summer months when usage is high.

b. **Energy Conservation:** Energy conservation is a term that has been used interchangeably with energy efficiency. However, energy conservation has the connotation of using less energy in order to save rather than using less energy to perform the same or better function more efficiently. The following is an overview of each SCE&G energy conservation offering:

   i. **Energy Saver / Conservation Rate**: Rate 6 (Energy Saver/ Conservation) rewards homeowners and homebuilders with a reduced electric rate when they upgrade existing homes or build new homes to a high level of energy efficiency. This reduced rate, combined with a significant reduction in energy usage, provides for considerable savings to customers. Participation in the program is easy as the requirements are prescriptive which is beneficial to all customers and trade allies.

   ii. **Seasonal Rates**: Many of our rates are designed with components that vary by season. Energy provided in the peak usage season is charged a premium to encourage conservation and efficient use.

c. **Demand Side Management Programs**: In 2017, the Demand Side Management portfolio of programs included six (6) programs targeting SCE&G's residential customer classes and two (2) programs targeting commercial and industrial customer classes that have not opted out of the DSM rider. With each program, considerable effort is made to cross-sell and promote other DSM offers, as appropriate, to help ensure customers are consistently informed of all available incentives. A description of each program follows:

i. **Residential Home Energy Reports** provides customers with monthly/bi-monthly reports comparing their energy usage to a peer group and providing household information to help identify, analyze and act upon potential energy efficiency measures and behaviors.

ii. **Residential Home Energy Check-up** provides customers with a visual energy assessment performed by SCE&G staff at the customer's home. At the completion of the visit, customers are offered an energy efficiency kit containing simple energy conservation measures, such as energy efficient bulbs, water heater wraps and/or pipe insulation. In the seventh program year (Dec 1, 2016 **–** Nov 30, 2017), the program completed the transition from providing CFL bulbs to all LED bulbs. The Home Energy Check-up is provided at no additional cost to all residential customers who elect to participate.

iii. **Residential ENERGY STAR® Lighting** incentivizes residential customers to purchase and install high-efficiency ENERGY STAR® qualified lighting products by providing deep discounts directly to customers. In 2017, SCE&G continued to offer lighting incentives via an online store, in addition to providing energy efficiency lighting kits to customers at various business office locations and via direct mail.

iv. **Residential Heating & Cooling Program** provides incentives to customers for purchasing and installing high efficiency HVAC equipment in existing homes. Additionally, the program provides residential customers with incentives to improve the efficiency of existing AC and heat pump systems through complete duct replacements, duct insulation and duct sealing.

v. **Neighborhood Energy Efficiency Program** provides income-qualified customers with energy efficiency education and direct installation of multiple low-cost energy conservation measures as part of a neighborhood door-to-door sweep approach to reach customers. In 2017, neighborhoods in Aiken County, Fairfax/Brunson, Edgefield and North Charleston participated in the program. Additionally, the Neighborhood Energy Efficiency Program continued offerings to mobile and manufactured homes to include additional measures specific to this housing stock and fully transitioned from providing CFLs to LEDs bulbs.

vi. **Appliance Recycling Program** provides incentives to residential customers for allowing SCE&G to collect and recycle less-efficient, but operable, secondary refrigerators, and/or standalone freezers, permanently removing the units from service.

vii. **EnergyWise for Your Business Program** provides incentives to non-residential customers (who have not opted out of the DSM rider) to invest in high-efficiency lighting and fixtures, high efficiency motors and other equipment. To ensure simplicity, the program includes a master list of prescriptive measures and incentive levels that are easily accessible to commercial and industrial customers on SCE&G's website. Additionally, a custom path provides incentives to commercial and industrial customers based on the calculated efficiency benefits of their particular energy efficiency plans or new construction proposals. This program applies to technologies and applications that are more complex and customer-specific. All aspects of this program fit within the parameters of retrofits, building tune-ups and new construction projects.

viii. **Small Business Energy Solutions Program** is a turnkey program, tailored to help owners of small businesses manage energy costs by providing incentives for energy efficiency lighting and refrigeration upgrades. The program is available to SCE&G's small business and small nonprofit customers with an annual energy usage of 350,000 KWh or less, and five or fewer SCE&G electric accounts.

2. Load Management Programs

The primary goal of SCE&G's load management programs is to reduce the need for additional generating capacity. There are four load management programs: Standby Generator Program, Interruptible Load Program, Real Time Pricing Rate and the Time of Use Rates. In addition

SCE&G plans to evaluate the creation of a winter peak clipping program. A description of each follows:

a. **Standby Generator Program:** The Standby Generator Program for wholesale customers provides about 25 megawatts of peaking capacity that can be called upon when reserve capacity is low on the system. This capacity is owned by SCE&G's wholesale customers and through a contractual arrangement is made available to SCE&G System Controllers. SCE&G has a retail version of its standby generator program in which SCE&G can call on participants to run their emergency generators. This retail program provides approximately 10 megawatts of additional capacity when called upon.

b. **Interruptible Load Program:** SCE&G has over 200 megawatts of interruptible customer load under contract. Participating industrial customers receive a discount on their demand charges for shedding load when SCE&G is short of capacity.

c. **Real Time Pricing ("RTP") Rate:** A number of customers receive power under SCE&G's real time pricing rate. During peak usage periods throughout the year when capacity availability is low in the market, the RTP program sends a high price signal to participating customers which encourages conservation and load shifting. Alternatively, during high capacity availability periods, prices are lower.

d. **Time of Use Rates:** SCE&G's time of use rates contain higher charges during the peak usage periods of the day and lower charges during off-peak periods. This encourages customers to conserve energy during peak periods and to shift energy consumption to off-peak periods. All SCE&G customers have the option of purchasing electricity under a time of use rate.

e. **Winter Peak Clipping Program:** Over the next few years SCE&G will evaluate several ways of reducing its winter peak demands. These peaks are infrequent and of short duration. SCE&G will consider the following types of programs: direct load control, voltage conservation, a winter only interruptible load program, a critical peak pricing program and perhaps others.

B. Supply Side Management

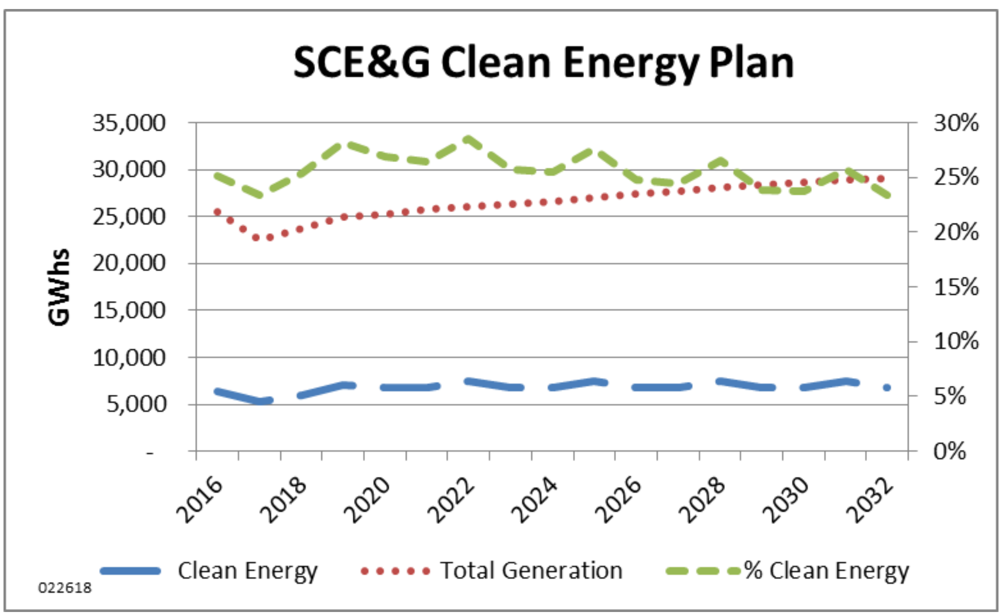
Clean Energy at SCE&G

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

1. Existing Sources of Clean Energy

SCE&G is committed to generating more of its power from clean energy sources. This commitment is reflected: in the amount of current and projected generation coming from clean sources, in the certified renewable energy credits that the Company generates each year, and in the Company's distributed energy resource program. Below is a discussion of each of these topics.

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



As seen in the chart above, SCE&G produces 25% of its total generation from clean energy sources.

b. **Net Energy Metering, PR-1 and PR-2 Rates:** Protecting the environment includes encouraging and helping customers to take steps to do the same. Net Energy Metering (NEM) provides a way for residential, commercial and industrial customers interested in generating their own renewable electricity to partially power their homes or businesses and sell the excess energy back to SCE&G. For residential customers, the generator output capacity cannot exceed the annual maximum household energy requirements or 20 kilowatts alternating current (kW AC), whichever is less. For commercial and industrial customers, the generator output capacity cannot exceed the annual maximum energy requirements of the business, the contract demand, or 1,000 kW AC, whichever is less. The total customer generator capacity under the NEM program is limited to 2% of the Company's previous five-year average retail peak demand. For SCE&G, this capacity limit is 84.5 MW AC.

Under Commission Order 2015-194, a Net Energy Metering Methodology ("NEM 2.0") was approved whereby a value per KWh will be calculated annually for distributed energy resources. This value will be the basis upon which the Company will continue to provide customers a retail NEM incentive and have the difference funded through the Distributed Energy Resource Program Act. Provided the total customer generator capacity cap has not been met, customers will be offered the NEM rate until January 1, 2021, and those customers taking service under the NEM rate will receive the Net Metering Incentive described above through December 31, 2025, or until they take service under a different rate, whichever occurs first.

The Company offers Qualifying Facilities as defined by the Federal Energy Regulatory Commission Order No. 70 under Docket No. RM 79-54 payments for power generated and transmitted to the SCE&G system. For Qualifying Facilities no greater than 100 kW, the PR-1 rate is available for these energy payments. For Qualifying Facilities greater than 100 kW but no greater than 80 megawatts (MW), the PR-2 rate is available for these energy payments. Both the PR-1 and PR-2 rates are developed using SCE&G's avoided costs.

c. **Distributed Energy Resource ("DER") Program:** SCE&G continues to manage the DER Customer Scale programs to include the approval and interconnection of systems under the NEM 2.0 rate. SCE&G also is processing the final 12.5 MW of Commercial and Industrial Bill Credit Agreement interconnections with an April 27, 2018, deadline. Finally, SCE&G anticipates that 14 MW of Community Solar farms will become interconnected in the first half of 2018, with another 2 MW AC in the first quarter of 2019.

In October of 2017 the Otarre Solar Park located on Saxe Gotha Road in the Otarre development corridor of Cayce, SC was interconnected to SCE&G's electric system and now supplies clean energy to SCE&G customers. This farm is one of nine utility-scale DER facilities interconnected and totaling 48.2 MW of capacity.

Otarre Solar Park facts:

- The park is located adjacent to the corporate campus of SCANA, parent company of SCE&G.
- The construction and interconnection of Otarre Solar Park brought an additional 1.62 MW of utility-scale solar power to SCE&G's grid.
- Otarre Solar Park, which consists of 6,156 panels, provides enough electricity to power approximately 283 homes. The park spans 7.5 acres and contains 54 inverters with a fixed tilt configuration.

Otarre Solar Farm, Cayce, SC

Jerry Zucker Solar Park facts:

- Located at Leeds Avenue in North Charleston, SC.
- Officially opened Jan 21, 2016 and was the first utility scale solar farm constructed under SC Distributed Energy Resource Act
- Zucker Solar Park's 2014 solar panels produce 0.5 MW-AC, enough energy to power approximately 88 homes

d. Non-DER Utility Scale Solar: In 2017, the Company experienced a significant increase in the independent power producer ("IPP") photovoltaic generator interconnection interest with respect to non-DER solar projects. These utility scale solar farms are contracted according to the PURPA avoided cost approved methodology and are currently producing clean power on the SCE&G system. Below is a list of non-DER utility scale solar farms currently in operation on SCE&G's system.

PURPA Utility Scale PPAs	Nameplate Capacity (MW-AC)
Hampton I	6.8
St. Matthews	10.2
Moffett Solar I (Jasper County)	71.4
Champion (Pelion, Lexington County)	10.88
Swamp Fox (Pelion, Lexington County)	10.88
Cameron	20
Estill I	20.24
Hampton II	20
Estill II	10.2
Southern Current One (Brunson, Hampton County)	10.2
	190.8

e. Nuclear Power: Unit 1 at the Summer Nuclear Station produces a substantial amount of clean energy and has a significant beneficial impact on the environment. The Unit came online in January 1984 and has a capacity of 966 MWs with SCE&G owning 647 MWs (two-thirds) and Santee Cooper owning the balance. In 2017, Unit 1 produced 4,610 gigawatt-hours (“GWh”) of clean energy for SCE&G’s customers. This represented 20% of SCE&G’s generation mix. Over the last 35 years of operation, Unit 1 has produced 159,011 GWhs for SCE&G’s customers. SCE&G received an extension to its original operating license in April 2004 and the Unit is now licensed to operate until August 2042. Over these next 25 years Unit 1 should produce another 124,283 GWhs of clean energy for SCE&G. If SCE&G were to generate this 60-years’ worth of energy with fossil fuels, it would result in approximately 212 million more tons of CO_2 emitted to the atmosphere. This amount represents only SCE&G’s two-thirds share of the Unit; when Santee Cooper’s share is also considered, the full impact of the unit to the environment is 50% greater.

f. Renewable Energy Credits: The SCE&G owned electric generator, located at the KapStone Charleston Kraft LLC facility, generates electricity using a mixture of coal and biomass. KapStone Charleston Kraft LLC produces black liquor through its Kraft pulping process and produces and purchases biomass fuels. These fuels are used to produce renewable energy which qualifies for Renewable Energy Certificates (“REC”). SCE&G

has also begun generating RECs from solar generation. The table below shows the MWhs of renewable energy generated by the KapStone biomass and various solar generators.

Year	Kapstone MWhs	Solar MWhs	% of Retail Sales
2007	371,573		1.7%
2008	369,780		1.7%
2009	351,614		1.7%
2010	346,190		1.5%
2011	336,604		1.5%
2012	414,047		1.9%
2013	385,202		1.8%
2014	404,526		1.8%
2015	385,470	22	1.8%
2016	394,814	1,005	1.8%
2017	382,696	90,234	2.1%

g. **Hydro-Power:** SCE&G owns five hydroelectric generating plants, one of which is a pumped storage facility, that combine for a total of 802 MW of clean capacity in the winter and 794 MW in the summer. The Saluda Hydro plant in Irmo, SC has a generating capacity of 200 MW. Saluda Hydro was put in service in 1930 and in August 2008 SCE&G filed an application requesting a new fifty year license with the Federal Energy Regulatory Commission ("FERC"). The Company is still waiting for the issuance of this new license. In 2017, SCE&G's hydroelectric plants produced 161 gigawatt-hours ("GWh") of clean energy for SC customers. SCE&G's pumped storage facility, Fairfield Pumped Storage, has a net dependable generating capacity of 576 MW and is a valuable asset to the SCE&G generation fleet. Fairfield Pumped Storage contributed 382 gigawatt-hours ("GWh") in 2017 and has been a reliable resource for responding to quick load changes on the SCE&G system.

2. Future Clean Energy

SCE&G is participating in activities seeking to advance clean energy technologies in the future. Specifically, the Company is involved with a) utility scale non-DER Solar b) off-shore wind activities in the state, c) smart grid opportunities, d) environmental mitigation activities, e) small modular new nuclear power and f) hydro relicensing. These activities are set forth in more detail below.

a. Utility Scale Non-DER Solar: The company gauges the future of utility scale solar based on the current volume of interconnection applications in the Company's interconnection queue. As of December 20, 2017, across the Company's State and FERC interconnection queues, there were 4,691 MW of "In-Progress" projects and 2,285 MW of "Withdrawn" projects logged.

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

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

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

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

SCE&G participated in the Regulatory Task Force for Coastal Clean Energy. This task force was established with a 2008 grant from the U.S. Department of Energy. The goal was to identify and overcome existing barriers for coastal clean energy development for wind, wave and tidal energy projects in South Carolina. Efforts included an offshore wind transmission study; a wind, wave and ocean current study; and creation of a Regulatory Task Force. The mission of the Regulatory Task Force was to foster a regulatory environment conducive to wind, wave and tidal energy development in state waters. The Regulatory Task Force was comprised of state and federal regulatory and resource protection agencies, universities, private industry and utility companies.

SCANA/SCE&G participated in discussions to locate a 40 MW demonstration wind farm off the coast of Georgetown. This effort, known as Palmetto Wind, included Clemson University's Restoration Institute, Coastal Carolina University, Santee Cooper, the S.C. Energy Office and various utilities. Palmetto Wind has been put on hold due to the high cost of the project.

In an effort to promote wind turbine research, SCE&G invested $3.5 million in the Clemson University Restoration Institute's wind turbine drive train testing facility at the Clemson campus in North Charleston. This new facility is dedicated to groundbreaking research, education, and innovation with the world's most advanced wind turbine drive train testing facility capable of full-scale highly accelerated mechanical and electrical testing of advanced drive train systems for wind turbines.

c. Smart Grid Activities:

AMI (Advanced Metering Infrastructure): SCE&G currently has approximately 14,000 AMI meters that are installed predominately on medium and large commercial and industrial customers. Other applications where this technology is deployed include all time-of-use accounts and all accounts with customer generation (net metering). These meters utilize public wireless networks as the communication backbone and have full two-way communication capability. Register readings and load profile interval data are remotely collected daily from all AMI meters. In addition to traditional metering functions, the technology also provides real-time monitoring capability including power outage/restoration, meter/site diagnostics, and power quality monitoring. Load profile data is provided to customers daily via web applications enabling these customers to have quick access to energy usage allowing better management of their energy consumption. SCE&G is in the planning stages for deploying mass AMI technology for all electric meters.

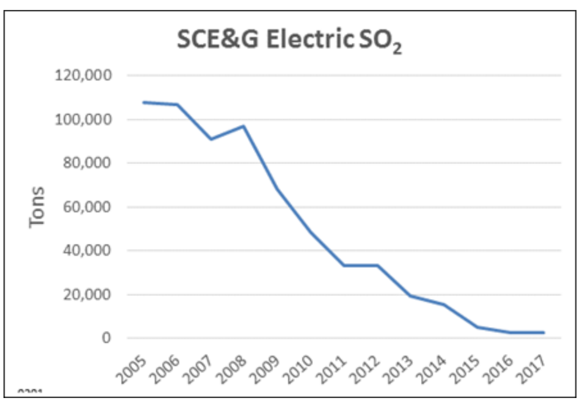
Distribution Automation: SCE&G is continuing to expand the penetration of automated Supervisory Control and Data Acquisition ("SCADA") switching and other intelligent devices throughout the system. SCE&G has approximately 1,060 SCADA switches and reclosers, most of which can detect system outages and operate automatically to isolate sections of line with problems thereby minimizing outage times to affected customers. Some of these isolating switches can communicate with each other to determine the optimal configuration to restore service to as many customers as possible without operator intervention. SCE&G continues to evaluate systems that will further enable these automated devices to communicate with each other and safely reconfigure the system in a fully automated fashion, let operators know exactly where the faulted section of a line is, and monitor the status of the system as it is affected by outages, switching, and customer generation (solar).

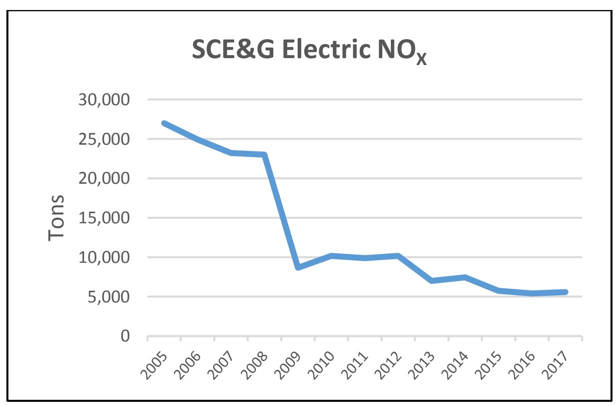
d. Environmental Mitigation Activities: The Cross State Air Pollution Rule (CSAPR), sets emission limits for annual and seasonal NO_X and for annual SO_2. The Acid Rain Program (ARP) also limits annual SO_2 emissions.

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

To meet the compliance requirements for SO_2, Williams and Wateree Stations have installed flue gas desulfurization ("FGD") equipment, commonly known as wet scrubbers. Cope Station has FGD equipment in the form of a dry scrubber.

The two charts below illustrate the significant emission reductions realized since 2005.





Mercury emission control is also realized via the operation of FGD equipment. Consequently, the continued operation of the FGD equipment has contributed to SCE&G's strategy for meeting the requirements of the US EPA's Mercury and Air Toxics Standard (MATS) that became effective on April 16, 2015. The Chem-Mod fuel additive used at Cope and Williams Stations similarly contributes to SCE&G's efforts to control mercury emissions, as well as for NO_X and SO_2. As a result of the MATS regulations for mercury, the company has also installed carbon injection systems at Williams, Wateree and Cope. This will allow for additional control of mercury emissions if needed to comply with MATS requirements.

In response to the EPA MATS regulations, the last coal-fired boiler at Urquhart Station, Unit 3, was converted to natural gas. Decommissioning of the plant's former coal handling facilities was completed in 2014. Also in response to MATS, Canadys Station ceased operations on November 6, 2013, and the plant infrastructure was decommissioned in 2015. McMeekin Units 1 & 2 were fully converted to gas in April 2016 with no coal utilized after that date.

In an effort to cease bottom ash sluicing to the Wateree Station's ash ponds, SCE&G installed two remote submerged flight conveyors that dewater boiler bottom ash sluice and recycle the overflow back to the boiler for reuse. This retrofit was completed for Units 1 and 2 during October 2012. The bottom ash is marketed as an ingredient in the manufacture of pre-stressed concrete products. In April 2016, Wateree Station completed construction of dry fly ash handling systems and discontinued sluicing ash to ponds. All fly ash is now managed dry. Fly ash at Williams and Cope Stations has been handled dry since those plants were constructed.

e. Nuclear Power in the Future – Small and Modular: Small Modular Reactor ("SMR") technology continues to be developed. DOE has awarded several grants to support the development of the SMR technology. At about a third, or less, of the size of current nuclear power plants, SMRs could make available, for a smaller capital investment, a modular design for specific generation needs. Multiple modules could be incrementally added to match load growth depending on the design. Modules are factory built for easy transportation and are installed below-grade in a seismically robust facility. SMR designs consider a smaller emergency planning zone and a reduced site boundary due to design enhancements in safety.

The process of licensing these reactors through the Nuclear Regulatory Commission ("NRC") is underway. NuScale's design is the most developed SMR design, completing their design certification application at the end of 2016 and being subsequently accepted for docketing in March of 2017. In December of 2017, the NRC approved NuScale's "Safety Classification of the Passive Nuclear Power Plant Electrical

Systems" Licensing Topical Report, which establishes the bases of how a design can be safe without reliance on any safety-related electrical power. Utah Associated Municipal Power Systems (UAMPS) Carbon Free Power Project (CFPP) will be the first planned NuScale SMR deployment with a 12-module (600 MWe gross) on the Idaho National Laboratory site. The expected commercial operation date of 2026 is dependent on federal production tax credits being extended.

In 2015 and 2016, SCE&G assisted an SMR vendor with a feasibility study for replacement of coal generation with the SMR technology. However, SCE&G has no current plans for SMR on its system but will continue to evaluate and monitor the development of this technology as it develops.

f. **Hydro-Power:** The Company is currently working on relicensing the Parr Hydroelectric Project which includes the Fairfield Pumped Storage Development and Parr Shoals Development. SCE&G will be filing an application with the FERC by June 2018 requesting a new fifty year license for the Parr Hydroelectric Project. The current license expires in June 2020. This project is critical for the future of SCE&G's generation portfolio. With the increased adoption rate of non-dispatchable solar generation on the SCE&G system, Fairfield Pumped Storage is an important asset for grid stability, reliability and power quality for SCE&G customers. SCE&G plans to continue reliance on clean dispatchable power from all of the existing hydro and pumped storage units through successful completion of the relicensing processes of Saluda, Parr and Fairfield Pumped Storage Facilities.

3. Summary of Proposed and Recently Finalized Environmental Regulations

The EPA has recently enacted a number of regulations with significant potential to impact SCE&G operations. These are: a) Cross-State Air Pollution Rule (CSAPR); b) Mercury and Air Toxics Standards (MATS): c) Clean Power Plan; d) Cooling Water Intake Structures Rule; e) Coal Combustion Residuals (CCR) Rule; f) Effluent Limitation Guidelines; and g) a 1-hour sulfur dioxide (SO2) National Ambient Air Quality Standard (NAAQS). A discussion of these proposed and finalized regulations follows.

a. Cross-State Air Pollution Rule (CSAPR): On July 6, 2011, the EPA issued the Cross-State Air Pollution Rule to reduce emissions of SO_2 and NO_X from power plants in the eastern half of the United States. A series of court actions stayed this rule until October 23, 2014. CSAPR requires a total of 28 states to reduce annual SO_2 emissions, annual NO_X emissions and/or ozone season NO_X emissions to assist in attaining the 1997 ozone and fine particle and 2006 fine particle National Ambient Air Quality Standards (NAAQS). The rule establishes an emissions cap for SO_2 and NO_X and limits the trading region for emission allowances by separating affected states into two groups with no trading between the groups.

On July 28, 2015, the Court of Appeals held that Phase 2 emissions budgets for certain states, including South Carolina, required reductions in emissions beyond the point necessary to achieve downwind attainment and were, therefore, invalid. The State of South Carolina has chosen to remain in the CSAPR program, even though this recent court ruling exempted the state. This allows the state to remain compliant with regional haze standards.

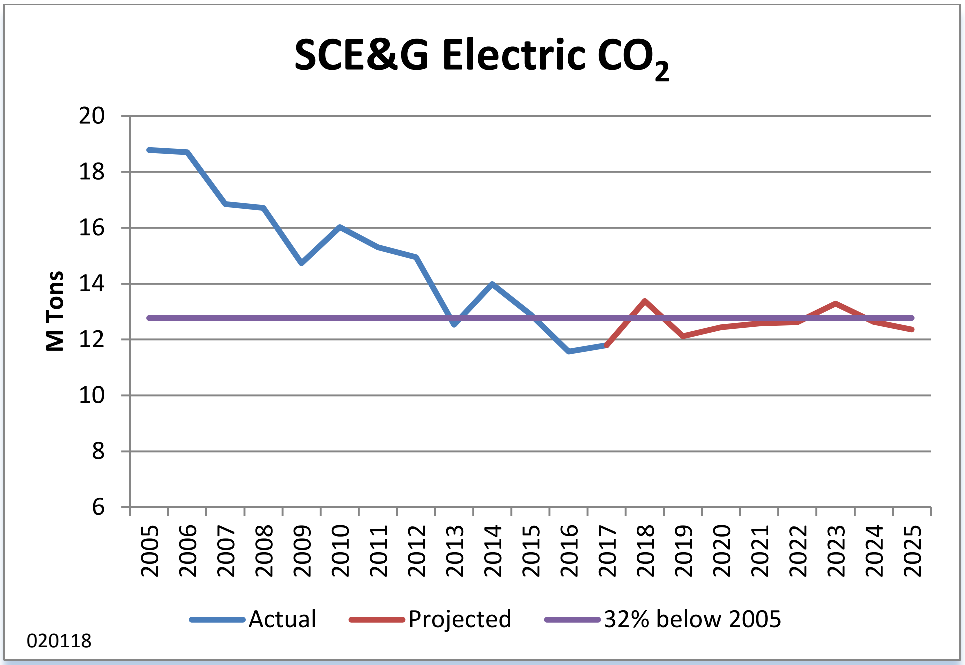
SCE&G generation is in compliance with the allowances set by CSAPR. Air quality control installations that SCE&G has already completed have positioned the Company to comply with the rule.

b. Mercury and Air Toxics Standards ("MATS"): The MATS rule set numeric emission limits for mercury, particulate matter as a surrogate for toxic metals, and hydrogen chloride as a surrogate for acid gases. MATS became effective on April 16, 2012, and compliance with MATS was required by April 2015. SCE&G and GENCO were granted a one year extension (through April 2016) to comply with MATS at Cope, McMeekin, Wateree and Williams Stations. These extensions allowed time to convert McMeekin Station to burn natural gas and to install additional pollution control devices at the other plants to enhance the control of certain MATS-regulated pollutants. In addition, SCE&G retired certain other coal-fired units during this time frame. The MATS rule has been the subject of ongoing litigation even while it remains in effect. SCE&G and GENCO are in compliance with the MATS rule and expect to remain in compliance.

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

The first of these rules amends the new source performance standards ("NSPS") for EGUs and establishes the first NSPS for greenhouse gas ("GHG") emissions. Carbon dioxide emissions from natural gas-fired EGUs are limited to 1000 lbs. CO_2/MWh. Coal-fired EGUs carbon dioxide emissions are limited to 1400 lbs. CO_2/MWh. The Company currently has no plans to add new coal-fired generation.

The second rule published in August 2015, was issued under the authority of Section 111(d) of the Clean Air Act and governs existing power plants. The EPA has determined a "Best System of Emissions Reduction" (BSER) for these existing plants. The BSER includes three "Building Blocks," including heat rate reduction at coal-fired plants; re-dispatch of electric generation from coal to natural gas plants; and substituting zero-emission generation for existing coal-fired plants. Using this BSER, the EPA established targets for each state covered by the 111(d) rule and has proposed various pathways for each state to comply with those targets. Those pathways include rate-based compliance plans, wherein each EGU would be required to meet an emission rate target. Alternatively, a state may select a mass-based compliance plan, in which an EGU would be allocated a CO_2 emission (in short tons) cap. In both the rate and mass-based plans, EGUs would have the opportunity to trade credits or allocations to assist in meeting those targets.



However, on February 9, 2016, the Supreme Court stayed the rule pending disposition of a petition of review of the rule in the Court of Appeals. As a result of an Executive Order on March 28, 2017, the EPA placed the rule under review and the Court of Appeals agreed to hold the case in abeyance. On October 10, 2017, the Administrator of the EPA signed a notice proposing to repeal the rule on the grounds that it exceeds the EPA's statutory authority. In a separate but related action, EPA issued an Advance Notice of Proposed Rulemaking (ANPRM) on December 18, 2017, to solicit information from the public about a potential future rulemaking to limit greenhouse gas emissions from existing units. Although the outcome of the future rulemaking is uncertain, EPA has more recently stated its understanding that the best system of emission reduction for a source should be based only on measures that can be applied to or at the source (facility-specific measures).

d. **Cooling Water Intake Structures:** The Clean Water Act Section 316(b) Existing Facilities Rule became effective on October 14, 2014. This rule is intended to reduce impacts to fish and shellfish due to impingement, when organisms are trapped against inlet screens, and entrainment, when small organisms are drawn through the screens into the facility's cooling water system. Facilities capable of withdrawing at least 2 million gallons per day are generally subject to the rule. Facilities that are subject to the rule must, at a minimum, submit a series of reports which describe the design and operation of the cooling water intake, as well as physical and biological characteristics of the cooling water source waterbody. For some facilities, operational or design changes will be necessary to meet the requirements of the rule. Potential design changes range from enhanced screening and reconfiguration of water intake systems to installation of closed-cycle cooling towers to reduce flow rates. Of the SCE&G generating facilities potentially subject to the rule, two stations, Wateree and Cope Stations, currently meet Best Technology Available (BTA) requirements for impingement mortality and entrainment. Two other stations, McMeekin and Jasper Stations, have been determined to be not-in-scope of the rule. SCE&G has conducted entrainment studies that demonstrate that Summer Station's existing intake structure fully complies with the rule. A biological study plan, which would evaluate current impacts to fish and shellfish, is being developed for Urquhart Station. Finally, Williams Station was issued a permit in December 2016 that requires biologic and intake study plans be conducted over the five year permit life. Modifications to the Williams Station intake structure, if any, may be delayed due to interferences of this intake with the Charleston Water Service intake for drinking water supplied to the Charleston Metro area.

e. Coal Combustion Residuals: In response to concerns over the potential structural failure of coal ash impoundment facilities, EPA has elected to further regulate coal combustion residual (CCR or ash) management in landfills and surface impoundments (ponds). The rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The rule became effective on October 19, 2015, and requires the phase-in of several activities including publishing information on the Company website, assessing the structural integrity of pond dikes, and additional monitoring of environmental conditions at each landfill and pond.

The rule acknowledges that CCR can be safely reused in encapsulated products such as cement, concrete and wallboard. SCE&G has long provided CCR as a useful raw material to those industries and expects to continue to do so.

CCR landfills at Cope, Wateree, and Williams Station are subject to the rule. Ponds at Wateree and Williams station are also covered by the rule. Notwithstanding this new CCR rule, SCE&G has already closed its ash storage ponds or has begun the process of ash pond closure at all of its operating facilities. Those ash storage ponds that are still open are subjected to a rigorous inspection and maintenance program to ensure the safe management of those units. SCE&G will continue to operate ponds for flue-gas desulfurization (FGD) solids for the foreseeable future, and will continue to operate CCR landfills.

SCE&G has been conducting compliance activities required by this rule, including, but not limited to: studies and monitoring of pond dikes; increased inspections of CCR units; additional groundwater monitoring; and publication on the internet of certain data required by the rule.

In December 2016, the U.S. Congress passed and the President signed legislation that creates a framework for EPA-approved state CCR permit programs. Under this legislation, an approved state CCR permit program functions in lieu of the self-implementing Federal CCR rule. The legislation allows states more flexibility in developing permit programs to implement the environmental criteria in the CCR rule. In August 2017, the EPA issued interim guidance outlining the framework for state CCR program approval. The EPA has enforcement authority until state programs are approved. The EPA and states with approved programs both will have authority to enforce CCR requirements under their respective rules and programs. To date, South Carolina has not begun drafting a CCR rule.

f. Effluent Limitation Guidelines: On September 30, 2015, the EPA amended the Effluent Limitation Guideline for Steam Electric Power Generators also referred to as the ELG Rule. The standards under this rule were set to match the "Best Available Technology" for wastewaters produced at this type of electric generating facilities. Although several types of wastewaters were given new discharge standards under this rule, the most significant and difficult water to treat is flue-gas desulfurization (FGD) wastewater. FGD wastewater is generated at Wateree and Williams Stations.

Under the Clean Water Act, compliance with applicable limitations is achieved under State-issued National Permit Discharge Elimination System (NPDES) permits. As a facility's NPDES permit is renewed (every 5 years) any new effluent limitations are incorporated. State environmental regulators will modify each renewed NPDES permit to match more restrictive standards, thus requiring utilities to retrofit affected facilities with new wastewater treatment technologies. Compliance dates will vary by type of wastewater and some will be based on a plant's 5-year permit renewal cycle and thus may range from 2020 to 2023. Based on the proposed rule, SCE&G expects that wastewater treatment technology retrofits will be required at Williams and Wateree at a minimum.

The ELG Rule is under reconsideration by the EPA and has been stayed administratively. The EPA has decided to conduct a new rulemaking that could result in revisions to certain flue gas desulfurization wastewater and bottom ash transport water requirements. Accordingly, in September 2017, the EPA finalized a rule that resets compliance dates under the ELG Rule to a range from November 1, 2020, to December 31, 2023. The EPA indicates that the new rulemaking process may take up to three years to complete, such that any revisions to the ELG Rule likely would not be final until the summer of 2020.

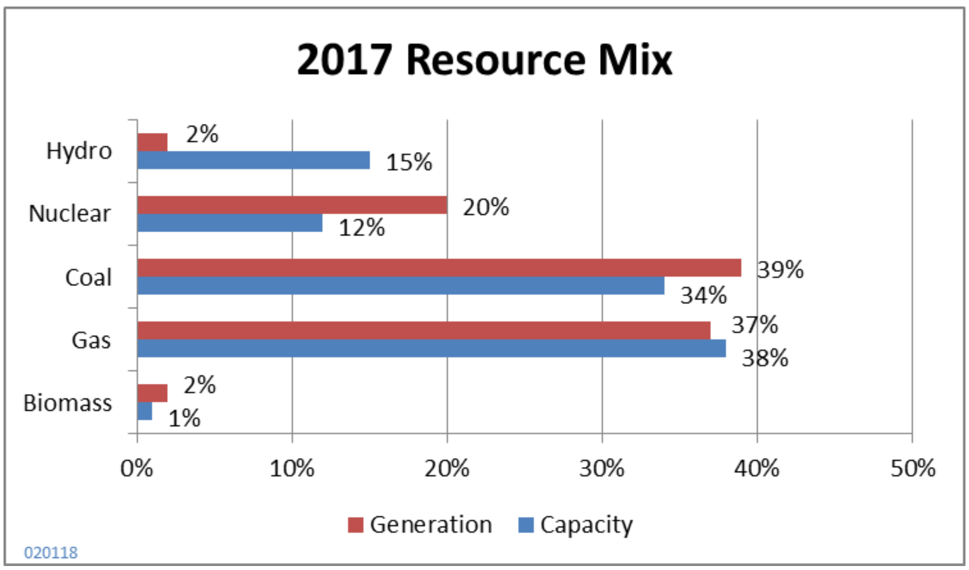
g. NAAQS 1-hour SO_2: In June 2010, EPA revised the primary SO_2 standard by establishing a new 1-hour standard at a level of 75 parts per billion ("ppb").

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

4. Supply Side Resources at SCE&G

a. Existing Supply Resources: SCE&G owns and operates three (3) coal-fired fossil fuel plants, two (2) gas-fired steam plants, two (2) combined cycle gas turbine/steam generator plants (gas/oil fired), seven (7) peaking turbine plants, four (4) hydroelectric generating plants, and one Pumped Storage Facility. In addition, SCE&G receives the output of 85 MWs from a cogeneration facility. The total fossil-hydro generating capability rating of these facilities is 4,586 MWs in summer and 4,758 MWs in winter. These ratings, which are updated at least on an annual basis, reflect the expectation for the coming summer and winter seasons. When SCE&G's nuclear capacity (647 MWs in summer and 661 MWs in winter), a long term capacity purchase (25 MWs), additional capacity (20 MWs) provided through a contract with the Southeastern Power Administration and 96MWs of summer only utility scale solar are added, SCE&G's total supply capacity is 5,374 MWs in summer and 5,464 MWs in winter. This is summarized in the table on the following page.

The bar chart below shows SCE&G's actual 2017 relative energy generation and relative capacity by fuel source.



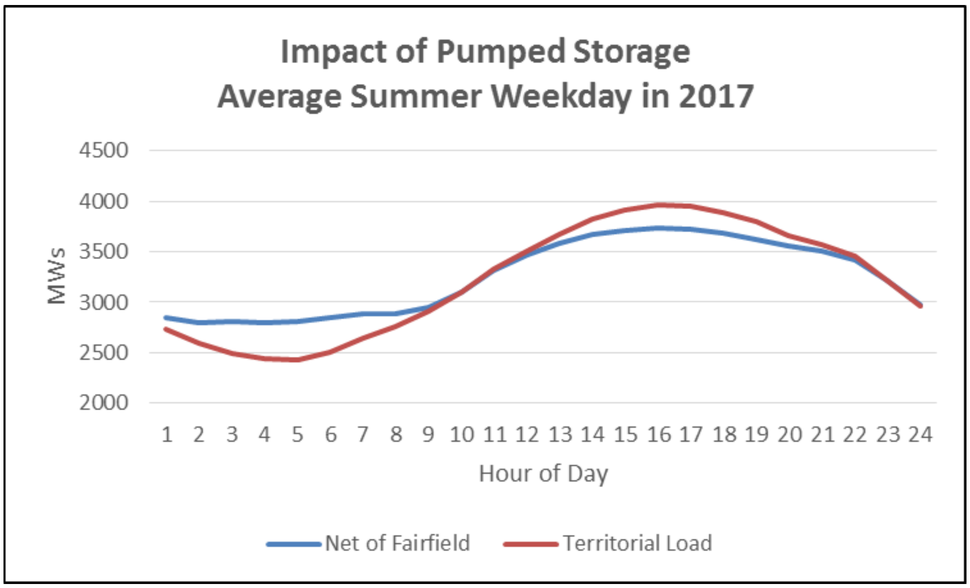
Existing Long Term Supply Resources

The following table shows the generating capacity that is available to SCE&G in 2018.

	In-Service Date	Summer (MW)	Winter (MW)
Coal-Fired Steam:			
Wateree – Eastover, SC	1970	684	684
Williams – Goose Creek, SC*	1973	605	610
Cope - Cope, SC	1996	415	415
KapStone – Charleston, SC	1999	85	85
Total Coal-Fired Steam Capacity		1,789	1,794
Gas-Fired Steam:			
McMeekin – Irmo, SC	1958	250	250
Urquhart – Beech Island, SC	1955	95	96
Total Gas-Fired Steam Capacity		345	346
Nuclear:			
V. C. Summer - Parr, SC	1984	647	661
I. C. Turbines:			
Hardeeville, SC	1968	9	9
Urquhart – Beech Island, SC	1969	39	48
Coit – Columbia, SC	1969	26	36
Parr, SC	1970	60	73
Williams – Goose Creek, SC	1972	40	52
Hagood – Charleston, SC	1991	126	141
Urquhart No. 4 – Beech Island, SC	1999	48	49
Urquhart Combined Cycle – Beech Island, SC	2002	458	484
Jasper Combined Cycle – Jasper, SC	2004	852	924
Total I. C. Turbines Capacity		1,658	1,816
Hydro:			
Neal Shoals – Carlisle, SC	1905	3	4
Parr Shoals – Parr, SC	1914	7	12
Stevens Creek - Near Martinez, GA	1914	8	10
Saluda - Irmo, SC	1930	200	200
Fairfield Pumped Storage - Parr, SC	1978	576	576
Total Hydro Capacity		794	802
Solar: (275 MWs Peak)	2015-2018	96	0
Other: Long-Term Purchases		25	25
Southeastern Power Administration (SEPA)		20	20
Grand Total:		5,374	5,464

* Williams Station is owned by GENCO, a wholly owned subsidiary of SCANA and is operated by SCE&G.
* Not reflected in the table is 300 MWs of firm capacity purchases for 2018.

b. DSM from the Supply Side: SCE&G is able to achieve a DSM-like impact from the supply side using its Fairfield Pumped Storage Plant. The Company uses off-peak energy to pump water uphill into the Monticello Reservoir and then displaces on-peak generation by releasing the water and generating power. This accomplishes the same goal as many DSM programs, namely, shifting use to off-peak periods and lowering demands during high cost, on-peak periods. The following graph shows the impact that Fairfield Pumped Storage had on a typical summer weekday.



In effect, the Fairfield Pumped Storage Plant was used to shave an average of 233 MWs from the daily peak times of 2:00 p.m. through 6:00 p.m. and to move about 2% of customer's daily energy needs off peak. Because of this valuable supply side capability, a similar capability on the demand side, such as a time of use rate, would be less valuable on SCE&G's system than on many other utility systems.

c. Planning Reserve Margin: Summer and Winter: All electric utilities require supply reserves to mitigate the risk of not being able to serve their load requirement because of demand-side related risk and supply-side related risk. Demand-side risk results from uncertainty in the level of demand which can increase because of abnormal weather or other unforeseen circumstances. Supply-side risk results from the possibility of supply resources either not being available at all or their capacity being reduced because of mechanical, fuel, weather or other circumstances. SCE&G is also required to carry operating reserves sufficient to meet its VACAR reserve sharing agreement. While SCE&G's share of the VACAR reserves can change each year, it is typically within a few megawatts of 200 MWs which is the amount SCE&G uses in its planning.

In determining its required reserve margin, SCE&G finds it necessary to analyze the need separately for the cooling season and the heating season. Additionally within each season it is necessary to distinguish between a peaking need and a base need. There are at least two reasons for this dichotomy. First very cold weather can make SCE&G's winter peak spike for an hour or two. A peak clipping resource or dispatchable energy storage device available for a few hours may be better suited to address this risk than a generating unit. Secondly, SCE&G anticipates a significant amount of solar capacity in its resource portfolio and the ability of solar to serve load can be substantially different during peak summer conditions, peak winter conditions and other times during the year.

For the summer months which include May through October, SCE&G requires base reserves in the amount of 12% of the summer peak load to operate the system reliably and 14% of summer peak load during the peak load periods. For the winter months of November through April, SCE&G requires 14% of the winter peak load forecast in base reserves to operate the system reliably and 21% for the peak load periods. The peak load period is the 10-20 days of highest demand on the system while the base period is the balance of the year. The following table summarizes SCE&G's reserve margin policy.

SCE&G's Reserve Margin Target		
	Summer	Winter
Base Reserves	12%	14%
Peaking Reserves	14%	21%
Increment for Peaking	2%	7%

d. New Nuclear Capacity: On July 31, 2017 SCE&G announced its decision to cease construction of the new nuclear project and file a Petition for Approval of Abandonment with the Public Service Commission of South Carolina. This decision followed Westinghouse's bankruptcy and Santee Cooper's decision to pull out of the new nuclear construction project.

Background

On Dec 27, 2016 Toshiba, the parent company of Westinghouse, announced that they were having financial problems. On March 29, 2017 Westinghouse filed for bankruptcy and let SCE&G and Santee Cooper know that they would not honor their contract to build VCS 2 & 3. In response to the Westinghouse bankruptcy, SCE&G began evaluating its options. Four options were considered:

1. Complete both units
2. Complete one unit and delay the completion of the other unit
3. Complete one unit and abandon the other unit
4. Abandon both units

After evaluating available options, SCE&G announced its decision to cease construction of the new nuclear project and file a Petition for Approval of Abandonment with the Public Service Commission of South Carolina. This decision followed Santee Cooper's decision to pull out of the new nuclear construction project.

On Aug. 15, 2017, SCE&G announced that it would voluntarily withdraw its Abandonment Petition from the Public Service Commission of South Carolina that was made under the Base Load Review Act (BLRA) concerning SCE&G's new nuclear project. SCE&G management met with various stakeholders and members of the South Carolina General Assembly, including legislative leaders, to discuss the abandonment of the new nuclear project and to hear their concerns. SCE&G's withdrawal decision was in response to those concerns, and to allow for adequate time for governmental officials to conduct their reviews.

On December 28, 2017 SCE&G filed a formal request with the Nuclear Regulatory Commission (NRC) to withdraw the combined operating licenses (COLs) for VC Summer Station Units 2 & 3. This action helps to ensure SCE&G captures approximately $2 billion in tax benefits for our customers to offset the costs of the new nuclear project. In its notification to the NRC, SCE&G states that it has irrevocably abandoned its interests in the VCS Units 2 and 3. All of its completion and preservation activities have ceased. Current work is limited to only those actions required to place the site in a safe condition, terminate construction and close active permits concerns.

e. Electric Vehicles: Electric vehicles represent the potential for the addition of electrical load on SCE&G’s system. An electric a car will go about 3 miles per KWh. Some cars will get more miles and some less but the figure is about right for both a Battery Electric Vehicle (“BEV”) which is all electric and a Plug-in Hybrid Electric Vehicle (“PHEV”) which runs partly on electricity and partly on gasoline. Although it varies, a gas power vehicle might get 30 miles to the gallon. If the cost of electricity is $0.14 per KWh and the cost of gasoline is $2.00 per gallon, then on electricity a car can go about 21.4 miles per dollar while on gasoline the car will go about 15.0 miles per dollar. Assuming the need to drive 15,000 miles per year, the annual fuel cost of the electric car will be about $700 while the annual fuel cost for the gasoline car will be about $1,000. Thus the more efficient electric car will save a driver about $300 per year in fuel costs. To counterbalance the better economics of operating an electric vehicle, the downsides include a larger capital outlay to purchase, a reduced driving range and fewer and less convenient opportunities to re-fuel on the road. All these dynamics continue to change and SCE&G will continue to monitor developments in the electric vehicle market.

In 2015 South Carolina had 1,784,004 vehicles. Assuming that 25% of those vehicles were in SCE&G’s territory then we can determine the impact to SCE&G’s load from an increase in the number of electric vehicles. The above analysis assumes 5000 KWh/year per electric vehicle. If 50% of the vehicles in SCE&G’s territory were electric then an additional 1115 GWh of load would be added or about 4.5% of the current 2025 territorial load forecast. A reasonable estimate for electric vehicles would be 3% of automobiles by 2025. An additional 3% of electric vehicles would add 66.9 GWh or 0.268% of the current 2025 territorial load forecast.

f. Battery Storage on the Grid and in the Home: Battery storage systems are likely to play a significant role in the future, both on the grid and in the home. The cost of battery storage has been decreasing consistently over the last several years and the technology continues to improve. Today battery storage can be cost effective in select grid integrations when supplying necessary stabilization services such as frequency response and voltage regulation. Batteries may also offer solutions to system integration challenges associated with intermittent renewable generation. Often these applications require specific, real-time analysis by the utility in examining the available battery storage solutions and the impact they have to the utility's transmission and distribution systems. This analysis is especially important in determining the potential for cost effectively storing and shifting large amounts of renewable energy. The dominant technologies currently are lithium-ion and a variety of flow batteries. Lithium-ion batteries have a high density storage coupled with a quick response time while flow batteries are better able to store energy for longer periods of time, hours to days. SCE&G will continue to monitor developments in battery storage technologies and their cost, and look for ways to improve the economics and reliability of service to our customers.

g. Projected Loads and Resources: SCE&G's resource plan for the next 15 years is shown in the table labeled "SCE&G Forecast Summer and Winter Loads and Resources – 2018" on a subsequent page. The resource plan shows the need for additional capacity and identifies, on a preliminary basis, whether the need is for summer or winter capacity.

Line 4 shows the amount of capacity available at the beginning of each summer and winter season. On line 7 the resource plan shows the amount of firm solar capacity expected to be added to serve the system summer peak. As shown on line 5, by 2020 this solar capacity accumulates to 865 MWs of solar capacity but only 35% of this capacity is assumed firm and therefore reflected in the resource plan. Also embedded in the peak demand forecast is the projected Net Energy Metering (NEM) solar capacity, i.e., behind the customer's meter, which is projected to increase to about 84 MWs by 2020.

The capacity related to the two combined cycle plants projected is shown on line 9. The first combined cycle plant is the Columbia Energy Center plant that is expected to become part of SCE&G no later than January 1, 2019. By the winter of 2023 the system will be short of capacity by 200MWs and a second combined cycle is added. On line 10 the resource plan shows a decrease in capacity of 85 MWs in 2018 and another decrease of 25 MWs in 2020. The reduction of 85 MWs represents the loss of the Kapstone generator and the 25 MWs is the expiration of a power purchase contract with Santee Cooper. The need for firm capacity purchases is shown on line 12. The Company has secured the purchase of 300 MWs in 2018. Capacity is added to maintain the SCE&G's winter planning reserve margin above a minimum of 21%. The resource plan thus constructed represents one possible way to reliably meet the increasing demand of our customers.

The Company believes that its supply plan, summarized in the following table, will be as benign to the environment as possible because of the Company's continuing efforts to utilize state-of-the-art emission reduction technology in compliance with state and federal laws and regulations. The supply plan will also help SCE&G keep its cost of energy service at a minimum since the generating units being added are competitive with alternatives in the market.

SCE&G Forecast of Summer and Winter Loads and Resources - 2018

(MW)

	YEAR	2018		2019		2020		2021		2022		2023		2024		2025		2026		2027		2028		2029		2030		2031		2032	
		S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W
Load Forecast																															
1	Baseline Trend	5103	5056	5148	5126	5239	5195	5333	5287	5459	5351	5559	5415	5652	5478	5738	5544	5820	5611	5900	5677	5976	5743	6049	5805	6116	5869	6186	5934	6254	5998
2	EE/Renewables Impact	-26	-32	-37	-55	-59	-78	-80	-101	-100	-123	-119	-158	-151	-179	-169	-197	-184	-220	-205	-245	-226	-270	-248	-295	-269	-317	-287	-340	-306	-361
3	Gross Territorial Peak	5077	5024	5111	5071	5180	5117	5253	5186	5359	5228	5440	5257	5501	5299	5569	5347	5636	5391	5695	5432	5750	5473	5801	5510	5847	5552	5899	5594	5948	5637
System Capacity																															
4	Existing	5278	5464	5782	5883	5697	5858	5672	5858	5672	5858	5672	5858	6212	6398	6182	6398	6182	6398	6182	6398	6182	6398	6182	6398	6182	6398	6182	6398	6275	6491
5	Existing Solar	58.73	0	96.36	0	161.6	0	302.79	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0
6	Demand Response	274	222	275	223	276	324	277	325	278	326	280	327	281	328	282	329	283	330	285	331	286	332	287	333	288	333	290	334	291	335
	Additions:																														
7	Solar Plant	37.63	0	65.21	0	141.2	0																								
8	Peaking/Intermediate																												93		
9	Baseload		504										540	-30																	
10	Retirements			-85		-25																									
11	Total System Capacity	5648	6190	6134	6106	6251	6182	6251.8	6183	6253	6184	6255	6725	6766	6726	6767	6727	6768	6728	6770	6729	6771	6730	6772	6731	6773	6731	6775	6825	6869	6826
12	Firm Annual Purchase	300			50		25		100		150																				
13	Total Production Capability	5948	6190	6134	6156	6251	6207	6251.8	6283	6253	6334	6255	6725	6766	6726	6767	6727	6768	6728	6770	6729	6771	6730	6772	6731	6773	6731	6775	6825	6869	6826
Reserves																															
14	Margin (L13-L3)	871.4	1166	1023	1085	1071	1090	998.79	1097	893.8	1106	814.8	1468	1265	1427	1198	1380	1132	1337	1075	1297	1021	1257	970.8	1221	925.8	1179	875.8	1231	920.8	1189
15	% Reserve Margin (L14/L3)	17.2%	23.2%	20.0%	21.4%	20.7%	21.3%	19.0%	21.2%	16.7%	21.2%	15.0%	27.9%	23.0%	26.9%	21.5%	25.8%	20.1%	24.8%	18.9%	23.9%	17.8%	23.0%	16.7%	22.2%	15.8%	21.2%	14.8%	22.0%	15.5%	21.1%

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III. Transmission System Assessment and Planning

SCE&G's transmission planning practices develop and coordinate a program that provides for timely modifications to the SCE&G transmission system to ensure a reliable and economical delivery of power. This program includes the determination of the current capability of the electrical network and a ten-year schedule of future additions and modifications to the system. These additions and modifications are required to support customer growth, provide emergency assistance and maintain economic opportunities for SCE&G's customers while meeting SCE&G and industry transmission performance standards.

SCE&G has an ongoing process to determine the current and future performance level of the SCE&G transmission system. Numerous internal studies are undertaken that address the service needs of customers. These needs include: 1) distributed load growth of existing residential, commercial, industrial, and wholesale customers, 2) new residential, commercial, industrial, and wholesale customers, 3) customers who use only transmission services on the SCE&G system and 4) generator interconnection services.

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 are considered acceptable if they will not cause equipment damage or result in uncontrolled cascading outside the local area.

Furthermore, SCE&G subscribes to the set of mandatory Electric Reliability Organization ("ERO"), also known as the North American Electric Reliability Corporation ("NERC") Reliability Standards for Transmission Planning, as approved by the NERC Board of Trustees and the Federal Energy Regulatory Commission ("FERC").

SCE&G assesses and designs its transmission system to be compliant with the requirements as set forth in these standards. A copy of the NERC Reliability Standards is available at the NERC website http://www.nerc.com/ .

The SCE&G transmission system is interconnected with Duke Energy Progress, Duke Energy Carolinas, South Carolina Public Service Authority ("Santee Cooper"), Georgia Power ("Southern Company") and the Southeastern Power Administration ("SEPA") systems. Because of these interconnections with neighboring systems, system conditions on other systems can affect the capabilities of the SCE&G transmission system and also system conditions on the SCE&G transmission system can affect other systems. SCE&G participates with other transmission planners throughout the southeast to develop current and future power flow, stability and short circuit models of the integrated transmission grid for the NERC Eastern Interconnection. All participants' models are merged together to produce current and future models of the integrated electrical network. Using these models, SCE&G evaluates its current and future transmission system for compliance with the SCE&G Long Range Planning Criteria and the NERC Reliability Standards.

To ensure the reliability of the SCE&G transmission system while considering conditions on other systems and to assess the reliability of the wide-area integrated transmission grid, SCE&G participates in assessment studies with neighboring transmission planners in South Carolina, North Carolina and Georgia. Also, SCE&G on a periodic and ongoing basis participates with other transmission planners throughout the southeast to assess the reliability of the southeastern integrated transmission grid for the long-term horizon (up to 10 years) and for upcoming seasonal (summer and winter) system conditions.

The following is a list of joint studies with neighboring transmission planners completed over the past year:

1. SERC NTSG Reliability 2017 Summer Study
2. SERC NTSG Reliability 2017/2018 Winter Study
3. SERC NTSG OASIS 2017 January Studies (17Q1)
4. SERC NTSG OASIS 2017 April Studies (17Q2)
5. SERC NTSG OASIS 2017 July Studies (17Q3)
6. SERC NTSG OASIS 2017 October Studies (17Q4)
7. SERC LTSG 2022 Summer Peak Study
8. CTCA 2018/19 Winter Peak, 2022 Summer Peak Reliability Study
9. SCRTP 2020 Summer, 2021 Summer, and 2021/22 Winter Transfer Studies

The acronyms used above have the following reference:

SERC – SERC Reliability Corporation
NTSG – Near Term Study Group
OASIS – Open Access Same-time Information System
LTSG – Long Term Study Group
CTCA – Carolinas Transmission Coordination Arrangement
SCRTP – South Carolina Regional Transmission Planning

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

Eastern Interconnection Planning Collaborative (EIPC)

The Eastern Interconnection Planning Collaborative ("EIPC") was initiated by a coalition of regional Planning Authorities (including South Carolina Electric & Gas Company). These Planning Authorities are entities listed on the NERC compliance registry as Planning Authorities and represent the majority of the Eastern Interconnection.

The EIPC provides a grass-roots approach which builds upon the regional expansion plans developed each year by regional stakeholders in collaboration with their respective NERC Planning Authorities. This approach provides coordinated interregional analysis for the entire Eastern Interconnection.

The EIPC purpose is to model the impact on the grid of various policy options determined to be of interest by state, provincial and federal policy makers and other stakeholders. This work builds upon, rather than replaces, the current local and regional transmission planning processes developed by the Planning Authorities and associated regional stakeholder groups within the entire Eastern Interconnection. Those processes are informed by the EIPC analysis efforts including the interconnection-wide review of the existing regional plans and development of transmission options associated with the various policy options.

Appendix A

Short Range Methodology

This section presents the development of the short-range electric sales forecasts for the Company. Two years of monthly forecasts for electric customers, average usage, and total usage were developed according to Company class and rate structures, with industrial customers further categorized individually or into SIC (Standard Industrial Classification) codes. Residential customers were classified by housing type (single family, multi-family, and mobile homes), rate, and by a statistical estimate of weather sensitivity. For each forecasting group, the number of customers and either total usage or average usage was estimated for each month of the forecast period.

The short-range methodologies used to develop these models were determined primarily by available data, both historical and forecast. Monthly sales data by class and rate are generally available historically. Daily heating and cooling degree data for Columbia and Charleston are also available historically, and were projected using a 15-out-of-17-year average of the daily values, after dropping the high and low values for each day. Industrial production indices are also available by SIC on a quarterly basis, and can be transformed to a monthly series. Therefore, sales, weather, industrial production indices, and time dependent variables were used in the short range forecast. In general, the forecast groups fall into two classifications, weather sensitive and non-weather sensitive. For the weather sensitive classes, regression analysis was the methodology used, while for the non-weather sensitive classes regression analysis or time series models based on the autoregressive integrated moving average (ARIMA) approach of Box-Jenkins were used.

The short range forecast developed from these methodologies was also adjusted for federally mandated lighting programs, new industrial loads, terminated contracts, or economic factors as discussed in Section 3.

Regression Models

Regression analysis is a method of developing an equation which relates one variable, such as usage, to one or more other variables which help explain fluctuations and trends in the first. This method is mathematically constructed so that the resulting combination of explanatory variables produces the smallest squared error between the historic actual values and those estimated by the regression. The output of the regression analysis provides an equation for the variable being explained. Several statistics which indicate the success of the regression analysis fit are shown for each model. Several of these indicators are R^2, Root Mean Squared Error, Durbin-Watson Statistic, F-Statistic, and the T-Statistics of the Coefficient. PROC REG of SAS was used to estimate all regression models. PROC AUTOREG of SAS was used if significant autocorrelation, as indicated by the Durbin-Watson statistic, was present in the model.

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

The development of average use models began with plots of the HDD and CDD data versus average use by month. This process led to the grouping of months with similar average use patterns. Summer and winter groups were chosen, with the summer models including the months of May through October, and the winter models including the months of November through April. For each of the groups, an average use model was developed. Total usage models were developed with a similar methodology for the municipal customers. For these customers, HDD and CDD were weighted based on monthly calendar weather. Simple plots of average use over time revealed significant changes in average use for some customer groups. Three types of variables were used to measure the effect of time on average use:

1. Number of months since a base period;
2. Dummy variable indicating before or after a specific point in time; and,
3. Dummy variable for a specific month or months.

Some models revealed a decreasing trend in average use, which is consistent with conservation efforts and improvements in energy efficiency. However, other models showed an increasing average use over time. This could be the result of larger houses, increasing appliance saturations, lower real electricity prices, and/or higher real incomes.

ARIMA Models

Autoregressive integrated moving average ("ARIMA") procedures were also used in developing the short range forecasts. For various class/rate groups, they were used to develop customer estimates, average use estimates, or total use estimates.

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

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

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

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

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

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

t	indexes time
B	is the backshift operator, that is $B\ (X_t) = X_{t-1}$
Z_t	is the original data or a difference of the original data
f(B)	is the autoregressive operator, $f(B) = 1 – f_1\ B - \dots - f_1\ B^p$
u	is the constant term
q(B)	is the moving average operator, $q\ (B) = 1 - q_1\ B - ... - q_q\ B^q$
a_t	is the independent disturbance, also called the random error
$X_{i,t}$	is the ith input time series
$y_i(B)$	is the transfer function weights for the ith input series (modeled as a ratio of polynomials)
$y_i(B)$	is equal to $w_i\ (B)/\ d_i\ (B)$, where $w_i\ (B)$ and $d_i\ (B)$ are polynomials in B.

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

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

Electric Sales Assumptions

For short-term forecasting, over 30 forecasting groups were defined using the Company's customer class and rate structures. Industrial (Class 30) Rate 23 was further divided using SIC codes. In addition, thirty-seven large industrial customers were individually projected. The residential class was disaggregated into several sub-groups, starting first with rate. Next, a regression analysis was done to separate customers into two categories, “more weather-sensitive” and “less weather sensitive”. Generally speaking, the former group is associated with higher average use per customer in winter months relative to the latter group. Finally, these categories were divided by housing type (single family, multi-family, and mobile homes). Each municipal account represents a forecasting group and was also individually forecast. Discussions were held with Industrial Marketing and Economic Development representatives within the Company regarding prospects for industrial expansions or new customers, and adjustments made to customer, rate, or account projections where appropriate. Table 1 contains the definition for each group and Table 2 identifies the methodology used and the values forecasted by forecasting groups.

The forecast for Company Use is based on historic trends and adjusted for Summer 1 nuclear plant outages. Unaccounted energy, which is the difference between generation and sales and represents for the most part system losses, is usually between 4-5% of total territorial sales. The average annual loss for the three previous years was 4.6%, and this value was assumed throughout the forecast. The monthly allocations for unaccounted use were based on a regression model using normal total degree-days for the calendar month and total degree-days weighted by cycle billing. Adding Company Use and unaccounted energy to monthly territorial sales produces electric generation requirements.

1. TABLE 1 Short-Term Forecasting Groups

A. Class Number	Class Name	Rate/SIC Designation	Comment
10	Residential Less Weather-Sensitive	Single Family	Rates 1, 2, 5, 6, 8, 18, 25, 26, 62, 64
		Multi Family	67, 68, 69
910	Residential More Weather-Sensitive	Mobile Homes	
20	Commercial Less Weather-Sensitive	Rate 9	Small General Service
		Rate 12	Churches
		Rate 20, 21	Medium General Service
		Rate 22	Schools
		Rate 24	Large General Service
		Other Rates	3, 10, 11, 14, 16, 18, 25, 26 29, 62, 67, 69
920	Commercial Space Heating More Weather-Sensitive	Rate 9	Small General Service
30	Industrial Non-Space Heating	Rate 9	Small General Service
		Rate 20, 21	Medium General Service
		Rate 23, SIC 22	Textile Mill Products
		Rate 23, SIC 24	Lumber, Wood Products, Furniture and Fixtures (SIC Codes 24 and 25)
		Rate 23, SIC 26	Paper and Allied Products
		Rate 23, SIC 28	Chemical and Allied Products
		Rate 23, SIC 30	Rubber and Miscellaneous Products
		Rate 23, SIC 32	Stone, Clay, Glass, and Concrete
		Rate 23, SIC 33	Primary Metal Industries; Fabricated Metal Products; Machinery; Electric and Electronic Machinery, Equipment and Supplies; and Transportation Equipment (SIC Codes 33-37)
		Rate 23, SIC 99	Other or Unknown SIC Code*
		Rate 27, 60	Large General Service
		Other	Rates 18, 25, and 26
60	Street Lighting	Rates 3, 9, 13, 17, 18, 25, 26, 29, and 69	
70	Other Public Authority	Rates 3, 9, 20, 21, 25, 26, 29, 65 and 66	
92	Municipal	Rate 60, 61	Three Individual Accounts

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

TABLE 2

Summary of Methodologies Used To Produce
The Short Range Forecast

Value Forecasted	Methodology	Forecasting Groups
Average Use	Regression	Class 10, All Groups Class 910, All Groups Class 20, Rates 9, 12, 20, 22, 24, 99 Class 920, Rate 9 Class 70, Rate 3
Total Usage	ARIMA/ Regression	Class 30, Rates 9, 20, 99, and 23, for SIC = 91 and 99 Class 930, Rate 9 Class 60 Class 70, Rates 65, 66
	Regression	Class 92, All Accounts Class 97, One Account
Customers	ARIMA	Class 10, All Groups Class 910, All Groups Class 20, All Rates Class 920, Rate 9 Class 30, All Rates Except 60, 99, and 23 for SIC = 22, 24, 26, 28, 30, 32, 33, and 91 Class 930, Rate 9 Class 60 Class 70, Rate

Appendix B

Long Range Sales Forecast

Electric Sales Forecast

This section presents the development of the long-range electric sales forecast for the Company. The long-range electric sales forecast was developed for six classes of service: residential, commercial, industrial, street lighting, other public authorities, and municipals. These classes were disaggregated into appropriate subgroups where data was available and there were notable differences in the data patterns. The residential, commercial, and industrial classes are considered the major classes of service and account for over 93% of total territorial sales. A customer forecast was also developed for each major class of service.

For the residential class, forecasts were produced for those customers categorized into two groups, more and less weather-sensitive. They were further disaggregated into housing types of single family, multi-family and mobile homes. Residential street lighting was also evaluated separately. These subgroups were chosen based on available data and differences in the average usage levels and/or data patterns. Commercial sales were estimated for four subgroups within this sector: small, medium, large, and “other”. Small commercial sales were limited to Rate 9 usage; medium was based on Rates 12, 20, 21, and 22; large was Rate 24, and other consisted of the special rates shown in Table 1 in Appendix A. Average use and customer equations were developed for each commercial subgroup, with the resulting sales projections combined to create the total commercial sales forecast. The industrial class was disaggregated into two digit SIC code classification for the large general service customers, while smaller industrial customers were grouped into an "other" category. These subgroups were chosen to account for the differences in the industrial mix in the service territory. With the exception of the residential group, the forecast for sales was estimated based on total usage in that class of service. The number of residential customers and average usage per customer were estimated separately and total sales were calculated as a product of the two.

The forecast for each class of service was developed utilizing an econometric approach. The structure of the econometric model was based upon the relationship between the variable to be forecasted and the economic environment, weather, conservation, and/or price.

Forecast Methodology

Development of the models for long-term forecasting was econometric in approach and used the technique of regression analysis. Regression analysis is a method of developing an equation which relates one variable, such as sales or customers, to one or more other variables that are statistically correlated with the first, such as weather, personal income or population growth. Generally, the goal is to find the combination of explanatory variables producing the smallest error between the historic actual values and those estimated by the regression. The output of the regression analysis provides an equation for the variable being explained. In the equation, the variable being explained equals the sum of the explanatory variables each multiplied by an estimated coefficient. Various statistics, which indicate the success of the regression analysis fit, were used to evaluate each model. The indicators were R^2, mean squared Error of the Regression, Durbin-Watson Statistic and the T-Statistics of the Coefficient. PROC REG and PROC AUTOREG of SAS were used to estimate all regression models. PROC REG was used for preliminary model specification, elimination of insignificant variables, and also for the final model specifications. Model development also included residual analysis for incorporating dummy variables and an analysis of how well the models fit the historical data, plus checks for any statistical problems such as autocorrelation or multicollinearity. PROC AUTOREG was used if autocorrelation was present as indicated by the Durbin-Watson statistic.

Prior to developing the long-range models, certain design decisions were made:

- The multiplicative or double log model form was chosen. This form allows forecasting based on growth rates, since elasticities with respect to each explanatory variable are given directly by their respective regression coefficients. Elasticity explains the responsiveness of changes in one variable (e.g. sales) to changes in any other variable (e.g. price). Thus, the elasticity coefficient can be applied to the forecasted growth rate of the explanatory variable to obtain a forecasted growth rate for a dependent variable. These projected growth rates were then applied to the last year of the short range forecast to obtain the forecast level for customers or sales for the long range forecast. This is a constant elasticity model, therefore, it is important to evaluate the reasonableness of the model coefficients.

- One way to incorporate conservation effects on electricity is through real prices or time trend variables. Models selected for the major classes would include these variables, if they were statistically significant.
- The remaining variables to be included in the models for the major classes would come from four categories:
  1. Demographic variables - Population.
  2. Measures of economic well-being or activity: real personal income, real per capita income, employment variables, and industrial production indices.
  3. Weather variables - average summer/winter temperature or heating and cooling degree-days.
  4. Variables identified through residual analysis or knowledge of political changes, major economics events, etc. (e.g., the gas price spike in 2005 attributable to Hurricane Katrina and recession versus non-recession years).

Standard statistical procedures were used to obtain preliminary specifications for the models. Model parameters were then estimated using historical data and competitive models were evaluated on the basis of:

- Residual analysis and traditional "goodness of fit" measures to determine how well these models fit the historical data and whether there were any statistical problems such as autocorrelation or multicollinearity.
- An examination of the model results for the most recently completed full year.
- An analysis of the reasonableness of the long-term trend generated by the models. The major criteria here was the presence of any obvious problems, such as the forecasts exceeding all rational expectations based on historical trends and current industry expectations.
- An analysis of the reasonableness of the elasticity coefficient for each explanatory variable. Over the years a host of studies have been conducted on various elasticities relating to electricity sales. Therefore, one check was to see if the estimated coefficients from Company models were in-line with others. As a result of the evaluative procedure, final models were obtained for each class.
- The drivers for the long-range electric forecast included the following variables.

Service Area Housing Starts
Service Area Real Per Capita Income
Service Area Real Personal Income
State Industrial Production Indices
Real Price of Electricity
Average Summer Temperature
Average Winter Temperature
Heating Degree Days
Cooling Degree Days

The service area data included Richland, Lexington, Berkeley, Dorchester, Charleston, Aiken and Beaufort counties, which account for the vast majority of total territorial electric sales. Service area historic data and projections were used for all classes with the exception of the industrial class. Industrial productions indices were only available on a statewide basis, so forecasting relationships were developed using that data. Since industry patterns are generally based on regional and national economic patterns, this linking of Company industrial sales to a larger geographic index was appropriate.

Economic Assumptions

In order to generate the electric sales forecast, forecasts must be available for the independent variables. The forecasts for the economic and demographic variables were obtained from Global Insight, Inc. and the forecasts for the price and weather variables were based on historical data. The trend projection developed by Global Insight is characterized by slow, steady growth, representing the mean of all possible paths that the economy could follow if subject to no major disruptions, such as substantial oil price shocks, untoward swings in policy, or excessively rapid increases in demand.

Average summer temperature (average of June, July, and August temperature) or CDD , and average winter temperature (average of December (previous year), January and February temperature) or HDD were assumed to be equal to the normal values used in the short range forecast.

After the trend econometric forecasts were completed, reductions were made to account for higher air-conditioning and water-heater efficiencies, DSM programs, and the replacement of incandescent light bulbs with more efficient CFL or LED light bulbs. Industrial sales were increased if new customers are anticipated or if there are expansions among existing customers not contained in the short-term projections.

Peak Demand Forecast

A demand forecast is made for the summer peak, the winter peak and then for each of the remaining ten months of the year. The summer peak demand forecast and the winter peak demand forecast is made for each of the six major classes of customers. Customer load research data is summarized for each of these major customer classes to derive load characteristics that are combined with the energy forecast to produce the projection of future peak demands on the system. Interruptible loads and standby generator capacity is captured and used in the peak forecast to develop a firm level of demand. By utility convention the winter season follows the summer season. The territorial peak demands in the other ten months are projected based on historical ratios by season. The months of May through October are grouped as the summer season and projected based on the average historical ratio to the summer peak demand. The other months of the year are similarly projected with reference to the winter peak demand.

EXHIBIT H-2

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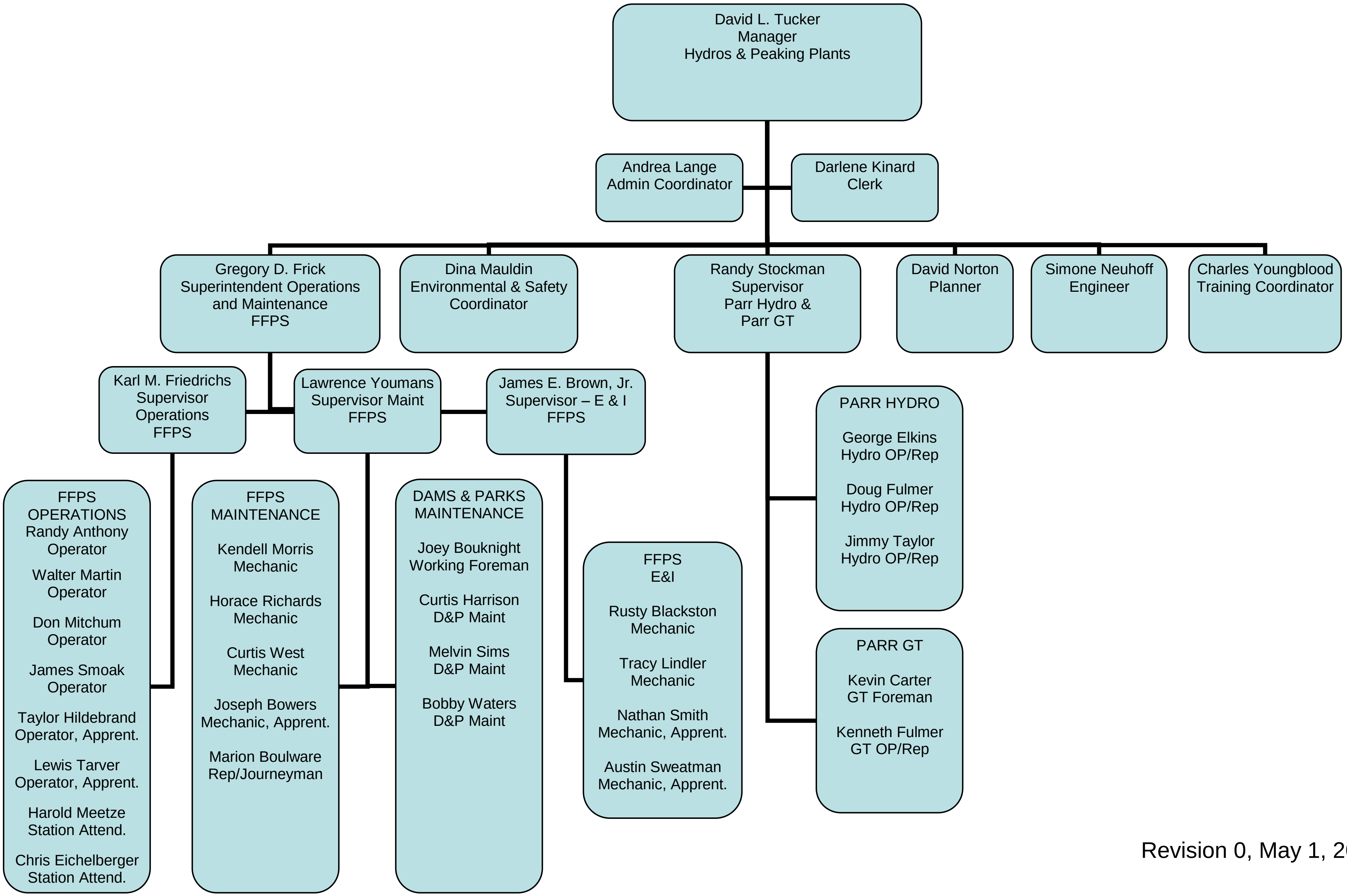
EXHIBIT H-3

PARR HYDROELECTRIC PROJECT NO. 1894

PROJECT PERSONNEL ORGANIZATION CHART



Revision 0, May 1, 2018

EXHIBIT H-4

PARR HYDROELECTRIC PROJECT NO. 1894

REQUIRED SAFETY TRAINING

Training Topic	Training Required For	Applicable Standard and/or SCE&G Safety Procedure	Training Frequency*	Parr Hydro Requirement
Ladder Safety	Employees who use ladders	29CFR1910.25-27 & 1926.1060 (OSHA)	Initially	**YES**
Scaffolding Erectors	Scaffold Inspectors and Scaffold Erectors	1910.28-29 & 1926.450-453 (OSHA) SD-305	Initially & Every Five Years	**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**
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 Two 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**
Access to Employee Exposure & Medical Records	Employees who have medical records or exposure records	1910.1020 (OSHA) SD-103	Initially & Annually	**YES**

EXHIBIT H-4

PARR HYDROELECTRIC PROJECT NO. 1894

REQUIRED SAFETY TRAINING

Training Topic	Training Required For	Applicable Standard and/or SCE&G Safety Procedure	Training Frequency*	Parr Hydro Requirement
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 TSP-690	Initially & Every Two years	**YES**
Driver & Vehicle Safety	Employees who operate a Company vehicle	SCE&G SD-400	Initially	**YES**
Power Actuated Tools	Employees who use power 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	**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

PARR HYDROELECTRIC PROJECT P-1894

REQUIRED OPERATOR/REPAIRMAN TRAINING

	OPERATOR/REPAIRMAN COURSE REQUIREMENTS	NCCER Hours	NCCER Earned Courses
1	**SAFETY TRAINING (ON-SITE)**		
	Plant Safety Training (Plant T/C)	25	Non-NCCER
2	**BASIC SAFETY (ON-SITE)**		
	Basic Safety	12.5	00101-09
3	**POWER PLANT FUNDAMENTALS (ON-SITE)**		
	PPF/Walkdown/Time with APOs	40	Non-NCCER
4	**POWER INDUSTRY**		
	Introduction to the Power Industry	12.5	49101-10
5	**BASIC MATH (ON-SITE AND CLASS)**		
	Intro to Construction Math	10	00102-09
	Craft-Related Mathematics	15	40106-07
6	**FORKLIFTS (ON-SITE)**		
	Intro to Materials Handling	5	00109-09
	Mobile & Support Equipment	10	40112-07
7	**HAND & POWER TOOLS**		
	Intro to Hand Tools	10	00103-09
	Intro to Power Tools	10	00104-09
8	**INTERMEDIATE RIGGING**		
	Intermediate Rigging	40	00106-09
8	**MATERIAL HANDLING & HAND RIGGING**		
	Material Handling & Hand Rigging	15	40111-07
9	**GASKETS & PACKING**		
	Gaskets and Packing	10	40105-07
10	**LUBRICATION**		
	Lubrication	12.5	40113-07
11	**PREVENTIVE AND PREDICTIVE MAINTENANCE**		
	Preventive and Predictive Maintenance	10	40401-09
12	**PUMPS & DRIVERS/ INTRODUCTION TO VALVES**		
	Pumps and Drivers	5	40108-07
	Introduction to Valves	5	40109-07
13	**FLAME CUTTING**		
	Oxyfuel Cutting	17.5	40104-07
14	**SHIELDED METAL ARC WELDING SETUP**		
	SMAW Equipment and Setup	5	29107-09
15	**HAZARDOUS LOCATIONS**		
	Hazardous Locations	10	40301-08
16	**HYDRAULICS**		
	Hydraulic Controls	15	40311-08
17	**PNEUMATICS**		
	Pneumatic Controls	15	40312-08

EXHIBIT H-5

PARR HYDROELECTRIC PROJECT P-1894

REQUIRED OPERATOR/REPAIRMAN TRAINING

	OPERATOR/REPAIRMAN COURSE REQUIREMENTS	NCCER Hours	NCCER Earned Courses
18	**PROGRAMMABLE LOGIC CONTROLLERS**		
	Programmable Logic Controllers	17.5	40409-09
19	**BLUEPRINTS AND DOCUMENTS**		
	Intro to Construction Drawings	10	00105-09
	Construction Drawings	12.5	40107-07
	Instrument Drawings & Documents Part One	15	40211-08
	E & I Drawings	10	40303-08
20	**ELECTRICAL SAFETY AND TEST EQUIPMENT**		
	Electrical Safety		
	Industrial Safety for E & I Technicians	12.5	40201-08
	Managing Electrical Hazards	12.5	26501-09
	Introduction to the *National Electrical Code* ®	5	40202-08
	Electrical Test Equipment		
	Introduction to Test Instruments	7.5	40110-07
	E & I Test Equipment	10	40205-08
21	**ELECTRICAL WIRING / NATIONAL ELECTRIC CODE**		
	Conductor Installations	10	26206-08
22	**CONDUCTOR SELECTION, RACEWAYS/BOX/FITTING FILL**		
	Conductor Selection and Calculation	15	40307-08
23	**CONDUCTOR INSTALL, TERMINATIONS/SPLICES**		
	Conductors and Cables	10	40212-08
	Conductor Terminations and Splices	10	40213-08
24	**CONDUIT BENDING AND INSTALLATION**		
	Hand Bending	10	40208-08
	Machine Bending of Conduit	15	40310-08
	Medium Voltage Terminations and Splices	10	26411-08
25	**FASTENERS/ANCHORS, BOXES/FITTINGS, CABLE TRAY**		
	Fasteners and Anchors	5	40103-07
	Tools of the Trade	5	40102-07
	Cable Tray	7.5	26207-08
26	**ELECTRICAL THEORY**		
	Electrical Theory	15	40203-08
	Alternating Current	20	40204-08
27	**MOTOR THEORY**		
	Motors: Theory and Application	20	26202-08
	Motor Calculations	12.5	26309-08
28	**MOTORS**		
	Motor Operation and Maintenance	10	26410-08
29	**MOTOR CONTROLS AND ADVANCED MOTOR CONTROLS**		
	Motor Controls	15	40304-08
	Advanced Motor Controls	20	26407-08

EXHIBIT H-5

PARR HYDROELECTRIC PROJECT P-1894

REQUIRED OPERATOR/REPAIRMAN TRAINING

	OPERATOR/REPAIRMAN COURSE REQUIREMENTS	NCCER Hours	NCCER Earned Courses
30	**MOTOR OPERATED VALVES**		
	Motor-Operated Valves	15	40313-08
31	**ELECTRICAL SERVICES, CKT BKRS, FUSES AND RELAYS**		
	Circuit Breakers and Fuses	12.5	26210-08
	Control Systems and Fundamental Concepts	12.5	26211-08
	Load Calculations-Branch and Feeder Ckts	17.5	26301-08
	Overcurrent Protection	25	26305-08
32	**CIRCUIT BREAKERS, PROTECTION, DISTRIBUTION**		
	Switchgear and Breaker Maintenance	25	50402-10
	Power Plant Electrical Systems	12.5	50301-11
33	**LIGHTING**		
	Electric Lighting	15	26203-08
	Practical Applications of Lighting	12.5	26303-08
34	**TRANSFORMERS**		
	Distribution Equipment	17.5	40305-08
	Transformer Applications	7.5	40306-08
	Specialty Transformers	10	26406-08
35	**GROUNDING**		
	Temporary Grounding	15	40308-08
	Grounding and Bonding	15	26209-08
36	**MAIN GENERATOR / BUSSES**		
	Generator Maintenance	20	50401-10
37	**BATTERIES, CHARGERS, STANDBY/EMERG. SYSTEMS**		
	Standby and Emergency Systems	12.5	40401-09
38	**HEAT TRACING AND FREEZE PROTECTION**		
	Heat Tracing	10	26409-08
39	**FLOW,PRESSURE,LEVEL AND TEMPERATURE**		
	Flow,Pressure,Level and Temperature	15	40206-08
40	**PROCESS MATHEMATICS**		
	Process Mathematics	15	40207-08
41	**TUBING**		
	Tubing	15	40209-08
	Clean, Purge & Test Tubing & Piping Systems	7.5	40210-08
42	**LAYOUT TUBING**		
	Layout & Installation of Tubing & Piping Systems	22.5	40309-08
43	**ELECTRONIC COMPONENTS**		
	Electronic Components	10	40302-08
44	**BASIC PROCESS CONTROL ELEMENTS**		
	Basic Process Control Elements, Transducers & Transmitters	15	40402-09

EXHIBIT H-5

PARR HYDROELECTRIC PROJECT P-1894

REQUIRED OPERATOR/REPAIRMAN TRAINING

	OPERATOR/REPAIRMAN COURSE REQUIREMENTS	NCCER Hours	NCCER Earned Courses
45	**INSTRUMENT CALIBRATION**		
	Instrument Calibration & Configuration	10	40403-09
46	**PNEUMATIC VALVES**		
	Pneumatic Control Valves, Actuators & Positioners (includes REM vendor)	40	40404-09
47	**PERFORMING LOOP CHECKS**		
	Performing Loop Checks	7.5	40405-09
48	**TROUBLESHOOTING & COMMISSIONING A LOOP**		
	Troubleshooting & Commissioning a Loop	10	40406-09
49	**PROCESS CONTROL LOOPS & TUNING**		
	Process Control Loops & Tuning	20	40407-09
50	**DATA NETWORKS**		
	Data Networks	15	40408-09
51	**DISTRIBUTED CONTROL SYSTEMS**		
	Distributed Control Systems	17.5	40410-09
	TOTAL	1108	

EXHIBIT H-6

PARR HYDROELECTRIC PROJECT P-1894

MAXIMUM PARR RESERVOIR LEVELS
TO PREVENT UPSTREAM FLOODING

Broad River Flow (CFS)	Parr Reservoir Not to Exceed (Ft. MSL)	Parr Reservoir Not to Exceed (Ft. NAVD88)
3,000	266.00	265.30
4,000	266.00	265.30
5,000	266.00	265.30
6,000	266.00	265.30
7,000	265.98	265.28
8,000	265.90	265.20
9,000	265.82	265.12
10,000	265.74	265.04
11,000	265.66	264.96
12,000	265.58	264.88
13,000	265.50	264.80
14,000	265.42	264.72
15,000	265.34	264.64
16,000	265.26	264.56
17,000	265.18	264.48
18,000	265.10	264.40
19,000	265.02	264.32
20,000	264.93	264.23
21,000	264.85	264.15
22,000	264.77	264.07
23,000	264.68	263.98
24,000	264.60	263.90
25,000	264.52	263.82
26,000	264.43	263.73
27,000	264.35	263.65
28,000	264.27	263.57
29,000	264.18	263.48
30,000	264.10	263.40
31,000	264.02	263.32
32,000	263.93	263.23
33,000	263.85	263.15
34,000	263.77	263.07
35,000	263.68	262.98
36,000	263.60	262.90
37,000	263.52	262.82
38,000	263.44	262.74
39,000	263.36	262.66
40,000	263.28	262.58

EXHIBIT H-7

PARR HYDROELECTRIC PROJECT P-1894

FERC LETTER TO SCE&G REGARDING DRAWDOWN OF MONTICELLO RESERVOIR

FEDERAL ENERGY REGULATORY COMMISSION

REGIONAL OFFICE

730 Peachtree Street, N. E.
Atlanta, Georgia 30308
February 22, 1979

Project No. 1894 - S.C.

Mr. W. E. Moore
Manager
Hydro Engineering
S. C. Electric & Gas Co.
Post Office Box 764
Columbia, S. C. 29218

Dear Mr. Moore:

This will acknowledge your letter of February 13, 1979, concerning emergency drawdown of your Monticello reservoir of the Fairfield development, PN 1894.

There are no specific operational drawdown requirements imposed on the facility by the license. The license text, the Environmental Impact Statement, and your Application for License for the project state that the normal drawdown would be to elevation 420.5 providing a 29,000 AF usable storage volume. However, we recognize that some flexibility during emergency situations is warranted. Therefore, since operation of the reservoir pool to elevation 418 would have no readily apparent effects on the structural integrity or safety of the components and would only be implemented during emergency conditions, we see no reason to disapprove your proposed operational change. We do request, however, that you notify our office each time the emergency operating status is implemented.

We appreciate your cooperation and timely reporting of emergency situations and conditions to our office.

Very truly yours,

Aarne O. Kauranen
Regional Engineer

EXHIBIT H-8

PARR HYDROELECTRIC PROJECT P-1894

SCE&G LETTER TO FERC REGARDING DRAWDOWN OF MONTICELLO RESERVOIR

SOUTH CAROLINA ELECTRIC & GAS COMPANY

POST OFFICE BOX 764

COLUMBIA, S. C. 29218

December 19, 1984

Mr. Aarne O. Kauranen, Regional Engineer
Federal Energy Regulatory Commission
Atlanta Regional Office
Room 800
730 Peachtree Street, N.E.
Atlanta, Georgia 30308

Dear Mr. Kauranen:

Subject: FERC Project No. 1894
Parr Hydroelectric Project
Fairfield Pumped Storage Facility

In our September 7, 1984, meeting with you in Atlanta, we discussed several items pertaining to the Parr Hydroelectric Project and the Fairfield Pumped Storage Facility, including the following:

1. In your August 23, 1984 letter to Mr. W. E. Moore, you stated that at Parr Dam, flows should be passed over gate numbers 3, 4, 5, and 6 to the maximum extent possible during the period of monitoring the dam for downstream erosion. In our September 7 meeting it was agreed that SCE&G will in fact do the opposite; that is, gates 3, 4, 5, and 6 will be the last to be lowered. This will enable us to prolong the time period before repairs must be made to the dam. We are continuing our monitoring of downstream erosion at Parr Dam, and attached to this letter is the report of the latest inspection (November 14, 1984). Since no significant changes were measured at the toe of the dam, we will continue monitoring at our present rate. The next measurements will be made in May, 1985. The new stability analyses of Parr Dam, required as a supplement to the 1983 Five-year inspection, will include an analysis of the dam in the area of toe erosion.

2. Your August 23, 1984 letter to Mr. W. E. Moore accepted the plan of adding the rock stability berm to Dam "D" at the Fairfield Pumped Storage Facility, providing that seepage pressures have stabilized (our Quarterly Surveillance Reports demonstrate this). You also stated that 60 days prior to beginning this work, plans and specifications should be submitted to you for review. Attached to this letter is the Requirement Outline for performing this work. SCE&G will begin the work on the rock berm when we receive approval of our Requirement Outline. In addition, as discussed in our September 7 meeting, we will inform you by telephone when the work begins so that if you so desire, a FERC representative can be present at the time the sand blanket is uncovered.

Finally, when the new stability analysis of Dam D is submitted together with the reminder of the supplement to the 1983 5-Year Inspection Report, the factor of safety for the stabilized Dam D will be added to the appropriate drawing (it was inadvertently left out previously).

3. In our September 7 meeting, we discussed the allowable Monticello Reservoir drawdown at the Fairfield Pumped Storage Facility. It was agreed that although SCE&G will continue normal operation between the levels of 425.0' MSL and 420.5' MSL (four and one-half foot drawdown as described in the Project No. 1894 license), we will be allowed to draw the Monticello Reservoir down to elevation 420.0' MSL on an occasional basis without notifying the Atlanta Regional Office. This will enable SCE&G to use the full 29,000 acre-feet of storage volume which the Project No. 1894 license spells out. SCE&G will continue to call the ARO if we draw Monticello Reservoir down below elevation 420.0' MSL in an emergency situation, in accordance with your February 22, 1979, letter to Mr. W. E. Moore. Attached to this letter is a copy of September 20, 1984 SCE&G Inter-Office Correspondence discussing the drawdown at Monticello Reservoir.

If you have any questions, or need any further information to evaluate the Parr Dam and Fairfield Dam D data, please let me know.

Yours very truly,

Kristina L. Massey

Kristina L. Massey
Senior Engineer

W. E. Moore

W. E. Moore, Group Manager
Production Engineering

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Enclosures

cc: E.H. Crews/W.E. Moore/M.L. Smith/K.L. Massey/
Files: 09-337.1006/03-337.1006

J.H. Young,Jr./B.L. Lowman/R.M. Webb
R.R. Mahan/B.C. Bissell