



COMBINED APPLICATION
For
Certificate of Environmental
Compatibility, Public Convenience
and Necessity
And For a Base Load Review Order

Public Service Commission
of South Carolina
Docket No. 2008-196-E

SAFE HARBOR STATEMENT

Statements included in this set of documents which are not statements of historical fact are intended to be, and are hereby identified as, "forward-looking statements" for purposes of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements include, but are not limited to, statements concerning future debt issuance, cost of capital, capital structure, revised rates filings, effective dates of rates, inflation rates, construction costs, AFUDC rates, capital expenditures, construction schedules, licensing and permitting activities, completion dates for new units, investment tax credits, fuel costs, generation mix, customer and demand growth, natural gas prices, uranium prices, coal prices, CO₂ emission costs, and construction and permitting contingencies and risks. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "forecasts," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential" or "continue" or the negative of these terms or other similar terminology. Readers are cautioned that any such forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties, and that actual results could differ materially from those indicated by such forward-looking statements. Important factors that could cause actual results to differ materially from those indicated by such forward-looking statements include, but are not limited to, the following: (1) the information is of a preliminary nature and may be subject to further and/or continuing review and adjustment; (2) regulatory actions, regulatory delay, and intervention by opposing parties in licensing and permitting proceedings; (3) collateral lawsuits, appeals and other litigation; (4) changes in rate regulation, environmental laws and regulations, and nuclear safety laws and regulations; (5) changes in the cost or availability of labor, equipment, components and materials; (6) performance of key contractors or suppliers of key components or services; (7) transportation and shipping problems; (8) delays in construction related to weather conditions or natural disasters both in South Carolina and affecting suppliers and contractors; (9) changes in the economy, especially in areas served by South Carolina Electric & Gas Company (SCE&G or the Company); (10) changes in the public, political and regulatory perception and support for nuclear power; (11) the results of financing efforts; (12) changes in SCANA's or its subsidiaries' accounting rules and accounting policies; (13) payment by counterparties as and when due; (14) the results of efforts to license, site and construct facilities for baseload electric generation; (15) the availability and prices of fuels such as coal, natural gas and enriched uranium used to produce electricity; (16) the level and volatility of future market prices for such fuels and purchased power; (17) the impact of competition from alternate energy sources; (18) the availability of purchased power and natural gas for distribution; (19) inflation; (20) capital market conditions; (21) compliance with regulations; and (22) the other risks and uncertainties described in **Exhibit J** to this Application and as described from time to time in the periodic reports filed by SCANA Corporation or SCE&G with the United States Securities and Exchange Commission (SEC). The Company disclaims any obligation to update any forward-looking statements.

BEFORE
THE PUBLIC SERVICE COMMISSION
OF
SOUTH CAROLINA
DOCKET NO. 2008-196-E

In Re: Combined Application of South Carolina)	COMBINED APPLICATION
Electric & Gas Company for a Certificate)	FOR A CERTIFICATE OF
of Environmental Compatibility and Public)	ENVIRONMENTAL
Convenience and Necessity and for a Base Load)	COMPATIBILITY AND PUBLIC
Review Order for the Construction and Operation)	CONVENIENCE AND
of a Nuclear Facility at Jenkinsville,)	NECESSITY AND FOR A BASE
South Carolina)	LOAD REVIEW ORDER
_____)	

South Carolina Electric & Gas Company (“SCE&G” or the “Company”) hereby applies to the Public Service Commission of South Carolina (the “Commission”) for a Certificate of Environmental Compatibility and Public Convenience and Necessity and for a Base Load Review Order to construct and operate a two 1,117 net megawatt (MW) nuclear facility to be located at the V. C. Summer Nuclear Station site near Jenkinsville, South Carolina (the “Facilities” or the “Units”). This Combined Application (“Application”) is filed pursuant to the provisions of the Utility Facility Siting and Environmental Protection Act, S.C. Code Ann. §§ 58-33-10 *et seq.* (2006) (hereafter the “Siting Act”) and the Base Load Review Act, S.C. Code Ann. §§ 58-33-210 *et seq.* (1976 as amended in 2007). Paragraphs 1-4 below comprise the introduction to the Application as required by S.C. Code Ann. § 58-33-260(A)(1).

In support of this Application, SCE&G would respectfully show to the Commission:

1. Applicant. SCE&G is a corporation duly organized and existing under the laws of the State of South Carolina, with its principal offices at 1426 Main Street, Columbia, South Carolina, 29201. The Company is engaged in the business of generating, transmitting, and delivering electricity, and providing electric service to public and private energy users for compensation.

2. Service Area. SCE&G operates an integrated electric utility system that serves over 643,000 customers in 24 counties in central and southern South Carolina. SCE&G's service territory includes the metropolitan areas of Charleston, Columbia, Beaufort, and Aiken and many other smaller cities and towns, and rural areas in South Carolina.

3. Description of the Facilities and Basis for Selection. To meet the growing demands of its customers for electric power, to support the continued economic development and prosperity of the State of South Carolina, and to maintain the reliability of its electric system, SCE&G proposes to construct a facility comprising two Westinghouse AP1000 Advanced Passive Safety Power ("AP1000") Plants in Jenkinsville, South Carolina. The Facilities will be located adjacent to and approximately one mile southwest of the present 966 MW Westinghouse reactor at the V. C. Summer Nuclear Station ("VCSNS") and will be jointly owned by SCE&G and the South Carolina Public Service Authority ("Santee-Cooper").

4. The Westinghouse AP1000 Reactor. The Westinghouse AP1000 reactor represents an advanced nuclear generating design which received its nuclear design certification from the Nuclear Regulatory Commission ("NRC") on September 13, 2004. The AP1000 includes technologically advanced passive shut-down systems to enhance the safety of the Units and simplify their operations. To ensure efficient construction and operation, the Units will be built using standardized designs pre-approved by the NRC and advanced modular construction

techniques. Pursuant to Section 58-33-120(1)(a) of the Siting Act and Section 58-33-250(4)(a) of the Base Load Review Act, a description and drawings of the Westinghouse AP1000 Units and the specifications of the Facilities as they will be constructed on the Summer Station site are attached as **Exhibit A**.

5. Unit Capacity and Output. The anticipated net dependable capacity from the Units in total will be approximately 2,234 MW, of which 1,228 MW or 55% will be available to serve customers of SCE&G. Pursuant to its agreement with Santee-Cooper, SCE&G will operate the Units. Santee-Cooper will pay 45% of the capital and operating costs of the Units and receive a like percentage of the electrical output. SCE&G intends to operate the Units at as high a capacity factor as can be achieved commensurate with sound engineering practices and prudent utility operations. SCE&G expects that the capacity factor for the Units, when adjusted for the effects of refueling and maintenance outages, will be in excess of 90%.

6. Choice of Suppliers of Major Components of the Facilities and Principal Contractors for Construction. SCE&G, for itself and as agent for Santee-Cooper, has entered into an Engineering, Procurement and Construction Agreement (“EPC Contract”) with a consortium consisting of Westinghouse Electric Co., LLC (“Westinghouse”) and Stone & Webster, Inc., (“Stone & Webster”). Stone & Webster is a subsidiary of the Shaw Group, Inc. (“Shaw”). Westinghouse is a subsidiary of Toshiba Corporation and will provide the nuclear systems for the Facilities.

SCE&G selected Westinghouse AP1000 Units for construction based on a number of features including the quality and safety of the design, the standardized nature of the design, the size and life-cycle economics of the Units, the similarity of the Units’ operating characteristics with those of the existing unit at VCSNS, and Westinghouse’s experience and proven track

record as a designer and manufacturer of nuclear systems and components. Stone & Webster is a leader in construction and engineering of nuclear power plants and other major energy facilities worldwide. Westinghouse/Stone & Webster have agreed to set more than fifty percent of the EPC Contract costs as fixed costs or firm costs with fixed escalation factors. In the coming months, they will offer to SCE&G the right to set an additional portion of the EPC Contract price at fixed cost or firm cost with fixed escalation. Pursuant to S.C. Code Ann. § 58-33-250(4)(b) and (c), SCE&G is providing herewith:

- **Exhibit B**, which provides further information concerning Westinghouse/Stone & Webster, and Shaw as the contractors or suppliers of the major components of the Facilities and the Company's basis for selecting them; and
- **Exhibit C**, which provides information concerning the principal terms of the EPC Contract.

7. Choice of Suppliers of Other Major Components of the Facilities and Principal Contractors. Under the EPC Contract, the selection of principal contractors and suppliers other than Westinghouse/Stone & Webster will be made by Westinghouse/Stone & Webster from a list of qualified suppliers approved by SCE&G. Pursuant to S.C. Code Ann. § 58-33-250(5), **Exhibit D** provides further information on principal suppliers and contractors, other than those listed in **Exhibit B**, which have been selected or qualified for selection as contractors and suppliers to the project.

8. Anticipated Construction Schedule. While construction of the Facilities is subject to scheduling and other risks further detailed in **Exhibit J** and other exhibits to this Application, and the construction schedule contingency set forth below, under the EPC Contract the date for substantial completion of VCSNS Unit 2 is April 1, 2016, and for VCSNS Unit 3 is January 1,

2019. Pursuant to S.C. Code Ann. § 58-33-250(1), further information concerning the anticipated construction schedule of the Facilities is attached as **Exhibit E**.

9. Construction Schedule Contingency. The Code of Laws of South Carolina, 1976, at Sections 58-33-270(B)(1) and 58-33-275(A)(1) provide for specified contingencies to be included in the construction schedules approved in base load review orders. In light of the complexity of nuclear permitting and construction, SCE&G requests that the Commission specify a thirty (30) month schedule contingency applicable to all milestones reflected in **Exhibit E** and to the substantial completion dates referenced above. The Company requests authorization to adjust the schedule of capital costs provided in **Exhibit F** to reflect any contingency-related changes in the construction schedule contained in **Exhibit E**, such adjustments to include appropriate inflation-related adjustments to associated capital cost amounts.

10. Anticipated Components of Capital Costs and Schedule. Pursuant to S.C. Code Ann. § 58-33-250(2), information concerning the anticipated components of capital cost for the Facilities and the annual schedule for incurring of those costs is attached as **Exhibit F**. As noted above, construction of the Facilities is subject to various costs and schedule risks discussed in **Exhibit J** and other attachments to this Application. SCE&G specifically requests that the base load order issued in this proceeding designate the figures provided under the heading “Cumulative Project Cash Flow” on **Exhibit F** to this Application plus applicable AFUDC to be the “approved capital cost estimate including specified contingencies” for the Facilities as required pursuant to S.C. Code Ann. §§ 58-33-275(A)(2).

11. Statement of Need and Necessity. Currently, SCE&G operates ten (10) coal-fired fossil fuel units (2,484 MW), one (1) cogeneration facility (90 MW), eight (8) combined cycle

gas turbine/steam generator units (gas/oil fired, 1,319 MW), eighteen (18) peaking turbines (347 MW), four (4) hydroelectric generating plants (227 MW), and one Pump Storage Facility (576 MW). The total net non-nuclear summer generating capability rating of these facilities is 5,043 megawatts. SCE&G's total net reliable generation capacity, including its two-thirds share of the output of the VCSNS Unit No. 1, is 5,687 MW, compared to a 2007 peak demand of 4,998 MW. The Company's peak demand continues to increase and is presently forecasted to be 5,791 MW by 2016 and 6,133 MW by 2019. SCE&G can efficiently meet as much as 209 MW of this increased demand through conservation, load-shifting, off-system purchases, renewable energy resources or through the installation of gas-fired peaking units. However, without the additional base load capacity represented by the proposed Facilities, SCE&G will not be able to meet the increasing need for efficient base load power in its electric service territory and assure reliable, reasonably priced electric supply to its customers and the State of South Carolina. The Company's demand forecast and considerations affecting this forecast are set forth more fully in **Exhibit G**.

12. Contribution to System Efficiency and Choice of Fuel Type. SCE&G has chosen nuclear generating capacity to meet its base load requirements having carefully evaluated the life-cycle costs, reliability, the fuel, and environmental risks of other options. The Company's evaluations of these factors are set forth more fully in **Exhibit H**.

13. Inflation Indices Used by SCE&G. Pursuant to S.C. Code Ann. §§ 58-33-250(7) and 58-33-270(B)(6), the Company is providing in **Exhibit I** the inflation indices it has used for determining the capital costs it expects to pay for constructing the Facilities. Included in **Exhibit I** are the sources of the data for each inflation index, and a five-year history of each index on an annual basis.

14. Cost Contingencies Used by SCE&G. SCE&G is providing in **Exhibit I** the basis on which it has calculated cost contingencies related to its capital cost schedules as contemplated in S.C. Code Ann. § 58-33-270(B)(2). The capital cost contingency amounts are set forth on **Exhibit F**. Because the timing of contingencies are by definition uncertain, SCE&G requests that the Commission approve the total amount of project contingency provided for in **Exhibit F** and allow SCE&G to use that contingency at such times and in such amounts as required during the course of construction of the Units. To the extent that SCE&G uses any contingency amounts in advance of the years with which they are otherwise associated, SCE&G would make appropriate inflation-related adjustments to the remaining contingency amounts.

15. Capital Cost Schedule Contingencies. S.C. Code Ann. § 58-33-270(B)(2) specifies that the base load order issued in this proceeding shall specify contingencies related to the schedule for incurring capital cost. SCE&G respectfully requests the Commission establish a twenty-four (24) month capital cost schedule contingency, such that if construction or component manufacturing work can be accelerated, SCE&G can accelerate its capital cost payments to reflect the accelerated schedule. To the extent that SCE&G accelerates any capital cost payment pursuant to the capital cost schedule contingency requested here, SCE&G would make appropriate inflation-related adjustments to the remaining capital cost forecast amounts.

16. Updating of Cost Projections. As set forth in **Exhibit I**, the EPC Contract ties certain categories of plant costs set forth in **Exhibit F** to fixed escalators or identified inflation indices. Other categories of plant costs set forth in **Exhibit F** have been estimated based on specified inflation indices selected by SCE&G as appropriate for planning and cost forecasting purposes. As required by Section 58-33-277(A)(3) and (4) of the Code of Laws of South Carolina, 1976, SCE&G will file quarterly updates of the capital cost schedules contained in

Exhibit F during the time that construction on the Facilities is progressing. As required by S.C. Code Ann. §§ 58-33-250(7) and 58-33-270(B)(6), those adjusted capital cost schedules will reflect the effects of inflation measured using the indices contained in **Exhibit I**, and cumulative projected cash flow figures for each year will be updated to reflect appropriate inflation-related changes in all prior periods. Inflation data will be used to update capital cost schedules as follows:

(a) For past periods where actual index information is available at the time SCE&G files its quarterly report, SCE&G proposes to use actual index information in measuring inflation and recalculating its capital cost projections for those past periods.

(b) For past periods where actual index data is not yet available at the time SCE&G files its report, SCE&G proposes to measure inflation during those past periods using an average of the applicable inflation index for the most recent 12-month period for which actual inflation index information is then available (the “Most Current 12-Month Data.”) If the Most Current 12-Month Data are used for any past period, those data will be updated in future reports when actual index information for the past period becomes available.

(c) SCE&G also proposes to use Most Current 12-Month Data to update forecasts for the 12-month period that follows the close of each current reporting period.

(d) For periods more than 12 months beyond the close of the current reporting period, SCE&G proposes to use the most current five-year average for the applicable inflation index.

(e) When out-of-period adjustments are made in index information, those adjustments will be reflected in the next report filed.

17. Risk Factors Related to Construction and Operation of the Plant. Pursuant to S.C. Code Ann. § 58-33-250(8), the Company is providing information identifying risk factors related to the construction and operation of the Facilities in **Exhibit J**. Additional information related to these risk factors will be provided in the testimony of witnesses to be presented at the hearing in this matter.

18. Proposed Rate Design and Class Allocation Factors for Revised Rates. Pursuant to S.C. Code Ann. § 58-33-250(9), the Company is providing in **Exhibit K** information identifying the proposed rate design and class allocation factors to be used in formulating revised rates.

19. Return on Equity for Plant Construction. Pursuant to S.C. Code Ann. §§ 58-33-250 and 58-33-220(16), SCE&G opts to apply the Return on Equity of 11% as established by the Commission in Order No. 2007-855, dated December 14, 2007, for calculating the weighted average cost of capital for the construction of the Facilities. Schedules providing the Company's current cost of debt and capitalization ratios, calculated pursuant to the methodologies applied in Order 2007-855, are attached hereto as **Exhibit L**.

20. Year-by-Year Revenue Requirements. The Company is providing in **Exhibit M** the projected year-by-year construction work in progress balances and revenue requirements associated with Cumulative Project Cash Flow as set forth on **Exhibit F**. **Exhibit M** also provides a year-by-year estimate of the percentage increase in SCE&G's retail electric rates associated with these revenue requirements assuming that they are reflected in revised rates through annual revised rates filings. As indicated on **Exhibit M**, the compound growth in total retail electric rates for the period 2008-2020 associated with VCSNS Units 2 & 3 is forecasted to

be 2.5%. The actual revenue requirements and revised rates adjustments, however, cannot be known with certainty at this time and depend on multiple factors as indicated on **Exhibit M**.

21. Date for Measuring Investment in Construction Work in Progress. The Base Load Review Act, S.C. Code § 58-33-280(B), provides that for purposes of the rates established in this proceeding, SCE&G may specify the date for each revised rates filing on which the outstanding balance of Construction Work in Progress (“CWIP”) shall be measured. As set forth in **Chart A to Exhibit M**, SCE&G specifies the CWIP balance as of June 30, 2008 as being appropriate for purposes of establishing revised rates in this proceeding. Setting June 30, 2008 as the date on which CWIP is to be measured in this proceeding is consistent with the Commission’s established practice in past SCE&G rate orders, including Order No. 2007-855, of measuring CWIP as of a date between the filing of the rate application and the hearing in the rate making proceeding.

22. Revised Rates. Pursuant to S.C. Code Ann. § 58-33-250(3) and (11), the Company is providing in **Exhibit N** the rates and tariff sheets that it is requesting to put into effect upon issuance of the base load review order in this proceeding. It has been the practice of the Company in past rate proceedings to increase the basic facilities charge for retail electric service in even increments of \$0.50 or more. For this reason, the Company is not proposing to make any adjustment to the basic facilities charges in the revised rates proposed in this proceeding, but to seek Commission approval to make those adjustments only when the amount of the adjustment in the basic facilities charge rounds up or down by whole increments of \$0.50.

23. In-Service Expenses. Pursuant to S.C. Code Ann. § 58-33-250(6), the Company is providing in **Exhibit O** information on its current estimates of the in-service expenses associated with the Facilities for the twelve months following commencement of commercial

operations of each unit as those expenses are currently estimated. The expenses listed on **Exhibit O** are estimates only. As contemplated by S.C. Code Ann. § 58-33-280(I), the in-service expense estimates provided in **Exhibit O** will be revised and updated in the last revised rate filing made before each unit's in-service date.

24. Environmental Assessment. Pursuant to S.C. Code Ann. § 58-33-120(1)(b), the Company is providing summaries in **Exhibit P** of the environmental studies related to the Facilities as submitted to the Nuclear Regulatory Commission as part of the Combined Operating License Application for the Facilities, dated March 31, 2008. These studies and the other information referenced in **Exhibit P** demonstrate that the Facilities can be constructed and can operate in compliance with all applicable State, Federal and local environmental and land-use permitting requirements.

25. Transmission Interconnection Studies. As required by Commission Order No. 2002-19, the Company is providing the transmission interconnection studies related to the Facilities as **Exhibit Q**. As indicated in the *Generator Interconnection System Impact Study: SCE&G V. C. Summer Nuclear #2*, at page 22, SCE&G Transmission Planning intends to adjust the VCSNS Unit No. 2 interconnection plan to better take into account the future native load needs of SCE&G's transmission system. This adjustment will involve rerouting lines serving VCSNS Unit 2 to follow a longer path that better serves the growth corridor along the Interstate 77 north of Columbia. In keeping with established transmission planning pricing policies, the VCSNS Nuclear construction project will be charged based on the cost of line as originally routed. The estimated cost of the line as originally routed is 74.2% of the estimated cost of the rerouted line. SCE&G proposes to treat 74.2% of the actual cost of constructing the rerouted line as the cost to the nuclear project and include that percentage of the line's costs in its quarterly

reports of actual expenditures on the Units. SCE&G seeks authorization to adjust this percentage if the scope of the line construction project is expanded in the future. It is not anticipated that other lines will be required similar treatment.

26. Public Notice. Pursuant to the terms of the Base Load Review Act, a Combined Application is to be noticed under the statutes and regulations that apply to the noticing of base rate case applications filed under Section 58-27-860 of the Code of Laws of South Carolina, 1976. Attached as **Exhibit R**, and made a part hereof, is a proposed form of public notice pursuant to S.C. Code Ann. § 58-27-860.

27. Correspondence or Communications. The name, title, address and telephone number of the persons to whom correspondence or communications relating to the Application should be addressed are as follows:

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WHEREFORE, South Carolina Electric & Gas Company respectfully requests that the Commission issue a Certificate of Environmental Compatibility and Public Convenience and

Necessity and Base Load Review Order for the Facilities according to the terms set forth above, and authorize the Company to put into effect the rates contained in this Application and order such other, further or different relief as may be justified.

SOUTH CAROLINA ELECTRIC & GAS COMPANY

BY:  _____

Kevin B. Marsh, President

Date: May 30, 2008.

LIST OF EXHIBITS

- EXHIBIT A Description of the Westinghouse AP1000 and the Facilities**
- EXHIBIT B Information Concerning Westinghouse Electric Company, LLC and Stone & Webster, Inc.**
- EXHIBIT C Information Concerning the Engineering, Procurement and Construction Agreement (“EPC Contract”)**
- EXHIBIT D Information Concerning Other Suppliers and Contractors**
- EXHIBIT E Anticipated Construction Schedule**
- EXHIBIT F Anticipated Components of Capital Costs and Schedule**
- EXHIBIT G Forecasted Need for Electric Generation and Fuel Type**
- EXHIBIT H Contribution to System Efficiency and Fuel Type**
- EXHIBIT I Inflation Indices**
- EXHIBIT J Risk Factors Related to Construction and Operation of the Facilities**
- EXHIBIT K Proposed Rate Design and Class Allocation Factors for Revised Rates**
- EXHIBIT L Cost of Debt and Capitalization Ratios**
- EXHIBIT M Year-by-Year Revenue Requirements and Projected Rate Impact of Investment**
- EXHIBIT N Revised Rates Requested in Base Load Review Order**
- EXHIBIT O In-Service Expenses**
- EXHIBIT P Environmental Assessment and Related Information**
- EXHIBIT Q Transmission Interconnection Studies**
- EXHIBIT R Public Notice**

EXHIBIT A

DESCRIPTION OF THE WESTINGHOUSE AP1000 AND THE FACILITY

Combined Application of South Carolina Electric & Gas Company for a Certificate of Environmental Compatibility and Public Convenience and Necessity and for a Base Load Review Order Public Service Commission Docket No. 2008-196-E

1. INTRODUCTION

This **Exhibit A** provides information concerning the location and selection of the location for the proposed Virgil C. Summer Nuclear Station (VCSNS) Units 2 & 3 and a description of the Units SCE&G proposes to build.

2. SITE LOCATION AND FACILITY DESCRIPTION

The proposed AP1000 Advanced Passive Safety Power Plants (AP1000), referred to as VCSNS Units 2 & 3, are to be located approximately one mile south-southwest from VCSNS Unit 1. VCSNS Unit 1 is located at the southern end of the Monticello Reservoir in Fairfield County, South Carolina; approximately 15 miles west of Winnsboro and 26 miles northwest of Columbia, as shown on Figure 3. The site has a 44 year history of nuclear power generation. The Parr Experimental Nuclear Plant, which was the first commercial nuclear generation station in the Southeast, went into commercial operation on part of the site in May of 1964. This plant has since been retired and is in the final stages of decommissioning.

VCSNS Unit 1, which went into commercial operation on January 1, 1984, is a Westinghouse pressurized water reactor plant licensed by the Nuclear Regulatory Commission (NRC) in 1982 and has been in commercial operation since 1984. The site is in a sparsely populated rural area. The nearest community is Jenkinsville, South Carolina, located approximately three miles southeast of the site. The Broad River is located approximately one mile west of the site and flows in a southerly direction, as shown on Figure 4. The north-south oriented Monticello Reservoir has an area of approximately 6,800 acres (6 miles long and 2.5 miles across). The 6,800 acres includes the 300 acre Monticello sub-impoundment recreation lake. The power plant footprints of Units 2 and 3 consist of an area of approximately 47 acres, as shown on Figure 5.

The proposed AP1000 units and support facilities for the VCSNS site are designed around the Westinghouse standardized unit approach. Each AP1000 unit consists of five principle generation structures—the nuclear island, turbine building, annex building, diesel generator building, and a radwaste building, as shown on Figure 6. Structures that make up the nuclear island include the containment, shield building, and auxiliary building. The containment is a freestanding steel containment vessel with elliptical upper and lower heads. It is surrounded by the shield building. The shield building is a reinforced concrete structure that, in conjunction with the internal structures of the containment, provides the required shielding for the reactor coolant system and other radioactive systems and components housed in the containment. The

shield building roof is a reinforced concrete conical structure. The auxiliary building is a reinforced concrete structure and shares a common base mat with the containment building and the shield building. The auxiliary building wraps around approximately 70% of the circumference of the shield building and provides protection and separation for the safety-related mechanical and electrical equipment located outside the containment.

The turbine building is a rectangular metal-sided building with its long axis oriented radially from the containment. The turbine building houses the turbine, generator, and associated mechanical and electrical systems. The annex building is a combination reinforced concrete structure and steel framed structure with insulated metal siding. The annex building provides the main personnel entrance to the power block. The building also contains the control support area, a machine shop, the ancillary diesel generators, other electrical equipment and various heating, ventilation, and air conditioning systems. The plant includes non-safety related diesel generators and a diesel generator building is a single-story steel-framed structure with insulated metal siding. The building houses two diesel generators to provide backup power in the event of disruption of the normal power source. The radwaste building is a steel-framed structure that houses low-level liquid radwaste holdup tanks and processing system.

The circulating water system for each unit consists of two mechanical draft cooling towers and a circulating water pump intake structure. The circulating water system cooling towers are located south of the proposed new units. Each cooling tower has a concrete shell with fan stacks on top rising to a height of approximately 70 feet. Internal construction materials include fiberglass-reinforced plastic or polyvinyl chloride for piping laterals, polypropylene for spray nozzles, and polyvinyl chloride for fill material. Mechanical draft towers use mechanical fans to generate air flow across sprayed water to reject heat to the atmosphere. The four cooling towers occupy an area of approximately 38 acres.

In addition to the circulating water system cooling tower footprint, VCSNS Units 2 & 3 require space for service water system cooling towers (one per unit). These mechanical draft cooling towers require an area of approximately 0.5 acre per unit and are located near the turbine building. The proposed new units share common intake structures, discharge structure, and certain support structures such as office buildings, water treatment, and waste handling facilities.

The Monticello Reservoir is used as makeup water for the circulating water and service water cooling systems. The plant discharge is to the Parr Reservoir. The new intake structure for the circulating water system makeup is located approximately 1,250 feet west of the VCSNS Unit 1 intake facilities. An additional intake structure for the remaining plant water (service water cooling makeup, potable water, fire water, demineralized water supply) is located approximately 5500 feet east of the VCSNS Unit 1 intake facilities. Modifications to existing infrastructure will be made to integrate VCSNS Units 2 and 3 with the existing unit; however, none of the existing unit's structures or facilities that directly support power generation are shared. A new security perimeter will be installed to encompass the new units. The existing Nuclear Learning Center will be expanded to support the training needs for the new units. Existing administrative buildings, warehouses, and other support facilities will be used, expanded, or replaced based on prudent economic and operational considerations.

After the completion of new unit construction, areas used for construction support are to be graded, landscaped, and planted to enhance the overall site appearance. Previously forested areas cleared for temporary construction facilities are to be revegetated, and harsh topographical features created during construction are to be contoured to match the surrounding areas. These areas include equipment laydown yards, module fabrication areas, concrete batch plant, areas around completed structures, and construction parking.

VCSNS Unit 1 interconnects with the regional power grid via 10 existing 230kV transmission lines. To connect the additional generation to the electric grid, SCE&G will construct six new 230kV transmission lines: three for VCSNS Unit 2 and three for VCSNS Unit 3. A new 230kV switchyard will be constructed approximately 1,000 feet northwest of VCSNS Units 2 and 3, and 4,000 feet west south west of the existing Unit 1 site. This new switchyard will be air-insulated and consist of ten bays in a breaker-and-a-half arrangement. It will be located within an area approximately 2,000 feet long, 600 feet wide and occupy about 28 acres.

A Description of the Westinghouse AP1000

Design Overview – The AP1000 design is derived directly from the AP600, a two-loop, 600 MWe Pressurized Water Reactor (PWR). In December 1999, the AP600 was granted design certification from the Nuclear Regulatory Commission (NRC). The AP600 was the first nuclear reactor design using passive safety technology licensed in the West or in Asia. However, Westinghouse determined that a 600 MWe unit was not cost competitive in US markets. Therefore, Westinghouse embarked on the development of the AP1000 design, which applies economies of scale to the AP600 design to reduce the cost per kW while maintaining the passive safety advantages established by the AP600. At present, approximately eight to twelve AP1000 units are proposed to be built in the United States, most of which are planned to be located in the Southeastern United States.

Like the AP600, the AP1000 utilizes passive safety features that, once actuated, depend on natural forces, such as gravity, condensation and natural circulation, to perform required safety functions. These passive safety systems result in increased plant safety and have also significantly simplified plant systems, equipment and plant operation and maintenance. In both the AP600 and AP1000 designs, there are 60 percent fewer valves, 75 percent less piping, 80 percent less control cable, 35 percent fewer pumps, and 50 percent less seismic building volume than in a conventional reactor. This greatly simplified design complies with all of the NRC regulatory and safety requirements and EPRI Advanced Light Water Reactor Utility Requirements Document. These features make this design easier and less expensive to build, operate, and maintain.

The AP1000 was design certified by the NRC under 10 CFR 52, Appendix D in 2004. It was also found to meet the U.S. NRC deterministic-safety and probabilistic-risk criteria with large margins. The results of the Probabilistic Risk Assessment (PRA) for the AP1000 design show a very low core damage frequency, *i.e.*, the probability of an accident that would result in core damage. The Nuclear Regulatory Commission requires that plants be designed such that the risk of core damage resulting from an emergency will occur 1 time or less in a 10,000 year period. The AP1000 is designed to have a core damage probability of 1 or less in every 2,500,000 years.

With the AP600 design certified by the NRC as a starting point, a minimum number of changes were made to realize a significant increase in power in AP1000. The reactor vessel for the AP1000 is the same diameter as for the AP600, but the number of fuel assemblies is only minimally increased from 145 to 157 and the height of the core was increased from 12 feet to 14 feet. In addition, to increase the output of the reactor, reactor coolant pumps and steam generators have been increased in size. The design of these larger reactor components are based on components that are used in operating PWRs or have been developed and tested for new PWRs. In order to maintain adequate safety margins, the capacity of the passive safety features have been selectively increased based on insights from the AP600 test and analysis results. As a result, more than 90 percent of the design for the plant had already been completed and more than 80 percent of the AP600 Safety Analysis Report remained unchanged for the AP1000. A pre-certification review phase was completed in March 2002 and was successful in establishing the applicability of the AP600 test program and AP600 safety analysis codes to the AP1000 design certification.

Electrical and Thermal Output – The AP1000 has a net electric output based a current engineering capabilities of 1,117MWe, reactor power (thermal) of 3,400 MWth. Its Fuel Type is 4.95% enriched UO₂. Major components include a single reactor pressure vessel, two steam generators, and four reactor coolant pumps for converting reactor thermal energy into steam. A single high-pressure turbine and three low-pressure turbines drive a single electric generator.

Detailed Description of the Components and Operations of the Unit – The AP1000 reactor is connected to two steam generators via two primary hot leg pipes and four primary cold leg pipes. A reactor coolant pump is located in each primary cold leg pipe to circulate pressurized reactor coolant water through the reactor core. The reactor coolant pumps circulate reactor coolant through the reactor core making contact with the fuel rods which contain the enriched uranium dioxide fuel. As the reactor coolant passes through the reactor core, heat from the nuclear fission process is removed from the reactor. This heat is transported to the steam generators by the circulating reactor coolant and passes through the tubes of the steam generators to heat the feedwater from the secondary system. The reactor coolant is then returned to the reactor by the reactor coolant pumps, where it is reheated to start the heat transfer cycle over again. Inside the steam generators, the reactor heat from the primary system is transferred through the walls of the tubes to convert the incoming feedwater from the secondary system into steam. The steam is transported from the steam generators by main steam piping to drive the high-pressure and low-pressure turbines connected to an electric generator to produce electricity. The turbine is an 1,800-rpm, tandem-compound, six-flow, reheat unit. The high-pressure turbine element includes one double-flow, high-pressure turbine. The low-pressure turbine elements include three double-flow, low-pressure turbines. The turbine generator system will be manufactured by Toshiba. After passing through the high and low pressure turbines, the steam is condensed back to water by cooled water circulated inside the titanium tubes located in the three condensers. The condensate is then preheated and pumped back to the steam generators as feedwater to repeat the steam cycle. The condenser is a three-shell, single-pass, multi-pressure unit. The unit thermal efficiency of the complete cycle is approximately 35%.

The AP1000 pressurized water reactor works on the simple concept that, in the event of a design-basis accident (such as a coolant pipe break), the plant is designed to achieve and maintain safe shutdown condition without any operator action and without the need for AC

power or pumps. The AP1000 passive safety systems require no operator actions to mitigate design-basis accidents. These systems use natural forces such as gravity, natural circulation, evaporation, condensation and compressed gas to achieve their safety function. No pumps, fans, diesels, chillers, or other active machinery are used, except for a few simple valves that automatically align and actuate the passive safety systems. To provide high reliability, these valves are designed to move to their safeguard positions upon loss of power or upon receipt of a safeguards actuation signal. Only a single move is required for each valve, which is powered by multiple, reliable Class 1E DC power batteries. The passive safety systems do not require the large network of active safety support systems (ac power, diesels, HVAC, pumped cooling water) that are needed in typical nuclear plants. As a result, in the case of the AP1000, active support systems no longer are considered to be “safety related”, and they are either simplified or eliminated. With less safety-related equipment, the seismic Category 1 building volumes needed to house safety-related equipment are greatly reduced. In fact, most of the safety equipment can now be located within containment, resulting in fewer containment penetrations.

Many active components are included in the AP1000, but are designated as non safety-related. Multiple levels of defense for accident mitigation are provided, resulting in extremely low core-damage probabilities while minimizing occurrences of containment flooding, pressurization and heat-up.

3. SITE SELECTION

SCE&G conducted the site selection study for one or more possible new nuclear units in 2005. In that study, SCE&G reviewed the evaluations that had already been performed on a number of potential power plant sites in its service territory. Those evaluations included the evaluation conducted in originally selecting the location of the VCSNS Unit 1, the evaluation for possible sites for a second unit, and several subsequent site evaluation studies related to the possible siting of additional fossil-fueled plants.

SCE&G added one additional site, the Savannah River Site (SRS), to this list of previously studied sites for evaluation in 2005. SRS was identified as a potential site since it was within SCE&G service territory and had been evaluated as a potential nuclear site in recent industry studies by third parties (including a study conducted by NuStart Energy Development, LLC (“NuStart”) an association of utilities considering constructing nuclear construction.

A siting study conducted by Dames & Moore in 1974 had evaluated 18 potential nuclear power plant sites located across the SCE&G service territory as possible sites for a second nuclear power plant in addition to VCSNS Unit 1. The findings of that study indicated that several potential locations within SCE&G’s service territory were suitable for such a unit. In 2005, SCE&G reevaluated these sites based on the results of the earlier study. Based on the 2005 evaluation, SCE&G determined that none of these 18 sites were “obviously superior” to VCSNS as sites for a new nuclear plant, especially considering:

- VCSNS’ status as an existing nuclear power plant site, the extensive nuclear-related infrastructure and personnel already present on the site, as well as SCE&G’s 25 years of experience in nuclear operations at that location;

- The availability on the VCSNS site of adequate land and water for construction of new units;
- The availability of existing transportation and transmission infrastructure on the VCSNS site; and
- The VCSNS site's favorable location with respect to SCE&G loads.

SCE&G had commissioned additional site selection studies in the 1980s (Dames & Moore 1982, 1988) to identify sites for potential future fossil-fueled power plants. Not all criteria used for fossil plant siting studies are directly applicable to nuclear plants. Nonetheless, these studies consistently identified sites at VCSNS as being among the most preferable of the sites they evaluated for the construction of a new, base load generating unit to serve SCE&G's system.

Based on the conclusion that no previously evaluated sites were "obviously superior" to VCSNS, the 2005 siting study focused on comparing VCSNS to the previously unevaluated SRS site. This aspect of the evaluation was conducted in accordance with the overall process outlined in the Electric Power Research Institute (EPRI) Technical Report TR-1006878, Siting Guide: Site Selection and Evaluation Criteria for an Early Site Permit Application (Siting Guide), March 2002. The technical evaluation for this study was conducted by Dr. Kyle Turner (McCallum-Turner) who was also the principal investigator for development of the EPRI Siting Guide. This process, as adapted for the SCE&G site selection study, is depicted in Figure 1 below.

Screening-level criteria developed from the EPRI Existing Site Criteria were applied to the evaluation of the two sites. Once these initial screening-level evaluations were developed, reconnaissance-level on-site visits were conducted to support the site selection analysis.

Using all available data (including reconnaissance data) and criteria developed based on the EPRI general site criteria, detailed site suitability evaluations of the two alternative sites were conducted and overall composite site suitability ratings were developed.

The VCSNS site was found to rate higher in the railroad access, transmission access, and seismic criteria; the two sites were rated essentially equal in the remaining criteria (Ref. Table 1). Overall, based on the screening-level composite evaluation, VCSNS was found to be a superior location for the SCE&G COL application (Ref. Figure 2). Environmental and geological information concerning the site is summarized on **Exhibit P** to this Application.

Figure 1: Site Selection Process Overview

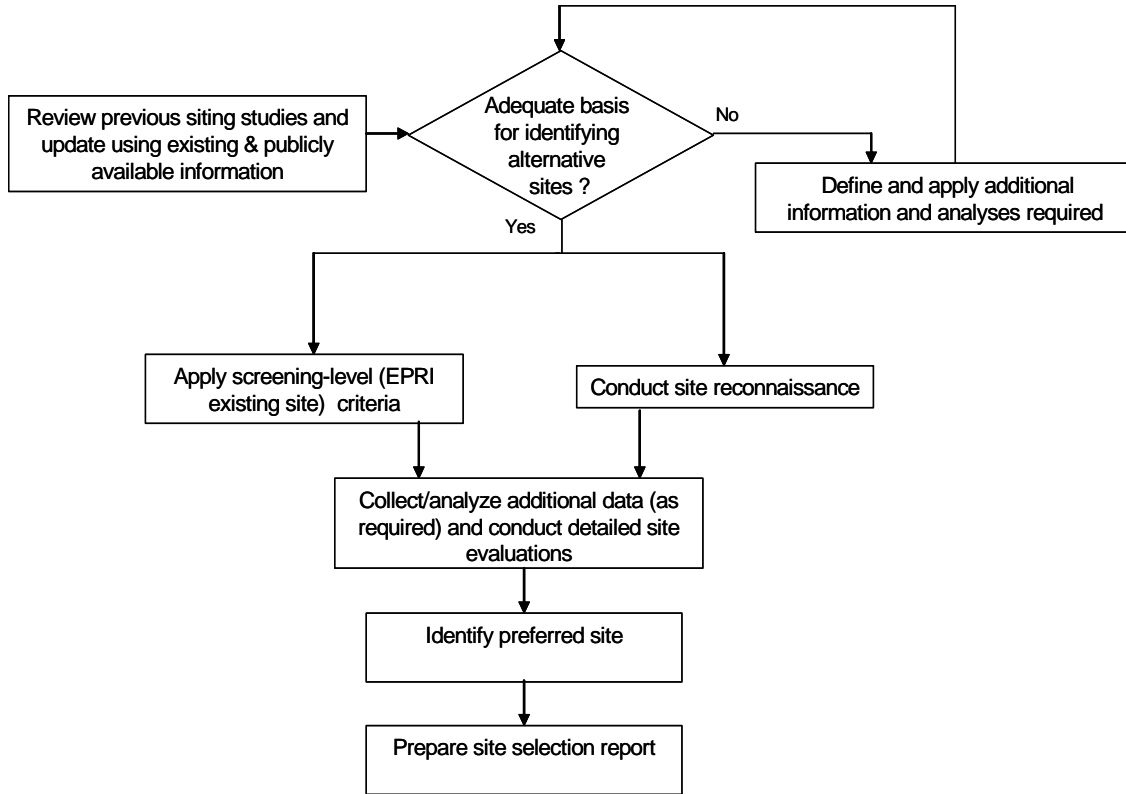


Table 1: Screening Evaluation Ratings

	Criterion										Composite Site Rating
	P1	P2	P3	P4	P5	P6	P7	P8	P9	P10	
	Cooling Water Supply	Flooding	Population	Hazardous Land Uses	Ecology	Wetlands	Railroad Access	Transmission Access	Geology & Seismic	Land Acquisition	
	Weight Factor										
Potential Site Name	9.8	4.4	8.6	5.9	5.6	5.6	6.7	7.4	9.8	6.3	
	Site Ratings										
SRS	3.5	5	4	4	4	4	4.79	1.00	2	4.5	246.6
VCSNS	4	5	4	4	4	4	4.96	4.94	3	5	294.7

Screening Criteria

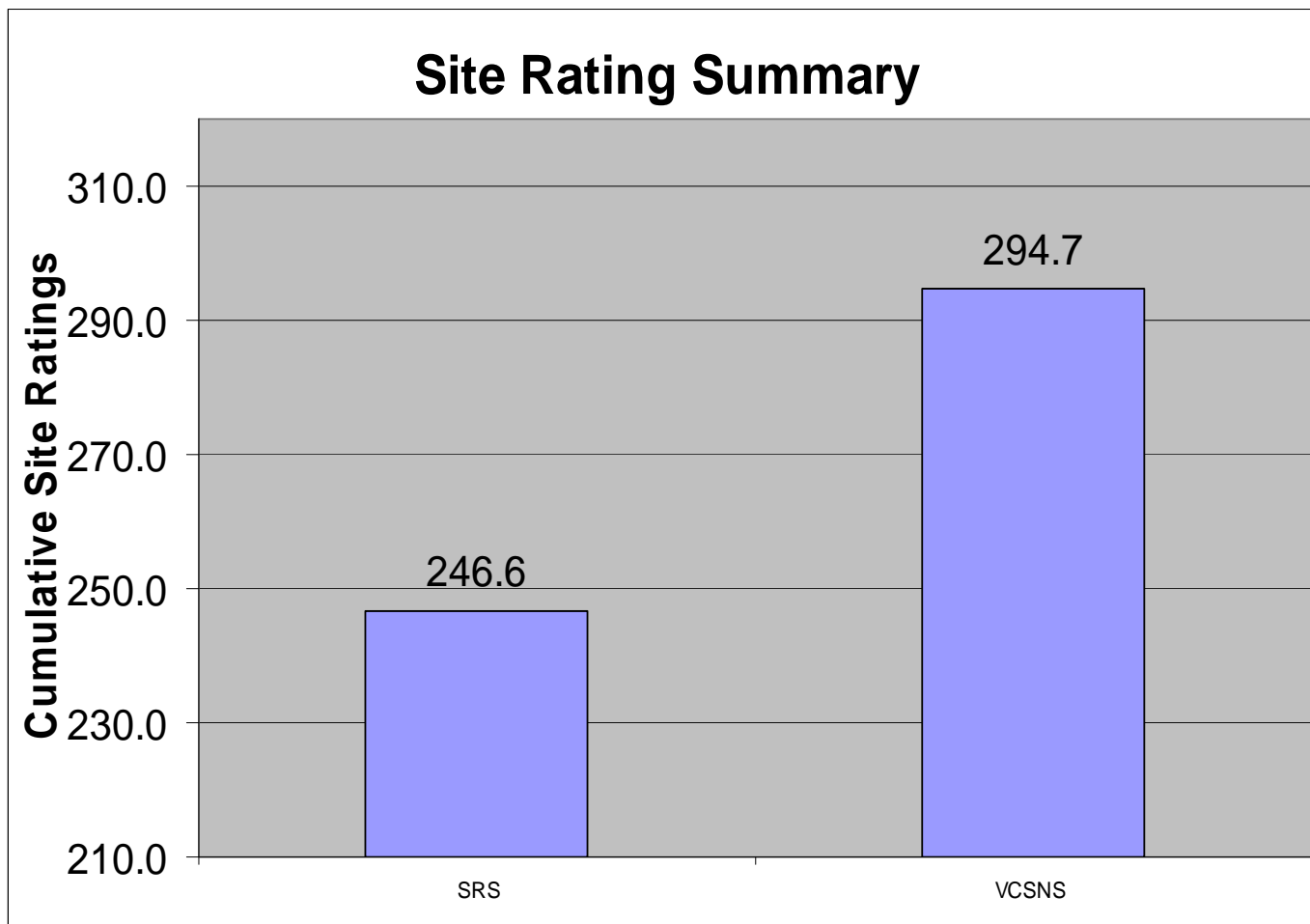
Criteria presented in Table 1, were derived from the existing site criteria listed in Section 4.2 of the EPRI Siting Guide: Site Selection and Evaluation Criteria for an Early Site Permit Application (Siting Guide), March 2002. They were intended to provide insights into the overall site suitability trade-offs between the two sites and to take advantage of data available during the site selection process.

Criterion Ratings – Each site was assigned a rating of 1 to 5 (1 = least suitable, 5 = most suitable) for each of the potential site evaluation criteria. Information sources for these evaluations included publicly available data, information available from SCE&G files and personnel, site visits, and large scale satellite photographs.

Weight Factors – Weight factors reflecting the relative importance of these criteria were synthesized from those developed for previous nuclear power plant siting studies. The weight factors were originally derived using methodology consistent with the modified Delphi process specified in the Siting Guide. Weight factors used (1 = least important, 10 = most important) are listed in the table below.

Composite Suitability Ratings – Ratings reflecting the overall suitability of each site were developed by multiplying criterion ratings by the criterion weight factors and summing over all criteria for each site.

Figure 2: Screening Evaluation Composite Site Suitability Ratings



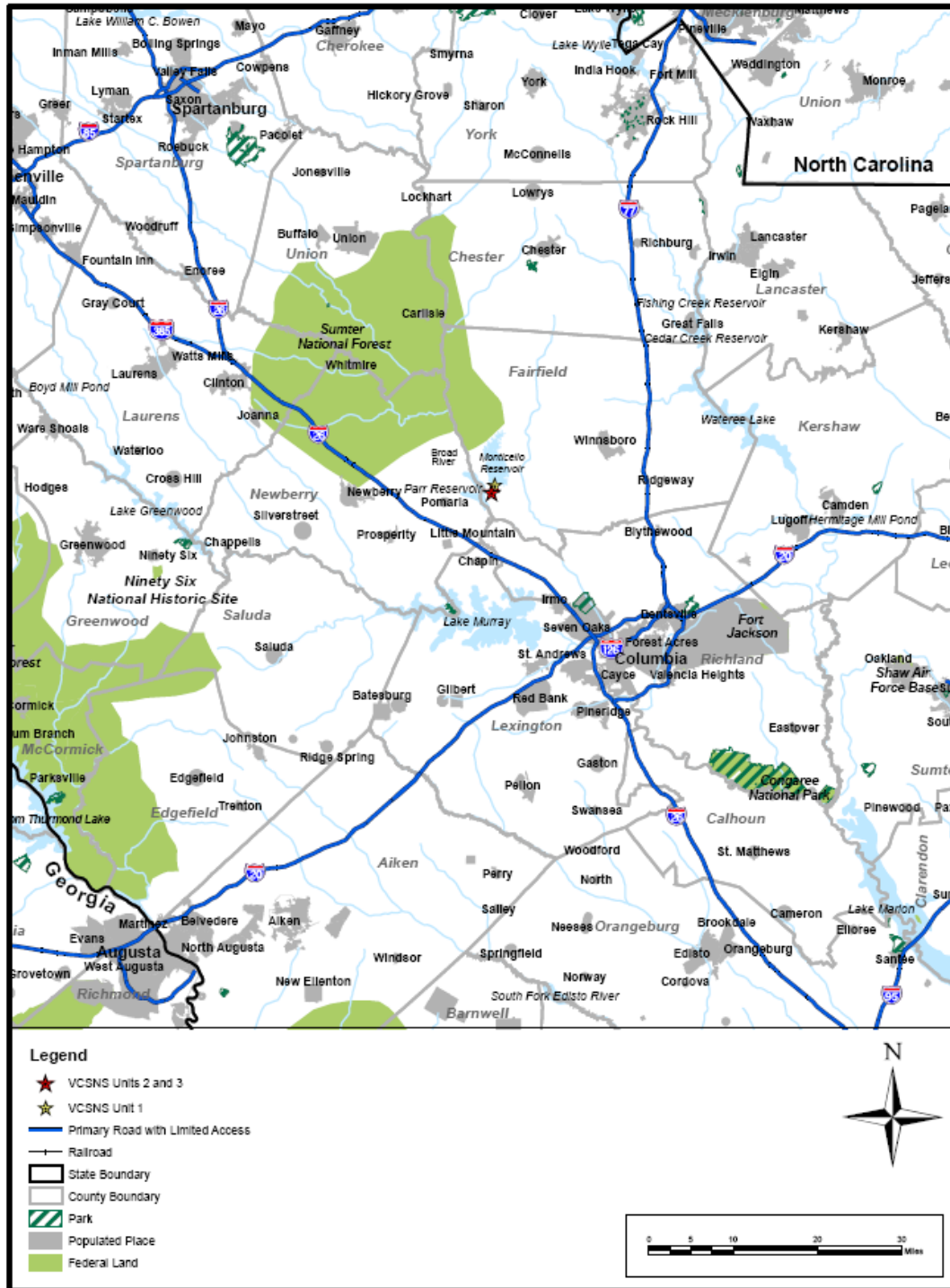


Figure 3: 50 mile radius

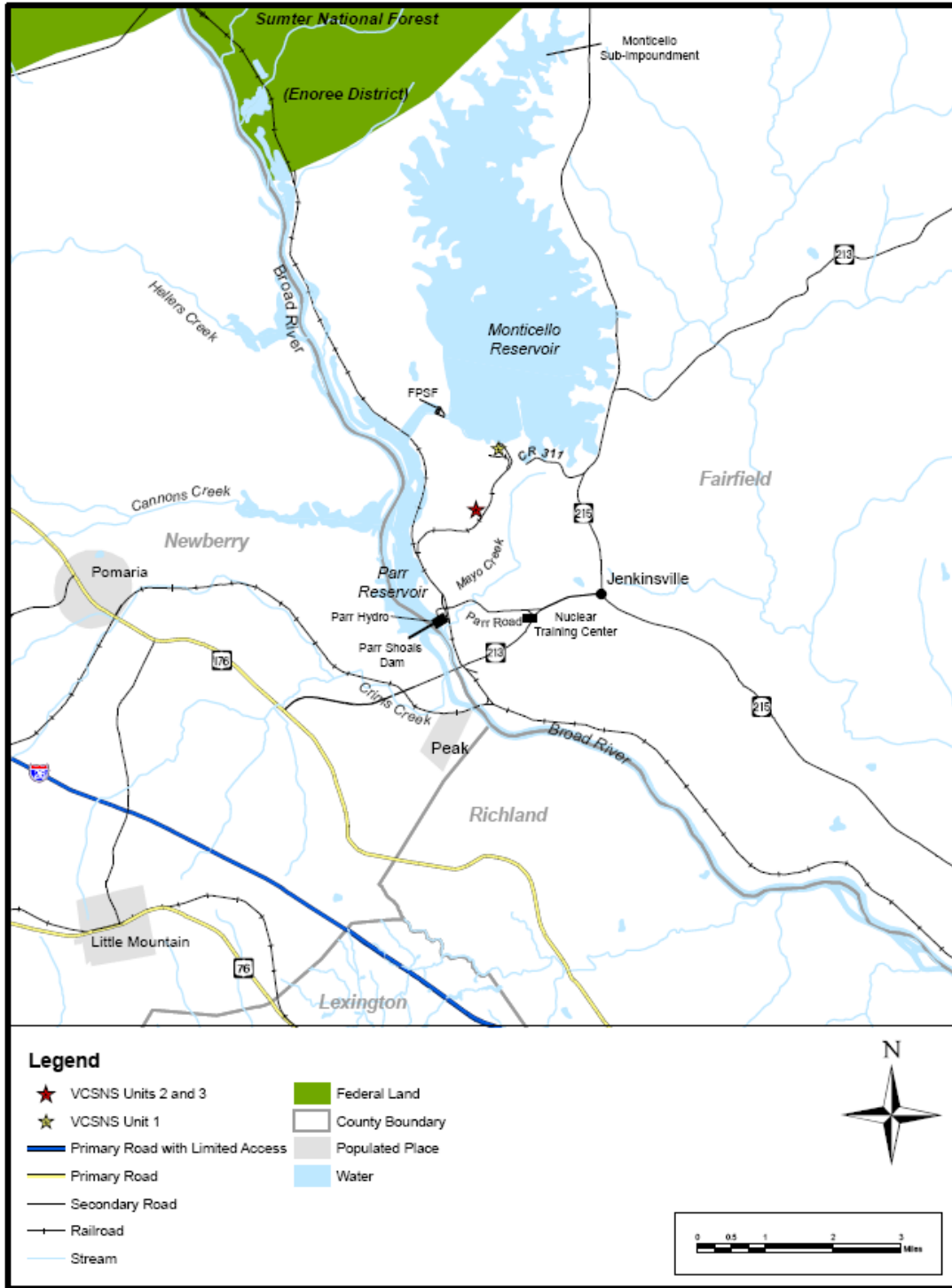


Figure 4: 6 mile radius

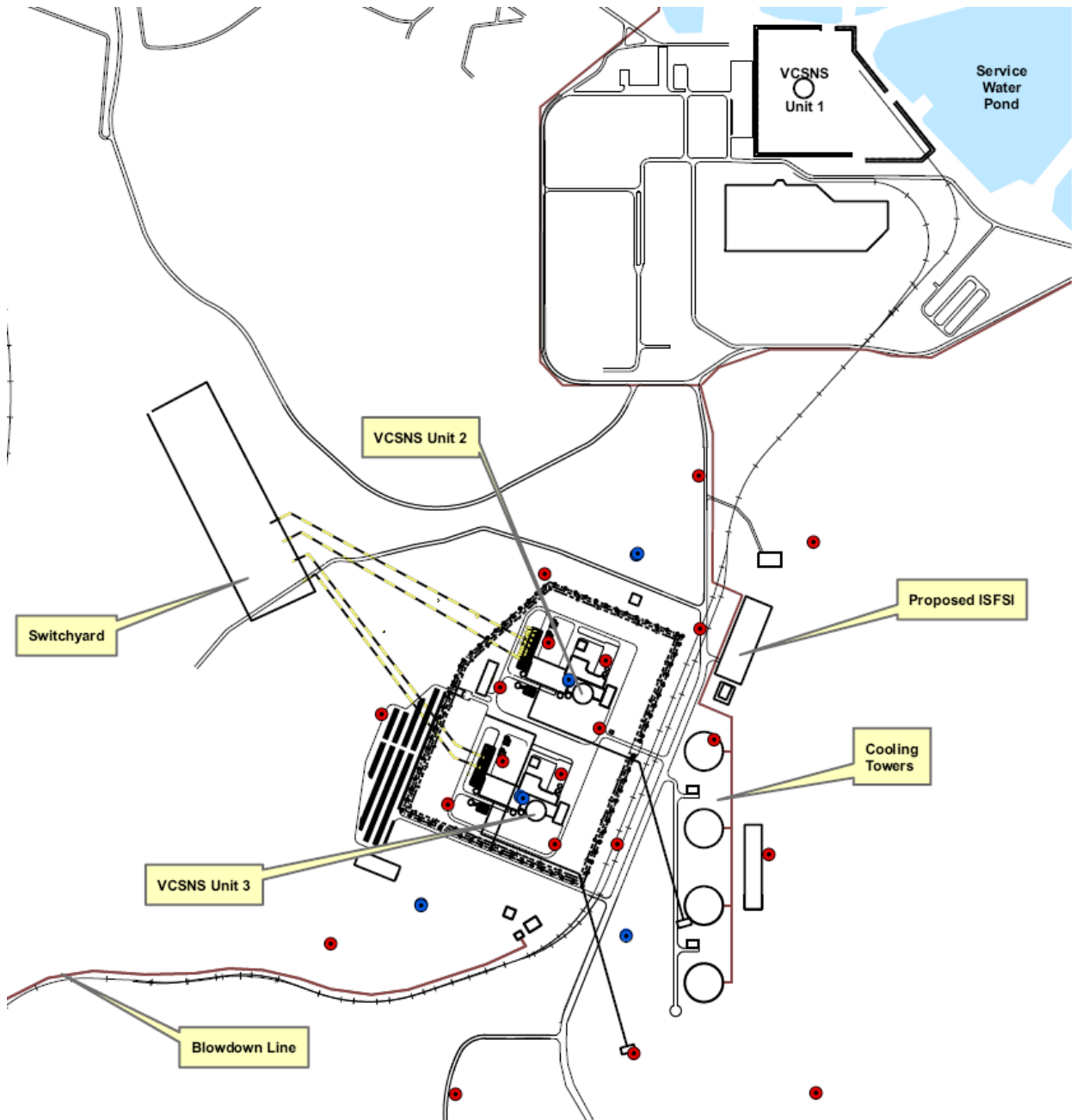


Figure 5: Site Layout

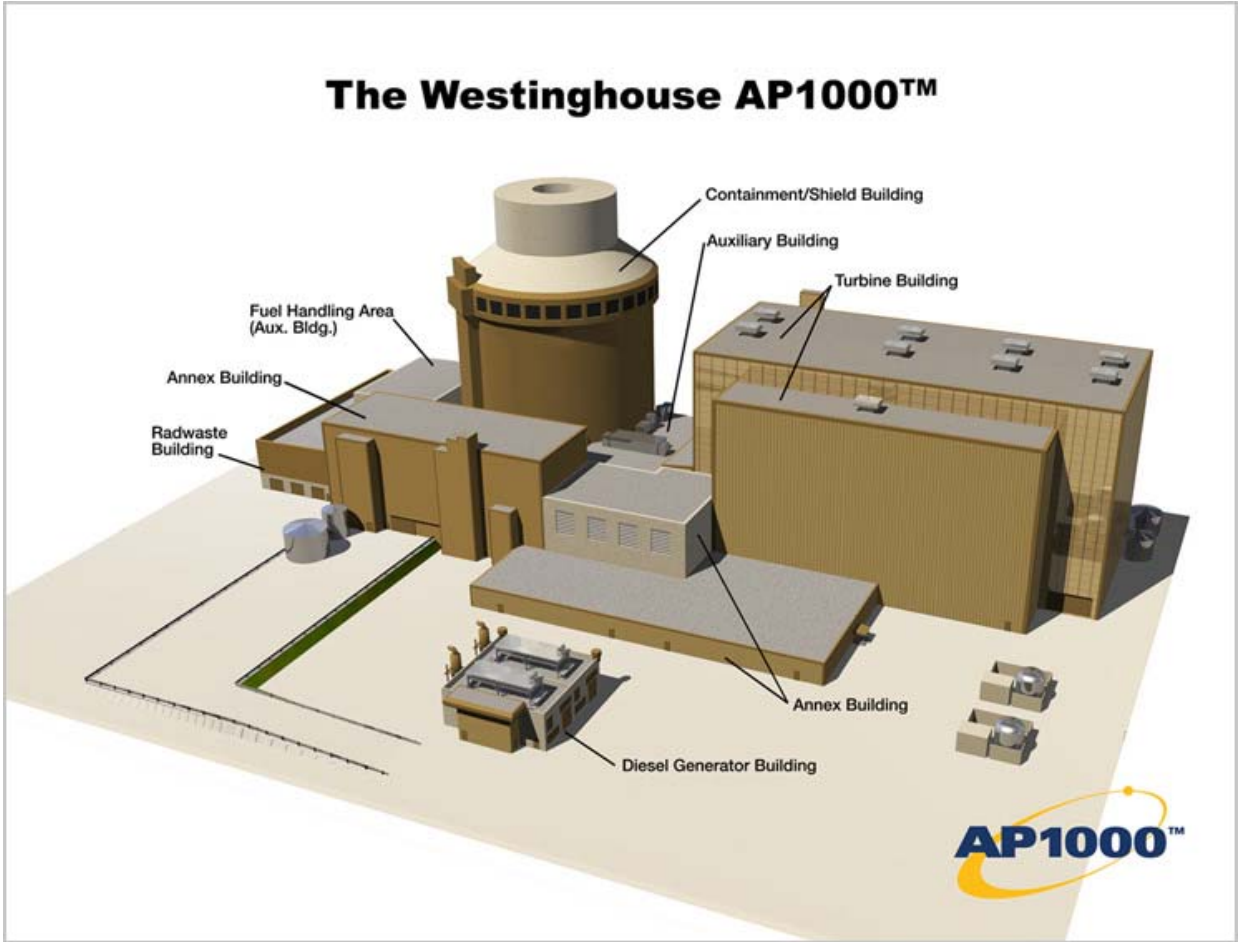


Figure 6: AP1000 Standard Plant Layout

EXHIBIT B

INFORMATION CONCERNING WESTINGHOUSE ELECTRIC COMPANY, LLC AND STONE & WEBSTER, INC.

Combined Application of South Carolina Electric & Gas Company for a Certificate of Environmental Compatibility and Public Convenience and Necessity and for a Base Load Review Order Public Service Commission Docket No. 2008-196-E

1. INTRODUCTION

This exhibit provides an overview of the terms of the qualifications of the members of the consortium of Westinghouse Electric Company, LLC and Stone & Webster, Inc., which will undertake to supply two Westinghouse AP1000 Advanced Passive Safety Power Plants (AP1000) units to be constructed as the as V. C. Summer Nuclear Station (VCSNS) Units 2 & 3 (the Units or the Facilities).

2. QUALIFICATIONS OF WESTINGHOUSE AND STONE & WEBSTER

South Carolina Electric & Gas Company (SCE&G) has signed an Engineering, Procurement and Construction Agreement (EPC Contract) with consortium of Westinghouse Electric Company, LLC (Westinghouse) and Stone & Webster, Inc. (Stone & Webster) to construct two AP1000 units in Jenkinsville, South Carolina. Westinghouse, a group company of Toshiba Corporation, is the world's pioneering nuclear power company and is a leading international supplier of nuclear plant products and technologies to utilities. Westinghouse supplied the world's first pressurized water reactor (PWR) in 1957 in Shippingport, Pennsylvania. and supplied the Parr Experimental Nuclear Plant reactor which SCE&G and a consortium of other Southeastern utilities operate adjacent to the VCSNS site in the mid-1960s. Today, Westinghouse technology is the basis for approximately one-half of the world's operating nuclear plants, including 60 percent of those in the United States. In addition, the Westinghouse AP1000 PWR technology has held design certification from the U.S. Nuclear Regulatory Commission (NRC) since 2004.

Stone & Webster, a wholly owned subsidiary of the Shaw Group, Inc. (Shaw), designed and constructed the first commercial reactor at Shippingport, Pennsylvania, and was integral in the licensing, design, engineering, and construction of numerous commercial nuclear power plants including Beaver Valley, Fitzpatrick, Nine Mile Point, North Anna, Maine Yankee, Shoreham, Surry, Millstone, and River Bend. Stone & Webster also participated in construction of the Parr Experimental Nuclear Plant.

A Fortune 500 company with nearly \$6 billion in annual revenues, Shaw is headquartered in Baton Rouge, Louisiana, and employs approximately 27,000 people at its offices and operations in North America, South America, Europe, the Middle East and the Asia-Pacific region. Westinghouse and Shaw have worked together over the past two and a half years in a teaming arrangement to develop a complete AP1000 Nuclear Plant standard "package" approach

which is being offered to the utility industry. Both companies have made substantial, internally funded financial and technical investments in the engineering and design, construction sequence and modularization planning of the AP1000 Nuclear Plant. In addition, Westinghouse is providing the design of the nuclear steam supply systems for four AP1000 units to be built in China, and both Westinghouse and Stone & Webster have signed an EPC Contract to build two units for Southern Company outside of Augusta, Georgia.

The purchase of Westinghouse by Toshiba Corporation and Shaw was completed in 2006. Toshiba Corporation is the majority owner and Shaw holds a 20% interest. Toshiba America, Inc. (TAI) is the holding company for one of the nation's leading group of advanced technology companies, with approximately 8,000 employees in the U.S. Toshiba Corporation is a multinational conglomerate manufacturing company, headquartered in Tokyo, Japan. The company's businesses are in high technology, electrical engineering and electronics fields. The company is the world's ninth largest integrated manufacturer of electric and electronic equipment, with some 161,000 employees worldwide and consolidated annual sales of over US\$53 billion. This consortium of companies provides a teaming agreement that offers utilities combined engineering, design, procurement, and construction services through a single entity for building an AP1000 Nuclear Power Plant.

The Westinghouse/Stone & Webster team has developed a detailed implementation plan and infrastructure for implementing AP1000 projects. A joint implementation plan, integrated EPC schedule and cost estimate have been developed. Stone & Webster has participated in the design of the “modular” construction approach with Westinghouse over the past several years and together the team has developed the processes and procedures for modular construction of AP1000 plants. Using this method, sections of the plant are fabricated in centralized manufacturing facilities remote to the site and transported to the site for final assembly. Modular assembly is a key means that will be employed to reduce the construction cost and optimize the construction schedule for VCSNS Units 2 & 3.

3. BASIS FOR SELECTING WESTINGHOUSE AND STONE & WEBSTER

Both technical and financial evaluations of new nuclear technologies, performed initially in 2005 and again in 2007, resulted in and confirmed the selection of the Westinghouse AP1000 design as the preferred technology for VCSNS Units 2 & 3. The evaluations were conducted as a structured process, assessing various attributes of the reviewed technologies for the reactor power plant consortiums. The technical evaluation appraised attributes in ten key areas weighted as follows: Cost Escalation Risk 20%, Ability to Meet Schedule/Commercial Operation Date 15%, Design Features/Technology 15%, Licensing 15%, Confidence in Ability to Execute 10%, Security 5%, Engineering Completeness 5%, Supply Chain 5%, Construction/Testing Duration 5%, Fleet Collaboration 5%. The cost evaluation criteria were Projected Operations & Maintenance Cost \$/MWh, and Overnight Construction Cost \$/KWe. Both the technical and financial evaluations indicated the AP1000 technology to be the preferred choice.

Reactor technologies and vendors evaluated were the: 1) Westinghouse - AP1000, 2) General Electric - Economic Simplified Boiling Water Reactor (ESBWR), and 3)

UniStar/AREVA - Evolutionary Power Reactor (EPR). The AP1000 and ESBWR are passive safety designs with the EPR being an active safety design. The AP1000 had significant strengths in the key attributes of:

Licensing

Under the procedures laid out in 10CFR Part 52 by the NRC, the first step for licensing of new nuclear technologies is the issuance of a Final Design Approval, which constitutes an approval of the design of the principal systems for a type of unit. At the time of selection, out of the ESBWR, EPR and AP1000 technologies, only the AP1000 had received NRC Final Design Approval. The AP1000 Safety Evaluation Report and the Final Design Approval provided the NRC's basis for concluding the AP1000 meets all of the applicable regulatory requirements and can be referenced by an applicant for a Combined Operating License (COL). At the time of selection, the ESBWR was in review by the NRC for Final Design Approval and the EPR technology had yet to be submitted to the NRC for Final Design Approval.

The second stage in the NRC review and licensing process is the licensing of a specific plant, including all systems, facilities and processes, through the COL process. The NRC expressed a preference that the potential owners and designer of each reactor technology collaborate in the filing of a lead reference plant COL Application (COLA), which is the Bellefonte Units No. 3 & No. 4 for the AP1000 technology. For follow-on power plants of like technology, the NRC will allow reference to the standard sections of the reference plant COLA. The NRC would then only have to review site specific deviations from the reference plant COLA. The utilization of a reference plant COLA minimizes multiple NRC reviews of the same material, thus more effectively utilizing resources and optimizing the review schedule without degradation of the quality of the safety review.

The COLA for the TVA Bellefonte Units 3 & 4 (AP1000 Reference Plant) was submitted for NRC review on October 30, 2007. Through its participation in NuStart Development, LLC, SCE&G and other entities considering building AP1000 units are assisting in coordinating the AP1000 Reference Plant licensing.

Ability to Meet the Desired Schedule/Commercial Operation Date

The Westinghouse/Stone & Webster consortium contractually committed to the 2016 Commercial Operation Date for VCSNS Unit 2. The AP1000 Design Control Document having received NRC Final Design Approval for reference in the COLA minimizes risk of issues arising during NRC COLA review that would negatively impact the 2016 commercial operation date schedule.

Cost

The construction and operation of two AP1000 nuclear power plants was calculated to have the lowest capital cost \$/KWe was evaluated to be competitive with the other reactor technologies on long term Operations & Maintenance cost \$/MWe, and was determined to be the

best site utilization for MWe (two medium sized units vs. one large unit). Considering licensing and design status along with industry/utility collaborative effort/support, the AP1000 was judged to be the best technology for cost containment during design and construction.

Collaboration Opportunities

Given the knowledge of industry activities and direction, including NuStart and the regional utilities with which SCE&G has long standing cooperative relationships, the greatest opportunity for collaboration from initial licensing activities through long term operation of the stations is with the AP1000 technology. It is likely that a number of AP1000 units will be built in the Southeast which will maximize the benefits of potential collaborative efforts.

Technology Preferences

The Pressurized Water Reactor technology was favored over the Boiling Water Reactor technology because of the knowledge base and experience at the current operating V. C. Summer Nuclear Station. Additionally, the synergistic effects achievable at a multiple unit station will be maximized by use of similar and familiar technologies.

As discussed in **Exhibit A**, above, the AP1000 provides dramatic simplifications in the plant design which has been achieved with the use of passive safety features. With the passive safety design, there are significantly fewer pumps, valves, and piping; therefore, regulatory programs, inspection requirements, maintenance programs, and procurement can be correspondingly simplified. The smaller, simpler, designs with significantly fewer components provide a clear advantage over active plant designs in regard to long term Operations & Maintenance considerations.

The AP1000 power output of 1117MWe is optimally sized to match the Company's projected load growth profile. It minimizes excess reserve margin and allows for the optimized addition of a second unit in sequence with the first to match system load growth. In addition, the interruption of power from a single unit of a twin AP1000 configuration would have a less dramatic impact on the Company's generation capacity and transmission grid stability than would the interruption of power from a single unit of roughly twice the size.

Based on results of the initial 2005 reactor vendor evaluation and the review of that evaluation performed in 2007, SCE&G determined that the AP1000 power plant technology supplied through the Westinghouse/Stone & Webster consortium was the preferred option to meet its need for new nuclear generation.

EXHIBIT C

INFORMATION CONCERNING THE ENGINEERING, PROCUREMENT AND CONSTRUCTION AGREEMENT (EPC CONTRACT)

Combined Application of South Carolina Electric & Gas Company for a Certificate of Environmental Compatibility and Public Convenience and Necessity and for a Base Load Review Order Public Service Commission Docket No. 2008-196-E

1. INTRODUCTION

This **Exhibit C** provides an overview of the terms of the Engineering, Procurement and Construction Agreement (EPC Contract) related to two Westinghouse AP1000 Advanced Passive Safety Power Plants units to be constructed as the V. C. Summer Nuclear Station (VCSNS) Units 2 & 3 (the Units or the Facility). The costs and payments related to construction of the Units are set forth in **Exhibit F** to this Application.

2. TERMS OF THE EPC CONTRACT

Overview – South Carolina Electric & Gas Co., for itself, and as agent for the South Carolina Public Service Authority (Santee-Cooper), has finalized an EPC Contract with a consortium consisting of Westinghouse Electric Co., LLC (Westinghouse) and Stone & Webster, Inc., a subsidiary of the Shaw Group, Inc. (Shaw). Westinghouse is engaged in the business of designing, developing and supplying commercial nuclear facilities and has developed a pressurized water nuclear power plant known as the AP1000. Shaw is engaged in the business of designing and constructing industrial and power generation facilities. Under the EPC Contract, Westinghouse and Shaw will provide the design, engineering, procurement and installation of the equipment and materials, and construction and testing of two nuclear units based on the AP1000 design. (Except as otherwise indicated, capitalized items indicate defined terms in the EPC Contract.)

Schedule – The proposed Guaranteed Substantial Completion Dates for the two nuclear units are April 1, 2016 and January 1, 2019, respectively. On March 31, 2008, SCE&G issued a Limited Authorization to Proceed to Westinghouse/Stone & Webster for the procurement of major equipment in order to meet this schedule. SCE&G and Westinghouse/Stone & Webster signed the EPC Contract on May 23, 2008. The Combined Construction and Operating License Application (COLA) was submitted to the NRC on March 31, 2008 with an anticipated NRC review time of three and one half years. NRC approval of the COLA is required prior to the initiation of nuclear safety related construction. In the meantime, non-nuclear safety related construction will proceed upon the approval of the Public Service Commission and other permitting agencies.

Performance Standards – The EPC Contract requires Westinghouse/Stone & Webster to perform and complete its obligations under the EPC Contract in accordance with applicable laws, the terms of the EPC Contract, Industry Codes and Standards and Good Industry Practices, all of which are explicitly defined in the EPC Contract. Westinghouse/Stone & Webster is solely responsible for all construction means, methods, techniques, sequences, procedures, safety and quality assurance and quality control programs in connection with the performance of the Westinghouse/Stone & Webster work. Project Work and financial reporting are clearly defined in the EPC Contract in order to maintain an ongoing awareness of the project status and communicate accurate work schedules and financial projections. The EPC Contract provides a detailed Scope of Work/Supply and Division of Responsibilities for Westinghouse/Stone & Webster and SCE&G.

Subcontractors and Vendors – Westinghouse/Stone & Webster has the right to have portions of the work performed by subcontractors who are identified in the EPC Contract and subject to SCE&G’s review. Westinghouse/Stone & Webster is responsible for the actions and omissions of all subcontractors. Westinghouse/Stone & Webster is responsible for all equipment meeting the requirements of the EPC Contract. For Major Equipment, specifically identified in the EPC Contract, Westinghouse/Stone & Webster contractually commits that it shall in good faith fully and promptly perform and observe all of the agreements, terms, covenants and conditions required to be performed by Westinghouse/Stone & Webster under any material provision of a subcontract for Major Equipment (a “Major Equipment Purchase Order”). The EPC Contract includes specific controls for Major Equipment Vendors, to include shop schedule reservation, default notices and follow-action required and termination protection requirements for SCE&G.

Permits and Licenses – SCE&G is responsible for obtaining, maintaining and paying for SCE&G permits and licenses, to include the Combined Operating License (“COLA”) for the Units. Westinghouse/Stone & Webster is committed to providing support in this effort including support for Nuclear Regulatory Commission (“NRC”) inspections, tests and analysis in accordance with the NRC’s Integrated Tests, Acceptance and Approval Criteria (ITAAC).

Quality Assurance – Westinghouse and Stone & Webster has sole responsibility for the quality assurance and quality control of their work. Westinghouse/Stone & Webster will utilize a Project Quality Assurance Program (PQAP) that meets the Code of Federal Regulations and that is accepted by SCE&G. The PQAP and associated policies and procedures shall address Westinghouse/Stone & Webster’s Scope of Work, including, without limitation, systems, structures and components in a manner consistent with their classification with respect to their importance to nuclear safety or their importance to the capacity, operability and reliability of the Facility as classified in the AP1000 Nuclear Power Plant Design Control Document. The EPC Contract (Article 5) also includes requirements for subcontractor quality assurance, reporting of defects and noncompliance, quality control and inspection activities, access and auditing at Westinghouse/Stone & Webster and subcontractor facilities, witness and hold points for

manufacturing and fabrication of equipment and SCE&G's right to inspect and stop work. SCE&G shall have reasonable access to the work at the Westinghouse and Stone & Webster's facilities and their subcontractor's facilities for observation and inspection, including auditing of activities for conformance with the requirements of the PQAP.

Pricing – The contract price and price adjustment provisions are detailed in the EPC Contract. The pricing model used to develop the definitive Contract Price is consistent with Westinghouse/Stone & Webster's Scope of Work and project schedule referenced in the EPC Contract. The EPC Contract provides detail for each of the pricing categories, to include Equipment, Transportation, Home Office, Construction – Direct, Construction – Indirect, QA , Other and Cost Contingency. The pricing model also includes three categories of pricing elements, to include Fixed or Firm (Fixed/Firm) Price, Target Price and Time and Material (T/M) Price.

Under Fixed/Firm pricing, fixed elements have no associated escalation rates. Firm elements are subject to definitively established escalation percentages, such that final price depends only upon the timing of completion of the work, or are subject to reported inflation indices. See **Exhibit I** to this Application for more information concerning the indices and escalation factors that apply to each of the categories of work under the EPC Contract.

The Fixed or Firm Price applies to the portions of Westinghouse/Stone & Webster's Scope of Work in a number of areas that are well defined, including Equipment, work with detailed scope descriptions and clear division of responsibilities, interfaces with other work, scheduling, manufacturing and procurement. Fixed/Firm price billing will be established with a series of progress and milestone payments based on project schedule milestones or equipment milestones.

Westinghouse/Stone & Webster and SCE&G's goal in the negotiations has been to maximize the Firm/Fixed portion of the pricing. More than fifty percent (50%) of the total EPC Contract cost is subject to Fixed/Firm pricing. An additional percentage of the contract cost projection may be converted to Fixed/Firm in future months upon acceptance by SCE&G of Fixed/Firm quotes from Westinghouse/Stone & Webster which Westinghouse/Stone & Webster has agreed to provide for aspects of the work. The precise percentages in question are provided on the Confidential Version of **Exhibit I**.

The Target Price applies to the portions of Westinghouse/Stone & Webster's Scope of Work that are not as well defined or would involve higher levels of price and schedule risk and contingency. As part of the Target Price approach, a payment structure is applied that provides incentive to complete the Target Price portion of work under the Established Target Price by having SCE&G and Westinghouse/Stone & Webster share proportionally the savings. Conversely, the Westinghouse/Stone & Webster profit is reduced in proportion to the degree to which the Target Price Work exceeds the Established Target Price with a profit minimum

established. A projected payment plan based on the work to be performed and with itemized projected costs will be provided to SCE&G prior to the commencement of Target Price Work.

The Time and Materials (T&M) portion of the Contract Price covers the portions of Westinghouse/Stone & Webster's Scope of Work which cannot be fully defined at this time for any number of reasons. T/M rates agreed upon by SCE&G and Westinghouse/Stone & Webster are included in the EPC Contract. The Westinghouse/Stone & Webster Sales, General & Administrative Costs (SGA) are clearly shown in the Contract Pricing and open for SCE&G's review. Estimated costs for these aspects of the work are included in the Contract price and is reflected on in the capital cost projections contained in **Exhibit F**.

Values for certain Westinghouse/Stone & Webster contingencies and risks have been negotiated and are set forth in **Exhibit I** to this Application. The price adjustment indices will include negotiated indices as well as industry and market based indices.

Change Orders – Article 9 of the EPC Contract specifies the criteria for authorized Changes in the work. Westinghouse/Stone & Webster is entitled to a Change Order under certain designated conditions, which specified conditions include, without limitation, such things as a Change in Law or an Uncontrollable Circumstance defined in Article 1 of the EPC Contract. The EPC Contract specifies those types of Changes that require SCE&G approval. Furthermore, SCE&G can request a Change if it does not adversely impact nuclear or industrial safety and if it results in a financial benefit to SCE&G. The Change Order process is outlined in Article 9, to include the information required with the Change Order submittal, review and agreement by Westinghouse/Stone & Webster and SCE&G, payment schedule and the handling of disputes.

Testing and Acceptance – Article 11 of the EPC Contract gives the scope of testing at the site, to include Construction and Installation Tests, Preoperational Tests, Startup Tests and the Performance Test. The adequacy of construction and installation of components and systems will be verified by construction inspection and installation tests. During the construction period, Westinghouse/Stone & Webster erects the structure, installs plant equipment and performs construction verification and inspection tests. All of these activities are executed, controlled and documented in accordance with Westinghouse/Stone & Webster approved procedures. On a system basis, completion of this phase of the test program demonstrates that the system is ready for Preoperational Testing.

The system will be turned over to the Joint Test Working Group consisting of Westinghouse/Stone & Webster and SCE&G personnel, under the direction of Westinghouse/Stone & Webster. Preoperational Tests will be performed to demonstrate that the components and systems perform in accordance with selected design requirements so that initial Nuclear Fuel loading, initial criticality and subsequent power operation can be safely undertaken in accordance with requirements of the Law and applicable Government Approvals.

Upon the successful completion of the Preoperational Test for a system or facility and provided that the other criteria specified in Article 12 of the EPC Contract are satisfied, Mechanical Completion for that system will be declared. At that point, Westinghouse/Stone & Webster will turn over care, custody and control of that system to SCE&G. Once all systems and facilities are turned over SCE&G, mechanical completion of the Plant is achieved.

The Startup Test program, which remains under the direction of the Joint Test Working Group, will begin with initial Nuclear Fuel loading and progresses through heat-up, criticality and power operations, completing the nuclear operating objectives and verifications specified in the EPC Contract. Upon successful completion of the Startup Tests, the Performance Test will be run to determine whether the Unit meets the Net Unit Electrical Output Guarantee. This test for the Unit will be conducted during a period of continuous operation of one hundred hours. Upon successful completion of the Performance Test, Substantial Completion will be declared.

Final Completion of a Unit shall be deemed to have occurred upon the completion of the Final Completion Punch List and other work required under the EPC Contract with the exception of obligations under the Warranties. Article 13 of the EPC Contract specifies the liquidated damages that Westinghouse/Stone & Webster will be responsible for due to Substantial Completion schedule delays and/or unsatisfactory Performance Test results.

Warranties – As required by Article 14 of the EPC Contract, Westinghouse/Stone & Webster warrants that the Equipment and each Unit shall be free from defects in design, workmanship and material and shall conform to the design specifications and drawings, and changes thereto, prepared by Westinghouse/Stone & Webster or its subcontractors for the design, engineering and construction of the Facility. This section of the EPC Contract covers other requirements, to include warranty periods, remedy, warranty work deferral, services warranty, warranty of title and limitations and disclaimers.

Miscellaneous – The remaining articles of the EPC Contract cover the following: Insurance; Limitation of Liability; Liens; Proprietary Data; Environmental - Hazardous Materials; Title - Risk of Loss; Suspension and Termination; Safety - Incident Reporting; Qualifications and Protection of Assigned Personnel (including provisions for fitness for duty and security screening; training to environmental, OSHA, NRC and other applicable Laws, NRC Whistleblower Provision and respirator protection); Records and Audits; Taxes; Dispute Resolution; Notices; Assignment; Waiver; Modification (pertains to EPC Contract provisions); Survival; Transfer; Governing Law - Waiver of Jury Trial - Certain Federal Laws; Relationship of Owner (SCE&G) and Contractor (Westinghouse/Stone & Webster); Third Party Beneficiaries; Representations and Warranties; and Miscellaneous Provisions.

EXHIBIT D

INFORMATION CONCERNING OTHER SUPPLIERS AND CONTRACTORS

Combined Application of South Carolina Electric & Gas Company for a Certificate of Environmental Compatibility and Public Convenience and Necessity and for a Base Load Review Order Public Service Commission Docket No. 2008-196-E

1. INTRODUCTION

This **Exhibit D** provides information concerning the supplier for major components of the proposed V. C. Summer Nuclear Station (VCSNS) Units 2 & 3 and the basis for selection of suppliers and quality control by the principal nuclear systems contractor, Westinghouse Electric Company, LLC (Westinghouse). Under the terms of the Engineering, Procurement and Construction Agreement (EPC Contract) for Units 2 & 3, certain suppliers of major components have been selected for the project, and other suppliers of major components will be selected from pre-approved lists. All suppliers will be screened and required to comply with Westinghouse's quality assurance program, as described below.

2. QUALITY ASSURANCE PROGRAM

Overview – Westinghouse uses a comprehensive evaluation methodology to select vendors to supply components for the AP1000 Advanced Passive Safety Power Plant (AP1000). Important factors influencing a decision to source a supplier for a component include: the supplier being listed on the Westinghouse qualified suppliers list, the supplier having a standing relationship with Westinghouse for the supply of the specific type of component, and the supplier having a proven track record of successfully supplying quality components to the nuclear industry. Once it has been determined that a vendor satisfies these criteria, Westinghouse conducts an onsite audit to perform an in-person assessment of the potential supplier's facilities, capabilities, and programs. The qualification process is further described below.

The Westinghouse Quality Management System – The Westinghouse Quality Management System (QMS) requires that suppliers of safety-related items and services be evaluated and approved by Westinghouse Quality prior to the supplier's designation as a qualified supplier, or placement of a purchase order to the supplier. Active qualified suppliers of safety-related items, including suppliers accredited under national industry codes such as ASME, are evaluated annually and audited, except under special circumstances, every three years. Westinghouse Quality determines the need to conduct supplier audits based on an evaluation that is conducted in accordance with ASME NQA-1. Documentation of the acceptability of suppliers is maintained and identifies the items and/or services to be supplied.

Suppliers are evaluated and selected considering the historical quality performance data and audit/survey reports to the extent applicable to the item or service being procured. Westinghouse has developed the procedures for the evaluation and selection of suppliers as well

as monitoring of supplier performance in accordance with quality requirements including the following:

- Westinghouse procedures specify the requirements for the Supplier's quality assurance program which must be established and implemented for the supply of the designated items and services. These documents specify the administrative requirements applicable to Westinghouse witness/hold points.
- Westinghouse procedures detail the requirements for the Supplier's quality system used in design, testing and manufacture of nuclear safety-related equipment, system and components. The requirements are derived from the basic and supplemental requirements of ASME NQA-1, Part 1, 1994 Edition. This procedure implements the requirements of PQR-1 for safety-related items.
- The Westinghouse procedure for Supplier Qualification and Evaluation establishes the requirements for evaluation and qualification of Suppliers and for conducting a quality program audit. Results of evaluations and audits performed under this procedure are documented in a Supplier Audit/Evaluation Survey (SAES) form. Suppliers that have been determined to be qualified, in accordance with Westinghouse procedures are placed on the Qualified Suppliers List for the item or service evaluated. Qualified Suppliers are to be audited or surveyed on a triennial basis, or more frequent if circumstances dictate.

For evaluation of Suppliers, Westinghouse may directly perform audits or, as member of the Nuclear Industry Assessment Committee (NIAC), evaluate audits performed by the NAIC's shared audit program. NIAC was formed in 1994 as an industry initiative to share the results of supplier audits. The NAIC Shared Audit Program is based on a standardized approach for the performance of supplier assessments, utilizing a standard assessment checklist approved by all member of the NIAC. The assessment checklist delineates those criteria of 10CFR50 Appendix B, ANSI N45.2, ASME NQA-1, ASME NCA-4000 and/or NCA-3800, which are applicable to nuclear suppliers for the item or service being supplied by the supplier. For suppliers that are ASME certificate holders, they may be placed on the Westinghouse Qualified Suppliers List based on their certificates and are then subsequently audited during the fabrication process.

3. DESIGNATED SUPPLIERS AND POTENTIAL SUPPLIERS

Table 1 contains a list of potential Westinghouse major component suppliers for the AP1000 units to be built as VCSNS. The table shows the suppliers that have been qualified by the above Westinghouse criteria, suppliers that will partake in the China AP1000 projects, suppliers that currently supply to operating US nuclear plants, and which suppliers have been visited by Westinghouse. The pages after Table 1 give brief descriptions of each major component vendor.

Reactor Vessel Head	Doosan Heavy Industries & Construction Company	X	X	X	X
Reactor Coolant Pumps	Curtiss-Wright/ Electro-Mechanical Corporation	X	X	X	X
Reactor Internals	Doosan Heavy Industries & Construction Company	X	X	X	X
	Major Tool & Machine, Inc				X
	Precision Custom Components				X
	Westinghouse Electric, LLC	X	X	X	X
Turbine Generator	Toshiba Corporation	X		X	
Transformers	Westinghouse Electric Supply Co.	X		X	X
Control Rod Drive Mechanism System	Curtiss-Wright/ Electro-Mechanical Corporation	X		X	X
Balance of Plant Pumps	Curtiss-Wright/ Electro-Mechanical Corporation	X		X	X
	Flowserve Corporation	X		X	X
	The Weir Group PLC	X			X
	KSB	X			X
Containment Air Baffle	Ansaldo Camozzi	X		X	X
	Chicago Bridge & Iron Company	X			
	Joseph Oat	X		X	X
Tanks	Ansaldo Camozzi	X		X	X
	IHI Corporation	X		X	X

Component Name	Vendor / Alternate Vendors	W Qualified Supplier	Supplier to China AP1000 Project	Supplier to Nuclear Fleet	Vendor Shop Visit by W SCM
Pressurizer	Ansaldo Camozzi	X		X	X
Reactor Coolant Piping	Tioga Pipe Supply Company	X		X	X
Containment Vessel	Ansaldo Camozzi	X		X	X
	Chicago Bridge & Iron Company	X			
	Northrop Grumman Newport News				
Diesel Generators	Caterpillar Inc.			X	
Variable Frequency Drive Unit for Reactor Coolant Pumps	Siemens Corporation	X	X	X	X
Cooling Towers	SPX Cooling Technologies, Inc. (Marley)			X	
	Zurn Company (Wilkins)			X	

Ansaldo Camozzi

The Camozzi Group is actively involved in the Energy sector through Ansaldo Camozzi Energy Special Components; the company has a long tradition in the nuclear special components market, having manufactured large-sized, high-complexity components that have met the highest quality standards and are in operation in various nuclear plants world-wide for many years.

The Energy Division develops its activity at the premises in Milan, Italy with more than 200 people and on a covered area of 16,000 sqm. Ansaldo Camozzi Nuclear & Energy Special Components is an ASME N stamp holder since 1973. It was the first company outside the USA to obtain the N and NPT ASME stamp. In 1977, Ansaldo Camozzi Nuclear & Energy Special Components was listed in NRC White Book. During 1994 the Certification of the Quality System according to ISO 9001 was obtained.

On December 21, 2007 – Ansaldo Camozzi Energy Special Components S.p.A. (Camozzi Group), and Mangiarotti S.p.A. announced the signature of a co-operation agreement aimed at strengthening the ability to take on the nuclear market demands, by guaranteeing the availability of a coastal plant for the optimization of the transportation and logistics of large-size components.

The synergy between Ansaldo Camozzi Nuclear & Energy Special Components S.p.A. and Mangiarotti S.p.A. is expected to lead to the employment of a total of 400 highly specialized technicians and to a production area of over 50,000 sqm, equipped with the best production equipment for the reference markets.

Quality programs and certifications (e.g. ASME N and NPT stamps) from Ansaldo Camozzi will apply to the new entity which will be known as "Mangiarotti Nuclear S.p.A."

This acquisition will require Westinghouse Quality review and approval prior to contract/fabrication implementation.

Caterpillar Inc.

Caterpillar, Inc. manufactures and sells construction and mining equipment, diesel and natural gas engines, and industrial gas turbines worldwide. Its machinery business includes the design, manufacture, marketing, and sale of construction, mining, and forestry machinery. The company also engages in the design, manufacture, remanufacture, maintenance, and services of rail-related products. The company's engines business comprises the design, manufacture, marketing, and sale of engines for its machinery; electric power generation systems; on-highway vehicles and locomotives; and marine, petroleum, construction, industrial, agricultural, and other applications, as well as related parts. The company was founded in 1925 under the name Caterpillar Tractor Co. and changed its name to Caterpillar, Inc. in 1986. Caterpillar, Inc. is headquartered in Peoria, Illinois. 2007 revenues at Caterpillar Inc. totaled \$42.0 billion.

Chicago Bridge & Iron Company

Chicago Bridge & Iron is a global specialty engineering and construction company of approximately 17,000 employees that design, construct, and maintain liquefied natural gas storage tanks; petrochemical and gas processing plants; steel pressure vessels for high-temperature and nuclear containment applications; and heat transfer equipment. CB&I has built approximately 75% of the nuclear containment vessels that exist in the United States today. The company also serves other large corporations in the hydrocarbon, energy, power generation, and petrochemical industries. Although it does about one-third of its business in Europe, Middle East, and Africa, almost half of CB&I's revenues are made in North America. CB&I U.S. Operations are headquartered in the Woodlands, TX, with offices in several geographically convenient locations in the U.S.

Curtiss-Wright Electro-Mechanical Corporation

Curtiss-Wright Electro-Mechanical Corporation (CW-EMD) is a leader in the supply of critical function, electro-mechanical products. It is headquartered in Cheswick, PA. Innovative system and product solutions are based in the legacy of over 100 years of Westinghouse technology. More than 50 years ago, CW-EMD built critical function pumps for the first nuclear powered submarine, the USS Nautilus. Today, CW-EMD continues to develop, design and supply advanced electro-mechanical solutions for the US Navy, including the Navy's most advanced motors, generators and secondary propulsors. Within the nuclear utility industry, CW-EMD supplies reactor coolant pumps, seals, motors and control rod drive mechanisms.

Doosan Heavy Industries & Construction Company

The Doosan Group, with a history spanning over 112 years, is the oldest and one of the largest conglomerates in Korea. Doosan currently has 21 subsidiary companies in Korea and 112 overseas branch corporations in 33 countries. With a total of over 35,000 employees (20,000 in Korea and 15,000 overseas), in addition to a worldwide network of over 3,700 dealers, Doosan continues to implement a truly diversified global management strategy.

Doosan's annual financial performance has improved from US \$2.3 billion in 2000 to US \$19.8 billion in 2007 for an annual average growth rate of 34%. In addition, Doosan posted a 25% annual growth in operating profits, rising from US \$191.5 million in 2000 to US \$1.75 billion in 2007. Today, the Doosan Group has become one of the top ten enterprises in Korea.

ENSA-Equipos Nucleares, S.A.

ENSA specializes in manufacturing high quality heavy components for nuclear plants and industrial facilities that require high standards of quality. The main product line is that of heavy components of the Nuclear Steam Supply System of nuclear reactors. Other lines include smaller items for nuclear reactors, components for storage and transport of spent fuel assemblies and the design, supply and installation of equipment for radioactive waste treatment. ENSA is located in Maliaño (Cantabria), on the northern

coast of Spain. The plant started operations at the end of 1976. ENSA is accredited as an ASME Section III qualified supplier and holder of an N-stamp. They are also certified to meet the requirements of ISO 9001.

Flowserve

Flowserve Corporation develops, manufactures, and sells precision-engineered flow control equipment, as well as provides a range of aftermarket equipment services. It operates in three divisions: Flowserve Pump, Flow Control, and Flow Solutions. The Flowserve Pump division offers engineered and industrial pumps and pump systems; submersible motors; replacement parts; and related equipment primarily to industrial markets. The Flow Control division designs, manufactures, and distributes industrial valve products. The Flow Solutions division offers mechanical seals, sealing systems, and parts principally to process industries. Flowserve Corporation operates in North America, Europe, Middle East, Africa, Asia Pacific, and Latin America. The company was founded in 1912 and is headquartered in Irving, Texas. Flowserve has more than 14,000 employees in more than 56 countries, and its revenues were \$3.8B in 2007.

IHI Corporation

IHI provides the primary equipment for hydroelectric, thermal and nuclear power systems. IHI is one of the three major Japanese manufacturers of boilers, which are a core element in thermal power plants. In addition to supplying boilers to many domestic Japanese power companies, IHI has been supplying power generation boilers to Australia, Southeast Asia, China, the Middle East and North America, including ten 660,000 kW boilers to Australia. IHI has manufactured and constructed ultra-large scale boilers of over 1 million kW capacities for power generation. In nuclear power generation, IHI supplies main components such as reactor pressure vessels, primary containment vessels and piping systems. IHI employees 6,864 people and had net sales of \$11.7 billion in 2007. IHI is headquartered in Tokyo, Japan and has a small ownership interest in Westinghouse Electric Company, LLC.

Joseph Oat

Joseph Oat Corporation is located on the Delaware River in Camden, New Jersey, directly across the river from Philadelphia, Pennsylvania. It is a privately owned company with approximately 117 employees. Joseph Oat Corporation's plant consists of 140,000 sq. ft. of manufacturing space which allows them to fabricate vessels up to 20 ft. (6.1 M) in diameter, weighing up to 400,000 lbs. (182,000 kg.) and having an overall length of up to 200 ft. (60.8M) in one piece

Joseph Oat Corporation produces heat exchangers, pressure vessels, and specialty products for general industrial applications and for the power industry as well as nuclear and fossil fueled power, geothermal, cogeneration and other power applications. The company fabricates products from virtually all metals used in construction, including carbon and low alloy steels, austenitic and ferritic grades of stainless steel, duplex steels, nickel alloys, copper and copper alloys, titanium and titanium alloys, zirconium, and

tantalum. The company also fabricates stainless clad, nickel alloy clad, and titanium and zirconium clad materials.

Joseph Oat holds the following Certificates of Authorization from ASME: N (N-1488), NA (N-1577), NPT (N-1489), NS (N-3014), R, U (Cert. # 184) U2 (Cert. # 27842), and S (Cert. # 25723). Most equipment the company produces is designed and fabricated in accordance with ASME Code standards, including ASME Section I, Section III (Class 1, 2, and 3), and Section VIII Div 1 and 2. They are ISO Certified 9001: 2000.

The Joseph Oat Corporation has previous Westinghouse experience of more than \$20 million in sales.

KSB

The KSB Group is one of the leading producers of pumps, valves and related systems. KSB has 14,000 employees around the world in building services, industry and water utilities, the energy sector and mining. KSB is increasingly a service partner and provides complete hydraulic systems for water supply and drainage. KSB has more than 30 manufacturing sites in 19 countries.

KSB supplies a full range of pumps, valves, motors, actuators and systems for building or upgrading power stations and district heating systems. These devices help manage boiler feed water, condensate, cooling water and coolant systems. The KSB Group operates in over 100 countries, with sales companies, offices, agencies and 32 manufacturing sites. KSB complies with rules of the American Society of Mechanical Engineers (ASME) and other international certification bodies. In 2007, KSB had \$2.5 billion in sales revenue. KSB is headquartered in Frankenthal, Germany.

Major Tool & Machine, Inc.

Major Tool & Machine, Inc is engineering, fabrication, and machining services company, with over 60 years of experience, serving the aerospace, defense, launch vehicle, power generation and transportation markets. Major Tool & Machine's main facility is located in Indianapolis, Indiana. Major Tools & Machine holds the following Certificates of Authorization from ASME: N, NA, NPT and NS Stamps.

Northrop Grumman Newport News

For more than a century, Northrop Grumman Newport News has designed, built, overhauled and repaired a wide variety of ships for the U.S. Navy and commercial customers. Today, Newport News is the nation's sole designer, builder and refueler of nuclear-powered aircraft carriers and one of only two companies capable of designing and building nuclear-powered submarines. The company also provides after-market services for a wide array of naval and commercial vessels, and in November 2001, became a sector of Northrop Grumman Corporation.

With facilities located on more than 550 acres along two miles of waterfront in Newport News, Virginia, the Newport News sector employs more than 21,000 people, many of whom are third and fourth generation shipbuilders.

Precision Custom Components

Precision Custom Components is a manufacturer of custom fabricated pressure vessels, reactors, casks, and heavy walled components requiring highly specialized machining, welding, and/or fabrication. PCC maintains full in-house capabilities, providing services for Engineering, Drafting, Inspection, Non-Destructive Testing, Metallurgical Testing, and Welding Development. PCC's flexible 250,000 square feet manufacturing facility has 280 employees is located on 11 acres in York, Pennsylvania. The company has sales revenue between \$25 million and \$49.9 million yearly. Precision Custom Components quality system programs meets or exceeds ASME Section III, Division 1 & 3, ASME Section VIII, Division 1, 2, & 3, ASME Section III Ferrous & New Ferrous Material Organization, 10CFR50 Appendix B, 10CFR71 Subpart H, 10CFR72, subpart G, 10CFR21, and ISO 9001 requirements. In addition, they hold ASME N, NS, NPT, U, U2, U3, and R stamps.

Siemens Corporation

Siemens Energy and Automation, founded in 1847, provides complete electrical, engineering and automation solutions through a commitment to innovative engineering that goes back more than 161 years.

Siemens AG is headquartered in Munich, Germany and employs more than 413,000 professionals at Siemens-affiliated companies worldwide. Siemens 2007 revenues totaled \$118.59 billion. Siemens AG operates as electronics and electrical engineering Company worldwide with operations in IT solutions, automation, drives, industrial solutions and services, building technology, power generation, power transmission and distribution, transportation systems, medical solutions, lighting and financial services.

SPX Cooling Technologies, Inc.

SPX is the leading full-line, full-service cooling tower and air-cooled condenser manufacturer. The companies that formed SPX Cooling Technologies were founded more than 100 years ago and have more than 250 global patents in the power generation, industrial, refrigeration, and HVAC markets. SPX's corporate headquarters is located in Overland Park, Kansas.

With more than 150 offices, subsidiaries, and partners worldwide, they have the global reach and local services necessary to deliver solutions. SPX Cooling Technologies is a unit of SPX Corporation, a global provider of technical products and systems, industrial products, flow technology, cooling technologies and service solutions.

The Weir Group PLC

The Weir Group PLC, together with its subsidiaries, provides specialized mechanical engineering solutions worldwide. It operates in three segments: Engineering Products; Engineering Services; and Defense, Nuclear, and Gas. The Engineering Products segment includes its minerals, clear liquid, and valves and controls operations. Its minerals

operations include the design and manufacture of pumps, valves, hydro-cyclones, and wear resistant linings for the mining and mineral processing, power sector, and general industries. The clear liquid operations involve the design, manufacture, and service of engineered pumps and fluid handling systems for oil and gas, power generation, water and waste water, hydrocarbon processing, and general industrial projects. The valves and controls operations include the development, manufacture, and supply of valves and controls for the power generation, oil and gas, and general industrial markets. The company was founded in 1871 and is headquartered in Glasgow, United Kingdom. Weir employs approximately 8,000 people worldwide. The Weir Group PLC grew revenues were \$2.1B in 2007.

Tioga Pipe Supply Company

For over 60 years Tioga has been a top quality material solutions supplier of industrial pipe, fittings, flanges and related products for the Global Power Generation, Nuclear Power Generation, Oil Refining, Gas & Chemical Processing & U.S. Military Shipbuilding. Tioga is headquartered in Philadelphia, PA. Tioga is the longest continuous supplier to have a Nuclear Quality Assurance Program. Tioga has continuously maintained a ASME Nuclear Certificate since 1982. Tioga has been audited by NUPIC and NIAC that meets the complex requirements of ASME Section III, 10CFR50 Appendix B, N45.2, NQA-1, and CAN3-Z299 SERIES.

Toshiba

Toshiba Corporation is a multinational group of manufacturing company, headquartered in Tokyo, Japan. The company's businesses are in high technology, electrical engineering and electronics fields. The company is the world's 9th largest integrated manufacturer of electric and electronic equipment. Toshiba was established in 1875 by Hisashige Tanaka. Toshiba has over 190,000 employees and assets in excess of \$50 billion.

Wilkins, a Zurn Company

Wilkins, a Zurn Company, has been supplying quality water control products to the marketplace since 1906. Products include backflow preventers, pressure regulators, and a variety of other support products. Wilkins has 162,000 square foot manufacturing facility in Paso Robles, CA, with over 200 employees and is now part of the Rexnord family of companies.

EXHIBIT E

ANTICIPATED CONSTRUCTION SCHEDULE

**Combined Application of South Carolina Electric & Gas
Company for a Certificate of Environmental Compatibility and Public Convenience and
Necessity and for a Base Load Review Order
Public Service Commission Docket No. 2008-196-E**

1. INTRODUCTION

This **Exhibit E** sets forth the current projected milestones under the EPC Contract that are proposed for use of the Office of Regulatory Staff in evaluating the progress of construction of VCSNS Units 2 and 3. These dates are subject to the schedule contingency requested in the Application.

This schedule is based on the generic schedule for Westinghouse AP1000 reactor construction which does not include project and site specific requirements. Certain activities such as the clearing, grubbing and grading at the site will need to commence earlier than listed here for reasons related to specific conditions at the VCSNS site (*i.e.*, the need to complete the site rail line relocation in advance of VCSNS Unit 1 Outage 18).

V. C. SUMMER PROJECT MILESTONES

Year	Quarter	Milestone
2008	2	08-2Q-1 Approve Engineering, Procurement and Construction Agreement. 08-2Q-2 Issue Purchase Orders to nuclear component fabricators for Units 2 and 3 Containment Vessels, Passive Residual Heat Removal Heat Exchangers, Accumulator Tanks, Core Makeup Tanks, Squib Valves, Steam Generators, Reactor Coolant Pumps, Pressurizer Vessels, Reactor Coolant Loop Hot Leg A Piping, Reactor Vessel Internals, Reactor Vessels, Reactor Integrated Head Packages, Control Rod Drive Mechanisms and Nuclear Island structural CA20 Modules.
2008	3	08-3Q-1 Start site specific and balance of plant detailed design. 08-3Q-2 Issue PO and submit payment to fabricator via Westinghouse for Units 2 and 3 Simulators. 08-3Q-3 Issue final Purchase Orders and submit payments to fabricators via Westinghouse for Units 2 and 3 Steam Generators, Reactor Vessel Internals and Reactor Vessels. 08-3Q-4 Issue Purchase Order and submit payment via Westinghouse to fabricator for Units 2 and 3 Transformers.
2008	4	08-4Q-1 Start clearing, grubbing and grading. 08-4Q-2 Issue final Purchase Orders and submit payments to fabricators via Westinghouse for Units 2 and 3 Core Makeup Tanks, Accumulator Tanks, Pressurizers, Reactor Coolant Loop Piping, Integrated Head Packages, Control Rod Drive Mechanisms and Passive Residual Heat Removal Heat Exchangers.

2009	1	<p>09-1Q-1 Start Parr Road intersection work.</p> <p>09-1Q-2 Issue final Purchase Order and submit payment via Westinghouse to fabricator for Units 2 and 3 Reactor Coolant Pumps.</p> <p>09-1Q-3 Issue Purchase Order for Long Lead Material and submit payment via Westinghouse to fabricator for Units 2 and 3 Integrated Head Packages.</p> <p>09-1Q-4 Submit partial payment to Westinghouse for Design Finalization.</p>
2009	2	<p>09-2Q-1 Start site development.</p> <p>09-2Q-2 Issue Purchase Orders and submit payments via Westinghouse for Units 2 and 3 Turbine/Generators and Main Transformers.</p> <p>09-2Q-3 Receive Units 2 and 3 Core Makeup Tank material at fabricator.</p> <p>09-2Q-4 Submit partial payment to Westinghouse for Design Finalization.</p>
2009	3	<p>09-3Q-1 Issue Purchase Order and submit payment via Westinghouse for Unit 2 Turbine Generator Condenser material.</p> <p>09-3Q-2 Submit payments to fabricators via Westinghouse for Units 2 and 3 Reactor Coolant Pumps and Passive Residual Heat Removal Heat Exchangers.</p> <p>09-3Q-3 Submit partial payment to Westinghouse for Design Finalization.</p>
2009	4	<p>09-4Q-1 Start erection of construction buildings, to include craft facilities for personnel, tools and equipment; first aid facilities; field offices for site management and support personnel; temporary warehouses; and construction hiring office.</p> <p>09-4Q-2 Receive Unit 2 Reactor Vessel flange nozzle shell forging at fabricator.</p> <p>09-4Q-3 Submit partial payment to Westinghouse for Design Finalization.</p> <p>09-4Q-4 Issue Purchase Order and submit payment via Westinghouse to fabricator for Units 2 and 3 Radiation Monitoring Systems.</p>
2010	1	<p>10-1Q-1 Receive Unit 2 Reactor Vessel Internals core shroud material at the fabricator.</p> <p>10-1Q-2 Payment to fabricator via Westinghouse for Unit 2 Turbine/Generator Feedwater Heater material.</p> <p>10-1Q-2 Receive raw material at fabricator for Unit 2 Reactor Coolant Loop piping.</p>
2010	2	<p>10-2Q-1 Receive Unit 2 Reactor Vessel Internals upper guide tube Material at the fabricator.</p> <p>10-2Q-2 Submit payment to Westinghouse for the Unit 2 Control Rod Drive Mechanisms.</p> <p>10-2Q-3 Perform cladding on Unit 2 Pressurizer bottom head at fabricator.</p>

2010	3	<p>10-3Q-1 Start excavation and foundation work for the standard plant for Unit 2.</p> <p>10-3Q-2 Receive Unit 2 Steam Generator tube sheet forging at the fabricator.</p> <p>10-3Q-3 Complete Unit 2 Reactor Vessel outlet nozzle weld to flange at the fabricator.</p> <p>10-3Q-4 Start Unit 2 Condenser fabrication at the fabricator.</p>
2010	4	<p>10-4Q-1 Complete preparations for receiving the first module on site for Unit 2.</p> <p>10-4Q-2 Receive Unit 2 Steam Generator transition cone forging at the fabricator.</p> <p>10-4Q-3 Complete Unit 2 Reactor Coolant Pump casing fabrication.</p> <p>10-4Q-4 Complete machining, heat treatment and Nondestructive examination of Unit 2 Reactor Coolant Loop Hot Leg A piping at the fabricator.</p>
2011	1	<p>11-1Q-1 Complete Unit 2 hydrotests for Core Makeup Tanks.</p> <p>11-1Q-2 Issue Purchase Order and submit payment via Westinghouse to fabricator for Units 2 and 3 Polar Crane main hoist drums and wire rope.</p>
2011	2	<p>11-2Q-1 Receive Unit 3 Control Rod Drive Mechanism latch housing/rod travel housing material at the fabricator.</p> <p>11-2Q-2 Complete Unit 2 Condenser shipment preparation at the fabricator.</p>
2011	3	<p>11-3Q-1 Start placement of mud mat for Unit 2.</p> <p>11-3Q-2 Receive Unit 2 Steam Generator tubing at the fabricator.</p> <p>11-3Q-3 Complete upper head welding on Unit 2 Pressurizer at the fabricator.</p> <p>11-3Q-4 Complete Unit 3 Reactor Vessel closure head cladding at the fabricator.</p>
2011	4	<p>11-4Q-1 Begin Unit 2 first nuclear concrete placement.</p> <p>11-4Q-2 Complete fabrication of Unit 2 Reactor Coolant Pump stator core at the fabricator.</p> <p>11-4Q-3 Begin Unit 2 Reactor Vessel Internals welding of core shroud panel ring at the fabricator.</p> <p>11-4Q-4 Complete 1st Unit 2 Steam Generator tubing installation at the fabricator.</p> <p>11-4Q-5 Ship Unit 2 Reactor Coolant Loop pipe to site.</p> <p>11-4Q-6 Ship Unit 2 Control Rod Drive Mechanism to site.</p> <p>11-4Q-7 Complete weld for Unit 2 Pressurizer lower shell to head at the fabricator.</p> <p>11-4Q-8 Complete 2nd Steam Generator tubing installation for Unit 3 at the fabricator.</p> <p>11-4Q-9 Submit partial payment to Westinghouse for Design Finalization.</p>

2012	1	<p>12-1Q-1 Set module CA04 for Unit 2.</p> <p>12-1Q-2 Complete post weld heat treat of 2nd tubesheet for Unit 2 Passive Residual Heat Removal Heat Exchanger.</p> <p>12-1Q-3 Complete 1st tubesheet drilling for Unit 2 Passive Residual Heat Removal Heat Exchanger.</p> <p>12-1Q-4 Complete girder fabrication for Unit 2 Polar Crane.</p> <p>12-1Q-5 Complete preparations for Unit 3 Turbine Generator Condenser shipment.</p>
2012	2	<p>12-2Q-1 Set Containment Vessel ring #1 for Unit 2.</p> <p>12-2Q-2 Deliver Unit 2 Reactor Coolant Pump casings to the site.</p> <p>12-2Q-3 Complete Unit3 Reactor Coolant Pump stator core.</p> <p>12-2Q-4 Receive core shell forging for Unit 3 Reactor Vessel.</p> <p>12-2Q-5 Complete Unit 3 Pressurizer cladding on bottom head.</p>
2012	3	<p>12-3Q-1 Set Nuclear Island structural module CA03 for Unit 2.</p> <p>12-3Q-2 Complete 1st Unit 2 Squib Valve factory operational test .</p> <p>12-3Q-3 Complete Unit 3 Accumulator Tank hydrotest.</p> <p>12-3Q-4 Complete electrical panel assembly for Unit 2 Polar Crane.</p>
2012	4	<p>12-4Q-1 Start containment large bore pipe supports for Unit 2.</p> <p>12-4Q-2 Ship Unit 2 Reactor Integrated Head Package to site from fabricator.</p> <p>12-4Q-3 Complete Unit 2 Reactor Coolant Pump stator fabrication.</p> <p>12-4Q-4 Complete 2nd Unit 3 Steam Generator tubing installation at fabricator.</p> <p>12-4Q-5 Complete 1st Unit 2 Steam Generator hydrotest at fabricator.</p>
2013	1	<p>13-1Q-1 Start concrete fill of Nuclear Island structural modules CA01 and CA02 for Unit 2.</p> <p>13-1Q-2 Ship Unit 2 Passive Residual Heat Removal Heat Exchanger to site from fabricator.</p> <p>13-1Q-3 Complete Unit 2 Refueling Machine Assembly factory acceptance test.</p> <p>13-1Q-4 Ship Unit 2 Reactor Vessel Internals to site from fabricator.</p>

2013	2	<p>13-2Q-1 Set Unit 2 Containment Vessel ring #3.</p> <p>13-2Q-2 Ship Unit 2 Steam Generator to site from fabricator.</p> <p>13-2Q-3 Complete preparation for Unit 2 Turbine/Generator shipment from Toshiba fabrication facility.</p> <p>13-2Q-4 Complete Unit 3 Pressurizer hydrotest at fabricator.</p> <p>13-2Q-5 Ship Unit 2 Polar Crane to site.</p> <p>13-2Q-6 Receive Unit 2 Reactor Vessel on site from fabricator.</p>
2013	3	<p>13-3Q-1 Set Unit 2 Reactor Vessel.</p> <p>13-3Q-2 Weld Unit 3 Steam Generator tubesheet to channel head.</p> <p>13-3Q-3 Complete Unit 3 Reactor Coolant Pump final stator assembly at fabricator.</p> <p>13-3Q-4 Ship Unit 2 Reactor Coolant Pumps to site from fabricator.</p> <p>13-3Q-5 Place first nuclear concrete for Unit 3.</p>
2013	4	<p>13-4Q-1 Set Unit 2 Steam Generator.</p> <p>13-4Q-2 Preparations complete for shipment of Unit 2 Main Transformers.</p> <p>13-4Q-3 Complete Unit 3 Steam Generator hydrotest at fabricator.</p> <p>13-4Q-4 Set Unit 2 Containment Vessel Bottom Head on basemat legs.</p>
2014	1	<p>14-1Q-1 Set Unit 2 Pressurizer Vessel.</p> <p>14-1Q-2 Complete Unit 3 Reactor Coolant Pump Factory Acceptance Test at fabricator.</p> <p>14-1Q-3 Ship Unit 3 Reactor Vessel Internals to site from fabricator.</p> <p>14-1Q-4 Issue Purchase Order and submit payment to fabricator via Westinghouse for Unit 3 Main Transformers.</p>
2014	2	<p>14-2Q-1 Complete welding of Unit 2 Passive Residual Heat Removal System piping.</p> <p>14-2Q-2 Ship Unit 3 Steam Generator to site from fabricator.</p> <p>14-2Q-3 Ship Unit 3 Refueling Machine Assembly to site.</p>
2014	3	<p>14-3Q-1 Set Unit 2 Polar Crane.</p> <p>14-3Q-2 Ship Unit 3 Reactor Coolant Pumps to site from fabricator.</p> <p>14-3Q-3 Complete shipment preparations for Unit 3 Main Transformers from fabricator.</p>
2014	4	<p>14-4Q-1 Ship last Unit 3 Spent Fuel Storage Rack module to site.</p>
2015	1	<p>15-1Q-1 Start electrical cable pulling in Unit 2 Auxiliary Building.</p> <p>15-1Q-2 Complete Unit 2 Reactor Coolant System cold hydro.</p>
2015	2	<p>15-2Q-1 Activate class 1E DC power in Unit 2 Auxiliary Building.</p>

		15-3Q-1 Complete Unit 2 hot functional test.
2015	3	15-3Q-2 Install Unit 3 ring 3 for containment vessel.
2015	4	15-4Q-1 Load Unit 2 nuclear fuel.
2016	1	16-1Q-1 Unit 2 Substantial Completion.
2016	2	16-2Q-1 Set Unit 3 Reactor Vessel.
2016	3	16-3Q-1 Set Unit 3 Steam Generator #2.
2016	4	16-4Q-1 Set Unit 3 Pressurizer Vessel.
2017	1	17-1Q-1 Complete welding of Unit 3 Passive Residual Heat Removal System piping.
2017	2	17-2Q-1 Set Unit 3 polar crane.
2017	3	17-3Q-1 Start Unit 3 Shield Building roof slab rebar placement.
2017	4	17-4Q-1 Start Unit 3 Auxiliary Building electrical cable pulling.
2018	1	18-1Q-1 Activate Unit 3 Auxiliary Building class 1E DC power.
		18-2Q-1 Complete Unit 3 Reactor Coolant System cold hydro.
2018	2	18-2Q-1 Complete Unit 3 hot functional test.
2018	3	18-3Q-1 Complete Unit 3 nuclear fuel load.
2018	4	18-4Q-1 Begin Unit 3 full power operation.
2019	2	19-1Q-1 Unit 3 Substantial Completion.

EXHIBIT F

ANTICIPATED COMPONENTS OF CAPITAL COSTS AND SCHEDULE

Combined Application of South Carolina Electric & Gas Company for a Certificate of Environmental Compatibility and Public Convenience and Necessity and for a Base Load Review Order Public Service Commission Docket No. 2008-196-E

1. INTRODUCTION

Chart A to this **Exhibit F** provides a summary of the anticipated components of capital cost and the forecasted schedule for incurring them as used by SCE&G in projecting the cash flows, construction work in progress balances, and other financial matters related to the construction of two Westinghouse AP1000 units as V. C. Summer Nuclear Station Units 2 & 3. These projections reflect the applicable inflation adjustments and indices as set forth in **Exhibit I** to this Application and are subject to the risk factors set forth in **Exhibit J** to this Application and to the cost and schedule contingencies requested in the Application. As set forth in the Application, SCE&G will update these projections periodically in its filings with the Office of Regulatory Staff to reflect the actual levels of inflation measured for past periods by the inflation factors and indices reflected in **Exhibit I** to this Application and to reflect any changes related to the contingencies requested in the Application. SCE&G will update the projections of capital costs for remaining future periods based on the same methodology reflected in this **Exhibit F**.

2. THE PUBLIC AND CONFIDENTIAL VERSIONS OF CHART A

Chart A to this **Exhibit F** is being filed in both a public and a confidential version. Both versions provide the full anticipated cost of the Units, year-by-year and in total, including all costs anticipated to be paid under the EPC Contract, all owner's costs and all transmission costs. The only difference between the two versions of the exhibits is the amount of detail given for EPC costs and Owner's costs.

Specifically, the confidential version differs from the public version in that it includes twelve rows of data not included on the non-confidential version. Those rows of data:

- A. Show the anticipated annual payments in 2007 dollars under the EPC Contract with Westinghouse/Stone & Webster broken out into the seven "EPC Categories" that are listed on **Exhibit I** to this Application;
- B. Show the estimated annual payments in 2007 dollars for the "Owner's Cost Categories: Project Target Estimates," that are listed on **Exhibit I** to this Application;
- C. Sum the unescalated project costs by and adjust the yearly sum by the applicable inflation factors, all consistent with the inflation factors listed on **Exhibit I** to this Application for the cost categories involved;

- D. Set forth the contingency amount applicable to each year's estimated construction costs in 2007 dollars, all consistent with the contingency factors listed on **Exhibit I** to this Application for the cost categories involved; and
- E. Adjusts the yearly contingency amount by the inflation factors applicable to the cost categories with which the contingencies are associated, all consistent with the inflation factors listed on **Exhibit I** to this Application.

The sum of these categories of cost data (EPC costs and Owner's costs) and the associated contingencies and inflation amounts equal the first row of data on the public version of **Chart A** to **Exhibit F**, "Plant Cost: Total Net Cash Flow."

SCE&G would emphasize that the public version of **Chart A** to this **Exhibit F** sets forth the full projected cost of the Facility. The public version of **Chart A** provides the specific year-by-year cost projections on which the Commission is asked to establish as the "approved capital cost estimate including specified contingencies" for the Facility, as required in S.C. Code Ann. §§ 58-33-275(A)(2) of the Code of Laws of South Carolina, 1976.

SCE&G is seeking confidential treatment of the data not included in the public version of **Chart A** to **Exhibit F** (the "Confidential Data"), because if disclosed in un-aggregated form, those data could allow competitors of Westinghouse/Stone & Webster to calculate specific prices being charged by Westinghouse/Stone & Webster under the EPC Contract, both in aggregate and for particular items or categories of items supplied. Westinghouse/Stone & Webster considers this pricing information to be proprietary information in the nature of a trade secret and has taken careful steps to maintain the confidentiality of this information. Westinghouse/Stone & Webster believes that public release of such data could injure Westinghouse/Stone & Webster commercially in its negotiations for the sale of other units.

SCE&G intends to make the Confidential Data available to parties who sign an appropriate confidentiality agreement.

EXHIBIT F, Chart A

Public VersionANTICIPATED CONSTRUCTION SCHEDULE

**Combined Application of South Carolina Electric & Gas Company for a
Certificate of Environmental Compatibility and Public Convenience and
Necessity and for a Base Load Review Order**

(Thousands of \$)

V.C. Summer Units 2 and 3 - Summary of SCE&G Capital Cost Components

<i>Plant Cost Categories</i>	<u>Total</u>	<u>2007</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>2012</u>	<u>2013</u>	<u>2014</u>	<u>2015</u>	<u>2016</u>	<u>2017</u>	<u>2018</u>
Fixed with Adjustment													
Firm with Fixed Adjustment A													
Firm with Fixed Adjustment B													
Firm with Indexed Adjustment													
Actual Craft Wages													
Non-Labor Costs													
Time & Materials													
Owners Costs													
Total Unescalated Project Costs													
Project Cost Escalation													
Contingency(2007 \$)													
Contingency Escalation													
Total Net Cash Flow	5,411,067	21,473	182,826	458,170	637,192	696,561	734,258	752,043	680,621	502,767	376,627	240,217	128,312
Transmission Projects													
Total Net Cash Flow	638,020	-	-	378	-	-	1,666	15,555	46,282	73,014	4,286	189,523	307,316
Total Project Cash Flow	6,049,087	21,473	182,826	458,548	637,192	696,561	735,924	767,598	726,903	575,781	380,913	429,740	435,628
Cumulative Project Cash Flow		21,473	204,299	662,847	1,300,039	1,996,600	2,732,524	3,500,122	4,227,025	4,802,806	5,183,719	5,613,459	6,049,087
AFUDC(Capitalized Interest)	264,289	645	5,204	17,292	24,459	31,461	34,135	34,466	33,650	28,726	13,395	17,577	23,279
Gross Construction	6,313,376	22,118	188,030	475,840	661,651	728,022	770,059	802,064	760,553	604,507	394,308	447,317	458,907
Construction Work in Process		22,118	210,148	685,988	1,347,639	2,075,661	2,845,720	3,647,784	4,408,337	5,012,844	5,407,152	5,854,469	6,313,376

Confidential

Notes:

AFUDC rate applied

5.52%

The AFUDC rate applied is the current SCE&G rate. AFUDC rates can vary with changes in market interest rates, SCE&G's embedded cost of capital, capitalization ratios, construction work in process, and SCE&G's short-term debt outstanding.

Public

EXHIBIT G
FORECAST NEED FOR ELECTRIC AND FUEL TYPE

**Combined Application of South Carolina Electric & Gas Company for a
Certificate of Environmental Compatibility and Public Convenience and
Necessity and for a Base Load Review Order
Public Service Commission Docket No. 2008-196-E**

1. INTRODUCTION

This **Exhibit G** shows the need of capacity and how SCE&G will meet its 12-18% reserve margin target over the next 15 years. Without the addition of any supply to its existing long term resources of 5,745 MWs, SCE&G's reserve margin would be below its target range currently and fall to 2.0% by 2016. With the addition of 614 MWs of nuclear capacity in 2016, the reserve margin will be 13.0% and with the addition of the second unit in 2019, 16.8%.

2. PROJECTED RESERVE MARGIN

Year	Firm Load (MW)	Reserve Margin Without Additions (%)	(MW)		Reserve Margin With Additions (%)
			One year Purchase	Capacity	
2008	5,181	10.9	100		12.8
2009	5,123	11.8	25	-19	12.3
2010	5,181	9.9	125	-34	12.3
2011	5,297	7.5	250		12.2
2012	5,416	5.1	375		12.0
2013	5,262	8.2	225		12.4
2014	5,367	6.1	325		12.1
2015	5,472	4.0	450		12.2
2016	5,582	2.0		614	13.0
2017	5,697	-0.1	75		12.0
2018	5,811	-2.0	225		12.4
2019	5,924	-3.9		614	16.8
2020	6,037	-5.7			14.6
2021	6,146	-7.4			12.6
2022	6,258	-9.0		93	12.1

3. EXISTING SUPPLY PORTFOLIO AND EXPANSION PLAN

The table on the following page shows SCE&G's existing supply portfolio and the next page shows the expansion plan.

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

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

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

EXHIBIT H

CONTRIBUTION TO SYSTEM EFFICIENCY AND FUEL TYPE

Combined Application of South Carolina Electric & Gas Company for a Certificate of Environmental Compatibility and Public Convenience and Necessity and for a Base Load Review Order Public Service Commission Docket No. 2008-196-E

1. INTRODUCTION

This **Exhibit H** provides information concerning the contribution that the proposed Virgil C. Summer Nuclear Station (VCSNS) Units 2 & 3 (the Facilities or Units) will make to the economy and reliability of the integrated electric system that serves the energy needs of SCE&G's customers and the people of the State of South Carolina. This exhibit also reviews various alternative sources of electric generation capacity and energy considered by SCE&G in choosing the proposed AP1000 Advanced Passive Safety Power Plants (AP1000) as the units to construct as VCSNS Units 2 & 3.

2. SYSTEM ECONOMY AND RELIABILITY

These nuclear facilities will serve system reliability because they will provide needed capacity as shown in **Exhibit G**. In addition SCE&G has more than twenty-five years experience operating a nuclear facility and has demonstrated its ability to operate a nuclear plant efficiently and reliably.

System economy is served by the addition of these nuclear facilities because:

- These nuclear facilities are the most economical form of generation to add under reasonable assumptions about the future.
- These nuclear facilities meet the Company's need for more base load capacity.
- These nuclear facilities are non-emitting resources and therefore serve to protect the environment while at the same time mitigating exposure to the cost of complying with future environmental regulations.
- These nuclear facilities support the need for fuel diversity in SCE&G's capacity mix.
- Renewable power, increased demand side management (DSM) and potential energy efficiency gains are not capable of replacing the need for more base load generation; however, they could fit nicely into the expansion plan by displacing some of the purchased power currently shown in the plan.

These matters are discussed in more detail below.

Regarding the Need for Base Load Capacity

The Company's need for base load capacity can be seen in the following table which shows the historical levels of base load capacity in SCE&G's resource mix, its current mix and the 2020 mix with and without these nuclear facilities. Base load capacity is defined as capacity which is intended to run at least 65-75% of the time in a given year. Historically on SCE&G's system only nuclear and coal capacity would meet this definition.

Percent of Base Load Capacity in Resource Portfolio				
1980	2000	Current	2020 with VCSNS Units 2 & 3	2020 Without VCSNS Units 2 & 3
68	74	56	63	45

As shown in the above table, SCE&G has maintained its base load capacity in the 68%-74% range historically. In part because of environmental pressures related to coal, SCE&G has added more gas capacity in recent years resulting in a 56% ratio of base load to total capacity which is low for our system. Clearly there is a need for additional base load capacity, that is, capacity that can generate energy at low cost.

This need for base load capacity is exacerbated by the age of SCE&G's existing base load plants. The table below shows the percent of base load capacity that is more than 40 years old currently and in 2020 with and without these nuclear facilities.

Percent of Base Load Capacity Over 40 Years Old			
2000	Current	2020 with VCSNS Units 2 & 3	2020 Without VCSNS Units 2 & 3
11	23	46	64

While no particular plant has been identified for retirement, the Company does expect to have to retire some capacity during the 40-year planning horizon evaluated in this filing.

Regarding Natural Gas Capacity

SCE&G has evaluated natural gas capacity as a potential economical alternative to these nuclear facilities. However as shown in the following table, adding significantly more gas capacity to the SCE&G system does not support the goal of fuel diversity and would subject SCE&G's customers to the volatility of the gas market at an unacceptable level.

% of Total Capacity	Current Mix	2020 with VCSNS Units 2 & 3	2020 Without VCSNS Units 2 & 3
Nuclear	11	27	9
Coal	43	37	37
Gas	30	24	42

In addition, the volume of gas that is required to replace the electrical output of these nuclear facilities is substantial and certainly would require investment in gas infrastructure.

The following table illustrates this point.

Illustration with Volume of Gas Equivalents	
2,234 MW Nuclear Output at 92% capacity factor	18,004.3 GWH
Equivalence in Millions of Dekatherms	127,900,000 DTs
Equivalence in Residential Customers	2,804,688 residences
Number of SCE&G Residential Customers 2007	273,000 residences
2007 Total SCE&G Gas LDC Sales	40,700,000 DTs

The following table compares the amount of annual emissions generated by the two nuclear plants compared to a similar amount of energy generated by gas.

Emissions	2,234 MWs of Nuclear	2,234 MWs of Natural Gas	
		Annually	60 Year Life
CO ₂	0	8,500,000 tons	510,000,000 tons
SO _x	0	55 tons	3,300 tons
NO _x	0	1,350 tons	81,000 tons

Regarding Renewable Power

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

As potentially valuable as renewable power may be in the future in South Carolina, it is important to keep in mind that it is not likely in the near future to approximate the amount of clean energy that can be produced by the two nuclear units described in this Application.

The following table provides some indication in terms of area of how much solar or wind power would be required.

Renewable Power: To Get Equivalent Energy As 2,234 MW Nuclear		
	Area	Description of Need to Generate 18,004 Million KWH
Solar	61,656 acres	10,276 MWs of solar panels using 6 acres of land per MW generating at a 20% capacity factor.
Wind	120,192 acres	2,284 off-shore wind turbines rated at 3 MWs each generating at a 30% capacity factor.

Since there are about 640 acres in a square mile, the area of 61,656 acres for solar is also 96.3 square miles and the area of 120,192 acres for wind is also 187.8 square miles. Furthermore, the required wind turbines must be given a one-quarter mile spacing for proper operation and so if placed off-shore would cover the length of the South Carolina coast line with three rows of turbines.

These proposed nuclear units also displace a significant amount of CO₂ that might otherwise have been emitted by a fossil plant. The following table shows how many trees would need to be planted to offset an equivalent amount of CO₂ on an annual basis.

Carbon Offsets: Using Equivalent Energy As 2,234 MW Nuclear			
Generation Source	CO ₂ Emitted in millions of Tons	Number of Trees in millions	Land Area in Acres
Coal	19.1	795	1,766,000
Gas	8.5	350	778,000

Note: A mature tree consumes 48 lbs of CO₂/year and about 450 trees require one acre of land.

Regarding Demand Side Management

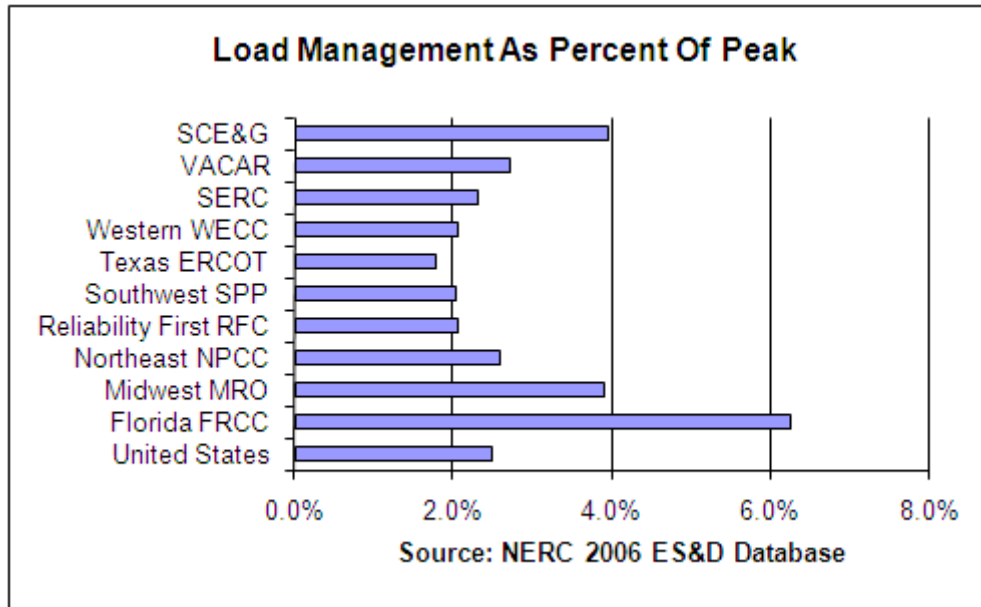
SCE&G has had a demand side management program in place for many years and has reported on it in its integrated resource plans which are currently filed annually. Below is an outline of these DSM programs.

1. Customer Information Programs
 - a. Annual Energy Campaign
 - b. Internet-Based Information and Use Analysis
2. Energy Conservation Programs
 - a. Value Visit Program
 - b. Energy Saver Rate
 - c. Seasonal Rates
3. Load Management Programs
 - a. Standby Generator Program
 - b. Interruptible Load Program
 - c. Real Time Pricing (RTP) Rate
 - d. Time of Use (TOU) Rates

A few measures of success of these programs are the following:

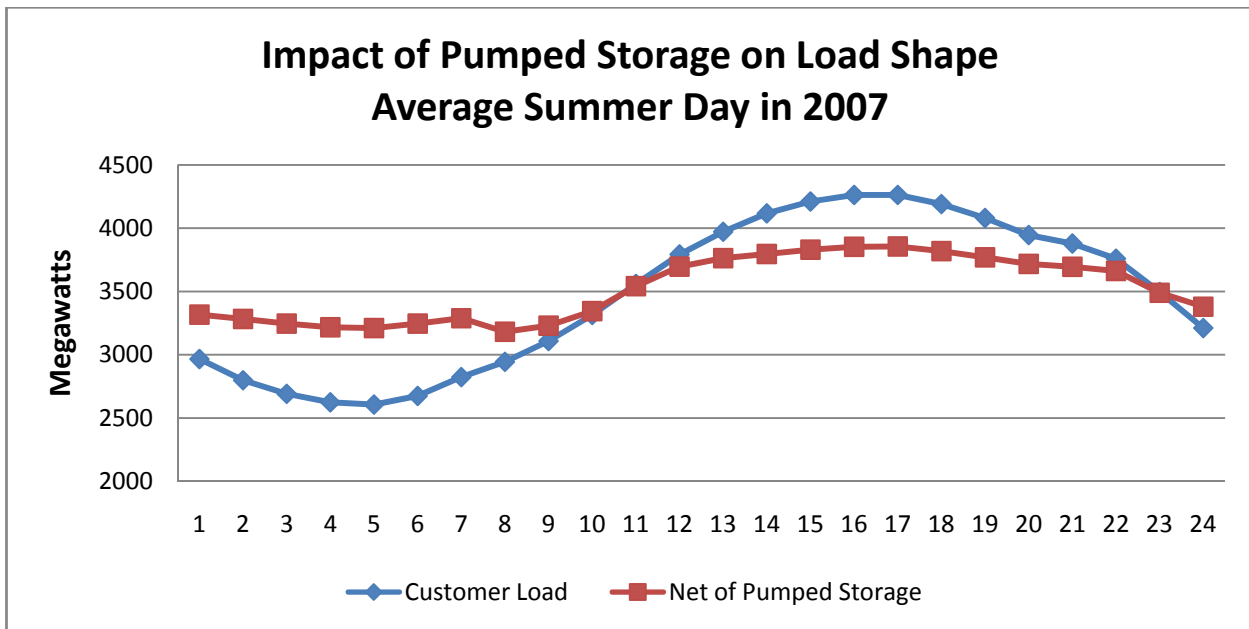
- Almost 200,000 customers are registered for internet access;
- Over 50,000 customers are on the Conservation Rate; and
- 20% of commercial sales are served on TOU or RTP rates.

Through our load management program, also known as demand response, we are able to avoid 234 MWs of capacity in the form of interruptible load and standby generation. To put this in perspective the following graph compares the magnitude of SCE&G's demand response program to other areas of the country.



As can be seen in the graph only Florida with its winter morning spikes in load has more demand side load management.

One other advantage that SCE&G has over many other utilities is its pumped storage facility in Fairfield County. The following graph shows the impact that this unit had on the system load shape during the summer of 2007.

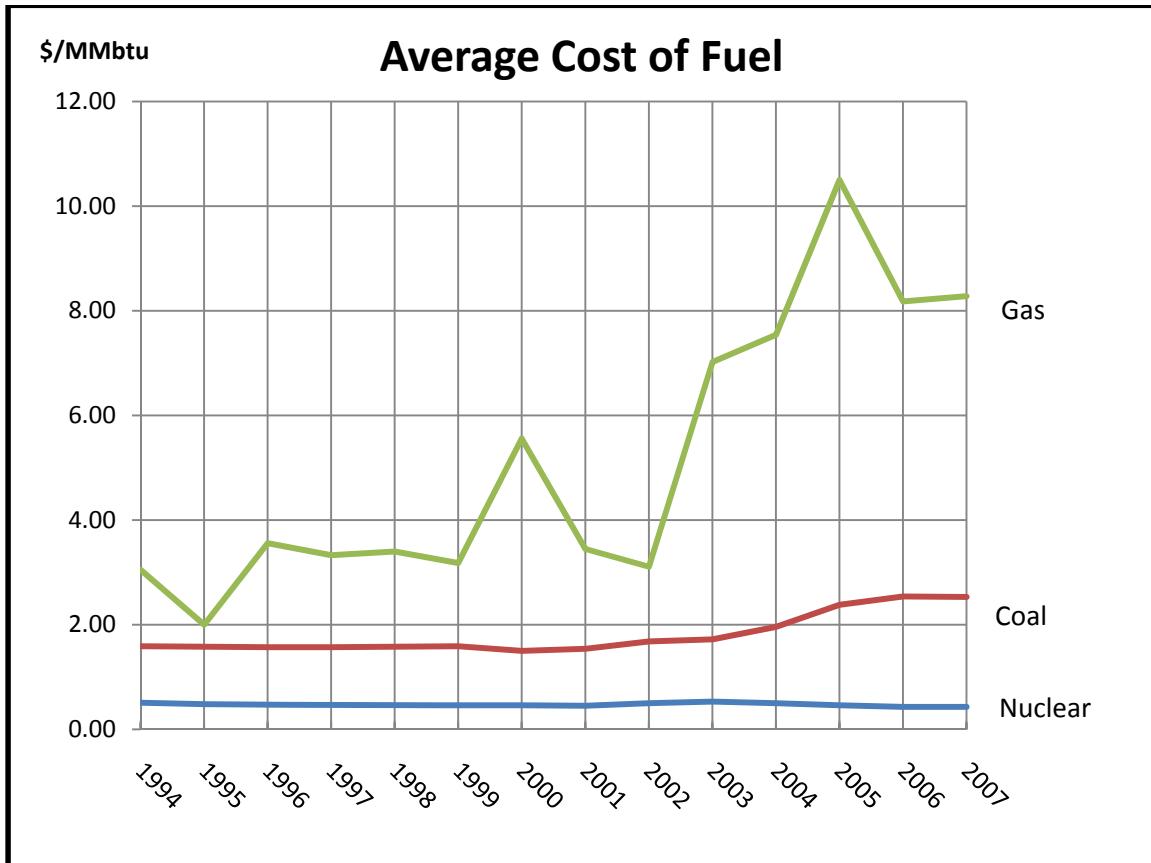


In effect the Fairfield Pumped Storage Plant shaved about 400MWs of load from the daily peak times of 2:00pm through 6:00pm and moved almost 4% of customer’s daily energy needs to the off peak. Clearly it would take a demand-side program of significant size to produce an equivalent peak load shifting effect on the system.

In addition to the above the company is taking steps to revise and expand its collection of DSM programs. A new department has been created within the Company this year with the mission of developing the best portfolio of DSM programs to serve SCE&G’s customers. As indicated above, DSM can play a useful and important role in reducing the demand for electricity on SCE&G’s system. Reasonably anticipated gains from DSM programs, while quite beneficial, would not displace the need for the new nuclear units.

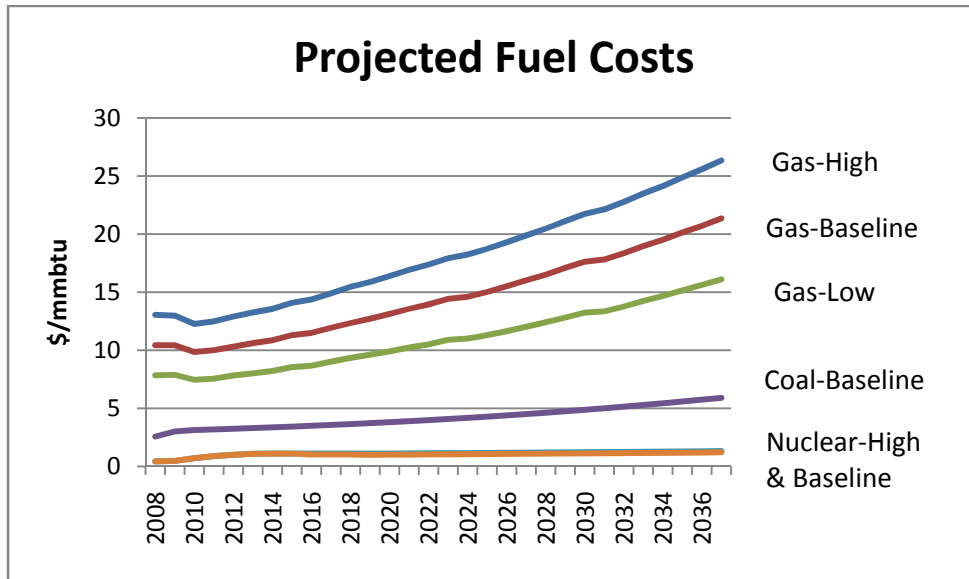
Regarding the Cost of Fuel

A significant advantage of nuclear power over gas in particular is the low cost and stability of the fuel price. The following graph shows SCE&G's experience with the cost of natural gas, coal and nuclear power over the last 15 years. The volatility of natural gas prices is shown in stark contrast to the relative stability of both coal and nuclear costs. The significant increase seen in natural gas prices especially in the last 5 years provides a strong argument for more fuel diversity away from reliance on natural gas generation.



Sources: Annual 10-K reports sent to Securities and Exchange Commission (nuclear, coal, gas:2001-2007)and FERC Form 1 annual reports (gas:1994-2000).

There were three scenarios of projected natural gas prices and two scenarios of nuclear prices constructed for the economic analysis that is discussed in the next section. The high and low gas price forecast is plus and minus 25% respectively of the baseline gas price forecast. The high nuclear price forecast is about 10% higher than the baseline forecast. Both nuclear price forecasts are purchased from the UX Consulting Company.



The high and baseline nuclear price forecasts are almost indistinguishable in the graph because of the scale required to include the higher gas prices even though the high nuclear price is almost 10% greater than the baseline price.

Regarding the Economic Analysis

Three expansion plan strategies are compared in an economic analysis using SCE&G’s baseline assumptions. These strategies are: the nuclear strategy, the gas strategy and the coal strategy. Both the nuclear and the coal strategies include gas capacity in the form of combustion turbine peaking units (CTs). The following table summarizes each planning strategy.

Strategy	Description
Nuclear Strategy	Add two nuclear units at 614MWs each in 2016 and 2019. Add 24 CTs at 93MWs each along with purchases throughout planning horizon as needed to maintain a 12% minimum reserve margin.
Gas Strategy	Add three combined cycle natural gas units at 520MWs each in 2016, 2024 and 2031. Add 20 CTs at 93MWs each along with purchases throughout planning horizon as needed to maintain a 12% minimum reserve margin.
Coal Strategy	Add two coal units at 600MWs each in 2016 and 2019. Add 24 CTs at 93MWs each along with purchases throughout planning horizon as needed to maintain a 12% minimum reserve margin.

The following table shows the results of an economic analysis using SCE&G’s baseline assumptions.

Levelized Present Value of Comparative Revenue Requirements (\$Million Per Year) – Shown as Change from the Nuclear Strategy	CO ₂ at \$15	CO ₂ at \$30	High Natural Gas Prices
1) Nuclear Strategy	-	-	-
2) Gas Strategy	15.1	125.2	68.5
3) Coal Strategy	94.9	267.5	99.0

Note: Revenue includes production costs for all plants and the capital costs of all new plants.

The nuclear strategy is seen to be the lowest cost option for SCE&G’s customers over the long run. Cost here is measured in terms of the impact on SCE&G’s customers’ bills and is quantified in the table as the levelized present value of comparative revenue requirements. Comparative revenue requirements refer to all fixed and variable production costs from all of the power plants plus the capital costs from all of the incremental power plants. Each of the three strategies includes enough capacity to meet a minimum reserve margin of 12%. For example, the “nuclear” strategy includes adding two nuclear units in 2016 and 2019 as well as sufficient purchases and peaking turbines to maintain the minimum reserve margin throughout the planning horizon of 40 years. Referring to this table, it can be seen that the gas strategy would cost SCE&G’s customers \$15.1 million per year more than the nuclear strategy if CO₂ costs \$15 per ton in 2012 and escalates at 7% per year. With CO₂ at \$30 per ton, the cost advantage of nuclear would be \$125.2 million per year. A higher natural gas price with CO₂ at \$15 per ton shows a nuclear cost advantage of \$68.5 million per year.

The following table shows the results from scenarios in which assumptions unfavorable to the nuclear strategy were made. For example, if uranium fuel prices follow a high track, the nuclear strategy still has a positive advantage over the gas strategy by \$13.2 million per year but if natural gas prices follow a low track, then the gas strategy has the advantage over nuclear by \$44.9 million per year. Additionally, if there is no legislation imposing additional costs on CO₂ emissions, the gas strategy has an \$86.5 million advantage over nuclear. However while higher uranium prices are possible, they are not expected. In addition, it does not seem reasonable at this point to expect low gas prices or no CO₂ legislation.

Levelized Present Value of Comparative Revenue Requirements (\$Million) – Shown as Change from the Nuclear Strategy	High Uranium Prices	Low Gas Prices	CO ₂ at \$0
1) Nuclear Strategy	-	-	-
2) Gas Strategy	13.2	-44.9	-86.5
3) Coal Strategy	87.5	90.1	-82.7

Note: Revenue includes production costs for all plants and the capital costs of all new plants.

As discussed earlier some of our existing coal plants are likely to be retired during the 40-year planning horizon. By adding the nuclear facilities the Company will be in a much better position to protect our customers from high fuel prices. The table below compares the impact of three

possible coal retirement scenarios. The “High Forced Outage Rate” scenario assumes that SCE&G continues to operate all its coal plants no matter the age but they become more unreliable with time. The “Retire Small Coal Plants” scenario envisions the need for more environmental investment at each plant, such as, the need to add carbon capture. This type investment is not likely to be economical at smaller coal plants. Finally, the “Retire All Coal When 60 Years Old” scenario is self-explanatory. All three scenarios represent future possibilities. As shown in the table, SCE&G is better able to protect its customers under these scenarios if it pursues the Nuclear Strategy.

Levelized Present Value of Comparative Revenue Requirements (\$Million) – Shown as Change from the Nuclear Strategy	High Forced Outage Rate	Retire Small Coal Plants	Retire All Coal When 60 Years Old
1) Nuclear Strategy	-	-	-
2) Gas Strategy	44.9	75.7	68.7

Note: Revenue includes production costs for all plants and the capital costs of all new plants.

While no one knows with certainty what a CO₂ credit may cost, the following table presents some points of reference.

\$ per Ton of CO ₂	Description
\$47	Price of carbon futures contract for December 2012 on the Inter-Continental Exchange: 27.75 Euros per metric ton @ 1.5607 exchange rate (4/25/2008) converted to \$ per short ton.
\$55	Cost to capture and sequester CO ₂ . Estimate from a U.S. Department of Energy website http://fossil.energy.gov/sequestration/capture/index.html
\$94	Price needed for gas generation at \$73 per MWH to displace coal generation at \$26 per MWH using variable production costs.

The table below shows the sensitivity of the economic results to the price of a CO₂ credit. For each combination of escalation rate and CO₂ price in 2012, the table shows the approximate difference in levelized revenue requirements between the nuclear strategy and the gas strategy. For example, if the CO₂ price in 2012 is \$20 and escalates at 5% per year, then the nuclear strategy would save SCE&G's customers about \$19 million per year on a levelized basis. On the other hand if the CO₂ price were only \$5 escalating at 2%, then the nuclear strategy would cost about \$71 million more per year than the gas strategy. The shaded area highlights the combinations of CO₂ price and escalation which result in the gas strategy being more economical than the nuclear strategy.

Change in Levelized Rev. Req.: Gas Strategy Minus Nuclear Strategy											
Positive Entries Represent Nuclear Advantage in Millions of Dollars											
CO₂ Price / Escalation	\$0	\$5	\$10	\$15	\$20	\$25	\$30	\$35	\$40	\$45	\$50
0%	-87	-75	-63	-51	-40	-28	-16	-5	7	19	31
2%	-87	-71	-55	-39	-23	-7	9	25	41	57	73
4%	-87	-64	-42	-20	2	24	47	69	91	113	135
5%	-87	-60	-34	-7	19	45	72	98	124	151	177
6%	-87	-55	-24	8	39	71	102	134	165	197	228
8%	-87	-41	5	50	96	141	187	233	278	324	369
10%	-87	-19	48	116	183	250	318	385	453	520	587

In Summary

Schedule H has shown that:

- These nuclear facilities are the most economical form of generation to add under reasonable assumptions about the future.
- These nuclear facilities meet the Company's need for more base load capacity.
- These nuclear facilities are non-emitting resources and therefore serve to protect the environment while at the same time mitigating exposure to the cost of complying with future environmental regulations.
- These nuclear facilities support the need for fuel diversity in SCE&G's capacity mix.
- Renewable power, increased demand side management (DSM) and potential energy efficiency gains are not capable of replacing the need for more base load generation; however, they could fit nicely into the expansion plan by displacing some of the purchased power currently shown in the plan.

Based on consideration of these factors, SCE&G has determined that constructing the nuclear facilities is the most reasonable and prudent response to its need for future base-load capacity to serve its customers and the people of South Carolina.

EXHIBIT I

INFLATION INDICES

PUBLIC VERSION

**Combined Application of South Carolina Electric & Gas Company for a
Certificate of Environmental Compatibility and Public Convenience and
Necessity and for a Base Load Review Order
Public Service Commission Docket No. 2008-196-E**

1. INTRODUCTION

This **Exhibit I** provides the inflation indices and escalators, and contingency factors used by SCE&G in projecting the capital cost of the two Westinghouse AP1000 Advanced Passive Safety Power Plant (AP1000) units it proposes to construct at V. C. Summer Nuclear Station (VCSNS) Units 2 & 3 (the Units or the Facilities).

2. EXPLANATION OF COST ELEMENTS SUBJECT TO ESCALATION (See Attached Chart A)

Chart A of Exhibit I provides the categories of capital investment that have been established for the project. These categories are defined by risk profiles documenting the escalations and contingencies that are applied to base project cash flow. The definitions of these profiles are determined by either contract terms or sound engineering and planning assumptions. Project cash flow is assigned to each risk profile based on common risk characteristics; and escalations and contingencies are applied to generate future cash flow for use in regulatory and planning schedules. Risk profiles are defined below:

- 1) **Fixed with No Adjustment** – These costs are fixed per the EPC Contract and escalation is not applied. Contingency risk for this cash flow is principally related to change orders and is predicted to be relatively low.
- 2) **Firm with Fixed Adjustment A** – These costs have a fixed escalation of a specified percentage applied as part of the EPC Contract. Contingency risk for this cash flow is principally related to change orders and is predicted to be relatively low.
- 3) **Firm with Fixed Adjustment B** – These costs have a fixed escalation of a specified percentage applied as part of the EPC Contract. Under the EPC Contract, this factor is expressed in two parts. One part is an inflation escalator equal to the percentage in item 2 above. The other is a small additional factor that is designated a nuclear industry administration adjustment to compensate Westinghouse for the undertaking the project.

Contingency risk for this cash flow is principally related to change orders and is predicted to be relatively low.

- 4) **Firm with Indexed Escalation** – Escalation for this schedule of costs is applied periodically under the EPC Contract based on the Handy–Whitman All Steam Generation Plant Index, South Atlantic Region. Handy-Whitman is a well recognized and commonly used construction index. The adjustment as billed under the EPC Contract will reflect the percentage increase in the Handy-Whitman All Steam Generation Plant Index, South Atlantic Region as measured between each bi-annual release of the index. For planning purposes, SCE&G is using the most recent one-year index change for 2008, and the most recent five-year average of the index for 2009 and beyond to escalate these costs. Contingency risk for this cash flow is predicted to be relatively low.
- 5) **Actual Craft Wages** – Site craft wages will be paid at actual costs. For planning purposes, SCE&G is using the most recent one–year index change of the Handy–Whitman All Steam & Nuclear Generation Plant Index, South Atlantic Region, for 2008, and the most recent five-year average of this index for 2009 and beyond to escalate these costs. Contingency risk for this cash flow is expected to be higher than average.
- 6) **Non-Labor Costs** – This schedule is paid at actual costs. For planning purposes, SCE&G is using the most recent one-year index change of the Handy–Whitman All Steam & Nuclear Generation Plant Index, South Atlantic Region, for 2008, and the most recent five-year average of this index for 2009 and beyond to escalate these costs. Contingency risk for this cash flow is expected to be moderately high.
- 7) **Time & Materials** – This schedule is paid at actual costs. For planning purposes, SCE&G is using the most recent one–year index change of the Handy–Whitman All Steam & Nuclear Generation Plant Index, South Atlantic Region, for 2008, and the most recent five-year average of this index for 2009 and beyond to escalate these costs. Contingency risk for this cash flow is expected to be moderately high.
- 8) **Owners Costs Target Estimates** – This schedule is paid at actual costs. For planning purposes, SCE&G is using the most recent one-year factor of the GDP Chained Price Index, a commonly used U.S. Government published general escalation index, to escalate 2008 costs. The most recent five-year average of this index is used to escalate costs for 2009 and beyond. Contingency risk for this cash flow is expected to be moderately high.
- 9) **Transmission Costs** – This schedule is paid at actual costs. For planning purposes, the base estimate is escalated based on the most recent Handy–Whitman Transmission Plant Index, South Atlantic Region index, and the most recent five-year average of this index,

is used to escalate costs for 2009 and beyond. Contingency risk for this cash flow is expected to be moderately high.

3. PUBLIC AND CONFIDENTIAL VERSION OF THE INTRODUCTION TO EXHIBIT I AND CHART A TO EXHIBIT I

In response to a claim of confidentiality made by Westinghouse under the provisions of the EPC Contract, SCE&G has prepared public and confidential versions of this introduction to **Exhibit I**, and of **Chart B to Exhibit I**. The differences between the two versions are as follows:

- a. The public version of this introduction to **Exhibit I** does not specify the percentage of the costs under the EPC Contract that fall within the Fixed/Firm pricing category and the additional percentage of cost that Westinghouse and Stone & Webster have agreed to offer for conversion to Fixed/Firm pricing. The confidential version of the introduction provides these percentages.
- b. The public version of this introduction to **Exhibit I**, and of **Chart B to Exhibit I** does not provide the specific inflation factors that the EPC Contract has established for the two Firm with Fixed Adjustment Categories. The confidential version sets forth these factors.
- c. The public version of **Chart B to Exhibit I** does not list the specific items of equipment or cost included in the four Fixed/Firm categories of cost. The confidential version of that document lists the specific items of equipment or cost under the heading "Cost Make-up."

SCE&G intends to make the confidential version of the introduction to **Exhibit I** and of **Chart B to Exhibit I** available to parties who sign an appropriate confidentiality agreement.

4. HANDY-WHITMAN AND GDP INDICES (See Attached Chart B)

Chart B to Exhibit I provides five years of historical data for the Handy-Whitman (HW) All Steam Generation Plant, All Steam & Nuclear Generation Plant, and Transmission Plant, for the South Atlantic Region; as well as the Gross Domestic Product (GDP) inflation index. These are the indices discussed in **Chart A of Exhibit I** and used by SCE&G in preparing cost projections related to the Facility.

Cost Elements Subject to Escalation & Contingency

EPC Category	Cost Make-up*	Escalation Indices/Assumptions	Contingency Assumptions
1) Fixed with no Adjustment	Various specified plant components	<i>Fixed Price not subject to escalation under the EPC Contract.</i>	<i>Low Risk – 5%</i>
2) Firm with Fixed Adjustment A	Other specified plant components	<i>Fixed escalation of a specified percentage under the EPC Contract.</i>	<i>Low Risk – 5%</i>
3) Firm with Fixed Adjustment B	Specific Westinghouse charges	<i>Fixed adjustment of different specified percentage under the EPC Contract.</i> <ul style="list-style-type: none"> - One part of the total percentage is base escalation, and - Another part is a nuclear industry administration adjustment. 	<i>Low Risk – 5%</i>
4) Firm with Indexed Adjustment	All equipment not listed elsewhere and other costs.	<i>Adjusted periodically under the EPC Contract by the Handy-Whitman All Steam Generation Plant Index.</i>	<i>Low Risk – 5%</i>
5) Actual Craft Wages	All site craft labor.	<i>Paid at actual costs. Base estimate is escalated at Shaw/Stone Webster developed market index for target purposes. Handy-Whitman All Steam & Nuclear Generation Index used to escalate for planning purposes.</i>	<i>High Risk – 20%</i>
6) Non-Labor Target	Construction Materials, consumables, furnish & erect subcontractors.	<i>Paid at actual costs. Base estimate is escalated at a Handy-Whitman All Steam & Nuclear Generation Index for planning purposes.</i>	<i>Moderate-High Risk – 15%</i>
7) T&M	Startup and COLA and other permitting and licensing support.	<i>Paid at actual costs under the EPC Contract. Base estimate is escalated at Handy-Whitman All Steam & Nuclear Generation Index for planning purposes.</i>	<i>Moderate-High Risk – 15%</i>

Owners' Cost Category	Cost Make-up	Escalation Indices/Assumptions	Contingency Assumptions
8) Project Target Estimates	All equipment, labor, materials, insurance, overhead, etc. not covered under the EPC Contract.	<i>Paid at actual costs. Base estimate is escalated at Gross Domestic Product Chained Price Index historical average for planning purposes.</i>	<i>Moderate-High risk – 15%</i>
9) Transmission Projections	New Transmission Lines and Transmission System upgrades to support interconnection of new Nuclear units per Generator Interconnection Facilities Studies.	<i>Paid at actual costs. Base estimate is escalated at Handy-Whitman Transmission Plant Construction Index for planning purposes.</i>	<i>Moderate-High risk – 15%</i>

* Associated overheads and profits will be included in cost elements.

Exhibit I, Chart B**HW All Steam Generation Plant**

<u>Year</u>	<u>Index</u>	<u>Yr/Yr change</u>	<u>Three year Average</u>	<u>Five Year Average</u>	<u>Ten Year Average</u>
2007	491	7.7%	7.0%	5.74%	4.1%
2006	456	7.5%	6.6%	4.8%	
2005	424	5.7%	4.5%	3.7%	
2004	401	6.6%	3.5%	3.6%	
2003	376	1.1%	2.0%	2.3%	
2002	372	2.8%	3.4%	2.5%	
2001	362	2.3%	2.6%		
2000	354	5.0%	2.5%		
1999	337	0.6%			
1998	335	1.8%			
1997	329				

Exhibit I, Chart B**HW All Steam + Nuclear Generation Plant**

<u>Year</u>	<u>Index</u>	<u>Yr/Yr change</u>	<u>Three year Average</u>	<u>Five Year Average</u>	<u>Ten Year Average</u>
2007	490	7.7%	7.0%	5.75%	4.1%
2006	455	7.6%	6.7%	4.8%	
2005	423	5.8%	4.5%	3.7%	
2004	400	6.7%	3.5%	3.6%	
2003	375	1.1%	2.0%	2.4%	
2002	371	2.8%	3.4%	2.5%	
2001	361	2.3%	2.6%		
2000	353	5.1%	2.5%		
1999	336	0.6%			
1998	334	1.8%			
1997	328				

Exhibit I, Chart B**HW All Transmission Plant**

<u>Year</u>	<u>Index</u>	<u>Yr/Yr change</u>	<u>Three year Average</u>	<u>Five Year Average</u>	<u>Ten Year Average</u>
2007	518	8.8%	8.1%	6.86%	4.5%
2006	476	9.2%	8.6%	5.3%	3.6%
2005	436	6.3%	5.4%	4.0%	
2004	410	10.2%	3.6%	4.0%	
2003	372	-0.3%	1.1%	1.6%	
2002	373	0.8%	3.4%	2.1%	
2001	370	2.8%	2.4%		
2000	360	6.5%	2.4%		
1999	338	-2.0%			
1998	345	2.7%			
1997	336				

EXHIBIT J

RISK FACTORS RELATED TO CONSTRUCTION AND OPERATION OF THE FACILITY

Combined Application of South Carolina Electric & Gas Company for a Certificate of Environmental Compatibility and Public Convenience and Necessity and for a Base Load Review Order Public Service Commission Docket No. 2008-196-E

1. INTRODUCTION

This **Exhibit J** provides an overview of certain of the major risk factors related to the permitting, construction and placing into service of two Westinghouse AP1000 Advanced Passive Safety Power Plants units at V. C. Summer Nuclear Station (VCSNS) Units 2 & 3 (the Units or the Facilities). The attached **Chart A** to this **Exhibit J** provides a list of certain of those risk factors in tabular form.

2. OVERVIEW

The risk factors related to the Facilities fall into several broad categories. Certain of the risk factors are risks that are typical of construction projects of the size and complexity of the Facilities. Others are related to the degree and sensitivity of the regulatory and safety oversight that are involved in nuclear construction. Still others are related to the fact that the Units will be among the first new nuclear units sited and built in the United States since the 1970s and 1980s, and will be among the first of what are anticipated to be a dozen or more new Westinghouse AP1000 units to be constructed in the United States and other countries over the next decade.

The discussion of risks that follows should be balanced by an appreciation of the factors that establish nuclear generation as the most prudent choice for meeting the growing energy needs of SCE&G's customers. Among those factors are the high cost of coal and new coal-fired capacity; the environmental concerns surrounding the construction of additional coal-fired generation; the uncertainty as to future costs or limitations imposed on CO₂ emissions; the uncertainty as to future natural gas prices and supplies; the relatively large amount of gas-fired generation already included in SCE&G's generation mix; the clear need for additional base load capacity, as opposed to intermediate gas-fired capacity, on SCE&G's system; the uncertainty as to the future costs and availability of AP1000 units or other nuclear units as the cost of alternative energy rises and global demand for these units increases; the value of special Federal tax incentives for those companies building nuclear units in the first phase of the present construction cycle; and other factors.

More specifically, the choice of the AP1000 units and Westinghouse/Stone & Webster as suppliers and contractors, are justified by the safety, simplicity, and logic of the AP1000 design; the superior experience and track record of Westinghouse and Stone & Webster in the nuclear power systems and nuclear power plant construction industries; and the wide acceptance of the AP1000 design among the utilities planning to build new nuclear units in the near future. In addition, because the Units will be among the first Westinghouse AP1000 units anticipated to be constructed in the United States, suppliers, contractors and others in the industry are expected to have a strong interest in supporting the success of SCE&G's construction and permitting process.

Nevertheless, there are a number of risk factors related to construction of the Units which SCE&G has taken into account in making the decision to construct Westinghouse AP1000 units at this time.

3. LICENSING AND REGULATORY, POLITICAL AND LEGISLATIVE RISK FACTORS

NRC Licensing – The NRC has stated that it prefers to follow a three-step process for the issuance of Combined Operating Licenses (“COLs”) for new nuclear facilities:

1. **Final Design Approval** – The first step for licensing of new nuclear units is the issuance of a final design approval which constitutes an approval of the conceptual design of the principal Nuclear Steam Supply Systems and Balance of Plant systems for a type of unit. The AP1000 nuclear design was approved by the Nuclear Regulatory Commission (“NRC”) on September 13, 2004 (the “Final Design Approval”). Since the Final Design Approval was initially granted, Westinghouse has applied for approval for design improvements and refinements for the AP1000 unit. Revisions 1-15 have been approved by the NRC. One additional revision is pending at this time.

2. **Reference Unit Licensing** – The second stage in the NRC review and licensing process is the licensing of a specific plant, including all plant systems, facilities and processes, through the Combined Operating License (“COL”) process. The NRC has expressed a preference that the potential owners and builder of each type of unit collaborate in the filing of a single, initial COL Application (“COLA”) for the type of unit that they are proposing to build. That initial COLA then can be used as a reference case for all similar units. The NRC approval of systems, facilities and processes can then be referenced in COLA proceedings related to other similar units.

SCE&G is participating in NuStart Energy Development, LLC (“NuStart”), an association of utilities considering constructing nuclear units and of nuclear-systems providers like Westinghouse. In keeping with NRC policy, all Westinghouse AP1000 units are planned to be largely identical except for limited variations required by specific site conditions. The COLA for TVA's Bellefonte Units 3 & 4 has been chosen as the

reference case for the AP1000 units (the “Reference Unit COLA”). It was submitted to the NRC on October 30, 2007. NuStart and the Department of Energy are sharing the cost of the Bellefonte licensing process.

3. **VCSNS Units 2 & 3 COL Application** – SCE&G’s application for a COL for VCSNS Units 2 & 3 was filed on March 31, 2008, with the NRC. This application builds on the Final Design Approval granted by the NRC for the Westinghouse AP1000 design, and the Reference Unit COLA for Bellefonte Units 3 & 4, and also includes the specific information necessary to allow licensing of construction of the Units at the Jenkinsville site.

Licensing Risk – SCE&G has carefully reviewed the Final Design Approval issued for the Westinghouse AP1000 and the application and the information contained in the Bellefonte Reference Unit COLA. SCE&G believes that AP1000 design can and should be licensed by the NRC for construction under the Reference Unit COLA. Moreover, as explained more fully in Exhibits A and P to this Application, SCE&G and consultants working on its behalf have conducted extensive environmental and site characterization work related to the Jenkinsville site. SCE&G had already studied and evaluated that site extensively as part of the licensing and license extension process for VCSNS Unit 1. Based on the foregoing, and SCE&G’s history of successful nuclear operations at the Jenkinsville site going back over 20 years, SCE&G believes that the risks related to the COLA process for the Units are reasonable and the decision to proceed with licensing and construction of the Units is prudent and in the best interest of its customers and the State of South Carolina.

Nonetheless, the risks related to the COLA process include the fact that many of the NRC regulations, standards and processes under which the licensing of the Units will take place are new and relatively untested; NRC staffing to support the new round of nuclear licensing is still being assembled; and many of the personnel that will be involved in this licensing process have not been part of the licensing of new nuclear units at any other time in their careers. As of mid-May of 2008, there were nine COLAs submitted to the NRC. Furthermore, a significant number of COLAs may be submitted in the next 12 months and these additional filings could make it more difficult for NRC to conduct timely reviews of applications.

There are clear advantages to SCE&G being an early applicant for a COL since personnel and resource issues may become more pronounced as the number of applications increase. Nevertheless, the fact remains that the NRC is in the early stages of the current licensing cycle and potential delays in the NRC licensing process can delay the construction schedule. In addition, the degree of opposition to the COLA from various groups cannot be gauged at this time. While the NRC enforces clear limitations on interventions and on the issues that interveners can raise, the degree of delay and expense that intervenor opposition might engender in the licensing process is difficult to predict at this time.

Substantive Design, Licensing or Regulatory Compliance Problems – From a substantive standpoint, SCE&G does not believe it is likely that the NRC’s COLA review will uncover material design or process issues related to the Units, or related to their siting at the Jenkinsville location. Alternatively, SCE&G believes that if any such flaws are discovered they will be remedied in a timely and cost-effective manner without unduly affecting the schedule or cost of the Units. However, the emergence of substantive design-related or process-related issues is not beyond possibility and the potential for additional cost and delay as a result of them are a part of the risk profile related to the Units. Also, changes in regulatory requirements during the course of construction could result in the need for redesigns, retrofits or reworking of work already completed.

Integrated Tests, Approvals, and Acceptance Criteria (“ITAACs”) – One subset of risks related to NRC licensing is the risk related to the criteria and protocols for testing, approval and acceptance of work on the Units as work is completed. This testing, approval and acceptance is known as ITAAC. Under the current approach to licensing adopted by the NRC, the NRC intends to issue a COL for new units in advance of the design/build team completing all aspects of plant design and engineering and before construction drawings are complete. However, to be allowed to proceed with construction and with plant operation, the plant and its major components and systems must meet stringent performance standards. Those standards are measured through performance testing routines and analysis, *i.e.*, ITAACs, which are conducted as important stages of the work are completed.

The NRC has established the ITAAC criteria which the Units and other new nuclear units must meet to ensure the plants will operate as intended. However, those ITAACs could change during the course of the Units’ licensing or construction. It is possible that the NRC could require additional ITAACs or increase the scope or stringency of existing ITAACs during the course of construction and testing of the Units. This could happen for any number of reasons, including pressure from interveners in the COL proceedings or changes in public or political attitudes toward nuclear power. In addition, the NRC is still developing the process for approving the results of the ITAAC tests once they are completed and for resolving disputes or other issues related to the results of those tests. The hearing process which would currently apply to ITAAC issues is untested. Those hearings could add expense and delay to the construction of the Units.

SCE&G does not have any basis at present to believe that the ITAAC process will pose significant risks to the schedule or cost estimates presented in this Application. However, risks related to the ITAAC process are risks to which the construction of the Units is subject.

NRC Licensing Generally – At this time, the most significant risks related to NRC licensing appear to be a) the risk of delay in the issuance of a COL, the resulting disruption of the construction schedule, and the increase in construction costs that such a delay would represent; and b) the risks related to changes or delays in the ITAAC process, particularly as construction

of the Units enters its latter stages. Nonetheless, the information available to SCE&G at this time indicates that SCE&G should be able to obtain a COL and comply with ITAACs on reasonable terms and conditions, without undue expense, and on a schedule that supports the construction schedule set forth elsewhere in this Application.

Federal Energy Regulatory Commission (“FERC”) Approval – The Units will take cooling water from the existing Monticello and Parr Reservoirs located on the Jenkinsville site. These reservoirs are part of a FERC-licensed water power development which was put in service in its current form in 1978 to support VCSNS Unit 1. Because VCSNS Units 2 & 3 will take cooling water from the Monticello Reservoirs, the construction and operation of certain aspects of the Units will require FERC approvals. The process for NRC/FERC interaction related to these approvals and the length of time required for FERC review and issuance of approvals is not well defined at present. SCE&G does not foresee any difficulty in obtaining the required FERC approvals, but the FERC approval process could delay the construction schedule and impose additional costs.

Other State and Federal Permits – SCE&G will need to obtain a substantial number of other permits from the State of South Carolina, the Corps of Engineers, and other regulatory bodies to complete the construction of the Units and place them into operation. A list of those permits is attached as **Chart B** to **Exhibit J**.

SCE&G’s assessment of the risks related to these permits is similar to its assessment of the risks related to the COL process. SCE&G is not aware of any facts that would indicate that any of the permits would be difficult or impossible to obtain on reasonable terms or schedules. The facts at SCE&G’s disposal presently indicate that the permits listed on **Chart B** should be available on reasonable terms and conditions, and on a schedule that supports the timely construction of the Units as set forth in other parts of this Application. However, SCE&G recognizes the risks related to these permits are risks of constructing the Units. Difficulty or delay in obtaining these permits could have an adverse impact on SCE&G’s ability to meet its construction schedules, and could increase the cost of the Units either through delay costs or through additional costs required in meeting regulatory requirements.

Political, Legislative, Regulatory or Public Opinion Risks – Concerns about climate change, about America’s dependency on imported energy supplies, about the recent volatility of natural gas prices, and about the availability of future natural gas supplies, as well as the U.S. nuclear industry’s 20 year track record of safety, efficiency and reliability, have all contributed to a political, legislative, regulatory and public climate that is supportive of nuclear generation. However, events that are hypothetical and difficult to predict could result in a change in the current level of political, legislative, regulatory and public support for nuclear generation in general or for the Units specifically. Such a change could in turn result in additional costs, delays and difficulty in receiving permits, licenses or approvals for the Units, and possibly could place the cost and schedule forecasts for the Units in jeopardy. While such events are difficult to

predict or envision, any major event that casts doubt on the continued safety and reliability of nuclear power, of the Westinghouse AP1000 design, or the suitability of the VCSNS site for additional nuclear units could result in such a reversal.

4. ENGINEERING RISK FACTORS

Final Engineering of the Units – As discussed above, the NRC has issued a Final Design Approval for the Westinghouse AP1000. The Reference Unit COL application has been submitted to the NRC and review of that application is underway. Nevertheless, under the current NRC licensing approach, there is engineering work related to the Units that will not be completed until after the COL is issued. Any engineering or design changes that arise out of that work, or the engineering or design changes required to address problems that arise once construction is underway, are potential risks which could impact cost schedules and construction schedules for the Units. While SCE&G expects some design changes in the due course of finalizing the design and engineering of the Units, SCE&G is not aware of any specific risks or problems related to the engineering remaining to be done, and does not have information that would lead it to believe that any material or significant change in the design or engineering of the Units will be required as a result of the remaining engineering or construction. Nonetheless, SCE&G considers these sorts of design and engineering-related risks to be risks to which the Units are subject.

Design-Related Vendor Risks – The Units, like other generation plants and other complex industrial facilities, are designed to use plant components that are generally available in the industry. As with all such plants or facilities, there is risk that component manufacturers may exit the business or change the design of their products such that they are no longer suitable to meet the requirements of the Units' design. Were this to occur, alternative components would need to be identified and included in the design, or the design would need to be otherwise modified to do without the unavailable component. Such events could result delay in the construction schedule or additional cost. SCE&G is not aware of any specific risks in this regard, nor has it identified any components or suppliers likely to pose such risks, but considers this design-related vendor risk as a risk which the Units share with other similar types of facilities.

5. PROCUREMENT AND TRANSPORTATION RELATED RISK FACTORS

Availability of Qualified Suppliers and Manufacturing Capacity – VCSNS Units 2 & 3 are being built at the beginning of a new cycle of nuclear construction. The Units are also likely to be among the first of a dozen or more new Westinghouse AP1000 units to be built in the United States. The supply chain for nuclear-grade plant components has not been supported by new construction for some decades and will need to be significantly expanded to meet the requirements of this new construction cycle.

In this context, it is helpful that Units will be built at the leading edge of the cycle, and should have the first call on the suppliers and manufacturing capacity that exist today. Nonetheless, the volume of anticipated nuclear construction around the world may create shortages in this capacity which may lead to increased costs and schedule delays in obtaining key components. Natural disasters, disruptions in normal industrial operations, material shortages, political unrest and other force majeure-type events could disrupt this supply chain. Such disruptions could in turn delay construction and increase the cost of the Units. SCE&G is not aware of any specific risks or problems related to the component supply chain and the manufacturing capacity that supports it. However, SCE&G does consider supply chain risk to be one of the risks to which the Units are subject.

Manufacturing and Quality Issues – Quality controls and manufacturing standards for components for nuclear plants are very stringent and the processes involved may place unique demands on component manufacturers. It is possible that manufacturers of unique components (*e.g.*, steam generators and pump assemblies or other large components or modules used in the Units) and manufacturers of other sensitive components may encounter problems with their manufacturing processes or in meeting quality control standards. Many of the very largest components and forging used in the Units can only be produced at a limited number of foundries or other facilities worldwide. Any difficulties that these foundries or other facilities encounter in meeting fabrication schedules or quality standards may cause schedule or price issues for the Units. SCE&G is not aware of facts that would indicate that such problems exist or are likely to occur. But if such problems do occur, they could lead to schedule delays for the Units and increased costs and so are properly considered risk factors related to the project.

Shipping Issues – Many of the components and assemblies for Units are quite large and pose unique shipping and delivery challenges. Some of the very largest components and assemblies will be fabricated in the Far East, shipped across the Pacific Ocean to Charleston or other U.S. East Coast ports, off-loaded, and then shipped by rail to the construction site. Certain of these assemblies will be as large as any items that are typically handled by the shippers involved.

In addition, much of the plant will be constructed using advanced modular construction techniques. Many of these modular components will be fabricated off-site at facilities dedicated to supporting construction of the AP1000 units. Those modules will be delivered by truck or rail to the Jenkinsville site for assembly. Regular and timely delivery of these components to the site is an important condition for successfully meeting the schedule and cost projections for construction.

If shipping problems for components and assemblies occur; if loss or damage occurs to unique assemblies during shipping and delivery; if damage or disruption were to occur to ports or rail facilities due to natural disasters, political unrest or other causes; or if rail lines serving the site were to prove to be inadequate, this could cause schedule impacts and additional cost for the

project. SCE&G believes that the shipping issues are manageable, but shipping risk is a risk of construction.

6. CONSTRUCTION RISKS

Benefit of Standardized Designs and Advanced Modular Construction – As indicated above, the construction of the Units will employ standardized designs and advanced modular construction processes. The project schedule and costs are based on efficiencies and economies anticipated from the use of these techniques. The projected benefits and the resulting schedules and cost estimates reflected in this Application appear to be reasonable. However, standardized design and advanced modular construction has not been used to build a nuclear facility in the United States to date. The construction process and schedule is subject to the risk that the benefits from standardized designs and advanced modular construction may not prove to be as great as anticipated.

Rework and Repair Risks – Westinghouse has contracted to supply the AP1000 design and selected components for four AP1000 units in China, and as of the time of this application, Westinghouse/Stone & Webster has signed an EPC contract with the Southern Company for the construction of two AP1000 units at the Plant Vogtle site on the Savannah River near Augusta, Georgia. While SCE&G believes the AP1000 to be a superior design, and has full confidence in the ability of Westinghouse and Stone & Webster as suppliers and contractors, it is nonetheless true that no AP1000 units have yet been built. Accordingly, problems may arise during construction that are not anticipated at this time. These problems may require repairs or rework to be corrected. Repairs and rework pose schedule and cost risk resulting both from the repair and rework itself, and from the time and expense required to diagnose the cause of the problem, and to plan, review and approve the work plan before implementation. Westinghouse and Stone & Webster have great experience and expertise in construction of power plants, and should be able to anticipate and avoid, or efficiently correct, construction problems as they become apparent. Nonetheless, repairs and rework represent a construction related risk of the AP1000 units.

Labor Risks – The construction of the Units will require a workforce of several thousand people at its peak. Many of the jobs involved will require workers with specialized construction skills such as specialty welding, pipefitting and electrical skills. In addition, successfully completing the project will require the recruitment and retention of skilled construction managers and supervisors.

- **Cost and Availability Risks** – The availability of the necessary employees, managers and supervisors for constructing the Units will depend on a number of factors, including overall economic and construction-related activity in the region, and the number of nuclear plants under construction in the region at the time the Units are being built. As one of the first nuclear construction projects anticipated

to get underway in the current construction cycle, the SCE&G construction project should have an advantage in attracting the required personnel over projects beginning later. But staffing risks for the Units include both the possible shortage of required workers, which could impact both schedule and costs, and the risk that bidding for the available work force will raise labor costs to levels higher than anticipated. Some inflation in labor costs is built into the cost projections and project pricing. However, actual inflation in labor costs could be higher than expected. Labor price and availability risks are important risks of the projects.

- **Training Risks** – Part of the challenge related to construction staffing will be that of properly training personnel in the skills necessary to successfully complete the project. Training costs can be a significant part of the project costs. If the construction labor force cannot be brought to the proper skill level, or maintained at that level in the face of employee turnover, then there will be a risk of excessive rework, schedule delays and increased costs.
- **Language Issues** – For a large number of construction workers, English may be their second language or they may have limited English skills. Making provisions for a large non-English speaking component of the work force may result in efficiency losses and require incurring additional costs for translation services.
- **Fitness for Duty Regulations** – The NRC has issued fitness for duty regulations for nuclear plant construction workers. Fitness for duty regulations are intended to provide reasonable assurance that nuclear plant personnel, including construction personnel, will perform their tasks in a reliable manner; that they are not under the influence of any substance, legal or illegal, that may impair their ability to perform; and that they are not mentally or physically impaired from any cause, including fatigue, illness or emotional distress, that can adversely affect their ability to competently perform their duties. Requirements under these regulations include pre-employment screening, drug and alcohol testing (with appropriate privacy protections), post-accident testing, and on-the-job behavioral awareness. Non-nuclear personnel are likely to be unfamiliar with the requirements imposed by these regulations. Concerns about the tests, or the failure to meet their requirements, may lead to increased turn-over or difficulty in hiring sufficient numbers of skilled employees, supervisors and managers.
- **Strikes or Walkouts** – While union activity is not as common in South Carolina as in other states, organization of the workforce for the Units is possible and labor disputes could result in strikes or walkouts.

These individual labor-related risks are part of the overall challenge of recruiting, training, retaining and supervising a large, diverse and highly-skilled work force to construct the Units. SCE&G believes these labor-related risks to be manageable, but they do constitute major risks related to the construction of the projects.

Scope Increases – Construction scope increases can result from changes in regulation, design changes, changes in the design and characteristics of components of equipment, and other similar factors. Many of the reasons for scope changes have been discussed in specific contexts above. In general, scope changes involve the cost and delay of redesign work, and of implementing the expanded scope. Scope changes represent an important category of risk to which the project is susceptible.

Transmission Siting and Construction – Transmission-related costs are properly considered as part of the capital cost of a plant for the purposes of Base Load Review Act proceedings. However, the Company does not plan to design and permit off-site transmission facilities for VCSNS Units 2 & 3 until the later stages of plant construction. This delay will allow the transmission lines to be configured to suit the needs of SCE&G’s transmission system as they may evolve over the course of the construction period. The actual transmission costs associated with the Units will depend on the final routing and design of the transmission facilities, the cost of right of way along the route chosen, the schedule and cost of the right of way acquisition and siting processes, and the cost of transmission construction at the times the lines are built.

7. OPERATIONAL RISKS

General Operations – SCE&G has successfully operated and maintained a Westinghouse Pressurized Water Reactor, *i.e.*, VCSNS Unit 1, for more than 20 years. SCE&G’s operations have consistently received high ratings by the NRC and by Institute of Nuclear Power Operations (INPO) and the availability factors for the plant have been very good. All the resources necessary for supporting the operations of such a unit are in place and functioning well at the Jenkinsville site.

Adding two new AP1000 units to the site will require significant expansion of SCE&G’s existing staff and capabilities. Recruiting, training and retaining the required staff is one of the risks related to operation of the plant, but it is a risk SCE&G believes that can be managed without undue difficulty.

Spent Fuel Storage – Each unit of VCSNS Units 2 & 3 will have the capability to store 18 years of fuel discharges from the reactor in its spent fuel storage pool. In the next several years, SCE&G will have to construct and place into operation a secure dry-fuel storage facility at the Jenkinsville site to receive and hold spent fuel from VCSNS Unit 1. This facility will be constructed large enough to facilitate storage of spent fuel from Units 2 & 3. The dry-fuel storage facility will have the capability to hold spent fuel safely until a permanent repository for it is available. SCE&G does not believe that spent-fuel storage is a material risk factor related to operation of the Units.

Fuel Cost Risk – SCE&G believes that nuclear fuel for its reactors will be available in sufficient quantities and at reasonable prices during the course of its operation of the Units. The cost of nuclear fuel has risen recently in response to the resurgence of interest in nuclear generation. However, SCE&G is not aware of any reason to believe that supplies of nuclear fuel or nuclear fuel fabrication capacity will be unduly constrained in the long-term. Moreover, the cost of fuel is a much smaller part of the cost of nuclear generation than it is for generation from fossil fuel sources. Accordingly, the economics of nuclear generation are much less dependent on fuel costs than are the economics of coal- or natural-gas-fired generation.

8. FINANCIAL AND GENERAL INFLATION RISKS

Financial Risk – As other exhibits show, construction of the Units will require the Company to access large amounts of capital on regular intervals to make the required payments to Westinghouse and Stone & Webster, and to fund its own internal costs related to the project. SCE&G believes that it will have access to the required capital on reasonable terms during the construction process. The present Base Load Review Act proceeding and future revised rates filings will play a critical role in the Company's ability to obtain that capital.

Nonetheless, instability in global or U.S. capital markets, future developments which bias capital markets against investments in nuclear power, or developments which call into question the future financial integrity of the Company or its ability to recover its costs of utility operations in a timely way, all could restrict SCE&G's access to capital on reasonable terms. Scope changes or cost increases that result in additional requirements for capital could also present financial challenges to the Company. Anything that might cause the Company to lose the ability to access required capital in a timely way could result in disruption of the construction process and schedule, and represents a potential risk factor for the construction of the Units.

Inflation and Supply Shortage Risks – Inflation related to nuclear construction labor, and to nuclear-plant materials and components has been discussed above. In addition, inflation in the cost of standard construction inputs like cement, steel, copper, nickel, gasoline and diesel fuel, all could result in increased costs for constructing the Units. Increasingly globalized markets have resulted in increased competition for supplies of such standard construction materials. Inflation is often accompanied by supply shortages. SCE&G has built reasonable inflation projections into its cost projections for the project. Nonetheless, supply shortages and unanticipated levels of price inflation for standard construction inputs represent a risk both to cost projections and schedule projections for constructing the Units.

9. SEVERE WEATHER AND NATURAL AND MAN-MADE DISASTERS

Severe Weather and Natural and Man-Made Disasters – The timely and successful construction of the Units depends on a supply chain that is global in scope as well as on conditions localized at the Jenkinsville site. Severe weather and natural and man-made disasters

at any point in that supply chain can interfere with the progress of the construction and affect both price and schedule risks. The problems disasters pose are most acute if they occur at sites which are vital to the manufacture or transport of unique and specialized components, or at the construction site itself. The list of potential natural and man-made disasters that could cause cost increases or schedule delays includes all the disasters commonly cited as examples of force majeure, and include: hurricanes, tornados, earthquakes, floods, landslides, fires, explosions, tsunamis, lightning-strikes, war, riots, sabotage, prolonged rains or cold weather at the site, railway or bridge failures, epidemics, and terrorist attacks. Insurance may provide protection against some of the cost of these events, but insurance may not cover all risks, and schedule delays may be unavoidable.

10. CONCLUSION

For a project of the scope and complexity of the licensing and construction of the Units, any list of potential risk factors compiled at this stage of the process will not be exhaustive. Risks that are difficult to predict or envision may arise during licensing and permitting that disrupt current cost or schedule forecasts. Nevertheless, SCE&G has reviewed the risks related to constructing the Units carefully and over an extended period of time. It has compared those risks to the risks of the other alternatives that are available to meet the energy needs of its customers and the State of South Carolina. SCE&G has also sought to manage the risks of constructing the Units by fixing costs, to the extent commercially reasonable, under the EPC Contract with Westinghouse/Stone & Webster, and by applying reasonable schedule and cost contingencies to the project. Based on the above, SCE&G has concluded that the benefits from constructing the Units and adding them to its system outweigh the risks as it understands them, particularly considering that this energy source involves significant no air emissions, is highly reliable, and is not subject to the fuel price risks or fuel availability risks that affect the fossil generation resources. SCE&G has concluded that constructing the Units is the most prudent and responsible course it can take at this time to meet the base-load generation needs of its customers.

But no project of this scope can expect to be completed without some risks or disruptions. In the end, this project's ability to meet its current schedule and cost projections will depend on the cumulative effect of those risk events that do occur on the schedule and cost projections contained in this Application. SCE&G will monitor these risks and their effects carefully. It will inform the Commission and the public if the effects of risks that do occur begin to fall outside of the cost and schedule contingencies built into this Application.

EXHIBIT J
Chart A
Certain Risks Associated with Construction and Operation of the Facilities

Types of Risk	Schedule Delay	Increase Cost
1. <u>Regulatory Risks</u>		
a. Office of New Reactors		
i. New 10CFR52 licensing process proceeds slowly due to complexity and/or resource issues	Yes	Yes
ii. Intervention results in lengthy NRC hearings	Yes	Yes
iii. New NRC regulations issued causes scope additions	Yes	Yes
iv. ITAACs		
1. Resolution of ITAACs delays fuel load	Yes	Yes
2. New ITAACs causes scope addition	Yes	Yes
b. NRC Region II		
i. Construction Inspection Process proceeds slowly due to complexity and/or resource issues	Yes	Yes
c. FERC license approval process proceeds slowly due to complexity and/or resource issues	Yes	Yes
d. State & local permits process proceeds slowly due to complexity and/or resource issues	Yes	Yes
2. <u>Engineering Risks</u>		
a. Completion of design results in changes to existing design	Yes	Yes
b. Construction problems require design changes	Yes	Yes
c. Equipment vendors go out of business or change products	Yes	Yes
3. <u>Procurement Risks</u>		
a. Inadequate number of qualified suppliers	Yes	Yes
b. Manufacturing problems causes delays	Yes	Yes
c. Shipping problems delay equipment arrival to site	Yes	Yes
4. <u>Construction Risks</u>		
a. Construction duration estimates are too optimistic	Yes	Yes
b. Construction problems requires rework/repair	Yes	Yes
c. Labor issues (strikes/inadequate supply) causes delays	Yes	Yes
d. Lack of proper training results in mistakes	Yes	Yes
e. Large non-English speaking workforce	Yes	Yes
f. Workers do not meet new fitness for duty standards	Yes	Yes
5. <u>Operational Risks</u>		
a. Inability to hire sufficient qualified people to operate plants	Yes	Yes
6. <u>Financial Risks</u>		
a. Cost of money limits ability to raise sufficient capital	No	Yes
b. Rising inflation & competition drives equipment and commodity prices upward	No	Yes
c. Scope increases require additional funding	Yes	Yes
7. <u>Uncontrollable Circumstances</u>		
a. Severe weather	Yes	Yes
b. War/sabotage/terrorist attack	Yes	Yes

EXHIBIT J
Chart B

Major Non-NRC Permits, Licenses, and Authorizations List

1. Federal Energy Regulatory Commission (FERC) Order for Non-Project Use of Project Land & Waters

Upon application to the FERC, the FERC will review, and if found not to be inconsistent with the provisions of the FERC Project 1894 (Parr/Monticello Hydroelectric Project) License, it will issue its order approving the construction of the inlet lines for the water treatment plant as well as intake and discharge structures (lines) for the Units 2 & 3 cooling towers crossing Project properties, and such other non-project use of Project resources, including land and water as will be necessitated by construction and operation of Units 2 & 3.

2. U. S. Army Corps of Engineers (COE) 404 Wetlands Permit

A permit is needed to disturb land and in some cases to fill areas determined to be wetlands and officially delineated by the COE.

3. Siting Act Certification for the Transmission Facilities

As indicated in **Exhibit Q** to this Application, additional transmission facilities will be required to integrate the Units into SCE&G's electric grid. Those transmission projects will be permitted separately from the permitting of the generation facilities with which they are associated.

4. Section 401 Water Quality Certification

A Section 401 Water Quality Certification by the South Carolina Department of Health and Environmental Control (DHEC) will be necessitated as a result of the need to secure a Section 404 permit. The review will be conducted in concert with the 404 wetlands permit process.

5. Part III Construction & Demolition Landfill Permit (Solid Waste Permit)

A DHEC Solid Waste Permit is needed for an Industrial Landfill for the purpose of disposal of construction, demolition, and land-clearing debris.

6. NPDES Stormwater Permit for Land Clearing

A DHEC issued Stormwater Permit is required for any land disturbing activities. This includes all land clearing activities such as grubbing and excavating of soil from the site.

7. SCDHEC/S.C. Fire Marshall Blasting Permit

Permits are required should it become necessary to blast rock that cannot be removed by other means.

8. SCDOT Site Access Road Permit

A permit is needed for enhancing the roadway at the intersection of Parr Rd. and Hwy. 213 to facilitate safer passage of construction traffic.

9. Construction Facilities Building Permit

Permits are needed for construction of buildings in the "construction city area."

10. SCDHEC Concrete Batch Plant Permit

A permit is needed to install a concrete batch plant onsite to produce concrete for the construction project.

11. Concrete Batch Plant NPDES Discharge Permit

A permit is needed to discharge water from the concrete batch plant into "Waters of the State."

12. Dredge and Fill (COE) Permit

A permit is needed for dredging areas in Parr Reservoir when installing a discharge pipe for Units 2 & 3.

13. SCDHEC Bureau of Air Quality (BAQ) Permits

A construction permit exemption is needed from BAQ for emergency generators, boilers (if applicable) and any other stationary sources exhausting emissions into the atmosphere at the water treatment plant/wastewater plant. This also applies to any future equipment on the site that emits to the atmosphere.

14. SCDHEC Construction Permit for Water Treatment Plant

A permit is needed to construct the building/equipment/lines for the Water Treatment Plant.

15. NPDES Water Permit for Water Treatment Plant

A permit is needed to produce water from the Water Treatment Plant.

16. NPDES Wastewater Permit (discharge water coming from Water Treatment Facility)

A permit is needed to discharge water from the Water Treatment Plant into Monticello Reservoir.

17. NPDES Wastewater Permit (discharge water coming from Wastewater Package Plant)

A permit is needed to discharge water from the Wastewater Package Plants (2 plants) into Mayo creek and Parr Reservoir.

18. Construction Permit for Wastewater Package Plant

A permit is needed to install two wastewater package plants (construction city area and on the table top area) into Mayo Creek and Parr Reservoir.

19. Federal Aviation Administration Permit

A permit is required from the FAA for Lampson construction cranes, because they will be over the height of 200 ft.

EXHIBIT K

PROPOSED RATE DESIGN AND CLASS ALLOCATION FACTORS FOR REVISED RATES

Combined Application of South Carolina Electric & Gas Company for a Certificate of Environmental Compatibility and Public Convenience and Necessity and for a Base Load Review Order Public Service Commission Docket No. 2008-196-E

1. INTRODUCTION

This **Exhibit K** provides the 2007 summer peak demand allocators for SCE&G's retail electric service which as required by S.C. Code Ann. § 58-33-270(D) have been calculated using the methodology approved by the South Carolina Public Service Commission in the order in SCE&G's most recent retail electric rate proceeding, Order No. 2007-855. The summer peak demand allocator is the peak demand allocator historically used by the Commission in setting SCE&G's rates and was calculated in the same way as the peak demand allocator used in Order No. 2007-855.

2. RATE DESIGN

Attached as **Chart A** to this **Exhibit K** is the rate design on which the rates proposed for approval in this proceeding are based. The rate design contained in **Exhibit K, Chart A** is based on the revenue requirements associated with CWIP associated with VCSNS Units 2 & 3 outstanding as of June 30, 2008. That revenue requirement is set forth in **Exhibit M** to this Application. **Exhibit K, Chart A** reflects the allocation of that revenue requirement among the various retail electric rates approved for collection by SCE&G in Order 2007-855. Subject to SCE&G's proposed treatment of the Basic Facilities Charge as set forth in Paragraph 22 of the Combined Application, this allocation is consistent with the rate design approved by the Commission in Order No. 2007-855. Tariff sheets incorporating the proposed rates are found in **Exhibit N** to this Application.

3. ALLOCATORS

South Carolina Electric & Gas Company Summer 2007 Retail Peak Demand Allocation

<u>Class</u>	<u>KW Demand</u>	<u>% of Retail</u>
Residential	2,163,867	48.10%
Small General Service	809,051	17.98%
Medium General Service	506,749	11.27%
Large General Service	<u>1,019,021</u>	<u>22.65%</u>
Retail Total	4,498,688	100.00%

SOUTH CAROLINA ELECTRIC & GAS COMPANY

**RATE DESIGN SUMMARY
INCREASE ON MAY, 2008 RATES**

RATE	MAY, 2008 REVENUE	PROPOSED REVENUE	\$ CHANGE	% CHANGE
	COL. 1	COL. 2	COL. 3	COL. 4
RESIDENTIAL				
Rate 1 - Good Cents	\$ 38,076,304	\$ 38,269,600	\$ 193,296	0.51%
Rate 2 - Low Use	\$ 3,233,926	\$ 3,249,354	\$ 15,428	0.48%
Rate 5 - Time-of-Use (KWH Only)	\$ 161,557	\$ 162,262	\$ 705	0.44%
Rate 6 - Energy Saver / Conservation	\$ 51,622,096	\$ 51,883,771	\$ 261,675	0.51%
Rate 7 - Time-of-Use Demand	\$ 1,221	\$ 1,228	\$ 7	0.57%
Rate 8 - Residential	\$ 735,055,847	\$ 738,906,956	\$ 3,851,109	0.52%
Total Residential Class	\$ 828,150,951	\$ 832,473,171	\$ 4,322,220	0.52%
SMALL GENERAL SERVICE				
Rate 3M - Municipal Power	\$ 13,060,939	\$ 13,120,691	\$ 59,752	0.46%
Rate 9 - Small General	\$ 268,113,710	\$ 269,438,049	\$ 1,324,339	0.49%
Rate 29 - Small General (Unmetered)	\$ 654,903	\$ 658,140	\$ 3,237	0.49%
Rate 10 - Small Construction	\$ 1,021,158	\$ 1,024,419	\$ 3,261	0.32%
Rate 11 - Irrigation	\$ 1,033,401	\$ 1,037,968	\$ 4,567	0.44%
Rate 12C - Church	\$ 14,427,376	\$ 14,478,805	\$ 51,429	0.36%
Rate 13 - Municipal Lighting	\$ 445,996	\$ 447,875	\$ 1,879	0.42%
Rate 14 - Farm	\$ 2,033,883	\$ 2,043,521	\$ 9,638	0.47%
Rate 16 - Time-of-Use	\$ 296,237	\$ 297,610	\$ 1,373	0.46%
Rate 22S - School	\$ 34,611,892	\$ 34,766,817	\$ 154,925	0.45%
Total Small General Service Class	\$ 335,699,495	\$ 337,313,895	\$ 1,614,400	0.48%
MEDIUM GENERAL SERVICE				
Rate 20 - Medium General	\$ 165,360,407	\$ 166,192,985	\$ 832,578	0.50%
Rate 21 - Time-of-Use	\$ 6,676,968	\$ 6,713,506	\$ 36,538	0.55%
Rate 21A - Experimental Time-of-Use	\$ 26,866,157	\$ 27,007,032	\$ 140,875	0.52%
Total Medium General Service Class	\$ 198,903,532	\$ 199,913,523	\$ 1,009,991	0.51%
LARGE GENERAL SERVICE				
Rate 23 - Industrial Power	\$ 241,067,164	\$ 242,159,107	\$ 1,091,943	0.45%
Rate 24 - Time-of-Use	\$ 133,558,974	\$ 134,195,740	\$ 636,766	0.48%
Contracts	\$ 90,436,985	\$ 90,742,864	\$ 305,879	0.34%
Total Large General Service Class	\$ 465,063,123	\$ 467,097,711	\$ 2,034,588	0.44%
TOTAL			\$ 8,981,199	

EXHIBIT L

COST OF DEBT AND CAPITALIZATION RATIOS

**Combined Application of South Carolina Electric & Gas Company for a
Certificate of Environmental Compatibility and Public Convenience and
Necessity and for a Base Load Review Order
Public Service Commission Docket No. 2008-196-E**

1. INTRODUCTION

This **Exhibit L** provides the current capitalization ratios and weighted average cost of debt and equity capital for SCE&G used in calculating the revenue requirements associated with investment in the two Westinghouse AP1000 Advanced Passive Safety Power Plant units proposed for construction as V. C. Summer Nuclear Station Units 2 & 3.*

Capitalization Ratios and Cost of Capital

**SOUTH CAROLINA ELECTRIC & GAS COMPANY / S.C. FUEL COMPANY
REGULATORY CAPITALIZATION RATIOS FOR ELECTRIC OPERATIONS
As of December 31, 2007 – Adjusted**

	<u>AMOUNT</u>	<u>RATIO</u>	<u>EMBEDDED COSTS</u>	<u>WEIGHTED AVERAGE COST OF CAPITAL</u>	<u>GROSS OF TAX</u>
Long-Term Debt	\$2,211,488,400	44.68%	6.22%	2.78%	2.78%
Preferred Stock	\$ 114,158,800	2.31%	6.42%	0.15%	0.24%
Common Equity	<u>\$2,623,463,867</u>	<u>53.01%</u>	11.00%	<u>5.83%</u>	<u>9.49%</u>
Total Capitalization	<u>\$4,949,111,067</u>	<u>100.00%</u>		<u>8.76%</u>	<u>12.51%</u>

* December 2007 actual adjusted for actual and planned debt issuances in 2008:

January 2008	\$250,000,000	First Mortgage Bonds
June 2008 - projected	\$100,000,000	First Mortgage Bonds
August 2008 - projected	\$40,000,000	Pollution Control Bonds

EXHIBIT M

YEAR-BY-YEAR REVENUE REQUIREMENTS AND PROJECTED RATE IMPACT OF INVESTMENT

Combined Application of South Carolina Electric & Gas Company for a Certificate of Environmental Compatibility and Public Convenience and Necessity and for a Base Load Review Order Public Service Commission Docket No. 2008-196-E

1. INTRODUCTION

Exhibit M provides the year-by-year revenue requirements associated with SCE&G's investment in V. C. Summer Nuclear Station ("VCSNS") Units 2 & 3. **Exhibit M, Chart B**, provides the projected rate impact associated with the Units.

2. YEAR-BY-YEAR REVENUE REQUIREMENTS

Chart A of **Exhibit M** provides the year-by-year revenue requirements associated with the amount of Construction Work in Progress (CWIP) and of VCSNS Units 2 & 3 as set forth in **Exhibit F** to this Application and the in-service expenses set forth on **Exhibit O** to this Application. As required by the Base Load Review Act, the revenue requirements set forth on this **Exhibit M, Chart A** have been calculated using the weighted average cost of capital set forth on **Exhibit L** to this Application.

The outstanding CWIP balance and associated revenue requirement provided in **Exhibit M, Chart A** is measured as of June 30th of each year during the construction of VCSNS Units 2 & 3. The filing date of future revised rates proceedings, the designated date for measuring CWIP to be considered in each proceeding, the amount of capital actually expended by each designated date, and other factors may vary, and as a result, the timing and amount of CWIP reflected in future revised rates adjustments may vary.

3. PROJECTED RATE IMPACT OF INVESTMENT

Also attached to this **Exhibit M** is **Chart B** which provides an estimate of the future impacts of the CWIP and in-service expenses associated with VCSNS Units 2 & 3 on SCE&G's retail electric rates. To isolate the impact of the investment in VCSNS Units 2 & 3 from other factors, the current retail fuel factor is assumed to remain constant, as are the margin revenues generated per billing unit by retail electric base rates. However, projected growth in retail customers' demand and energy sales and the benefit of additional nuclear generator or fuel costs where VCSNS Units 2 & 3 connection line are reflected in the analysis. The projections in this **Exhibit M, Chart B**, also include the effects of estimated Federal Production Tax Credits. As

indicated in the notes to **Exhibit O, Chart A**, the Company intends at a future date to seek Commission approval to pass any available Federal Production Tax Credits through to customers by means of credits to electric fuel cost expenses.

Many of the factors related to this analysis and to future rate increases are subject to change over time. Those factors include the amount and timing of CWIP expenses and in-service expenses; the timing of revised rates filings; the amount of AFUDC included in capital costs; the rates of growth in demand and energy sales on SCE&G's system; the amount and timing of future base rate increases; changes in fuel costs and generation mix; changes in the cost of debt, cost of equity and capital structure that make up the weighted average cost of capital; and other factors. As a result, the actual rate increases associated with investment and operation of VCSNS Units 2 & 3 may vary from those reflected on **Chart B of Exhibit M**.

EXHIBIT M, Chart A

Schedule of Year by Year Revenue Requirements

**Combined Application of South Carolina Electric & Gas Company for a
Certificate of Environmental Compatibility and Public Convenience and
Necessity and for a Base Load Review Order**

(Thousands of \$)

Nuclear Construction	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Totals
<i>Construction Work in Process in Rates</i>	\$ 71,848	\$ 384,570	\$ 524,227	\$ 705,797	\$ 775,704	\$ 794,209	\$ 764,233	\$ 603,063	\$ 553,098	\$ 280,400	\$ 195,851	\$ 5,653,000
<i>Cumulative</i>	\$ 71,848	\$ 456,418	\$ 980,645	\$ 1,686,442	\$ 2,462,146	\$ 3,256,355	\$ 4,020,588	\$ 4,623,651	\$ 5,176,749	\$ 5,457,149	\$ 5,653,000	
<i>Incremental Revenue Required</i>	\$ 8,986	\$ 48,098	\$ 65,565	\$ 88,274	\$ 97,017	\$ 99,332	\$ 95,583	\$ 75,425	\$ 69,176	\$ 35,070	\$ 24,495	\$ 707,021
<i>Cumulative Revenue Required</i>	\$ 8,986	\$ 57,084	\$ 122,649	\$ 210,923	\$ 307,940	\$ 407,272	\$ 502,855	\$ 578,280	\$ 647,456	\$ 682,526	\$ 707,021	
Transmission Projects	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Totals
<i>Construction Work in Process in Rates</i>	\$ -	\$ 192	\$ 203	\$ 3	\$ 845	\$ 10,010	\$ 30,475	\$ 61,679	\$ 40,785	\$ 98,345	\$ 417,839	\$ 660,376
<i>Cumulative</i>	\$ -	\$ 192	\$ 395	\$ 398	\$ 1,243	\$ 11,253	\$ 41,728	\$ 103,407	\$ 144,192	\$ 242,537	\$ 660,376	
<i>Incremental Revenue Required</i>	\$ -	\$ 24	\$ 25	\$ -	\$ 106	\$ 1,252	\$ 3,812	\$ 7,714	\$ 5,101	\$ 12,300	\$ 52,259	\$ 82,593
<i>Cumulative Revenue Required</i>	\$ -	\$ 24	\$ 49	\$ 49	\$ 155	\$ 1,407	\$ 5,219	\$ 12,933	\$ 18,034	\$ 30,334	\$ 82,593	
Total	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Totals
<i>Construction Work in Process in Rates</i>	\$ 71,848	\$ 384,762	\$ 524,430	\$ 705,800	\$ 776,549	\$ 804,219	\$ 794,708	\$ 664,742	\$ 593,883	\$ 378,745	\$ 613,690	\$ 6,313,376
<i>Cumulative</i>	\$ 71,848	\$ 456,610	\$ 981,040	\$ 1,686,840	\$ 2,463,389	\$ 3,267,608	\$ 4,062,316	\$ 4,727,058	\$ 5,320,941	\$ 5,699,686	\$ 6,313,376	
<i>Incremental Revenue Required</i>	\$ 8,986	\$ 48,122	\$ 65,590	\$ 88,274	\$ 97,123	\$ 100,584	\$ 99,395	\$ 83,139	\$ 74,277	\$ 47,370	\$ 76,754	\$ 789,614
<i>Cumulative Revenue Required</i>	\$ 8,986	\$ 57,108	\$ 122,698	\$ 210,972	\$ 308,095	\$ 408,679	\$ 508,074	\$ 591,213	\$ 665,490	\$ 712,860	\$ 789,614	

Assumptions:

<i>Gross Weighted Average Cost of Capital</i>	12.51%
<i>Annual Base Load Review Filing</i>	May 30
<i>Annual CWIP True-Up</i>	June 30
<i>Rates Effective</i>	March 30, 2009, October 30, 2009, and annually on October 30

EXHIBIT M, Chart B**Retail Rate Impact Projections****Combined Application of South Carolina Electric & Gas Company for a Certificate of Environmental Compatibility and Public Convenience and Necessity and for a Base Load Review Order**

(Millions of \$)

	<u>2007</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>2012</u>	<u>2013</u>	<u>2014</u>	<u>2015</u>	<u>2016</u>	<u>2017</u>	<u>2018</u>	<u>2019</u>	<u>2020</u>	<u>Total</u>
Retail Margin Forecast (existing rates)	\$ 1,272	\$ 1,303	\$ 1,340	\$ 1,373	\$ 1,401	\$ 1,365	\$ 1,378	\$ 1,392	\$ 1,420	\$ 1,449	\$ 1,478	\$ 1,508	\$ 1,538	\$ 1,559	
Base Retail Fuel Costs @ existing rates	\$ 575	\$ 618	\$ 633	\$ 650	\$ 665	\$ 657	\$ 665	\$ 673	\$ 686	\$ 700	\$ 714	\$ 728	\$ 743	\$ 754	
Nuclear Fuel Cost Adjustment										\$ (123)	\$ (123)	\$ (123)	\$ (255)	\$ (255)	
Production Tax Credits Applied to Fuel Costs										\$ (124)	\$ (101)	\$ (65)	\$ (98)	\$ (98)	
Net	\$ 575	\$ 618	\$ 633	\$ 650	\$ 665	\$ 657	\$ 665	\$ 673	\$ 686	\$ 452	\$ 489	\$ 540	\$ 389	\$ 401	
Total Base Revenues	\$ 1,847	\$ 1,921	\$ 1,973	\$ 2,024	\$ 2,066	\$ 2,022	\$ 2,043	\$ 2,065	\$ 2,106	\$ 1,901	\$ 1,968	\$ 2,048	\$ 1,927	\$ 1,960	
Incremental Revenue Requirements-BLRA	\$ -	\$ 9	\$ 48	\$ 66	\$ 88	\$ 97	\$ 100	\$ 100	\$ 83	\$ 298	\$ 53	\$ 71	\$ 216	\$ -	\$ 1,229
Cumulative Revenue Requirements-BLRA	\$ -	\$ 9	\$ 57	\$ 123	\$ 211	\$ 308	\$ 409	\$ 508	\$ 591	\$ 889	\$ 942	\$ 1,013	\$ 1,229	\$ 1,229	
Gross Revenue	\$ 1,847	\$ 1,930	\$ 2,030	\$ 2,146	\$ 2,277	\$ 2,330	\$ 2,452	\$ 2,573	\$ 2,697	\$ 2,790	\$ 2,910	\$ 3,061	\$ 3,156	\$ 3,189	
Retail Sales	22,150	22,764	23,300	23,958	24,476	24,200	24,482	24,784	25,268	25,778	26,298	26,822	27,356	27,774	
Total \$/KWH	\$ 0.0834	\$ 0.0848	\$ 0.0871	\$ 0.0896	\$ 0.0930	\$ 0.0963	\$ 0.1001	\$ 0.1038	\$ 0.1067	\$ 0.1082	\$ 0.1107	\$ 0.1141	\$ 0.1154	\$ 0.1148	
Annual Rate Change		0.49%	2.8%	2.8%	3.8%	3.5%	4.0%	3.7%	2.8%	1.4%	2.2%	3.1%	1.1%	-0.5%	2.49%

Incremental Revenue requirements in 2016 and 2019 include projected in-service costs

The forecasts listed here are indicative of the rate impacts that may be expected from construction and operation of VCSNS Units 2 & 3 on a stand-alone basis.

These forecasts do not reflect overall rate changes during the period, which may include changes in such things as fuel costs, and base rates. In addition, actual rate impacts from the Units will vary based on such things as the actual rates of growth in customers and demand during the period, changes in SCE&G's cost of capital, changes in the amount and timing of investment in the Units, changes in in-service expenses, and other factors. Please see the introduction to the Exhibit for additional information.

EXHIBIT N

REVISED RATES REQUESTED IN BASE LOAD REVIEW ORDER

**Combined Application of South Carolina Electric & Gas Company for a
Certificate of Environmental Compatibility and Public Convenience and
Necessity and for a Base Load Review Order
Public Service Commission Docket No. 2008-196-E**

1. INTRODUCTION

This **Exhibit N** provides the revised rates and charges that SCE&G requests the Commission to authorize in the Order in this proceeding. These rates and charges have been computed in conformity with the cost allocations and rate design set forth in **Exhibit K** to this Application.

**SOUTH CAROLINA ELECTRIC & GAS COMPANY
PROPOSED ELECTRIC RATE SCHEDULES**

Listed are the proposed electric rate schedules included as follows:

<u>Rate</u>	<u>Description</u>
1 (RGC)	Good Cents Residential Service
2	Low Use Residential Service
3	Municipal Power Service
5	Time-of-Use Residential Service
6 (RGCC)	Energy Saver/Conservation Residential Service
7	Time-of-Use Demand Residential Service
8	Residential Service
9	General Service
10	Small Construction Service
11	Irrigation Service
12 (C)	Church Service
13 (ML)	Municipal Lighting Service
14	Farm Service
15 (SS-1)	Supplementary and Standby Service
16	Time-of-Use General Service
19	Concurrent Demand Time-of-Use General Service
20	Medium General Service
21	General Service Time-of-Use Demand
21A	Experimental Program – General Service Time-of-Use Demand
22 (S)	School Service
23	Industrial Power Service
24	Large General Service Time-of-Use

Contract Rates

RATE 1 (RGC)

RESIDENTIAL SERVICE
GOOD CENTS RATE

AVAILABILITY

Effective January 15, 1996 this schedule is closed and not available to any new structure.

This rate is available to customers who meet the Company's Good Cents requirements and use the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system to individually metered private residence and individually metered dwelling units in apartment structures or other multi-family residential structures. It is not available for resale service nor shall service be supplied to dwelling units having a total of more than ten rooms, five or more of which are rented or offered for rent to any person or persons not a member, or members, of the immediate family of the owner or lessor of the dwelling units.

A dwelling unit is defined as a room or group of rooms having, in addition to living quarters, kitchen facilities for the sole use of the family or individual occupying such dwelling unit.

CERTIFICATION REQUIREMENTS

Prior to construction, the customer or prospective customer must contact the Company to ascertain the requirements of the Good Cents Program and to arrange for on-site inspections for compliance.

The dwelling unit must be certified by the Company to meet or exceed the Company's Good Cents Program requirements in force at the time of application in order to qualify for service under this rate schedule.

CHARACTER OF SERVICE

Alternating Current, 60 hertz, single phase, 120 volts, 2 wire or 120/240 volts 3 wire.

RATE PER MONTH

	<u>Summer</u> (Billing Months June-September)	<u>Winter</u> (Billing Months October-May)
Basic Facilities Charge:	\$ 8.00	\$ 8.00
Plus Energy Charge:		
First 800 Kwhrs. @	\$ 0.09630 per Kwhr.	\$ 0.09630 per Kwhr.
Excess over 800 Kwhrs. @	\$ 0.10593 per Kwhr.	\$ 0.09245 per Kwhr.

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge as stated above.

ADJUSTMENT FOR FUEL AND VARIABLE ENVIRONMENTAL COSTS

Fuel costs of \$.02742 per Kwhr. are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

The energy charges above include a storm damage component of \$.00043 per Kwhr. for accumulation of a storm damage reserve.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when customer pays the difference in costs between non-standard service and standard service or pays the Company its normal monthly facility charge based on such difference in costs.

TERM OF CONTRACT

Contracts shall be written for a period of not less than one (1) year. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 2

LOW USE RESIDENTIAL SERVICE

AVAILABILITY

This rate is available to customers that meet the special conditions listed below, and are served by the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system to individually metered private residences and individually metered dwelling units in apartment structures or other multi-family residential structures. It is not available for resale service nor shall service be supplied to dwelling units having a total of more than ten rooms, five or more of which are rented or offered for rent to any person or persons not a member, or members, of the immediate family of the owner or lessor of the dwelling units.

A dwelling unit is defined as a room or group of rooms having, in addition to living quarters, kitchen facilities for the sole use of the family or individual occupying such dwelling unit.

SPECIAL CONDITIONS OF SERVICE

- 1) This rate schedule is available to those accounts where the consumption has not exceeded 400 Kwhrs. for each of the twelve billing months preceding the billing month service is to be initially billed under this rate schedule. The customer must have occupied the dwelling unit for the entire time necessary to determine eligibility under this rate schedule.
- 2) Consumption during a billing period of more than 30 days, used to determine eligibility under this rate schedule, shall be adjusted to a 30 day billing period by application of a fraction, the numerator of which shall be 30 and the denominator of which shall be the actual number of days in the billing period.
- 3) The second billing month within a twelve billing month period that consumption under this rate schedule exceeds 400 Kwhrs. will terminate eligibility under this rate schedule.
- 4) Service will be billed under the previous rate schedule the next twelve billing periods before the customer will again be eligible for the Low Use Rate.

CHARACTER OF SERVICE

Alternating Current, 60 hertz, single phase, 120 volts, 2 wire or 120/240 volts 3 wire.

RATE PER MONTH

Basic Facilities Charge:	\$ 8.00
Plus Energy Charge:	
All Kwhrs. @	\$ 0.07242 per Kwhr.

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge as stated above.

ADJUSTMENT FOR FUEL AND VARIABLE ENVIRONMENTAL COSTS

Fuel costs of \$.02742 per Kwhr. are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

The energy charges above include a storm damage component of \$.00043 per Kwhr. for accumulation of a storm damage reserve.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

TERM OF CONTRACT

Contracts shall be written for a period of not less than one (1) year. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 3 (M)**MUNICIPAL
POWER SERVICE****AVAILABILITY**

This rate is available to municipal customers using the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system. This includes all municipally owned and operated facilities for power purposes including, but not restricted to public buildings and pumping stations. It is not available for resale or standby service.

CHARACTER OF SERVICE

Alternating Current, 60 hertz. Voltage and phase at the option of the Company.

RATE PER MONTH

Basic Facilities Charge: \$ 16.50

Plus Energy Charge:

Summer Billing Months (June-September)
All Kwhrs. @ \$ 0.08423 per Kwhr.

Winter Billing Months (October-May)
All Kwhrs. @ \$ 0.08423 per Kwhr.

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge as stated above, provided however, when construction costs exceed four (4) times the estimated annual revenue excluding fuel revenue to be derived by the Company, the customer may make a contribution in aid of construction of the excess cost or pay the Company's standard facility rate on the excess construction cost in addition to the rate charges above.

ADJUSTMENT FOR FUEL AND VARIABLE ENVIRONMENTAL COSTS

Fuel costs of \$.02728 per Kwhr. are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

The energy charges above include a storm damage component of \$.00038 per Kwhr. for accumulation of a storm damage reserve.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

Service shall not be supplied under this rate for establishments of a commercial nature, nor to operations primarily non-municipal. Under no conditions will the Company allow the service to be resold to or shared with others.

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

TERM OF CONTRACT

Contracts shall be written for a period of not less than ten (10) years. Contracts shall be written for a period of not less than ten (10) years.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 5

RESIDENTIAL SERVICE
TIME OF USE**AVAILABILITY**

This rate is available on a voluntary basis to customers using the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system to individually metered private residences and individually metered dwelling units in apartment structures or other multi-family residential structures. It is not available for resale service nor shall service be supplied to dwelling units having a total of more than ten rooms, five or more of which are rented or offered for rent to any person or persons not a member, or members, of the immediate family of the owner or lessor of the dwelling units.

A dwelling unit is defined as a room or group of rooms having, in addition to living quarters, kitchen facilities for the sole use of the family or individual occupying such dwelling unit.

CHARACTER OF SERVICE

Alternating Current, 60 hertz, single phase, 120 volts, 2 wire or 120/240 volts 3 wire.

RATE PER MONTH**I. Summer Months of June-September**

A. Basic Facilities Charge:	\$ 12.00
B. Energy Charge:	
All on-peak Kwhrs. @	\$ 0.22303 per Kwhr.
All off-peak Kwhrs. @	\$ 0.07439 per Kwhr.
C. Minimum Bill:	
The monthly minimum charge shall be the basic facilities charge	

II. Winter Months of October-May

A. Basic Facilities Charge:	\$ 12.00
B. Energy Charge:	
All on-peak Kwhrs. @	\$ 0.20976 per Kwhr.
All off-peak Kwhrs. @	\$ 0.07439 per Kwhr.
C. Minimum Bill:	
The monthly minimum charge shall be the basic facilities charge	

DETERMINATION OF ON-PEAK HOURS**A. On-Peak Hours:**

Summer Months of June-September:

The on-peak summer hours are defined as the hours between 2:00 p.m.-7:00 p.m., Monday-Friday, excluding holidays.*

Winter Months of October-May:

The on-peak winter hours are defined as the hours between 7:00 a.m.-12:00 noon, Monday-Friday, excluding holidays.*

B. Off-Peak Hours:

The off-peak hours in any month are defined as all hours not specified as on-peak hours.

*Holidays are: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

ADJUSTMENT FOR FUEL AND VARIABLE ENVIRONMENTAL COSTS

Fuel costs of \$.02742 per Kwhr. are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

The energy charges above include a storm damage component of \$.00043 per Kwhr. for accumulation of a storm damage reserve.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

The Company shall have the right to install and operate special metering equipment to measure customer's loads or any part thereof and to obtain any other data necessary to determine the customer's load characteristics.

The Company's levelized payment plans are not available to customers served under this rate schedule.

TERM OF CONTRACT

Contracts shall be written for a period of not less than one (1) year. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 6 (RGCC)**RESIDENTIAL SERVICE
ENERGY SAVER/
CONSERVATION RATE**
(Page 1 of 2)**AVAILABILITY**

This rate is available to customers using the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system to individually metered private residences and individually metered dwelling units in apartment structures or other multi-family residential structures. It is not available for resale service nor shall service be supplied to dwelling units having a total of more than ten rooms, five or more of which are rented or offered for rent to any person or persons not a member, or members, of the immediate family of the owner or lessor of the dwelling units.

A dwelling unit is defined as a room or group of rooms having, in addition to living quarters, kitchen facilities for the sole use of the family or individual occupying such dwelling unit.

The builder or homeowner must provide the following:

- 1) For new homes only - Proof that home meets the Council of American Building Officials Model Energy Code.
- 2) Receipts showing the purchase and installation of a new AC unit that meets the requirements as shown below.
- 3) A certificate issued by an installer showing a wall total cavity R value of 15 (R-15).
- 4) Certification from builder stating that requirements have been met.

The Company may perform an on-site audit to verify that customer meets availability requirements as stated herein.

THERMAL AND AIR CONDITIONING REQUIREMENTS FOR ENERGY CONSERVATION

The following requirements are predicated on the Council of American Building Officials Model Energy Code and subject to change with a change in the Council of American Building Officials Model Energy Code. Sufficient application of thermal control products and specified air conditioning requirements must be met to satisfy the minimum standards outlined below:

- Ceilings:** Ceilings of newly constructed homes shall be insulated with a total "as installed" thermal resistance (R) value of 30 (R-30).
Ceilings of manufactured housing shall be insulated with a thermal resistance (R) value of 30 (R-30).
Ceilings of existing housing shall be insulated with a total "as installed" thermal resistance (R) value of 38 (R-38).
- Lighting:** Recessed ceiling lights shall be sealed.
- Walls:** Walls exposed to the full temperature differential (TD), or unconditioned areas, shall have a total cavity R value of 15 (R-15).
*This is not a requirement for existing housing.
- Floors:** Floors over crawl space or crawl space walls shall have insulation installed having a total R value of 19 (R-19).
100% of the exposed earth in a crawl space shall be covered with a vapor barrier of no less than (4) mills.
- Windows:** Windows shall be insulated (double) glass or have storm windows.
- Doors:** Doors exposed to full TD areas must be weather-stripped on all sides and of solid construction.
- Ducts:** Air ducts located outside of conditioned space must have: 1) all joints properly fastened and sealed, and, 2) the duct shall have a minimum installed insulation R-value of 6.0. All joints in ductwork outside of the conditioned space must be permanently sealed with the application of duct sealant. Transverse joints, take-offs, transitions, supply/return connections to the air handler, boot connections to the floor/ceiling/wall, and framed-in and panned passages must be made airtight with duct sealant.
- Attic Vent:** Attic ventilation must be a minimum of one square foot of net free area for each 150 square feet attic floor area.
- Water Heaters:** Electric water heaters must have insulation surrounding the tank with minimum total R value of 8 (R-8).
- Air Condition:** All air conditioners must have a SEER rating of 1.5 SEER higher than the rating shown in the Council of American Building Officials Model Energy Code or 12 SEER or any federal or state mandated energy codes, whichever is higher.
- Other:** Chimney flues and fireplaces must have tight fitting dampers.

*Insulation thermal resistance values are shown for insulation only, framing corrections will not be considered.

The "as installed" thermal resistance (R) value for all loose fill or blowing type insulation materials must be verifiable either by installed density using multiple weighted samples, the manufacturer's certification methods, Federal Trade Commission's procedures or other methods specified by local governing agencies.

RATE 6 (RGCC)

**RESIDENTIAL SERVICE
ENERGY SAVER/
CONSERVATION RATE**
(Page 2 of 2)

CHARACTER OF SERVICE

Alternating Current, 60 hertz, single phase, 120 volts, 2 wire or 120/240 volts 3 wire.

RATE PER MONTH

	<u>Summer</u> (Billing Month June-September)	<u>Winter</u> (Billing Month October-May)
Basic Facilities Charge:	\$ 8.00	\$ 8.00
Plus Energy Charge:		
First 800 Kwhrs. @	\$ 0.09630 per Kwhr.	\$ 0.09630 per Kwhr.
Excess over 800 Kwhrs. @	\$ 0.10593 per Kwhr.	\$ 0.09245 per Kwhr.

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge as stated above.

ADJUSTMENT FOR FUEL AND VARIABLE ENVIRONMENTAL COSTS

Fuel costs of \$.02742 per Kwhr. are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

The energy charges above include a storm damage component of \$.00043 per Kwhr. for accumulation of a storm damage reserve.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

TERM OF CONTRACT

Contracts shall be written for a period of not less than one (1) year. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 7**RESIDENTIAL SERVICE
TIME-OF-USE DEMAND****AVAILABILITY**

This rate is available on a voluntary basis to customers using the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system to individually metered private residences and individually metered dwelling units in apartments structures or other multi-family residential structures. It is not available for resale service nor shall service be supplied to dwelling units having a total or more than ten rooms, five or more of which are rented or offered for rent to any person or persons not a member, or members, of the immediate family of the owner or lessor of the dwelling units.

A dwelling unit is defined as a room or group of rooms having, in addition to living quarters, kitchen facilities for the sole use of the family or individual occupying such dwelling unit.

CHARACTER OF SERVICE

Alternating Current, 60 hertz, single phase, 120 volts, 2 wire or 120/240 volts 3 wire.

RATE PER MONTH

I. Basic Facilities Charge:	\$ 12.00
II. Demand Charge:	
A. On-Peak Billing Demand	
Summer Months of June-September @	\$ 10.25 per KW
Non-Summer Months of October-May @	\$ 6.44 per KW
III. Energy Charge:	
All on-peak Kwhrs. @	\$ 0.06795 per Kwhr.
All off-peak Kwhrs. @	\$ 0.05227 per Kwhr.

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge as stated above.

BILLING DEMAND

The maximum integrated fifteen minute demand for the current month occurring during the on-peak hours specified below. The maximum integrated fifteen minute demand for any period may be recorded on a rolling time interval.

DETERMINATION OF ON-PEAK HOURS**A. On-Peak Hours:**

Summer Months of June-September:

The on-peak summer hours are defined as the hours between 2:00 p.m.-7:00 p.m., Monday-Friday, excluding holidays.*

Non-Summer Months of October-May:

The on-peak winter hours are defined as the hours between 7:00 a.m.-12:00 noon, Monday-Friday, excluding holidays.*

B. Off-Peak Hours:

The off-peak hours in any month are defined as all hours not specified as on-peak hours.

*Holidays are: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

ADJUSTMENT FOR FUEL AND VARIABLE ENVIRONMENTAL COSTS

Fuel costs of \$.02742 per Kwhr. are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

The energy charges above include a storm damage component of \$.00043 per Kwhr. for accumulation of a storm damage reserve.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

The Company shall have the right to install and operate special metering equipment to measure customer's loads or any part thereof and to obtain any other data necessary to determine the customer's load characteristics.

The Company's levelized payment plans are not available to customers served under this rate schedule.

TERM OF CONTRACT

Contracts shall be written for a period of not less than one (1) year. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 8

RESIDENTIAL SERVICE

AVAILABILITY

This rate is available to customers using the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system to individually metered private residences and individually metered dwelling units in apartment structures or other multi-family residential structures. It is not available for resale service nor shall service be supplied to dwelling units having a total of more than ten rooms, five or more of which are rented or offered for rent to any person or persons not a member, or members, of the immediate family of the owner or lessor of the dwelling units.

A dwelling unit is defined as a room or group of rooms having, in addition to living quarters, kitchen facilities for the sole use of the family or individual occupying such dwelling unit.

CHARACTER OF SERVICE

Alternating Current, 60 hertz, single phase, 120 volts, 2 wire or 120/240 volts 3 wire.

RATE PER MONTH

	<u>Summer</u> (Billing Month June-September)	<u>Winter</u> (Billing Month October-May)
Basic Facilities Charge:	\$ 8.00	\$ 8.00
Plus Energy Charge:		
First 800 Kwhrs. @	\$ 0.10008 per Kwhr.	\$ 0.10008 per Kwhr.
Excess over 800 Kwhrs. @	\$ 0.11009 per Kwhr.	\$ 0.09608 per Kwhr.

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge as stated above.

ADJUSTMENT FOR FUEL AND VARIABLE ENVIRONMENTAL COSTS

Fuel costs of \$.02742 per Kwhr. are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

The energy charges above include a storm damage component of \$.00043 per Kwhr. for accumulation of a storm damage reserve.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

TERM OF CONTRACT

Contracts shall be written for a period of not less than one (1) year. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 9

GENERAL SERVICE

(Page 1 of 2)

AVAILABILITY

This rate is available to customers using the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system for general light and/or power purposes such as commercial, industrial, religious, charitable and eleemosynary institutions. It is not available for resale service.

CHARACTER OF SERVICE

Alternating Current, 60 hertz. Voltage and phase at the option of the Company.

RATE PER MONTH

	<u>Summer</u> (Billing Months June-September)	<u>Winter</u> (Billing Months October-May)
Basic Facilities Charge:	\$ 16.50	\$ 16.50

Demand Charge:

<u>First 250 KVA of Billing Demand</u>	No Charge	<u>No Charge</u>
<u>Excess over 250 KVA of Billing Demand @</u>	\$ 3.05 per KVA	<u>No Charge</u>

The Billing Demand (to the nearest whole KVA) shall be the maximum integrated fifteen (15) minute demand measured during the billing months of June through September.

Energy Charge:

<u>First 3,000 Kwhrs. @</u>	\$ 0.09956 per Kwhr.	<u>\$ 0.09956 per Kwhr.</u>
<u>Over 3,000 Kwhrs. @</u>	\$ 0.10593 per Kwhr.	<u>\$ 0.09249 per Kwhr.</u>

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge and demand charge as stated above, provided however, when construction costs exceed four (4) times the estimated annual revenue excluding fuel revenue to be derived by the Company, the customer may make a contribution in aid of construction of the excess cost or pay the Company's standard facility rate on the excess construction cost in addition to the rate charges above.

ADJUSTMENT FOR FUEL AND VARIABLE ENVIRONMENTAL COSTS

Fuel costs of \$.02728 per Kwhr. are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

The energy charges above include a storm damage component of \$.00038 per Kwhr. for accumulation of a storm damage reserve.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

POWER FACTOR

If the power factor of the Customer's installation falls below 85%, the Company may adjust the billing to a basis of 85% power factor.

TEMPORARY SERVICE

Temporary service for construction and other purposes will be supplied under this rate in accordance with the Company's Terms and Conditions covering such service.

PAYMENT TERMS

All bills are net and payable when rendered.

RATE 9

GENERAL SERVICE

(Page 2 of 2)

SPECIAL PROVISIONS

This rate is available for residential service where more than one dwelling unit is supplied through a single meter, provided service to such dwelling unit was established prior to July 1, 1980.

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

UNMETERED SERVICE PROVISION

When customer's usage can be determined and in the sole opinion of the Company, installation of metering equipment is impractical or uneconomical, monthly Kwhrs. may be estimated by the Company and billed at the above rate per month, except that the basic facilities charge shall be \$5.25.

TERM OF CONTRACT

Contracts for installation of a permanent nature shall be written for a period of not less than one (1) year. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 11

IRRIGATION SERVICE

AVAILABILITY

This rate is available to customers using the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system. It is not available for resale. This schedule is available for service furnished for the operation of electric motor driven pumps and equipment supplying water for the irrigation of farmlands and plant nurseries, and irrigation to provide adequate moisture for vegetative cover to control erosion and provide runoff. The pumping units served hereunder shall be used solely for the purpose of irrigation.

All motors of more than 5 H.P. shall be approved by the Company. The Company reserves the right to deny service to any motor which will be detrimental to the service of other customers. Upon request, customer may pay all cost associated with upgrading the system to the point at which starting the customer's motor will not degrade the service to the other customers.

CHARACTER OF SERVICE

Alternating Current, 60 hertz. Voltage and phase at the option of the Company.

RATE PER MONTH

I. Summer Months of June-September

A. Basic Facilities Charge:	\$	20.15	
B. Energy Charge:			
All on-peak Kwhrs. @	\$	0.18170	per Kwhr.
All shoulder Kwhrs. @	\$	0.10720	per Kwhr.
All off-peak Kwhrs. @	\$	0.05974	per Kwhr.

II. Winter Months of October-May

A. Basic Facilities Charge:	\$	20.15	
B. Energy Charge:			
All Kwhrs. @	\$	0.05974	per Kwhr.

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge as stated above, except when the revenue produced by the customer does not sufficiently support the investment required to serve the load. The Company will determine in each case the amount and form of payment required to correct the revenue deficiency.

DETERMINATION OF ON-PEAK SHOULDER, AND OFF-PEAK HOURS

A. On-Peak Hours:

Summer Months of June-September:

The on-peak summer hours are defined as the hours between 2:00 p.m.-6:00 p.m., Monday-Friday, excluding holidays.*

B. Shoulder Hours:

Summer Months of June-September:

The shoulder summer hours are defined as the hours between 10:00 a.m.-2:00 p.m. and 6:00 p.m.-10:00 p.m., Monday-Friday, excluding holidays.*

C. Off-Peak Hours:

The off-peak hours in any month are defined as all hours not specified as on-peak or shoulder hours.

*Holidays are Independence Day and Labor Day.

ADJUSTMENT FOR FUEL AND VARIABLE ENVIRONMENTAL COSTS

Fuel costs of \$.02728 per Kwhr. are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

The energy charges above include a storm damage component of \$.00038 per Kwhr. for accumulation of a storm damage reserve.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

The Company shall have the right to install and operate special metering equipment to measure customer's loads or any part thereof and obtain any other data necessary to determine the customer's load characteristics.

TERM OF CONTRACT

Contracts for installations shall be written for a period of not less than ten (10) years. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 12 (C)**CHURCH SERVICE****AVAILABILITY**

This rate is available to customers using the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system for general light and/or power service to churches. It is not available for resale or standby service. It is only available to recognized churches.

CHARACTER OF SERVICE

Alternating Current, 60 hertz. Voltage and phase at the option of the Company.

RATE PER MONTH

Basic Facilities Charge:	\$	10.80
Plus Energy Charge:		
All Kwhrs. @	\$	0.08447 per Kwhr.

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge as stated above, provided however, when construction costs exceed four (4) times the estimated annual revenue excluding fuel revenue to be derived by the Company, the customer may make a contribution in aid of construction of the excess cost or pay the Company's standard facility rate on the excess construction cost in addition to the rate charges above.

ADJUSTMENT FOR FUEL AND VARIABLE ENVIRONMENTAL COSTS

Fuel costs of \$.02728 per Kwhr. are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

The energy charges above include a storm damage component of \$.00038 per Kwhr. for accumulation of a storm damage reserve.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Under no conditions will the Company allow the service to be resold to or shared with others. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

When a church offers activities that, in the sole opinion of the Company, are of a commercial nature such as day care, camps or recreational activities, the Company may require that the account be served under the appropriate general service rate.

TERM OF CONTRACT

Contracts shall be written for a period of not less than five (5) years. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 13 (ML)

**MUNICIPAL
LIGHTING SERVICE**

AVAILABILITY

This rate is available to municipal customers using the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system. This includes all municipally owned and operated facilities for lighting streets, highways, parks and other public areas, or other signal system service. It is not available for resale or standby service.

CHARACTER OF SERVICE

Alternating Current, 60 hertz. Voltage and phase at the option of the Company.

RATE PER MONTH

Basic Facilities Charge:	\$	16.50
Plus Energy Charge:		
All Kwhrs. @	\$	0.07918 per Kwhr.

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge as stated above, provided however, when construction costs exceed four (4) times the estimated annual revenue excluding fuel revenue to be derived by the Company, the customer may make a contribution in aid of construction of the excess cost or pay the Company's standard facility rate on the excess construction cost in addition to the rate charges above.

ADJUSTMENT FOR FUEL AND VARIABLE ENVIRONMENTAL COSTS

Fuel costs of \$.02728 per Kwhr. are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

The energy charges above include a storm damage component of \$.00038 per Kwhr. for accumulation of a storm damage reserve.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

Service shall not be supplied under this rate for establishments of a commercial nature, nor to operations primarily non-municipal. Under no circumstances will the Company allow the service to be resold or shared with others.

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

TERM OF CONTRACT

Contracts shall be written for a period of not less than ten (10) years.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 14

FARM SERVICE

AVAILABILITY

This rate is available to customers using the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system on farms for producing but not processing agricultural, dairy, poultry and meat products.

Service shall not be supplied under this rate for establishments of a commercial nature such as stores, shops, stands, restaurants, service stations or any non-farm operations; nor for processing, distributing or selling farm or other products not originating through production on the premises served. Motors rated in excess of 20 H.P. will not be served on this rate. It is available for farm commercial operations including irrigation, grain elevators and crop drying for farm products produced on the premises served. It is not available for resale service.

CHARACTER OF SERVICE

Alternating Current, 60 hertz. Voltage and phase at the option of the Company.

RATE PER MONTH

	<u>Summer</u> (Billing Months June-September)	<u>Winter</u> (Billing Months October-May)
Basic Facilities Charge:	\$ 8.00	\$ 8.00
Plus Energy Charge:		
First 800 Kwhrs. @	\$ 0.09988 per Kwhr.	\$ 0.09988 per Kwhr.
Excess over 800 Kwhrs. @	\$ 0.10989 per Kwhr.	\$ 0.09588 per Kwhr.

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge as stated above, provided however, when construction costs Exceed four (4) times the estimated annual revenue excluding fuel revenue to be derived by the Company, the customer may make a contribution in aid of construction of the excess cost or pay the Company's standard facility rate on the excess construction cost in addition to the rate charges above.

ADJUSTMENT FOR FUEL AND VARIABLE ENVIRONMENTAL COSTS

Fuel costs of \$.02728 per Kwhr. are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

The energy charges above include a storm damage component of \$.00038 per Kwhr. for accumulation of a storm damage reserve.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state and governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

TERM OF CONTRACT

The contract terms will depend on the conditions of service. No contract shall be written for a period of not less than five (5) years. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 15 (SS-1)**SUPPLEMENTARY AND STANDBY SERVICE****AVAILABILITY**

Available to Small Power Producers and co-generators that are a Quality Facility as defined by the Federal Energy Regulatory Commission (FERC) Order No. 70 under Docket No. RM 79-54. This schedule is not available to Qualifying Facilities with a power production capacity greater than 100 KW.

SUPPLEMENTARY SERVICE

Supplementary service is defined herein as power supplied by the Company to a Qualifying Facility in addition to that which the Qualifying Facility generates itself. Supplementary service will be provided by the Company under a retail electric service schedule which the customer will establish in conjunction with the implementation of this Supplementary and Standby Service rate.

SUPPLEMENTARY SERVICE

- 1) Standby service under this schedule is defined herein as power supplied by the Company to a Qualifying Facility to replace energy ordinarily generated by a Qualifying Facility during a scheduled or unscheduled outage.
- 2) Standby service is available to customers establishing a firm demand which is billed under a retail electric service schedule of the Company. If no firm demand is established by the customer for the purpose of taking Supplementary power, then Standby service will be provided as Supplementary service and billed on the applicable retail electric service schedule.
- 3) Standby service is defined for each 15-minute interval as the minimum of: (1) the Standby contracted demand, and, (2) the difference between the measured load and the contracted firm demand, except that such difference shall not be less than zero.
- 4) Supplementary Service is defined as all power supplied by the Company not defined herein as Standby Service.
- 5) The Standby contract demand shall be limited to the power production capacity of the Qualifying Facility.

STANDBY SERVICE POWER RATE PER MONTH

Basic Facilities Charge	\$ 155.00
Demand Charge per KW of Contract Demand	\$ 4.49
Energy Charge:	
On-Peak KWH	\$ 0.04604
Off-Peak KWH	\$ 0.03509

DETERMINATION OF ON-PEAK AND OFF-PEAK HOURS

- A. On-Peak Hours:**
On-peak hours are defined to be 10:00 a.m. - 10:00 p.m. for the months of June-September, excluding weekends.
- B. Off-Peak Hours:**
All hours not defined as on-peak hours are considered to be off-peak.

POWER FACTOR

The customer must maintain a power factor of as near unity as practicable. If the power factor of the customer's installation falls below 85%, the Company shall adjust the billing demand to a basis of 85% power factor.

LIMITING PROVISION

The Standby Service power rate will be available for 1325 annual hours of consumption beginning in May and ending in April, or for a prorated share thereof for customers who begin to receive service in months other than May. Accounts on this rate are subject to the following condition: Standby service will be available for a maximum of 120 On-Peak Hours.

If this account exceeds: (1) 1325 hours of Standby service annually, or (2) 120 on-peak hours of Standby service, the account will be billed on the rate normally applied to customer's Supplementary service load for the current billing month and the subsequent eleven months.

ADJUSTMENT FOR FUEL AND VARIABLE ENVIRONMENTAL COSTS

Fuel costs of \$.02716 per Kwhr. are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

The energy charges above include a storm damage component of \$.00008 per Kwhr. for accumulation of a storm damage reserve.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The customer is responsible for all costs associated with interconnection to the Company's system for the purpose of obtaining Supplementary or Standby power.

TERM OF CONTRACT

Contracts shall be written for a period of not less than three (3) years.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and a part of this rate schedule.

RATE 16

**GENERAL SERVICE
TIME-OF-USE**

AVAILABILITY

This rate is available to any non-residential customer using the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system for power and light requirements and having an on-peak demand of less than 1,000 KW. The second billing month within a twelve billing month period that on-peak demand exceeds 1,000 KW will terminate eligibility under this rate schedule. It is not available for resale service.

CHARACTER OF SERVICE

Alternating Current, 60 hertz. Voltage and phase at the option of the Company.

RATE PER MONTH

I. Basic Facilities Charge:	\$ 20.15
II. Energy Charge:	
A. On-Peak Kwhrs.	
1. Months of June-September	\$ 0.18170 per Kwhr.
2. Months of October-May	\$ 0.14318 per Kwhr.
B. Off-Peak Kwhrs.	
First 1,000 off-peak Kwhrs. @	\$ 0.07268 per Kwhr.
Excess over 1,000 off-peak Kwhrs. @	\$ 0.07733 per Kwhr.

DETERMINATION OF ON-PEAK HOURS

A. On-Peak Hours:

June-September:

The on-peak summer hours are defined as the hours between 1:00 p.m.-9:00 p.m., Monday-Friday, excluding holidays.*

October-May:

The on-peak non-summer hours are defined as those hours between 6:00 a.m.-10:00 a.m. and 6:00 p.m.-10:00 p.m.

Monday-Friday, excluding holidays.*

B. Off-Peak Hours:

The off-peak hours in any month are defined as all hours not specified as on-peak hours.

*Holidays are: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge as stated above, provided however, when construction costs exceed four (4) times the estimated annual revenue excluding fuel revenue to be derived by the Company, the customer may make a contribution in aid of construction cost in addition to the rate charges above.

ADJUSTMENT FOR FUEL AND VARIABLE ENVIRONMENTAL COSTS

Fuel costs of \$.02728 per Kwhr. are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

The energy charges above include a storm damage component of \$.00038 per Kwhr. for accumulation of a storm damage reserve.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

POWER FACTOR

If the power factor of the customer's installation falls below 85%, the Company may adjust the billing to a basis of 85% power factor.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

TERM OF CONTRACT

The contract terms will depend on the conditions of service. Contracts for installations of a permanent nature shall be written for a period of not less than one (1) year. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

Effective Upon Approval Of The Public Service Commission Of South Carolina

RATE 19

GENERAL SERVICE
CONCURRENT DEMAND
TIME-OF-USE

(Page 1 of 2)

AVAILABILITY

This rate is available at the Company's discretion, to a maximum of 10 business entities using the Company's standard electric service. Each business entity shall be comprised of at least 2 non-contiguous premises having a total combined contract demand of at least 1,000 KVA. In addition, each premises shall have a minimum contract demand of 50 KVA. A business entity is defined as a single corporation, partnership, or individual owner. This rate is not available for individual franchise units of a business, nor for subsidiaries operating as a separate corporation or partnership. The individual premises which comprise the business entity should possess similar characteristics and/or load patterns common to the industry in which the entity does business. This schedule is not available to entities which form an association or similar organization solely in an attempt to qualify for service under this rate. The Company reserves the right to make a final determination on what constitutes a business entity as well as the premises making up that entity. This rate is not available for residential customers or resale service.

Service under this rate schedule is dependent on the Company procuring and installing necessary metering equipment and may not be available to premises where multiple delivery points on contiguous properties are not currently combined under contract.

CHARACTER OF SERVICE

Alternating Current, 60 hertz, three phase metering at the delivery voltage which shall be standard to the Company's operation.

RATE PER MONTH

I. The Diversity Charge will be computed utilizing actual data or modeled using available sample data from similar entities. Once actual data is available for a twelve month period, the Diversity Charge will be reviewed and may be adjusted. The Diversity charge will not be less than zero. The Diversity Charge will be computed according to the following formula:

$$\text{Diversity Charge} = \frac{\text{AC1} - \text{AC2}}{12}$$

Where AC1 = Annual Cost Under Current Rate(s)
AC2 = Annual Cost Projected Under Concurrent Rate

II. Basic Facilities Charge: \$ 155.00 per Premises

III. Demand Charge:

A. Concurrent On-Peak Billing Demand

1. Summer Months of June-September @ \$ 19.15 per KVA
2. Non-Summer Months of October-May @ \$ 12.72 per KVA

B. Concurrent Off-Peak Billing Demand

1. All Off-Peak Billing Demand @ \$ 3.56 per KVA

IV. Energy Charge:

A. On-Peak Kwhrs.

1. Summer Months of June-September @ \$ 0.06986 per Kwhr.
2. Non-Summer Months of October-May @ \$ 0.04604 per Kwhr.

B. Off-Peak Kwhrs.

1. All Off-Peak Kwhrs. @ \$ 0.03509 per Kwhr.

BILLING DEMAND

The concurrent billing demand for the entity will be the maximum integrated 15 minute concurrent demand which may be on a rolling time interval for all the premises' metering points during the calendar month.

For the summer months, the concurrent on-peak billing demand shall be the maximum integrated fifteen minute concurrent demand measured during the on-peak hours of the current month.

For the non-summer months, the concurrent on-peak billing demand will be the greater of: (1) the maximum integrated fifteen minute concurrent demand measured during the on-peak hours of the current month, or (2) eighty percent (80%) of the maximum integrated concurrent demand occurring during the on-peak hours of the preceding months.

The concurrent off-peak billing demand shall be the greatest of the following positive differences: (1) the maximum integrated fifteen minute concurrent demand measured during the off-peak hours minus the on-peak billing demand, (2) the contract demand minus the on-peak billing demand, or (3) 50 KVA per premises minus the on-peak billing demand.

RATE 19**GENERAL SERVICE
CONCURRENT DEMAND
TIME-OF-USE**

(Page 2 of 2)

DETERMINATION OF ON-PEAK AND OFF PEAK HOURS**A. On-Peak Hours During Summer Months:**

June-September:

The on-peak summer hours are defined as the hours between 1:00 p.m.-9:00 p.m., Monday-Friday, excluding holidays.*

B. On-Peak Hours During Non-Summer Months:

May and October:

The on-peak non-summer hours are defined as the hours between 1:00 p.m.-9:00 p.m., Monday-Friday, excluding holidays.*

November-April:

The on-peak non-summer hours are defined as the hours between 6:00 a.m.-12:00 noon and 5:00p.m.-9:00 p.m., Monday-Friday, excluding holidays.*

C. Off-Peak Hours:

The off-peak hours in any month are defined as all hours not specified above as on-peak hours.

*Holidays are: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

ADDITION OR REMOVAL OF A PREMISES

An additional premises may be added subsequent to the initial five (5) year contract without an increase in the diversity charge if the entity extends the existing concurrent contract so that the term extends five (5) years after the addition of the new premises. A premises existing at the time that the entity initially elects to take service under this rate schedule may be added without an extension in the concurrent contract term; however, there will be an increase in the diversity charge as each pre-existing premises is added. If an entity wants to terminate service to a premises under this rate schedule and the same time does not add another premises which includes an extension of the contract term, the Company will determine the appropriate termination charge. Alternatively, if the entity adds an additional premises and prefers not to extend the contract term, the diversity charge will increase accordingly and the entity agrees to reimburse the Company for the total cost of connection to the Company's system if service to the new premises is terminated within five (5) years of the service date.

ADJUSTMENT FOR FUEL AND VARIABLE ENVIRONMENTAL COSTS

Fuel costs of \$.02716 per Kwhr. are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

The energy charges above include a storm damage component of \$.00022 per Kwhr. for accumulation of a storm damage reserve.

BILLING AND PAYMENT TERMS

Bills will be calculated on a monthly basis. Each premises will receive an individual information bill and the entity will receive a combined bill summarizing all of the premises. All payments, as well as any credit and collection activities, will be at the entity level. All bills are net and payable when rendered.

SALES AND FRANCHISE TAX

For each premises served under this rate, any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body, will be added to the monthly bill..

METERING

Service under this rate will be provided only after the Company procures and installs at each premises metering which has interval data capabilities to allow for the aggregation of demand for each 15 minute interval in the billing period. Each entity may be required to contribute to the cost of metering installed by the Company to qualify for service under this rate. In addition, the entity must provide a dedicated phone line at each metering point.

TERM OF CONTRACT

The contract terms will depend on the conditions of service above. No contract shall be written for a period of less than five (5) years. A master contract shall be written to include all premises amended as premises are added or deleted.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 20**MEDIUM GENERAL SERVICE****AVAILABILITY**

This rate is available to any non-residential customer using the Company's standard service for power and light requirements and having a contract demand of 75 KVA or over. It is not available for resale service.

CHARACTER OF SERVICE

Alternating Current, 60 hertz, three phase, metering at the delivery voltage which shall be standard to the Company's operation.

RATE PER MONTH**Demand Charge:**

<u>First 75 KVA of Billing Demand</u>	<u>\$ 1,260.50</u>
<u>Excess over 75 KVA of Billing Demand @</u>	<u>\$ 14.94 per KVA</u>

The billing demand (to the nearest whole KVA) shall be the greatest of: (1) the maximum integrated fifteen minute demand measured (which may be on a rolling time interval) during the current month; or (2) eighty percent (80%) of the highest demand occurring during the billing months June through September in the eleven preceding months; or (3) sixty percent (60%) of the highest demand occurring during the billing months of October through May in the eleven preceding months; or (4) the contract demand; or (5) 75 KVA.

Plus Energy Charge:

<u>First 75,000</u>	<u>\$ 0.03947 per Kwhr.</u>
<u>Excess over 75,000</u>	<u>\$ 0.03710 per Kwhr.</u>

MINIMUM CHARGE

The monthly minimum charge is the demand as determined above. The Company may allow a buildup period not to exceed six months for new and expanding accounts during which time the contract demand and/or the minimum demand specified in the rate schedule may be waived. The Company shall not commit itself to a buildup period exceeding six months without prior approval of the Commission for the specific account involved.

ADJUSTMENT FOR FUEL AND VARIABLE ENVIRONMENTAL COSTS

Fuel costs of \$.02716 per Kwhr. are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

The energy charges above include a storm damage component of \$.00022 per Kwhr. for accumulation of a storm damage reserve.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

TERM OF CONTRACT

The contract terms will depend on the conditions of service. No contract shall be written for a period of less than five (5) years. A separate contract shall be written for each meter.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and a part of this rate schedule.

RATE 21

GENERAL SERVICE
TIME-OF-USE-DEMAND

(Page 1 of 2)

AVAILABILITY

This rate is available to any customer using the Company's standard service for power and light requirements and having a contract demand of 50 KVA and a maximum demand of less than 1,000 KVA. It is not available for resale service.

CHARACTER OF SERVICE

Alternating current, 60 hertz, three phase, metering at the delivery voltage which shall be standard to the Company's operation.

RATE PER MONTH

I. Basic Facilities Charge:	\$ 155.00
II. Demand Charge:	
A. On-Peak Billing Demand:	
1. Summer Months of June-September @	\$ 19.15 per KVA
2. Non-Summer Months of October-May @	\$ 12.72 per KVA
B. Off-Peak Billing Demand	
1. All Off-Peak Billing Demand @	\$ 3.56 per KVA
III. Energy Charge:	
A. On-Peak Kwhrs.	
1. Summer Months of June-September @	\$ 0.06986 per Kwhr.
2. Non-Summer Months of October-May @	\$ 0.04604 per Kwhr.
B. Off-Peak Kwhrs.	
1. All Off-Peak Kwhrs. @	\$ 0.03509 per Kwhr.

BILLING DEMAND

The billing demands will be rounded to the nearest whole KVA. The maximum integrated fifteen minute demand for any period may be recorded on a rolling time interval.

For the summer months, the on-peak billing demand shall be the maximum integrated fifteen minute demand measured during the on-peak hours of the current month.

For the non-summer months, the on-peak billing demand will be the greater of: (1) the maximum integrated fifteen minute demand measured during the on-peak hours of the current month, or (2) eighty percent (80%) of the maximum integrated demand occurring during the on-peak hours of the preceding summer months.

The off-peak billing demand shall be the greatest of the following positive differences: (1) the maximum integrated fifteen minute demand measured during the off-peak hours minus the on-peak billing demand, (2) the contract demand minus the on-peak billing demand or (3) 50 KVA minus the on-peak billing demand.

DETERMINATION OF ON-PEAK AND OFF-PEAK HOURS

A. On-Peak Hours During Summer Months:

June-September:

The on-peak summer hours are defined as the hours between 1:00 p.m.-9:00 p.m., Monday-Friday, excluding holidays.*

B. On-Peak Hours During Non-Summer Months:

May and October:

The on-peak non-summer hours are defined as the hours between 1:00 p.m.-9:00 p.m., Monday-Friday, excluding holidays.*

November-April:

The on-peak non-summer hours are defined as these hours between 6:00 a.m.-12:00 noon and 5:00 p.m.-9:00 p.m.,

Monday-Friday, excluding holidays.*

C. Off-Peak Hours:

The off-peak hours in any month are defined as all hours not specified as on-peak hours.

*Holidays are: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

RATE 21

**GENERAL SERVICE
TIME-OF-USE-DEMAND**

(Page 2 of 2)

ADJUSTMENT FOR FUEL AND VARIABLE ENVIRONMENTAL COSTS

Fuel costs of \$.02716 per Kwhr. are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

The energy charges above include a storm damage component of \$.00022 per Kwhr. for accumulation of a storm damage reserve.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

TERM OF CONTRACT

The contract terms will depend on the conditions of service. No contract shall be written for a period less than five (5) years. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and a part of this rate schedule.

RATE 21A

EXPERIMENTAL PROGRAM - GENERAL SERVICE
TIME-OF-USE-DEMAND

(Page 1 of 2)

AVAILABILITY

This rate is available on a voluntary "first come, first serve" basis to the first 250 Rate 20 customer accounts and any Rate 21 customer account that qualify under the provisions of the stipulation approved by the South Carolina Public Service Commission in Docket #2002-223-E order No. 2003-38 dated January 31, 2003. This rate will be closed after the initial participant group is established, except there will be 25 additional customer accounts that will be allowed to participate on a "first come first serve" basis for new facilities constructed by customers in the initial participant group and as provided for in the stipulation as referenced above. The stipulation referenced above shall provide guidance as to any issue regarding availability on this rate. It is not available for resale service.

CHARACTER OF SERVICE

Alternating current, 60 hertz, three phase, metering at the delivery voltage which shall be standard to the Company's operation.

RATE PER MONTH

I. Basic Facilities Charge:	\$ 155.00
II. Demand Charge:	
A. On-Peak Billing Demand:	
1. Summer Months of June-September @	\$ 18.38 per KVA
2. Non-Summer Months of October-May @	\$ 11.41 per KVA
B. Off-Peak Billing Demand	
1. All Off-Peak Billing Demand @	\$ 3.56 per KVA
III. Energy Charge:	
A. On-Peak Kwhrs.	
1. Summer Months of June-September @	\$ 0.06566 per Kwhr.
2. Non-Summer Months of October-May @	\$ 0.04327 per Kwhr.
B. Off-Peak Kwhrs.	
1. All Off-Peak Kwhrs. @	\$ 0.03298 per Kwhr.

BILLING DEMAND

The billing demands will be rounded to the nearest whole KVA. The maximum integrated fifteen minute demand for any period may be recorded on a rolling time interval.

For the summer months, the on-peak billing demand shall be the maximum integrated fifteen minute demand measured during the on-peak hours of the current month.

For the non-summer months, the on-peak billing demand will be the greater of: (1) the maximum integrated fifteen minute demand measured during the on-peak hours of the current month, or (2) eighty percent (80%) of the maximum integrated demand occurring during the on-peak hours of the preceding summer months.

The off-peak billing demand shall be the greatest of the following positive differences: (1) the maximum integrated fifteen minute demand measured during the off-peak hours minus the on-peak billing demand, (2) the contract demand minus the on-peak billing demand or (3) 50 KVA minus the on-peak billing demand.

DETERMINATION OF ON-PEAK AND OFF-PEAK HOURS

A. On-Peak Hours During Summer Months:

June-September:

The on-peak summer hours are defined as the hours between 1:00 p.m.-9:00 p.m., Monday-Friday, excluding holidays.*

B. On-Peak Hours During Non-Summer Months:

May and October:

The on-peak non-summer hours are defined as the hours between 1:00 p.m.-9:00 p.m., Monday-Friday, excluding holidays.*

November-April:

The on-peak non-summer hours are defined as these hours between 6:00 a.m.-12:00 noon and 5:00 p.m.-9:00 p.m., Monday-Friday, excluding holidays.*

C. Off-Peak Hours:

The off-peak hours in any month are defined as all hours not specified as on-peak hours.

*Holidays are: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Effective Upon Approval Of The Public
Service Commission Of South Carolina

RATE 21A**EXPERIMENTAL PROGRAM - GENERAL SERVICE
TIME-OF-USE-DEMAND**

(Page 2 of 2)

ADJUSTMENT FOR FUEL AND VARIABLE ENVIRONMENTAL COSTS

Fuel costs of \$.02716 per Kwhr. are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

The energy charges above include a storm damage component of \$.00022 per Kwhr. for accumulation of a storm damage reserve.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

TERM OF CONTRACT

The contract terms will depend on the conditions of service. The contract for this experimental program shall be written for a period of 48 months as provided for in the stipulation approved by the South Carolina Public service Commission in docket No. 2002-223-E, order No. 2003-38 dated July 31, 2003. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and a part of this rate schedule.

Effective Upon Approval Of The Public
Service Commission Of South Carolina

RATE 22 (S)**SCHOOL SERVICE****AVAILABILITY**

This rate is available to customers using the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system for general light and/or power service to schools. It is not available for resale service. It is only available to recognized non-boarding schools with up through grade twelve.

CHARACTER OF SERVICE

Alternating Current, 60 hertz. Voltage and phase at the option of the Company.

RATE PER MONTH

Basic Facilities Charge:		\$ 10.80
Plus Energy Charge:		
First	50,000 Kwhrs.@	\$ 0.08662 per Kwhr.
Excess over	50,000 Kwhrs.@	\$ 0.10048 per Kwhr.

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge as stated above, provided however, when construction costs exceed four (4) times the estimated annual revenue excluding fuel revenue to be derived by the Company, the customer may make a contribution in aid of construction of the excess cost or pay the Company's standard facility rate on the excess construction cost in addition to the rate charges above.

ADJUSTMENT FOR FUEL AND VARIABLE ENVIRONMENTAL COSTS

Fuel costs of \$.02728 per Kwhr. are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

The energy charges above include a storm damage component of \$.00038 per Kwhr. for accumulation of a storm damage reserve.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Under no conditions will the Company allow the service to be resold to or shared with others. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

When a school offers activities that, in the sole opinion of the Company, are of a commercial nature such as day care, camps or recreational activities, the Company may require that the account be served under the appropriate general service rate.

TERM OF CONTRACT

Contracts shall be written for a period of not less than five (5) years. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 23**INDUSTRIAL POWER SERVICE****AVAILABILITY**

This rate is available to any customer classified in the major industrial group of manufacturing with 10-14 or 20-39 as the first two digits of the Standard Industrial Classification or 21 or 31-33 as the first two digits of the six digit North American Industry Classification System using the Company's standard service for power and light requirements and having a contract demand of 1,000 KW or over. It is not available for resale service.

CHARACTER OF SERVICE

Alternating Current, 60 hertz, three phase, metering at the delivery voltage which shall be standard to the Company's operation.

RATE PER MONTH**Demand Charge:**

First 1,000 KW of Billing Demand	\$ 13,600.00
Excess over 1,000 KW of Billing Demand @	\$ 12.20 per KW

The billing demand (to the nearest whole KW) shall be the greatest of: (1) the maximum integrated fifteen minute demand measured (which may be on a rolling time interval) during the current month; or (2) eighty percent (80%) of the highest demand occurring during the billing months of June through September in the eleven preceding months; or (3) sixty (60%) of the highest demand occurring during the billing months of October through May in the eleven preceding months; or (4) the contract demand; or (5) 1,000 KW.

The customer shall maintain a power factor of as near unity as practicable. If the power factor of the customer's installation falls below 85%, the Company will adjust the billing demand to a basis of 85% power factor.

Plus Energy Charge:

All Kwhrs. @	\$ 0.03567 per Kwhr.
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DISCOUNT

A discount of \$0.60 per KW of billing demand will be allowed when the service is supplied at a delivery voltage of 46,000 volts or higher.

MINIMUM CHARGE

The monthly minimum charge is the demand as determined above. The Company may allow a buildup period not to exceed six months for new and expanding accounts during which time the contract demand and/or the minimum demand specified in the rate schedule may be waived. The Company shall not commit itself to a buildup period exceeding six months without prior approval of the Commission for the specific account involved.

ADJUSTMENT FOR FUEL AND VARIABLE ENVIRONMENTAL COSTS

Fuel costs of \$.02685 per Kwhr. are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

The energy charges above include a storm damage component of \$.00008 per Kwhr. for accumulation of a storm damage reserve.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

TERM OF CONTRACT

The contract terms will depend on the conditions of service. No contract shall be written for a period less than five (5) years. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and a part of this rate schedule.

RATE 24

LARGE GENERAL SERVICE
TIME-OF-USE

(Page 1 of 2)

AVAILABILITY

This rate is available to any customer using the Company's standard service for power and light requirements and having a contract demand of 1,000 KW or over. It is not available for resale service.

CHARACTER OF SERVICE

Alternating Current, 60 hertz, three phase, metering at the delivery voltage which shall be standard to the Company's operation.

RATE PER MONTH

I. Basic Facilities Charge:	\$ 1,400.00
II. Demand Charge:	
A. On-Peak Billing Demand	
1. Summer Months of June-September @	\$ 14.97 per KW
2. Non-Summer Months of October-May @	\$ 10.48 per KW
B. Off-Peak Billing Demand	
1. All Off-Peak Billing Demand @	\$ 4.49 per KW
III. Energy Charge:	
A. On-Peak Kwhrs.	
1. Summer Months of June-September @	\$ 0.06299 per Kwhr.
2. Non-Summer Months of October-May @	\$ 0.04231 per Kwhr.
B. Off-Peak Kwhrs.	
1. All Off-Peak Kwhrs. @	\$ 0.03230 per Kwhr.

BILLING DEMAND

The billing demands will be rounded to the nearest whole KW. If the power factor of the customer's current month maximum integrated fifteen minute demand for the on-peak and off-peak time periods are less than 85%, then the Company will adjust same to 85%. The maximum integrated fifteen minute demand for any period may be recorded on a rolling time interval.

For the summer months, the on-peak billing demand shall be the maximum integrated fifteen minute demand measured during the on-peak hours of the current month.

For the non-summer months, the on-peak billing demand will be the greater of: (1) the maximum integrated fifteen minute demand measured during the on-peak hours of the current month, or (2) eighty percent (80%) of the maximum integrated demand occurring during the on-peak hours of the preceding summer months.

The off-peak billing demand shall be the greatest of the following positive differences: (1) the maximum integrated fifteen minute demand measured during the off-peak hours minus the on-peak billing demand, or (2) the contract demand minus the on-peak billing demand, or (3) 1,000 KW minus the on-peak billing demand.

DISCOUNT

A discount of \$0.60 per KW of on-peak and off-peak billing demand will be allowed when the service is supplied at a delivery voltage of 46,000 volts or higher.

DETERMINATION OF ON-PEAK HOURS

A. On-Peak Hours During Summer Months:

June-September:

The on-peak summer hours are defined as the hours between 1:00 p.m.-9:00 p.m., Monday-Friday, excluding holidays.*

B. On-Peak Hours During Non-Summer Months:

May and October:

The on-peak non-summer hours are defined as the hours between 1:00 p.m.-9:00 p.m., Monday-Friday, excluding holidays.*

November-April:

The on-peak non-summer hours are defined as those hours between 6:00 a.m.-12:00 noon and 5:00 p.m.-9:00 p.m., Monday-Friday, excluding holidays.*

C. Off-Peak Hours:

The off-peak hours in any month are defined as all hours not specified as on-peak hours.

*Holidays are: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Effective Upon Approval Of The Public
Service Commission Of South Carolina

RATE 24

LARGE GENERAL SERVICE

TIME-OF-USE

(Page 2 of 2)

MINIMUM CHARGE

The monthly minimum charge is the demand as determined above. The Company may allow a buildup period not to exceed six months for new and expanding accounts during which time the contract demand and/or the minimum demand specified in the rate schedule may be waived. The Company shall not commit itself to a buildup period exceeding six months without prior approval of the Commission for the specific account involved.

ADJUSTMENT FOR FUEL AND VARIABLE ENVIRONMENTAL COSTS

Fuel costs of \$.02685 per Kwhr. are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

The energy charges above include a storm damage component of \$.00008 per Kwhr. for accumulation of a storm damage reserve.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

TERM OF CONTRACT

The contract terms will depend on the conditions of service. No contract shall be written for a period of less than five (5) years. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and a part of this rate schedule.

SOUTH CAROLINA ELECTRIC & GAS COMPANY

ELECTRIC CONTRACTED RATES

<u>Name of Customer</u>	<u>Rate</u>
<p>State Line Accounts*</p> <p>U. S. Department of Energy Savannah River Operations</p> <p style="padding-left: 40px;">Base Contract</p>	<p>23</p> <p><u>Demand Charge:</u></p> <p>Basic Facility Charge \$ 1,400.00</p> <hr/> <p>First 20,000 Kw \$ 10.37 per KW</p> <hr/> <p>Excess over 20,000 Kw \$ 12.20 per KW</p> <p><u>Energy Charge:</u></p> <hr/> <p>All KWhr. @ \$ 0.03567 per KWhr.</p>
<p>INTERNATIONAL PAPER Eastover Mills</p> <p style="padding-left: 40px;">Economy Power Rate</p> <p style="padding-left: 40px;">Standby Power Rate</p>	<p><u>Administrative Charges:</u> \$ 1,400.00 per month</p> <p><u>On-Peak Energy Charge:</u></p> <p>Fuel cost of highest cost generation unit or purchased power (other than cogeneration) plus \$ 0.01101 per KWhr.</p> <p><u>Off-Peak Energy Charge:</u></p> <p>Fuel cost of highest cost generation unit or purchased power (other than cogeneration) plus \$ 0.00605 per KWhr.</p> <p><u>Excess Demand Charge:</u> \$ 17.50 per KW</p> <p><u>Demand Charge:</u></p> <p>On-peak June-September \$ 0.32449 per KW/Day</p> <hr/> <p>On-peak October-May \$ 0.17688 per KW/Day</p> <hr/> <p>Off-peak \$ 0.12789 per KW/Day</p> <p><u>Energy Charge:</u></p> <p>Same as that for Economy Power above</p> <p><u>Excess Demand Charge:</u> \$ 17.50 per KW</p>

Effective Upon Approval Of The Public
Service Commission Of South Carolina

SOUTH CAROLINA ELECTRIC & GAS COMPANY

ELECTRIC CONTRACTED RATES

INTERNATIONAL PAPER - continued

Maintenance Power Rate	<u>Demand Charge:</u>	\$ 0.38137	per KW/Day
	<u>Energy Charge:</u>	\$ 0.03567	per Kwhr.
	<u>Company Provided KVAR</u>	\$ 0.14773	per KVAR

Montenay Charleston Recovery Inc

Standby Power Rate	<u>Facility Charge:</u>	\$ 1,400.00	per Month
	<u>Demand Charge:</u>		
	First 1325 hours of standby service	\$ 5.49	per KW
	Excess over 1325 hours of standby service	\$ 12.20	per KW
	<u>Energy Charge:</u>		
	On-peak	\$ 0.04289	per Kwhr.
	Off-peak	\$ 0.03567	per Kwhr.
Maintenance Power Rate	<u>Demand Charge:</u>	\$ 0.27676	per KW/Day
	<u>Energy Charge:</u>	\$ 0.03567	per Kwhr.

Contracted lighting, signal and roadway lighting, etc.

Negotiated Contracts

* After contractual (1925 and 1955) adjustments

- Note: (1) Fuel costs of \$.02685 per KWhr are included in the Energy Charge and subject to adjustment by order of the Public Service Commission of South Carolina.
- (2) The Energy Charges above include a storm damage component of \$.00008 per KWhr for accumulation of a storm damage reserve except contracted lighting, including signal and roadway lighting, which is \$.00152 per KWhr.

EXHIBIT O

IN-SERVICE EXPENSES

**Combined Application of South Carolina Electric & Gas Company for a Certificate of Environmental Compatibility and Public Convenience and Necessity and for a Base Load Review Order
Public Service Commission Docket No. 2008-196-E**

1. INTRODUCTION

This **Exhibit O, Chart A** provides SCE&G's current forecast of the in-service expenses associated with the placing into service of two Westinghouse AP1000 Advanced Passive Safety Power Plant units as V. C. Summer Nuclear Station (VCSNS) Units 2 & 3 (the Units or the Facilities).

2. DESCRIPTION OF ANNUALIZED IN-SERVICE SERVICE COST ESTIMATES (SEE ATTACHED TABLE)

- 1) ***Fixed Operation and Maintenance Expense*** – These are estimated costs that will not vary with the operation of the plant. Examples include plant staff, insurance, security, etc. Current estimates are based on experience at VCSNS Unit 1.
- 2) ***Variable Operation and Maintenance Expense*** – These are estimated costs that will vary with the operation of the plant. Examples include certain supplies, chemicals, gases, outside services, and other consumables.
- 3) ***Decommissioning Expense*** – At this time, an external sinking fund in the form of a trust is the method that SCE&G plans to use to provide reasonable assurance of the availability of its share of funds to decommission the facility. Amounts collected through rates would be transferred to the external trust and such deposits along with trust fund earnings must provide an amount equal to or greater than the formula-derived decommissioning cost for the facility.
- 4) ***Fuel Costs*** – Estimated cost of nuclear fuel for the period including uranium, enrichment, fabrication, and other associated costs.
- 5) ***Depreciation*** – This estimate is the annual straight-line depreciation expense associated with the projected closing amount of each unit, assuming a sixty year economic life of each nuclear unit. Transmission property is depreciated in accordance with currently approved depreciation rates.

- 6) ***Taxes Other Than Income*** – These costs include property taxes, gross receipts taxes, and support of PSC taxes. Property tax projections are based on the Inducement Resolution with Fairfield County with regard to fee in lieu terms applied to the in-service cost of the eligible property. Transmission property is taxed in accordance with projected system average tax millage and assessment ratios.

- 7) ***Return on Materials, Supplies, and Working Capital*** – These costs were estimated by applying the SCE&G’s weighted average cost of capital to projected balances for fuel inventories, materials and supplies, and working capital (one-eighth of non-fuel O&M costs).

VCS Unit 2 and Unit 3
Table of In-Service Expenses
(\$000)

<i>Line item:</i>	<i>Unit # 2</i> <i>2016</i>	<i>Unit # 3</i> <i>2019</i>
Fixed Operation and Maintenance Expense	\$38,212	\$27,653
Variable Operation and Maintenance Expense	\$18,041	\$19,618
Decommissioning Expense	\$4,372	\$4,777
Fuel Costs	\$45,624	\$45,578
Depreciation	\$57,710	\$51,827
Taxes Other than Income	\$44,550	\$52,103
<u>Return on Materials, Supplies, and Working Capital</u>	<u>\$14,827</u>	<u>\$14,786</u>
Total	\$223,336	\$216,342

SCE&G expects to receive Federal production tax credits related to the Units when they become operational. Because of the year-to-year variability of the amount of those credits, SCE&G presently intends to seek Commission approval at a future date to pass the value of the available credits through to customers directly as a credit to electric fuel costs. Accordingly, the benefit of these credits is not shown above.

EXHIBIT P

ENVIRONMENTAL ASSESSMENT AND RELATED INFORMATION

Combined Application of South Carolina Electric & Gas Company for a Certificate of Environmental Compatibility and Public Convenience and Necessity and for a Base Load Review Order Public Service Commission Docket No. 2008-196-E

1. INTRODUCTION

This **Exhibit P** provides a summary of the comprehensive Environmental Report related to the permitting, construction and placing into service of two Westinghouse AP 1000 Advanced Passive Safety Power Plant units at V. C. Summer Nuclear Station (VCSNS) Units 2 & 3 (the Units or the Facilities). SCE&G submitted the Environmental Report to the Nuclear Regulatory Commission (NRC) on March 31, 2008 as a part of its filing for a Combined Operating License for the Units. This **Exhibit P** also summarizes the geological, geotechnical and seismic information contained in the Combined Operating License Application for the Units.

An electronic copy of the Environmental Report is available on the NRC website. SCE&G will make electronic copies available to parties to this proceeding on request.

2. PROPOSED PROJECT

South Carolina Electric & Gas Company (SCE&G), an investor-owned utility, and South Carolina Public Service Authority, a state-owned utility commonly referred to as Santee Cooper, have determined that additional electrical generating capacity is needed to satisfy the growth projections for energy within their electric serve areas and those of their re-sale customers in South Carolina. Their need-for-power analysis is documented in Chapter 8 of the Environmental Report submitted to the U.S. Nuclear Regulatory Commission (NRC) as part of an application for a license to construct and operate two nuclear power units at the current V.C. Summer Nuclear Station Unit 1 near Jenkinsville, South Carolina. Maps of the Facilities and its location are found in Exhibit A to this Application.

SCE&G has conducted its environmental impact studies and assessments for the VCSNS Units 2 & 3 in accordance with the regulatory parameters encompassed within the NRC's Environmental Standard Review Plan as contained in NUREG 1555, implementing provisions of Title 10, Code of Federal Regulations, Part 51 (10 CFR 51), "Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions," and other guidance related to new site/plant applications. The discussion that follows generally tracks the sections and subjects required to be addressed, and hence were those investigated, analyzed, and are reported upon in the Environmental Report (ER). The ER comprises the content of Part Three of the Combined Operating License (COL) filed by SCE&G with the NRC on March 31, 2008.

The two new units are to be Westinghouse AP1000 advanced light water reactors. Each AP1000 has a rated thermal power of 3,400 megawatts thermal with a net electrical output of

approximately 1,117 megawatts electric. Based on the engineering computations that were current when the Environmental Reports were finalized, the forecast output of the plant was 1,107 megawatts electric. These new generation units incorporate passive design features that significantly improve the safety of the reactor over existing nuclear plants.

Water is a primary resource consideration with any power plant. Its consumption, treatment, and thermal characteristics are carefully analyzed. The two units would use water from the Monticello Reservoir for plant cooling and for all other plant-related use or consumption. Each unit would use closed-cycle, wet cooling towers for both circulating water system cooling and service water system cooling. An intake structure located on the Monticello Reservoir west of the existing Unit 1 would supply circulating water system makeup water. A water treatment facility located along the Monticello Reservoir to the east of Unit 1, comprised of a water treatment plant with its own separate intake structure, would also supply water withdrawn from the Monticello Reservoir for service water system makeup and to the potable water system, fire protection system, and plant demineralized water supply system. Monticello Reservoir receives water from the Broad River (Parr Reservoir) through the Fairfield Pumped Storage Facility.

Plant water discharges have also been carefully studied. The blowdown water from the cooling towers discharges to Parr Reservoir. The temperature of this effluent is slightly elevated above the normal river water temperatures and contains enhanced levels of natural salts, as well as, occasionally, very low permitted levels of radioactivity.

Additional detailed description on the proposed project can be found in Chapter 3 of the Environmental Report.

3. AFFECTED ENVIRONMENT

The Affected Environment is a description of the existing environmental conditions at the VCSNS site, the site vicinity, and the region. The environmental descriptions provide sufficient detail to identify those environmental resources that have the potential to be affected by the construction, operation, or decommissioning of the new units. Chapter 2 of the Environmental Report provides greater detail.

The VCSNS site is defined as the approximately 2,560 acres within the site boundary that include VCSNS Unit 1, the Fairfield Pumped Storage Facility, the southern portion of the Monticello Reservoir, and the location of the proposed Units 2 and 3; plus approximately 1,000 acres south of the site boundary. This additional land would be involved in construction activities (temporary facilities, laydown areas, and spoils disposal areas) or contain easements for the discharge pipeline and the access road. Total area for the site is approximately 3,600 acres.

The largest use within the 2,560 acres enclosed by the VCSNS Unit 1 site boundary is mixed forest, comprising 1,110 acres. Approximately 784 acres of the area within the VCSNS Unit 1 site boundary are covered by the waters of the Monticello Reservoir. A significant portion of the property (approximately 492 acres) consists of urban or built up land including: generation and maintenance facilities, laydown areas, parking lots, roads, mowed grass, and transmission line

rights-of-way. Approximately 174 acres of the area within the VCSNS Unit 1 site boundary are classified as transitional areas that are barren land.

The topography of the site consists of low rolling hills carved by a creek and drainages with elevations ranging from approximately 560 feet to 210 feet above Mean Sea Level. The Mayo Creek crosses the VCSNS site from north to south and discharges into the Broad River downstream of the Parr Reservoir. Streamside management zones at the site are protected in accordance with best management practices established by the South Carolina Forestry Commission. Forested areas within the VCSNS site are actively managed by SCANA Services' Forestry Operations group, and timber is occasionally harvested. Once timber is removed, the harvested areas are replanted with tree species appropriate to the terrain, soils, and drainage characteristics of a site.

The vicinity within 6 miles of the site occupies portions of Fairfield, Newberry, and Richland Counties and is rural, with a few homes and small farms, but much undeveloped land. The topography of the vicinity consists of low rolling hills. The community of Jenkinsville is approximately 2 miles southeast of VCSNS. The town of Peak (census year 2000 population of 61) is approximately 1.5 miles south and Pomaria (census year 2000 population of 178) is approximately 7 miles to the west.

The 4,400-acre Parr Hydro Wildlife Management Area managed by the South Carolina Department of Natural Resources for public waterfowl hunting and fishing, is adjacent to the VCSNS site. The Wildlife Management Area includes designated lands within the Enoree District of the Sumter National Forest, the Broad River (SC 34 to the dam at SC 16), and the Monticello and Parr Reservoirs. Camping is allowed along the Broad River within the Sumter National Forest. Other recreation activities such as boating, picnicking, and hiking can be enjoyed at select locations on the Monticello Reservoir, Parr Reservoir, and Broad River, and on the southern portion of Enoree District of the Sumter National Forest.

With the amount of land resource committed to this project, an understanding of the ecological resources that have the potential to be impacted by the construction and operation of new nuclear units on the VCSNS site is essential. Both terrestrial and aquatic resources could potentially be impacted and have been carefully defined and studied, and adequate precautions instituted, to keep ecological impacts within acceptable limits.

The U.S. Fish and Wildlife Service (USFWS) is responsible for designating areas of "critical habitat" for federally listed endangered and threatened terrestrial species. Such areas are considered essential to the species' conservation, and may require special management and protection. No areas designated by the USFWS as critical habitat exist at or near the VCSNS site. "Critical habitat" or similarly defined classifications do not exist for State-listed species in South Carolina. A survey for federally and state-listed species classified as threatened or endangered was conducted in May 2002 at the VCSNS site. The bald eagle was the only federally or state-listed animal species observed at the site during the 2002 survey. The bald eagle is state-listed as endangered. The USFWS removed the bald eagle from the federal list of threatened and endangered species effective August 8, 2007. At the federal level, the bald eagle is still protected under the Bald and Golden Eagle Protection Act and the Migratory Bird Treaty Act.

Surveys for federally and state-listed species classified as threatened or endangered were conducted in June 2006, September 2006, April 2007, and October 2007 in areas that would be disturbed by proposed construction activities. No federally or state-listed plants or animals were found during the 2006 surveys. A juvenile bald eagle was observed along the eastern shoreline of Parr Reservoir during the April 2007 survey; no other federally or state-listed plants or animals were observed during the April 2007 survey. In addition, no federally or state-listed plants or animals were found on the existing transmission corridors.

SCE&G has sited the proposed facilities and infrastructure so as to minimize impacts to wetlands. The upper portion of one small intermittent stream and its associated wetland extend slightly into the area in which the cooling towers would be located. The heavy haul road would cross Mayo Creek and its associated narrow wetland. Otherwise, no streams or wetlands are located in areas in which facilities or structures would be located.

The surface water bodies of interest, i.e., those that could potentially be affected by construction and operation of new units at the VCSNS site, are the Broad River, Parr Reservoir, Monticello Reservoir, the Monticello Sub-impoundment, and onsite streams, most notably Mayo Creek. Routine and special surveys of fish populations were conducted as early as three years before the operation of Unit 1 and two years after the beginning of operations. The fish community of the Parr Reservoir appeared to be largely unaffected by operations of VCSNS. Likewise, after extensive surveys conducted by biologists, South Carolina Department of Natural Resources personnel, and contractors, there was no indication that Unit 1 operations had an effect on fish populations in the Monticello Reservoir. Other surface water bodies have been carefully studied and data from over long periods of time have been analyzed with no indication that aquatic populations have been adversely and permanently affected by operation of VCSNS. Fish conservation efforts continue in the Broad River with SCE&G partnering to restore naturally dwindling numbers of the robust redhorse (*Moxostoma robustum*), a large catostomid believed to be extinct until 1991.

Historic and cultural resources also can be potentially disturbed or damaged by new construction. To support the COL application, SCE&G performed cultural resource surveys of the VCSNS site and the adjoining SCE&G property potentially affected by construction of Units 2 and 3.

Properties listed on the National Register of Historic Places and structures and buildings that have been determined as eligible for the National Register were identified using the South Carolina Department of Archives' Cultural Resources Inventory System. SCE&G met with the State Historic Preservation Office in June 2006 regarding the VCSNS COL application. During the visit, past landscape alterations and current conditions were discussed, as well as any need for additional cultural resource surveys, and results of background site files and cartographic research.

There are known to be 21 archaeological sites and standing structures within 10 miles of the proposed site that are currently listed on the National Register of Historic Places. None are located on SCE&G property. Fifty three standing structures within a 10-mile radius have been

determined to be eligible or contributing to the eligibility of a National Register district. None of these are located on SCE&G property. No archaeological sites within the 10-mile radius have been determined eligible, although four are listed on the National Register. A cemetery containing approximately 30 graves including that of General John Pearson, a Fairfield County native who served with distinction in the American Revolutionary War, is partially within the proposed site boundary. SCE&G has fenced this cemetery, and SCE&G's Forestry Operations group is familiar with this cemetery, which is marked on their timber inventory and land cover maps. SCE&G takes measures to protect the cemetery when conducting forest management activities.

Although transmission line rights-of-way associated with Unit 1 have not been specifically systematically surveyed for cultural resources, no known significant archaeological sites or standing structures currently exist within them. The routes of the new transmission lines have not yet been determined but they would follow the existing routes where possible. New corridors would be thoroughly researched to avoid disturbing cultural or historical resources.

The Catawba Indian Nation is the only federally recognized tribe in South Carolina. There are no tribal lands in the VCSNS vicinity.

4. IMPACT OF CONSTRUCTION

SCE&G examined the potential environmental impacts of construction of VCSNS Units 2 and 3. In accordance with 10 CFR 51, impacts are analyzed, and a single significance level of potential impact to each resource (i.e., small, moderate, or large) is assigned consistent with the criteria that NRC established in 10 CFR 51, Appendix B, Table B-1, Footnote 3 as follows:

SMALL Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. For the purposes of assessing radiological impacts, the Commission has concluded that those impacts that do not exceed permissible levels in the Commission's regulations are considered small.

MODERATE Environmental effects are sufficient to alter noticeably, but not to destabilize, any important attribute of the resource.

LARGE Environmental effects are clearly noticeable and are sufficient to destabilize any important attributes of the resource.

The following environmental or sociological resource areas were evaluated as having **SMALL** impacts:

- Land Use
- Water use
- Water Quality
- Terrestrial Ecology
- Aquatic Ecology
- Public and Worker Health (radiological and nonradiological)

Impacts other than SMALL are discussed below:

Land use for new transmission lines are expected to have MODERATE impacts; however, the exact routes of these transmission lines are not currently known. SCE&G would follow siting procedures established by the South Carolina Public Service Commission. Santee Cooper would follow a technically comparable process for their transmission lines.

SCE&G estimates that most in-migrating construction workers and their families would leave the region upon project completion, and residential and commercial activity would return to approximately preconstruction levels. Therefore, offsite land-use changes would be small, thus, the impact would be considered SMALL in surrounding counties of Lexington, Richland, and Newberry, but MODERATE in Fairfield County.

Commuting construction workers would have a MODERATE to LARGE impact on the traffic on two-lane highways in Fairfield and Newberry County, specifically SC 215, SC 213, and the highways that feed into them. Mitigation, such as staggering shifts, infrastructure improvements, and traffic management planning, would be necessary to accommodate the additional vehicles on SC 215 and 213.

The large construction project would reduce unemployment and create business opportunities for housing and service-related industries. SCE&G concludes that the impacts from construction on the economy or labor force in the region of influence would be SMALL in Lexington, Newberry, and Richland Counties. The impacts in Fairfield County would be LARGE because the proposed project is located in the county and because the county currently has such a small labor pool and population base. Changes to population and employment baselines would result in a LARGE impact in Fairfield County.

SCE&G concludes that the potential beneficial impacts from all types of taxes collected during construction period in various forms (personal income, business income, inventory, payroll related, sales, and personal and real property, etc) would be LARGE in Fairfield County and SMALL in Newberry, Lexington, and Richland Counties.

Chapter 4 of the Environmental Report provides greater detail on construction impacts.

5. IMPACTS OF OPERATION

SCE&G also examined the potential environmental impacts of operation of VCSNS Units 2 and 3. In accordance with 10 CFR 51, impacts are analyzed, and a single significance level of potential impact to each resource (i.e., small, moderate, or large) as defined in Section 3. The following environmental or sociological resource areas were evaluated as having SMALL impacts:

Land Use
Water use
Water Quality

Terrestrial Ecology
Aquatic Ecology
Public and Worker Health (radiological and nonradiological)

Impacts other than SMALL are discussed below:

The commuting of the combined operations workforce for all three units would have a SMALL to MODERATE impact on the traffic on two lane highways in Fairfield and Newberry County, specifically SC 215 and 213 and the highways that feed into them. Mitigation, such as staggering shifts, infrastructure improvements, and a traffic plan, would be necessary to accommodate the additional vehicles on SC 215 and 213.

In the general region, impacts of operations on the economy would be beneficial and SMALL, but economic impacts to Fairfield and Newberry counties would be MODERATE because of their rural nature and because of the significant impacts that operations would have on the tax base of Fairfield County. One of the main sources of economic impact would be property taxes assessed on the facility. A second source of property taxes would be on housing owned by the new workforce.

Chapter 5 of the Environmental Report provides greater detail on operational impacts.

6. ALTERNATIVES

SCE&G evaluated possible alternatives to construction and operation of new nuclear units at the VCSNS site.

The no-action alternative (doing nothing more than is currently being done) is not a viable alternative assuming a reasonable rate of growth in electricity demand within South Carolina.

Several alternatives exist that do not require new generating capacity, such as purchasing power from other utilities, reactivating or extending the life of current power systems, managing demand, or a combination of these alternatives. Some power is already purchased but additional purchases would not be adequate to provide the required increase in base load capacity projected into 2015. SCE&G has already extended the life of VCSNS Unit 1 and has not identified any other existing plants that could undergo life extension to meet the project demand

Demand side management is the practice of reducing customers' demand for energy through programs such as energy conservation, efficiency, and load management so that the need for additional generation capacity is eliminated or reduced. Many programs are being implemented already, and there is not much more to be gained from this alternative.

Alternative technologies such as wind, solar, hydroelectric, geothermal, biomass, municipal solid waste, petroleum liquids, fuel cells, coal, natural gas, and combinations of alternative technologies have been evaluated. Alternative technologies are worthy of additional investigation in terms of the national energy supply options. Many of them may have important

contributions to make to the energy mix, but most, for various reasons, especially in South Carolina, cannot provide the energy needed in the amounts required.

SCE&G has determined, based on environmental impacts, that neither a coal-fired nor a gas-fired plant would provide an appreciable reduction in overall environmental impact relative to a nuclear plant. This conclusion is shown in detail in Chapter 9 in the Environmental Report. Furthermore, each of these types of plants would entail a significantly greater relative environmental impact on air quality than would the proposed project. Therefore, SCE&G concludes that neither a coal-fired or gas-fired plant would be environmentally preferable to the proposed project.

Alternative sites were also considered. Impacts associated with alternative sites were compared. The comparison studied the environmental impacts of construction and operation of the proposed project at each of the alternative sites with impacts at the VCSNS site. This site-by-site comparison did not result in identification of a site obviously superior to the VCSNS site.

SCE&G also examined the use of direct cooling (without cooling towers) from the Monticello Reservoir and the use of natural draft cooling in lieu of mechanical draft cooling towers. Neither of these alternatives was found to be technically, economically, or environmentally preferable.

7. SUMMARY OF GEOLOGIC, GEOTECHNICAL AND SEISMIC STUDIES

South Carolina Electric & Gas Company also investigated the geological, seismological and geotechnical characteristics of the proposed location of the V.C. Summer Nuclear Station, Units 2 & 3 to confirm that the site was safe for the construction and operation of new nuclear power plants. The investigation also provided information on geotechnical and seismic site characteristics for input into site specific aspects of the power plant design.

The geologic investigation consisted of both regional and site studies. The geological and seismological information is presented in detail in Section 2.5 of the Final Safety Analysis Report and summarized in Section 2.6 of the Environmental Report. This information was developed from a review of previous reports prepared for the V.C. Summer Unit 1 investigation, published geologic and seismologic literature, interviews with experts in the geology and seismicity of the region surrounding the site, aerial photo analysis and geologic field reconnaissance conducted as part of the of the Unit 2 & 3 investigation. Office studies also evaluated regional geophysical maps (gravity and magnetism) to identify geologic structures deep in the earth's crust and those exposed at the ground surface. Field work included drilling 111 boreholes, conducting 36 cone penetrometer tests, installing 31 groundwater observation wells, and excavating 4 test pits at the Units 2 and 3 sites. Four deep boreholes were drilled at the site of each nuclear island; one to 350 ft, one to 215 ft, and two to 175 ft. Downhole geophysical surveys were performed in each of these boreholes. Geophysical testing included the use of a compression wave-shear wave (P-S) suspension logging tool to measure the shear wave velocity of the bedrock, a parameter important to calculating earthquake vibratory ground motions. Borings at the site provided the geological and geotechnical data to characterize the soil, underlying rock and geophysical properties of the soil and bedrock units.

The field investigation program was supplemented by a laboratory testing program to characterize material properties of both the soil and rock. SCE&G obtained values for standard engineering properties of the soils, weathered rock, sound rock, and potential backfill obtained from a local quarry. In addition, resonant column torsional shear tests were conducted on both native soils and backfill to help define the dynamic behavior of these materials.

The investigation verified that the site location is typical of the Piedmont physiographic province. The site topography consists of gently to moderately rolling hills and well-drained mature valleys. Most of the local terrain is mantled by residual soils and saprolite overlying the more-than 300 million year old Winnsboro granitic plutonic complex that intruded older metamorphic country rock consisting of deformed gneiss and amphibolite. The geotechnical data indicate that soils overlying the hard bedrock vary from highly weathered residual soils (consisting of silt and silty sand with variable clay content) to saprolite (consisting of completely weathered rock that retains relict rock structure).

The soil beneath the nuclear islands will be excavated down to sound rock and the structures of the nuclear island important to safety will be founded on sound rock or on concrete placed on sound rock. The non-safety-related annex building will be founded on structural fill placed on sound rock. Permanent perimeter slopes in the soil are at least 600 feet away from the nearest point of the nuclear islands, and at least 500 feet away from the nearest point of the non-safety-related annex buildings. Failure of these slopes, under any of the conditions to which they could be exposed during the life of the plant, will not adversely affect the safety of the nuclear power plant facilities. The temporary slopes that will be excavated for plant construction will be backfilled prior to plant operation and, therefore, will not affect the safety of the nuclear power plant facilities.

The seismic investigation consisted of a systematic evaluation of historic earthquakes and seismic (earthquake) source zones relevant to determination of the seismic hazard at the site. The earthquake catalog developed in the late 1980s by the Electric Power Research Institute and reviewed by the Nuclear Regulatory Commission was updated to incorporate earthquakes that had occurred since its publication. The assessment of vibratory ground motion incorporates developments in ground motion estimation models; updated models for earthquake sources; methods for determining site response; and new methods for defining a site-specific, performance-based earthquake ground motion [the Ground Motion Response Spectra (GMRS)] which is characterized by horizontal and vertical response spectra determined as free-field motions on hard rock.

The site-specific probabilistic seismic hazard analysis performed for Units 2 and 3 incorporates the updated earthquake catalog, and updated models of the Charleston (South Carolina) and New Madrid (Missouri) Seismic Source Zones. These two updated models incorporate the results of recent research integrating information on geologic structures and earthquake recurrence. Uncertainties in geologic and seismologic parameters are explicitly incorporated in this hazard assessment.

The geologic investigation conducted for the V.C. Summer site indicates that there are no active faults within a 200-mile radius. In addition, there is no potential for surface fault rupture within a 5-mile radius of the site. The results of the geologic, geotechnical and seismological investigations indicate that the V.C. Summer Units 2 & 3 site meets the design requirements for the Westinghouse AP1000 reactor design as certified by the U. S. Nuclear Regulatory Commission.

EXHIBIT Q

TRANSMISSION INTERCONNECTION STUDIES

**Combined Application of South Carolina Electric & Gas Company for a
Certificate of Environmental Compatibility and Public Convenience and
Necessity and for a Base Load Review Order
Public Service Commission Docket No. 2008-196-E**

1. INTRODUCTION

This **Exhibit Q** contains copies of the principal transmission system interconnect studies performed by SCE&G's transmission planning and engineering department related to VSCNS Units 2 & 3. For purposes of this cost projections in this proceeding, SCE&G has obtained from Transmission Engineering the unadjusted cost data related to these projects which is the data contained in **Exhibit F** to this Application under the heading Transmission Projects, Cash Flow.

1. Generator Interconnection System Impact Study for SCE&G V.C. Summer Nuclear #2
2. Generator Interconnection System Impact Study for SCE&G V.C. Summer Nuclear #3
3. Generator Interconnection Facilities Study SCE&G V.C. Summer Nuclear #2
4. Generator Interconnection Facilities Study SCE&G V.C. Summer Nuclear #3 – Revision #2



**Generator Interconnection System Impact Study
for
SCE&G V.C. Summer Nuclear #2**

Prepared for:
SCE&G Nuclear Group

July 5, 2007

Prepared by:
SCE&G Transmission Planning

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Generator Interconnection System Impact Study for SCE&G V.C. Summer Nuclear #2

A Generator Interconnection System Impact Study is an extension of the previous Generation Interconnection Feasibility Study, and is a detailed study of the SCE&G transmission system considering the full output of the proposed new generation. The System Impact Study includes a full test of the NERC Reliability Standards Table 1 and the SCE&G Internal Transmission Planning Criteria.

General Discussion

The SCE&G Nuclear Group has applied for interconnection of a new 1375 MVA nuclear generator near the existing V.C. Summer site. This new generator would be jointly owned by SCE&G and Santee Cooper, SCE&G would own 55% and Santee Cooper would own the remaining 45%. In this study Santee Cooper's portion of the generator output was represented as delivered to the Santee Cooper system.

In addition to this Interconnection System Impact Study, SCE&G Transmission Planning participated in a joint study with Southern Company, Santee Cooper, Duke Energy and other interconnected transmission providers to evaluate the effect of this generator and other planned generators in the region. Results of this joint study indicated no unacceptable interaction between these planned generators or the identified associated transmission expansion.

In the future, SCE&G Transmission Planning will periodically review the results of this Interconnection System Impact Study to determine if the recommended expansion remains valid.

The previously completed Feasibility Study recommended the following transmission line improvements:

1. Construct a VC Summer #2-Killian 230kV line with B1272 conductor
 - (add 230kV terminal at Killian)
2. Construct a VC Summer #2-Lake Murray 230kV line with B1272 conductor
 - (add 230kV terminal at Lake Murray)
3. Construct a VC Summer #2-VC Summer (existing) Bus #2 230kV line with B1272 conductor
 - (add 230kV terminal at VC Summer #1 Bus #2)
4. Construct a VC Summer #2-VC Summer (existing) Bus #3 230kV line with B1272 conductor
 - (add 230kV terminal at VC Summer #1 Bus #3)
5. Upgrade the existing Denny Terrace-Lyles 230kV line to B1272
6. Upgrade the existing Parr-VC Summer #1 230kV line to B1272
7. Upgrade the existing Parr-VC Summer #2 230kV line to B1272
8. Add a 3rd 230/115kV 336 MVA auto transformer at Lake Murray
9. Add a 3rd 230/115kV 336 MVA auto transformer at Denny Terrace

10. Upgrade the existing Saluda-McMeekin 115kV line to B1272
11. Upgrade the existing Lake Murray-McMeekin 115kV line to B1272
12. Upgrade the existing Lake Murray-Saluda 115kV to with B1272

In addition, it will be necessary to construct a new 230kV generator substation at the proposed site using a breaker-and-a-half design with seven 230kV terminals.

1. One - for the generator step up transformer
2. One - for station service
3. One - for the new 230kV line to the existing V. C. Summer 230kV bus #2
4. One - for the new 230kV line to the existing V. C. Summer 230kV bus #3
5. One - for the new 230kV line to Lake Murray
6. One - for the new 230kV line to Killian
7. One - for the new 230kV line to Santee Cooper

A total of eleven 230kV breakers are needed at the new generator substation for this design.

To resolve overstressed conditions of several 230kV and 115kV breakers as described in the Short Circuit Analysis section, Transmission Planning recommends replacing the following breakers with higher interrupting capability breakers:

Location	Voltage	Breaker #
VC Summer	230	8722
VC Summer	230	8732
VC Summer	230	8742
VC Summer	230	8772
VC Summer	230	8792
VC Summer	230	8832
VC Summer	230	8842
VC Summer	230	8852
VC Summer	230	8892
VC Summer	230	8912
VC Summer	230	8942
Parr	230	6402
Parr	230	6412
Parr	230	6422
Parr	230	6432
Parr	230	6442
Saluda Hydro	115	562
McMeekin	115	1051
McMeekin	115	2051
Edenwood	115	2712
Edenwood	115	3672
Edenwood	115	3682
Denny Terrace	115	8032
Denny Terrace	115	8042
Denny Terrace	115	8092

The report will be presented as follows:

- I. Generation Information
- II. Transmission Studies
 - A. Power Flow Analysis
 - B. Short Circuit Analysis
 - C. Stability Analysis
- III. Required Interconnection Facilities
- IV. Engineering Design & Cost

I. Generator Information

The generator design consists of a single nuclear unit and one step-up transformer. The generator unit will have a maximum gross MVA output capacity of 1,375 MVA and a maximum continuous net MW of 1,165 MW.

The generator design consists of the following information:

MVA – gross:	1375
MW – net:	1165
Power Factor:	between .90 and 1.05
Voltage:	22kV
Speed:	1800 rpm
X'd-sat.: 0.465 PU;	X''d-sat.: 0.325 PU
X2-sat.: 0.320 PU;	X0: 0.237 PU

II. Transmission Studies

A. Power Flow Analysis

Since the completion of the Generation Interconnection Feasibility Study, modifications were made to the 230kV generator substation layout and the arrangement of lines connecting to the existing V.C. Summer substation and the proposed V.C. Summer substation. These changes resulted in the proposed retirement of the Parr 230kV substation. The original improvements along with these proposed modifications were modeled and Transmission Planning has run more detailed power flow analysis of the SCE&G transmission system to include a full test of the NERC Reliability Standards Table 1 and the SCE&G Internal Transmission Planning Criteria. This analysis shows the following overload condition due to the additional generation:

Overloaded Facility	Emergency Rating (MVA)	Loading (%)	Contingency
Lake Murray-Lyles 115kV line	123	101	Outage of Denny Terrace 230kV Bus #1 and #2 (Category C-9)

Transmission Planning recommends that this contingency event be mitigated by installing a 2nd bus tie breaker at the Denny Terrace 230kV bus.

B. Short Circuit Analysis

The previously complete feasibility study indicated sixteen 230kV breakers and nine 115kV breakers were overstressed due to the additional generation at V. C. Summer and must be replaced. However, five of these 230kV breakers are at Parr 230kV substation and because of the proposed retirement of the Parr 230kV substation, these five breaker replacements are no longer required. Additionally, two 230kV breakers are eliminated at the VC Summer #1 Substation with the new line arrangement. Transmission Planning now recommends that nine 230kV breakers and nine 115kV breakers be replaced as listed in the recommendations section of this report.

C. Stability Analysis

1. Overview of Stability Analysis.

The stability study of the connection of the V.C. Summer #2 AP1000 generator to the SCE&G and SCPSA transmission systems assessed the ability of this generator to remain in synchronism following selected transmission system contingencies. Also reviewed were the adequacy of damping of generation/transmission oscillations and the impact of the proposed generator on the stability performance of other system generators. System voltage responses were examined for indications of voltage instability. In addition, generator frequency responses and the effects of protective system performance were evaluated.

For the system peak load cases, the nearby V.C. Summer #1 generator was simulated as switched off except for where noted as otherwise. In addition, the 230kV transmission line connecting the V.C. Summer #2 generator switchyard to SCPSA's Pomaria substation was switched out. These outages were simulated in order to account for the possibility that major generation and transmission could be out of service during the operation of the connecting facility. Power flow studies showed that these were the generation and transmission outages that resulted in the greatest impact on the reactive output of the V.C. Summer #2 generator.

Rotor angle responses of the V.C. Summer #2 generator were simulated in order to determine if angular instability could result from likely contingencies. Generator frequency deviations were examined in order to determine if generator frequency protection could result in generator tripping. The results of the loss of the V.C.

Summer #2 generator were examined in order to determine if any resulting underfrequency relay operations would lead to system load shedding. Finally, the effects of each contingency on the V.C. Summer #2 230kV switchyard bus were examined along with voltages at the existing V.C. Summer #1 230kV and 115kV Offsite Power Supply buses to determine if the voltage requirements of the Offsite Power Supply buses were violated. Generator response plots are not included but are available for review upon request.

An initial 30 second steady state simulation for the selected connection configuration was performed in order to establish that steady state conditions existed prior to fault conditions. The simulation of each contingency repeated the steady state condition for 1 second prior to introducing permanent fault conditions so that the responses could be compared to the initial steady state condition. In order to determine the effects on all system generators, contingencies were simulated under system peak load conditions and system valley load conditions.

Contingencies were selected in order to satisfy each of four categories as specified by NERC Reliability Standards TPL-001 through TPL-004. As a companion to this study, SCPSA has performed a study of this generator interconnection and has determined that the NERC Reliability Standards are satisfied for its system. An Executive Summary of the SCPSA study of generator rotor angle responses to contingencies on its system follows the results of the SCE&G stability analysis. Although not included in this report, a stability study of this interconnection was also performed for the VCS #2 & VCS #3 Combined Operating License Application (COLA). The results of that study support the findings of this Interconnection Study.

The results of the stability analysis are described in the following sections and are summarized following the detailed results.

2. Results of Peak Load Stability Analysis.

A.1. Steady state conditions (NERC Category A condition)

The interconnection of the V.C. Summer #2 generator was shown to result in system steady state conditions. Generator rotor angles and frequencies showed no deviations through out the 30 second simulation. The voltage at the V.C. Summer #2 bus remained at 232.3kV during the simulation. The voltages at the V.C. Summer #1 Offsite Power Supply buses were constant at 232.3kV and 117.75kV.

A.2. Normal clearing of a three phase fault on the V.C. Summer #2 generator terminal 26kV bus (NERC Category B-1 Contingency)

Following a 1 second steady state period, a permanent fault was simulated at the 26Kv side of the V.C. Summer #2 generator step up transformer. This results in the opening of the generator breaker 5 cycles after the appearance of the fault. Since the station service buses are normally served from the 26kV bus, this operation would result in the loss of the station service loads. However, the station fast transfer scheme switches these loads to the switchyard 230kV bus and allows the continued service of these loads.

Rotor angle oscillations were moderate and well damped with no indication of angular instability. There was no indication of voltage instability. Likewise, system

frequency responses were also moderate and well damped with no indication of system underfrequency load shedding or generator under/overfrequency operations.

During the application of the fault, the voltage at the V.C. Summer #2 bus dropped to 121.41kV. The V.C. Summer #1 230kV and 115kV Offsite Power Supply bus voltages dropped to 125.06kV and 78.98kV respectively. This allowed the degraded voltage and loss of voltage relay timers to initiate. However, the voltages recovered enough to reset the timers within 1 cycle of the clearing of the fault.

Steady state conditions were reestablished with no further system operations.

A.3. Delayed clearing of a single line to ground fault on the future V.C. Summer #2 switchyard to the existing V.C. Summer #1 generator switchyard bus #2 (NERC Category C-8 contingency)

Since this contingency places a fault near the existing V.C. Summer #1 generator, this unit was modeled as switched on. All local transmission lines were also modeled as in service. Following a 1 second steady state period, a permanent single phase-to-ground fault was simulated at the V.C. Summer #2 end of the V.C. Summer #2 – V.C. Summer #1 230kV transmission line #2. The circuit breaker at the V.C. Summer #1 end of the line was simulated as operating normally. The breaker and a half scheme at the V.C. Summer #2 switchyard cleared the fault following a fault duration of approximately 0.25 seconds.

During the application of the fault, the voltage at the V.C. Summer #2 bus dropped to 121.44kV. The V.C. Summer #1 230kV and 115kV Offsite Power Supply bus voltages dropped to 126.94kV and 71.20kV respectively. This allowed the degraded voltage and loss of voltage relay timers to initiate. However, the voltages recovered enough to reset the timers within 1 cycle of the clearing of the fault.

Rotor angle oscillations were moderate and were adequately damped with no indication of angular instability. There was no indication of voltage instability. Likewise, system frequency responses were also moderate and adequately damped with no indication of system underfrequency load shedding or generator under/overfrequency operations.

Steady state conditions were reestablished with no further system operations.

A.4. Normal clearing of a three phase fault on the existing V.C. Summer #1 generator switchyard bus #1 (NERC Category D-10 contingency)

Since this contingency places a fault near the existing V.C. Summer #1 generator, this unit was modeled as switched on. All local transmission lines were also modeled as in service. Following a 1 second steady state period, a permanent single three phase fault was simulated at the V.C. Summer #1 bus #1. Since this is the bus that the V.C. Summer #1 generator is connected to that generator was tripped when the fault was cleared. In addition, in order to prevent the Fairfield Pumped Storage generators from becoming unstable, a Special Protection System will need to be installed at the V.C. Summer #1 switchyard that will trip those units

as well. The operations to clear the fault and trip the generators will occur within 6 cycles from the appearance of the bus fault.

During the application of the fault, the voltage at the V.C. Summer #2 230kV bus dropped to 6.99kV. The V.C. Summer #1 230kV and 115kV Offsite Power Supply bus voltages dropped to 0.00kV and 21.79kV respectively. This allowed the degraded voltage and loss of voltage relay timers to initiate. However, the voltages recovered enough to reset the timers within 14-15 cycles following the appearance of the fault.

Rotor angle oscillations were moderate and were adequately damped with no indication of angular instability. There was no indication of voltage instability. Likewise, system frequency responses were also moderate and adequately damped with no indication of system underfrequency load shedding or generator under/overfrequency operations.

Steady state conditions were reestablished with no further system operations.

3. Results of Low Load Stability Analysis.

A.1. Steady state conditions (NERC Category A condition)

The interconnection of the V.C. Summer #2 generator was shown to result in system steady state conditions. Generator rotor angles and frequencies showed no deviations through out the 30 second simulation. The voltage at the V.C. Summer #2 bus remained at 232.3kV during the simulation. The voltages at the V.C. Summer #1 Offsite Power Supply buses were constant at 232.3kV and 116.84kV.

A.2. Normal clearing of a three phase fault on the V.C. Summer #2 generator terminal 26kV bus (NERC Category B-1 Contingency)

Following a 1 second steady state period, a permanent fault was simulated at the 26Kv side of the V.C. Summer #2 generator step up transformer. This results in the opening of the generator breaker 5 cycles after the appearance of the fault. Since the station service buses are normally served from the 26kV bus, this operation would result in the loss of the station service loads. However, the station fast transfer scheme switches these loads to the switchyard 230kV bus and allows the continued service of these loads.

Rotor angle oscillations were small but poorly damped due to the smaller level of synchronizing torque within the system due to the reduced amount of generation on line during system low load conditions. However, the generator rotor angle oscillations were eventually damped and there was no indication of angular instability. There was no indication of voltage instability. Likewise, system frequency responses were also small and poorly damped but with no indication of system underfrequency load shedding or generator under/overfrequency operations.

During the application of the fault, the voltage at the V.C. Summer #2 bus dropped to 133.47kV. The V.C. Summer #1 230kV and 115kV Offsite Power Supply bus voltages dropped to 136.00kV and 74.82kV respectively. This allowed the degraded

voltage and loss of voltage relay timers to initiate. However, the voltages recovered enough to reset the timers within 1 cycle of the clearing of the fault.

Steady state conditions were reestablished with no further system operations.

A.3. Delayed clearing of a single line to ground fault on the future V.C. Summer #2 switchyard to the existing V.C. Summer #1 generator switchyard bus #2 (NERC Category C-8 contingency)

Since this contingency places a fault near the existing V.C. Summer #1 generator, this unit was modeled as switched on. All local transmission lines were also modeled as in service. Following a 1 second steady state period, a permanent single phase-to-ground fault was simulated at the V.C. Summer #2 end of the V.C. Summer #2 – V.C. Summer #1 230kV transmission line #2. The circuit breaker at the V.C. Summer #1 end of the line was simulated as operating normally. The breaker and a half scheme at the V.C. Summer #2 switchyard cleared the fault following a fault duration of approximately 0.25 seconds.

During the application of the fault, the voltage at the V.C. Summer #2 bus dropped to 115.83kV. The V.C. Summer #1 230kV and 115kV Offsite Power Supply bus voltages dropped to 121.03kV and 67.65kV respectively. This allowed the degraded voltage and loss of voltage relay timers to initiate. The voltages recovered enough to reset the timers within 2-3 cycles of the clearing of the fault.

Rotor angle oscillations were small and were adequately damped with no indication of angular instability. There was no indication of voltage instability. Likewise, system frequency responses were also small and adequately damped with no indication of system underfrequency load shedding or generator under/overfrequency operations.

Steady state conditions were reestablished with no further system operations.

A.4. Normal clearing of a three phase fault on the existing V.C. Summer #1 generator switchyard bus #1 (NERC Category D-10 contingency)

Since this contingency places a fault near the existing V.C. Summer #1 generator, this unit was modeled as switched on. All local transmission lines were also modeled as in service. Following a 1 second steady state period, a permanent three phase fault was simulated at the V.C. Summer #1 bus #1. Since this is the bus that the V.C. Summer #1 generator is connected to, that generator was tripped when the fault was cleared. In addition, in order to prevent the Fairfield Pumped Storage generators from becoming unstable, a Special Protection System will need to be installed at the V.C. Summer #1 switchyard that will trip those units as well. The operations to clear the fault and trip the generators will occur within 6 cycles from the appearance of the bus fault.

During the application of the fault, the voltage at the V.C. Summer #2 230kV bus dropped to 5.89kV. The V.C. Summer #1 230kV and 115kV Offsite Power Supply bus voltages dropped to 0.00kV and 18.19kV respectively. This allowed the degraded voltage and loss of voltage relay timers to initiate. However, the voltages

recovered enough to reset the timers within 12-17 cycles of the appearance of the fault.

Rotor angle oscillations were moderate and were adequately damped with no indication of angular instability. There was no indication of voltage instability. Likewise, system frequency responses were also moderate and adequately damped with no indication of system underfrequency load shedding or generator under/overfrequency operations.

Steady state conditions were reestablished with no further system operations. The plots for this case are shown in

A.5. Three phase fault with normal clearing on the existing V.C. Summer #1 generator bus #2 to Fairfield Pumped Storage Generators # 5-8 (NERC Category D-11 contingency)

Since this contingency places a fault near the existing V.C. Summer #1 generator, this unit was modeled as switched on. All local transmission lines were also modeled as in service. Following a 1 second steady state period, a permanent three phase fault was simulated on the 230kV transmission line that connects the V.C. Summer #1 bus #2 to the Fairfield Pumped Storage units #5-8. When this line was opened these units which were operating in the pumping mode were taken off line. This represents the largest load that can be removed from the system as a result of a single event.

During the application of the fault, the voltage at the V.C. Summer #2 230kV bus dropped to 6.00kV. The V.C. Summer #1 230kV and 115kV Offsite Power Supply bus voltages dropped to 0.00kV and 18.40kV respectively. This allowed the degraded voltage and loss of voltage relay timers to initiate. The voltage recovery differed between the 230kV and 115kV Offsite Power Supply buses but was easily sufficient to allow all relay timers to reset to prevent the switching of the Engineered Safeguard Features buses from the Offsite Power Supply buses.

Rotor angle oscillations were moderate and were adequately damped with no indication of angular instability. Likewise, system frequency responses were also moderate and adequately damped with no indication of system underfrequency load shedding or generator under/overfrequency operations.

Steady state conditions were reestablished with no further system operations.

V.C. Summer #2 STABILITY STUDY RESULTS **Peak System Load Cases**

A.1. Steady state conditions

- A. Generator rotor angles demonstrate steady state condition.
- B. There was no indication of voltage instability.
- C. Generator frequencies show no deviation.
- D. No negative impact on existing V.C. Summer #1 offsite power.
- E. NERC Reliability Standard TPL-001 compliance demonstrated.

A.2. Three phase fault with normal clearing on the V.C. Summer #2 generator terminal 26kV bus

- A. Moderate rotor angle oscillation for SCE&G generators with good damping and no indication of instability.
- B. There was no indication of voltage instability.
- C. Generator frequency responses are moderate and well damped with no system UFLS or generator under/over frequency operations.
- D. No negative impact on existing V.C. Summer #1 offsite power.
- E. NERC Reliability Standard TPL-002 compliance demonstrated.

A.3. Single line to ground fault with delayed clearing on the future V.C. Summer #2 switchyard to the existing V.C. Summer #1 generator switchyard bus #2

- A. Moderate rotor angle oscillation for SCE&G generators with good damping and no system instability.
- B. There was no indication of voltage instability.
- C. Generator frequency responses are moderate and well damped with no system UFLS or generator under/over frequency operations.
- D. No negative impact on existing V.C. Summer #1 offsite power.
- E. NERC Reliability Standard TPL-003 compliance demonstrated.

A.4. Three phase fault with normal clearing on the existing V.C. Summer #1 generator bus #1

- A. Moderate rotor angle oscillation for SCE&G generators with adequate damping, but Special Protection Scheme to trip Fairfield Pumped Storage generators is needed.
- B. There was no indication of voltage instability.
- C. Generator frequency responses are moderate and well damped with no system UFLS or generator under/over frequency operations.
- D. Special Protection System to trip Fairfield Pumped Storage #1-8 required.
- E. No negative impact on existing V.C. Summer #1 offsite power.
- F. NERC Reliability Standard TPL-004 compliance demonstrated.

V.C. Summer #2 STABILITY STUDY RESULTS
System Low Load Cases

A.1. Steady state conditions

- A. Generator rotor angles demonstrate steady state condition.
- B. There was no indication of voltage instability.
- C. Generator frequencies show no deviation.
- D. No negative impact on existing V.C. Summer #1 offsite power.
- E. NERC Reliability Standard TPL-001 compliance demonstrated.

A.2. Three phase fault with normal clearing on the V.C. Summer #2 generator terminal 26kV bus

- A. Small rotor angle oscillation for SCE&G generators with poor but adequate damping.
- B. There was no indication of voltage instability.
- C. Generator frequency oscillations small with poor but adequate damping.
- D. No negative impact on existing V.C. Summer #1 offsite power.
- E. NERC Reliability Standard TPL-002 compliance demonstrated.

A.3. Single line to ground fault with delayed clearing on the future V.C. Summer #2 switchyard to the existing V.C. Summer #1 generator switchyard bus #2

- A. Small rotor angle oscillation for SCE&G generators with adequate damping.
- B. There was no indication of voltage instability.
- C. Generator frequency oscillations also small with adequate damping.
- D. NERC Reliability Standard TPL-003 compliance demonstrated.

A.4. Three phase fault with normal clearing on the existing V.C. Summer #1 generator bus #1

- A. Moderate rotor angle oscillation for SCE&G generators with adequate damping.
- B. There was no indication of voltage instability.
- C. Generator frequency oscillations moderate and adequately damped.
- D. Special Protection System to trip Fairfield Pumped Storage #1-8 required.
- E. No negative impact on existing V.C. Summer #1 offsite power.
- F. NERC Reliability Standard TPL-004 compliance demonstrated.

A.5. Three phase fault with normal clearing on the existing V.C. Summer #1 generator bus #2 to Fairfield Pumped Storage Generators #5-8

- A. Moderate rotor angle oscillation for SCE&G generators with adequate damping.
- B. There was no indication of voltage instability.
- C. Generator frequency oscillations moderate and adequately damped.
- D. No negative impact on existing V.C. Summer #1 offsite power.
- E. NERC Reliability Standard TPL-004 compliance demonstrated.

3. SCPSA Executive Summary

Santee Cooper has completed a portion of a joint utility assessment evaluating the dynamic performance of the bulk transmission system performance with the addition of a proposed 1,165 MW generating unit at the existing V.C. Summer site. Assessments are based on Reliability Standards adopted by the North American Electric Reliability Corporation (NERC) used simulated contingency events of projected 2015 summer and light-load seasons.

This study assesses both the transient stability and dynamic stability under normal operation and for selected contingencies simulated within the Santee Cooper electric system. The study focuses on selected contingency events addressing each of the four contingency Categories defined by NERC Reliability Standards TPL-001 through TPL-004. Contingencies selected for inclusion in this study focus on assessing the impact of specific, proposed changes in the power system network configuration and operating scenario associated with the proposed 1,165 MW generating unit addition at the existing V.C. Summer site.

Study scenario contingencies are applied to dynamic simulation models representing projected summer peak and light-load system conditions for 2015. These models were developed with coordinated input from Santee Cooper, SCE&G, Southern Company, Duke and Progress Energy Carolinas. Since it is impractical to include all possible contingency scenarios in specific stability assessments, those contingency scenarios judged most likely to impact the stability of Santee Cooper facilities are incorporated in this evaluation of actual or proposed system changes. Contingency events evaluated and assessments of each simulation are detailed in Table 1. Selected plots for each scenario are included for each simulation under projected summer peak and light-load conditions.

Review and appraisal of each of the scenarios evaluated do not identify any performance issues within the Santee Cooper bulk transmission system resulting from the proposed additional generation at the V.C. Summer site. Each of the selected contingency scenarios from Categories A, B and C and D of NERC Planning Standard TPL-001 through 004, Table 1 indicates that the Santee Cooper system is expected to comply with the requirements outlined for these contingency categories in the projected representation of both the 2015 summer and light-load seasons.

**Table 1
Contingency Simulations**

Scenario #	NERC Category	Description	Findings
1	B-2	Newberry 230 kV to Pomaria 230 kV line has a fault next to Newberry 230 kV Switching 230 kV switching station. The line is opened and closed under normal breaker operation causing the fault to clear.	Both seasonal case scenarios exhibit good damping following the disturbance. Machine relative angles quickly return to pre-disturbance values without significant swings.
2	C-3	Newberry 230 kV to Greenwood County 230 kV line has a fault next to Newberry 230 kV Switching 230 kV switching station. The line is opened under normal breaker operation causing the fault to clear. This line is not closed. 5 seconds later the Newberry 230 kV to Pomaria 230 kV line has a fault next to Newberry 230 kV Switching 230 kV switching station. The line is opened and closed under normal breaker operation causing the fault to clear.	Both seasonal case scenarios exhibit good damping following both the 1 st and 2 nd disturbance. Machine relative angles quickly return to pre-disturbance values without significant swings during either of the disturbances.
3	C-5	Failure of common structure causes both Greenwood to Hodges 230 kV and Greenwood to Rainey 230 kV lines to have a single line to ground fault. Both lines are taken out of service by normal breaker operation resulting in the clearing of the fault.	Both scenarios exhibit good damping following the disturbance. The summer scenario indicates that machine relative angles quickly returning to pre-disturbance values with no significant swings following the disturbance. The light-load scenario shows machine relative angles quickly finding new steady states of operation with no significant swings.
4	C-7	A single line to ground fault on the Camden to Lugoff 230kV occurs near the Camden switching station. Due to slow breaker operation there is a delay in clearing the fault. The Camden to Lugoff 230 kV line is opening and then closed resulting in clearing the fault.	Both scenarios exhibit good damping following the disturbance. The machine relative angles quickly return to pre-disturbance values no significant swings.
5	D-3	Fault on line near Newberry 230 kV station is not cleared due to breaker failure. The station is then drop by secondary breaker protection.	Machine relative angles exhibit wider swings than those identified for the summer season, though both seasonal scenarios exhibit good damping following the disturbance.
6	D-4	Fault occurs on Pomaria 230 kV buss tie breaker resulting in delayed clearing of 230 kV lines and loss of Pomaria bus.	Results indicate that oscillations following the disturbance are well-damped for both seasonal scenarios.
7	D-5	Fault on Blythewood 230 to 69 kV transformer results in opening and closing of both VC Summer to Blythewood 230 kV and Blythewood to Lugoff 230kV lines. Both Blythewood 230 to 69 kV transformers are tripped resulting in loss of 230 kV support to the Santee Cooper 69kV system.	Both scenarios exhibit good damping following the disturbance. The machine relative angles quickly return to pre-disturbance values no significant swings.

4. Stability Study Conclusions

This study demonstrates that the proposed V.C. Summer #2 generator interconnection to the SCE&G and SCPSA systems is compliant with NERC Reliability Standards. There was no indication of voltage instability. None of the simulations indicated that system UFLS or generator under/overfrequency operations would occur. Neither does the interconnection have a negative impact on the existing V.C. Summer #1 offsite power quality. Several cases with faults located near the V.C. Summer #1 and the Fairfield Pumped Storage units revealed a need for a Special Protection System that will trip the Fairfield units to prevent instability. The SCE&G Relay and SCADA Applications department has identified the operating features of such a scheme and will need to make the required system protection improvements.

III. Required Interconnection Facilities

The analyses performed in this study confirmed the results of the Feasibility Study and show that constructing two new 230kV lines from the VC Summer site to the Columbia Area load center, plus additional transmission improvements described below, are required to reliably transmit the 1,165 MW of the proposed VC Summer #2 generator from of the VC Summer area to the remainder of the SCE&G system. Also, the analyses show that constructing two new 230kV lines is less costly and more effective than upgrading the numerous existing 230kV transmission facilities that currently transmit power from the VC Summer area.

The required transmission improvements:

1. Construct a VC Summer #1 bus #1 - Killian 230kV line with B1272 conductor. (add 230kV terminal at Killian)
2. Construct a VC Summer #2 - Lake Murray 230kV line with B1272 conductor. (add 230kV terminal at Lake Murray)
3. Construct a VC Summer #2 - VC Summer #1 bus #2 230kV line with B1272 conductor. (add 230kV terminal at VC Summer #1 bus #2)
4. Construct a VC Summer #2 - VC Summer #1 bus #3 230kV line with B1272 conductor. (add 230kV terminal at VC Summer #1 bus #3)
5. Upgrade the existing Denny Terrace-Lyles 230kV line to B1272
6. Add a 3rd 230/115kV 336 MVA auto transformer at Lake Murray
7. Add a 3rd 230/115kV 336 MVA auto transformer at Denny Terrace
8. Upgrade the existing Saluda-McMeekin 115kV line to B1272
9. Upgrade the existing Lake Murray-McMeekin 115kV line to B1272
10. Upgrade the existing Lake Murray-Saluda 115kV to with B1272
11. Add a second 230kV bus tie breaker at Denny Terrace

Construct a new 230kV generator substation at the proposed site using a breaker-and-a-half design with ten 230kV terminals. To minimize the number of line crossings and to retire the Parr 230kV substation, several existing lines are being re-terminated at the VC Summer #2 substation and some of the new required lines are terminating at the VC Summer #1 substation.

1. VC Summer #2 generator step up transformer
2. VC Summer #2 station service
3. New 230kV line to VC Summer #1 bus #2
4. New 230kV line to VC Summer #1 bus #3
5. New 230kV line to Lake Murray
6. Re-terminate existing 230kV line to Lake Murray
7. Re-terminate existing 230kV line to Bush River (Duke)
8. Re-terminate existing 230kV line to Graniteville
9. Re-terminate existing 230kV line to Denny Terrace
10. Re-terminate existing 230kV line to Newberry (Santee)

A total of eighteen 230kV breakers are needed at the new generator substation for this design.

To resolve overstressed conditions of several 230kV and 115kV breakers as described in the Short Circuit Analysis section, the following breakers must be replaced with higher interrupting capability breakers:

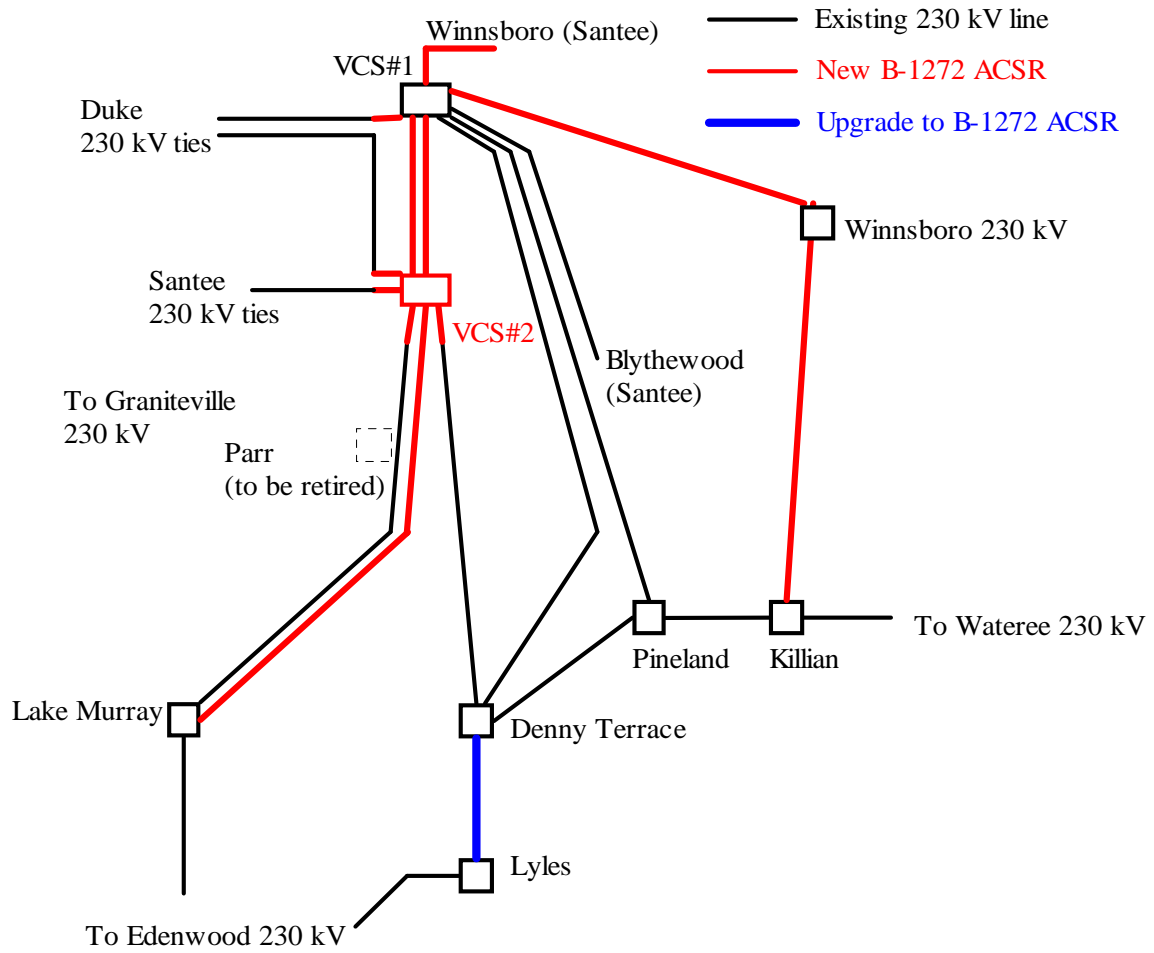
Location	Voltage	Breaker #
VC Summer	230	8722
VC Summer	230	8772
VC Summer	230	8792
VC Summer	230	8832
VC Summer	230	8842
VC Summer	230	8852
VC Summer	230	8892
VC Summer	230	8912
VC Summer	230	8942
Saluda Hydro	115	562
McMeekin	115	1051
McMeekin	115	2051
Edenwood	115	2712
Edenwood	115	3672
Edenwood	115	3682
Denny Terrace	115	8032
Denny Terrace	115	8042
Denny Terrace	115	8092

As stated in the stability analysis section, several cases with faults located near the V.C. Summer #1 and the Fairfield Pumped Storage units revealed a need for a Special Protection System that will trip the Fairfield units to prevent instability. The SCE&G Relay and SCADA Applications department has identified the operating features of such a scheme and will need to make the required system protection improvements.

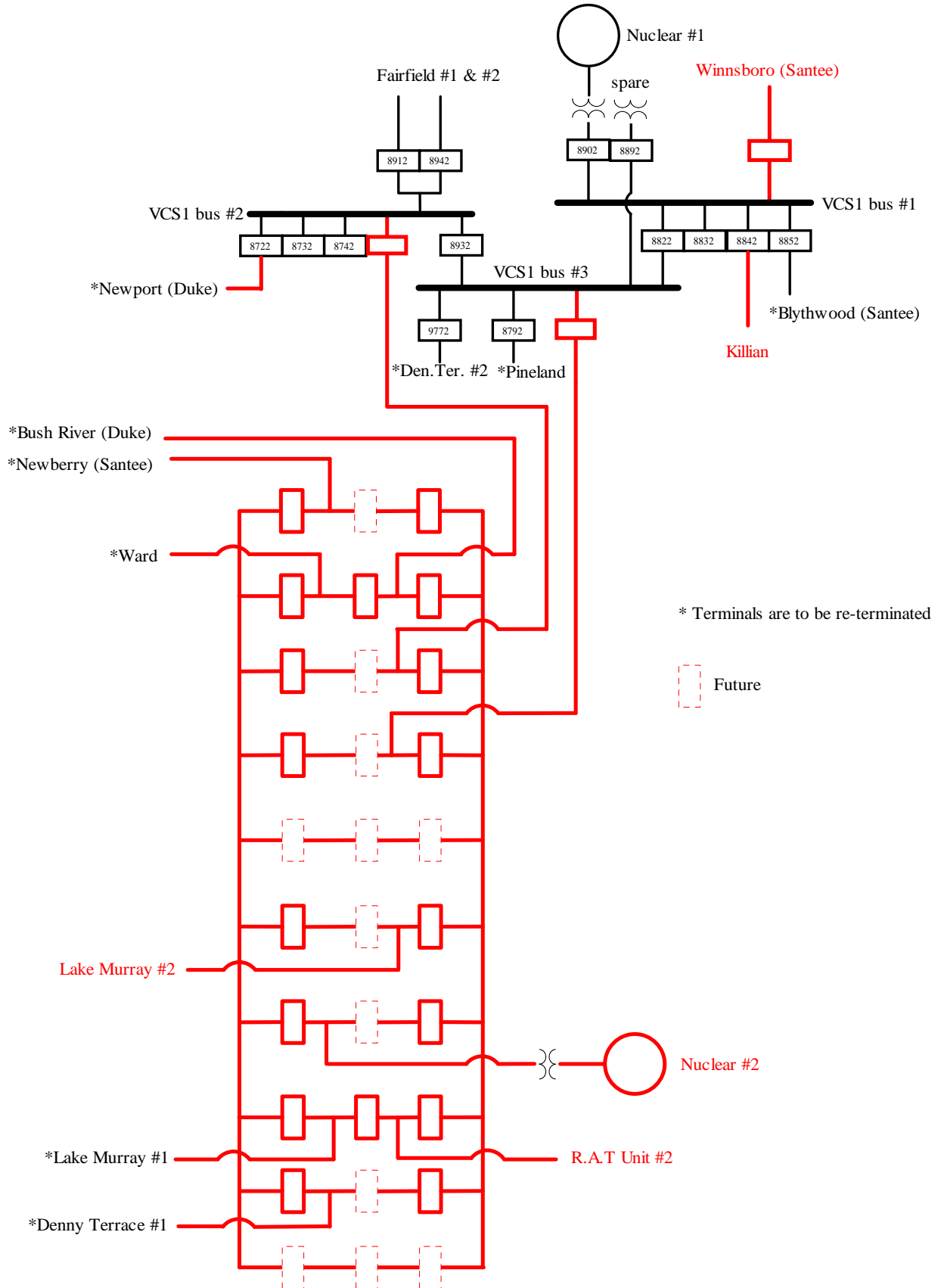
IV. Engineering Design & Cost

A. Engineering Single line Layout & Substation Arrangement

Transmission Single Line



Substation Arrangement



B. Transmission & Substation Cost

All cost estimates are in 2006 dollars.

- | | |
|---|------------|
| 1. Construct VC Summer-Killian 230kV | 25,000,000 |
| • (add 230kV terminal at Killian)..... | 600,000 |
| 2. Construct VC Summer-Lake Murray 230kV..... | 17,000,000 |
| • (add 230kV terminal at Lake Murray) | 600,000 |
| 3. Construct VC Summer #2-VC Summer #1 bus #2 | 600,000 |
| • (add 230kV terminal at VC Summer #1 bus #2) | 600,000 |
| 4. Construct VC Summer #2-VC Summer #1 bus #3 | 600,000 |
| • (add 230kV terminal at VC Summer #1 bus #3) | 600,000 |
| 5. Upgrade existing Denny Terrace-Lyles 230kV | 1,500,000 |
| 6. Add a 3rd 230/115kV 336 MVA auto transformer at Lake Murray | 5,000,000 |
| 7. Add a 3rd 230/115kV 336 MVA auto transformer at Denny Terrace | 8,000,000 |
| 8. Upgrade existing Saluda-McMeekin 115kV line | 125,000 |
| 9. Upgrade existing Lake Murray-McMeekin 115kV line..... | 500,000 |
| 10. Upgrade existing Lake Murray-Saluda 115kV | 450,000 |
| 11. Add second 230kV bus tie breaker at Denny Terrace | 500,000 |

Construct a new 230kV generator substation at the proposed site using a breaker-and-a-half design with ten 230kV terminals 12,589,000

Construct Transmission from VC Summer #2 Generator to VC Summer #2 Switchyard.....340,000

Re-terminate VC Summer area lines to the VC Summer #2 Substation 1,271,000

1. Re-terminate Bush River (Duke) 230kV line to VC Summer #2 substation
2. Re- terminate Newberry (SCPSA) 230kV line to VC Summer #2 substation (paid by SCPSA)
3. Re-terminate Ward 230kV line to VC Summer #2 substation
4. Re-terminate Lake Murray 230kV #1 line to VC Summer #2 substation
5. Re-terminate Denny Terrace 230kV #1 line to VC Summer #2 substation

Re-terminate VC Summer area lines to the VC Summer #1 Substation681,000

1. Re-terminate Blythewood (SCPSA) 230kV line to VCS bus #1 (paid by SCPSA)
2. Re-terminate Pineland 230kV line to VCS bus #3
3. Re-terminate Denny Terrace 230kV line #2 to VCS bus #3
4. Re-terminate Newport (Duke) 230kV line to VCS bus #2

Replace overstressed

- | | |
|-----------------------------|-----------|
| 1. 230kV breakers - 9 | 4,500,000 |
| 2. 115kV breakers - 9 | 2,700,000 |

Total Cost Estimate.....\$83,756,000

V. Adjustments to the VC Summer #2 Interconnection Plan

SCE&G Transmission Planning is adjusting the VC Summer #2 generator interconnection plan to consider future native load needs of the system. The existing system has limited capability to serve future load growth along the Interstate 77 corridor. Without reactive compensation, the system can serve only an additional 40 MW of customer load. With reactive compensation, 81 MW can be served.

Transmission Planning is expecting the load along I-77 to grow rapidly in the future, exceed the additional 81 MW amount and, at that time, the area will need additional transmission expansion to reliably serve the growing load.

Transmission Planning is recommending that the VC Summer – Killian 230kV transmission line, discussed above in this report, be routed from VC Summer to Winnsboro and then to Killian. This will extend the 230kV line but with relatively little additional cost this will also provide for service along the I-77 corridor for many years into the future.



**Generator Interconnection System Impact Study
for
SCE&G V.C. Summer Nuclear #3**

Prepared for:
SCE&G Nuclear Group

August 31, 2007

Prepared by:
SCE&G Transmission Planning

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Generator Interconnection System Impact Study for SCE&G V.C. Summer Nuclear #3

A Generator Interconnection System Impact Study is an extension of the previous Generation Interconnection Feasibility Study, and is a detailed study of the SCE&G transmission system considering the full output of the proposed new generation. The System Impact Study includes a full test of the NERC Reliability Standards Table 1 and the SCE&G Internal Transmission Planning Criteria.

General Discussion

The SCE&G Nuclear Group has applied for interconnection of an additional 1375 MVA nuclear generator near the existing V.C. Summer site. This new generator would be jointly owned by SCE&G and Santee Cooper, SCE&G would own 55% and Santee Cooper would own the remaining 45%. In this study Santee Cooper's portion of the generator output was represented as delivered to the Santee Cooper system.

In the future, SCE&G Transmission Planning will periodically review the results of this Interconnection System Impact Study to determine if the recommended expansion remains valid.

The previously completed Feasibility Study recommended the following transmission line improvements:

1. Construct VCS New-St George 230kV Double Circuit B1272 line (135 miles)
(Add two 230kV terminals at VC Summer New using breaker-and-a-half design)
2. Construct VCS New-VCS#1, Bus #1 230kV line
(Add one 230kV terminal at existing VC Summer Bus #1)
(Add one 230kV terminal at VC Summer New using breaker-and-a-half design)
3. Establish a St George 230kV Switching Station using breaker-and-a-half design
(6 terminals - 9 breakers)
(Add land)
4. Fold-in the Canadys-Santee 230kV line at St George 230kV
5. Upgrade the Canadys-St George 230kV line to B1272
(Upgrade Canadys terminal)
6. Fold-in the Wateree-Summerville 230kV line at St George 230kV
7. Upgrade the St George-Summerville 230kV line to B1272

(Upgrade Summerville terminal)

8. Upgrade Saluda-Georgia Pacific 115kV Double Circuit line to 1272
(Upgrade Saluda terminal)

Add five (5) terminals (9 breakers) to the VC Summer New substation using breaker-and-a-half design.

1. One - for VC Summer #3 generator step up transformer
2. One - for VC Summer #3 station service
3. One - for the new 230kV line to the existing VC Summer #1 230kV bus #1
4. Two - for the 2 new 230kV lines to St George

To resolve overstressed conditions of the breakers as described in the Short Circuit Analysis section, Transmission Planning recommends replacing the following breakers with higher interrupting capability breakers:

Location	Voltage	Breaker #
VC Summer	230	8822
VC Summer	230	8932
VC Summer	230	8902
Lyles	115	732
Edenwood	115	3052
Dunbar	115	1112
A.M. Williams	115	5712
St. George	115	5002
St. George	115	5022
St. George	115	5052
St. George	115	5082

I. Generator Information

The generator design consists of a single nuclear unit and one step-up transformer. The generator unit will have a maximum gross MVA output capacity of 1,375 MVA and a maximum continuous net MW of 1,165 MW.

The generator design consists of the following information:

MVA – gross:	1375
MW – net:	1165
Power Factor:	between .90 and 1.05
Voltage:	26kV
Speed:	1800 rpm
X'd-sat.: 0.397 PU;	X''d-sat.: 0.261 PU
X2-sat.: 0.261 PU;	X0: 0.176 PU

II. Transmission Studies

A. Power Flow Analysis

Since the completion of the Generation Interconnection Feasibility Study, modifications were made to the 230kV generator substation layout and the arrangement of lines connecting to the existing V.C. Summer substation and the proposed V.C. Summer substation. These changes resulted in the proposed retirement of the Parr 230kV substation. The original improvements along with these proposed modifications were modeled and Transmission Planning has run more detailed power flow analysis of the SCE&G transmission system to include a full test of the NERC Reliability Standards Table 1 and the SCE&G Internal Transmission Planning Criteria.

Three different projected loading conditions were simulated for the 2019 time period: Summer Peak Load, Shoulder Load (75% of peak) and Light Load (38% of peak).

For the Summer Peak Load and Shoulder Load simulations, the analysis identified no additional overload conditions due to the additional generation that had not already been previously identified in the Feasibility Study. However, for the Light Load simulation, the following new conditions occurred:

In the basecase, with no outages, the VC Summer-Newport (Duke) 230kV line loads to 98% of its continuous rating of 437 MVA.

The n-2 analyses show the following overload conditions due to the additional generation:

Overloaded Facility	Rating (MVA)	Loading (%)	Contingency(s)
VC Summer #1 bus #2-Newport (Duke) 230kV line	456	104	VC Summer #1 bus #1-Winnsboro (Santee Cooper) 230kV line and VC Summer #1 bus #1-Blythewood (Santee Cooper) 230kV line
VC Summer #1 bus #2-Newport (Duke) 230kV line	456	104	VC Summer New-Pomaria (Santee Cooper) 230kV line #1 and VC Summer New-Pomaria (Santee Cooper) 230kV line #2
VC Summer #1 bus #2-Newport (Duke) 230kV line	456	103	VC Summer New-Bush River (Duke) 230kV line and VC Summer #1 bus #1-Blythewood (Santee Cooper) 230kV line
VC Summer #1 bus #2-Newport (Duke) 230kV line	456	103	VC Summer New-Bush River (Duke) 230kV line and VC Summer #1 bus #1-Winnsboro (Santee Cooper) 230kV line
VC Summer #1 bus #2-Newport (Duke) 230kV line	456	101	VC Summer New-Bush River (Duke) 230kV line and VC Summer New-Ward 230kV line
VC Summer #1 bus #2-Newport (Duke) 230kV line	456	101	VC Summer New-Bush River (Duke) 230kV line and VC Summer New-St George 230kV line

The installation of a series reactor on the VC Summer #1-Newport (Duke) 230kV line will reduce the current flow on the line and eliminate these conditions.

B. Short Circuit Analysis

The previously completed feasibility study indicated three 230kV breakers and eight 115kV breakers were overstressed due to the additional generation at V. C. Summer and must be replaced. This analysis identified no overstressed breakers due to the additional generation that had not already been previously identified in the Feasibility study.

The addition of the VC Summer #3 unit will increase the fault current in the VC Summer area to the point where 80kA breakers will be approaching the point of becoming overstressed. As the fault current capability of the interconnected transmission system increases in the future, this will require breakers with larger interrupting capability.

C. Stability Analysis

1. Overview of Stability Analysis.

The stability study of the connection of the V.C. Summer #3 AP1000 generator to the SCE&G transmission system assessed the ability of this generator to remain in synchronism following selected transmission system contingencies. Also reviewed were the adequacy of damping of generation/transmission oscillations and the impact of the proposed generator on the stability performance of other system generators. System voltage responses were examined for indications of voltage instability. In addition, generator frequency responses and the effects of protective system performance were evaluated.

For the system peak load cases, the adjacent V.C. Summer #2 generator was simulated as switched off except for where noted as otherwise. In addition, the 230kV transmission line connecting the V.C. Summer #3 generator switchyard to SCE&G'S Denny Terrace substation was switched out. These outages were simulated in order to account for the possibility that major generation and transmission could be out of service during the operation of the connecting facility. Power flow studies showed that these were the generation and transmission outages that resulted in the greatest impact on the reactive output of the V.C. Summer #3 generator.

Rotor angle responses of the V.C. Summer #3 generator were simulated in order to determine if angular instability could result from likely contingencies. Generator frequency deviations were examined in order to determine if generator frequency protection could result in generator tripping. The results of the loss of the V.C. Summer #3 generator were examined in order to determine if any resulting underfrequency relay operations would lead to system load shedding. Finally, the effects of each contingency on the V.C. Summer #2 & #3 230kV switchyard bus were examined along with voltages at the existing V.C. Summer #1 230kV and 115kV Offsite Power Supply buses to determine if the voltage requirements of the Offsite Power Supply buses were violated. Generator response plots are not included but are available for review upon request.

An initial 30 second steady state simulation for the selected connection configuration was performed in order to establish that steady state conditions existed prior to fault conditions. The simulation of each contingency repeated the steady state condition for 1 second prior to introducing permanent fault conditions so that the responses could be compared to the initial steady state condition. In order to determine the effects on all system generators, contingencies were simulated under system peak load conditions and system valley load conditions.

Contingencies were selected in order to satisfy each of four categories as specified by NERC Reliability Standards TPL-001 through TPL-004. Although not included in this report, a stability study of this interconnection was also performed for the VCS #2 & VCS #3 Combined Operating License Application (COLA). The results of that study support the findings of this Interconnection Study.

The results of the stability analysis are described in the following sections and are summarized following the detailed results.

2. Results of Peak Load Stability Analysis.

A.1. Steady state conditions (NERC Category A condition)

The interconnection of the V.C. Summer #3 generator was shown to result in system steady state conditions. Generator rotor angles and frequencies showed no significant deviations through out the 30 second simulation. The voltage at the V.C. Summer #3 bus remained at 232.38kV during the simulation. The voltages at the 230kV and 115kV V.C. Summer #1 Offsite Power Supply buses were constant at 232.30kV and 117.65kV.

A.2. Normal clearing of a three phase fault on the V.C. Summer #2 generator terminal 26kV bus (NERC Category B-1 Contingency)

Following a 1 second steady state period, a permanent fault was simulated at the 26Kv side of the V.C. Summer #3 generator step up transformer. This results in the opening of the generator breaker 5 cycles after the appearance of the fault. Since the station service buses are normally served from the 26kV bus, this operation would result in the loss of the station service loads. However, the station fast transfer scheme switches these loads to the switchyard 230kV bus and allows the continued service of these loads.

Rotor angle oscillations were moderate and well damped with no indication of angular instability. There was no indication of voltage instability. Likewise, system frequency responses were also moderate and well damped with no indication of system underfrequency load shedding or generator under/overfrequency operations.

During the application of the fault, the voltage at the V.C. Summer #3 230Kv bus dropped to 119.42kV. The V.C. Summer #1 230kV and 115kV Offsite Power Supply bus voltages dropped to 121.436kV and 77.27kV respectively. This allowed the degraded voltage and loss of voltage relay

timers to initiate. However, the voltages recovered enough to reset the timers within 1 cycle of the clearing of the fault.

Steady state conditions were reestablished with no further system operations.

- A.3. Delayed clearing of a single line to ground fault on the future V.C. Summer #2 & #3 switchyard to the existing V.C. Summer #1 generator switchyard bus #1 (NERC Category C-8 contingency)

Since this contingency places a fault near the existing V.C. Summer #1 generator and both future VCS #2 & #3 generators, these units were modeled as switched on. All local transmission lines were also modeled as in service. Following a 1 second steady state period, a permanent single phase-to-ground fault was simulated at the V.C. Summer #2 & #3 end of the V.C. Summer #2 & #3 – V.C. Summer #1 230kV transmission line #1. The circuit breaker at the V.C. Summer #1 end of the line was simulated as operating normally. The breaker and a half scheme at the V.C. Summer #2 & #3 switchyard cleared the fault following a fault duration of approximately 0.25 seconds.

During the application of the fault, the voltage at the V.C. Summer #2 & #3 bus dropped to 107.12kV. The V.C. Summer #1 230kV and 115kV Offsite Power Supply bus voltages dropped to 109.64kV and 62.11kV respectively. This allowed the degraded voltage and loss of voltage relay timers to initiate. The voltages did not recover in time to reset the loss of voltage relay timers within the required 0.24 seconds of the appearance of the fault. Consequently, both the 230kV and the 115kV loss of voltage relays will operate, resulting in a loss of offsite power and switching of the Engineered Safeguard Features 7.2kV buses to the diesel generators. This operation is not caused by the VCS #3 generator since any nearby fault with delayed clearing will depress the VCS#1 230kV switchyard and local 115kV transmission system voltages for a longer period of time than the VCS #1 loss of voltage relay timers are set for.

Rotor angle oscillations for local generators were pronounced but were adequately damped with no indication of angular instability. There was no indication of voltage instability. Likewise, system frequency responses were also moderate and adequately damped with no indication of system underfrequency load shedding or generator under/overfrequency operations.

Steady state conditions were reestablished with no further system operations.

- A.4. Normal clearing of a three phase fault on the existing V.C. Summer #1 generator switchyard bus #1 (NERC Category D-10 contingency)

Following a 1 second steady state period, a permanent single three phase fault was simulated at the V.C. Summer #1 bus #1. Since this is the bus that the V.C. Summer #1 generator is connected to that generator was tripped when the fault was cleared. In addition, in order to prevent the Fairfield Pumped Storage generators from becoming unstable, a Special Protection System that was identified as needed when V.C. Summer #2 goes into service will need to be installed at the V.C. Summer #1 switchyard in order to trip those units as well. The operations to clear the fault and trip the generators will occur within 6 cycles from the appearance of the bus fault.

During the application of the fault, the voltage at the V.C. Summer #3 230kV bus dropped to 5.51kV. The V.C. Summer #1 230kV and 115kV Offsite Power Supply bus voltages dropped to 0.00kV and 34.47kV respectively. This allowed the degraded voltage and loss of voltage relay timers to initiate. However, the voltages recovered enough to reset the timers within 9 cycles following the appearance of the fault.

Rotor angle oscillations were moderate and were adequately damped with no indication of angular instability. There was no indication of voltage instability. Likewise, system frequency responses were also moderate and adequately damped with no indication of system underfrequency load shedding or generator under/overfrequency operations.

Steady state conditions were reestablished with no further system operations.

3. Results of Light Load Stability Analysis.

A.1. Steady state conditions (NERC Category A condition)

The interconnection of the V.C. Summer #3 generator was shown to result in system steady state conditions. Generator rotor angles and frequencies showed no significant deviations through out the 30 second simulation. The voltage at the V.C. Summer #3 bus remained at 232.30kV during the simulation. The voltages at the 230kV and 115kV V.C. Summer #1 Offsite Power Supply buses were constant at 232.30kV and 117.88kV.

A.2. Normal clearing of a three phase fault on the V.C. Summer #3 generator terminal 26kV bus (NERC Category B-1 Contingency)

Following a 1 second steady state period, a permanent fault was simulated at the 26Kv side of the V.C. Summer #3 generator step up transformer. This results in the opening of the generator breaker 5 cycles after the appearance of the fault. Since the station service buses are normally served from the 26kV bus, this operation would result in the loss of the station service loads. However, the station fast transfer scheme switches these loads to the switchyard 230kV bus and allows the continued service of these loads.

Rotor angle oscillations were small but poorly damped due to the smaller level of synchronizing torque within the system due to the reduced amount of generation on line during system low load conditions. However, the generator rotor angle oscillations were eventually damped and there was no indication of angular instability. There was no indication of voltage instability. Likewise, system frequency responses were also small and poorly damped but with no indication of system underfrequency load shedding or generator under/overfrequency operations.

During the application of the fault, the voltage at the V.C. Summer #3 bus dropped to 125.70kV. The V.C. Summer #1 230kV and 115kV Offsite Power Supply bus voltages dropped to 127.60kV and 72.95kV respectively. This allowed the degraded voltage and loss of voltage relay timers to initiate. However, the voltages recovered enough to reset the timers within 1 cycle of the clearing of the fault.

Steady state conditions were reestablished with no further system operations.

- A.3. Delayed clearing of a single line to ground fault on the future V.C. Summer #2 & #3 switchyard to the existing V.C. Summer #1 generator switchyard bus #2 (NERC Category C-8 contingency)

Following a 1 second steady state period, a permanent single phase-to-ground fault was simulated at the V.C. Summer #2 & #3 end of the V.C. Summer #2 & #3 – V.C. Summer #1 230kV transmission line #1. The circuit breaker at the V.C. Summer #1 end of the line was simulated as operating normally. The breaker and a half scheme at the V.C. Summer #2 & #3 switchyard cleared the fault following a fault duration of approximately 0.25 seconds.

During the application of the fault, the voltage at the V.C. Summer #2 & #3 bus dropped to 98.93kV. The V.C. Summer #1 230kV and 115kV Offsite Power Supply bus voltages dropped to 101.03kV and 60.79kV respectively. This allowed the degraded voltage and loss of voltage relay timers to initiate. The voltages did not recover in time to reset the loss of voltage relay timers within the required 0.24 seconds of the appearance of the fault. Consequently, both the 230kV and the 115kV loss of voltage relays will operate, resulting in a loss of offsite power and switching of the Engineered Safeguard Features 7.2kV buses to the diesel generators. This operation is not caused by the VCS #3 generator since any nearby fault with delayed clearing will depress the VCS #1 230kV switchyard and local 115kV transmission system voltages for a longer period of time than the VCS #1 loss of voltage relay timers are set for.

Rotor angle oscillations were large and were poorly damped due to the reduced generation during light load conditions and the resulting reduction in system synchronizing torque. An extended simulation showed that the generator rotor angle oscillations were eventually damped and there was no indication of angular instability. There was no indication of voltage

instability. Likewise, system frequency responses were also moderate and adequately damped with no indication of system underfrequency load shedding or generator under/overfrequency operations.

Steady state conditions were reestablished with no further system operations.

A.4. Normal clearing of a three phase fault on the existing V.C. Summer #1 generator switchyard bus #1 (NERC Category D-10 contingency)

Following a 1 second steady state period, a permanent three phase fault was simulated at the V.C. Summer #1 bus #1. Since this is the bus that the V.C. Summer #1 generator is connected to, that generator was tripped when the fault was cleared. In addition, in order to prevent the Fairfield Pumped Storage generators from becoming unstable, a Special Protection System that was identified as needed when V.C. Summer #2 goes into service will need to be installed at the V.C. Summer #1 switchyard in order to trip those units as well. The operations to clear the fault and trip the generators will occur within 6 cycles from the appearance of the bus fault.

During the application of the fault, the voltage at the V.C. Summer #2 230kV bus dropped to 5.84kV. The V.C. Summer #1 230kV and 115kV Offsite Power Supply bus voltages dropped to 0.00kV and 19.93kV respectively. This allowed the degraded voltage and loss of voltage relay timers to initiate. However, the voltages recovered enough to reset the loss of voltage relay timers within 13-14 cycles of the appearance of the fault. The voltage recovery allowed the degraded voltage relay timers to reset within 29-32 cycles following the fault.

Rotor angle oscillations were moderate and were adequately damped with no indication of angular instability. There was no indication of voltage instability. Likewise, system frequency responses were also moderate and adequately damped with no indication of system underfrequency load shedding or generator under/overfrequency operations.

Steady state conditions were reestablished with no further system operations. The plots for this case are shown in

A.5. Three phase fault with normal clearing on the existing V.C. Summer #1 generator bus #2 to Fairfield Pumped Storage Generators # 5-8 (NERC Category D-11 contingency)

Following a 1 second steady state period, a permanent three phase fault was simulated on the 230kV transmission line that connects the V.C. Summer #1 bus #2 to the Fairfield Pumped Storage units #5-8. When this line was opened these units which were operating in the pumping mode were taken off line. This represents the loss of a large load removed from the system as a result of a single event.

During the application of the fault, the voltage at the V.C. Summer #2 230kV bus dropped to 5.97kV. The V.C. Summer #1 230kV and 115kV Offsite Power Supply bus voltages dropped to 0.00kV and 20.21kV respectively. This allowed the degraded voltage and loss of voltage relay timers to initiate. The voltage recovery differed between the 230kV and 115kV Offsite Power Supply buses but was sufficient to allow all relay timers to reset to prevent the switching of the Engineered Safeguard Features buses from the Offsite Power Supply buses. Transmission system voltages showed poorly damped oscillations with a return to steady state conditions during an extended 60 second simulation.

Rotor angle oscillations were moderate but poorly damped during the 30 second simulation due to the reduced system synchronizing torque during reduced system load conditions. However, an extended simulation to 60 seconds demonstrated an eventual return to steady state conditions. Switching the power system stabilizer at V.C. Summer #3 did not noticeably degrade the rotor angle damping. There was no indication of angular instability. Likewise, system frequency responses were also poorly damped but with no indication of system underfrequency load shedding or generator under/overfrequency operations.

Steady state conditions were reestablished with no further system operations.

V.C. Summer #3 STABILITY STUDY RESULTS

Peak System Load Cases

- A.1. Steady state conditions
 - A. Generator rotor angles demonstrate steady state condition.
 - B. There was no indication of voltage instability.
 - C. Generator frequencies show no deviation.
 - D. No negative impact on existing V.C. Summer #1 offsite power.
 - E. NERC Reliability Standard TPL-001 compliance demonstrated.

- A.2. Three phase fault with normal clearing on the V.C. Summer #3 generator terminal 26kV bus
 - A. Moderate rotor angle oscillation for system generators with good damping and no indication of instability.
 - B. There was no indication of voltage instability.
 - C. Generator frequency responses are moderate and well damped with no system UFLS or generator under/over frequency operations.
 - D. No negative impact on existing V.C. Summer #1 offsite power.
 - E. NERC Reliability Standard TPL-002 compliance demonstrated.

- A.3. Single line to ground fault with delayed clearing on the future V.C. Summer #3 switchyard to the existing V.C. Summer #1 generator switchyard bus #2
 - A. Pronounced rotor angle oscillation for local generators with good damping and no system instability.
 - B. There was no indication of voltage instability.
 - C. Generator frequency responses are moderate and well damped with no system UFLS or generator under/over frequency operations.
 - D. Loss of offsite power to V.C. Summer #1 Engineered Safeguard Features 7.2kV buses not due to V.C. Summer #3 generator.
 - E. NERC Reliability Standard TPL-003 compliance demonstrated.

- A.4. Three phase fault with normal clearing on the existing V.C. Summer #1 generator bus #1
 - A. Moderate rotor angle oscillation for system generators with adequate damping.
 - B. There was no indication of voltage instability.
 - C. Generator frequency responses are moderate and well damped with no system UFLS or generator under/over frequency operations.
 - D. Special Protection System to trip Fairfield Pumped Storage #1-8 required as previously identified for V.C. Summer #2 generator.
 - E. No negative impact on existing V.C. Summer #1 offsite power.
 - F. NERC Reliability Standard TPL-004 compliance demonstrated.

V.C. Summer #3 STABILITY STUDY RESULTS

System Light Load Cases

- A.1. Steady state conditions
 - A. Generator rotor angles demonstrate steady state condition.
 - B. There was no indication of voltage instability.
 - C. Generator frequencies show no deviation.
 - D. No negative impact on existing V.C. Summer #1 offsite power.
 - E. NERC Reliability Standard TPL-001 compliance demonstrated.

- A.2. Three phase fault with normal clearing on the V.C. Summer #3 generator terminal 26kV bus
 - A. Small rotor angle oscillation for system generators with poor but adequate damping.
 - B. There was no indication of voltage instability.
 - C. Generator frequency oscillations small with poor but adequate damping.
 - D. No negative impact on existing V.C. Summer #1 offsite power.
 - E. NERC Reliability Standard TPL-002 compliance demonstrated.

- A.3. Single line to ground fault with delayed clearing on the future V.C. Summer #3 switchyard to the existing V.C. Summer #1 generator switchyard bus #2
 - A. Large rotor angle oscillation for system generators with poor damping.
 - B. There was no indication of voltage instability.
 - C. Generator frequency oscillations moderate with adequate damping.
 - D. Loss of offsite power to V.C. Summer #1 Engineered Safeguard Features 7.2kV buses not due to V.C. Summer #3 generator.
 - E. NERC Reliability Standard TPL-003 compliance demonstrated.

- A.4. Three phase fault with normal clearing on the existing V.C. Summer #1 generator bus #1
 - A. Moderate rotor angle oscillation for system generators with adequate damping.
 - B. There was no indication of voltage instability.
 - C. Generator frequency oscillations moderate and adequately damped.
 - D. Special Protection System to trip Fairfield Pumped Storage #1-8 required previously identified for V.C. Summer #2 generator.
 - E. No negative impact on existing V.C. Summer #1 offsite power.
 - F. NERC Reliability Standard TPL-004 compliance demonstrated.

- A.5. Three phase fault with normal clearing on the existing V.C. Summer #1 generator bus #2 to Fairfield Pumped Storage Generators #5-8
 - A. Moderate rotor angle oscillation for SCE&G generators with poor damping due to reduced system synchronizing torque during low system load conditions.
 - B. There was no indication of voltage instability.
 - C. Generator frequency oscillations moderate but poorly damped.
 - D. No negative impact on existing V.C. Summer #1 offsite power.
 - E. NERC Reliability Standard TPL-004 compliance demonstrated.

4. Stability Study Conclusions

This study demonstrates that the proposed V.C. Summer #3 generator interconnection to the SCE&G system is compliant with NERC Reliability Standards. There was no indication of voltage instability. None of the simulations indicated that system UFLS or generator under/overfrequency operations would occur. Neither does the interconnection have a negative impact on the existing V.C. Summer #1 offsite power quality. The cases that resulted in the loss of offsite power for the V.C. Summer #1 generator were caused by delayed clearing relay settings and not by the V.C. Summer #3 generator. Several cases with faults located near the V.C. Summer #1 and the Fairfield Pumped Storage units confirmed the need for a Special Protection System that will trip the Fairfield units to prevent instability. The need for this Special Protection System was identified during the V.C. Summer #2 System Impact Study. The SCE&G Relay and SCADA Applications department has identified the operating features of such a scheme and will make the required system protection improvements.

III. Required Interconnection Facilities

The analyses performed in this study confirmed the results of the Feasibility Study and show that constructing two new 230kV lines from the proposed VC Summer #3 generator to near the Charleston area load center, plus additional transmission improvements described below, are required to reliably transmit SCE&G's ownership portion of the 1,165 MW of the proposed VC Summer #3 generator from the VC Summer area to the remainder of the SCE&G system. Additionally, the off-peak analysis identified the need for a series reactor on the VC Summer #1-Newport (Duke) 230kV line to limit the power flow on that line.

The required transmission improvements:

1. Construct VC Summer New-St George 230kV Double Circuit B1272 line (135 mi)
(Add 2 230kV terminals at VC Summer New using breaker-and-a-half design)
2. Construct VC Summer New-VC Summer #1 Bus #1
(Add 230kV terminal at existing VC Summer #1 Bus #1)
(Add 230kV terminal at VC Summer New using breaker-and-a-half design)
3. Establish a St George 230kV Substation using breaker-and-a-half design
(6 terminals - 9 breakers)
(Future 2 terminals - 3 breakers)
(Add land)
4. Fold-in the Canadys-Santee 230kV line at St George 230kV
5. Upgrade the Canadys-St George 230kV line to B1272
(Upgrade Canadys terminal)
6. Fold-in the Wateree-Summerville 230kV line at St George 230kV
7. Upgrade the St George-Summerville 230kV line to B1272
(Upgrade Summerville terminal)
8. Upgrade Saluda-Georgia Pacific 115kV Double Circuit line to 1272
(Upgrade Saluda terminal)
9. Install a 230kV Series Reactor (25% on a 500 MVA base) on the VC Summer #1-Newport (Duke) 230kV line

Add six (6) terminals (8 breakers) to the VC Summer New substation using breaker-and-a-half design.

10. One - for VC Summer #3 generator step up transformer
11. One - for VC Summer #3 station service

- 12. One - for the new 230kV line to the existing VC Summer #1 bus #1
- 13. Two - for the 2 new 230kV lines to St George 230kV
- 14. One - for the new 230kV line to Sandy Run (Santee Cooper)

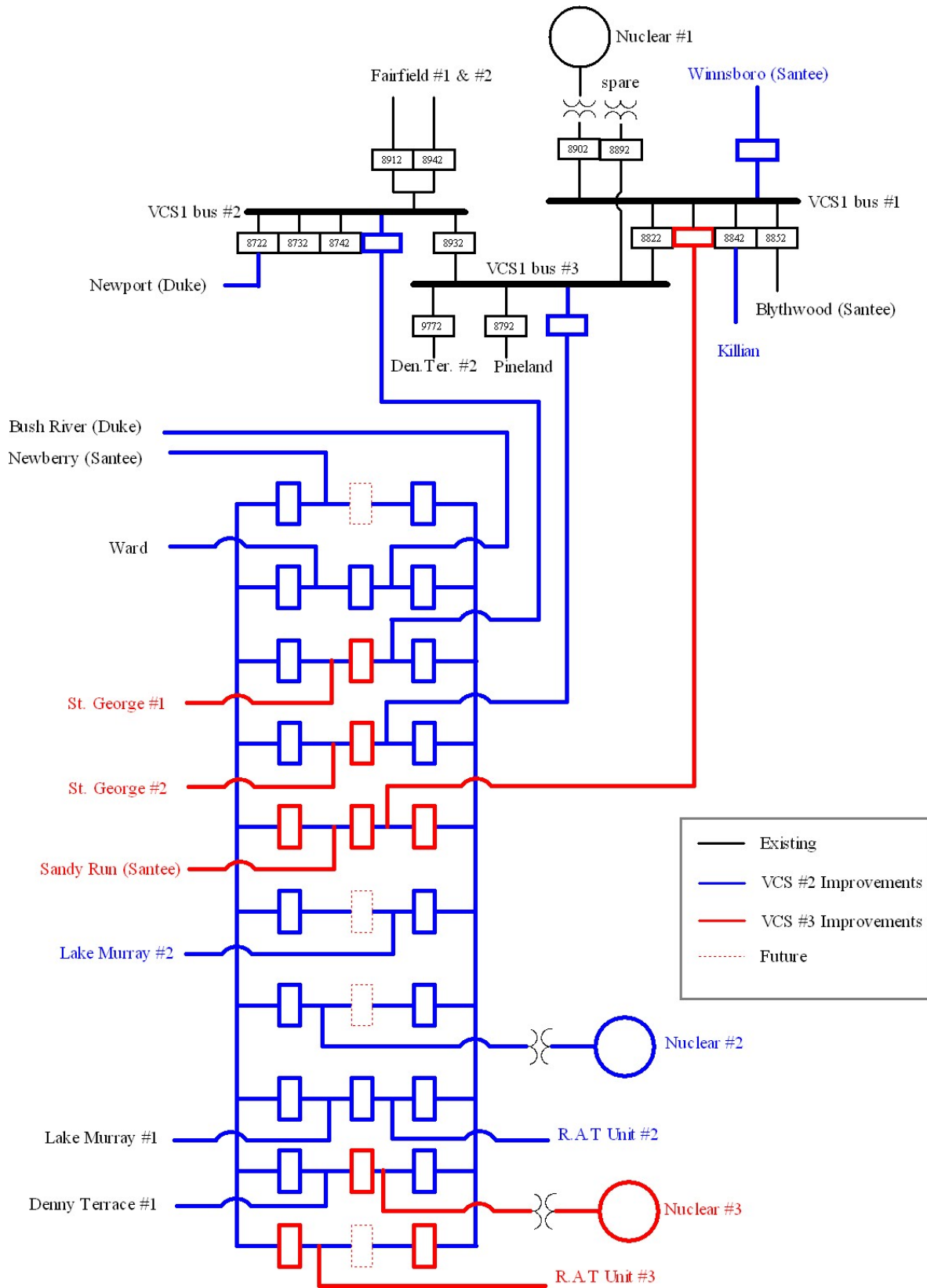
To resolve overstressed conditions of the breakers as described in the Short Circuit Analysis section, Transmission Planning recommends replacing the following breakers with higher interrupting capability breakers:

Location	Voltage	Breaker #
VC Summer #1	230	8822
VC Summer #1	230	8932
VC Summer #1	230	8902
Lyles	115	732
Edenwood	115	3052
Dunbar	115	1112
A.M. Williams	115	5712
St. George	115	5002
St. George	115	5022
St. George	115	5052
St. George	115	5082

As stated in the stability analysis section, several cases with faults located near the VC Summer #1 and the Fairfield Pumped Storage units revealed a need for a Special Protection System that will trip the Fairfield units to prevent instability. The SCE&G Relay and SCADA Applications department has identified the operating features of such a scheme and will make the required system protection improvements.

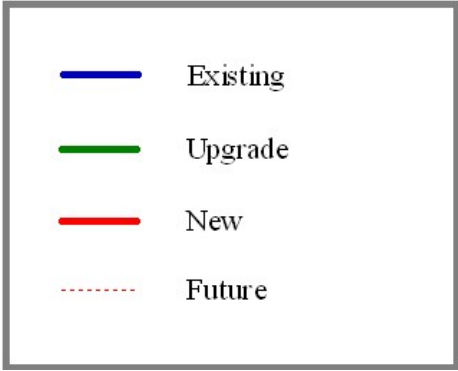
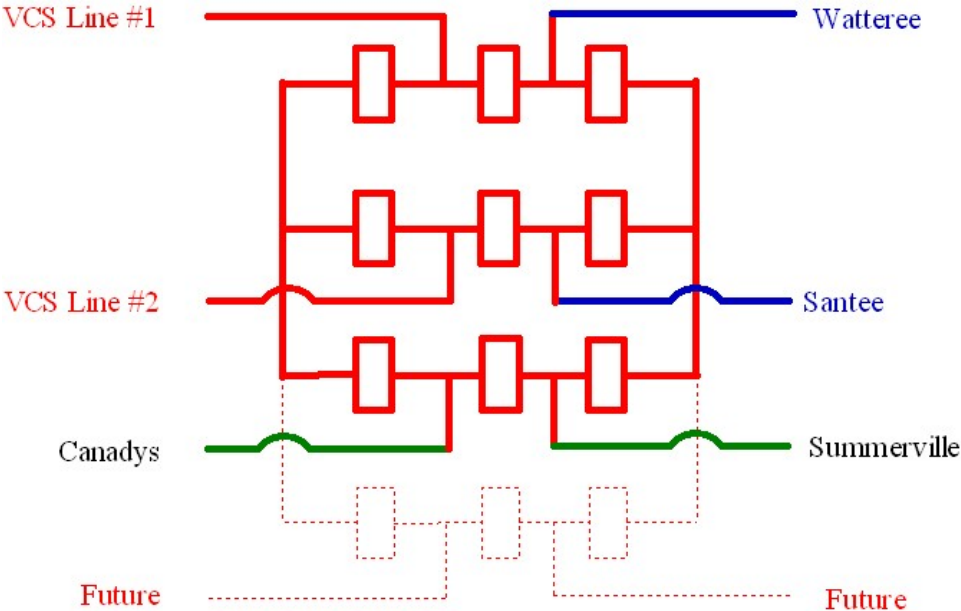
Substation Arrangement

VC Summer #3



Substation Arrangement

St George 230kV



B. Transmission & Substation Cost

All cost estimates are in 2006 dollars.

1. Construct VC Summer New-St George 230kV
Double Circuit B1272 line (135 miles)\$153,950,000
2. Construct VC Summer New-VC Summer #1 Bus #1).....\$600,000
(Add 230kV terminal at existing VC Summer #1 Bus #1).....\$1,100,000
3. Construct St George 230kV Substation using
breaker-and-a-half design\$11,400,000
4. Fold-in the Canadys-Santee 230kV line at St George 230kV\$1,100,000
5. Upgrade the Canadys-St George 230kV line to B1272\$7,300,000
6. Fold-in the Wateree-Summerville 230kV line at St George 230kV\$1,100,000
7. Upgrade the St George to Summerville 230kV line to B1272.....\$15,300,000
8. Upgrade Saluda-Georgia Pacific 115kV Double Circuit line to 1272 \$11,900,000
9. Add six (6) 230kV terminals (8 breakers) at VC Summer New using
breaker-and-a-half design\$12,000,000
10. Install a 230kV Series Reactor (25% on a 500 MVA base) on the
VC Summer #1-Newport (Duke) 230kV line.....\$3,800,000

Replace overstressed breakers

11. Three (3) 230kV breakers\$660,000
12. Eight (8) 115kV breakers\$1,200,000

Total Cost Estimate\$221,410,000



Generator Interconnection Facilities Study

SCE&G V.C. Summer Nuclear #2

Prepared for:
SCE&G Nuclear Group

April 14, 2008

Prepared by:
SCE&G Transmission Planning

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IV. Electrical Switching Configuration Page 7

Generator Interconnection Facilities Study

SCE&G V.C. Summer Nuclear #2

A Generator Interconnection Facilities Study is an extension of the previous Generation Interconnection System Impact Study, and specifies and estimates the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the Interconnection System Impact Study in accordance with Good Utility Practice to physically and electrically connect the Interconnection Facility to the Transmission System. A Generator Interconnection Facilities Study also identifies the electrical switching configuration of the connection equipment, including, without limitation: the transformer, switchgear, meters, and other station equipment; the nature and estimated cost of any Transmission Provider's Interconnection Facilities and Network Upgrades necessary to accomplish the interconnection; and an estimate of the time required to complete the construction and installation of such facilities.

General Discussion

The SCE&G Nuclear Group has applied for interconnection of a new 1375 MVA nuclear generator near the existing V.C. Summer site. This new generator would be jointly owned by SCE&G and Santee Cooper, SCE&G would own 55% and Santee Cooper would own the remaining 45%. In this study Santee Cooper's portion of the generator output was represented as delivered to the Santee Cooper system.

The previously completed System Impact Study recommended the following transmission line improvements:

1. Construct VC Summer-Winnsboro- Killian 230kV
 - (add 230kV terminal at Killian)
2. Construct VC Summer-Lake Murray 230kV
 - (add 230kV terminal at Lake Murray)
3. Construct VC Summer #2-VC Summer #1 bus #2
 - (add 230kV terminal at VC Summer #1 bus #2)
4. Construct VC Summer #2-VC Summer #1 bus #3
 - (add 230kV terminal at VC Summer #1 bus #3)
5. Upgrade existing Denny Terrace-Lyles 230kV
6. Add a 3rd 230/115kV 336 MVA auto transformer at Lake Murray
7. Add a 3rd 230/115kV 336 MVA auto transformer at Denny Terrace
8. Upgrade existing Saluda-McMeekin 115kV line
9. Upgrade existing Lake Murray-McMeekin 115kV line
10. Upgrade existing Lake Murray-Saluda 115kV
11. Add second 230kV bus tie breaker at Denny Terrace

Construct a new 230kV generator substation at the proposed site using a breaker-and-a-half design with ten 230kV terminals

Construct Transmission from VC Summer #2 Generator to VC Summer #2 Switchyard

Re-terminate VC Summer area lines to the VC Summer #2 Substation

1. Re-terminate Bush River (Duke) 230kV line to VC Summer #2 substation
2. Re- terminate Newberry (SCPSA) 230kV line to VC Summer #2 substation (paid by SCPSA)
3. Re-terminate Ward 230kV line to VC Summer #2 substation
4. Re-terminate Lake Murray 230kV #1 line to VC Summer #2 substation
5. Re-terminate Denny Terrace 230kV #1 line to VC Summer #2 substation

Re-terminate VC Summer area lines to the VC Summer #1 Substation

1. Re-terminate Blythewood (SCPSA) 230kV line to VCS bus #1 (paid by SCPSA)
2. Re-terminate Pineland 230kV line to VCS bus #3
3. Re-terminate Denny Terrace 230kV line #2 to VCS bus #3
4. Re-terminate Newport (Duke) 230kV line to VCS bus #2

Replace overstressed

1. 230kV breakers - 9
2. 115kV breakers - 9

In the future, SCE&G Transmission Planning will periodically review the results of this Interconnection Facilities Study to determine if the recommended transmission expansion and the associated cost estimates remain valid.

I. Generator Information

The generator design consists of a single nuclear unit and one step-up transformer. The generator unit will have a maximum gross MVA output capacity of 1,375 MVA and a maximum continuous net MW of 1,165 MW.

The generator design consists of the following information:

MVA – gross:	1375
MW – net:	1165
Power Factor:	between .90 and 1.05
Voltage:	22kV
Speed:	1800 rpm
X'd-sat.: 0.465 PU;	X''d-sat.: 0.325 PU
X2-sat.: 0.320 PU;	X0: 0.237 PU

II. Cost Estimates of Transmission Provider's Interconnection Facilities and Network Upgrades and Completion Dates

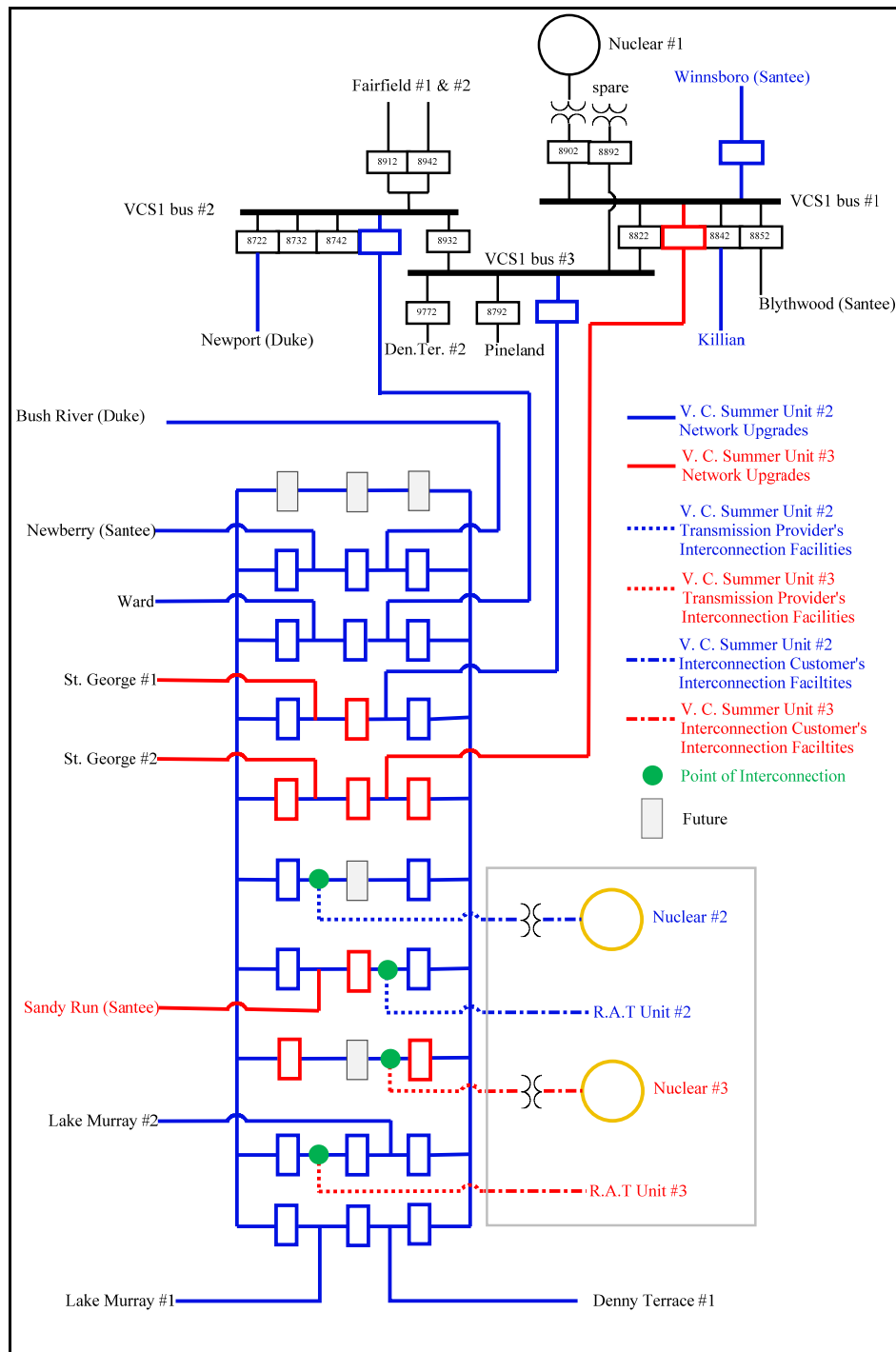
The Table below includes the cost estimate for the required Transmission Provider Interconnection Facilities, the required Network Upgrades and the estimated completion date for each of these required projects.

VC Summer Unit #2 Transmission Cost Estimates
Escalated at 4% per year from 2008

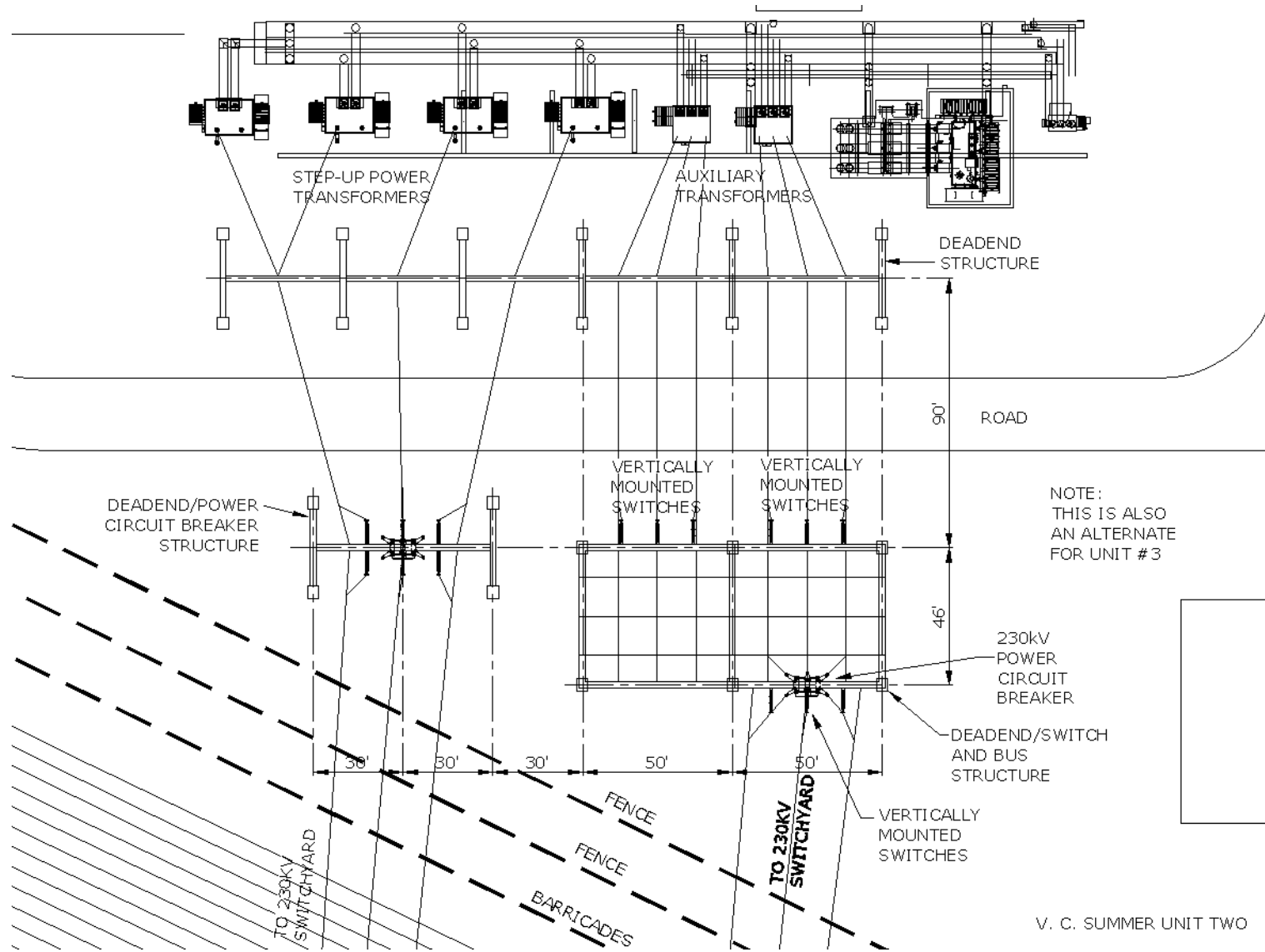
Project Name	Scheduled End Date	Budget 2008	Budget 2009	Budget 2010	Budget 2011	Budget 2012	Budget 2013	Budget 2014	Budget 2015	Budget 2016	Budget 2017	Budget 2018	Totals
Summer Unit #2 230KV Switchyard - Construct	12/31/2013				1,000,000	15,000,000	17,000,000		Budgeted in Nuclear				33,000,000
Summer #1-Killian -230KV Line - Construct B1272 (Estimate includes R/W. Assume rebuild of current H-frame for approx approx 24 miles single circuit single shaft – no additional R/W required and a single shaft single circuit for 3 miles. Assume additional R/W of 70ft alongside existing R/W from Pineland to Killian – approx 26 acres @ 80,000 per Acre)	12/31/2015					500,000	1,500,000	14,000,000	19,000,000				35,000,000
Killian Add 230KV Term – Summer-Construct	12/31/2015								840,000				840,000
VCS #2-Lake Murray Trans #2-230KV Line - Construct (assume rebuild of current H-frame approx 19 miles single circuit single shaft – no additional R/W required)	12/31/2015					800,000	3,000,000	10,000,000	10,000,000				23,800,000
Lake Murray Transmission: Add 230KV Term VCS#2	12/31/2015								840,000				840,000
Summer Unit #2-230KV Tie to Bus #2 - Construct (Assume 0.75 mile)	12/31/2013						840,000						840,000
Summer Unit #1 – Add 230KV Term to Bus #2 - Construct	12/31/2013						840,000						840,000
Summer Unit #2-230KV Tie to Bus #3 – Construct (Assume 0.75 mile)	12/31/2013						840,000						840,000
Summer Unit #1 – Add 230KV Term to Bus #3 - Construct	12/31/2013						840,000						840,000
Denny Terrace-Lyles 230KV – Rebuild to B1272 (Approx 2.75 mile)	12/31/2015							100,000	2,000,000				2,100,000
VC Sum Area: Reterminate 230kV lines to VCS #1 Sub	12/31/2013						950,000						950,000
VC Sum Area: Reterminate 230kV Lines to VCS #2 Sub	12/31/2013						1,800,000						1,800,000
Lake Murray Trans – Add 3 rd 336 Autobank	12/31/2015							3,000,000	4,000,000				7,000,000
Denny Terrace – Add 3 rd 336 Autobank / 230kV BT	12/31/2015							5,000,000	6,000,000				11,000,000
Saluda-McMeekin 115KV Line – Upgrade (Approx 0.2 mile)	12/31/2015						200,000						200,000
Lake MurrayTrans-McMeekin 115KV Line – Upgrade (Approx 0.6 mile)	12/31/2015								700,000				700,000
Lake Murray-Saluda 115KV Line Upgrade (Approx 0.5 mile)	12/31/2015								630,000				630,000
Various 115KV PRCB Upgrade Interrupter Rating (Assume 9 PRCBs)	12/31/2015							800,000	3,000,000				3,800,000
Various 230KV PRCB Upgrade Interrupter Rating (Assume 9 PRCBs)	12/31/2015							1,300,000	5,000,000				6,300,000
VC Summer Unit #2 to Unit #2 Sub 230kV Line: Const	12/31/2013						500,000						500,000
VC Summer RAT #2 to Unit #2 Sub 230kV Line: Constr	12/31/2013						500,000						500,000
VCS - Parr 115kV Safeguard Line: Raise for Unit 2	12/1/2009		70,000										70,000
VC Summer Sub: 230kV BB Bus Tie between #1 & #3	5/1/2009		250,000										250,000
		0	320,000	0	1,000,000	16,300,000	28,810,000	34,200,000	52,010,000	0	0	0	132,640,000

III. Facilities Classifications

The Facilities Study report must identify and estimate the cost of any Transmission Provider's Interconnection Facilities and Network Upgrades necessary to accomplish the interconnection. The diagram below includes color and line style indications of which facilities fall into the classification of Network Upgrades, Transmission Provider's Interconnection Facilities or Interconnection Customer's Interconnection Facilities. Cost estimates for all Network Upgrades and Transmission Provider's Interconnection Facilities are included in Section II of this report. *The diagram below is different from the diagram in the System Impact Study and reflects the most recent substation design.*



IV. Electrical Switching Configuration





Generator Interconnection Facilities Study
SCE&G V.C. Summer Nuclear #3 – Revision #2

Prepared for:
SCE&G Nuclear Group

April 10, 2008
May 27, 2008 – Revision #1
May 29, 2008 – Revision #2

Prepared by:
SCE&G Transmission Planning

May 29, 2008 – Revision #2

This revision renames and rearranges one of the associated projects in the narrative and in the cost estimate table for clarification. The rest of the report is unchanged and included in its entirety.

May 27, 2008 – Revision #1

This report corrects a double entry line item in the cost estimate for the VC Summer #3 interconnection. The rest of the report is unchanged and included in its entirety.

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Generator Interconnection Facilities Study

SCE&G V.C. Summer Nuclear #3

A Generator Interconnection Facilities Study is an extension of the previous Generation Interconnection System Impact Study, and specifies and estimates the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the Interconnection System Impact Study in accordance with Good Utility Practice to physically and electrically connect the Interconnection Facility to the Transmission System. A Generator Interconnection Facilities Study also identifies the electrical switching configuration of the connection equipment, including, without limitation: the transformer, switchgear, meters, and other station equipment; the nature and estimated cost of any Transmission Provider's Interconnection Facilities and Network Upgrades necessary to accomplish the interconnection; and an estimate of the time required to complete the construction and installation of such facilities.

General Discussion

The SCE&G Nuclear Group has applied for interconnection of a new 1375 MVA nuclear generator near the existing V.C. Summer site. This new generator would be the third nuclear generator on this site and would be jointly owned by SCE&G and Santee Cooper, SCE&G would own 55% and Santee Cooper would own the remaining 45%. In this study Santee Cooper's portion of the generator output was represented as delivered to the Santee Cooper system.

The previously completed System Impact Study for VC Summer #3 recommended the following transmission line improvements:

1. 230KV Switchyard Additions for Unit #3 - Add six (6) 230kV terminals (8 breakers) at VC Summer New using breaker-and-a-half design
2. Construct VC Summer New-St George 230kV Double Circuit B1272 line (135 miles)
3. Construct VC Summer New-VC Summer #1 Bus #1
(Add 230kV terminal at existing VC Summer #1 Bus #1)
4. Construct St George 230kV Substation using breaker-and-a-half design
5. Fold-in the Canadys-Santee 230kV line at St George 230kV
6. Upgrade the Canadys-St George 230kV line to B1272
7. Fold-in the Wateree-Summerville 230kV line at St George 230kV
8. Upgrade the St George to Summerville 230kV line to B1272
9. Upgrade Saluda-Georgia Pacific 115kV Double Circuit line to 1272
10. Install a 230kV Series Reactor (25% on a 500 MVA base) on the VC Summer #1-Newport (Duke) 230kV line

Replace overstressed breakers

11. Three (3) 230kV breakers
12. Eight (8) 115kV breakers

In the future, SCE&G Transmission Planning will periodically review the results of this Interconnection Facilities Study to determine if the recommended transmission expansion and the associated cost estimates remain valid.

I. Generator Information

The generator design consists of a single nuclear unit and one step-up transformer. The generator unit will have a maximum gross MVA output capacity of 1,375 MVA and a maximum continuous net MW of 1,165 MW.

The generator design consists of the following information:

MVA – gross:	1375
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Power Factor:	between .90 and 1.05
Voltage:	22kV
Speed:	1800 rpm
X'd-sat.: 0.465 PU;	X''d-sat.: 0.325 PU
X2-sat.: 0.320 PU;	X0: 0.237 PU

II. Cost Estimates of Transmission Provider's Interconnection Facilities and Network Upgrades and Completion Dates

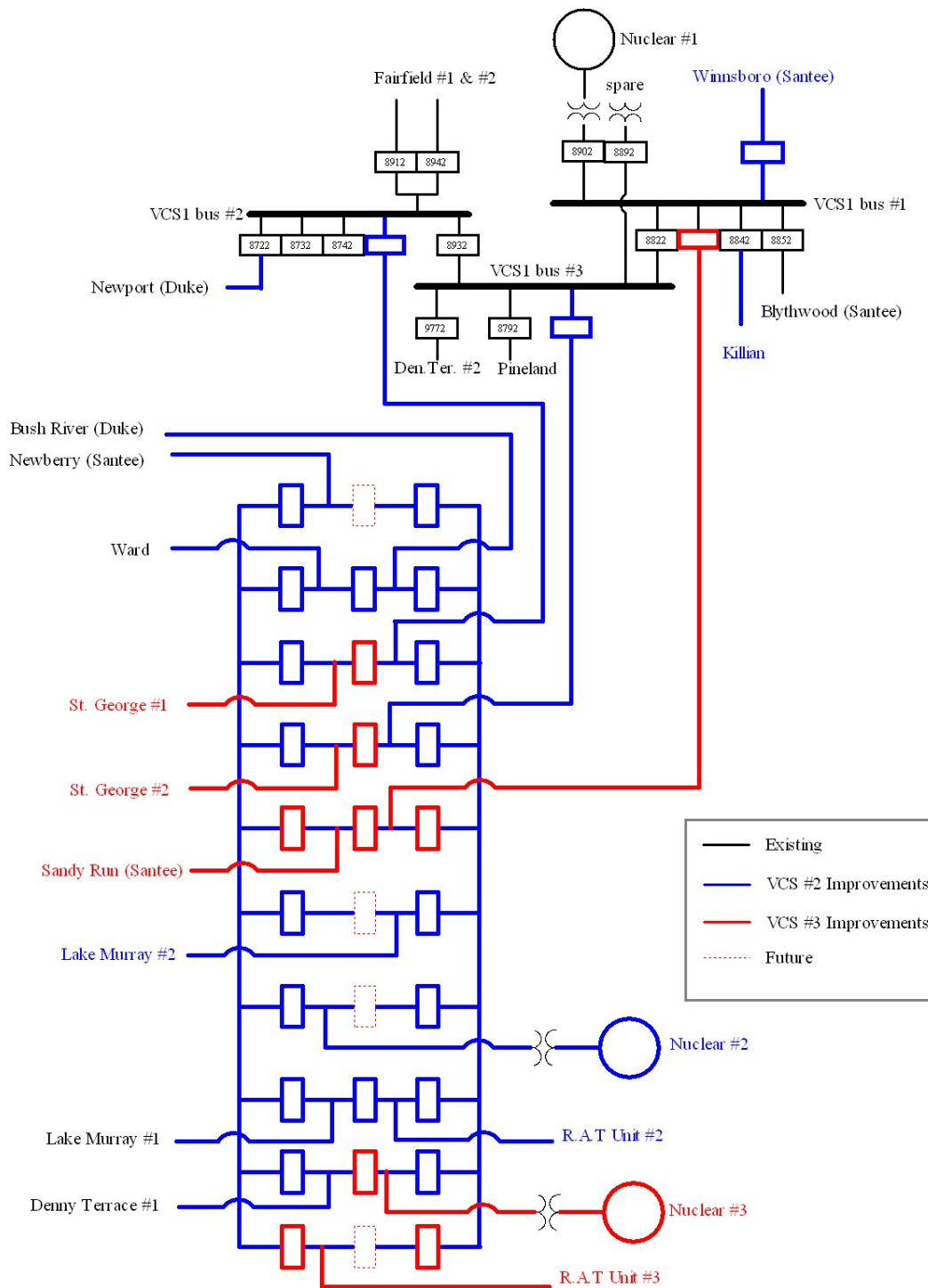
The Table below includes the cost estimate for the required Transmission Provider Interconnection Facilities, the required Network Upgrades and the estimated completion date for each of these required projects.

VC Summer Unit #3 Transmission Cost Estimates
Escalated at 4% per year from 2008

Project Name	Schedule d End Date	Budget 2008	Budget 2009	Budget 2010	Budget 2011	Budget 2012	Budget 2013	Budget 2014	Budget 2015	Budget 2016	Budget 2017	Budget 2018	Totals	
230KV Switchyard Additions for Unit #3 - Add six (6) 230kV terminals (8 breakers) at VC Summer New using breaker-and-a-half design	12/1/2018									700,000	6,400,000	11,800,000	18,900,000	
VCS #2 to St. George 230kV - Construct b1272 line (135 miles)	12/1/2018								500,000	1,500,000	100,000,000	144,320,000	246,320,000	
Summer Unit #3-230KV Tie to Bus #1 – Construct (Assume 0.75 mile)	12/1/2018											960,000	960,000	
VCS #1, Bus #1: Add Term to VCS #2 Sub	12/1/2018											1,760,000	1,760,000	
VC Summer Unit #3 to #2 Sub 230kV Line: Const	12/1/2018											600,000	600,000	
VC Summer RAT #3 to #2 Sub 230kV Line: Constr	12/1/2018											600,000	600,000	
St. George 230kV Switching Station: Const Brkr ½	12/1/2018									240,000	8,000,000	10,000,000	18,240,000	
Canadys - Santee 230kV: Fold In to St. George 230kV	12/1/2018											1,760,000	1,760,000	
Canadys - St. George 230kV: Upgrade to B1272	12/1/2018									680,000	4,000,000	7,000,000	11,680,000	
Wateree - Sum'ville 230kV: Fold In to St. George 230kV	12/1/2018											1,760,000	1,760,000	
St. George - Sum'ville 230kV: Upgrade to B1272	12/1/2018									480,000	8,000,000	16,000,000	24,480,000	
Sal Hydro - Ga Pac 115kV Double Ckt: Upgd to 1272	12/1/2018									100,000	8,000,000	11,000,000	19,100,000	
VCS #1 Sub: Add 230kV Series Reactor in Newport Duke Line	12/1/2018										1,100,000	5,000,000	6,100,000	
Various 230KV PRCB Upgrade Interrupter Rating (Assume 3 PRCBs)	12/1/2018											1,056,000	1,056,000	
Various 115KV PRCB Upgrade Interrupter Rating (Assume 8 PRCBs)	12/1/2018											1,920,000	1,920,000	
		0	0	0	0	0	0	0	0	500,000	3,700,000	135,500,000	215,536,000	355,236,000

III. Facilities Classifications

The Facilities Study report must identify and estimate the cost of any Transmission Provider's Interconnection Facilities and Network Upgrades necessary to accomplish the interconnection. The diagram below includes color coded indications of which facilities fall into the classification of Network Upgrades, Transmission Provider's Interconnection Facilities or Interconnection Customer's Interconnection Facilities. Cost estimates for all Network Upgrades and Transmission Provider's Interconnection Facilities are included in Section II of this report.



V. Facilities Diagram with VC Summer #2 and VC Summer #3

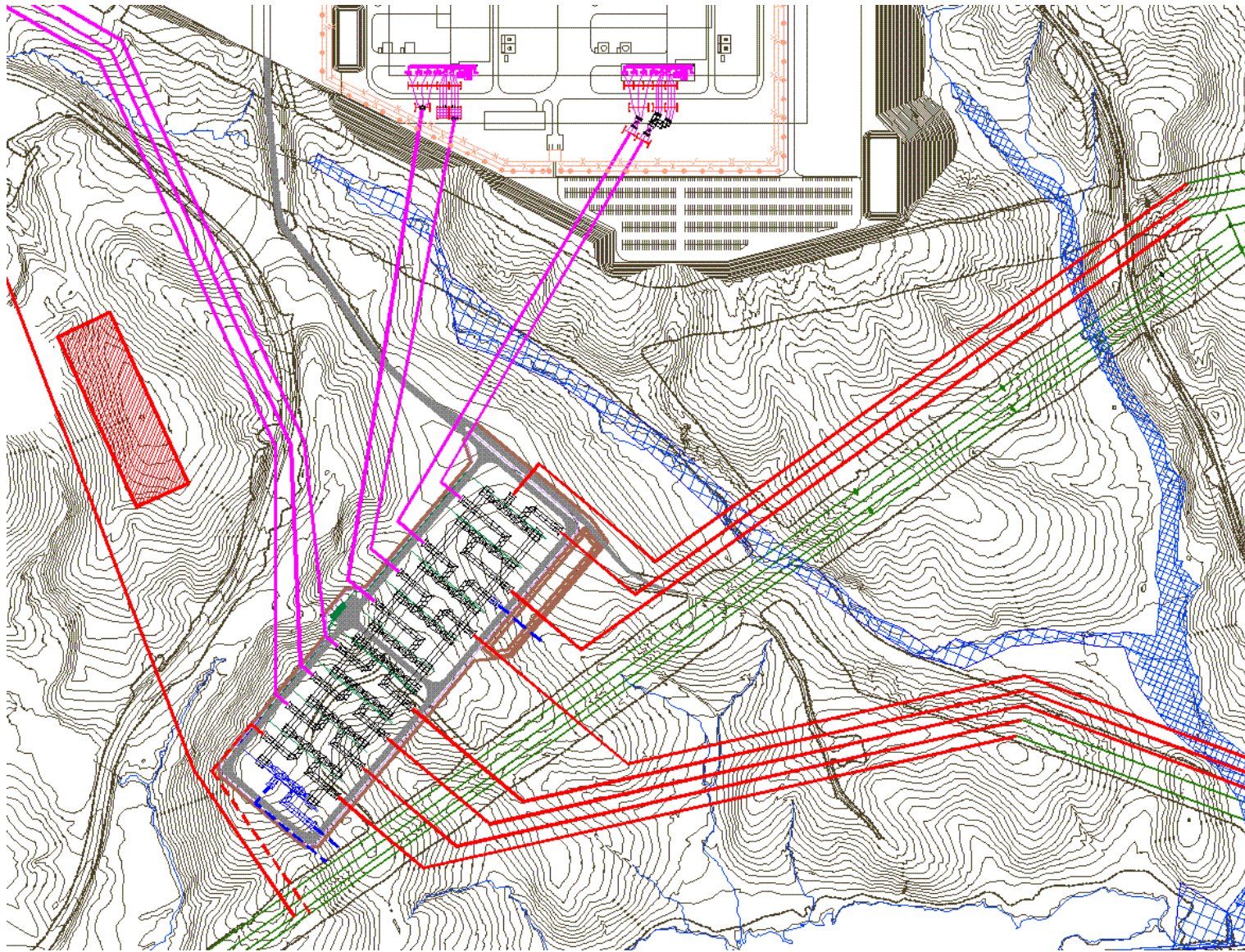


EXHIBIT R

PUBLIC NOTICE

**Combined Application of South Carolina Electric & Gas Company for a
Certificate of Environmental Compatibility and Public Convenience and
Necessity and for a Base Load Review Order
Public Service Commission Docket No. 2008-196-E**

1. INTRODUCTION

This **Exhibit R** provides the Public Notice of filing and hearing of the Combined Application for Certificate of Environmental Compatibility and Public Convenience and Necessity and for a Base Load Review Order with the Public Service Commission of South Carolina.

PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

DOCKETING DEPARTMENT

NOTICE OF FILING AND HEARING

DOCKET NO. 2008-196-E

SOUTH CAROLINA ELECTRIC & GAS COMPANY – COMBINED APPLICATION FOR CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY AND PUBLIC CONVENIENCE AND NECESSITY AND FOR A BASE LOAD REVIEW ORDER

On May 30, 2008, South Carolina Electric & Gas Company (“SCE&G” or “Company”) filed an Application with the Public Service Commission of South Carolina (“Commission”) requesting that the Commission issue a Certificate of Environmental Compatibility and Public Convenience and Necessity and for a Base Load Review Order authorizing SCE&G to construct and operate two (2), 1,117 net megawatt nuclear facilities to be located at the Virgil C. Summer Nuclear Station site (“Summer Station”) near Jenkinsville, South Carolina. The Application was filed pursuant to the provisions of the Utility Facility Siting and Environmental Protection Act, S.C. Code Ann. §§ 58-33-10 *et seq.* (1976, as amended); the Base Load Review Act, S.C. Code Ann. §§ 58-33-210 *et seq.* (1976, as amended); and the Commission’s Rules of Practice and Procedure, 26 S.C. Code Ann. Regs. 103-823 (1976, as amended).

SCE&G states in the Application that in order to meet the growing demands and needs of its customers for electric power, to support the continued economic development and prosperity of the State of South Carolina, and to maintain the reliability of its electric system, the Company plans to construct two nuclear generating units, namely, AP1000 Advanced Passive Safety Power Plants (“AP1000”), located near Jenkinsville, South Carolina and approximately one (1) mile from Summer Station Unit 1. The AP1000 units, identified in the Application as Unit 2 and Unit 3, and associated facilities will be jointly owned by SCE&G and the South Carolina Public Service Authority. According to the Application, the AP1000 represents an advanced nuclear generating design that has been approved and certified by the United States Nuclear Regulatory Commission. Moreover, the Company states that the AP1000 units and associated facilities will be constructed by a consortium consisting of Westinghouse Electric Company, LLC and Stone & Webster, Inc. SCE&G anticipates that AP1000 Unit 2 and Unit 3 will become operational in 2016 and 2019, respectively.

SCE&G further requests in its Application authorization to revise its current schedules of electric rates and charges to add the incremental revenue requirements related to the Company’s investment in the nuclear generating facilities described above during construction. The Company requests that the proposed increases be effective March 2009. The proposed average increase to the residential class is 0.52%; small general service class is 0.48%; medium general service class is 0.51%; and large general service class is 0.44%. Amount and percentage increases vary by rate schedules within these classes, and individual customer bill increases may also vary depending upon actual usage patterns and amount of consumption.

A copy of the Company’s Application may be obtained from the Commission at the following address: Public Service Commission of South Carolina, Docketing Department, 101 Executive Center Drive, Columbia, South Carolina 29210. Additionally, the Application is available on the Commission’s website at www.psc.sc.gov and is available from the corporate office of South Carolina Electric & Gas Company at 1426 Main Street, Columbia, South Carolina, 29201.

South Carolina Electric & Gas Company

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In order to receive testimony and evidence from all interested parties, a public hearing will be held in the Commission's Hearing Room, Synergy Business Park, 101 Executive Center Drive, Columbia, South Carolina beginning on _____, _____, 2008, commencing at 10:30 a.m.

Any person who wishes to participate in this matter, as a party of record with the right of cross-examination should file a Petition to Intervene in accordance with the Commission's Rules of Practice and Procedure on or before _____, 2008, and indicate the amount of time required for his presentation. Please include an email address for receipt of future Commission correspondence in the Petition to Intervene. *Please refer to Docket No. 2008-196-E.*

Any person who wishes to testify and present evidence at the hearing should notify the Docketing Department, in writing, at the address below, the South Carolina Office of Regulatory Staff at Post Office Box 11263, Columbia, South Carolina 29211, and K. Chad Burgess, Senior Counsel, South Carolina Electric & Gas Company, 1426 Main Street, Mail Code 130, Columbia, South Carolina 29201, on or before _____, 2008, and indicate the amount of time required for his presentation. *Please refer to Docket No. 2008-196-E.*

Any person who wishes to be notified of the hearing, but does not wish to present testimony or be a party of record, may do so by notifying the Docketing Department, in writing, at the address below on or before _____, 2008. *Please refer to Docket No. 2008-196-E.*

PLEASE TAKE NOTICE: Any person who wishes to have his or her comments considered as part of the official record of this proceeding **MUST** present such comments, in person, to the Commission during the hearing.

Persons seeking information about the Commission's Procedures should contact the Commission in Columbia at 803-896-5100.

Public Service Commission of South Carolina
Attn: Docketing Department
Post Office Drawer 11649
Columbia, SC 29211

5-30-08